NAVIGANT

Unconventional Gas

The potential impact on UK Gas Prices

Prepared for:
Department of Energy and Climate Change

Navigant Consulting (Europe) Ltd
25 Basinghall Street
London
EC2V 5HA
020 7469 1111

Authored by:
Paul Rathbone
Richard Bass

www.navigant.com

This document is confidential and proprietary in its entirety.
© 2012 Navigant Consulting (Europe) Ltd.

We would like to thank the following colleagues for their contributions and support to the preparation of this document:

Ed Osterwald
Gordon Pickering
Rick Smead
Genevieve Stawski
Rowan Watson
Ian Shrubb

NAVIGANT

Contents

NAVIGANT

Definitions

bcm	billion cubic metres
BGR	Bundesanstalt für Geowissenschaft und Rohstoffe
BGS	British Geological Survey
BTU	British thermal units
CBM	coal bed methane
EC JRC	Joint Research Council of the European Commission
EIA	US Energy Information Administration
ERR	economically recoverable resources
EUR	estimated ultimate recovery
FERC	Federal Energy Regulatory Commission
GIIP/GIP	gas (initially) in place
IEA	International Energy Agency
LNG	liquefied natural gas (mainly methane)
LPG	liquefied petroleum gas (mainly propane and/or butane)
mmBTU	million British thermal units
NBP	National Balancing Point
NGL	natural gas liquids
OECD	Organisation for Economic Co-operation and Development
OGIP	original gas in place
OIES	Oxford Institute for Energy Studies
tcm	trillion cubic metres
TRR	technically recoverable resources
URR	ultimately recoverable resources
WEC	World Energy Council

1. Executive Summary

The world has very significant amounts of unconventional gas resources. These have been known about for a long time. Victorian coal miners knew all about the methane contained in the coal seams and carried canaries to warn them of it. Shales, as well as holding significant gas (and oil) resources, are the source rock for the conventional reservoirs that provide most of our current gas production. “Tight gas” is simply gas in sandstone that has poor flow so is not accessible by the “conventional” means. What has changed is that we now have the technology to extract such gas in a cost effective manner.

Estimating the total gas in place in these coal beds, sandstones and shales around the world is a very imprecise science. Generally geologists have approached such estimates by taking broad views of the likely volume of rock and indicative hydrocarbon content. But to a certain extent trying to make detailed estimates of such resources is unnecessary. There is a lot of it. Dr Hans-Holger Rogner, author of one of the most quoted reports on the subject, estimates total gas in place globally of 870 tcm and others have subsequently more than doubled some of his regional estimates. Current global demand for gas is 3.4 tcm each year, so there is plenty of gas still to be extracted if we need it. In the context of what impact unconventional gas might have on UK gas prices over the next 20 years, the more relevant question is how much gas might be recoverable from these rocks in that timeframe and where can that be done in a cost effective manner.

The three regions where one can reasonably confidently predict significant production of unconventional gas in the next two decades are North America, China and Australia.

The US started producing tight gas in significant quantities in the 1940s, followed by coal bed methane (CBM) in the 1980s. It is now producing shale gas in ever increasing quantities. So there is no doubt that, in the right circumstances, large quantities of gas can be extracted from unconventional sources. Most commentators expect the volumes of US gas produced to continue to increase, whilst at the same time keeping down the gas price in the US. Production of unconventional gas in the US could reasonably reach 550bcm/year by 2030. Canada is also well resourced with shale gas and production is expected to climb significantly in the next 10 years, reaching over 100 bcm/year by 2030.

China has large resources of both shale gas and CBM and has recently started to develop its shale gas resources. Although there is some scepticism about whether it will meet its 12th 5-Year Plan targets for 6.5 bcm/year by 2015, it is expected to be producing more than 60 bcm/year by 2020 and perhaps over 200 bcm/year by 2030. China’s main constraint is lack of water in some of the main shale basins. But its record of delivering large capital projects cheaply gives confidence that these impediments will be resolved.

Australia has significant CBM and shale resources and is actively developing the CBM. Three LNG plants exporting 28 bcm of CBM each year are in development and will be running by 2016. In addition, development has already started on shale gas production in the Cooper Basin. Australian production of unconventional gas is expected to be in the order of 100 bcm/year by 2030, assuming that buyers can be found for the gas (or more specifically LNG exports).

Continental Europe’s unconventional gas resources are also thought to be substantial, but the social issues surrounding extraction of unconventional gas in densely populated areas, with considerable public antipathy to the industry, makes the barriers much higher. In addition, the supply chain to drill and stimulate the huge number of wells required to produce meaningful quantities of gas does not exist at present. Current projections from the IEA and EIA vary between 20 to 65 bcm/year by 2030, or 3-10% of demand. However, in the right set of circumstances this could be improved upon further given the estimated gas resources available.

The UK faces similar issues to the rest of continental Europe. There are certainly at least two promising shale plays and plenty of CBM opportunities. However public concern is substantial and the commercial case for gas production is marginal at current costs and gas prices. The general consensus is that exploration will continue, but major development will either need a belief that the unit cost can be brought down quickly, as in the US, or the promise of natural gas liquids to increase returns.

There are five key sensitivities in looking at the prospects for unconventional gas production and the potential impact on UK gas prices:

1. the rate at which the gas estimated to be in place will be recoverable – this is a factor of both geology and the application of technology;
2. development of the unconventional gas supply chain, particularly drilling and stimulation, in areas outside North America, so that production costs fall towards US levels;
3. how Chinese energy supply and demand evolves in the future and in particular whether China will try to minimise its price of energy (to compete with the US) or prioritise energy consumption;
4. "political" barriers to exploration and development, particularly through public opposition but also fiscal policies and over-burdensome environmental regulations; and
5. climate change policies and in particular how gas prices evolve when carbon taxes or similar policies start to reduce gas demand.

There is a sixth major sensitivity to UK gas prices which is unrelated to unconventional gas production and that is the oil price. If oil prices go down, then so will the price of long term gas supplies linked to the oil price. This will in turn have a beneficial effect on UK gas prices but potentially decrease the incentive for production of unconventional resources.

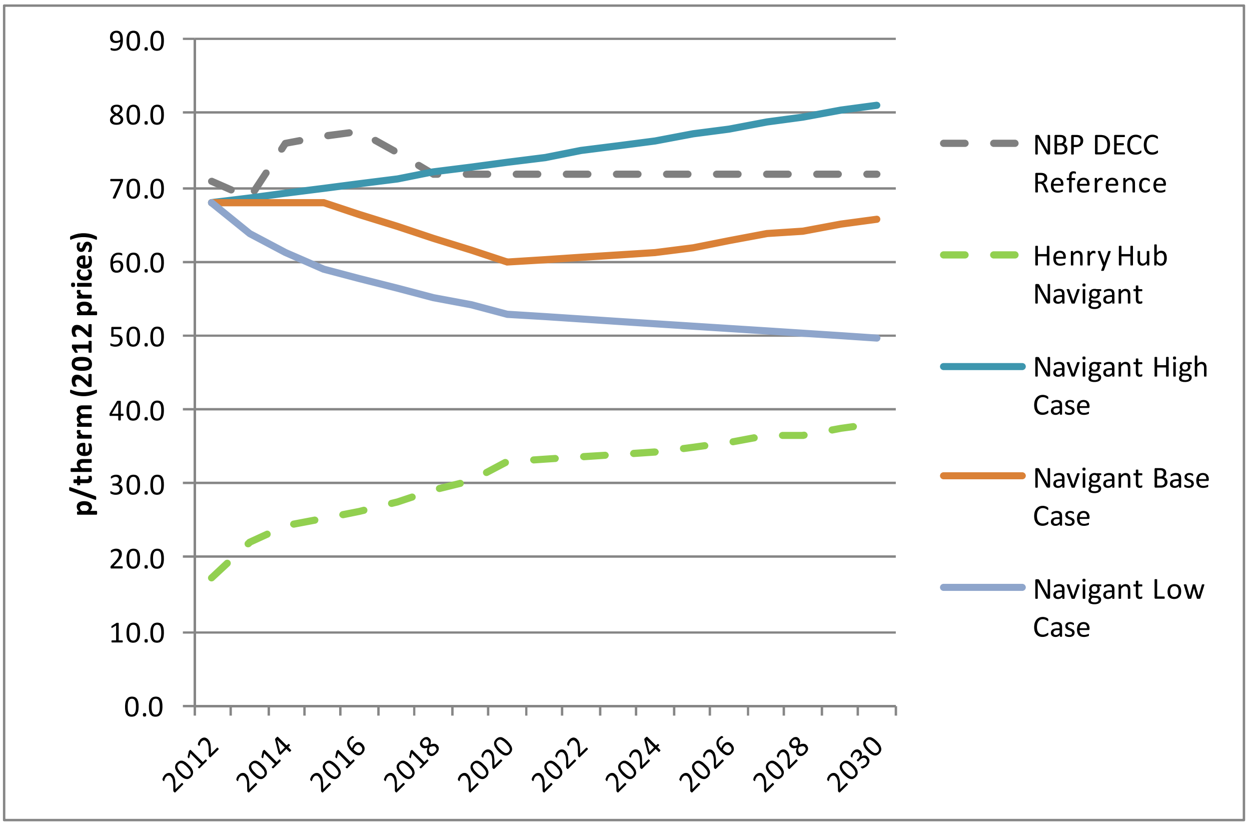
Understanding the potential impact on the UK of global unconventional gas production needs an understanding of global LNG trade patterns and how they might impact UK and European gas pricing. Any reduction in gas price will require some significant disruption to the current supply balance, which is being kept above long run marginal cost by long term supply contracts linked to the oil price and the market power of the major pipeline and LNG importers who own those contracts.

We believe that if the US exports LNG in large quantities these are likely to act as a price support on UK prices – they won't reduce prices down to US levels, but the imports may well be sufficiently disruptive that prices could decrease by 10-20% (in real terms) as long as the US prices stay low, as currently predicted. The first US exports, from Sabine Pass, will come into the market during 2016, and most US observers expect at least 2 or 3 more LNG facilities to be up and running in the couple of years thereafter, so by 2018 UK prices could have moved to a "Henry Hub + transportation" basis. For UK gas prices to fall further, one would either need a fall in the oil price, or substantial new supplies of gas to the UK and/or Europe, which could be realised if significant investment is made in unconventional gas production.

Given the high degree of uncertainty surrounding any price forecast, particularly where one is making predictions of policy decisions in several different countries, we have approached the question of price impact by looking at three scenarios. Our low price scenario is a picture of how gas prices could fall significantly in the UK from their current levels, if a number of different things happen. Our high price case is similarly a picture of how, in a different set of circumstances, the price could continue to rise from current levels. Our base case is a set of circumstances that produce a "middle" result between low and high. We regard each of these circumstances as being quite believable, although we attach no firm probabilities to each.

Our base case price projection thus envisages continuing growth of unconventional gas production in the US, some of which will be exported. It also assumes significant unconventional gas production in China, so that Chinese LNG import prices are moderated and the Asian LNG arbitrage gap is not as large as it is now. We also assume that oil prices will fall somewhat from their current level, following the current forward curve down to around $90 in 2019. However, our base case assumes that European unconventional gas production is limited in the next twenty years. As a result we would expect UK gas prices to fall slightly in the near future, following the oil price, and then to be supported by US LNG imports as they come on line from 2016 onwards. This predicts prices falling to around 60p/therm in 2020, and then moving upwards in line with expected trends in the US gas prices.

Figure 1: Gas Price Scenarios



Our low price case scenario assumes the same for the US and China, but also assumes significant unconventional gas production (perhaps 100 bcm/year) in the UK and continental Europe in the second decade (2020-2030). In this scenario, a combination of local gas with falling production costs (as the supply chain develops) and readily available LNG puts sufficient pressure on oil price indexed gas supplies that gas prices fall towards the long run marginal cost, getting to 50p/therm by 2030 and potentially moving downwards after that if cost efficiencies continue, down to somewhere between perhaps 35p and 50p/therm (in 2012 prices).

Our high price case either has US gas production declining before current expectations, or perhaps more readily imaginable a political limitation on large scale LNG exports. In addition, we assume that China is willing to pay more for its imported gas (either because unconventional production has not lived up to expectations, demand has outstripped supply or because China wishes to address environmental concerns and favours imported gas over domestic coal) and that little unconventional gas is produced in Europe. In this case it is highly likely that the oil price link will continue to be the largest influencer on UK gas prices and that the price is likely to go up inexorably as Asian demand for oil keeps rising. We have assumed in this scenario that the oil price increases by 1% above inflation for the foreseeable future, in line with several other "high oil price" forecasts.

Our three scenarios give a wide range of potential gas prices by 2030, between 50p and 80p per therm at 2012 prices. In one of our scenarios we predict a fall in prices from current levels quite soon, although this reflects our view that, as predicted by forward markets, the oil price (particularly Brent) is likely to fall somewhat from current levels. In the second half of the period under review, the main factor determining the gas price in our view will be the extent to which US LNG exports and indigenous European unconventional gas production are able to disrupt the current oil price indexed European gas markets.

Table 1: Unconventional Gas Key Statistics

Resources (in trillion cubic metres)		**Minimum**	**Maximum**
Total Gas in Place, Globally		870	1,185
Technically Recoverable Unconventional Gas		129	342
Technically Recoverable Conventional Gas		208[1]	462[2]
Current Global Consumption		3.4	3.4
Global Consumption by 2035		3.6	4.8
Production of Unconventional Gas (in percentage of global gas production)		**Minimum**	**Maximum**
Currently		13%	14%
In 2020		17%	20%
In 2030		23%	25%
UK Gas Price Scenarios (in 2012 pence/therm)	**Low**	**Medium**	**High**
2015	59.0	67.8	69.9
2020	52.8	59.8	73.4
2025	51.3	62.0	77.2
2030	49.7	65.7	81.1

[1] BP Statistical Review of World Energy - 2011 proven reserves only

[2] IEA World Energy Outlook 2012

2. Introduction

2.1 *Scope*

The rapid rise in volumes of natural gas produced by "unconventional" means in the US over recent years has completely changed the outlook for North American energy markets and through displacement of LNG exports originally destined for the US, the "shale gas revolution" is now having a clear effect on energy markets globally.

DECC has commissioned a study to understand the potential of unconventional gas resources globally and specifically the impact these gas supplies may have on UK gas prices over the next twenty years. For the purposes of this report unconventional gas includes tight gas fields, coal bed methane and shale gas. DECC has asked us to address six specific questions:

- How are unconventional gas resources distributed globally?
- What are the prospects for (i) European and (ii) global (split by region) unconventional gas over the next 20 years?
- What are the key sensitivities associated with this view?
- Where there are significant prospects in countries that might supply the UK, what are the barriers to investment / production / exports?
- To what extent will growth in unconventional gas production lead to increases in gas demand, e.g. due to countries switching to more gas use in electricity generation?
- What will be the impact on UK prices?

The scope of this study is based on a review of existing literature and public data on the subject matter, combined with the results of interviews with a number of stakeholders and experts with knowledge of the key areas involved. A list of interviewees and a summary of their main responses are set out at Appendix B.

2.2 *Units*

One of the potentially confusing aspects of the various reports on gas production and markets is the number of different units used, both volumetric and thermal (energy). We have generally used cubic meters (cm) of natural gas in this report, scaled up to billion cubic meters (bcm) and trillion cubic metres (tcm) where appropriate. This is the unit of measurement used by most European commentators. US sources usually use Standard Cubic Feet (SCF), scaled up to MMCF (million or 10^6 standard cubic feet), BCF (billion or 10^9 standard cubic feet) and TCF (trillion or 10^{12} standard cubic feet). This is a common metric used in the oil & gas industry, based on a cubic foot of gas at 60 degrees Fahrenheit and one atmosphere pressure.

The energy content of one m^3 of natural gas varies depending on the precise composition and qualities of the gas. Gas passing through the UK's National Grid mainland pipeline system has a calorific value of 37.5 MJ/m^3 to 43.0 MJ/m^3, which is equivalent to 35,598 to 40,824 British thermal units (btu). For purposes of this report we will take one m^3 natural gas to be equivalent to 37,928 BTU (equivalent to 1,074 btu/SCF). The normal UK pricing unit for natural gas is a therm, which is equivalent to 100,000 BTU.

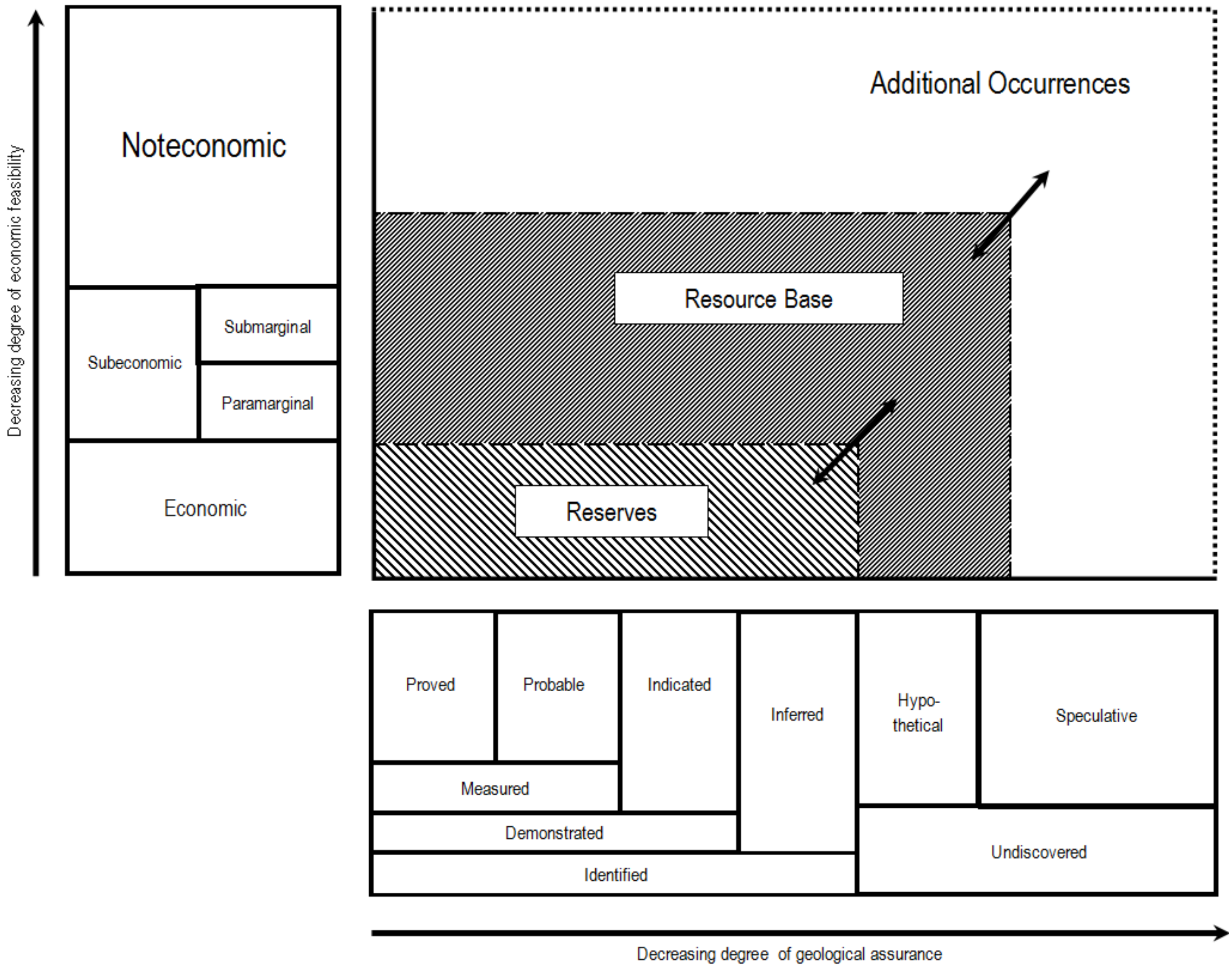
1 bcm = 35.32 BCF = 37.9x10^6 MMBTU = 379 million therms = 0.0375 EJ (Exajoules = 10^{18} Joules) = 0.96 million tonnes of oil equivalent (MMTOE)

2.3 Definitions

Adding to the complexity in understanding resource estimates is the geological terminology for different measures of resource level. Terms such as "original gas in place" (OGIP) or "gas (initially) in place" (GIIP/GIP) refer to the total volume of gas contained within the rock in question. This cannot all be extracted, so one has to apply a recovery factor to the total amount to get to an estimate of how much gas might actually be extractable from that formation. The "technically recoverable resources" (TRR) is an estimate of how much gas can be extracted using current technology. "Ultimately recoverable resources" (URR) or "Estimated Ultimate recovery" (EUR) is an estimate of what might be extractable using current and future technology. Neither TRR nor URR take account of what is cost effective to extract – the "economically recoverable resources" (ERR) estimate does that, limiting the extractable volumes to those which can be extracted profitably. Finally, reserve estimates are made where drilling wells have proven that gas is there, can be produced and delivered to a market profitably. Terms such as 1P, 2P and 3P refer to the proven, probable and possible reserves that might be produced from a given well or set of wells once drilling has confirmed both the presence of hydrocarbons and the flow rates and there are defined development plans.

All of these estimates are subject to uncertainty, with resource estimates being much more uncertain than reserve estimates. In Rogner's study he sets out a modified "McKelvey box" showing how the different levels of reserve and resource estimate relate to degrees of geological certainty and economic feasibility.

Figure 2: Rogner's McKelvey box



2.4 *Sources*

We have reviewed over 50 papers, reports and articles in preparing this report. The most comprehensive reports into unconventional gas include the following:

- The European Commission's Joint Research Council's (EC JRC) "Unconventional Gas: Potential Energy Market Impacts in the European Union" in October 2012
- The US Energy Information Administration's (EIA) "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States" based on work commissioned from Advanced Resources International (ARI)
- The EIA's annual International Energy Outlook reports
- The International Energy Agency's (IEA) annual World Energy Outlook reports and the special edition on unconventional gas called "Golden Rules for a Golden Age of Gas"
- Dr Hans-Holger Rogner's paper "An Assessment of World Hydrocarbon Resources" in 1997 which estimated conventional and unconventional resources worldwide and is still used as a reference by many commentators

- The World Energy Council's report "Survey of Energy Resources: Focus on Shale Gas" published in 2010 and the update "Survey of Energy Resources: Shale Gas – What's New" published in 2012
- Pöyry Consulting's report for Ofgem, "The Impact of Unconventional Gas on Europe"
- Florence Gény of the Oxford Institute of Energy Studies' report "Can Unconventional Gas be a Game Changer in European Gas Markets?"

Some of these reports, particularly the EC JRC report, refer widely to other reports on more specific aspects. A full list of references is set out at Appendix A.

In order to ensure that we have an up to date view of this fast moving sector and to gather input from stakeholders who do not always put their views into writing, we have also carried out some 29 interviews with stakeholders in industry, commerce, academia and other areas and received two written responses. The results of these interviews have been used to add further commentary and data points to the analysis of the various reports. A list of interviewees and a general summary of the responses is provided at Appendix B.

3. Resources

3.1 Background

In the last several years there has been a plethora of reports and articles on unconventional gas resources. A reasonably comprehensive list up to early 2012 is published in the EC JRC Report[3] and there have been a few more since then, including an update to the World Energy Council report and the IEA's World Outlook 2012 report. In this section we review the reports that deal with global resources together with a selection of the others and distil the key contents into a summary of resources.

3.2 Different Types of Unconventional Gas

We have been asked to cover three types of unconventional gas resource: tight gas, shale gas and coal bed methane (CBM). Other forms of unconventional gas exist, particularly methane hydrates, but most industry experts agree that we are unlikely to see commercial production of these other resources in the next twenty years.

There are a number of different definitions of the three types of unconventional gas covered by this report. We have used the American Association of Petroleum Geologists (AAPG) Energy Minerals Division's definitions, slightly amended for clarity.

The term "tight gas" sands refers to low permeability sandstone reservoirs that produce primarily dry natural gas. A tight gas reservoir is one that cannot be produced at economic flow rates or recover economic volumes of gas unless the well is stimulated by a large hydraulic fracture treatment and/or produced using horizontal wellbores (Holditch, 2006).

"Gas shales" are thought of dually as hydrocarbon source rocks and fine-grained tight reservoirs. Economic gas-shale plays include both a hydrocarbon source rock for the source of methane (thermogenic and/or biogenic) and a brittle lithology that contains natural and induced fractures that provide permeability to access the gas-storage sites. Lacking either a source of methane or permeability will result in an uneconomic gas shale.

Coal is both the source rock and the reservoir for CBM. As organic material (peat) is buried, temperature and pressure increase, and methane, water, and other volatile substances are liberated. As these fluids are released, the coally matter contracts and fractures in a distinctive manner. The fractures align themselves according to the existing stress fields in the earth. These fractures are called cleats and they provide permeability pathways through which the fluids may pass. Some gas may escape the coal. However, if formation pressure is sufficient, quantities of methane are retained in the pressurised coal matrix in an adsorbed state. To produce the methane, wells are drilled into the coal and pressure is reduced by removing formation water. Pumps are generally required to dewater the formation. This allows methane to desorb and pass into its gaseous state, so that it may be produced in the conventional manner and delivered into a pipeline. It is usually necessary to compress the gas before it may be put into the collection system.

[3] Appendix F, Table F-1, page XXV

3.3 Geology

Much of the literature on unconventional gas resources (and especially shale gas) refers to the presence of "sedimentary basins." It is important for readers to understand the geologic processes that created both these sedimentary basins and the constituent sedimentary formations they contain, if they are to fully appreciate why there is so much uncertainty amongst estimates of unconventional resources (either gas or oil).

Most shale formations are composed of combinations of organic matter, minerals and rock fragments that were deposited by the forces of erosion in fluvial or marine environments, originally forming the "sediment" at the bottom of large lakes or seas. The major basins contain sequences of sedimentary rock that can be thousands of feet in thickness. Different rock units ("formations") resulted from changes in the deposits being made over time. Any shift in rock type signifies an alteration in source of erosional material, water velocity, continental movement etc.

The geologic processes that drive basin formation have only become clear relatively recently (e.g. since the latter half of the 20th Century), as geoscientists learned to apply the principles of plate tectonics to the deformation of the Earth's crust. Geological interactions at plate boundaries and zones of fault activity or regional subsidence have created most large sedimentary basins.

It is important to note that a major component of all shale formations is clay minerals (termed "phyllosilicates"). Phyllosilicates are small, flat silicon-based minerals created by the degradation of other minerals in the presence of water. Because of their small size and flat shape, phyllosilicates are easily transported in water, typically much greater distances than larger minerals and fragments that form sandstones and conglomerates. The latter group are larger and heavier and require higher water velocity to transport. Thus clay minerals are major constituents of sedimentary basins but were usually the last to be deposited.

As subsidence in a basin continued, older layers became progressively deeper in the Earth, where temperatures and pressures were inevitably higher. Typically these formations were formed where oxygen content was low, i.e. an anaerobic environment. In such conditions organic material could not be oxidised and was preserved and eventually converted into oil and gas through the influence of heat and pressure over millions of years.

Since these hydrocarbons are less dense than the surrounding rock and entrapped water, they naturally migrated upward, provided that the porosity and permeability of the surrounding rocks was sufficiently high for this process to happen. If so, traditional oil and gas reserves accumulated whenever a suitable structural or stratigraphic trap was reached.

However, what are currently described as "unconventional" resources are different. In the case of shale gas, although also derived from organic material, the porosity and permeability of surrounding rock is low, so migration of the hydrocarbons was not possible. Oil and gas held within these shales can only be extracted when permeability is "manufactured" through hydraulic fracturing of the surrounding material.

This is why estimating the extractable quantities of any unconventional hydrocarbon is difficult, since it depends on projecting the impact of enhancing porosity and permeability through the use of hydraulic fracturing technology and the hydrocarbon content of the rock over very large areas. Each formation is different, because it resulted from a myriad of geologic factors that evolved over millions of years. Hence it is not surprising that estimates of reserves outside North America based on geologic analogy to the United States are prone to error.

Perhaps more importantly, this also means that unconventional shale gas resources are far more pervasive because their presence is not dependent on a combination of source rock, migration to and accumulation in a geological trap. Instead, what is required are rock layers with high organic content and not too much clay (so that the shale is brittle enough to be fractured), that can be stimulated through hydraulic fracturing and other processes to extract the constituent hydrocarbons. These areas are commonly known as "sweet spots".

Tight gas is different because porosity and permeability of the rock is somewhat higher than a shale gas resource and because the gas has usually migrated from source rock underneath. The host rock for tight gas is more likely to be sandstone and / or limestone, and the constituent gas may be pervasive throughout the volume of rock into which it has permeated. Tight gas wells will likely not result in any commercial level of gas flow without stimulation by hydraulic fracturing or other techniques.

Coal and associated methane reserves are different again. Most of the world's coal formed when vast low-lying coastal forests were progressively buried within sedimentary basins. The anaerobic environment prevented oxidation and ultimately the organic material was converted into combustible coal containing methane.

Methane derived from coal differs significantly chemically and geologically from shale / tight gas because it is contained within the chemical matrix of the coal ("adsorbed") and is only released when exposed to lower pressure. Most coal bed methane is extracted by drilling horizontal wells through the coal seams and extracting any water that might be present, which then leads to the required pressure drop to release the gas. Stimulation through hydraulic fracturing is usually not required and indeed may be inappropriate in narrow coal bed seams that are often found close to the water table.

Water is a common theme in unconventional gas reservoirs. In the case of shale gas and tight gas, significant volumes of water need to be sourced for hydraulic fracturing activities; in the case of CBM however, significant volumes of produced water need to be disposed of.

3.4 Methodologies

There are two main approaches used in estimating unconventional gas resources: by analysis of geological parameters and by extrapolation of production experience. The EC JRC report looks into both in some detail. Ultimately, however, since the extrapolation approach only works where there is significant production experience, for the largest resource, shale gas, it is really only relevant to the US where such production experience exists. Thus all of the estimates of non-US shale gas use some form of analysis of the geological parameters, although sometimes these are then matched to the closest equivalent US shale and resources estimates based on these comparisons.

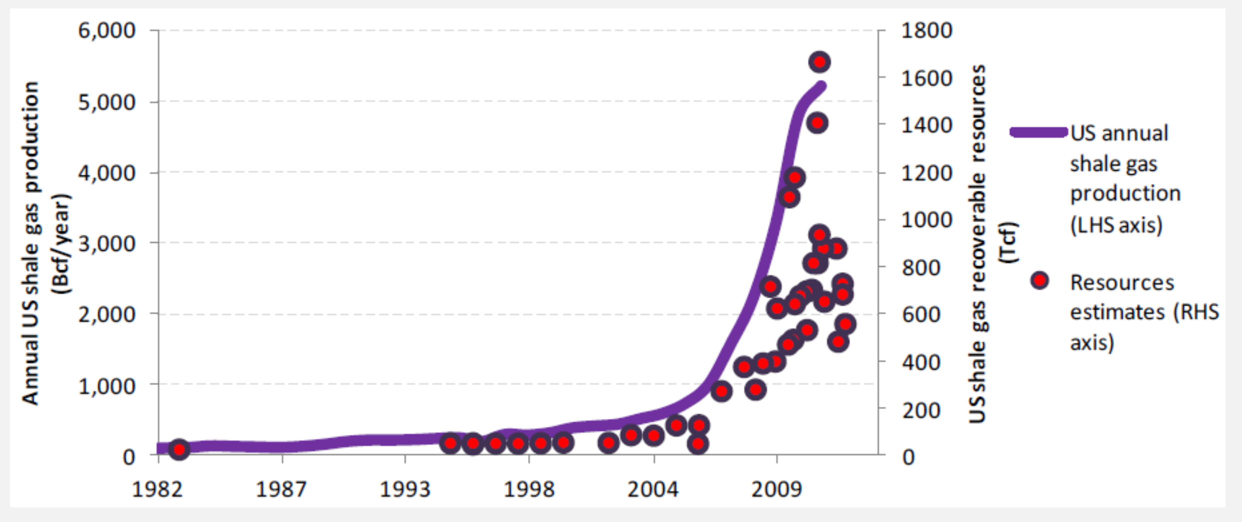
The prior assessments also vary considerably in the level of detail. The first major global estimate of unconventional resources, by Rogner in 1997, took data on relevant geological basins on a national or regional level and applied a gas content factor based on US experience. Other geological assessments have been made on a basin level, or by analysis of a specific formation within a basin. When one gets to a formation specific level, then one can start making qualitative judgements about which US precedent is most relevant and apply data specific to that particular US formation to the formation in question. However, even at this level the process is fraught with the potential for error.

Data on the precise nature of the formation is usually only available from analysis of rocks where that particular formation reaches the surface – it is a brave assumption to assume that the rock is homogenous throughout its extent. Even where drilling has occurred in the past, either for research projects or for conventional oil and gas exploration, old well logs are less reliable, the relevant data may not have been collected or well samples might now be lost.

Ultimately, the only way of telling whether a particular formation of rock has the potential for commercial gas extraction is to drill a number of exploratory and appraisal wells and test them for gas flow. Even here there is a considerable difference of opinion over how many wells are required to "prove" the resources and commerciality of an unconventional formation. We have been told by industry respondents that the first 60 wells drilled in the US Haynesville shale deposit were uneconomic and that it took 100 wells to demonstrate that flow rates could reach economic quantities over a wide area of the region. The UK exploration companies believe that investment will be forthcoming for development after only a few wells have found good gas flow, however how much drilling will have to be done to get to that stage remains to be seen. One quote we were given for CBM was that of 10 wells drilled, 2 would be good, 4 would be OK and 4 would be dry.

A good way of demonstrating how quickly recoverability estimates have changed as wells are drilled is to look at the relationship between shale gas production and shale gas resource estimates in the US, as set out in Figure 3 below.

Figure 3: Shale gas production and resource estimates by year, USA



Source: McGlade, Speirs and Sorrell, ICEPT Working Paper: Unconventional Gas – A Review of Estimates (2012)

3.5 Sources

A fact that becomes very evident after reading through the literature is how many of the non-US resource estimates lead back to Rogner's study done in 1997. One major oil company representative told us that he was still using Rogner's figures in presentations, since they were public data that were comfortably close to his own internal estimates. Another oil company upstream expert quoted to us, "the various reports are all trying to extrapolate from not very much". The fact is that, except for the US and Australia

(CBM only), very little drilling has taken place to allow geologists to improve estimates that are based on very high level analysis.

3.5.1 Rogner: An Assessment of World Hydrocarbon Resources (1997)

Rogner's report was written relatively early on in the climate change debate and sought to identify, at a high level, all sources of hydrocarbons in the world. It thus covers conventional as well as unconventional oil and gas. In the introduction he makes the point that, when looking at energy forecasts over many decades, one should seek to understand the full potential supply of the different energy sources even if they are uneconomic to exploit at current prices and technologies. Rogner sets out estimates of OGIP for eleven world regions, but does not make any estimates of how much might be recoverable. Several of the other reports on global unconventional gas resources simply take Rogner's OGIP estimates and apply a recovery factor (usually between 15% and 40%) to derive a figure for TRR.

3.5.2 EIA: World Shale Gas Resources (2011)

The only other substantive public study that takes an analytical approach to non-US resources is ARI's 2011 study into 32 individual countries worldwide commissioned by the US Energy Information Agency (EIA) and published in 2011. The report focuses on 14 regions and excludes Russia and the Middle East on the basis they already have significant quantities of conventional natural gas in place, reducing the likelihood of unconventional developments in the near future.

Rather than using existing literature, the analysis is drawn from a large amount of publically provided geological information, specific to each region, to which a methodology is then applied to calculate risked gas in place and technically recoverable gas. The authors accredit Rogner (1997) as the only study prior to their report that attempts to document global shale gas resource based on the analysis of geological data. Development and production costs are not considered with the EIA study.

Commenting on the EIA report (2011), however, the authors of the EC JRC report (below) note the huge increase in estimated shale gas TRR by the EIA from their previous reports, the basis for which is arguably unproven and suggest worldwide shale gas TRR results have been overestimated by the EIA in this report.

3.5.3 EC Joint Research Council (EC JRC): Unconventional Gas (2012)

The literature review undertaken in the EC JRC report confirms there is little consistency in estimated of global unconventional gas resources and what could be considered as technical recoverable gas reserves (TRR). In response, the authors took a systematic approach to analyzing a wide range of reports that considered shale gas, CBM and tight gas on a global basis.

Acknowledging the huge variations[4] in estimated shale gas resources for China, Europe and North America, the report establishes three data ranges to input into their model: lowest estimate, mean estimate and highest estimate. The full results are listed in Appendix C and are summarised in Table 2 below.

Conversely, just one tight bed gas and CBM resource figure is quoted by the EC JRC report for each region. Direct references are not supplied, but we can deduce that the country specific figures are drawn

[4] The report explains the use of Sandrea and Laherrere distort the shale gas results. We have not included either report in this review.

from a similar selection of reports including EIA/ARI (2011), Kuuskraa (2009), Mohr and Evans (2011), Rogner (1997) and the WEC Survey (2010), the sources of which are illustrated in Figure 4 below.

3.5.4 Kuuskraa: Worldwide Gas Shales and Unconventional Gas: A Status Report (2009)

This report, prepared by V. Kuuskraa of American Resources International Inc on behalf of the American Clean Skies Foundation and the Research Partnership for Secure Energy for America, is widely regarded by analysts in this field. Mohr and Evans draw on this research for their North America shale gas URR estimates, alongside Theal (2009), FERC (2010), Dawson (2010), Henning (2010) and Skipper (2010)[5].

Kuuskraa usefully provides regional data for CBM resources both in place and recoverable. The EU JRC report (2012) suggests this is based upon data taken from the IEA WEO report from 2009 and Rogner 1997. There is little mention of tight gas. More detail is given on shale gas, with an explicit focus on the Alum Shale in Sweden, Silurian Shales in Poland, Mikulov Shale in the Vienna Basin and the Mako Trough in Hungary in Europe. Beyond Australia, Canada and the US, however, regional or country specific results are not supplied. Kuuskraa is the principle author for ARI, the consultants commissioned for the 2011 EIA report, which is likely to have drawn upon the results of this study.

3.5.5 Medlock, Jaffe and Hartley: Shale Gas and US National Security (2011)

Medlock, Jaffe and Hartley at Rice University take their research one step further by modelling the breakeven price for shale gas in Canada, Mexico, Europe, Pacific as well as the US. The report uses the Rice World Gas Trade Model (RWGTM), inputting demand and production estimates at 10 year intervals from 2010 to 2040, with mean TRR shale gas data gathered through a literature review of a range of unspecified sources.

The report goes the furthest to establishing the cost of production of shale gas in regions outside the US establishing the breakeven price as the average price for the development of up to 60% of TRR. However the authors caveat the accuracy of their results by stating, 'the dearth of commercial activity in shale plays outside of the US and Canada renders any assessment in those regions highly uncertain, meaning the data represented in the RWGTM may actually underestimate the potential'.

3.5.6 Mohr and Evans: Long Term Forecasting of Natural Gas Production (2011)

This paper draws upon a range of sources to analyse unconventional gas resources outside of North America. As with the EU JRC report (2012), the authors establish a low, a high and a best guess figure for the regions selected based on a literature review. Many of the reports used were published before 2008, with the majority of the non-US data analysed sourced either directly or indirectly[6] from Rogner (1997).

- Coal Bed Methane resources by country categorised as low, high and best guess, draw upon Campbell and Heaps (2009) + 25% , Aluko (2001) +25 %, Boyer and Qinghao (1998) +25% , Cramer et al (2009) + 25%, the Australian URR from Brown (2008) and Kuuskraa (2009) in comparative analysis.
- Shale gas URR estimates by country draw solely on Rogner (1997) with a 15% recovery factor.
- Tight gas URR estimates by country are categorized as low, high and best guess and draw largely upon Cramer et al (2009) and data from Total, citing Rogner (1997) in comparative analysis

[5] Again, given the narrow geographical focus of these reports, we have excluded them from our study.
[6] Research from Cramer et al (2009) draws on Holditch and Chianelli (2008) which in turn is informed by the geological data published by Rogner (1997) and is the main source of global data used for CBM and Tight gas.

3.5.7 World Energy Council (WEC) Survey of Energy Resources: Focus on Shale Gas (2010)

The WEC Survey uses data from IGU 2003, VNIIGAS 2007, USGS 2008 and Cramer et al (BRG 2009) to establish shale gas TRR potential for 9 regions across the world. This report is accredited by the EU JRC (2012) as containing original data and suggests they have applied a 40% recovery factor to convert to ERR. However, notwithstanding the other sources used the WEC Survey is closely linked to Rogner (1997). In January 2012 the WEC produced an update to their report, drawing directly on the EIA (2011) analysis instead of their own earlier estimates.

3.5.8 International Energy Agency (IEA) (2011 and 2012)

The IEA reports are another frequently referenced source of data for global unconventional gas potential. The World Energy Outlook (2011) and the Golden Rules Report (2012) source the majority of their global data from the EIA (2011) report. The 2012 World Energy Outlook, released very recently, contains a set of worldwide TRR estimates based on BGR (2011), DOE/EIA (2011) and USGS (2010) reports together with the IEA's own data and analysis.

The Golden Rules (2012) report also estimates the costs of production and the impact on global and regional energy markets. The premise of the report is an assumption that unconventional gas development and production will increase and, in order to mitigate the inevitable social and enviromental risks that will follow, establishes a set of Golden Rules to earn public acceptance and legitimacy – 'a social licencse to operate' which will ultimately improve environmental performance. The Golden Rules case predicts a huge increase in unconventional gas production after 2020, once countries have had the time to develop unconventional resources.

Additionally, the report puts forward a low unconventional gas scenario where resource base could turn out to be much smaller than currently estimated or production and recovery factors are lower than initially thought due to a myriad of potential reasons, such as complex extraction, problems with water availability and government support for development. The IEA's World Energy Model is used to determine possible outcomes of either trajectory on the development of the unconventional gas market.

3.5.9 Bundesanstalt für Geowissenschaft und Rohstoffe (BGR): Reserven, Ressourcen und Verfügbarkeit von Energierohstoffen (2011)

The BGR is Germany's Federal Agency for Geology and Raw Materials. It publishes a report on reserves and resources which contains global resource estimates as well as more German-specific data. Because of Germany's large coal resources the report makes its own estimates of coal bed methane resources world wide.

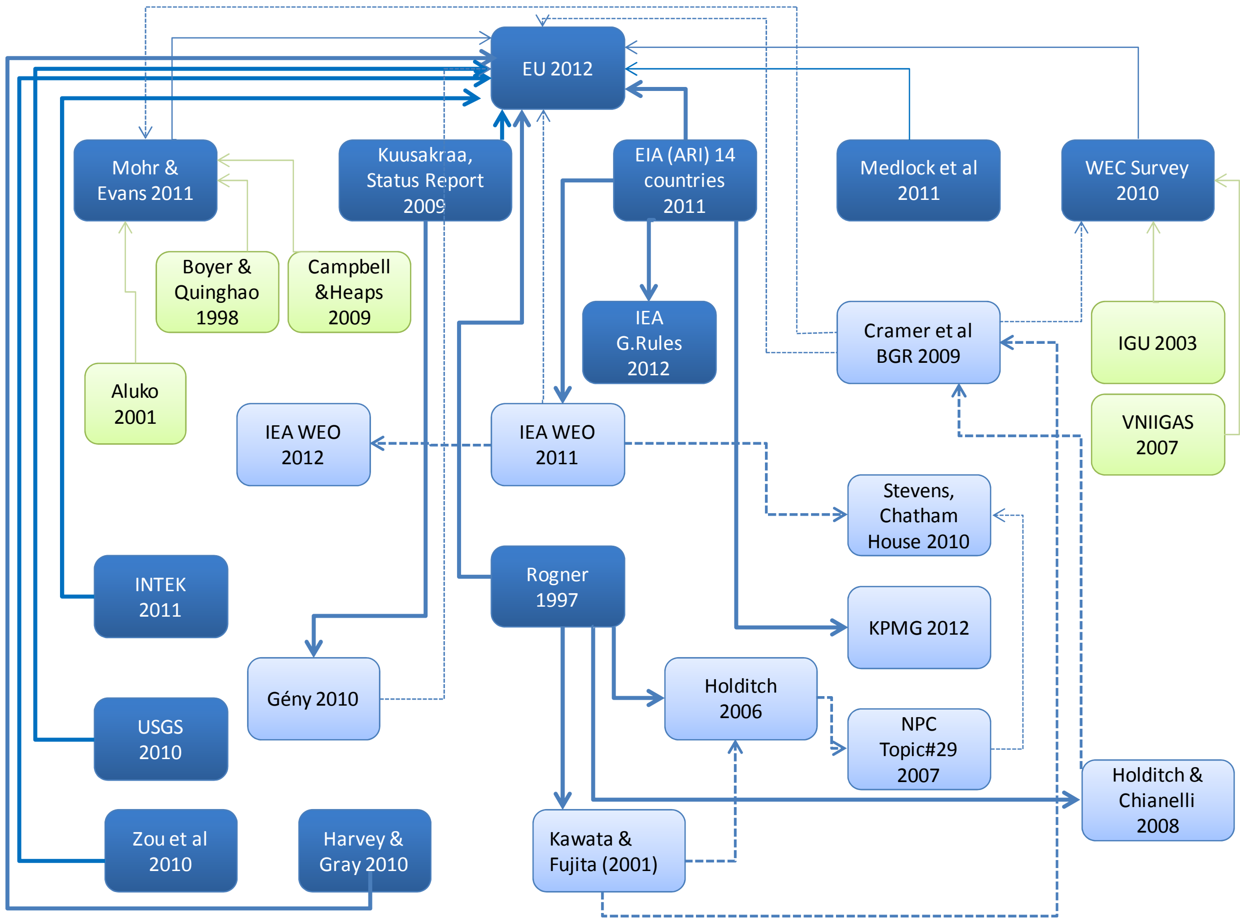
3.5.10 Pöyry Consulting's report for Ofgem, "The Impact of Unconventional Gas on Europe" (June 2011)

Pöyry's report extracts its summary resource numbers straight from the EIA, however it does also discuss other local estimates of resources made on a country by country level in the detailed text.

3.6 Global Resource Literature Summary

Whilst there are large numbers of reports dealing with unconventional gas resources, many of them only consider shale gas and there are fewer that include original analysis of the data available. The dependency of some of the main "global" reports on a limited number of precedents can be seen from Figure 4 below.

Figure 4: The interrelationship of the main reports on unconventional resources



In Figure 4 above:

- Dark blue represents original research [7]
- Light blue are reports that reference secondary sources without further data analysis
- Light green are those reports where their source material is unidentified

We set out the various quantitative assessments of resources in section 3.7 below.

3.6.1 Other Non-Global Reports

As well as the reports that cover global resources, we have also reviewed a number of reports that deal with the specific resources in one region or country.

The United States Geological Survey "National Assessment of Oil and Gas Resources Update" 2010 gives resource estimates by basin for all discovered oil and gas resources in the USA.

[7] For the purposes of this report, this is defined as either analysis of new primary geological data of unconventional gas resources or new data analysis from existing published reports.

The report "Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays", prepared by INTEK, Inc. for the U.S. Energy Information Administration (EIA) summarises technically recoverable resources for all 20 of the shale gas formations that have been discovered. Its estimates are for a subset of total gas resources of 24.1 tcm, but it can be reconciled to a full TRR figure for the USA.

Florence Gény of the Oxford Institute of Energy Studies produced a report "Can Unconventional Gas be a Game Changer in European Gas Markets?" (2010) on European shale gas. The report draws on a number of different sources for resource estimates, including Rogner, ARI, Schlumberger, Wood Mackenzie and IHS. Some of these sources are proprietary and not available for our review however, the resource estimates quoted by Gény are reasonably consistent with other published figures. The bulk of the report, however, focuses on what it would take for unconventional gas to be produced economically and is thus of more relevance to the next section of our report.

Harvey and Gray (2010) seek to establish a geological framework to assess shale gas potential in the UK, based on UK Onshore Geophysical Library data. Acknowledging the UK's shale formations are largely untested, the authors propose the most useful method by which to estimate shale gas potential, namely by analogy with developed basins in America, that share similar geological characteristics. For example, they suggest the Weald and Wessex Basins Jurassic shale plays in the UK offer a realistic analogue to the Antrim Shale in Michigan. Overall, Harvey and Gray estimated in 2010 potential UK shale gas recoverable resources at 150 bcm. This report is widely believed by the UK independent exploration companies to be low in its estimates and is now being revised with new data from recent drilling activity.

Zou et al (2010) take a similar approach to draw conclusions for unconventional gas resources in China. The report takes a considered view of the 'depositional environment, geochemical and reservoir characteristics, gas concentration and prospective resource potential' and applies this to three different types of shale found in certain areas in China. Based on this analysis, it makes a number of comparisons with developed shale gas basins in the US in an attempt to calculate informed estimates on the potential of shale gas in China. At this level of detail, however, further calculations are needed to work the data into usable TRR or ERR estimates for the purpose of this report.

Medlock and Hartley have also examined Chinese prospects in their 2011 paper "Quantitative Analysis of Scenarios for Chinese Domestic Unconventional Natural Gas Resources and their Role in Global LNG Markets".

3.7 Worldwide Resource Estimates – Original Gas in Place

Only Rogner has produced estimates of OGIP for all three unconventional gas types on a worldwide basis. The BGR has produced its own estimate of CBM resources, but its shale gas and tight gas estimates are directly derived from Rogner. EIA (ARI) has calculated OGIP for shale gas for 32 countries across 14 regions. Table 1 below compares those three sets of estimates.

Table 2: Original Gas in Place Estimates

Region	Rogner 1997			BGR 2009	EIA (ARI) 2011
	CBM	Tight Gas	Shale Gas	CBM	Shale Gas
	TCM	TCM	TCM	TCM	TCM
North America (incl. Mexico)	80.6	36.6	102.6	133.0	109.2
Latin America	1.0	34.6	56.5	0.0	129.4
Western Europe	4.2	9.4	13.6	3.0	42.6
Central & Eastern Europe	3.1	2.1	1.0	3.0	30.6
Former Soviet Union	105.7	24.1	16.8	156.0	N/A
Middle East & North Africa	0.0	22.0	68.1	3.0	62.1
Sub-Saharan Africa	1.0	20.9	7.3	0.0	51.9
China & CPA	32.5	9.4	94.2	37.0	144.5
Australasia & Japan	12.6	18.8	61.8	16.0	39.1
Asia Pacific	0.0	14.7	8.4	13.0	N/A
South Asia	1.0	5.2	0.0	0.0	14.0
	241.9	**197.9**	**430.3**	**364.0**	**623.5**

In the 14 years between Rogner's study and ARI's assessment, the whole US shale gas industry had developed, with much more knowledge available on actual resources. It is thus no surprise that the North American estimate increased significantly. However, ARI's methodology, looking at each major basin separately, has also lead to substantially increased estimates for several other regions. To quote ARI: "*Our detailed basin-by-basin assessments of the shale gas resource show that the shale gas resource in-place is larger than estimated by Rogner, even accounting for the fact that a number of the large shale gas resource areas (such as Russia and the Middle East) have not yet been included in our study (but are included in Rogner's shale gas resource numbers).*"

It is interesting that the BGR shows no CBM resources for either South Africa or India. Both these countries have substantial coal reserves and a number of our interviewees have mentioned one or both countries as potential producers of CBM.

3.8 Worldwide Resource Estimates – Technically Recoverable Resources

The estimates of recoverable reserves vary even more widely than the OGIP ones, with a range of different recovery factors put on the various OGIP figures. The key reports dealing with worldwide TRR on a consistent basis are EIA (ARI), Mohr & Evans, Medlock Jaffe & Hartley, the BGR, the IEA and the EU JRC. We set out below three tables showing the range of global TRR estimates for shale gas, tight gas and CBM respectively.

Table 3: Global TRR estimates for shale gas

Shale Gas Region	Mohr & Evans[8]	Medlock et al	EIA/ARI	BGR	EC JRC "best case"	IEA 2012
	2011	2011	2011	2011	2012	2012
	TCM	TCM	TCM	TCM	TCM	TCM
North America (incl. Mexico)	26.3	26.5	53.5	47.3	44.1	47.0
Latin America	8.5	n/a	34.7	35.1	34.7	33.0
Western Europe	2.1	2.8	10.5	8.8	11.6	16.0
Central & Eastern Europe	0.2	3.4	7.1	6.2	4.3	} 12.0
Former Soviet Union	2.5	n/a	n/a	10.7	32.0	
Middle East & North Africa	10.3	n/a	16.2	15.9	16.0	4.0
Sub-Saharan Africa	1.1	n/a	13.7	13.7	n/a	30.0
China & CPA	14.2	6.5	36.1	17.2	21.2	} 57.0
Australasia & Japan	9.3	1.4	11.2	11.2	6.3	
Asia Pacific	1.3	n/a	n/a	0.0	n/a	0.0
South Asia	0.0	n/a	3.2	0.0	1.8	0.0
	75.6	**40.7**	**186.3**	**166.1**	**172.0**	**199.0**

All reports have a high resource estimate for North America, although the range differs by a factor of two[9]. Similarly most reports except Mohr & Evans believe there to be significant resources in Latin America. Estimates for the rest of the world show much more variation. Chinese resource estimates in particular vary by a factor of nine. This underlines the uncertainty about how many of the resources in place can actually be recovered.

Feedback from the interviewees also shows differing views. Most respondents view China as a potentially very large unconventional gas producer. Views on Europe vary more widely – but a lot of the commentary here is based more on the non-geological issues surrounding exploration and production. It is certainly notable from the chart above that the Western European TRR estimates have been gradually increasing over time.

Tight gas has much less attention paid to it. Partially this is due to the current focus on shale gas, where the resource potential is both larger and to a certain extent easier to find (in that all shales contain hydrocarbons). Tight gas is found in sandstone and limestone reservoirs, but the reservoir is not the source rock, unlike shale or coal beds, so one also needs to identify a source and migration path to find a tight gas play. Many have been identified throughout the world but there is less focus on global prospects for this aspect, with only two reports (Mohr & Evans and IEA) offering TRR estimates on a global basis.

[8] Mohr & Evans describe their estimates as URR but they use recovery factors similar to those others use for TRR and consolidating reports such as the EU JRC report tend to treat them as TRR estimates anyway.

[9] It is worth noting that the USGS in its 2010 resource update estimated the US shale gas resources at only 3,002 bcm. This has been discussed by several commentators and the EU JRC report has a whole section discussing the USGS approach, which concludes that "figures provided by the USGS should be interpreted as 'potential additions to reserves'" in known formations, rather than technically recoverable resources nationwide.

Table 4: Global TRR estimates for tight gas

Tight Gas	Mohr & Evans 2011	IEA 2012
Region	TCM	TCM
North America (incl. Mexico)	17.5	11.0
Latin America	0.5	15.0
Western Europe	0.0	4.0
Central & Eastern Europe	0.0	}11.0
Former Soviet Union	5.6	
Middle East & North Africa	3.7	9.0
Sub-Saharan Africa	0.0	10.0
China & CPA	10.2	} 21.0
Australasia & Japan	5.1	
Asia Pacific	0.5	0.0
South Asia	0.0	0.0
	43.0	**81.0**

It is unclear why Mohr & Evans excluded tight gas resources from Europe and Africa when they had estimated other regions simply by applying a recovery factor to Rogner's OGIP estimates. Ultimately the IEA estimate is more recent and more comprehensive.

There is a little more consistency for CBM, with three recent papers giving global TRR estimates by region.

Table 5: Global TRR estimates for CBM

Coal Bed Methane	Mohr & Evans 2011	BGR 2011	IEA 2012
Region	TCM	TCM	TCM
North America (incl. Mexico)	8.7	8.1	9.0
Latin America	0.0	0.2	0.0
Western Europe	1.2	1.0	2.0
Central & Eastern Europe	0.8	0.5	} 20.0
Former Soviet Union	36.3	16.1	
Middle East & North Africa	0.7	0.0	0.0
Sub-Saharan Africa	0.2	0.9	0.0
China & CPA	7.9	10.9	} 16.0
Australasia & Japan	5.8	4.4	
Asia Pacific	0.2	1.6	0.0
South Asia	0.5	1.9	0.0
	62.3	**45.6**	**47.0**

The largest known resources of coal bed methane are in North America, Russia, China and Australia, all of which are covered by the three reports. As noted above, a number of our interview respondents have mentioned both India and South Africa as having interesting potential for CBM, so we would also expect some gas to be coming from them.

3.9 What is "Significant"?

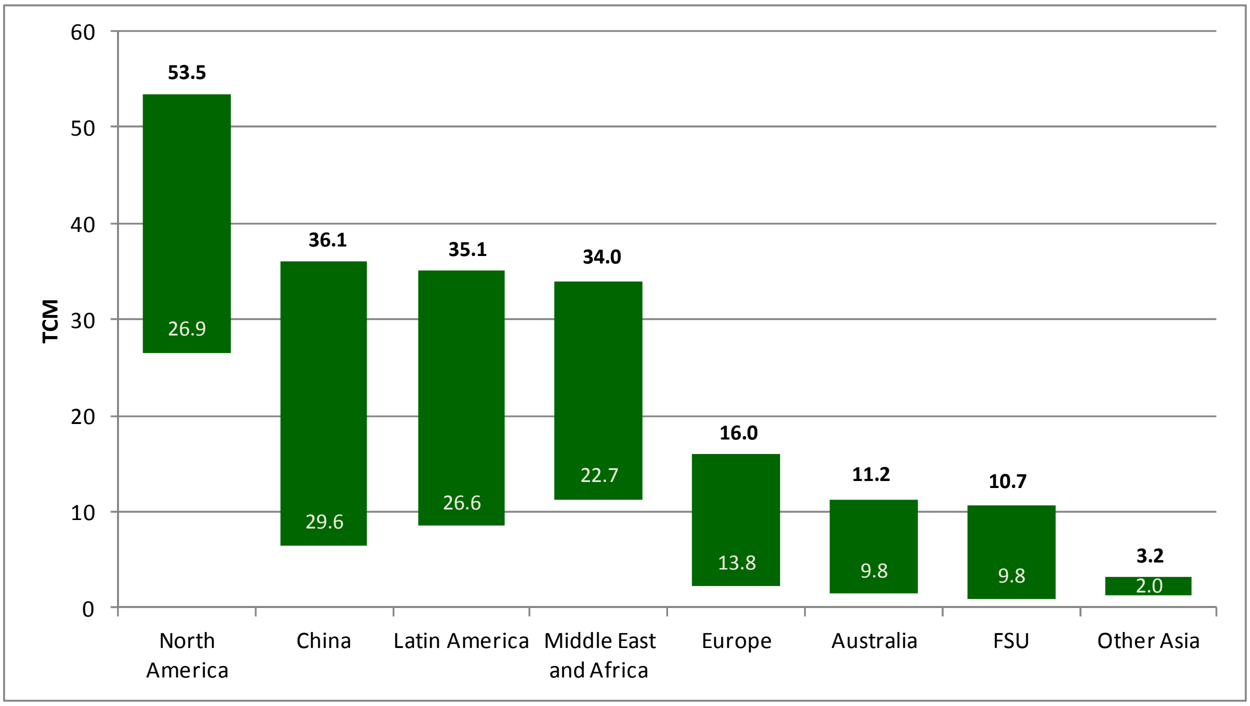
So what does access to these additional resources mean for world gas reserves? In its latest report, the IEA estimates remaining technically recoverable conventional natural gas resources at 370,539 bcm and unconventional gas reserves at 263,064 bcm, so unconventional gas resources now amount to 42% of total TRR. Global production in 2010 was 3,284 bcm, and the IEA now projects production (and thus consumption) in 2035 to be between 3,971 and 5,286 bcm. Given that five years ago unconventional gas was considered peripheral to gas reserves, this has significantly changed the future outlook – one can fairly say that the technology advances have given us access to unconventional gas that has added 70-100 years of potential gas supply globally.

3.10 Conclusions

Unconventional gas resources are widely distributed over the globe, reflecting the common continental occurrence of deep basins containing sedimentary deposits with significant organic content. Most commentators agree that there are large quantities of gas in place in North America (US, Canada and Mexico), South America, the FSU, China and Australia. Opinion differs over the potential size of the resource in Europe, Middle East and Africa but there is a reasonable body of opinion that believes the resources in those continents too are substantial.

However, there is much more uncertainty about whether and if so how much of, that gas in place can be extracted. There are actually very few published sources estimating TRR for tight gas or coal bed methane. More reports give estimates of shale gas recoverable and the ranges are shown graphically in Figure 5 below.

Figure 5: Ranges for technically recoverable resource estimates of global shale gas



Estimating TRR once gas in place has been identified is a complex problem involving geology (is the shale brittle enough to fracture rather than flex?), society (will I be allowed to drill?) and technology (how much gas can I extract?). In addition to access to economically recoverable resources, one needs to address the fundamental economics of the opportunity: can I get the gas to market for more than the cost of extraction? The geological questions can only really be answered after exploratory drilling. Except for North America and coal bed methane in various parts of the world, there just hasn't been enough exploratory activity to really know how much gas can be economically extracted.

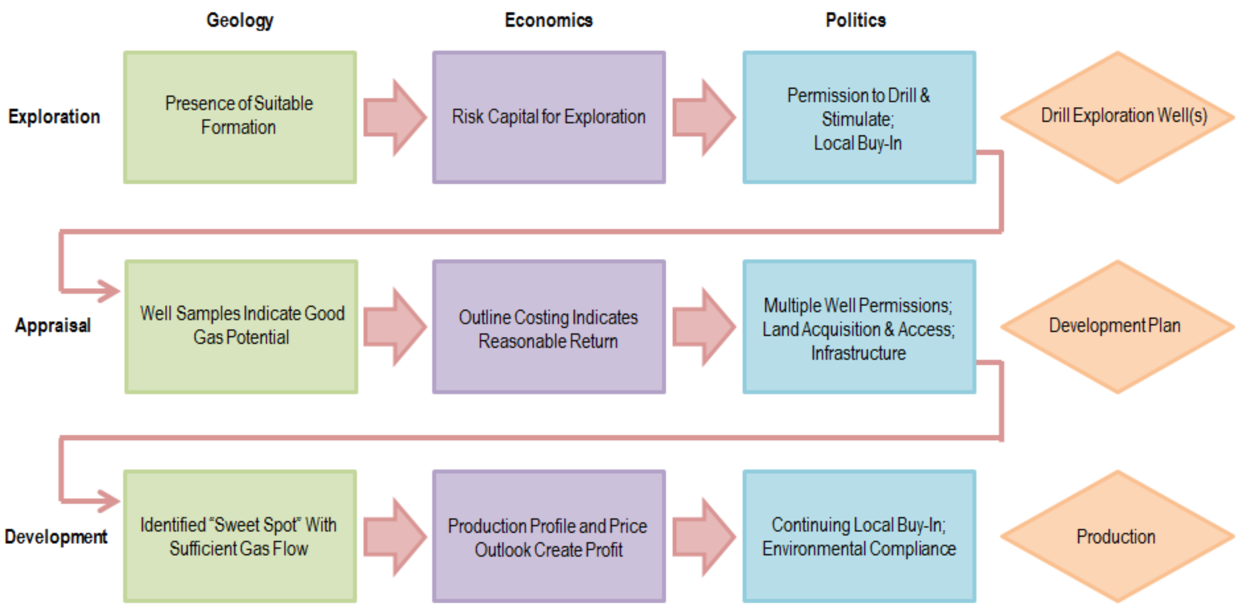
Our conclusion is that there are significant potential opportunities for unconventional gas production in many countries and regions around the world. What is then relevant to the objectives of this report is to consider which of these countries are likely to see significant production of that resource within the next twenty years. This very much depends on the political, technical and economic issues which we consider in the next section.

4. Prospects

In this section we discuss the general issues surrounding the prospects for unconventional gas over the next 20 years. In the following chapters we then consider supply and demand globally and then how unconventional gas production might affect supply and demand balances in (i) Europe and (ii) the rest of the world.

Our approach to examining the prospects for unconventional gas is to consider the potential barriers to the three phases of exploitation. We have categorised the barriers into three types: Geology, Economics and Politics. At each stage of exploitation, these barriers will have to be overcome before proceeding. This can be shown in diagrammatic format as set out in Figure 6 below.

Figure 6: Stages of Unconventional Gas Development



We have considered the geological questions in section 2. In this chapter we look at the economic issues and the "societal" barriers which will determine whether or not a shale gas rich area is likely to be exploited in the next two decades.

4.1 *Economic Issues*

The only large body of cost data for drilling and production of unconventional gas comes from the US. Even here, there is a wide range of costs, reflecting the very different characteristics of the various basins and also operators. The two most widely quoted cost parameters are cost of drilling wells (usually expressed in $ per well) and the overall cost of production (usually expressed in $ per mmbtu).

4.1.1 Costs of Production

The IEA very usefully put together some indicative costs of production on a $ per mmbtu basis by region and type of gas, summarised in Table 6 below. The estimates are for dry gas only and exclude liquids. Blank spaces indicate no data available.

Table 6: Indicative Dry Gas Production Costs

Region	Conventional $/mmbtu	Tight Gas $/mmbtu	Shale Gas $/mmbtu	CBM $/mmbtu
OECD North America	3-9	3-7	3-7	3-8
Latin America	3-8	3-7		
OECD Europe	4-9			
E. Europe & Russia	2-6	3-7		3-6
Middle East	2-7	4-8		
Africa	3-7			
Asia/Pacific	4-8	4-8		3-8

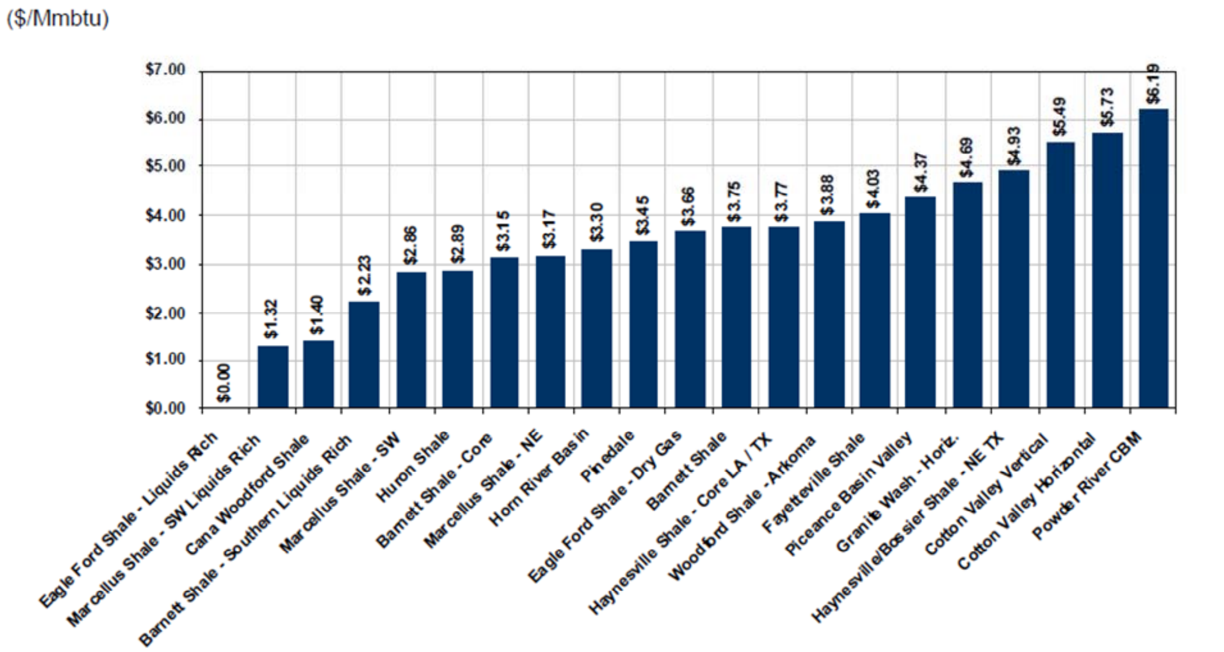
Source: IEA World Energy Outlook 2011 Table 2.1, in real 2009 dollars

There is considerable debate about the true level of shale gas costs in the US. Some analysts have suggested that the true cost, once cost of capital and "dry" wells are taken into account, is somewhat higher than the $3-7/mmbtu (19-45 p/therm) range quoted above, possibly nearer $8-9/mmbtu (51-58 p/therm). Industry sources argue that drilling costs are coming down as technology improves horizontal drilling rigs and targeting of wells is now getting much better as more is learned about the geology of shales. What seems clear is firstly that costs can actually be very variable, depending on the nature of the geology and secondly that until a basin's geology is properly understood (which can require many wells being drilled) the risk of wells with low or no gas flow is higher.

Geologists agree that industry's current understanding of the characteristics of shale is nowhere near as detailed as is the understanding of sandstone and the other rock types where conventional oil and gas congregates. This understanding will improve over the next few decades, bringing further efficiency into well targeting and design.

The other important factor in considering breakeven costs is the presence of natural gas liquids (NGLs). Where NGLs are found with the gas, the economics can be significantly improved, since these liquids (typically ethane, propane butane and condensate) are valued in direct relation to the oil price. What can be confusing is the practice of sometimes quoting breakeven costs on dry gas alone and sometimes on a basis net of any NGL or oil revenues. For instance, Figure 7 below shows breakeven costs for a number of different shale production areas in the US after taking liquids sales as a "negative" cost. Thus one producing area appears to have a zero cost of gas extraction.

Figure 7: NYMEX breakeven price for 10% ATAX ROR



Source: Credit Suisse

4.1.2 *European Production Costs*

Since data on shale gas production costs is only available for the US, one needs to carry out some further analysis to estimate how much it will cost in other regions of the world. This can be done by comparing the "economic" factors that make up the cost in the US, which must include all factors, including land access costs, drilling costs, infrastructure, fiscal terms, regulatory costs and costs of getting public endorsement. Two reports, Gény (2010) and EC JRC (2012) consider European economic factors in some detail.

Gény's report looks at the economic profitability of hypothetical development in shale gas basins in each of Germany and Poland. She had access to drilling and operating cost data provided by Schlumberger and made a number of assumptions based on knowledge of the two basins at that time. Her conclusions were that at 2010 European costs, break even prices were in the range of $12.3-13.0/mmbtu (80-84 p/therm), which could drop to $7.8-8.2/mmbtu (50-53 p/therm) under fast cost optimisation assumptions[10].

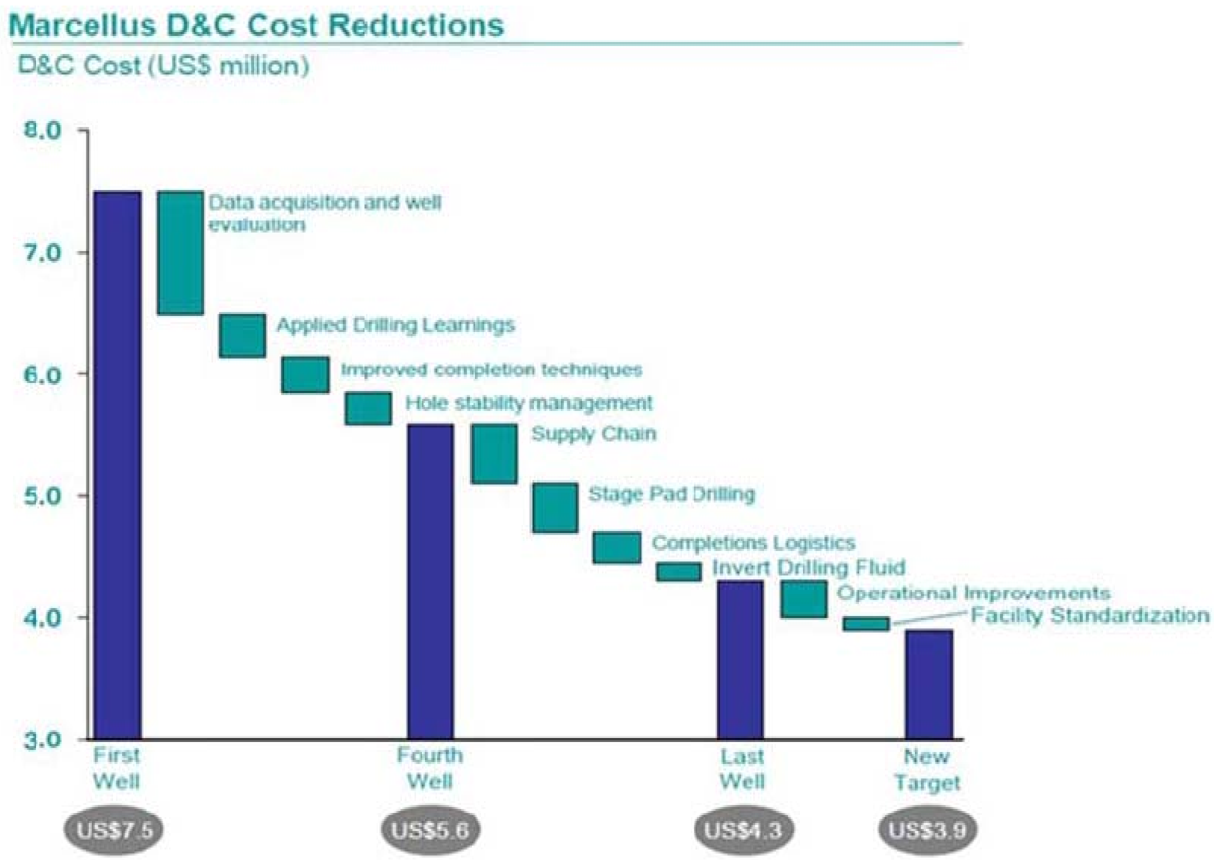
This compares to a breakeven price of $4.25/mmbtu [11] (27p/therm) computed for the Fayetteville shale which Gény used as a comparative. The reasons she sets out for the European costs never being expected to get down to the US comparatives are multiple and include greater depth of the shale formations, less competition for well services, different royalty regimes and potentially higher land acquisition costs among others.

[10] Gény also computed a higher scenario for Germany on the assumption that the current tight gas royalty concession would not be advanced to shale gas. This significantly increases the cost of extraction, to the point that it is unlikely that anything would be developed in Germany.

[11] Source: Medlock et al "Shale Gas and US National Security" 2011

The cost optimisation issue is an important one. All our interviewees have confirmed what both the Gény and the EC JRC reports state: the supply chain for onshore drilling across Europe is very rudimentary and costs are currently a lot higher than the US. One recent rig count identified 1,900 land rigs and 500 frack crews in the US compared to 77 rigs and 10 frack crews in Europe. But all respondents agree that one can expect costs to fall as activity increases and there are several precedents within the US shale gas industry to draw on to judge the potential scale.

Figure 8: Indicative Drilling and Completion Cost savings over time in US shale gas production



Source: Talisman Energy, from Gény

The Schlumberger numbers used by Gény suggest European well costs of between £5.4 and £8.5 million depending on type, depth and location, whereas well costs in the Fayetteville are around £1.8 million[12]. Gény assumed a potential decrease in drilling costs of up to 50%, which at one level is consistent with the US experience, but seems modest given the fact that European circumstances are very different from where the US was in 2007. Europe has very little onshore drilling supply chain at all, whereas the US had a considerable drilling and fracking industry even then, and all it had to do was adapt to a new type of geology.

The current quoted figures are consistent with feedback from the UK independents, which suggests drilling and fracking an onshore shale gas exploration well in the UK costs around £7 million. We would

[12] Southwest Energy Form 8K April 2012 – SWN is one of the three big operators in the Fayetteville

expect these costs to reduce considerably, more than Gény's 50%, if sufficient activity and investment came into the market.

Gény concluded in 2010 that, to be economic, the pricing of unconventional gas volumes will have to be sustained at a level above $8-10/mmbtu (52-65p/therm) and also pointed out that these estimates were "higher than historical prices and current market expectations". Those market expectations have now moved on, with the GASPOOL forward curve showing a constant average of about 67p/therm[13]. But the point remains the same and is confirmed by some of the UK independents: if gas prices drop somewhat from their current levels, exploitation of unconventional gas in Europe may be delayed since it just won't be economic given the current supply chain costs.

The EC JRC report goes into even more analysis than Gény on drilling and stimulation costs. As well as a range of costs, they also consider a range of well gas production ranges (the URR much quoted in US shale gas reports) and also consider wells with and without natural gas liquids. For their base case production per well (URR 0.06 bcm), with 100,000 bbl liquids, the cost estimates range from $3.10 to $5.90/mmbtu (20 to 37p/therm) whereas without liquids the cost range is between $5.38 to $10.30/mmbtu (34 to 65p/therm). The three cost scenarios reflect current cost base (the highest cost), a "most likely" scenario of a cost situation which should be reasonably achievable on current knowledge and an "optimistic" scenario assuming further technology advances. They are summarised in Table 7 below.

Table 7: European shale gas production estimates

	Current Cost Base	"Most Likely" Long Run Cost $/mmbtu	"Optimistic" Long Run Cost $/mmbtu
Well with liquids	5.90/mmbtu	4.07/mmbtu	3.10/mmbtu
Well with dry gas only	10.30/mmbtu	7.07/mmbtu	5.38/mmbtu

Source: EC JRC Report

The methodologies used by Gény and the EC JRC are difficult to compare. One item clearly at odds between what the reports disclose is the surface assets, which Schlumberger estimate at £32.4 million, against a £5 million figure for "field development, infrastructure and processing costs" in the EC JRC report. This may to some extent reflect the specific regional analysis carried out by Gény against the "average across the EU" approach used by the EC JRC; for instance, access to pipeline infrastructure is a key infrastructure cost that varies considerably across the EU, depending upon the nature of the gas grid. In addition, Gény takes account of specific royalty payments that are ignored by the EC JRC. However, if one assumes that Gény was ignoring liquids (which given the depth of the German and Polish shales she was analysing is fair), then her estimate of $8-10/mmbtu (52-65p/therm) on an assumed URR of 0.07 bcm[14] is consistent with the EU's "as is" cost estimate of $10.8/mmbtu (70p/therm) on an URR of 0.06 bcm.

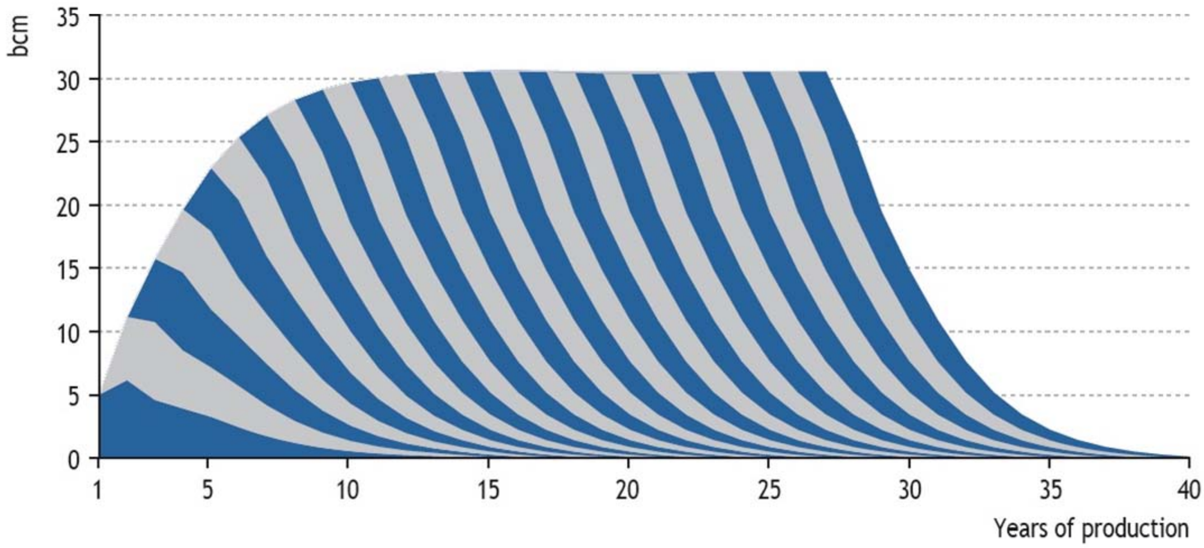
[13] Analysis of the ICE GASPOOL 1-month forward contract price curve, 20 November 2012

[14] Gény does not specifically state that this was her assumption, but one can reasonably deduce it since she uses the Fayetteville as a comparator in other parts of the analysis and quotes this volume from the Fayetteville elsewhere in her report.

4.1.3 Scale of Investment

The other economic issue to consider is the very scale of investment required to reach significant quantities of gas production. The IEA calculated a hypothetical analogy, based on the typical profile of Barnett shale wells, which suggests that to get to annual production of 30 bcm in a basin for twenty years, one would need to drill close to 22,000 wells over a 27 year period.

Figure 9: Hypothetical production profile of a new gas play



Notes: assumes 800 wells drilled annually for 27 years. Coloured segments represent production from each vintage.
Source: IEA World Outlook 2009

The EU JRC carried out a similar analysis, which we reproduce below.

> *"The cumulative production of shale gas in Europe in an optimistic case of high demand, low costs and plentiful reserves would total close to some 3,000 bcm over the period 2025-2040, an average withdrawal rate of 200 bcm/year. Two independent assessments made within this report have estimated the ultimate recovery of gas from a single well to stand at approximately 0.057 bcm over an assumed lifetime of 30 years. Extrapolating from the US experience over the last ten years, the authors assume the need for ten exploratory wells and ten dry holes for every 100 shale gas producing wells drilled. 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."*

If one applies the EC JRC lower well cost figures to this number, this implies a potential investment requirement of around £25.3 billion a year for 15 years. It is helpful to consider this scale of investment – when one realises the amount of expenditure required, it is easier to believe that competitive pressures will bring down costs in Europe significantly. But there is no doubt that the investment requirements are considerable. As a comparison, IHS CERA forecasts a total investment of £1.2 trillion in the US shale industry between 2010 and 2035[15], at which point both EIA and IEA expect the US to be producing around 561 bcm/year.

[15] Source: "The Economic and Employment Contributions of Shale Gas in the United States" IHS Global Insight December 2011

4.2 Political Barriers

Many of the recent reports on shale gas go into the various issues and concerns surrounding the industry which are not necessarily "economic" in nature, although they often have economic consequences. These are either tied to legal or regulatory issues, or are issues of public concern. We have categorised these as "political" simply because these issues that both vary by country, since national laws are all different and they tend not to be within the power of industry to address, but rather require input by Governments. We discuss each of the major issues below.

4.2.1 Land and Access Rights

Many of the written reports, and some interviewees, point out that the US shale gas boom has required large numbers of wells over significant areas of land and that this might be difficult to replicate in more densely populated countries, particularly Europe. This is certainly a potential issue, however more recently commentators have pointed to the development of the Marcellus shale in Pennsylvania as an example of where the industry is going. Here the need for land has been reduced by drilling multiple wells from a single area (or "well pad"). Both Gény and EC JRC comment that this approach is the one likely to be adopted in Europe and that has been confirmed by a number of the UK independents. Indeed Cuadrilla has suggested that, because of the thickness of the Bowland shale, they might drill as many as 32 wells from one pad.[16]

Access to land for pads is also raised as a potential obstacle, particularly as many regions where unconventional resources are thought to exist have legal systems where mineral rights lie with the Government rather than the landowner. A number of commentators point out that the speed of US development has been helped by the fact that the landowner gets a royalty, which can be between 12.5% and 25% of revenue generated from wells on his land. However, most of the industry players take the pragmatic view that a deal can almost always be done with the landowner to ensure they back the project. Thus the issue becomes more of a "fiscal terms" problem if the jurisdiction in question charges a revenue-based royalty that goes to the Government, so that the producer pays both a royalty to the Government and a land rent to the land owner. In jurisdictions where there is simply a profits-based tax, the land rent is tax deductible and thus there is no "double charging".

4.2.2 Water

Water use is another potential barrier to development raised by many commentators. Although drilling normally uses specialist lubrication called "drilling mud", which is largely recycled, the hydraulic fracturing process requires large amounts of water. There are three separate issues connected with water use in hydraulic fracturing:

1. availability of water generally
2. transportation of water to the drilling site and
3. treatment of waste water that comes back to the surface after hydraulic fracturing

In terms of availability, a single stage of hydraulic fracturing can require anywhere between 10,000-30,000 m3 of water. Whilst this seems a lot, it is not that big in terms of industrial usage generally. Figure 10 below sets out the typical water requirement per mmbtu of various different energy types,

[16] Cuadrilla Resources – evidence to the Parliamentary Committee on Energy and Climate Change October 2012

showing shale gas as the least water intensive. Conventional gas together with wind and solar power use even less water than this.

Figure 10: Water Use per million BTU for various energy generation technologies

Gallons of Water per million BTU		
	Range	Mid Point of Range
➢ Deep Shale Natural Gas	1-6	3
➢ Nuclear (Uranium ready to use in a power plant)	8-14	11
➢ Conventional Oil	8-20	14
➢ Synfuel – coal gasification	11-26	18
➢ Coal (ready to use in a power plant)	13-32	23
➢ Oil Shale	22-56	39
➢ Tar Sands	27-68	47
➢ Fuel ethanol from corn	2,510 – 29,100	15,805
➢ Biodiesel from soy	14,000 – 75,000	44,500

Source: Ground Water Protection Counsel and the US Department of Energy, from Cuadrilla

Thus this is really an issue only in areas where water supply is already scarce. However, certain regions with large potential unconventional resources are water deprived and thus gas production there may either be more costly or even impossible as a result.

In particular, several of the Chinese shale gas basins are located in water constrained regions, as can be seen in Figure 11.

Figure 11: Water Access Issues

Source: Barclay's Capital Commodities Research

This limitation may eventually be overcome by technology. Some US companies are already looking into ways of fracturing shale using either propane gel or compressed air.

A further issue connected with water is transportation – how does the water get to the well site. In countries with a highly developed water grid this may not be much of an issue; as long as the well pad is near a water main a pipe can be laid. However in more remote areas, water has to be brought in by road, which is not only costly but also has environmental consequences for the local community given the sheer volume of trucks passing daily to fill up the water tanks.

A much more contentious debate is the treatment of waste water. Water used in hydraulic fracturing operations not only has various chemicals added to it, but will also absorb minerals from the well, which can in certain cases include traces of radioactive metals. Similarly, water pumped out of coal beds in preparation for CBM production is contaminated with methane and other substances. So the safe treatment of this water prior to disposal is crucial to avoid contamination of local surface water.

There have been a number of cases in the US where contaminated water has escaped, which has been picked up by the environmental community as evidence that the industry is unsafe. From the various commentators on the subject, including a preliminary environmental assessment by the EU, it certainly seems likely that in places such as Europe, more expensive procedures, such as holding the water in a closed tank rather than an open tank prior to disposal, will be required. This is not an insuperable barrier – the technology to treat the water is well proven and appropriate regulations governing standards exist in most countries. But it is an additional cost factor that will vary according to the local water treatment infrastructure.

The final issue connected with water is the potential for unconventional gas drilling to pollute aquifers. A number of concerns have been raised, both about methane in water and about the potential for the chemicals used in the stimulation process to enter aquifers. The situation with methane contamination in particular is complicated, since there are several ways that methane can get into ground water naturally.

The scientific advice in both the US and Europe is that the risk of hydrocarbons from oil and gas wells getting into aquifers is very much connected to poor installation of well lining and that these risks are the same in both conventional and unconventional oil and gas drilling. The studies believe that existing laws and regulations are sufficient to prevent the problem if implemented and enforced correctly. Part of the concern in the US has also been caused by the lack of methane monitoring prior to drilling in prior years, as well as a lack of disclosure of what chemicals were being added to the fracturing fluids. This has now been acted upon by the industry, so that standard practice is now to carry out pre-drilling surveys of ground methane and water quality and to clearly disclose the chemicals being used.

4.2.3 Other Environmental Issues

Methane escape is another issue that has caused substantial debate. One study by a Cornell University team estimated that "3.6% to 7.9% of the methane from shale gas production escapes to the atmosphere in venting and leaks over the lifetime of the well"[17] and calculated that this meant that shale gas had a higher carbon imprint than coal. Another, different Cornell team sharply criticised some aspects of the methodology used and the debate continues. However this has highlighted the risk of gas leakage during well completion and fracturing, which seems to be the main area which contributed to the higher estimates. The US EPA has now revised some of its standards to deal with this issue as well as other air pollution sources from the oil and gas industry, which will add cost to future operations.

A further environmental concern is noise, particularly from truck movements bringing equipment and water to and from drilling sites. Noise abatement procedures will have to be implemented in accordance with local regulations and in more densely populated countries this will tend to have an incremental cost over and above the US experience.

4.2.4 Regulated Prices

Countries with regulated gas prices, such as China and Latin America, may also face a barrier to investment where the regulated price is less than market prices and more importantly the economic cost of shale gas production, at least in the first years of exploration and production. This is a complex issue which needs to be considered on a country specific basis, since each regulatory system is different.

4.2.5 Access to Infrastructure

Many commentators make the point that one of the big advantages the US had in developing its unconventional gas industry was the large existing infrastructure in gas pipelines, the ease of building new pipelines and the fact that, by law, all these pipelines must offer "open access" to all who wish to use

---

[17] Howarth et al, Methane and the greenhouse gas footprint of natural gas from shale formations"

them. Whilst some areas of Europe also have good gas pipeline infrastructure, it is less well developed in others. In other countries, in particular China, India and Latin America, substantial investments in pipeline infrastructure will be required to give unconventional gas resources access to markets.

A further issue with pipeline infrastructure that was highlighted in our interviews is the ease of planning approvals for connections to the gas grid. Again in the US it is relatively easy to build a pipeline. In the UK, as a counter example, we were told that permission to build a pipeline more than 16km long was a major planning issue and could take as long as 5 years if there were objections.

4.2.6 Public Confidence

Any industrial activity in the developed world needs to be mindful of the local community in which it operates. The development of unconventional gas is no different. Indeed, because some of the unconventional production areas are in regions where communities have no experience of mineral extraction, there are considerably more barriers to overcome in this regard. Environmental concerns, mentioned above, are usually the major source of concern. But a simple increase in traffic can also cause major tensions.

Lack of knowledge and understanding is the root cause of a lot of the concern. Following a lead taken in some parts of the US, the UK independent sector is now investing a lot of time and resource in explaining to local communities what they are doing, why, how long they will be doing it for and what the site will look like after the drilling is completed. As revenue is generated, further contributions can be made to local "good causes", which may take many forms.

One point made to us by several commentators was the importance in having confidence not just in industry but in regulators too. This is particularly an issue in ex-Communist Europe, where there are often fears that officials will turn a blind eye to corporate transgressions. There is a delicate balance for regulators here, for too heavy a regulatory burden might add so much cost that the industry will never take off. However, public confidence will only be achieved if people believe not only are the operations fundamentally safe, but also, if anyone doesn't follow the safety guidelines and procedures, they will be suitably punished.

4.3 Conclusion

It is not easy to summarise a set of issues and objections which have been presented and argued about from many different points of view. However, we believe that they fundamentally fall into three categories:

- those which simply reflect the higher cost base of other regions compared to the US, some of which as we have discussed will reduce as the industry scales up;
- those which relate to public acceptance and trust, where the industry needs to prove that what it is doing is safe and regulators need to prove that they are have sufficient oversight and control over development and operating practices; and
- those which relate to Government, where laws, regulations or fiscal regimes present barriers that could be alleviated by appropriate changes.

5. Overview of Gas Supply and Demand

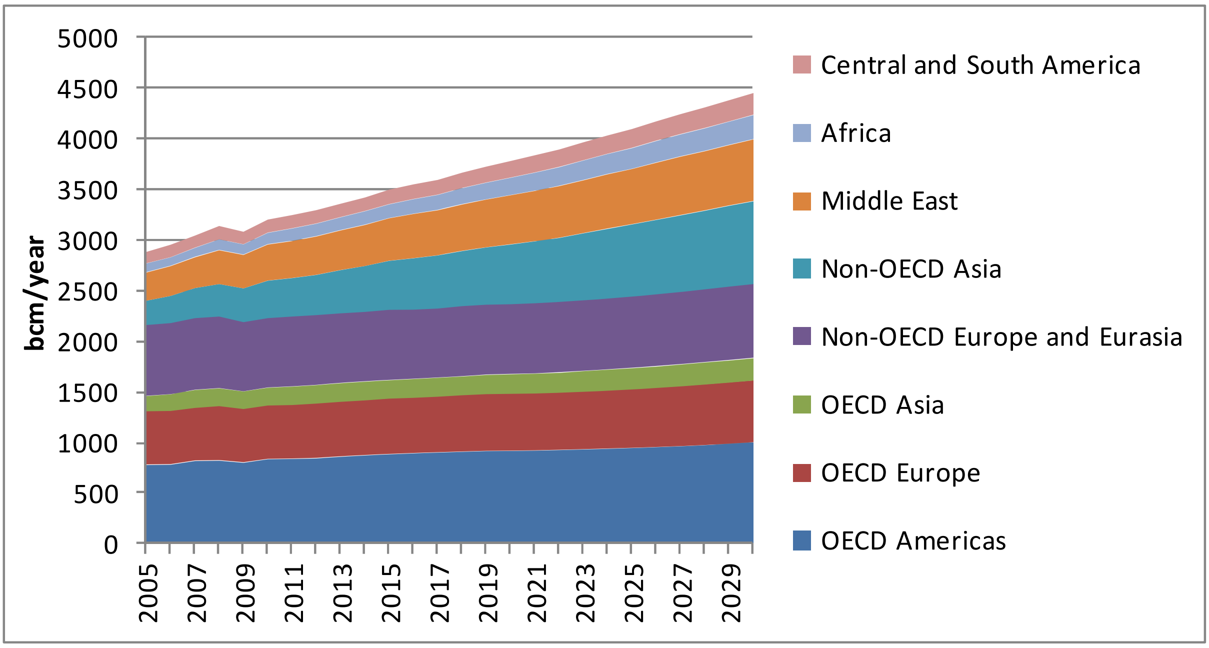
5.1 Global Supply / Demand Scenarios

Prior to considering the prospects for unconventional gas development by region, it is useful to look at the global picture of gas supply and demand. In this section we set out the various views on how supply and demand might develop over the next twenty years and some of the uncertainties that might affect those views.

A number of organisations have developed future global gas supply and demand scenarios. We have used the EIA International Energy Outlook (2011) as the base line for comparison to the other public gas forecasts. The other gas forecasts we have reviewed include the IEA World Energy Outlook (2012), various oil company forecasts including BP and ExxonMobil (both 2012), the EC JRC review of Unconventional Gas (2012) and one published by the Baker Institute at Rice University in 2011[18].

5.2 Gas Demand

Figure 12



Source: EIA International Energy Outlook 2012

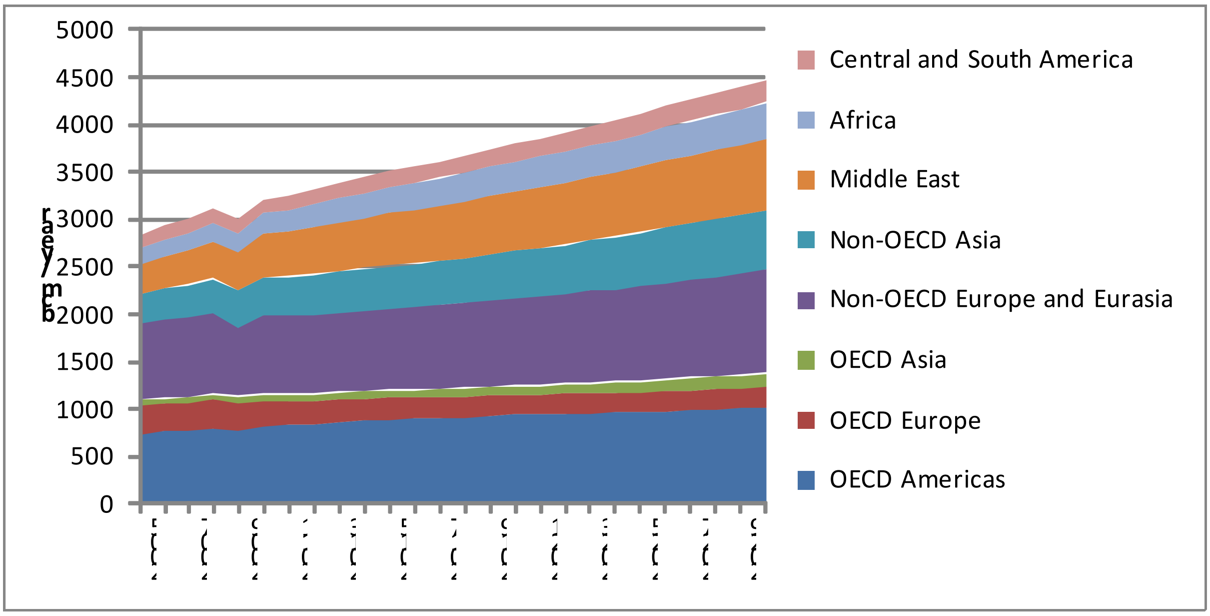
The EIA's reference case anticipates global gas demand will increase by approximately 1.7% per annum (pa) from 2010 through 2030 to reach a total of 4.4 tcm/year, from 3.2 tcm/year in 2010. However there are significant differences in gas demand growth between regions and countries. Despite the recent increases in both shale gas reserve estimates and production, gas consumption in the United States is expected to have one of the slowest growth rates, 0.42% pa. Other low gas demand growth regions are anticipated to be Japan (0.39% pa), Russia (0.15% pa) and OECD Europe (0.68% pa).

[18] Medlock et al., Shale Gas and US National Security, 2011

High gas demand growth regions in Asia are expected by the EIA to be China (5.8% pa), India (3.6% pa) and other non-OECD Asia (3.2% pa). Outside of Asia, Africa (3.9% pa), the Middle East (2.7% pa) and Central / South America (2.6% pa) will be the fastest increasing gas consumers.

5.3 *Gas Supply*

Figure 13

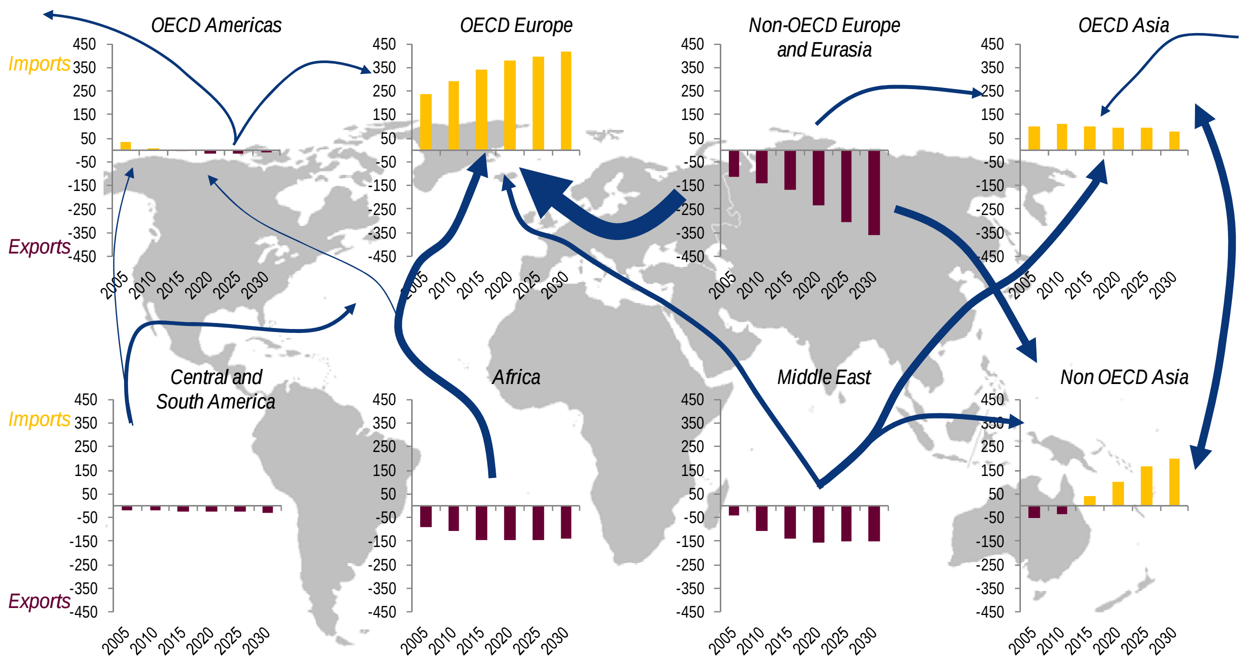


Source: EIA International Energy Outlook 2012

Gas supply growth across the regions as envisaged by the EIA is equally varied. United States gas production growth will outstrip demand growth, 0.9% pa verses 0.4% pa respectively. In Asia, Australia and China are expected to increase gas production by approximately 4.1%. Gas production in the Middle East (2.5% pa) and Central / South America (2.6% pa) will likely match demand growth. Africa's gas production growth of 2.7% pa is well below the anticipated demand increase, however the EIA forecast was developed before some of the major gas discoveries in east Africa were made public and the same is true of most other forecasts we have reviewed.

5.4 *Major Trade Flows*

Figure 14



Source: EIA, Navigant Analysis, all charts bcm

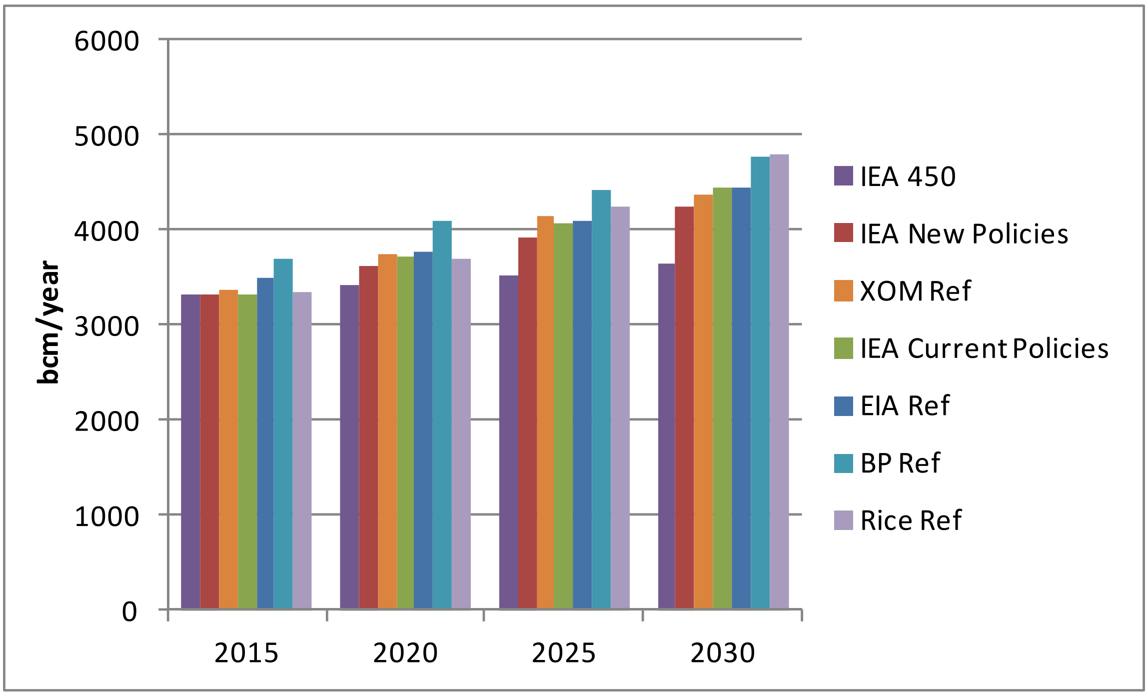
Looking at the global trade patterns envisaged by the EIA, Europe's requirement for imported gas is expected to continue to increase as demand escalates and domestic gas production declines persist. In Asia, Japanese LNG imports are expected to be fairly static up to 2030. The most significant change in Asia trade patterns, indeed global trade patterns, according to the EIA will be the emergence of China as major gas importer. By 2030 Chinese gas imports, via LNG and Russian / Caspian pipeline gas, will be close to half that of Europe's gas import requirements. Indian and other Asian demand is also expected to increase strongly.

Offsetting these import requirements North America is expected to become a net exporter of gas through LNG to Asia and Europe and in the latter half of this decade. The EIA also expects Russia and Caspian region gas production to increase to meet demand in both Europe and Asia. Australia's multiple LNG projects will also make a major impact on LNG trade flows around Asia. The Middle East is expected to maintain current export levels in this scenario.

In addition to the EIA forecast several other gas supply and demand projections have been made publicly available.

5.5 *Gas Demand Variations*

Figure 15



Source: Navigant Analysis

Looking out to 2030 four of the reviewed forecasts have a reasonable degree of agreement on the global demand for gas. The EIA's reference case, two of the IEAs cases (New Policies and Current Policies) as well as ExxonMobil's estimate suggest that gas demand will be around 4.2 tcm/year in 2030.

The IEA's 450 scenario, under which radical changes to energy policies are made to achieve climate change objectives, the gas demand is limited to 3.7 tcm/year in 2030. In this scenario overall energy demand growth is only 0.6% pa and gas is the only fossil fuel for which demand increases over this time period.

Both BP and Rice expect gas demand to be close to 4.8 tcm/year by 2030.

The EIA forecasts Non-OECD Asia to experience the highest demand growth between 2010 and 2035 at 3.6% followed by Africa at 3.5% growth. Similarly the IEA forecasts Non-OECD Asia to experience the highest demand growth but at a higher rate of 4.3% in the new policies scenario (2010-2035). This higher growth rate results in Non-OECD Asia having the highest regional gas demand by 2030, unlike the EIA forecast where OECD America continues to hold its lead to 2030.

Another difference in the forecasts is the projection for Africa. The EIA forecast for Africa's natural gas demand is much higher than the IEA (up to 80 bcm in 2030). The EIA forecast Africa's demand to exceed Central and South America's from 2020 onwards and OECD Asia from 2030 whereas the IEA forecast that Africa will have the lowest demand consistently over the time period.

The Rice University, ExxonMobil and BP have grouped their regions slightly differently and have not separated OECD and Non-OECD regions, however, when these subcategories are removed from the IEA and EIA forecasts all of assessed the forecasts show very similar trends. BP's gas demand forecasts are typically the highest of the group in all regions with the exceptions of Europe & Asia and the Africa. The IEA's figures are generally the lowest across all regions. BP's forecast demand for the Middle East is significantly higher than the other forecasters.

5.6 Gas Production Variations

The EIA and the IEA show similar projections for natural gas production up to 2030. Both forecast Non-OECD Eastern Europe/Eurasia and OECD Americas to have the highest levels of production amongst the regions. The EIA forecasts Non-OECD Eastern Europe/Eurasia to produce approximately 1.1 tcm in 2035 and IEA forecast 1.2 tcm.

In the supply forecasts the IEA generally exceeds the EIA forecasts with the exception of the Middle East (2020-2035) and Africa (2010-2025). The regions with the highest difference in projection, over 29 bcm, are Non-OECD Europe and Eurasia and Non-OECD Asia. The IEA forecast these regions between 29 and 81 bcm higher than the EIA between 2015 and 2035.

Again, BP and Rice's forecasting differs in appearance to the IEA and EIA forecasts due to the way the regions are grouped. However, when the OECD and Non-OECD regions are combined with the other regions the forecasts show similar trends.

BP's natural gas production projection forecasts Europe & Eurasia to achieve the highest production levels followed by North America. BP forecast Europe & Eurasia to produce 1.3 tcm in 2030 and North America to produce 1.0 tcm of natural gas. BP also forecast the Middle East to have the highest growth rate between 2010 and 2030 (3.48%) followed by Africa with 3.25%.

When the IEA, EIA and BP regional forecasts are grouped in the same way the forecasts are very similar, although BP's forecasts for the Middle East and Asia Pacific are higher than the IEA and EIA forecasts by as much as 156 bcm.

Middle East exports are one area where there is considerable uncertainty on the supply side; two issues may change the outlook from that currently forecast by the EIA and others. In the medium term Iraq has significant potential to export pipeline gas to Europe and LNG globally and in the longer term Iran could become a major gas exporter. However Iran faces some significant challenges to realise its potential; domestic gas consumption is increasing quickly and currently numerous political obstacles exist.

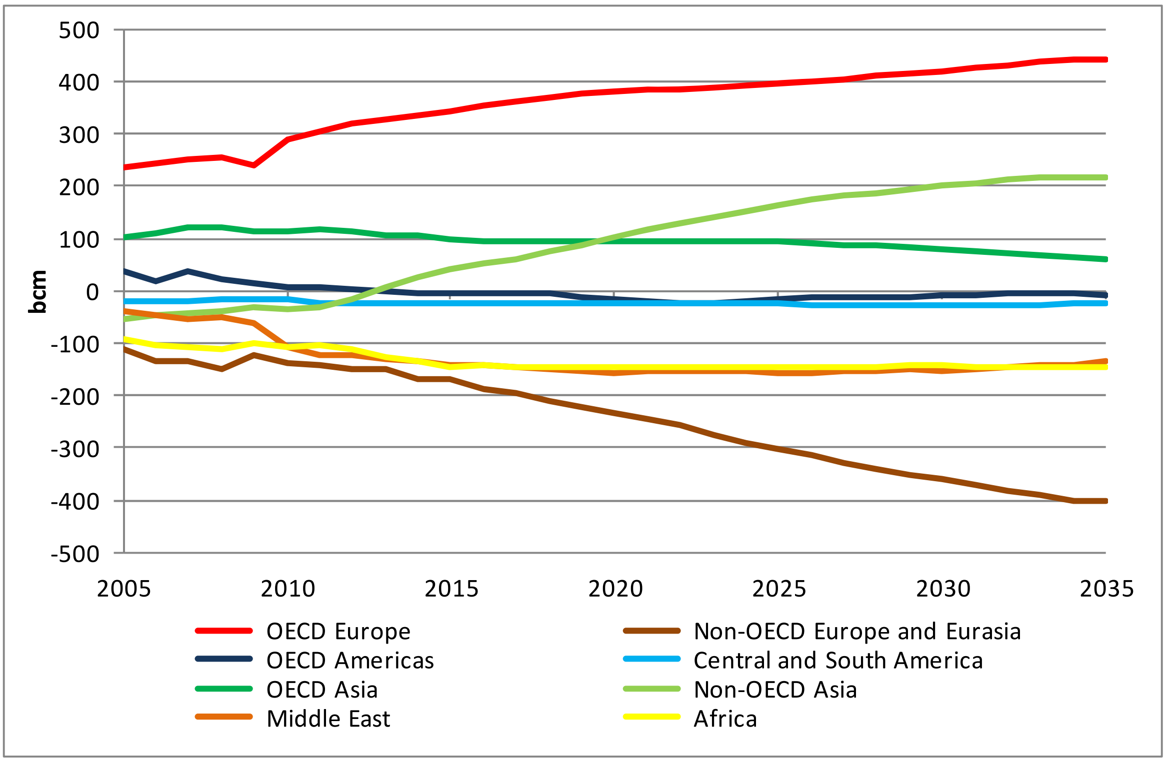
Elsewhere recent gas discovery announcements in East Africa indicate that this region could provide a meaningful contribution to LNG trade, with the likely beneficiaries being Europe and Asia. In addition, a number of commentators have suggested that Australian export projections may be over-ambitious and that the huge cost escalation seen recently could lead to several planned projects being delayed or even cancelled.

5.7 Trade

The EIA forecasts that OECD Europe will have the highest trade figures for natural gas in 2035 at 442 bcm; they will be followed by Non-OECD Asia with 215 bcm. Non-OECD Europe and Eurasia will have the lowest trading figures dropping to -402 bcm by 2035. The IEA forecast is relatively similar, although the IEA only provide three data points. The IEA differs in the forecast of 2035 trade for the Middle East and Africa and forecasts these much lower than the EIA, by 34 bcm and 144 bcm respectively.

The EIA forecasts for natural gas trade by region are presented below; negative numbers denote exports and positive number denote imports. IEA trade figures in general show similar trends. OECD Europe is seen as the main area of growth in demand, although Non-OECD Asia is also seen as an increasingly large importer over time.

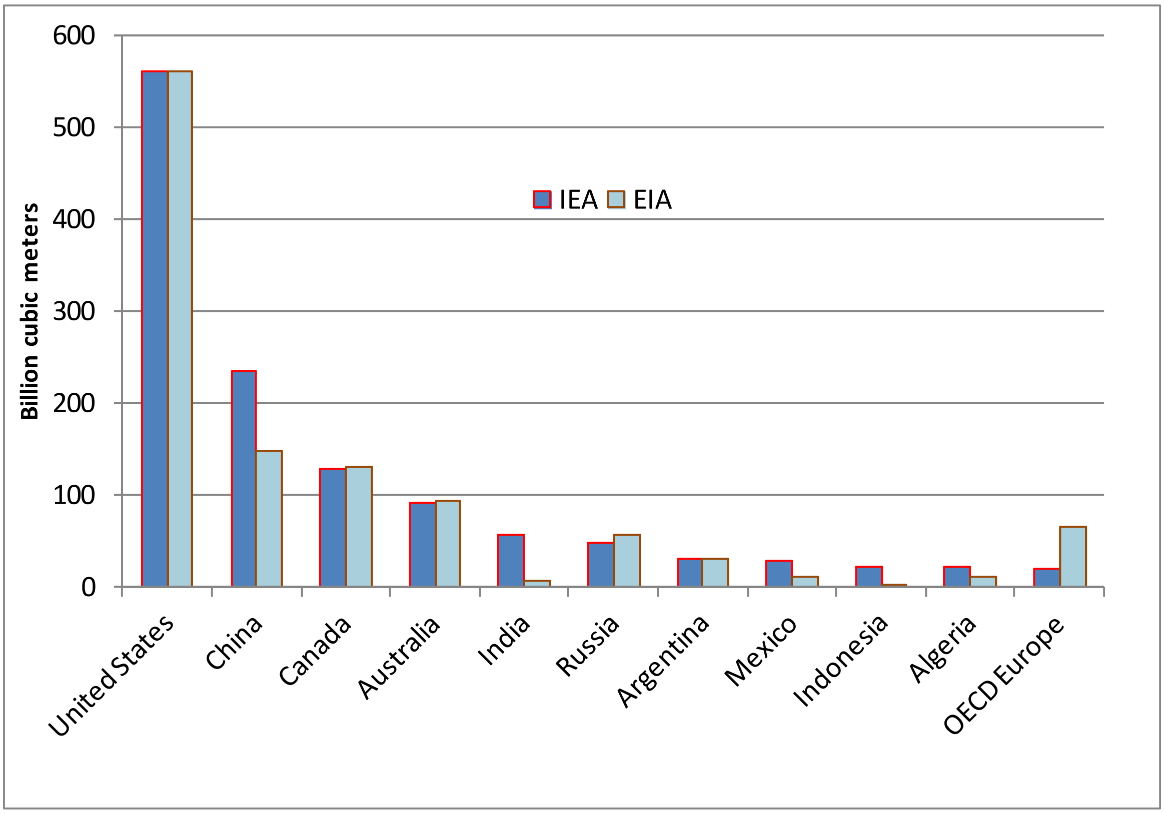
Figure 16: EIA World net trade in natural gas by region, 2008-2035, Reference case



5.8 *Production of Unconventional Gas*

The EIA and IEA forecasts of unconventional gas production in the top 10 producing countries are broadly similar. However there are some important differences. The EIA's forecast for China's unconventional gas production is about 30% lower than the IEA. India's production is considerable smaller in the EIA projections. Another interesting difference is that the EIA is much more upbeat about the prospects for unconventional gas production in Europe, with their production being three times higher than the IEA.

Figure 17: Unconventional Gas Production by Region, 2035



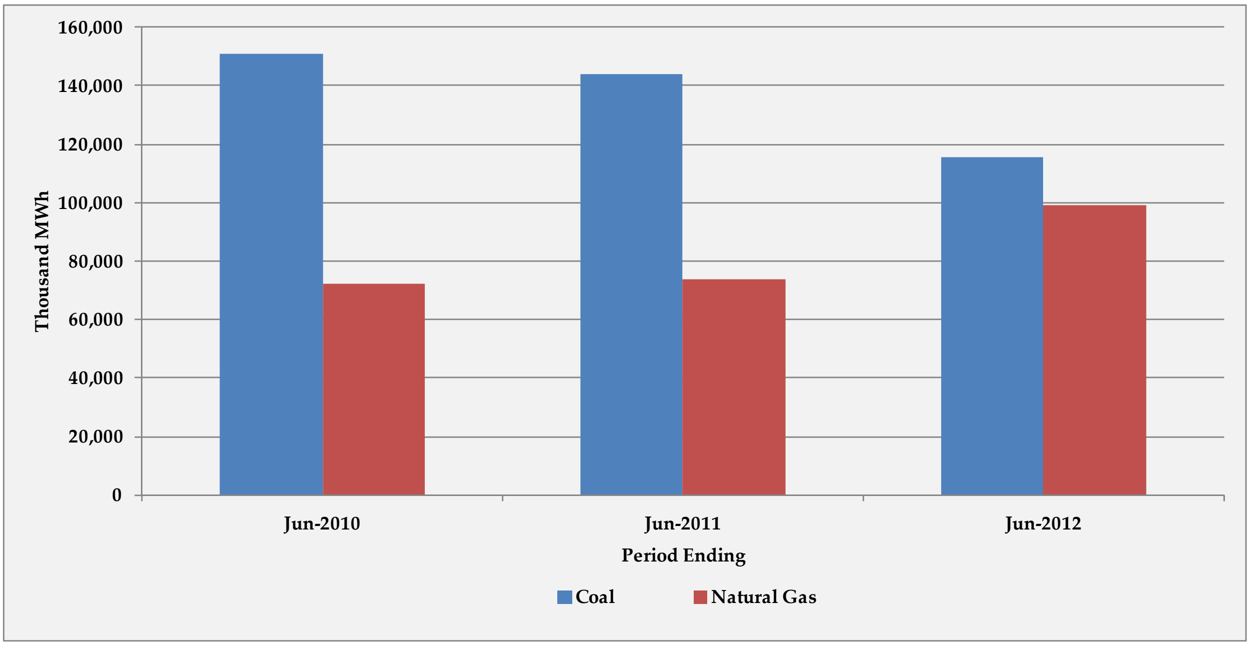
5.9 *Sensitivity of Gas Demand to Additional Supply*

Gas demand is largely inelastic to price changes, except in particular circumstances where the physical ability to shift fuels quickly exists. If supply changes and markets are competitive, then prices can fall substantially, as we have seen in the US. However, over time, changes in prices will cause demand shifts and it is important to consider this when looking at long term prospects for prices. We discuss in this section four of the key areas of demand and how each might change with gas price changes.

5.9.1 Power Generation

The ability of gas demand for power generation to react to changes in prices depends very much on the available surplus generation capacity within the market and where gas generated power comes in the cost rankings. In the US, where surplus generation capacity is available, the competitive power markets are able to react quickly to differential fuel pricing. There has been significant switching from coal to gas and this has been particularly evident for the first half of 2012.

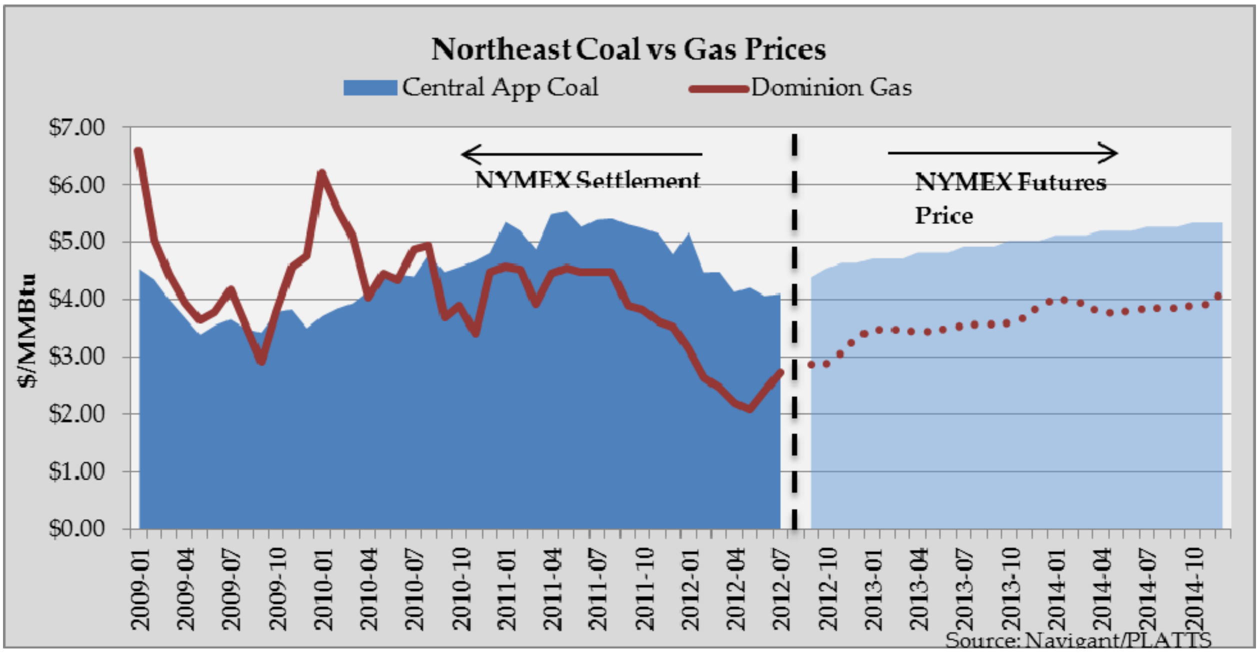
Figure 18: Average US Monthly Electricity Production by Fuel Type



Source: Navigant analysis

A comparison of coal and gas prices in the north east of the US illustrates that a material differential between coal and gas prices opened up at the later part of 2011. During the first half of 2012 power generation fuel switching became significant. Underpinning this, futures prices for gas and coal indicate that this advantage for gas will be sustained.

Figure 19: Northeast US Coal vs Gas Prices

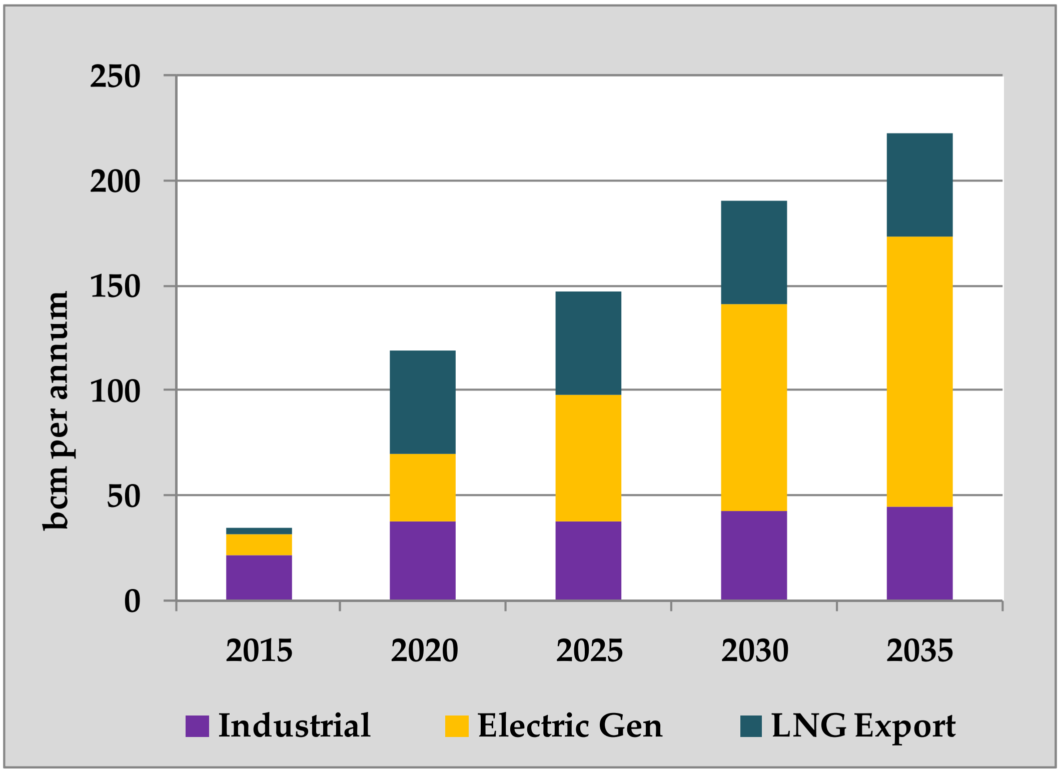


However the fuel pricing differential and consequently fuel switching is not universal across the US. Coal and gas prices in the western US did not begin to move in favour of gas until the early 2012 and the differential is not as large as in the north east. Looking at future prices in this region the price advantage for gas is not expected to be maintained. As a consequence fuel switching in the west has been somewhat limited to date.

This fuel switching is made possible by the existing availability of spare capacity for gas generation. By using this spare capacity the power companies are able to optimise the utilisation of their existing generation fleets based on fuel prices.

The optimisation of the generation fleet utilisation can be achieved quickly. Optimising the make up of generation fleet is much harder to achieve and a far slower process. Even so coal fired generation retirements, particularly in the north east of the US are accelerating. Navigant's North American energy team expects that gas use in US power generation will increase from 298 bcm/year in 2012 to over 460 bcm/year by 2035, at an annual average growth rate of nearly 2%. In total US gas demand is expected to increase by 37 percent over the period to 2035; from 790 bcm/year in 2012 to 1,080 bcm/year in 2035.

Figure 20: US Incremental Gas Demand From 2013 Levels by Sector



5.9.2 Industrial Demand

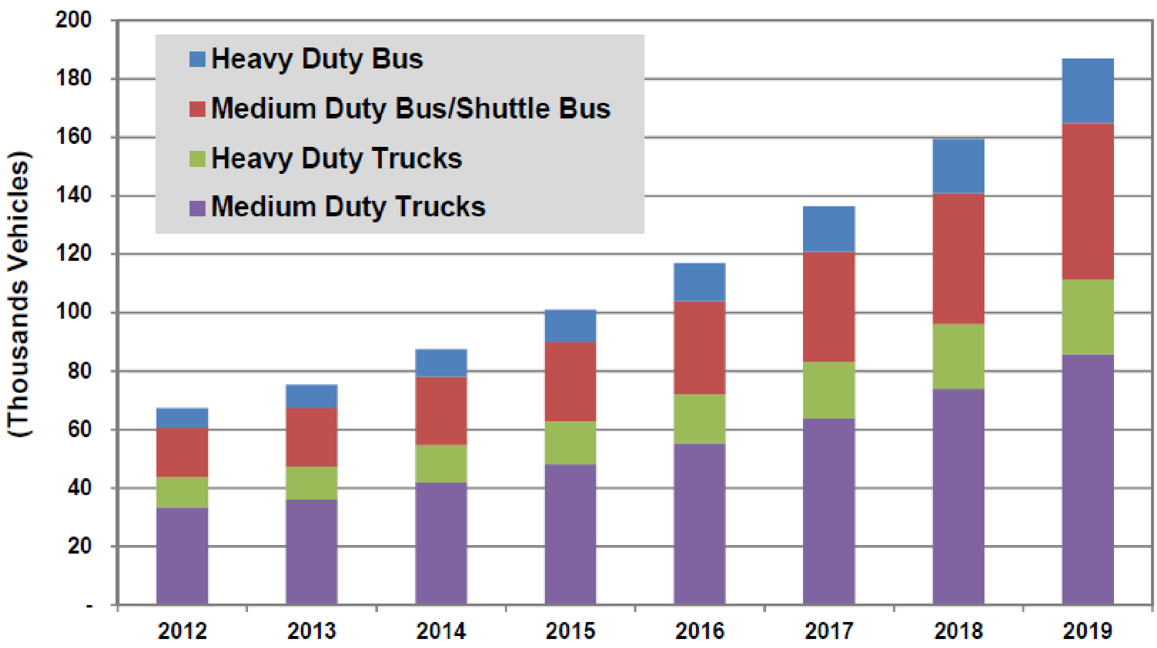
In addition to changes in power generation, industrial gas use is set to increase, taking advantage of not only the underlying low gas price but the increased availability of petrochemical feedstocks such as ethane and gas condensates, which are being produced with shale gas. The US Natural Gas Supply Association anticipates that 30 new "greenfield" industrial projects are in planning or development in the US as a direct result of the low natural gas price. The petrochemicals industry is expected to be the largest beneficiary but several steel producers are considering new production capacity as well. Beyond these greenfield developments there are 15 project expansions in progress and a further 5 restarts of previously mothballed petrochemical facilities. Some of these facilities are being develop in what would previously be considered unusual locations. For example a petrochemicals facility in Pennsylvania is being actively considered by Shell to utilise natural gas liquids being produced from the Marcellus shale gas region. By 2035 Navigant's North American energy team anticipates that gas demand from the industrial sector will have risen by 120 bcm/yr from the 2012 level, with most of this increase occurring before 2020.

5.9.3 Transportation

There are other sources of gas demand coming onto the market as gas prices fall. In particular interest in gas powered commercial vehicles (both CNG and LNG) is expanding rapidly in the US (albeit from a small base). Commercial fleets, where fuelling can take place at a central depot, have significant potential to utilise natural gas in the short term. Natural gas for private vehicles, whilst technically possible, presents a far greater infrastructure and economic challenge and therefore natural gas is not expected to make inroads into this market in the short to medium term.

Pike Research (a part of Navigant) expects the global market for natural gas trucks to grow at a compound annual growth rate (CAGR) of 14% between 2012 and 2019. Asia Pacific is the largest natural gas bus market, accounting for 86% of natural gas bus sales by 2019. While the North American and Western European markets will see strong natural gas bus growth (10% CAGR), Asia Pacific will see growth rates of 21% with India, China and Thailand leading the region in natural gas bus sales.

Figure 21: Annual Sales of Natural Gas Trucks and Buses by Segment, World Markets: 2012-2019



Source: Pike Research

5.9.4 Domestic Consumption

Domestic consumption of natural gas for heating and cooking changes very slowly. Households only change their domestic appliances infrequently, and will usually make a decision based on prices at the time of change not on expectations of future pricing. Thus domestic demand patterns will only change slowly and in response to prolonged price changes.

6. Review of European Prospects

6.1 *Supply and Demand Overview*

As discussed in the last section, European gas demand is typically expected to rise from its current level of around 550 bcm/year to around 650 bcm/year by 2030. However, there are also different views on this. In the IEA 450 scenario gas demand is expected to drop to 510 bcm/year by 2030 with the adoption of a range of climate change policies.

On the supply side, most scenarios expect European conventional gas production to continue its current decline, reaching around 170 bcm/year (IEA) or 224 bcm/year (EIA) by 2030, with Norway providing most of the conventional gas. The EIA projection is higher mainly because it predicts higher unconventional production – 65 bcm/year against the IEA's 20 bcm/year in 2035.

This situation leaves Europe dependent on imported gas. In Europe as a whole reliance on Russian gas imports may be moderated slightly but not significantly reduced. The IEA calculates that Europe will be importing close to 198 bcm/year from Russia by 2030, still in excess of 40% of Europe's import requirement. In Poland, Ukraine and other eastern European nations where unconventional gas development (shale gas in particular) is being pursued, along with LNG import terminals, the dominance of Russian gas may be reduced. For Western Europe Norway will continue to be a primary source of conventional gas supplies. LNG supply options will increase with additional North, West and later East African LNG supplies being available as the North American markets moves from import to export mode. With North American markets moving from net importers into surplus production, it is possible that LNG exports from the East and Gulf Coasts may also find their way to Western Europe – we discuss this further in section 9. The Middle East is also expected to continue to supply significant quantities of LNG into the European markets. However, the availability of LNG imports to Europe will be impacted by Asian demand for LNG and particularly China's appetite for imported gas.

6.2 *United Kingdom*

Unconventional resource estimates for the UK vary considerably. The last BGS study estimated shale gas TRR of 150 bcm, however many commentators view this as conservative and BGS are now updating their estimate of the Bowland shale in more detail. A number of the independent oil and gas exploration companies have announced estimated gas in place numbers which amount in total to around 8,496 bcm, which even on a 10% recovery rate would suggest potential shale gas TRR of at least 850 bcm. The ARI study for the EIA assessed the UK's shale gas resources to be in the order of 566 bcm.

The BGS has also investigated the possibility for CBM resources in the UK. A 2004 study identified a total resource base of over 2,900 bcm, however recovery rates were estimates to be extremely low (at 1%) due to perceived low coal seam permeability, low gas content and resource density. However, the industry view on the basis of appraisal to date is that permeability is higher and Dart Energy is confident that it can obtain commercial levels of gas flow from its development in Scotland. CBM developments in the US and Australia have shown that far higher recovery rates can be achieved (30- 40%).

To give some idea of the scale of this in terms of the UK, 2011 conventional gas production was 36 bcm and demand (consumption) was 82 bcm. So if just a 10% recovery rate was achieved in both shale and

CBM, this would exceed thirty years of current North Sea production. Supporting this analysis, many commentators have pointed out that (a) in the US, at least for shale gas, recoverability rates are between 20% and 50% of OGIP and (b) the shale gas OGIP estimate is only for the current Petroleum Exploration & Development Licence areas and more than half the Bowland shale plus extensive areas of the Lyassic shales in Southern England lie unexplored. So actual technically recoverable gas could be very considerable indeed. Several geologists we have spoken to believe that these shales are also very likely to contain liquids, making their exploitation more likely to be economic.

Having shown that there is a lot of gas in place, there has also been much commentary about the practical problems that would be faced in extracting this gas. These are many and include variations on all the issues discussed in "Political Issues" above. However, at least two of the independent companies still hope to have producing wells coming on stream next year. All of the UK unconventional gas companies we have talked to fully understand the need to gain public acceptance and trust and they each have ideas on how to go about this.

One crucial point of feedback we have had is that the economics of unconventional gas in the UK are marginal given the current supply chain cost base and current gas price. This is consistent with some of the cost analyses set out above. There are also concerns about the fiscal regime (how existing field-based regime will be converted to apply to continuous resources) and danger of over-regulation.

Overall, most sources believe that some unconventional gas will be produced in the UK, but significant quantities are unlikely to come within the next 5-10 years. Pöyry predicts between 1 and 5 bcm/year being produced by 2030, with National Grid projecting a similar range . Whilst in theory production could be much higher, this would require significant levels of investment, an acceptance by local population of a reasonable density of drilling pads and associated truck movements and a bit of luck in the geology being favourable for gas extraction.

We discuss UK gas supply, demand and pricing further in section 9.

6.3 Western Europe

There is good resource potential for unconventional gas in many other Western European countries, including France, Netherlands, Germany, Sweden and Norway. However there is the same paucity of good information on the precise geology as there is in most other countries. This will only improve after exploratory drilling.

There is considerable public opposition in many European countries , to shale gas and hydraulic fracturing. For example France and Germany have currently have moratoria on hydraulic fracturing.

Some exploration activity is going on in the Netherlands and since this is one of the few European countries with a reasonable level of conventional onshore gas production public opposition appears to be more restrained. However, capital allocation is likely to prefer lower cost conventional gas whilst new conventional projects exist. We would however expect current unconventional exploration activity to continue, which over time should lead to production as conventional reserves tail off.

The balance of opinion seems to be that any significant Western European production is some time away and exploitation in many countries is only likely once other European countries (e.g. UK, Netherlands or Poland) have proved that it can be done safely, responsibly and economically. Consequently, given the time required for exploration and then development, any significant production in these countries seems unlikely to happen within the next decade.

6.4 Central and Eastern Europe (CEE)

There are a large number of shale gas and tight gas prospects identified in CEE.

In Poland there are three separate basins being actively explored, with about 25 wells drilled to date. Although the Lublin Basin has suffered a setback, with ExxonMobil pulling out after drilling two wells saying simply that there were "no demonstrated sustained commercial hydrocarbon flow rates", a number of other companies, including Chevron and ConocoPhilips, remain active in exploration in the country. But most reports suggest that the geology in Poland is more complicated than the USA shale plays.

Hungary has extensive tight gas fields, which MOL has been exploring for the last 10 years. However large scale development of these will take some time, with initial production not currently expected until 2015.

Ukraine is also talked about as an area with major potential. Several exploration licences have been issued, with Shell and Chevron winning tenders for the Yuzivska and Olesska areas respectively. The regulatory regime has recently been changed.

Generally, most respondents consider shale gas production in Central and Eastern Europe to still be 5-10 years away. Whilst there are certainly many potential targets to explore and most Governments are being more supportive, there is still very little knowledge about the detailed geology itself, requiring substantial exploratory drilling and there is also local concern and opposition in several areas.

6.5 Conclusions

The two detailed analyses of potential European shale gas economics suggest that, even at the current high cost levels, shale gas in Europe should be at least break-even at current prices. This is also the view of some of the shale gas exploration companies that we have talked to. These analyses assume that reasonable quantities of gas will be found, or that liquids will also be present, but on a medium term view this is a safe assumption: the US experience is that as development takes place, the geology is better understood and new development focuses on the more productive areas.

Although some of the exploration companies are confident that they will get wells into commercial operation as early as next year, most commentators believe that developing scale will take some time. This is not only an issue of supply chain but also of capital – bringing production up to 28 bcm per year (1 tcf – a commonly used industry target) for 10 years could easily cost some £90 billion.

There is fairly wide disparity of views on the volume of unconventional gas production in Europe by 2030. This also varies by exactly how the studies define Europe and there is some inconsistency across the various reports on how far their definition of Europe pushes east into the FSU. However, putting geographical definitions to the side, unconventional gas is expected by forecasters to add between 28 and 85 bcm/year to European gas supply. Most base case studies still conclude that unconventional gas production will not be sufficient to fully offset the decline in conventional gas production. Only in the upside scenarios for unconventional gas is European gas production decline abated.

The general consensus is that it is unlikely that significant quantities of unconventional gas will come on stream in Europe much before 2020. However, once scale does emerge, everyone expects that the supply chain issues will largely be resolved and cost of extraction will reduce significantly. This in turn could exert significant downward pressure on European gas prices, which we discuss further in section 8.

7. Review of Global Prospects

7.1 US

Historically the US has produced large quantities of CBM and tight gas, although these are both in decline. Indeed, the recent rise in shale gas exploitation reflects the use of technology first developed for extracting tight gas from sandstone. It is interesting to note that this initial development was helped by targeted R&D grants and tax incentives, which are now largely withdrawn.

Multiple shale basins are now in production. Production of unconventional gas in 2010 was 360 bcm and TRR estimates of unconventional gas amount to 13,650 bcm.

The US remains a highly competitive market, with large numbers of players both large and small. Whilst current drilling focus has moved from gas to shale oil, the gas supply is holding up despite low prices as a result of gas associated with shale oil production, as well as some contracted drilling.

Whilst some commentators have raised notes of caution on how long the gas production can last, pointing to the rapid decline curves experienced in shale gas wells, there are still a large number of unexploited areas where shale is thought to exist and a vast unexploited resource. There is little reason to expect unconventional gas production in the US to drop any time soon.

The development and production of unconventional gas resources in North America has transformed the natural gas sector. The lower 48 states of the US particular were expected to move into terminal gas production decline and an ever greater reliance on imported gas (pipelines from Canada and LNG from Africa and the Middle East) was seen an inevitable in the mid 2000s. Now multiple LNG export project are planned. Whilst only one (Cheniere's Sabine Pass) has so far achieved the complete suite of approvals another 16 projects have approvals pending. Cheniere's project will be capable of exporting almost 28 bcm/year of gas and the capacity has already been fully sold to a number of different gas trading companies. It is planning to come into operation during 2016.

Feedback from the majority of interviewees shows a general expectation that a further 2 or 3 LNG export plants are expected to be implemented, providing in total 57 to 85 bcm/year to world LNG markets. The potential for LNG exports from the North American West coast, primarily Canada and to a lesser extent from the US Pacific Northwest, would provide the opportunity for North American LNG exports to compete in Asia. Gulf Coast LNG exports to Asia would need to transit the newly expanded Panama Canal and the economics of this voyage have yet to be finalised, since the Panama Canal Authority has stated that tolls will be related to the value of the cargo. It is thus quite likely that some if not a majority of any Gulf coast LNG will find its way to Europe.

The potential for fuel switching (particularly from coal to gas) is already being realised. In the longer term generation capacity in North America is anticipated to move more towards gas from coal as well. Industrial gas demand and commercial CNG opportunities also exist.

A number of studies have been conducted for the potential LNG exporters into the potential pricing impact of the additional gas demand in North America. Natural gas prices are expected by most industry observers to remain in the range of 25 to 38p/therm (US$4-6/mmbtu) (real terms) over the next twenty years. Due to the abundance of unconventional natural gas the export of LNG is not anticipated to make a material difference to this price expectation. Navigant's extensive work in the area of North American LNG exports certainly supports this view.

7.2 *Canada*

In Canada, there is little unconventional gas production at the moment but there are several interesting basins. In particular, the Bakken shale goes over the border into Saskatchewan and a number of companies are developing operations here. There are also a number of plays in Western Alberta and Eastern British Columbia, such as Montney, the Horn River and the Duvernay, that are now being developed.

The regulatory system in Canada is reasonably friendly to gas producers and all commentators expect Canadian unconventional gas to increase. One important issue is the free access to and from US markets under NAFTA, so Canada has been mentioned as a potential route for US gas to be exported. However this, as well as significant exports of its own gas, requires major pipeline investment either over the Rockies to the West Coast in British Columbia or eastwards to the Canadian maritime region.

7.3 *China*

External estimates of China's TRR of shale gas range from anywhere between 6,514 bcm and 36,108 bcm. There is a further estimated 16,992 to 22,656 bcm of tight gas and CBM. China's 12th Five-year Plan for Shale Gas Development released by NDRC (National Development and Reform Commission), released on 16 March 2012, has identified about 600 bcm of recoverable resources and regions containing at least 198 bcm are now available for exploration.

Figure 22: The distribution of shale gas in China

Source: 12th Five-year Plan for Shale Gas Development released by National Development and Reform Commission. Black symbols represent existing exploratory wells. Red symbols represent identified resources.

China launched the first round of shale gas exploration tender (4 explore sites) in June 2011. In September 2012, the second round of shale gas exploration tender was launched and the 20 exploration sites are located in Chongqing, Guizhou, Hubei, Hunan, Jiangxi, Zhejiang, Anhui and Henan provinces. The tender was open for Chinese energy companies or joint-ventures, with Chinese companies taking the majority stake according to the Ministry of Land and Resources.

Currently, China doesn't have any commercial shale gas production, but several demonstration projects are under development by Sinopec, Shell, BP and Chevron. The government spent nearly 100 million CNY on shale gas development in 2011 according to China Land and Resources News. According to the 12th Five year plan, the main tasks for the next three years are developing the key technologies for exploration and establishing the technical standards and regulations and national industry policies.

According to the 12th Five-year Plan, the annual production target for shale gas is 6 bcm by 2015. There is some doubt locally whether this target can be achieved, but this was expressed solely as a concern that it would take time for US technology transfer to be understood and applied efficiently to the Chinese geological circumstances. Commercial shale gas exploration is expected to take off in next five year period (2016-2020).

As a centrally planned economy, with the major oil and gas companies being State-owned, the mobilisation of significant resources to exploit unconventional gas is less of an issue in China than many other countries. After the release of the 12th Five-year Plan for Shale Gas Development, the Chinese government announced it will offer State subsidies to encourage the development in China. According to the Ministry of Finance and National Energy Administration, the developers will receive 0.4 CNY for each cubic meter (10.2 p/therm) of shale gas they developed between 2012 to 2015.

However, as shown in Figure 22 above, many of the Chinese unconventional prospects are in remote and water deprived areas. Consequently infrastructure costs to extract and bring gas to demand centres could be high.

Most importantly, many observers believe that China will find a way exploit these resources for strategic reasons, to avoid the need for major imports to meet its growing energy needs. Whilst imported LNG is currently priced at levels similar to Japan, around 89 p/therm, most internal regulated gas prices in China are set between 32 and 38 p/therm. Industry can and does pay more for excess supplies (usually pricing off LPG), but there is general resistance to paying high prices. Negotiations with Russia on new supplies is still held up because the price is currently considered unacceptable. Consequently, we would expect China to be producing significant quantities of unconventional gas within 5 years.

That China will be a big gas consumer is not in doubt. However there is considerable debate about exactly how much gas China will consume and how that gas will be sourced. The EIA is more conservative than most, expecting only 289 bcm/year by 2030. Others such as Rice University, BP and the IEA anticipate that China's gas demand will be between 396 and 467 bcm/year. One interesting observation on the IEA analysis is the lack of variation of Chinese gas demand under its various scenarios. The New Policies and 450 scenarios result in almost identical gas use figures of around 467 bcm/year by 2030, although the 450 scenario assumes radical policy changes to address climate change.

Chinese gas production is expected to cover roughly 30 to 55% of its gas demand by 2030 by most international forecasts, up from about 4% in 2011. How that gas production is achieved differs by forecast and there are significant discrepancies upon this issue. In the lowest case only 40% of gas production is expected to come from unconventional sources. In the highest case unconventional gas contributes almost 70% of the domestic production. In contrast, local sources believe that this level of increase in gas demand is unlikely to be achieved, because coal will continue to be cheaper, and consequently domestically produced gas will dominate gas consumption.

How much gas China will import is a function of both its domestic production capability and the import price. There is a range of plausible outcomes for Chinese gas imports but in essence we see two possible scenarios:

1. China puts a priority on gas supply over price and contracts most of the region's available LNG supplies, together with substantial gas supply through pipelines from central Asia and Russia. China would underpin the massive LNG expansions in Australia and North America's Pacific LNG projects, and would be the primary buyer for other regional LNG projects such as East Africa. The key driver for this scenario would be a need to reduce the growth of coal consumption, especially near Chain's major cities, with the aim of cutting air pollution levels. In this scenario China's unconventional gas production is less relevant since the overall objective would be to reduce coal consumption as much as possible.

2. China would be more selective about its gas import policy, instead choosing to invest in domestic gas production and incentivising unconventional gas resource development. In this scenario gas imports would still be an important part of the energy mix, but the price China would be willing to pay would be moderated by its desire to maintain its industrial competiveness, especially compared the United States.

Which of these scenarios is a better representation of the future is rather difficult to discern – opinions amongst interviewees differ considerably. The one certainty is that China's demand for gas will continue to grow.

7.4 Australia

Australia has large resources of both CBM and shale gas. Country TRR estimates range from between 5,664 to 11,328 bcm for shale gas and 4,248 to 5,664 bcm for CBM. CBM is expected to underpin a number of the additional LNG facilities mentioned above (BG's Queensland Curtis, Santos' Gladstone and ConocoPhillips' Australia Pacific). Additionally the first commercial shale gas production outside of North America was recently brought on line by Santos in the Cooper Basin, South Australia. Production is currently 0.076 mmcm/d. The shale production site is located next to one of the main gas pipelines and close to a gas processing plant. Integration of the shale gas into the gas transmission system was completed quickly and at relatively low cost.

There is the potential for shale gas and CBM to be complimentary in Australia. CBM typically produces very lean gas, whereas shale gas is often, but not always produced with natural gas liquids (LPG and condensate). The Asian markets that the Australian LNG exporters would be targeting often require rich gas and LPG injection would be required to meet the target customer gas specification. By blending shale gas and CBM, or using the LPGs extracted from shale gas, the economics of the CBM LNG projects could be improved.

One issue that Australia is struggling with on its LNG export projects is cost inflation. Labour and other costs are currently very high, primarily due to the large number of projects (oil, gas, mining etc) being undertaken in Australia in a compressed timeframe. It is possible that a number of the planned and proposed projects may get delayed or even cancelled as the high costs may make these projects uneconomic. A further issue for consideration is how the CBM LNG projects would compete with LNG exports from North America, particularly if one of the proposed export projects from the Canadian West coast can be completed. As a result of this, it may well be that shale exploitation is delayed until the current big LNG and CBM projects are completed, with only exploration activities being carried out in next several years.

Finally there is the potential for Australia's gas resources to facilitate industrial development. However the gas resources are located far from major urban areas and so the sort of industrial renaissance expected in North America may be more challenging for Australia to replicate.

Australia also has few of the population density problems that Europe faces. Bigger issues are route to market (domestic demand is low, so liquefaction is required) and in some areas water supply is restricted.

Australian gas demand is fairly modest at under 25 bcm/year. In comparison gas production is currently 45 bcm/year, with the difference being exported as LNG. Australia's LNG capacity is being expanded with seven projects in construction and these have a total additional capacity of 76 bcm/year. A number of other projects are planned that would bring Australia's LNG export capacity to the same level as Qatar (105 bcm/year). Further expansions and greenfield developments have been proposed, which if implemented would propel Australia to the world's largest LNG exporter with a total capacity in excess of 127 bcm/year. These LNG exports would be delivered into Asia and primarily China.

In conclusion, Australia has all the fundamentals needed to produce unconventional gas in significant quantities. The major barrier to further development will simply be whether customers exist to take the gas at a price high enough to justify development.

7.5 Latin America

Gas demand in Latin America is forecast to increase by approximately 2.5% pa through to 2030 but this will be more than met by increases in domestic gas production. LNG exports are expected to increase by 14 bcm/year by 2030.

Latin America is believed to have large shale gas resources, particularly the Vaca Muerta Basin in Argentina, where YPF has drilled some 30 exploratory wells already. Exploitation of these resources could potentially make a big contribution to the region's energy needs.

However the current policies of "resource nationalism", particularly in Argentina but also other nations, cast doubt on the region's ability to raise the considerable capital required to exploit these resources. Most observers believe that Latin America has long term potential but are sceptical that this will lead to substantial production even within 20 years because international investors will prefer to put their scarce capital into more reliable constituencies.

7.6 Middle East and Africa

The Middle East and North Africa also have considerable potential for shale gas, but with their own conventional resources and low lifting cost, as well as water scarcity, significant production in the near future is considered less likely. Whilst Algeria has announced the intention to explore its shale gas resources, its fiscal regime is likely to deter investors, and this is true of other countries in the region too:

fiscal regimes designed for low cost conventional gas are often inappropriate for the more expensive unconventional plays

Saudi Arabia is looking with interest at the potential for shale gas and tight gas in its country, since it is short of gas to meet domestic demand for power and water (obtained through desalination). Saudi Aramco may thus carry out some unconventional gas exploration, however if this leads to production it is likely all to be consumed internally, displacing oil currently used for power generation.

Gas export capacity, both pipeline and LNG is expected to increase significantly across the Middle East and the African continent. Most additional production will come from conventional gas resources. East African LNG is a particularly interesting development as exports could reach either Europe or parts of Asia at broadly equal cost. Iraqi gas reserves, particularly in Kurdistan, could reach Europe via the Nabucco pipeline if that is eventually built – but this is at least five years away. In the longer term, assuming a political settlement that allows the current sanctions to be relaxed, Iran could develop into a major LNG exporter. Egypt's gas industry is currently suffering from a lack of investment in new production, however long term potential remains.

7.7 Russian and Central Asia

Many observers, including Russian nationals, believe that the considerable conventional resources of Russia mean that unconventional resources will be ignored for many years. A more sophisticated view is that the Russian oil and gas companies will certainly look at where they may have access to unconventional resources, but would only exploit them if it were cost effective to do so.

As a major exporter, Russia will continue firstly to do its best to maximise its overall revenue. If shale gas or CBM appears to be more cost effective than new conventional supplies, for instance those in the Arctic, then we would expect those resources to be developed. There has certainly been some development done on CBM resources in the Kuzbass basin area by a subsidiary of Gazprom, with planned production initially being 3.96 bcm/year. This would supply local demand and not be exported.

7.8 India

India is thought by many to have considerable CBM resources and potentially shale as well, although many of the main reports do not deal with it in any detail. There is considerable difference of opinion, however, about if and when these resources might be developed. Whilst there is no doubt that India needs the gas, the current regulatory structure and State owned industries creates considerable barriers.

One can take a more nuanced view with India that, if ways are found to exploit its indigenous resources, then most if not all of these will be consumed locally.

7.9 Other Asia

Besides China another potentially interesting development in Asia is the increase in nations seeking to implement LNG import projects. Regasification projects, floating and traditional onshore facilities are in development of have been proposed in Vietnam, Indonesia, Pakistan, the Philippines and others. This expansion in LNG off takers could help to create an LNG network in Asia.

Indonesia also has substantial CBM assets, which tend to have been overlooked by the main global resource reviews. Pöyry quotes the Indonesian Ministry of Energy and Mineral Resources as estimating the total CBM resource at 12,801 bcm (presumed to be gas in place).

7.10 Mexico

Mexico has the potential for large unconventional resources, particularly in the North near Texas. However, there is a question mark over whether Pemex can find the investment resources, or if not whether Government will permit third party/private-sector involvement.

7.11 Conclusions

North America, particularly the US but increasing Canada too, will continue to expand unconventional gas production to meet domestic demand and some exports.

China is very likely to invest significantly in its own unconventional gas resources, both for security of supply reasons and as an alternative to expensive LNG and is expected to become a major producer within about 5 years. China will still remain a net importer, but if its own production is large enough it could disrupt the Asian LNG market in the same manner that increasing US domestic production disrupted North Atlantic LNG.

Australia will continue to develop CBM and increasingly shale gas for export, as long as sufficient prices are achievable; this is highly sensitive to Chinese demand for imported LNG and the price it is willing to pay for it.

The general consensus seems to be that other areas of the world are less likely to produce significant quantities of unconventional gas within the time frame under consideration.

8. Key Sensitivities and Barriers to Investment

8.1 Key Sensitivities

There is a lot of uncertainty over many of these potential outcomes. The key factors that could have most effect are:

- the ultimate recoverability of unconventional gas in place;
- the approach taken by China to meeting its own rising energy demand;
- the potential for "political" barriers to delay or frustrate development of unconventional gas despite economic attractiveness;
- the lack of development of the necessary supply chain making the prospect initially uneconomic; and
- the effect of global or regional climate change policies on gas economics and ultimately gas demand

8.1.1 Recoverability of Gas in Place

The biggest uncertainty is the recoverability of unconventional gas in all the basins which have not yet been fully explored. One really needs drilling to improve the knowledge base and this takes time and capital.

Whilst the US experience is that, eventually, commercially viable solutions have been found to exploit all main basins, this may not be the case elsewhere, particularly where economics are seen to be marginal. In any event, the investment required to explore these areas is considerable and where either "resource nationalism" or perceived barriers to development dissuade investors from exploring, some potential resources may remain unexplored for years.

In addition, technology has already had a huge impact on recoverability and may continue to do so. Certainly industry commentators say that there is still room for further improvement in understanding the geology and in drilling efficiency.

8.1.2 China

Chinese demand and particularly its appetite for LNG, will have a significant effect on global LNG markets and thus on prices.

If China acts as an "LNG sink", taking as much gas as possible with more regard to volumes than price, then development of gas resources worldwide will be high but prices will be unlikely to fall. In this scenario, new sources of Middle Eastern and East African LNG would all be directed to China, US LNG exports would also head for the Pacific and the North Atlantic LNG market would tighten.

If however China decides that it needs to keep its energy prices as low as possible, in order to compete with the low US prices, it is more likely to develop its own gas resources, keep more coal in its fuel mix and only take imported gas when prices are acceptable. In this scenario, LNG markets would probably have several years of volatility, until other Asian gas markets increased demand as existing resources depleted.

8.1.3 "Societal" Barriers

We have discussed the various non-economic issues faced by unconventional gas developments in section 4 above. There is no doubt that, in many countries, particularly in Europe, such issues are currently a major barrier to development. Given that these are not factors that businesses themselves can easily address, it will require some form of Government intervention to unblock development where these barriers are substantial.

8.1.4 Supply Chain Limitations

The supply chain limitation is an economic issue, but can lead to a "chicken and egg" dilemma. As described in section 3, as investment in unconventional activity increases, there is every reason to believe that unit costs will decrease quite significantly over time. However, at present in Europe and other undeveloped areas, the economics of unconventional extraction are marginal. It will therefore take one or more investors who are willing to risk the cost reductions coming quickly to get things moving. But these investors may prefer to put their scarce capital to work in the US, where the cost base has already fallen.

Whilst Governments can hope that market forces will eventually make these investments happen, they can assist the decision making process by modifying fiscal terms so that early investors' risks are moderated.

8.1.5 Global Climate Change Policies

The other factor that could also significantly affect the future path is how global climate change policies develop. There is a clear role for gas as a back-up fuel to cover intermittent renewable generation for many years to come, until such time as energy storage technology becomes cost effective or a technology breakthrough occurs, but future projections as to demand are very variable.

Consequently, whether unconventional gas forms part of this back-up will depend on the economics surrounding future energy markets and the strategies taken by the major suppliers of conventional gas. If underlying gas prices (excluding any carbon tax or similar charge) rise, then there will be a clear incentive for unconventional gas production in localities where there is little conventional gas production.

If however gas prices (excluding any carbon tax or similar charge) fall, as the major gas suppliers reduce prices to maintain volume in a shrinking market, there may be no economic sense in exploiting unconventional gas as long as existing conventional supplies are available.

There is a potential technology factor here which could further complicate the economics, since both coal and shale can act as a CO_2 sequestration agent. If CO_2 is pumped into a coal seam, it is absorbed by the coal and methane can be released. Thus a number of research projects are looking into whether systems can be developed to combine Carbon Capture and Storage with CBM or shale gas extraction.

8.2 Barriers to Investment

The major barrier to investment in unconventional gas at present is the outright ban on hydraulic fracturing in many countries following public concern about the technique and the potential that the various reviews going on could lead to over-onerous environmental legislation.

All commentators agree that gaining public acceptance is key – as is confidence in regulation. The issue for Governments is thus how to find a balance between demonstrating to the public that safety and the environment is paramount without putting so many costs on industry that investment is made elsewhere.

An important part of this is making sure that regulations are "objective based" rather than prescriptive, so that innovation is encouraged and also that decision making on approvals is fast and efficient, to avoid delays. The feedback we have had from industry is that they welcome a proper framework of standards that are clearly stated and monitored and they understand that regulators need the powers to crack down hard when someone fails to meet those standards. What they require in return is operational flexibility within those standards and a minimum of delay.

Ensuring local communities get some of the benefit from the gas extracted is very helpful in gaining local acceptance. However, structuring this is not easy, since every community has different characteristics and different needs. Central Government can be helpful in this, in setting out guidelines and making sure that regulatory structures allow appropriate contributions. However there needs to be considerable local flexibility to make sure that the precise form of contribution meets local needs.

An important lesson from the US is that research and development grants made a significant contribution to developing the hydraulic fracturing and horizontal drilling technologies that have allowed the exploitation of hydrocarbon reserves once thought unreachable. Similar grants or tax allowances may be helpful to adapt that technology to other countries' specific problems. Similarly, encouraging the research into CCS within coal and shale and how to combine this with gas production, may prove extremely valuable in ensuring that local investment in the gas industry continues as climate change policies begin to bite.

Fiscal calculations can make all the difference to an investor's choice of country or region. Fiscal regimes based on conventional hydrocarbon operations can create extra economic barriers and many need adapting for unconventional operations where there is no clearly delimited reservoir. In addition, the higher cost base and continuing capital requirements of unconventional gas extraction may need consideration when reviewing tax rates and capital allowances. The other message we have had is that, for the major investments required, particularly in the exploration and development stage, the expectation of a steady and predictable fiscal regime is an important investment criterion.

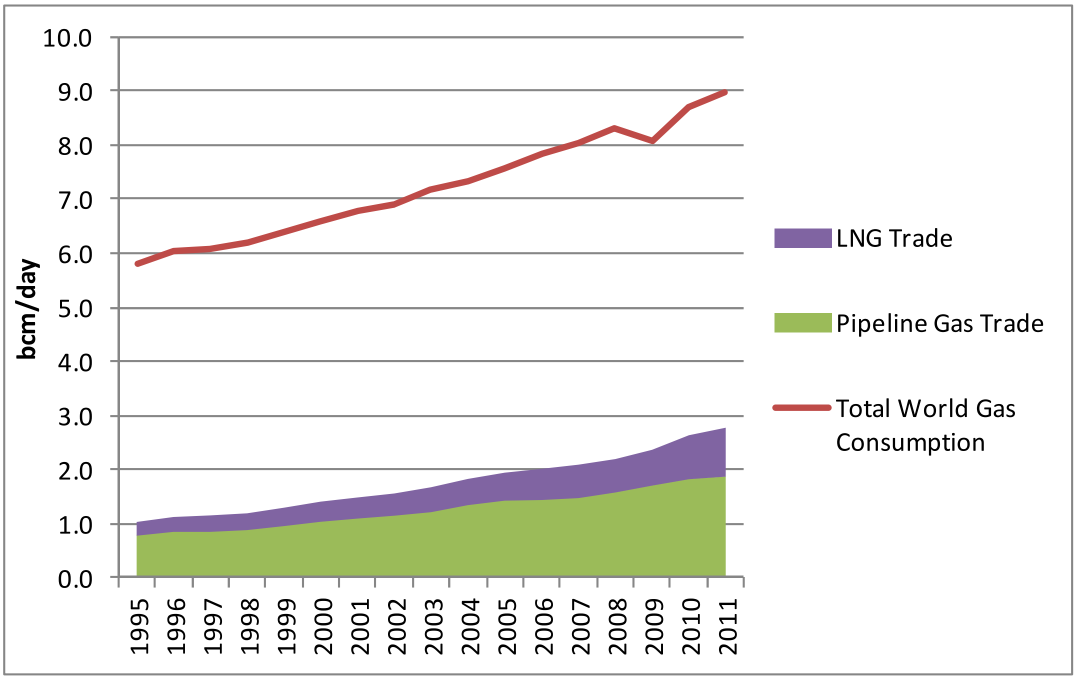
Free markets will help both gas price flexibility and reduction in the supply chain cost base. US export approvals should be encouraged as they will bring much needed competitive pressure to the North Atlantic. Similarly, given the need for considerable investment in drilling rigs if Europe is to scale up unconventional gas production, a review of the different rig standards between the US and EU to consider whether these could be harmonised would allow US rig manufacturers to supply the EU market with greater ease.

9. Gas Market Pricing

9.1 *The Tyranny of Distance*

Global gas consumption in 2011 was 8.8 bcm/day. Of this approximately 30% was traded internationally, either as pipeline gas (1.9 bcm/day) or shipped as liquefied natural gas (LNG, 0.9 bcm/day). Whilst international gas trade is growing at almost double the rate of gas consumption (6.5% against 2.7%) international gas trade is still a significantly lower proportion of gas production than international oil trade is of oil production.

Figure 23 Gas Trade bcm/day



Source BP Statistical Review 2012

Part of the reason for only one third of gas production being internationally traded compared to two thirds of oil production (either as crude oil or refined products) is because of the high transportation cost of gas. Transporting gas is expensive compared to moving oil. The transportation cost can be a material component of the delivered gas price. Depending upon distance, transportation method and gas pricing methodology the transportation cost can contribute between 10 to 50% of the delivered wholesale gas price. Cheniere have recently summarised the costs of shipping LNG from their terminal at Sabine Pass to Europe and Asia as set out in Table 8 below.

Table 8: LNG logistics costs

Cost of delivered gas from Sabine Pass to Europe/Americas & Asia = $8 - $10 / MMBtu

($/MMBtu)	Europe/Americas	Asia
Henry Hub	$ 4.00	$ 4.00
Capacity Charge	2.50	2.50
Shipping	1.00	2.80
Fuel/Basis	0.60	0.60
Delivered Cost	$ 8.10	$ 9.90

Source: Cheniere presentation March 2012

A comparison of the energy densities of crude oil, LNG and pipeline gas provides one explanation as to why gas is more expensive to transport than oil. One cubic meter of oil can provide approximately 340 therms of energy whilst one cubic meter of LNG only provides 210 therms, 40% less than for a cubic meter of oil. This comparison is made even more compelling when the cost of transforming gas into LNG is taken into account. A world scale liquefaction plant currently costs around £506 per ton of plant capacity. Such a plant can typically process around 5.5 million tonnes of LNG a year, costing in the region of £2.8 billion. At the other end of the delivery chain the LNG has to be regasified and a large onshore regasification facility can cost in the order of £316 million. In addition some of the gas is consumed along this complex transportation chain. Approximately 13% of the produced gas will be consumed to fuel the liquefaction, shipping and regasification processes.

Transporting gas though pipelines is also far more expensive than transporting oil in a similar manner. Compared to the 340 therms per cubic meter for oil, pipeline gas provides only 7 therms for each cubic meter delivered. Typical pipeline costs for a 5,000km pipeline would be between 12 and 19p/therm[19] depending upon pipe diameter.

Gas transportation costs could potentially be reduced by the implementation of smaller scale, lower cost floating LNG systems. Additionally such technologies may enable the commercial exploitation of smaller more remote gas resources. However despite this and other advances in gas transportation, gas will remain significantly more expensive to move around the globe than oil. The impact of the transportation gas on the gas markets has led to the divergent pricing of gas markets around the globe, as the ability to arbitrage prices across countries and regions is in part constrained by the cost of moving the gas from production source to demand centre.

9.2 *Gas Pricing Mechanisms*

Gas pricing is currently highly regionalised and unlike oil there is no single price that can be reasonably applied to gas across the globe.

In North America gas is commonly priced at infrastructure hubs, the most commonly quoted of which is Henry Hub in Louisiana. The gas price is set at these hubs based on the competitive supply of and demand for gas. Multiple factors influence the gas price at these hubs including availability of pipeline capacity to ship gas to end users, gas storage inventories, weather patterns, gas import availability from

[19] Polinares working paper no 24, Transport of Natural Gas, March 2012

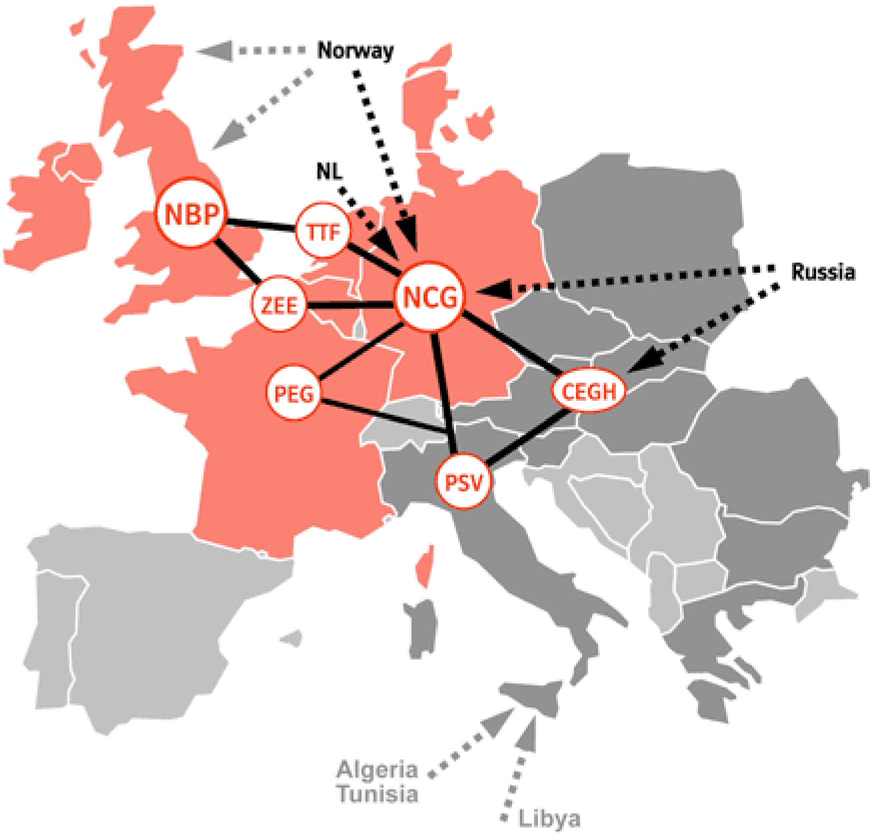
LNG or pipelines from Canada, underling gas demand profiles, coal and nuclear power production prices, gas supply constraints and so on.

In Asia LNG supplies are predominantly priced by reference to oil or other commodity indexation. The pricing formula typically averages the oil price over a number of months to reduce pricing volatility. The pricing mechanisms can include variable indexation and / or floor and ceiling prices, so called "S-Curve" formula. Pipeline gas trade is currently limited to small gas volumes flowing into Singapore from Indonesia and Malaysia. The prices for domestically produced gas vary by country but are often regulated and can be significantly below what would be considered a market price in other regions.

In Europe two price setting mechanisms exist. Most gas pipeline imports and some LNG import prices are indexed to a variety of other commodities. Oil (both crude oil and / or refined products) is a common indexation mechanism but gas prices have also been indexed to coal or electricity prices. Inflation and other economic metrics are also components of some gas pricing formulae.

Competitive gas pricing hubs also exists in Europe. The UK's National Balancing Point (NBP) is the most well-known and heavily traded of the European gas hubs. NBP, established in 1994, is the wholesale gas price setting mechanism in the UK and prices are set competitively based on the market for gas. However this hub price is also influenced by oil indexed gas pricing through the UK's connection to continental Europe.

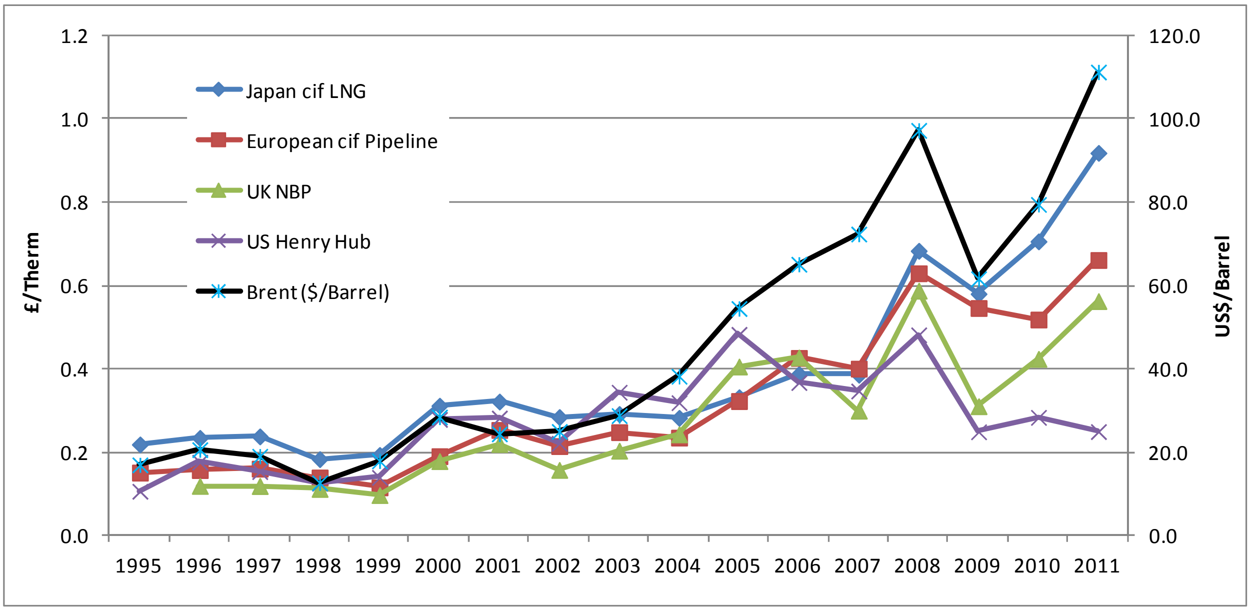
Figure 24: Main European gas hubs



Source: Eon

The other gas pricing hubs across Europe include: Zeebrugge Platform, Belgium (ZEE), Title Transfer Facility, Netherlands (TTF), Gas Exchange Point, France (PEG), Net Connect Germany (NCG), Gaspool, Denmark (GPL), Single Balancing Point, Spain (CDG), Virtual Exchange Point, Italy (PSV) and Central European Gas Hub, Austria (CEGH).

Figure 25 Annual Average Oil and Gas Prices



Whilst the gas pricing mechanisms used around the globe vary, which resulted in different absolute pricing levels, oil and gas prices historically tended to follow a similar pricing trend. However the advent of large scale shale gas production in North America has disrupted this relationship. As late as 2008 there was an expectation from the US EIA (and others) that around 60 bcm/year of LNG imports would be required by 2015 for North America. As a consequence over 50 LNG import terminals were proposed to be built on the coasts of the US, Canada and Mexico. A number of LNG export terminals were built in West Africa (Angola, Nigeria and Equatorial Guinea) and the Middle East (Qatar) primarily with the aim of supplying the North America gas market.

Very few of the proposed North American LNG import terminals actually got built. Now the expectation is that North America will be a significant net exporter of LNG by the end of this decade. Most of the North America's LNG import facilities have applied for permits to convert to liquefaction and therefore export mode. In addition to the conversion of the existing LNG import terminals a number of new LNG export facilities have been proposed, including several on the Pacific coast.

The abundance of shale gas in North America has held gas prices down at 25p/therm even as oil prices have risen from a low of $33 per barrel at the end of 2008 to back over $128 per barrel in early 2012. During 2012 gas prices have dropped as low as 16 p/therm.

The downward price pressure in North America has also been felt indirectly in Europe too. The majority of LNG volumes that were anticipated to be delivered to North America were no longer required. This LNG therefore needed to find a new market. These additional LNG supplies became available in Europe and at the same time European energy demand was falling due to the overall economic impact of the 2008 financial crisis. These two factors changed the balance of gas supply and demand in Europe and had the effect of lowering the gas price at Europe's gas trading hubs. The lower European gas hub prices had a very substantial impact on some of Europe's major energy companies. These firms were tied into long term gas pipeline supply contracts that indexed the gas price to the price of oil. The oil price was rising and the price indexation formulae were leading the pipeline gas prices to also rise. A number of Europe's energy firms incurred substantial losses on some of their gas supply contracts as the oil indexed purchase price was substantially higher than the hub based wholesale gas price. Europe's hub based gas prices are currently below the level that would be implied by the gas pipeline import contracts, but are still some way above the prevailing gas prices in North America.

Some of the LNG diverted from North America has flowed to Asia and particularly Japan following the nuclear incident at Fukushima. Asian LNG prices have continued to rise in line with the oil indexation formulae of the main supply contracts. There has been limited downward movement on Asian LNG prices, in contrast to the situation in Europe. Two factors have helped to support the oil indexation status quo in Asian. Firstly, unlike Europe, Asian gas demand remained strong, mainly as a consequence of reduced nuclear power generation in the region following the Fukushima accident. Secondly there is currently no alternative gas price setting mechanism in Asia, since there are no competitive gas pricing hubs are there are in Europe.

9.3 How Oil (Trading) Became Global

When the modern oil trading system began to evolve the 1980s, several sources of oil emerged as benchmarks (or "markers") for each of the key trading regions, against which nearly all other crude oils around the world are priced. Today, the major markers are:

Marker	Applicable Regions
• Dated Brent	Europe, Africa, Middle East (prices >60% of global oil supplies)
• West Texas Intermediate (WTI)	North and South America
• Dubai and Oman	Middle East and Asia

But it wasn't always like this. Up to the 1970s, when concerns about an "energy crisis" first emerged, crude oil price markers, forward hedging and the use of derivatives did not exist. For decades, most of the world's supply of crude oil had been handled through long term arrangements between producing countries (some of which eventually joined OPEC) and the major international oil companies (the "Seven Sisters"). An inflexible supply system, combined with lack of price transparency, virtually assured that if a physical supply dislocation occurred, other crude oil could not be easily reallocated because the necessary market signals did not exist.

This rigid system began to break down when OPEC emerged in the late 1960s. It caused the majors to lose control of supply from well head to consumer. The so-called "energy crisis" was actually a "supply inflexibility crisis."

As more cargoes began to appear that were not part of the majors' global supply systems, physical spot trading of crude oil and fuel products emerged. By the early 1980s, traders had learned how to arbitrage differences in these emerging spot prices between regions and continents. This was the trigger for the modern oil trading networks that are in place today, which has assured smooth delivery of oil to global markets despite such unpredictable events as wars, hurricanes, revolutions etc. Physical spot trading was soon following by the ability to hedge price risk. The crude oil markers listed above are a key element of this structure.

Oil supply has always been "global" simply because moving liquids is relatively straightforward and not technically complex. Transporting oil is also relatively cheap compared to the value of the underlying oil price. Trading became global in response to a change in industry structure.

9.4 Will Gas Markets Become Global?

Recently changes in the North America gas market (primarily production of shale gas in large volumes) have had knock on consequences for the gas price in Europe. However whilst the availability of LNG has increased in Asia, the price of the LNG imported into the region has not appreciably moved from the traditional and expected level set by oil indexation. Rather than bringing gas prices closer together, the availability of shale gas in North America has, for the moment at least, created greater disparity between regional gas prices.

So could gas pricing ever become global? Currently gas pricing is regional in part due to the lack of connectivity between gas producers and consumers and the comparatively high costs of transporting gas around the world. Gas transport via pipeline is inflexible with fixed supply and destination points. Creating a pipeline network can increase flexibility, but restrictions still exist as the end points of the network remain fixed and the majority of gas pipelines only flow in one direction.

Shipping gas (as LNG) is potentially more flexible, but that potential has yet to be fully realised. The majority of LNG projects are based on bilateral sale and purchase contracts, much like a pipeline. This is because the LNG projects require very large investments in liquefaction, shipping and regasification assets. Financing an LNG project usually requires that contracts are put in place for the majority of the LNG sales before a spade is turned on the project's construction.

Flexibility in LNG trade is increasing and spot or short terms LNG trades now accounts for a larger share of the LNG market than a decade ago. This is a result of the de-bottlenecking of liquefaction facilities (increasing LNG availability beyond the initial production volumes), an increase in LNG shipping not tied to long term contracts and a rise in the number of nations developing regasification terminals. However this is still a long way short of the share of spot or short terms trading for oil and the flexibility available for sourcing and delivering oil.

Flexibility and connectivity of gas markets will increase as traded volumes grow. This will be helped by the significant LNG volumes that are anticipated to be supplied from North America. If LNG can be exported in large volumes from the Gulf and Pacific coast then the LNG industry will experience a step change in connectivity. Australia is also rapidly expanding its LNG export potential and these LNG volumes will also add to the LNG market's supply options.

As well as the underlying market connectivity and trade there will need to be the development of competitive gas pricing markers along the similar basis that exist in the oil markets. These markers are often based around the potential for multiple suppliers and buyers to trade gas at a hub. Physical gas storage in reasonably close proximity to the hub is usually, but always, available to facilitate trading activity. As well as physical trading of gas at these hubs financial trading (in gas futures or other derivatives) is an important element in the successful development of the hub into a price marker. At successful hubs the financial trading volume often dwarfs the physical traded volume. It is this combination of physical and financial traded volumes that provides the "liquidity" in the market for the hub to operate efficiently as a price marker.

These markers exist in North America, the UK and are gaining prominence in continental North West Europe. The redirection to Europe of LNG volumes originally intended for delivery to North America (as well as the re-export of LNG cargoes from the US Gulf) has created an indirect link between the North American and European gas markets. The possibility of LNG exports from North America to Europe will strengthen this relationship. These exports will likely not lead to the European gas price dropping to a North American level as the costs of LNG transportation is significant, as discussed earlier. North American LNG could probably be delivered into a European regasification facility in the region of 50 to 65 p/therm currently, assuming an underlying Henry Hub price in the region of 25 to 38 p/therm. As a result gas trading across the Atlantic will probably increase significantly as companies seek to identify and take advantage of price arbitrage opportunities that may develop. This arbitrage will in part be determined by the development of pricing for Europe's pipeline gas imports. The vast majority of the (long term) contracts for these gas volumes still stipulate oil indexation. Recent contract renegotiations and arbitrations have started to chip away at this oil pricing link, but it is probable that oil indexation will continue to exert some influence over European gas prices for some time to come.

Large scale North American exports into the Pacific also have the potential to influence Asian gas prices. The development of multiple projects in Australia, some of which on the east coast are based on the exploitation of CBM resources may also help to increase gas (LNG) trading connectivity. However Asia is currently lacking a viable pricing hub though which competitive gas prices could be established. Another current impediment to competitive gas pricing is the willingness of some Asian LNG purchasers, notably Japan and South Korea, to pay a price premium to secure long term stable gas supplies. The lack of domestic energy resources has lead these nations to place a high commercial value on security of supply, which has resulted in traditionally higher prices for gas in the Asian region than either Europe or North America.

What options exist for a competitive gas hub in Asia? Currently Asia lacks pipeline connectivity on the scale of North America or even Europe. The geographic nature of the Asian continent makes pipeline connectivity and the development of an integrated pipeline network difficult and vastly expensive. An LNG based trading hub is more likely, although still challenging. One possible option is the development of Singapore's LNG facility into a competitive gas pricing hub. Singapore has the advantage of its physical location being (relatively) near to both large suppliers and purchasers of LNG. It is also connected by pipeline to both Malaysia and Indonesia. However the actual Singapore gas market is small compared to its neighbours and redelivery options are (currently) somewhat limited. Gas storage is also constrained, this could be partially addressed by using LNG carriers moored offshore as temporary storage.

Another possible option for a competitive gas or LNG hub would be a location on the Chinese coast. The potential tie in to China's West-East pipeline system could provide for significant volumes through the hub. However growing gas demand in China may limit LNG re-export potential and therefore it is unclear how significant truly tradable volumes would be. Additionally the transparency of a pricing mechanism at a Chinese based hub may be challenging to validate, at least in the short term.

Our interview feedback concluded that a truly global gas price may be possible in the very long term however a number of obstacles remain to be addressed. Greater interconnectivity between North America and Europe gas markets is assured but a pricing differential is expected to remain in place. None of our interviewees saw European prices dropping to North American levels simply as a result of LNG exports from North America. The majority view was that creating a robust and tradable competitive Asian gas pricing mechanism remains a challenge. However a couple of interviewees thought that a Singapore LNG pricing hub may be possible but would take some time to develop scale. Above all the biggest obstacle to a global "one price fits all" gas price is that gas (and LNG) transportation is expected to remain expensive and a material component of delivering gas from supply to end users across and even within regions.

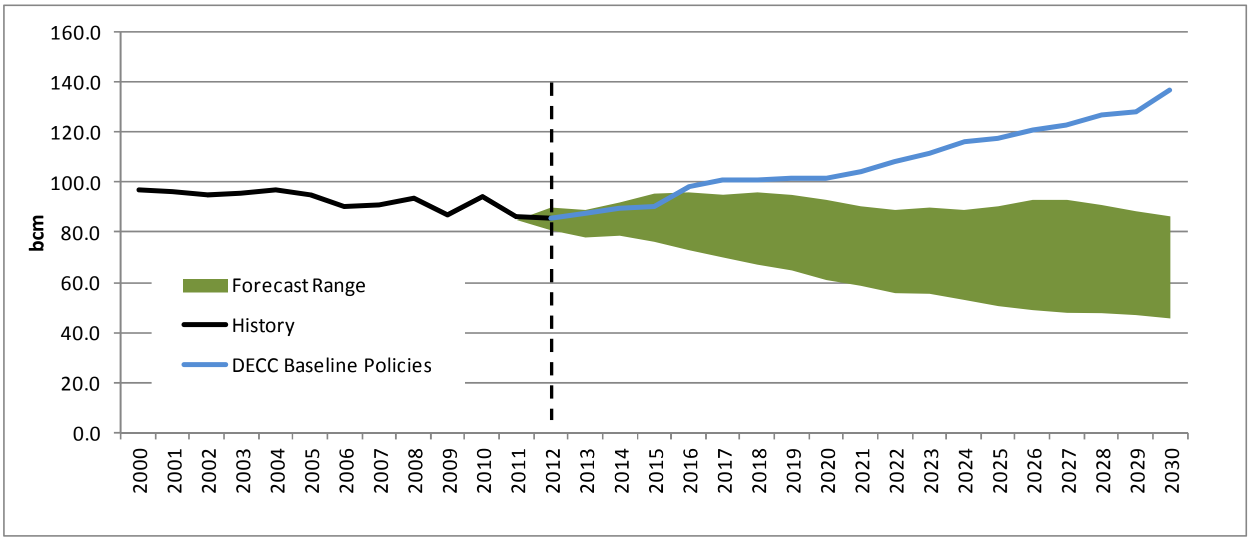
10. Impact on UK Gas Prices

10.1 UK Gas Demand Scenarios

UK gas demand has been hovering between 85 and 96 bcm/year for the last decade. We have assessed a number of forecasts for UK gas demand. DECC's Baseline Policies gas demand profile excludes the package of policy measures set out in the UK Low Carbon Transition Plan and therefore projects a steady increase in gas demand. This is therefore a useful benchmark by which to compare other scenarios. Under this Baseline Policies scenario gas demand rises by over 50% to reach 127 bcm/year. Other scenarios by DECC, Pöyry (Ofgem) and National Grid assume varying degrees of climate change policy influence reducing gas demand.

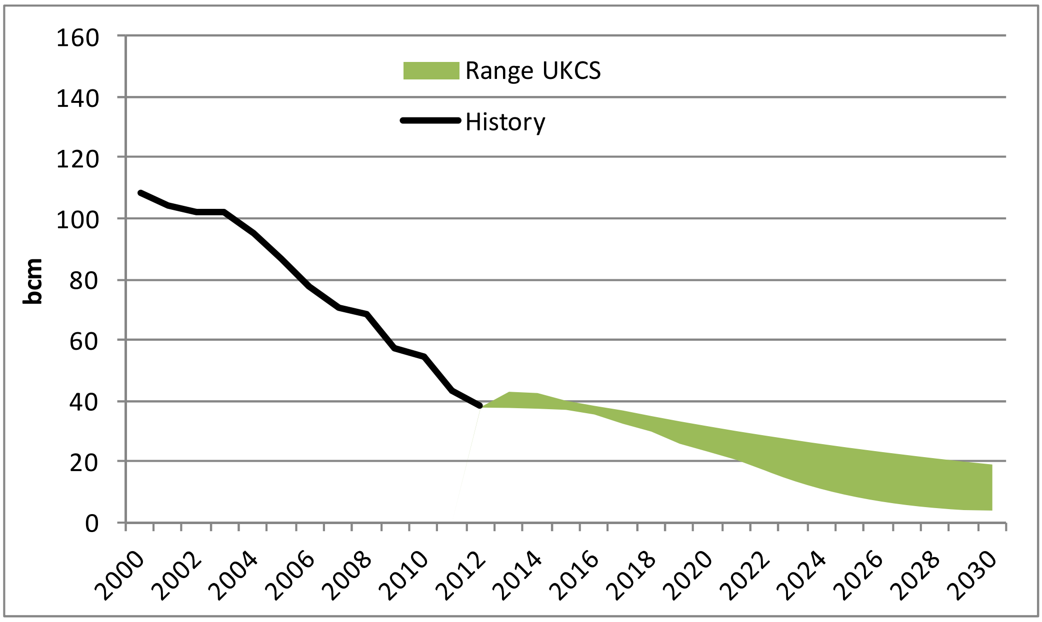
Most cases assume gas demand holds steady, or declines slightly to just under 85 bcm/year. National Grid's "Accelerated Growth" scenario results in the lowest gas demand and assumes that from 2016 closure of existing gas plants and significant increases in renewable generation (particularly offshore wind). New nuclear plants in the 2020s combined with further deployment of renewable generation result in a significant decline in gas demand until the late 2020s when some new gas plants fitted with Carbon Capture and Storage are implemented.

Figure 26: UK Gas Demand Forecasts



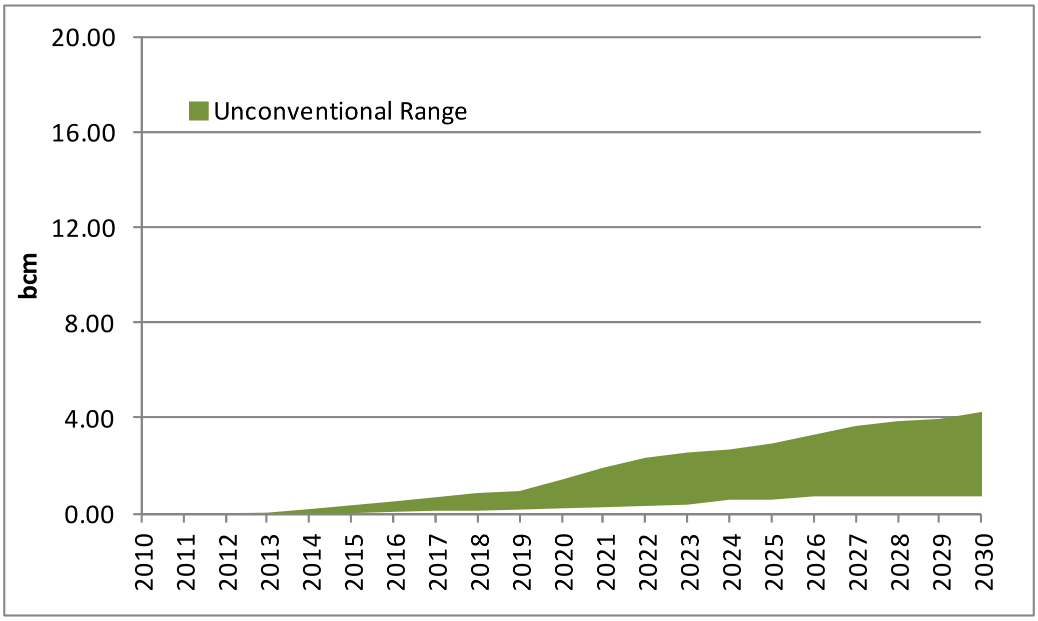
To meet this demand the UK will require both LNG and pipeline gas imports to supplement its declining conventional gas production. DECC, the Pöyry report commissioned by Ofgem and National Grid all see UK Continental Shelf gas production dropping to below 20 bcm/year or lower by 2030, and National Grid's "accelerated growth" forecast has production down to under 4 bcm/year by then.

Figure 27: UKCS gas production forecasts



As we have discussed in section 6, unconventional gas is not generally expected to make a significant impact on the UK's overall gas production by 2030. Even the most optimistic published forecast expects only 4.2 bcm/year from unconventional gas by 2030.

Figure 28: UK forecast unconventional gas production



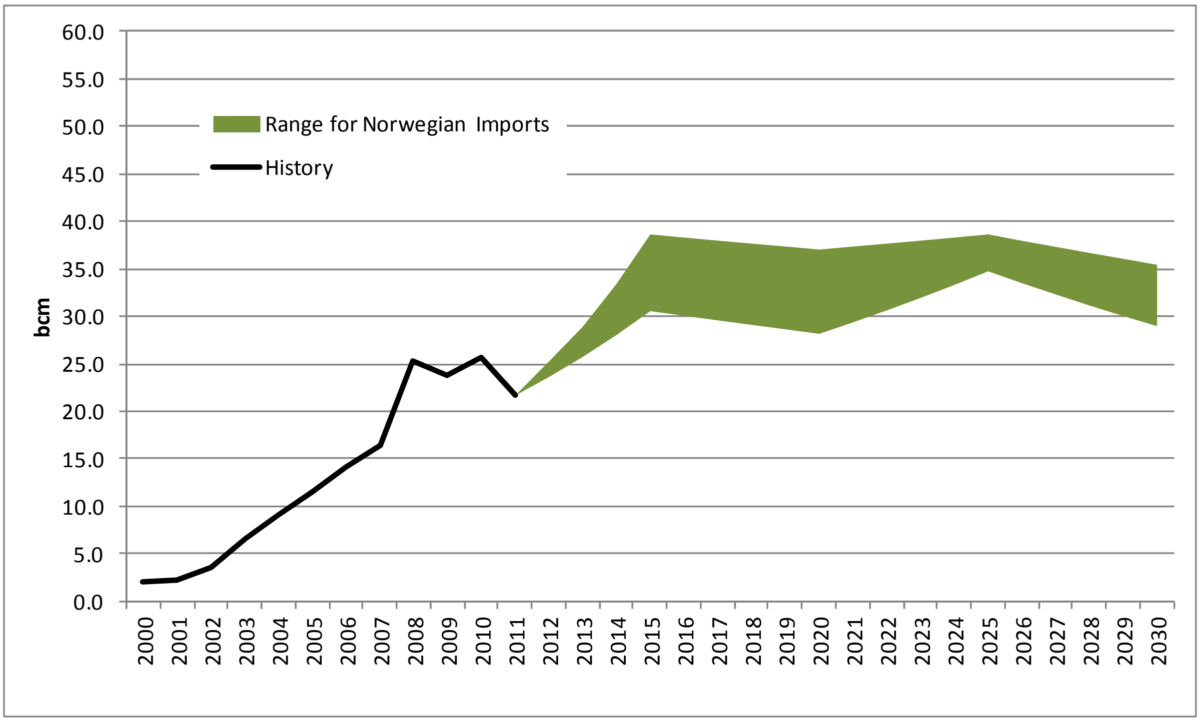
Declining conventional gas production and limited short term potential for UK unconventional gas production leaves the UK with a significant gas import requirement. Three gas import options exist for the UK: Norway, Continental Europe (with gas ultimately sourced from Russia, the Caspian and other long haul sources), or from LNG.

10.1.1 Norway

Norwegian gas production has increased over the last 15 years from 28 bcm/year to over 105 bcm in 2011. The IEA and Pöyry (Ofgem) anticipate that this production level will be maintained over the next twenty years. The National Grid study is more pessimistic about Norwegian production in two of its three scenarios, with production dropping to either 59 or 34 bcm/year. These lower gas production profiles relate to the lower gas demand scenarios under which climate change policies move away from hydrocarbon fuels.

Gas imports from Norway have risen to 25 bcm in recent years. The import scenarios from Norway follow the broad trend of the Norwegian gas production forecasts. The Pöyry (Ofgem) scenarios project that Norwegian gas imports to the UK are maintained in the range of 28 to 40 bcm/year. These import forecasts are broadly in line with gas production forecasts for Norway. The National Grid scenarios are significantly more diverse, ranging from a modest decline through 2030 to imports tailing off to near zero. The National Grid production scenarios are considered more reflective of the energy policy choices under these scenarios, rather than being a reflection of Norwegian export capability and are therefore excluded from the figure below.

Figure 29: Forecasts of Norwegian gas imports to the UK



10.2 *Gas Supplies from the Continent*

The gas supplies to the UK from continental Europe via the UK Interconnector (Zeebrugge, Belgium to Bacton) or the BBL (Balgzand, in the Netherlands to Bacton) pipeline can ultimately be sourced from a number of locations. Domestic European production, Russia, Algeria, the Caspian, Iraq or even in the longer term Iran could theoretically supply gas to the UK via these pipelines.

Continental Europe's conventional gas supplies are in decline. The IEA sees overall European production declines from around 198 bcm/year to 108 bcm/year by 2030. Whilst Europe has potential to exploit unconventional resources the IEA, EIA and others do not expect unconventional gas to offset the decline in conventional gas production, let alone keep pace with the expected 113 bcm/year increase in gas demand. The IEA sees unconventional gas production providing around 20 bcm/year, the EIA 48 bcm/year, towards European gas production in 2030.

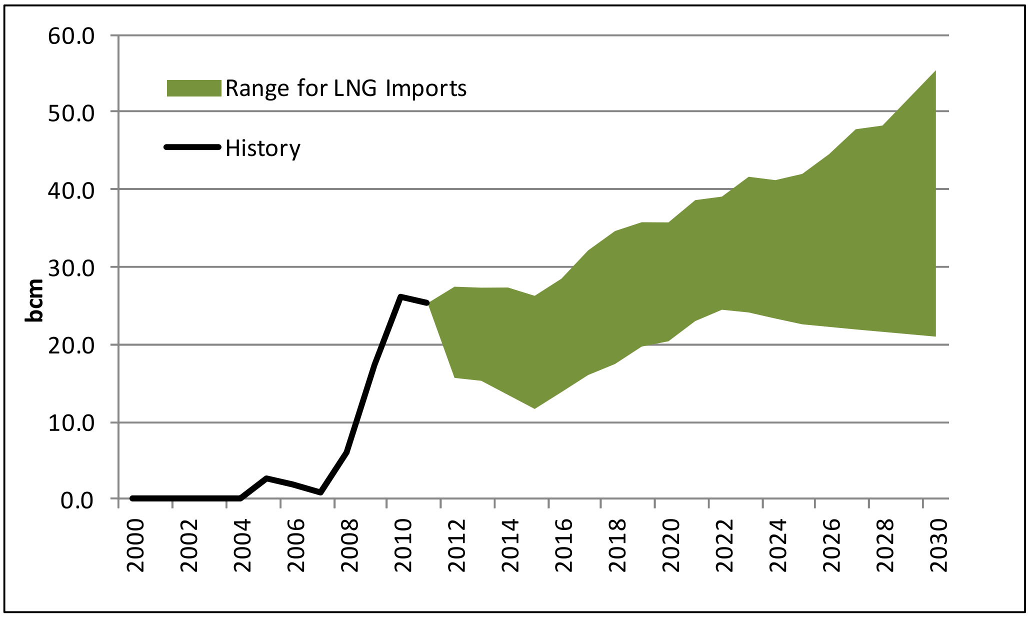
Continental Europe's reliance on imported gas is expected to rise. Russian gas is expected to make up the majority of this at just over 184 bcm/year by 2030 up from 127 bcm/year now according to the IEA. Russia's overall share of Europe gas imports is anticipated to reduce slightly, but under the IEA scenario Russia will still be Europe's largest gas supplier by some margin.

10.3 LNG Supplies

The UK has four operational LNG facilities (Dragon LNG and South Hook both in Milford Haven, Isle of Grain and Teeside) with a further three planned at Canvey Island, Anglesey and Barrow-in-Furness. The UK's total LNG imports were 25 bcm/year and were sourced from Trinidad & Tobago, Norway, Qatar, Yemen, Algeria, Egypt and Nigeria. The current capacity of the existing terminals is about 58 bcm/year or around 60% of current demand.

The options for LNG supply will increase over the next twenty years. Whilst Australia is adding significantly to its LNG capacity it is very unlikely that any cargoes will find their way west of the Suez Canal. Of more relevance is the Angola LNG facility that is due to load its first commercial cargo by the end of 2012. Additional LNG trains in Equatorial Guinea, Nigeria and Russia are of more direct relevance. However perhaps the biggest opportunity for the UK to source LNG may come from the expected LNG facilities being planned in the United States. More speculative are LNG export projects in Venezuela and Iran.

Figure 30: Forecast levels of LNG imports to the UK



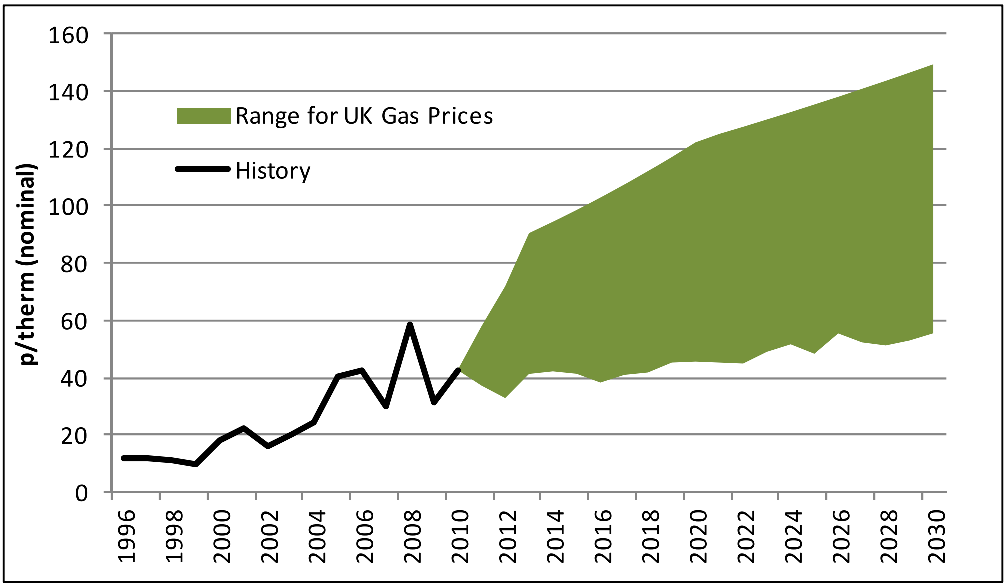
10.4 UK Pricing Outlook

The UK's gas prices are set by a number of factors; some of them local, regional and others global. Local issues would include gas the numerous drivers for demand, the outlook for UK continental shelf gas supply and the prospects for shale gas and CBM production. The UK's connections into the European gas network via the Interconnector and BBL means European pricing factors, such as the reliance on Russian pipeline gas supplies, also influence the UK gas market. Global factors like the emergence of North American shale also have the ability to change UK gas pricing; as LNG originally destined for North America seeks other markets, the potential for additional LNG supplies into Europe helped to move NBP and other European hub prices below those of Europe's oil indexed pipeline gas supply contracts.

UK gas pricing cannot be considered in isolation and therefore significant changes to far flung gas markets can have a substantial impact.

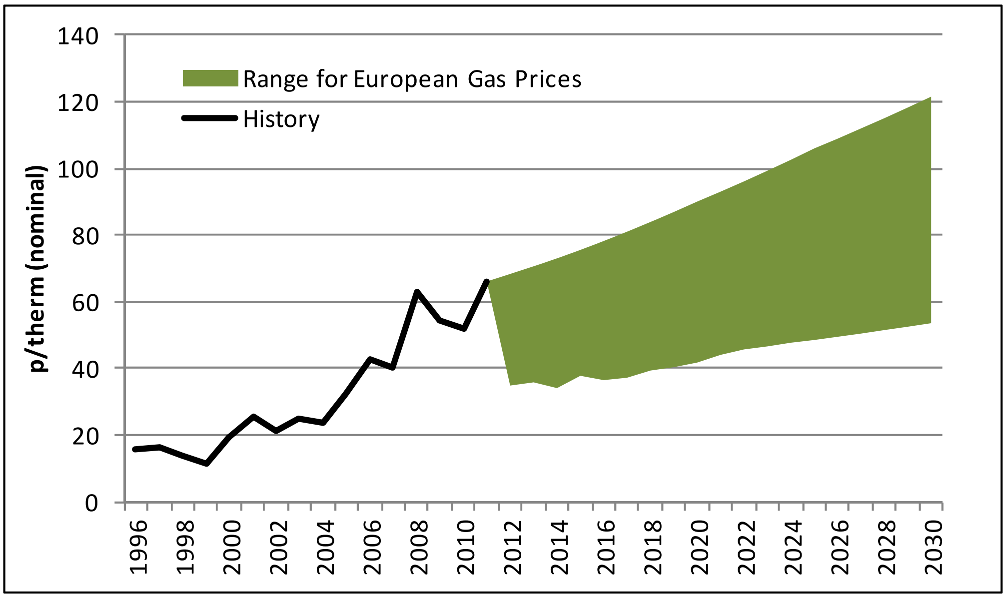
Three organisations have provided gas price forecasts for the UK. These provide a wide (95 p/therm) range of possible gas prices by 2030, demanding on the outlook for climate change policies, gas supply and other factors.

Figure 31: UK Gas Price Forecasts (DECC, National Grid, Pöyry)



In addition a number of forecasts have been developed for European gas pricing.

Figure 32: European Gas Price Forecasts (IEA, EC JRC, Rice)



One of the UK price forecasters and two of the EU ones predict a significant fall in prices in the immediate future. We suspect this to be a function of the economic models used for the forecasts, particularly if they are based on gas prices falling to long run marginal cost (LRMC) estimates. Whilst this is classical economic theory and might be expected to happen over time, particularly if disruptive amounts of unconventional gas are produced in several areas of Europe, it is unlikely to happen so quickly because of structural issues. In the last few years we have seen prices rise to well above LRMC of the swing suppliers. This reflects the reality of the long term oil indexed contracts in place with many gas offtakers and the market power of the dominant gas suppliers who have largely resisted attempts to reopen pricing clauses as the oil price was rising.

Encouraging production of unconventional gas offers the prospect of weakening the oil price link and eventually seeing lower gas prices.

10.5 Scenarios

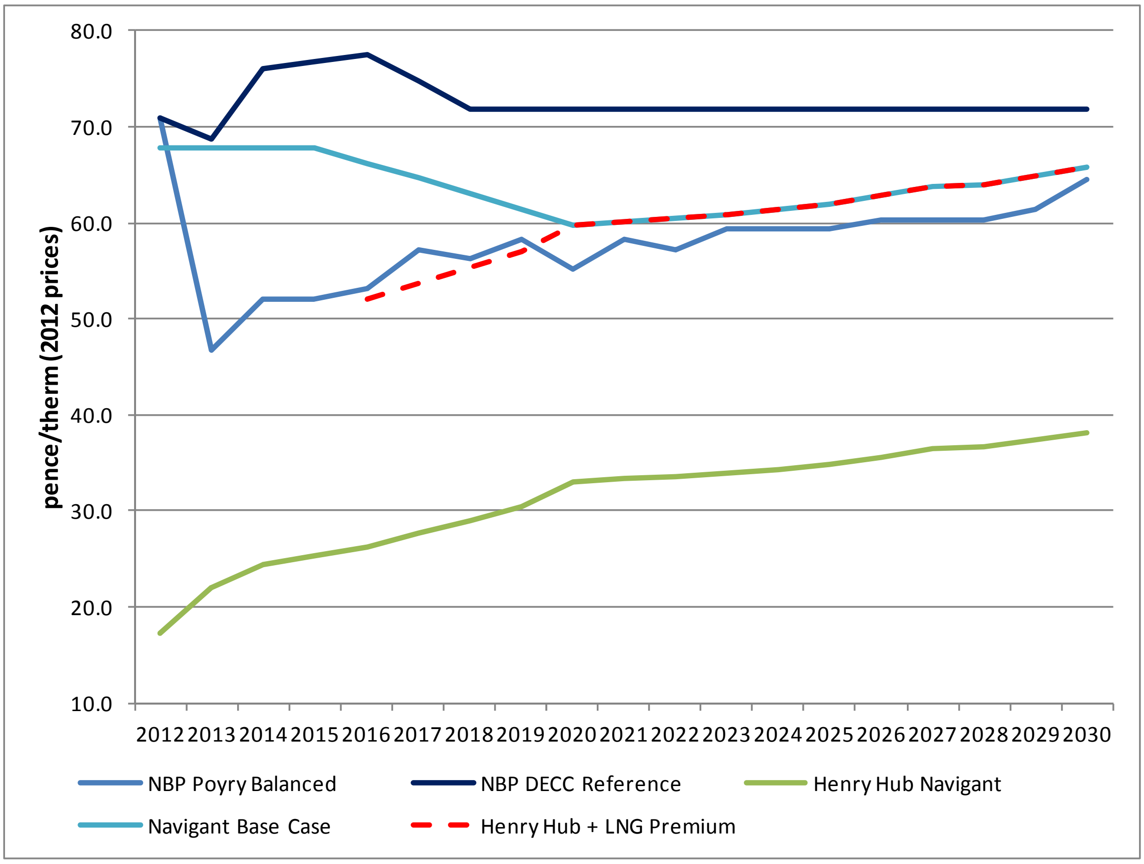
On review of the existing pricing forecasts and collation of the feedback from the study's interview programme we have developed three pricing scenarios for the UK. These scenarios reflect a diverse range of outcomes for the global gas industry and unconventional gas production in particular.

10.5.1 Base Case

Our base case scenario is consistent with many of the published reports. It envisages that unconventional gas production in Europe does not rise to any significant level, as a result perhaps of public opposition, poor geology or lack of capital given marginal economics. Consequently, imports into the UK and the wider EU increase as North Sea reserves run down. However, US unconventional production continues to rise and at least 2 other East Coast export projects are approved and commissioned, bringing US LNG Export capacity to about 85 bcm/year. Henry Hub prices follow our Fall forecast, gradually rising from 25 to 38p/therm real over the next 15 years. Oil prices stay constant until the end of 2019. In this scenario, we see China meeting the bulk of its growth in energy needs from its own internal resources, in order to remain cost competitiveness with the US. Thus a reasonable amount of LNG is available in the Atlantic, however China and other Asian nations take enough LNG to prevent new projects such as Iraq or East Africa from displacing other LNG into the North Atlantic.

Under this scenario, we predict that real UK gas prices would stay constant until 2015, at which point we predict they would start to fall slightly from the current level, moving towards a Henry Hub plus premium base. Sabine Pass starts shipping in 2016, and ramps up over two years, with others planning to follow in the next few years, so under this scenario we envisage the price being affected by US exports from 2016 onwards and reaching parity in 2020. Figure 33 below shows how our base case scenario synchronises with the projected US LNG import price, and lies between DECC's Reference Case and the Pöyry (Ofgem) balanced price projections.

Figure 33: Henry Hub and NBP Price Projections



10.5.2 Optimistic Case

Our optimistic scenario makes the same assumptions for US and Chinese unconventional production and the approval of more US export facilities. The difference comes with a significant investment in shale gas production fin the UK and Central Europe, and a falling oil price. By the early 2020s one would see significant levels of production of shale gas in both Central Europe and the UK, reaching around 100 bcm/year, or more than 20% of EU demand. Furthermore, the scale of investment to reach those levels (several hundred billion dollars) would in turn have allowed the supply chain to develop and unit costs come down significantly. In this scenario, China would not be a major LNG importer, having developed its own unconventional gas resources to meet rising gas demand.

A falling oil price under this scenario brings UK gas prices down somewhat from current prices, then synchronising with the Henry Hub plus shipping curve by the end of the first decade. Once local production is both significant and cheaper, from about 2020, one would start to see prices falling further (in real terms) as the oil price indexed contracts become untenable given both the cheaper local unconventional gas from multiple sources and the additional LNG in the North Atlantic displaced by lower than anticipated sales to China. Prices would eventually stabilise towards around 50p/therm by 2030. In theory it could continue to fall after that, towards the higher of the long run marginal shale gas production cost (perhaps 32 to 51 p/therm) or the Russian break-even cost (estimated by the IEA to be between 27 and 33 p/therm in 2008 prices[20]).

[20] IEA World Economic Outlook 2009, page 482

10.5.3 Pessimistic Case

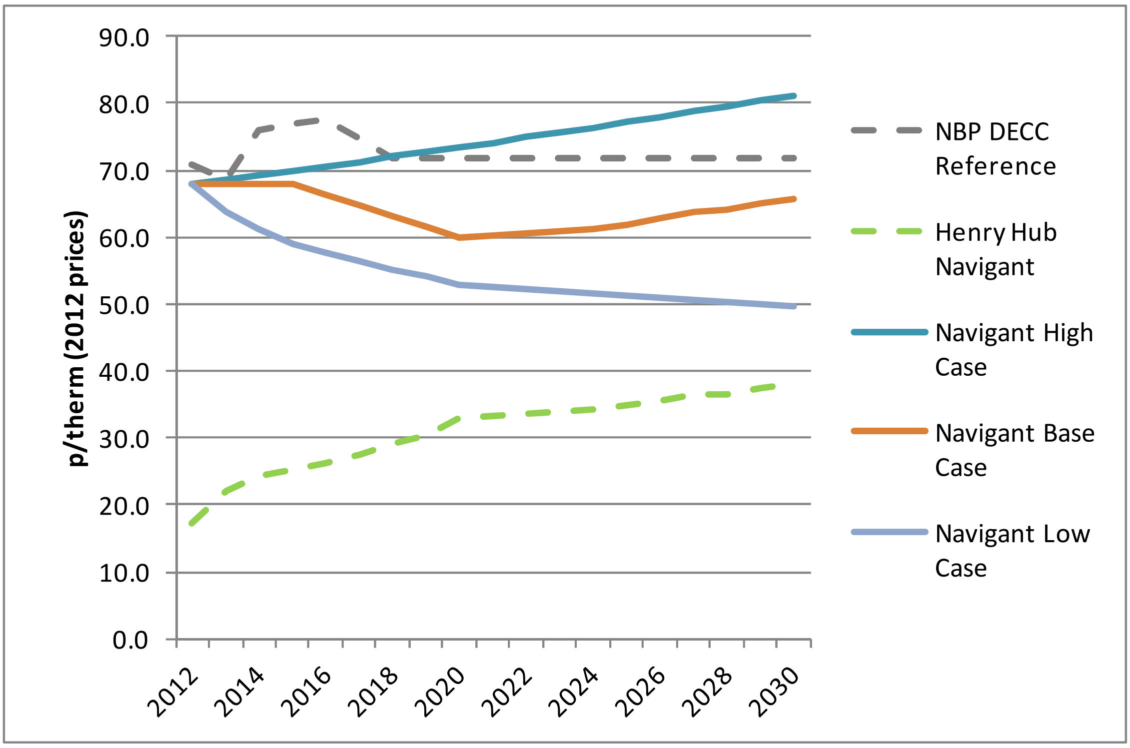
A more pessimistic scenario would lack both US LNG exports and local European production of unconventional gas and have China less price sensitive than the other scenarios because of unabated energy demand growth, or a desire to limit emission from coal fired power generation. In this scenario, China would not be able to meet its gas requirements through local unconventional gas production and thus be forced to buy large quantities of LNG, thus supporting prices in the LNG market. Europe would rely more and more on imported gas, whether from Russia and Central Asia/Iraq via pipeline or through LNG. The oil price link would thus be maintained and consistent with China's energy consumption growth, a rising oil price would raise gas prices. Without alternative sources of energy, Europe and the UK's gas prices would rise in step with the oil price.

It is harder to put indicative numbers on this scenario, since it assumes that the oil price link remains and thus one needs to take a view on the potential oil price rise if China does keep buying energy regardless of price. We have modelled this as a steady 1% rise in real oil prices, which is consistent with a number of published "high" oil price scenarios.

10.5.4 Summary

Our three scenarios give a wide range of potential gas prices by 2030, between 50p and 80p / therm at 2012 prices. In two out of three of our scenarios we predict a fall in prices from current levels quite soon, although this reflects our view that, as predicted by forward markets, the oil price (particularly Brent) is likely to fall somewhat from current levels. In the second half of the period under review, the main factor determining the gas price in our view will be the extent to which US LNG exports and indigenous European unconventional gas production are able to disrupt the current oil price indexed European gas markets.

Figure 34



Appendix A. References

The American Oil & Gas Reporter, "Study assesses shale decline rates" (May 2011)

BP Energy Outlook 2030 (January 2012)

BP Statistical Review of World Energy 2012

Bundesanstalt für Geowissenschaft und Rohstoffe (BGR): Reserven, Ressourcen und Verfügbarkeit von Energierohstoffen 2011

Cheniere, Corporate Presentation 2012

Dart Energy, Investor Presentation – update on Dart Australia (March 2012)

Mark Finley, "The Oil Market to 2030—Implications for Investment and Policy", International Association for Energy Economics (2012)

Florence Gény, Oxford Institute of Energy Studies, "Can Unconventional Gas be a Game Changer in European Gas Markets?" December 2010

Harvey and Gray (2010)

House of Commons Energy and Climate Change Committee: Shale Gas, Fifth Report of Session 2010-2012

IGas Energy PLC – Results Presentation and Shale Update June 2012

IHS CERA "Fuelling North America's Energy Future" (2009)

IHS Global Insight, "The Economic and Employment Contributions of Shale Gas in the United States" (2011)

Institute of Directors "Britain's Shale Gas Potential" (2012)

International Energy Agency (IEA), World Energy Outlook 2009-2012

International Energy Agency (IEA), Special Report "Golden Rules for a Golden Age of Gas"

Jaffe, "Geopolitics of Shale Gas: Influencing Factors, Iran, Venezuela and China", Baker Institute (2011)

Joint Research Council of the European Commission, "Unconventional Gas: Potential Energy Market Impacts in the European Union", October 2012

Kuuskraa, "Worldwide Gas Shales and Unconventional Gas: A Status Report" (2009)

Lin & Wang, "Forecasting natural gas supply in China: Production peak and import trends", China Center for Energy Economics Research, Xiamen University (2011)

McGlade, Speirs and Sorrell, ICEPT Working Paper: Unconventional Gas – A Review of Estimates (2012)

Medlock, "The Rice World Gas Trade Model (RWGTM): Report of Reference Case Results" (2012)

Medlock and Hartley "Quantitative Analysis of Scenarios for Chinese Domestic Unconventional Natural Gas Resources and their Role in Global LNG Markets", 2011

Medlock & Hartley, "The Rise of China and its Energy Implications" Energy Forum (2012)

Medlock, Jaffe and Hartley "Shale Gas and US National Security", Energy Forum (2011)

Anthony Melling, "Natural Gas Pricing and its Future" Carnegie Endowment for Global Peace (2010)

Mohr and Evans: Long term forecasting of natural gas production (2011)

National Grid, "UK Future Energy Scenarios" (2012)

NERA Economic Consulting "Macroeconomic Impacts of LNG Exports from the United States" (2012)

Oil & Gas Investor "An Investor's Guide to unconventional Gas: Shales and Coalbed Methane" (2008)

Polinares working paper no 24, Transport of Natural Gas, by Jürgen Messner and Georg Babies, March 2012

Pöyry Consulting's report for Ofgem, "The Impact of Unconventional Gas on Europe"

Howard Rogers, "European Gas Contracts: Will Oil-Indexation Persist?" OIES (2011)

Howard Rogers, "The Impact of Import Dependency and Wind Generation on UK Gas Demand and Security of Supply to 2025", OIES (2011)

Dr Hans-Holger Rogner, "An Assessment of World Hydrocarbon Resources" (1997)

The Royal Society and The Royal Academy of Engineering "Shale gas extraction in the UK: a review of hydraulic fracturing" (2012)

Sandrea, "Global Natural Gas Reserves – A Heuristic Viewpoint" (2005)

Stern and Rogers, "The Transition to Hub-Based Gas Pricing in Continental Europe", OIES (2011)

Paul Stevens, "The Shale Gas Revolution: Hype and Reality", Chatham House (September 2010)

Paul Stevens, "The Shale Gas Revolution: Developments and Changes", Chatham House (August 2012)

Tsygankova, "Netback Pricing as a Remedy for the Russian Gas Deficit", Oil and Gas Business (2009)

U.S. Department of Energy, "Modern Shale Gas Development in the United States, a Primer", (2009)

US Energy Information Administration (EIA), "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States" based on work commissioned from Advanced Resources International (ARI)

US Energy Information Administration (EIA), "Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays", prepared by INTEK, Inc.

US Energy Information Administration (EIA), "International Energy Outlook 2011-2012"

US Energy Information Administration (EIA), "Effect of Increased Natural Gas Exports on Domestic Energy Markets" (2012)

United States Geological Survey "National Assessment of Oil and Gas Resources Update" 2010

Jim Watson, "UK Gas Security: Threats and Mitigation Strategies", University of Sussex (2010)

World Energy Council, "Survey of Energy Resources: Focus on Shale Gas" 2010

World Energy Council, "Survey of Energy Resources: Shale Gas – What's New" 2012

Zou Caineng, Dong Dazhong, Wang Shejiao, Li Jianzhong, Li Xinjing, Wang Yuman, Li Denghua and Cheng Keming, "Geological characteristics and resource potential of shale gas in China" (2010)

Appendix B. Interviews

We are very grateful to the following people who agreed to be interviewed as part of the research into this report. Any views quoted are their personal views and not necessarily the views of their employers or sponsoring organisations.

Andrew Austin	IGas Energy
John Blaymires	IGas Energy
John Underwood	Heyco Energy Group
Grant Emms	Third Energy Holdings
Mike Smith and Andrew Mennear	BP
Melvin Giles and Linsey Tinios	Shell
Stephen Bull	Statoil
Andrew Lodge	Premier
Justin Johnson, Paul Howarth and James Haran	Centrica
Jason Bennett	Baker Botts
Nick Hooke and Chris Longman	Challenge Energy
Tim Shingler	MNA Global
Fivos Spathopoulos	Imperial College
Paul Stevens	Chatham House
Mark Lappin	Dart Energy
Skip Horvath	Natural Gas Supply Association
Erica Bowman	America Natural Gas Association
Peter Parsons	National Grid
David Neslin	Davis Graham & Stubbs
Michael Stephenson	BGS
Nick Riley	BGS
Richard Davies	Durham University
Peter Hartley	Baker Institute
Chris McGill	American GasAssociation
Jeff Wright	FERC
Gabriel Wayne	Talisman
Bob Braddock	Jordan Cove

Two other interviewees preferred not to be identified. In addition, two organisations, ExxonMobil and the EIA, submitted written responses rather than participating in interviews.

The interviews were structured around nine questions focussed on the scope of the report. We set out below the questions and a précis of the feedback received from interviewees. Views of respondents are also recorded in the main report where relevant to the analysis.

Note that a number of interviewees were only willing to comment on areas where they had expertise, so for instance some economists were reluctant to discuss geology and some geologists had no comments on pricing issues.

Which parts of the world do you consider to have significant quantities of unconventional gas resources?

All respondents considered North America and Australia to have significant resources. Many also specifically mentioned China. Most respondents with geological expertise noted that there are significant resources in place all over the world, although the recoverability of many of those resources is very uncertain at present.

What is your view of the likely range of recoverable resources in each of those areas?

Most respondents directed us to the main published reports on the subject. The EIA report and Rogner's paper were the most quoted, with the IEA's World Energy Outlooks also being mentioned frequently.

There were many comments on the fundamental uncertainties of estimating recoverability at such an early stage of appraisal. Except for North America, there is a dearth of hard information on geological characteristics of the various gas-retaining formations. Many respondents made the point that, until significant investment had been spent on exploration and appraisal, this fundamental uncertainty would remain.

How much unconventional gas is likely to be produced next 20 years?

All respondents agreed that North America would continue to produce significant quantities of unconventional gas throughout the period. Most people also mentioned China and Australia as likely to be producing in quantity by the second half of the period.

Opinion differed over the potential for other regions, particularly the UK. Whilst everyone made the point that it would take some time for significant volumes to be produced in regions that were not yet explored, this time lapse varied between 5 years to 20 years. Apart from the time required for exploration and appraisal, the other main reasons, mentioned by several people, were development of the supply chain, unattractive fiscal regime and unfavourable politics.

Can other regions replicate the North America experience? What factors could help or hinder this?

The large majority of respondents said that, whilst other regions can learn a lot from the North American experience, there are also significant local factors which have to be taken into account in considering the likely exploitation of any new resource. The most important of these are geology, since each formation is different, supply chain and local gas infrastructure. Several respondents discussed the geological issues which could have a great effect on extraction cost and gas flow rate.

What are the major uncertainties over production in the next 20 years?

The major uncertainty expressed by all was the geological risk. Until plays are properly explored, no one at this stage can really tell whether gas extraction can be done economically.

Another uncertainty is over the development of the supply chain. Whilst all agree that the supply chain in Europe and other region as is far less developed than the US, there are differences of opinion over how long it will take for costs to converge. Many commentators expressed the view that, although there would be savings, costs would never fall to US levels in Europe.

Public opinion and community engagement was also much discussed. All agreed that it was vital to make sure local communities were informed and also compensated in some manner. There were more mixed views on how that should happen, and how long it might take to placate public concern.

What other key trends do you see as emerging in the gas sector which could affect UK gas prices?

What happens in China was raised by several respondents as potentially important for global LNG prices and thus for the UK. There were a range of opinions ranging from China acting as an "LNG Sink" through to China developing its own resources in large quantities and restricting LNG imports to coastal regions.

There were also a number of comments around the subject of whether all US LNG exports would end up in Asia. Whilst most commentators agreed that Asian LNG prices would remain higher than North Atlantic ones, some pointed out that the Panama Canal, which is upgrading its capacity to fit larger ships including LNG tankers, was proposing to charge tolls based on the value of cargo. Thus a significant element of the additional Asian arbitrage gap could well be taken by the Panama Canal Company and not kept by the trader. This would mean more gas being potentially available in the North Atlantic.

What are the likely trends for North American prices?

All respondents who expressed an opinion on US gas prices believed that they would stay at or below $6/mmbtu (in real terms) for some time to come, with new drilling coming on line whenever prices rose, thus driving prices down again. Most commentators thought that 2 or 3 LNG export projects would be permitted by US authorities, however others expressed caution about the total amount of gas that might be exported.

Will the oil price linkage survive in Asia and Continental Europe?

There were some very different views on oil price indexation. Many of the academics we talked to believed that the appearance of large amounts of unconventional gas in new places around the world would mean the end of oil indexation and generally lead to lower gas prices everywhere. Industry commentators tended to be more cautious, in particular in terms of the Asian markets. High demand growth and a willingness to pay more for security of supply were both mentioned as factors that might limit any break up of oil indexation in Asia. Several people commented that, in order to finance these large gas developments (both conventional and unconventional), there needed to be some certainty over prices, so some form of indexation was likely to continue in long term supply contracts. But it was also accepted by many that we could see a "rebasing" of indexation to a lower level than that driven by the current oil price and existing formulas.

How do you see UK gas prices evolving over the next 20 years?

There were a number of different views on this, and many respondents gave scenarios rather than one definitive answer. Other interviewees were reluctant to give price forecasts at all. No respondents gave specific numbers on price expectations. Answers included:

- "Would expect gas price in EU to go up with EU recovery"
- "Either Gazprom reduces price, or the Norwegians get generous, or NBP will move up to an Asian netback basis – in 20 years, Russian and Norwegian gas will be cheaper than LNG"
- "Big 6 want an indexed price. Interested parties seem to dominate the hub"
- "UK gas prices will rise, but may be mitigated somewhat by local production"
- "Can't expect prices to go down by a lot"
- "UK unconventional gas can arrest the price rise, or at least soften it a little"

- "Won't go down much but may well move towards a US LNG import price basis"
- "Likely to be volatile, as a commodity market, but on a downward trend"
- "Our model sees displaced US LNG setting UK NBP, but we forecast few US exports landing in the UK"
- "Gas price is likely to be higher if we don't exploit shale gas"
- "My personal view is that they will continue decreasing over time. As long as the dash for gas doesn't happen on a global scale, their prices will go down. As the US continues to develop shale production, I don't see how gas prices will increase from that respect. There is so much shale in the world that can be developed."
- "In Europe there is more opportunity to break the oil indexed pricing for LNG because of the greater supply options available"
- "Could a falling gas price be an opportunity to bring forward carbon capture and storage?"

Appendix C. EC JRC Estimates of Shale Gas Resources by Country

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

Central and South America		34.7		ARI
Eastern Europe[126]		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 Europe[129]		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