



THE IMPACT OF UNCONVENTIONAL GAS
ON EUROPE

A report to Ofgem

June 2011

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FOREWORD

The speed of the development of unconventional gas reserves in the US, in particular shale gas production, has been in many ways quite astounding. After slow growth for a decade, new technology led shale gas production to more than double from around 36bcm in 2007 to 87bcm in 2009. By 2010, shale gas made up 23% of total US gas production.

These developments have not gone unnoticed in Europe, with a number of countries looking to repeat the fortunes of the US. However, is a shale gas revolution in Europe a possibility? Can the US model sensibly be applied elsewhere? In June of last year Ofgem commissioned an independent report by Pöyry Management Consulting to answer these questions. We asked Pöyry to investigate the possible impact of shale gas and other types of unconventional gas on Europe, examining the prospects for their development, both in Europe and elsewhere, and the implications for GB and wider European gas markets.

The analysis, which uses three scenarios to reflect the considerable uncertainty surrounding the development of unconventional gas, shows that there is a wide range of price and volume outcomes. Environmental concerns render a US-type shale boom in Europe unlikely; while on the other hand, significant production in Poland could put downward pressure on European gas prices in the future.

In November 2011, the Department of Energy and Climate Change asked Ofgem to look into whether further interventions are needed to ensure medium- to long term gas security of supply. In light of the on-going work in this area we are now sharing this report with a wider audience.

The report has not been updated to reflect the latest assumptions for commodity prices and demand growth, but Ofgem feels the analysis presents a plausible range of future scenarios, and the key messages are robust. In future work, we may choose to explore the potential effects of the US exporting LNG derived from its shale gas boom.

As always we are seeking stakeholders' views on these issues. Please contact Maria Brooks (maria.brooks@ofgem.gov.uk) with any comments or questions about this report.

Alistair Buchanan CBE
Group Chief Executive, Ofgem

February 2012

EXECUTIVE SUMMARY

In the past few years the US gas market has been transformed by the rapid and large scale development of shale gas. Large reserves, high gas prices, technological advances and a well-developed onshore drilling industry have all contributed to its dramatic growth. The growth is such that it is likely to contribute around a fifth of total US gas production this year.

In fact shale gas is only one type of 'unconventional gas': a category which also includes coal bed methane (CBM), tight gas and methane hydrates.

CBM has great potential worldwide and significant reserves are already in production in Australia and Russia. In the US, CBM is also present in abundance, but it is generally the shale resources that are considered more economic, and receive the most attention.

Tight gas is specifically defined in US taxation rules according to the permeability of the rocks in which it is found and is the predominant form of unconventional gas production in the US. Outside the US the term 'tight gas' is more loosely defined and reserves are not reported separately from conventional sources.

Based on expectations of relatively high-priced oil-indexed gas from Russia and LNG in the Far East, gas producers are now exploring unconventional gas sources all over the world. This has led many to question whether the experience of the US can be repeated in Europe and if so what would be the implications for the European gas market.

Ofgem commissioned Pöyry to, for the first time, fully examine the drivers behind unconventional gas development, potential barriers to development and the impacts on both gas prices and security of supply for the gas markets in GB and wider Europe.

Our findings suggest that there is potential within Europe for unconventional gas to become a major source of supply. However, the favourable conditions that have facilitated the shale gas revolution in the US may not be repeated in Europe. For instance, environmental constraints and/or environmental compliance costs could prevent significant volumes of unconventional gas being developed.

In some places environmental concerns have led to calls for shale gas drilling operations to be suspended or even stopped. The relevant authorities in the State of New York, Quebec, France, India and South Africa have all recently introduced moratoria on their shale gas activities following concerns over the availability of water and potential pollution arising from the use of drilling and fracking fluids. In future, it is likely that these concerns will lead to a tight regulation and monitoring of shale gas drilling operations. It is possible that this may result in a higher cost of production that may, in some cases, make some drilling operations uneconomic.

Given these uncertainties, a wide range of shale gas extraction in Europe is projected, reaching 10-75bcm/year by 2030. The greatest potential and impetus is in Poland, which could produce up to 24bcm/year of shale gas by 2030. In the UK, our expectation is that only 1-4bcm/year could be produced by that time.

There are some indirect effects from shale gas development elsewhere. Reserves in Russia and Ukraine could have a significant impact on pipeline gas available to Europe; while further afield Australia could potentially export additional LNG. We believe that in regions such as China and Indonesia, with strong domestic energy demand growth, they

are most likely to deploy shale gas production to displace domestic coal and any additional gas resources there will be absorbed within their own markets.

In the US, increased shale gas production has significantly depressed market prices, and we wanted to examine whether GB and European market prices could react in the same way. So for this study three scenarios were constructed to examine the impact of different unconventional gas developments:

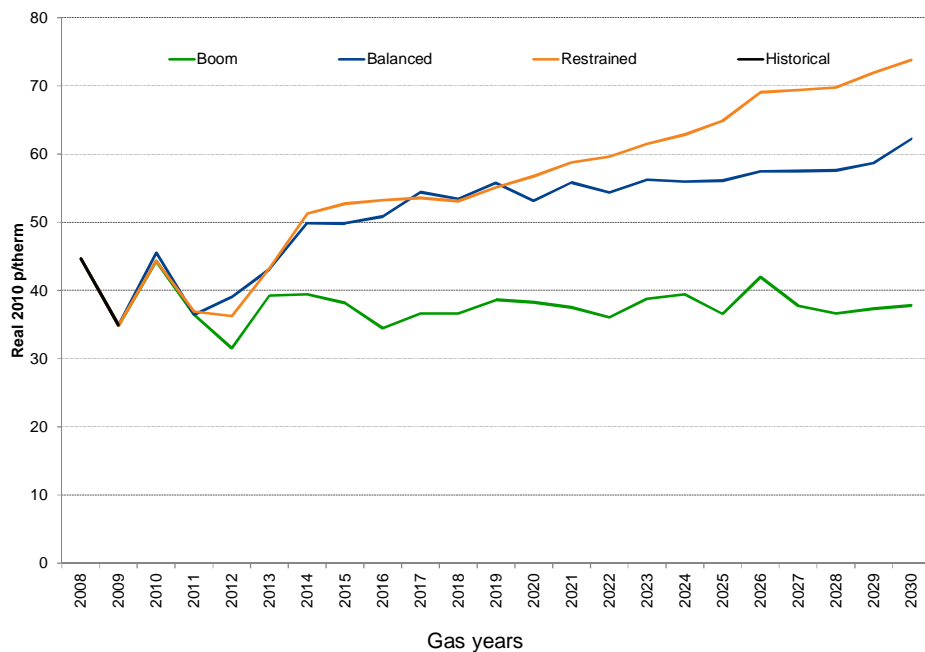
A ‘Boom’ Scenario in which there is a US-style boom in unconventional gas production in Europe. It takes an optimistic view, with shale gas getting strong political and local support and geology proving to be good in multiple countries. Lessons from the US industry are readily adaptable to European shales and technological advances continue. Technological advances also provide an upside to Russian and Ukrainian production and Australian LNG liquefaction, and deliver small improvements in production over and above that already projected by the EIA for the US.

A ‘Balanced’ Scenario in which political support for shale development is mixed and local communities need to be convinced of the economic and social benefits. Water and environmental problems slow the approvals process.

A ‘Restrained’ Scenario in which NIMBYism is rife and political support is poor in most countries. Early instances of pollution slow the approvals process considerably and geology is poor. US expertise is available but does not readily translate to European shales; equipment must meet more stringent industry standards and low production volumes make this expensive. Under this scenario US unconventional gas production stalls around 2014 and production rates plateau leading the US to import increasing volumes of LNG.

Figure 1 illustrates the impact on GB gas prices under the three scenarios.

Figure 1 – GB prices across the three scenarios



We conclude that there is potential for shale gas to affect GB gas prices, but only the Boom Scenario has significantly lower prices. However, this is not directly due to production in GB, but caused by the increased imports, be they from the Continent, Norway or through LNG shipments. The economic production of unconventional gas in Europe makes more low cost gas available to GB, displacing expensive sources.

In volume terms, by 2030 10% of NW European gas demand is met from unconventional sources in the Boom Scenario, compared to only 5% and 2% in the Balanced and Restrained Scenarios respectively.

In our opinion environmental concerns are likely to prove a considerable hindrance to the development of unconventional gas resources in Europe, making the volumes underlying the Boom Scenario unlikely. However if large scale developments occur in Poland they have the potential to suppress European gas prices for some time; and even moderate development of unconventional gas resources in Europe could keep gas prices in Great Britain lower from 2020 onwards, than if no resources are developed at all.

If the governments of Europe do not make the US mistakes of initially allowing low environmental standards, and back them up with well-resourced and stringent regulation, it is possible European development could proceed without hindrance in this sphere. However it must be recognised that to achieve the production levels in the Boom Scenario, both favourable geological and technical environments are needed, suggesting that these production levels represent an upper level.

1. INTRODUCTION

1.1 Background

In the past few years the US gas market has been transformed by the large scale development of shale gas. Large shale gas reserves, high gas prices, technological advances and a well-developed onshore drilling industry have contributed to favourable conditions under which shale gas production is expected to be around 20% of total US production in 2011.

The success of shale gas in the US has had implications for the global gas market as the increase in domestic production has offset the requirement for imported Liquefied Natural Gas (LNG). This has enabled LNG that was intended for the US market to be diverted to other gas markets, including Europe, leading to an increase in gas supplies, and a downward pressure on gas prices.

Shale gas is only one type of unconventional gas; a category which also includes, coal bed methane (CBM), tight gas and methane hydrates.

CBM has enormous potential worldwide and has already been developed in Australia and Russia. In the US, CBM is also present in abundance, but it is generally the shale resources that are considered more economic, and receive the most attention. Nearly all of the information from the US refers to shale gas developments.

Tight gas is specifically defined in US taxation rules according to the permeability of the rocks in which it is found and is the predominant form of unconventional gas production in the US. Outside the US the term 'tight gas' is more loosely defined and reserves are not reported separately from conventional sources.

Methane hydrates are not yet technically recoverable.

Unconventional gas reserves are not only present in the US, but exist in a number of locations around the world, including Europe. In particular, shale gas deposits are thought to be considerable and may potentially be double the conventional gas resources in the world. Based on expectations of relatively high-priced oil-indexed gas from Russia and LNG in the Far East, producers are now exploring unconventional gas sources all over the world, including Europe and GB. Security of gas supply in Europe would also improve if unconventional gas added to indigenous reserves.

This has led many to question whether the experience of the US can be repeated in Europe and if so what would be the implications for the European gas market.

The characteristics of the European unconventional gas deposits are not yet well established. The regulatory and legal issues are different in Europe, particularly in relation to mineral rights and environmental procedures, greater population density and higher land values. Given these issues, there is a great deal of uncertainty over the development of shale gas deposits in Europe, as potential higher costs and/or environmental concerns may exceed the perceived benefits from new gas close to market.

Ofgem has commissioned this report to better understand the drivers behind unconventional gas developments, the barriers to development and the potential impacts on gas prices and security of supply for the GB and wider European gas markets.

This report presents the results of our research into this area and develops our findings into scenarios that are utilised by our suite of models to produce supply and demand and price projections. This allows us to assess the potential impacts of unconventional gas development into the future.

1.2 The scenarios

Throughout this report we refer to three scenarios which we have developed to examine the impact of different unconventional gas assumptions. They are described in detail in section 8 but are summarised here.

1.2.1 The Boom Scenario

The Boom Scenario projects a US-style boom in unconventional gas production in Europe. It is an optimistically high case where shale gets strong political and local support. The geology proves to be good in multiple countries. Lessons from the US industry are readily adaptable to European shales and technological advances continue.

Technological advances also provide an upside to Russian and Ukrainian production and Australian LNG liquefaction, and small improvements in production over and above that already projected by the EIA for the US.

1.2.2 The Balanced Scenario

Under the Balanced Scenario, political support for shale development is mixed and local communities need to be convinced of the economic and social benefits. Water and environmental problems slow the approvals process.

Projections for production in this scenario are based upon Pöyry's central projections.

1.2.3 The Restrained Scenario

Under the Restrained Scenario, NIMBYism is rife and political support is poor in most countries. Early instances of pollution slow the approvals process considerably and geology is poor. US expertise is available but does not readily translate to European shales, equipment must meet more stringent industry standards and low volumes make this expensive.

Under this scenario US unconventional gas production stalls around 2014 and production rates plateau leading the US to commence much greater imports of LNG.

1.3 Report Structure

In Section 2 of this report, we describe the various types of unconventional gas and outline current estimates of global reserves and production.

In Section 3, we describe the US shale gas 'success' and the history of shale gas development including an outline of the environmental concerns.

Section 4 discusses the economics of unconventional gas production and the differences between the US experience and other potential developments.

Section 5 examines the GB market in detail and outlines unconventional gas prospects and potential regulatory and legislative barriers.

In Sections 6 and 7 we discuss the European and global potential for unconventional gas development.

In order to assess the impact of unconventional gas development on the GB and European gas markets we have used a number of our modelling tools. Section 8 describes the scenarios that have been fed into the models which have been developed as part of this project. In Section 9 we present the results of our modelling and describe the impacts on gas prices and gas flows in GB and Europe.

We present our main findings and conclusions in Section 10.

1.4 Conventions

Unless otherwise attributed the source for all tables, figures and charts is Pöyry Management Consulting.

Unless otherwise noted, all values are in gas years, which commence in October each year.

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2. UNCONVENTIONAL GAS – WHAT IS IT AND WHY IS IT IMPORTANT?

Unconventional gas, in general terms, differs from conventional gas due to its extraction process. Conventional gas is found in gas reservoirs whereas unconventional gas is found in geological formations that are impermeable and require some form of hydraulic fracturing or horizontal drilling to release the gas.

The recent growth of shale gas in the US has significantly raised the profile of unconventional gas. There are four types of unconventional gas:

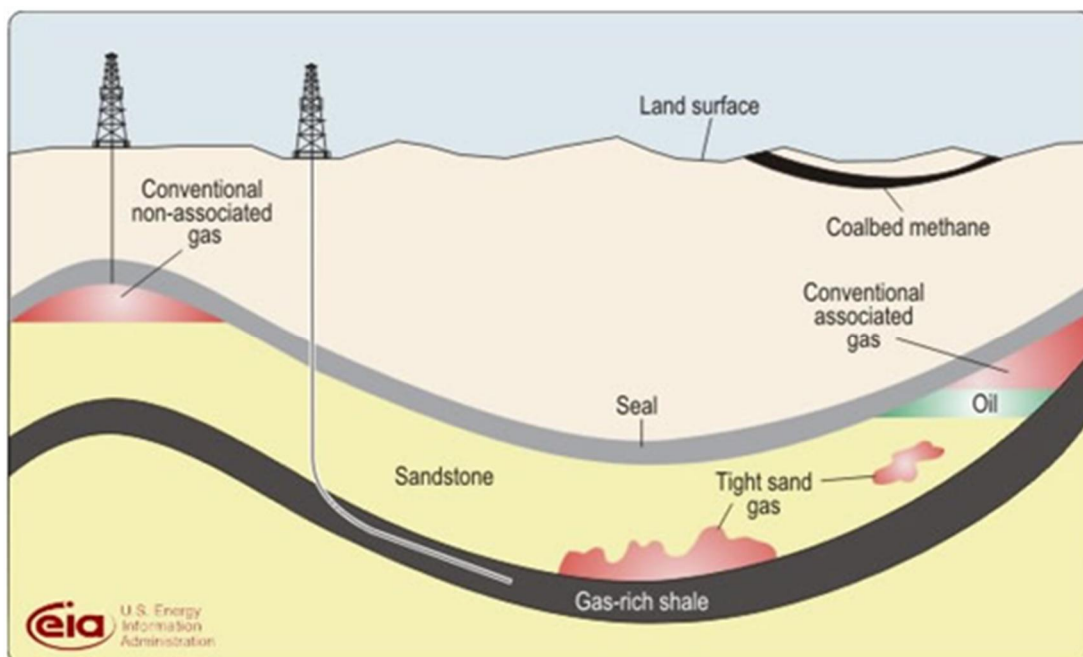
- shale gas;
- coalbed methane (CBM);
- tight gas; and
- methane hydrates.

Methane hydrates are not yet technically recoverable and tight gas does not have a universally accepted definition.

Conventional gas is found in rocks that have a wide spectrum of porosity and permeability. Tight gas refers to those at the low porosity/low permeability end of the spectrum. A threshold of permeability, such as that used by the US taxation authorities serves a useful function in drawing a dividing line between conventional gas and unconventional tight gas. However, many countries around the world do not differentiate between conventional and tight gas production.

For the purpose of this report the term ‘unconventional gas’ refers to shale gas and CBM. The formation of unconventional gas is represented in Figure 2.

Figure 2 – The geology of natural gas



Source: EIA and US Geological Survey

2.1 Shale Gas

Shale gas is natural gas produced from sedimentary shale layers, several thousand metres below the surface.

Shale strata are often a source rock for conventional hydrocarbons, which are generated over geological time under the action of heat and pressure, from the decay of organic matter within the shale. Under certain conditions these hydrocarbons can migrate upwards from the source rock, and become 'trapped' in high concentrations within porous rocks above the shale. These trapped hydrocarbons are the target accumulations for conventional oil and gas production.

In many cases there are much greater volumes of hydrocarbons remaining within the source shale rock, which is often of very low porosity and permeability. For many years the hydrocarbons within the shales were considered uneconomic to produce. However, in the last decade, the combined techniques of horizontal drilling and hydraulic fracturing have brought large quantities of 'unconventional' shale gas reserves within the economic reach of world gas markets.

However, no two shales are alike. Vertical heterogeneity is very complex and needs to be taken into account when developing shale reservoirs.

2.2 Coal bed Methane (CBM)

CBM is also known as coal bed gas or, in Australia, as coal seam gas.

CBM does not migrate from shale, but is generated during the transformation of organic material to coal. It is extracted from coal seams, rather than in the sandstone reservoirs that hold conventional natural gas.

Like conventional natural gas, CBM is predominantly methane but may contain other hydrocarbons, inert gases, sulphurous compounds, and other liquids. CBM is often produced together with significant quantities of water. Like conventional natural gas, CBM generally needs to be processed before onward transportation to end customers. Once processed, CBM can be blended with conventional natural gas, and is used for the same purposes.

CBM occurs when the coal is formed deep underground by a process of heating and compressing plant matter. The gas is trapped in the coal in tiny fractures, known as seams or cleats, typically 300-600 metres underground. The gas is held in place by water pressure and is extracted via wells drilled into the coal seams. Water is pumped from the coal seam, which reduces the pressure and natural gas is released from the coal. In order to increase the flow of gas and water from wells, hydraulic fracturing may be used. Gas leaves the well head under low pressure of around 1-4 bars. The gas is processed to remove water and other impurities, and then piped to compression plants for injection into gas transmission pipelines.

CBM wells typically take from three days to three weeks to mobilise, drill and complete. Times vary according to well depth, geology of the area and the type of rig used. Wells are lined with steel casing, cemented in place to contain the fluids and isolate from aquifers. Once operational, a CBM well may produce for 10 to 20 years.

CBM has been exploited in small volumes for hundreds of years, but in recent decades, large-scale commercial exploitation has been developed and it has become an important

source of energy in the US, Canada, and Australia – where it is being used as the source of methane for future LNG export projects. Other large resources are located in Russia, the Middle-East, China and India, where it is only beginning to be exploited.

The economics of CBM are heavily dependent on the quality, depth and thickness of the coal resources. The methane content is a key factor, and the ease of exploitation is strongly assisted by shallow depth. The thickness of the seam helps to increase the productivity per well. A number of countries have plentiful resources but seams that are poor quality, too deep, or too thin for low-cost commercial exploitation.

In the US, where CBM and shale gas resources are both present in abundance, it is generally the shale resources that are considered more economic, and receive the most attention. The established CBM industry, having achieved steady expansion for many years has seen its growth checked, and experienced a number of bankruptcies, as shale gas production has taken off. It remains to be seen if a similar trend will take place in other areas of direct shale gas to CBM competition (such as Australia, Canada, and China) or whether developments in CBM exploitation (technical and/or economic) will reverse the trend.

Underground Coal Gasification (UCG) is a specific method of CBM extraction where injection wells are used to supply oxygen to ignite the hydrocarbon underground. Through the combustion process, pressure is created within the seam, and gas is extracted to the surface through production wells drilled into the coal-seam at points distant from the combustion process.

Combustion is generally conducted at temperature of 700–900°C. The process decomposes coal and generates carbon dioxide, hydrogen, carbon monoxide and small quantities of methane and hydrogen sulphide.

UCG is considered unlikely to gain widespread approval in Europe due to the limited geological opportunities, controversial method of exploitation, potential risk of pollution to aquifers and the production of significant volumes of CO₂ that can be released at the processing stage.

2.3 Global reserves and production

The most widely quoted study of the world's unconventional natural gas resources in-place is that compiled by Rogner in 1997¹. Amidst a climate of dwindling hydrocarbons reserves, and the prospect of declining production, it was this study that identified the potential for unconventional gas production.

The methodology behind Rogner's work was firstly to capture the available resources data, which covered only a relatively small percentage of the overall estimates. The gaps were then filled in by studying the volume of potential natural gas, tight gas, shale and coal bearing strata and methane hydrate formations across the globe. In summary, the study used all available data available and filled the (sometimes large) gaps with informed estimates. It was far from perfect, but it was the best international study available at the time.

¹ 'An assessment of world hydrocarbon resources', Annual Review of Energy and Environment 1997, Rogner

Following on from the work of Rogner, other academics and organizations such as Cedigaz, Wood Mackenzie, Energy Information Administration (EIA) and International Energy Agency (IEA), have produced studies of various categories of unconventional resources.

2.3.1 Shale Gas

In April 2011, the EIA released a preliminary study of technically recoverable shale gas resources, part of which is reproduced in Table 1. However, despite being the latest and probably the most rigorous public assessment currently in existence, estimating the world's unconventional gas resources remains a very uncertain science.

Russia and Central Asia, Middle East, South East Asia, and Central Africa were not addressed in the EIA report. This was primarily because there are either significant quantities of conventional natural gas reserves noted to be in place (as in Russia and the Middle East), or because there is a general lack of information to carry out even an initial assessment.

In their 2011 summary analysis, EIA identifies two country groupings that emerge where shale gas development may appear most attractive.

- Countries that are currently highly dependent upon natural gas imports and possess some gas production infrastructure. Examples include Poland, Turkey, Ukraine, South Africa, Morocco, and Chile.
- Countries where the shale gas resource estimate is large (above 200tcf \approx 566bcm) and there already exists a significant natural gas production infrastructure for internal use or for export. In addition to the United States, notable examples of this group include Canada, Mexico, China, Australia, Libya, Algeria, Argentina, and Brazil.

Virtually all of the world's current shale gas production currently takes place in the US (133bcm/year²) and Canada (9bcm/year³).

² EIA

³ Petroleum Services Association of Canada

Table 1 – EIA world shale gas estimates, April 2011 (bcm)

	Proved natural gas reserves	Technically recoverable shale gas
Europe		
France	6	5,097
Germany	176	227
Netherlands	1,388	481
Norway	2,039	2,350
U.K.	255	566
Denmark	59	651
Sweden	-	1,161
Poland	164	5,295
Turkey	6	425
Ukraine	1,104	1,189
Lithuania	-	113
Others	77	538
North America		
United States	7,716	24,409
Canada	1,756	10,987
Mexico	340	19,284
Asia		
China	3,030	36,104
India	1,073	1,784
Pakistan	841	1,444
Australia	3,115	11,213
Africa		
South Africa	-	13,734
Libya	1,549	8,212
Tunisia	65	510
Algeria	4,502	6,541
Morocco	3	311
Western Sahara	-	198
Mauritania	28	
South America		
Venezuela	5,066	311
Colombia	113	538
Argentina	379	21,917
Brazil	365	6,400
Chile	99	1,812
Uruguay	-	595
Paraguay	-	1,756
Bolivia	750	1,359
Total of above areas	36,064	187,512

Note: 'Proved natural gas reserves' refers to conventional gas production.

2.3.2 CBM

According to Rogner, North America and Russia hold the largest resources of CBM, with a combined 77% of world resources. Of the remaining resource, the bulk is held by China, India and Australia. Europe holds about 3% of the world's resources.

CBM production takes place in a number of countries but relatively few of them currently produce significant volumes. Total world production of CBM is about 72bcm/year, which is about 2.5% of world gas production.

2.3.2.1 *Russia*

For Russia, Rogner suggests a total resource of 112tcm, and this is supported by a more recent estimate of 83.7tcm in the major coal basins, by Gazprom in 2010.

2.3.2.2 *North America*

Rogner's estimate for CBM in North America was 86tcm, but the US Potential Gas Committee (PGC), which measures on a different basis and only includes the technically recoverable reserves, estimated a volume of 4.6tcm.

In both the cases of Russia and the US, the variations reflect the that the information is far from complete, but it should be noted that estimates for CBM are likely to be more accurate and consistent than for the much less studied shale gas.

The US currently produces in excess of 50bcm/year of CBM.

2.3.2.3 *Rest of the World*

China, India, Australia, Indonesia and South Africa all have considerable reserves that are being exploited for CBM. Other countries have significant reserves, but many lack the thick, gas-rich coal seams at suitable depths for the reliable commercial exploitation of CBM.

Australia produces around 5bcm/year and China produces in excess of 1bcm/year.

2.4 **Conclusions**

There are significant unconventional gas resources available with the potential to become major sources of supply to the future world market. However, an abundance of reserves does not necessarily translate into significant volumes of gas production.

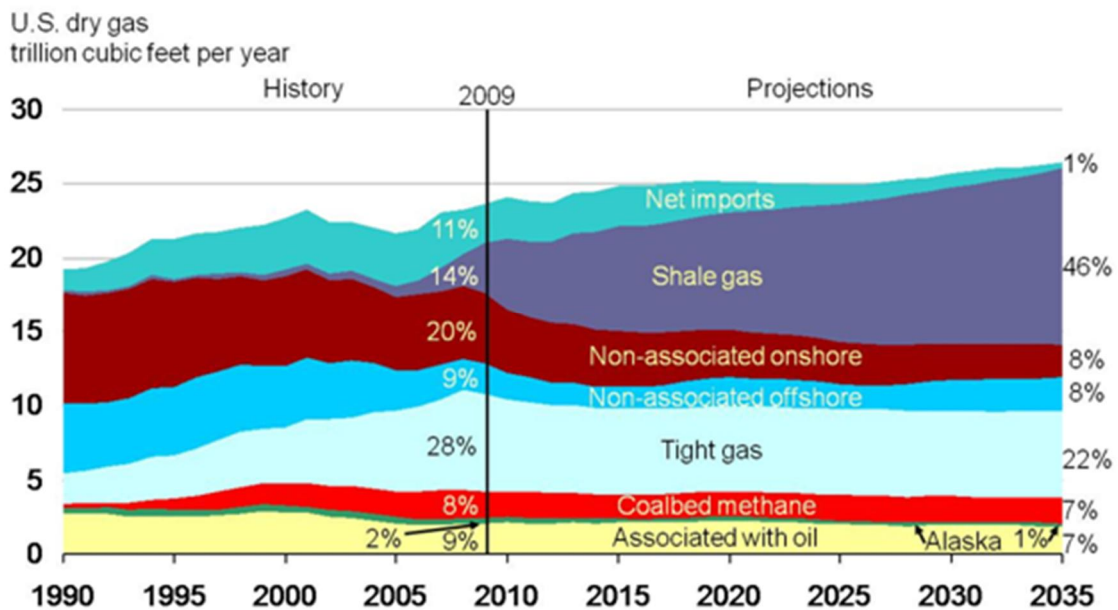
A whole range of factors affect commercial decisions to develop reserves into production. Whilst experience from the US would indicate that it is economic to develop large quantities of shale gas, it is not clear that this is, in fact, the case. The factors that have allowed the shale gas success story in the US and some of the reasons why this may not be repeated elsewhere are explored in the following sections of this report.

3. GROWTH OF SHALE GAS IN THE US

3.1 Introduction

The US gas market is well developed in terms of pipeline infrastructure, number of players and sophistication of traded markets. The recent development of unconventional gas sources has played a significant role in changing the US supply-demand balance and has been termed a ‘shale gas revolution’ by some commentators. By 2030 shale gas is forecast to make up almost 50% of total US gas supply, as shown in Figure 3. This will significantly reduce the requirement for the US to import gas in the form of LNG, which in turns means that there will be more LNG available for the world market.

Figure 3 – Historical and projected natural gas supplies in the US



Calendar years. Source: EIA, Energy Outlook 2011

This section outlines the history of shale gas development in the US and addresses the growing environmental concerns surrounding its extraction.

3.2 History of shale gas development

Historically, the economics of shale gas production have been generally inferior to the economics of conventional gas production. Shale gas is extracted directly from source rocks which have a porosity and permeability much lower than conventional hydrocarbon plays. By contrast, conventional gas drilling targets the accumulations of hydrocarbons that have migrated from the source rock, over millions of years, and concentrated in porous ‘reservoir’ rocks, which are attractive targets for drillers. Flow rates and cost per well are generally much higher for conventional wells than unconventional wells.

Shale hydrocarbons had actually been exploited for hundreds of years in Europe for the shale oil that could be extracted, and this became a major industry in Scotland in the 1800s. In parallel, in the US, shale gas was extracted by vertical drilling as early as 1821.

However, none of these early initiatives could have competed economically with the exploitation of the prime reserves of conventional hydrocarbons that was to follow.

In the US today, there are numerous mature hydrocarbons plays where the 'easy' gas appears to have been exhausted. The remaining conventional hydrocarbons concentrations are smaller, deeper and more difficult to identify. Over many years, geologists and geophysicists developed their seismic skills to locate these smaller and deeper targets with production techniques developing to keep pace. However, despite these advances, production from the mature conventional basins continues to decline as the number of commercial targets reduces over time.

Prior to the large scale production of shale gas, the anticipated supply deficit contributed to the boom in proposals to build LNG import terminals in the US. In 2005 there were five LNG import terminals (with three dating from the 70s, and one from the 80s) with a further 43 proposed in the US and 12 proposed in Canada and Mexico. However, as of March 2011, only 9 new LNG terminals have been built.

The arrival of shale was not a single event, but an evolutionary process which began with the Barnett gas shale play in Texas in the early part of the decade. Faced with fewer opportunities for conventional gas production, a small number of highly imaginative drillers began to look for alternative or unconventional sources of hydrocarbons, armed with new tools that had initially been developed for marginal conventional production; such as horizontal drilling technology and hydraulic fracturing techniques. Initial application of these tools to shale layers indicated that, whilst production rates were lower than conventional wells, there was potential for shale gas to compete with the rising prices in US gas commodity markets.

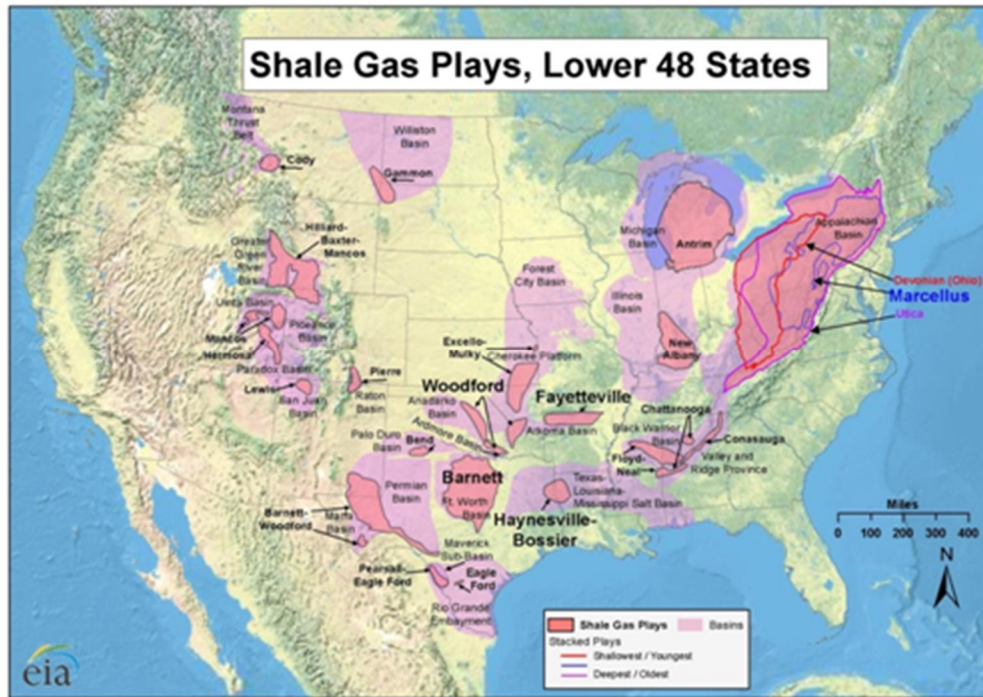
In the early 2000s production techniques had improved and gas commodity prices were also beginning to increase. By mid-decade, it looked as if shale gas would be competing with the rising trend of US spot gas markets, with world LNG as the marginal source of supply. Devon Energy was beginning the mass exploitation of its extensive acreage in the Barnett shale and other drillers were ready to make major investments in the relatively shallow Fayetteville shale in Arkansas. This was followed by movements towards the more prolific Haynesville and Marcellus shales, and towards the liquids-rich portions of the plays.

Initially the focus was on solving the technical problems associated with releasing the natural gas from low permeability shales, and by 2005, the combination of proven and improving technology, rising gas prices, declining conventional supplies, low financing costs, a supportive federal government, and a surging economy provided a perfect situation for a dramatic lift-off.

Early movers made large profits in the high-price markets, and aggressive movers (like Chesapeake) made a dash-for-acreage in deeper and challenging plays such as Haynesville and Marcellus until the credit crunch of 2008. Technology continued to improve steadily, allowing more challenging shale plays to be exploited. Productivity from new wells continued to rise, so that, combined with the technological improvements and high prices, drilling expanded to other shales that were deeper and more expensive to produce.

Figure 4 shows the geographic coverage of shale gas in the US and illustrates the large acreage of the plays.

Figure 4 – Shale plays in the US (lower 48 states)



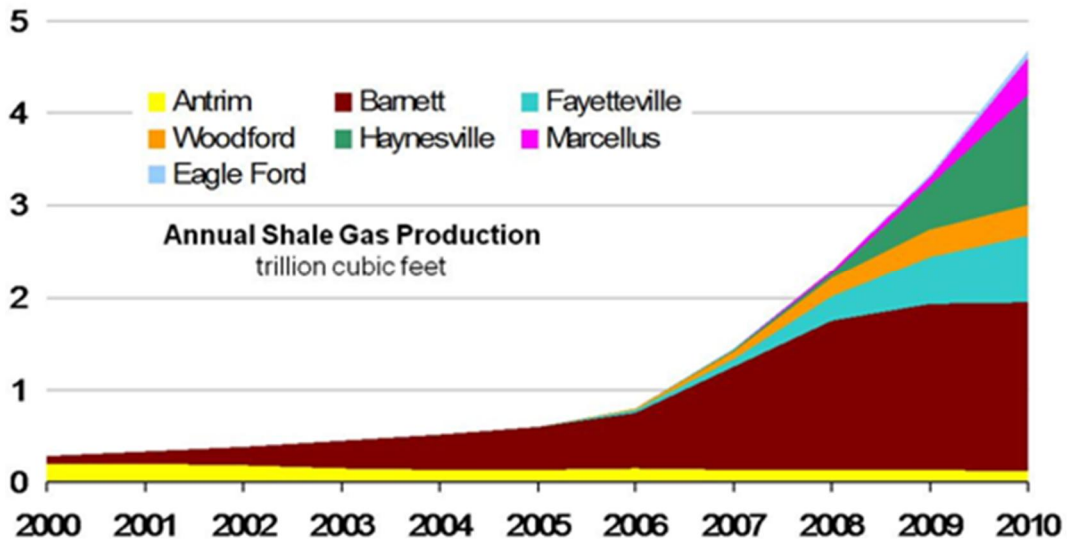
Source: EIA, March 2010

When the economic crash occurred in 2008, gas prices collapsed and the market value of many producers, both shale and conventional, fell dramatically. Cash-flows were also hit hard, although this was mitigated somewhat by producers increasing their use of price hedging.

Falling prices focused the industry on reducing drilling costs and identifying the most productive areas within the shales. At the same time, the focus of the game was already shifting towards the Marcellus shale plays (located close to high-value markets), and liquids-rich plays, both within established gas shales and in new locations, such as the Eagle Ford shale.

Despite the falling prices, the shallower plays and the oil-rich and/or highly productive areas of the deeper plays remained profitable. Figure 5 shows shale gas volumes continued to increase throughout the economic downturn.

Figure 5 – Shale gas production volumes in the US



Calendar years. Source: EIA, March 2010

Today, US investors consider the Barnett shale, where the revolution began more than a decade ago, to be a mature development. Nevertheless, significant drilling advancements continue to improve productivity from new wells and extend the life of older wells. In today’s market conditions, the focus is on liquids rich shales (such as the Eagle Ford), targeting the most productive acreage within plays.

In the wake of the recession, some of the early-movers found themselves over-committed to large acreages with high leasehold commitments, or less profitable economics, in some cases sub-commercial. However, this has been offset by the progressive cost reductions, and the re-deployment of gas rigs into more profitable liquids-rich shale zones.

A further notable trend is the move of integrated gas majors, both domestic and foreign, into the US market. The motivations of these new participants often are thought to be strategic rather than short-term, with the aim of gathering expertise in shale drilling techniques that can be applied elsewhere.

3.3 Environmental concerns

The success of shale gas in the US has not been without its critics. There is a growing unease over the environmental impact of shale gas drilling, and hydrocarbon production in general, following events in 2010.

The year began with the release in January, of the film documentary ‘Gasland’, which polarised the debate on environmental pollution from shale drilling. There was a strong rebuttal to the claims made in ‘Gasland’ from the industry and they even released a video⁴.

⁴ <http://www.anga.us/truthaboutgasland>

On 20 April 2010 the Macondo well incident in the Gulf of Mexico, raised environmental concerns to an unprecedented level, and onto the political centre stage.

By the end of the summer, it was clear that regulatory interest in a range of exploration activities had reached a new level, and operators would need to be increasingly proactive in countering the environmental opposition. This was not confined to the US; the impact of both events quickly spread to governments and regulatory authorities across the globe. The extent of the impact of 'Gasland', and subsequent investigations in the US is illustrated by the fact that the relevant authorities in New York State, Quebec, France, India and South Africa have all recently introduced moratoria on their shale gas activities following concerns over the availability of water, and potential pollution arising from the use of drilling and fracking fluids.

3.3.1 Experiences in the US

The US gas industry is currently the only significant case study for the range of potential environmental impacts caused by extensive shale gas drilling. Initially concerns were relatively few, while production was confined to historic hydrocarbons production areas. As shale horizontal drilling and fracking has expanded away from the oil heartland, concerns have increased about the potential environmental and human health damages it might cause. Most importantly this has concerned whether water supplies can be contaminated or excessively depleted. Some instances of poor, or illegal practices, and reports of water contamination (both deliberate and accidental) have intensified the concern.

In the US, state agencies regulate oil and gas exploration and drilling on non-federal land under state oil and gas laws and also under federal laws such as the Clean Streams Law, the Dam Safety Act, the Solid Waste Management Act, and the Water Resources Act.

Pennsylvania is currently in the public eye, with the recent rapid growth in Marcellus shale drilling, including areas with no prior oil and gas drilling. As Marcellus drilling spread across Pennsylvania public concern grew, the Pennsylvania Department of Environmental Protection (DEP) and other agencies uncovered several violations including poorly constructed and dangerous water impoundments, inadequate erosion and sediment controls, improper waste and fluid disposal, and improper and unregistered withdrawals of water from streams. DEP, on occasion, has ordered the shutdown of drilling operations, and has stepped up state-wide inspections of drilling operations. Houston-based Cabot Oil & Gas Corp. agreed to provide drinking water and put \$4.1 million into escrow for families in Pennsylvania who said their drinking water was polluted by the company's wells, settling a claim by the DEP.

Excluding some extreme views, on both sides of the environmental debate, it is widely believed that state agencies have taken a pragmatic, technical view that sufficient protection is a matter of refining standards and beefing up enforcement. New York State has taken the most dramatic step by imposing a moratorium while it reviews this situation. Additionally, the federal Environmental Protection Agency (EPA) is conducting a study which is due to be completed in Q2/Q3 of 2011.

The complexities of developing and refining standards and maintaining proper oversight has not been helped by the over-stretching of regulatory resources. Regulatory staffing has not kept up with the rapid growth in shale gas production and has been exacerbated by government budget constraints since the 2008 economic crash.

3.3.2 Water pollution

There are two distinct phases to the establishment of a production well: drilling and completion.

In the drilling phase, the fluid used in large quantities is known as 'mud'. It serves multiple functions of cooling and lubrication of the drill bit, as a flow medium to carry the cuttings to the surface, and as a counter-weight to underground gas pressures that might otherwise cause a well 'blow-out'. Shale gas drilling is fundamentally the same process as conventional well drilling and the mud consists of the same ingredients as conventional well programs, which may differ in composition according to the well characteristics. At intervals during the drilling process, the well is lined with steel well-casing which is secured in place by pumping concrete in between the well bore and the casing. In some cases the cement will cover the entire length of the casing; in other cases a partial cementation is sufficient. Procedures for disposal of drilling mud and excess cement have been generally well established over a large number of years so drillers have no reasonable excuse for poor practice.

The completion phase takes place after the well has been drilled and lined. In shale wells the lower (generally horizontal) portion of the casing that lies within the target portion of the shale horizon will firstly be perforated using numerous small explosive charges that create holes through the well casing and into the reservoir shales. This also creates an extended large surface area through which the gas can flow into the well casing and to the surface. The second part of the completion process is where the fracking fluid is pumped into the well at extremely high pressure. This expands the fissures in the shale, creating extensive fractures, into which the proppant (sand is often used) flows to maintain an expanded surface area from which the hydrocarbons can flow.

Fracking operations can, depending on local conditions, typically require around 20,000 cubic meters of water per well, and the first environmental concern is that the sourcing of this water does not deplete local resources. If water is sourced from outside the region, the volumes required imply up to 1,000 truck-loads of water for the fracking of each well.

The second and main concern is the composition of the fracking fluids, ten tanker-loads of which are added to the water used in a typical fracking operation. For a number of years, fracking fluid suppliers refused to publish the composition of these fluids on the grounds that it was commercially sensitive information which could not be patented. However, following intense pressure from environmentalists and legislators, Halliburton, a major supplier, finally published limited information on their web site in November 2010.

The additives are a variety of chemicals that improve the effectiveness of the fracking, (thickeners and friction reducers), and protect the production casing (corrosion inhibitors and biocides). Most fracking fluids contain a variety of registered toxic chemicals, which, suppliers argue have everyday uses in household products. However, in sufficient concentrations, the ingredients are harmful to humans and wildlife.

Fracking fluids may also contain diesel fuel which contains benzene, a registered toxic chemical and widely-researched carcinogen which attacks the neurological, immune and liver systems of the human body. In February 2011, it was revealed by a congressional investigation that oil and gas service companies had injected over 32 million gallons of diesel fuel, or hydraulic fracturing fluids containing diesel fuel, into wells in 19 states between 2005 and 2009. Furthermore this had been done without the required permits (Under the 2005 Energy Policy Act, any company that performs hydraulic fracturing using diesel fuel must receive a permit to be in compliance with the Safe Drinking Water Act).

Drillers often argue that shale layers, where the hydraulic fracking operations take place are several thousand feet below the drinking water aquifers, and the pathway between the well bore and the casing is filled with cement that effectively blocks the flow of any fluid from the shale layer into the aquifer layer. However, there have been reported instances of the cementation being poorly implemented and hydrocarbons fluids have been detected at the surface. Equally, once the fracking operation begins, the operator has no control over the flow of fluids, which will take the path of least resistance. In some of the shallower shales there is an increased risk of aquifer contamination. In most cases, however, these problems are avoidable and simply highlight the requirement for good operating practice and effective implementation of drilling regulations.

Accidental spillage of drilling fluids has also been a cause of environmental pollution. There have been reported instances of fluid reservoir overflows during heavy rain, pipe leakages into streams, and groundwater contamination through poor reservoir lining.

In the 1990's the US oil & gas industry lobbied hard, and won, an exemption from the Safe Water Drinking Act, in the belief that this would be to their benefit. Predictably, the environmental lobby made an issue of this, arguing that if fracking does not pollute the water supply, why does the industry need an exemption?

In summary, few people in the US believe that environmental concerns could significantly stunt the exploitation of shale gas resources. However, in an abundance of caution and political response to public concern, environmentally sensitive areas such as New York, might impose more stringent requirements and restrictions that would increase costs and slow the pace of development.

In all cases, it is important that companies engage with local communities on these issues in a constructive and empathetic manner. Additionally, it is reasonable to expect that there will be more detailed regulation and monitoring of the management of contaminated water to minimise spills, chemical evaporation, inadequate treatment, and illegal dumping.

3.3.3 Air pollution

There are several possible sources of air pollution from shale drilling, all of them avoidable where good practice is applied.

3.3.3.1 Methane release into the atmosphere

Methane is a naturally occurring gas and millions of tonnes are released into the atmosphere every year through decay of vegetation, cattle farming, natural seepage, and leakage or venting of hydrocarbons by the oil & gas industry. Unnecessary release of methane is undesirable as it is many times more effective as a greenhouse gas than carbon dioxide.

In the shale drilling industry methane releases have been identified from a variety of sources, including:

- at the wellhead, methane can be released where the well casing has been poorly cemented to the well bore ;
- pipe leakage and release of methane from drilling fluid; and
- controlled release such as venting and flaring.

Given that gas sales are often the principal income stream, operators are financially incentivised to reduce methane releases, and legislation has increased progressively to

minimise the wastage. Volumes from the shale industry should not be significantly different to those released by conventional gas production.

3.3.3.2 Radon gas release

Shale drilling processes inject liquids into the shale which co-mingle with the brine that has been in contact with the shale for millennia, and relatively small quantities of radon are brought to the surface. This could pose a health risk to drilling operators if they worked in a confined space where radon gas could collect to dangerous levels, or breathed fumes from the radioactive wastewater, or handled the concentrated materials regularly for 20 years. Without these types of intensive or confined exposures, the gas is less dangerous.

The dangers of radon to the general public are thought to be insignificant, but the hazards posed by radioactive liquids are a more substantial problem.

3.3.4 Radioactive liquids from well drilling and production

During the build-up phase of gas drilling in the Marcellus Shale, New York State's Department of Environmental Conservation (DEC) analysed samples of wastewater from drilling and found that they contained levels of radium 226 (a derivative of uranium), as high as 267 times the limit safe for discharge into the environment and thousands of times the recommended safe limit for people to drink.

Naturally occurring radioactive materials are a known issue in oil and gas drilling waste, and especially in brine water that has been soaking in the shale for millennia. In other states, the waste is frequently re-injected underground, but New York has relatively few injection disposal wells and those available are not licensed to receive radioactive waste. Until the problem was identified, most drilling wastewater was treated by municipal or industrial water treatment plants and discharged back into public waterways. If the moratorium on shale drilling is lifted in New York State, drillers can expect tighter regulation of the methods used to dispose of waste.

There is no precedent for examining how these radioactive materials might affect the environment when brought to the surface at the volumes and scale expected in New York. What is known is that radium causes bone, liver and breast cancers, and the EPA publishes exposure guidelines, but there is still disagreement over exactly how dangerous low-level doses can be to workers who come into contact with it, or to the public.

The difficulty is therefore the uncertainty, not only about the safe limits, but around the legislative position of drilling companies in their responsibilities towards workers, towards the public, and the fact that there is no established water treatment infrastructure to handle the waste.

The Marcellus shale also extends into Pennsylvania and here, drillers trucked at least half of this wastewater to public sewage treatment plants in 2008 and 2009, according to state officials. Some of the wastewater has also been sent to other states, including New York and West Virginia.

In March 2011 the Pennsylvania EPA announced that water sampling on seven Pennsylvanian rivers found no radiation problems related to Marcellus Shale wastewater. However, the US EPA has urged additional testing and said it will take a significantly more active role in reviewing permits and environmental impacts from the discharges.

The EPA has also recommended that municipal drinking water systems near sewage treatment plants receiving Marcellus Shale wastewater should be required to conduct regular radiation testing. The pollution permits of all sewage treatment plants accepting gas well wastewater must be amended to include provisions for its treatment. It has urged the state to establish monitoring requirements and effluent limits for those facilities that 'ensure protection of drinking water and aquatic life,' and has asked the DEP to provide a list of sewage treatment plants that accept the wastewater and a schedule for completing the permit modifications.

3.3.5 Road congestion

The onshore drilling industry makes extensive use of road transportation, not only for the rigs, but the well casings, pumps, support services and equipment, and the fluids required for drilling.

In many cases water may be piped to drilling sites using local pipe networks but in other cases water may have to be trucked to the sites. A deep well with multi-stage fracking could require up to 30,000 tonnes of water over a number of days. In some cases this might have to be delivered entirely by road and require up to 2000 truck-loads of water, with resulting wear and tear on the local road infrastructure and transport emissions. A percentage of the water (typically 30-80%), contaminated by fracking chemicals and down-hole liquids will be produced in the first few weeks of production, and smaller quantities thereafter. This will require trucking to treatment, re-cycling and disposal plants. In the US, companies often contribute directly towards the cost of local roads in order to bring the local community on side. This is widely expected, and evidence to date supports, that this will also be the case in Europe.

3.4 Conclusions

The growth of shale gas in the US has been a major success story. Developments in technology, relatively high gas prices and a growing supply shortfall resulted in the conditions being right for the rapid growth of the industry. This has reduced the US' dependence on imported gas which has had knock-on effects to the world gas market.

However, there are growing environmental concerns surrounding the shale gas extraction process and in some cases these concerns have led to calls for shale gas drilling operations to be suspended or even stopped.

In future, it is likely that these concerns will lead to a tight regulation and monitoring of shale gas drilling operations. It is possible that this may result in a higher cost of production that may, in some cases, make some drilling operations uneconomic.

There are two important questions to be addressed:

- Will the US maintain its growth in shale gas production?
- Will the US shale gas revolution be repeated in Europe or other parts of the world?

In the next section of this report we look at the important issue of shale gas economics to help us to answer these questions.

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4. SHALE GAS ECONOMICS

With the prospect of enormous shale gas resources outside the US potentially being unlocked by newly-developed technology, the implications of a global spread of the US shale gas experience is a significant issue for the world's gas markets. Leaving aside the stark differences in views about the environmental merits of shale gas production, there also remain a wide range of views about the underlying long-term economics of shale gas production in the US, and much debate about how the cost-base will be affected by different economic, social, cultural and environmental regimes across the globe.

In this section, Pöyry reviews how various factors concerning shale gas exploration and production affect shale gas economics. For this, the US experience is the obvious point of reference. Given the relative newness, incredible pace and evolving technology of US shale gas developments, it is understandable that the shale gas economic prospects remain subject to debate.

4.1 Shale economics debate – contrarians versus industry

4.1.1 *The Contrarian View*

There are some technical and financial analysts that express serious doubts about costs of production and the quality of the US shale reserves. These views differ considerably to the viewpoint presented by shale gas producers and other analysts. The 'contrarian' view as it has become known, is not the mainstream view, but it is worthy of consideration because it represents one end of a spectrum of economic viewpoints, and highlights some of the key issues and uncertainties of modern shale gas exploration and production.

In its Annual Energy Outlook issued in April 2011, the US EIA acknowledges this uncertainty, noting 'although more information on shale resources has become available as a result of increased drilling activity in developing shale gas plays, estimates of technically recoverable resources and well productivity remain highly uncertain....The increases in recoverable shale gas resources embody many assumptions that might prove to be incorrect over the long term.'

According to the contrarians, the shale developers hold all of the information necessary to make informed judgements about the economics of shale exploitation, but are selective about the facts they present to analysts, stock markets and the public.

The contrarians do not dispute, in fact readily acknowledge, that the potential natural gas resource base in the US is very large. The point at which they differ from shale developers relates to the estimates of production costs: How much of the gas is economic to produce and at what price?

The shale developers frequently argue that shale gas production is sustainable and economic at future prices in the \$5-6/mmbtu range. Some argue that their businesses are not only sustainable, but highly profitable at prices below \$4/mmbtu. The contrarians believe that the developers are ignoring costs, long-term well performance, and the limited extent of good opportunities within formations, with the result that the marginal cost of

shale gas production is \$7-8/mmbtu, and perhaps much higher depending on the shale play⁵.

Houston geologist Art Berman is a widely quoted shale gas contrarian. He argues that most shale gas wells are uneconomic at current levels of capital and operating costs, and gas prices. In January 2011, he critiqued the EIA's Annual Energy Outlook Early Release⁶, finding it troubling for the improbably low values of gas prices in light of the reserves estimates and cost of production.

Noting that EIA's estimate of technically recoverable unproved US shale gas resources more than doubled since last year's report, from 10tcm to 23.4tcm, Berman notes the wide range of uncertainty about this value as reflected in the varying estimates by numerous parties in the 2008-2010 period. His main commercial criticism is EIA's shale gas production and price forecasts based on the expanded shale gas resource base. The problem, he says, is the uncertainty of converting 'technically recoverable resources' to 'reserves' and more particularly 'proved developed reserves', as the 'resources' designation does not take commercial considerations into account. He sees the main issues as:

- reserve quality across formations;
- decline rates; and
- optimistic long-run cost of production.

Concerning reservoir quality, Berman argues that over time, interest in shale plays has gravitated towards a core area that is a fraction of the entire formation, at the expense of drilling in the lower quality areas. For example, in his view the Hayesville core area includes ~110,000 acres, which represents approximately 10% of the play area in Louisiana defined by limits of drilling (1.5 million acres). In February 2011 Haynesville surpassed Barnett in production, where the core area had already been heavily exploited. This selective exploitation of the premium areas, which is the perfectly logical behaviour of producers, does raise the question as to how long production levels can be sustained at current prices.

Based on his study of company reports, shown in Annex A, Berman claims operators' statements of profitability at sub-\$5/mmbtu gas prices exclude significant costs such as debt service, overheads, dry hole cost, and plugging and abandonment expense. His conclusion is that gas operators require at least \$7/mmbtu on average to break even in the shale plays. He notes that in November 2010, aggressive shale gas producer Chesapeake stated that it was undertaking drilling only for lease holding requirements or a joint venture partner carry until gas prices rose above \$6/mmbtu. This contrasts with the EIA wellhead natural gas price projection for 2020, at \$4.59/mmbtu.

Berman has also argued that companies' present production decline rates are unrealistically optimistic. His analysis of decline rates is shown in Annex A.

Berman's geological-based conclusions are supported by some financial analysts such as Ben Dell, a senior energy analyst at Bernstein Research in New York, who noticed some

⁵ Prices and cost references to shale production are commonly made in \$/mmbtu. At current exchange rates these are equivalent to p/therm as follows: 4\$/mmbtu = 26p/therm, 6\$/mmbtu=38 p/therm, 8\$/mmbtu=51p/therm

⁶ <http://petroleumtruthreport.blogspot.com/2011/01/eia-annual-energy-outlook-2011-dont.html>

unexplained discrepancies in the corporate reporting of rates of return on shale drilling operations. Dell does not accuse the oil companies of lying, but says they can be selective with the facts they present, that we only hear about the best numbers and the successful wells.

For example, he notes that companies can present impressive production rates for individual wells without defining the duration, and with horizontal wells the peak production may last only a short period. Because of wide variations in actual decline rates, and the possibility of early well failures, the initial production rate is a fraction of the information you need to evaluate its profitability. Dell also questions if the all in costs of a well are being amortized properly into the economics that appear in a company's press release.

4.1.2 The Industry view

The shale gas industry points out that there is a constant process of improvement as we learn more about shale gas production; costs go down as learning curve goes up. There are a number of new developments that if properly utilised and transferred to other parts of the world, can ensure that this can be repeated.

There was a 20-year learning curve to get the first shale play into large scale commercial production. As production increased, the learning curve did not slow down, it accelerated, and this is still happening both within the existing shales, and in new plays.

Production techniques are also improving month by month. Drilling rigs are more powerful and accurate; wells are quicker and more precise. At the same time the horizontal distances are increasing from under 1,000 feet in early wells, to over 5,000 feet today. This gives the opportunity for more perforations and production increases that are roughly pro-rata to the horizontal length.

Further economies can then be achieved by drilling multiple wells from a single pad. Rigs spend less time mobilizing, de-mobilizing and on the road, and more time actually drilling. Concentrations of wells in an area can thus help reduce the transportation costs on laterals connecting to the main pipelines, and help operators share the gas processing and trunk-line costs between multiple wells and operators.

Proppants and fracking fluids are also improving with time and operators are learning how to perform hydraulic fracturing much better, using special mixes of chemicals and water. The most widely used proppant to date is sand, but ceramic spheres have been developed to increase flow rates. 'Slick' fluids allow better flow of the proppants deeper into the well perforations, enabling greater production rates for longer. In practice, it can sometimes take some expensive trials and errors to optimise the fracking operation.

The leading operators now have extensive databases of core samples and well data which help them to analyse new plays more quickly. This is illustrated by the dramatic decreases in the times required to bring new plays into commercial production.

It is interesting to note that the shale developers devote relatively little of their time to defending themselves directly from the arguments of the contrarians. The developers prefer to argue that things are improving, and that operating costs are still coming down in North American gas and oil plays. This doesn't show up immediately as reduced all-in costs on the financial statements of these energy producers, but it feeds through over months and years as the more improved activities increasingly dominate the asset portfolio.

Producers continue to announce longer, cheaper wells and new wells with record production rates, and large volumes of associated liquids. It is hard to argue against these claims as developers really are getting better at their art, and they are shifting their exploration expenditures, wherever possible, into the liquids rich plays.

There is a general industry consensus about several current market conditions.

- Suppressed natural gas prices – US gas prices will continue to average around the present level (which everyone terms low) for at least 12 to 18 months. Some companies are a bit more bearish as to both level and length.
- Strong oil prices – few companies see oil prices below a minimum of \$70-80 /barrel. The variations in opinion seem only to be about how long oil will stay above \$100/barrel.
- Environmental concerns – until recently US shale gas producers have been dismissive of the environmental charges made against them. In their defence they touted their industry best practices and their local value creation of jobs, royalties, and domestic energy. However, this has changed and recently, the industry has made concessions concerning revealing fracking ingredients and improving water conservation/recycling initiatives. The companies are now being forced to consider a future that includes higher environmental compliance costs.

4.2 Key factors affecting unconventional gas costs

From the US experience there can be seen a number of key factors affecting the cost of exploration and production of unconventional gas. Given the nascent status of shale gas in GB and Europe generally, these factors could be constraints or even barriers to determining and exploiting the potential benefits of shale gas resources.

For instance, Shell, in testimony to the GB Government’s Energy and Climate Change Committee opined that:

- simple extrapolation from experiences in North American is difficult;
- assessment of unconventional gas potential will first require 1-4 years investment in seismic, exploration drilling, and geological study activities across many areas;
- this will need to be followed by 2-5 years of appraisal drilling and production testing; and
- it is estimated that 20-40 wells (exploration, appraisal, pilot) are required to prove commerciality in many basins.

Shell states that companies with diversified portfolios and revenues will be better able to absorb this exposure, but to succeed they will also need positive government support such as the right fiscal framework and the granting of drilling permits.

4.2.1 Geological knowledge

Across Europe the shale layers have been known, and studied, to varying degrees. However, little is useful for determining the commercial prospects of a shale formation.

Where extensive commercial exploration activity has been established, there is often a large amount of seismic data available, but this is of varying quality, with older data being of limited use, and modern 3D seismic imaging providing greater detail. Analysis of the

data has focused primarily on the potential for conventional hydrocarbons, rather than the shale layers.

The same principal applies to core sampling of shales. Where this was done, the focus of investigation was generally not on the characteristics that are now considered to be essential or desirable for gas production. As a result, the geological data is of varying quality, with relatively little focused on the attributes of modern shale production.

In the case of coal producing basins, there is also a large quantity of data that has been collected over many years but, as with shale data, the focus of studies has rarely been the modern commercial extraction of gas.

However, there remains a considerable inventory of data that identifies the shale and coal strata, their dimensions, and basic qualities. This brings the problem that access to data is variable. In some cases, such as Germany, the hydrocarbons industries are mostly privately owned and the data remains confidential to the drilling companies. It will therefore be of assistance to the owners but not generally available in the public domain.

In other countries, notably in Eastern Europe where the exploration used to be state controlled, much of the data remains in government hands. In this respect the Polish authorities are reported to have been extremely co-operative with private companies, and this has been appreciated within the industry.

4.2.2 Gas prices

As discussed earlier, in the US the shale gas technology developments enabling the leap in shale gas productivity coincided with a period of rising US gas prices due to falling conventional production and strong demand from a booming economy. The rising prices provided a strong tailwind to help shale gas production through the learning curve.

In Europe, the fact some gas contract prices are linked to oil products (which are currently high), and the approaching depletion of North Sea conventional production – while unfortunate for the overall economies – may provide support to new unconventional technology.

4.2.3 Technological developments

Europe has the potential to benefit from the US shale gas technological developments of the last decade. However, at present it does not have the technology in the field.

4.2.3.1 Fracking technology improvements

Early shale wells achieved a recovery rate of around 2%. However, modern shale wells typically achieve recovery rates in the range 15-35%.

4.2.3.2 Faster drilling

The latest generation of horizontal drilling rigs is now being fitted with engines of around twice the previous size. Combined with the latest hard-wearing bits, wells can be drilled faster and horizontal sections longer. Although the day rates for these rigs are higher than for older rigs, the economics are improved by the greater productivity. In the US overall rig utilisation rates fell in 2010, but the modern rigs' utilisation remained close to 100%.

4.2.3.3 *Development of multi-well drilling pads*

In order to reduce development times and costs, shale wells are now drilled almost exclusively in 'pads', with multiple wells being drilled in different directions from each pad. In the US a typical spacing is one well per 80 acres. This spacing can be optimised for each particular location, between shale horizons and within shale plays.

Recently, a figure of 8 wells per pad was regarded as typical but with increased lateral drilling lengths, the number of wells per pad has been rising to 10, 12 and now moving to as many as 24 wells.

Well-spacing, measured in terms of the land area that can be drained from a single well, is also the subject of much research, and a key commercial driver that will be varied according to shale characteristics.

4.2.4 *Licensing and permits*

The US licensing and permit model is favourable to land access and drilling. On private lands, generally it involves a private contract between the energy company and the mineral rights owners – usually the land owners. The mineral rights owner receives financial compensation upfront and a royalty payment on production. With the local incentives provided by this structure along with the generally favourable business environment, drilling and production occurs in the US even in urban areas.

US drilling companies have found that the economics of production are dependent on land access to the 'sweet-spots' in the shale gas plays. The US experience is that access to the high-value areas is often restricted by overriding land-use requirements, or other constraints such as: densely populated areas, land reserved for military training, areas of outstanding natural beauty, environmentally sensitive areas, historic sites, national parks, nature reserves, etc. This experience will only be magnified in Europe, due to the higher population density and reduced land area.

4.2.5 *Taxation*

It is common in the US for states to impose taxes on gas production, based either on the volume or the value of the gas. The effective rates after various deductions, exemptions, and rate reductions, can be markedly less. For example, in Texas the severance tax is 7.5%, but in recent years the overall effective rate has been 1.1–1.9%. It is not clear whether the existing tax regime has had any hindrance on the exploitation of shale gas. The strong performance in exploitation activities seem to indicate that it has not.

However, tax incentives enacted in the energy crisis of the late 1970s, and other government research and development funding have been recognised as providing key support to the development of unconventional gas technology, and similar, though not identical, policies could be applied to Europe.

4.2.6 *Technical resource availability*

The availability of drilling rigs, support equipment through the oilfield support services industries in the US has been appreciated as a key enabling factor of the shale gas industries. In the US the shale gas boom was preceded by extensive conventional drilling for oil and gas, and the services sector was not only well-established but hungry for the new opportunities.

Elsewhere across the world the situation varies considerably by region, with the services sectors often integrated within oil and gas companies, controlled either by the state or by national champions. Outside the US, a concern for independent developers is that these service providers may be uncooperative, or lacking the appropriate equipment, and that costs increases are inevitable. It remains to be seen how much truth there is in these concerns. The industry view is that, where possible, exploration and drilling programs will utilise the technical resources available locally, at least in the initial phases.

4.2.7 Downstream infrastructure access

Infrastructure access in the US is through bi-lateral agreements with pipeline companies, and the market is extremely competitive, with there often being multiple pipelines looking to attract new business from gas production companies. Elsewhere throughout the world, there is rarely the choice of pipeline services provider, with high pressure pipelines often under the ownership of single national, or several regional, companies. Local distribution services are often under franchise agreements.

In Europe, the technical skills to build gas collection systems are abundant, and most countries have extensive distribution and transmission engineering networks and industries. The planning and development skills are generally within monopoly distribution and transmission system companies, with the construction works contracted-out.

Developers often express concerns that the pipeline companies may be unresponsive to requests for access, or that the processes may be too slow and bureaucratic. However, with the oversight of regulators, there is an incentive both for the pipeline companies to be cooperative, and to earn revenues from the new business.

Planning processes vary across Europe and it is likely that in some areas the planning processes will not be as fast as the gas companies would like.

One way to side-step downstream gas infrastructure concerns is to establish onsite gas-fired power generation. In the UK, there is one operating pilot CBM project that has on-site generation. The potential availability of this option depends largely on electrical interconnection specifics, which have their own complexities.

4.2.8 Water resources and environmental impact

Northern Europe is generally well-endowed with water resources but, as in North America, the development of the local supply infrastructure can vary considerably from one area to another. Therefore the problem is not so much the availability of water as the logistics of transportation to drilling sites. Once the wells have been drilled the problem is transformed into the problem of treatment and disposal. Much of the water is returned to the surface during the drilling and fracking operations, but a percentage remains in the ground and may be produced in the early months of production. Additionally, water may be present in the produced gas, and this also needs treatment and disposal.

4.2.8.1 Volume requirements

It is generally (but not always) true that deeper layers require more water for fracking. Deep shale wells with long horizontal sections can require up to 30,000 tonnes of water per well during the initial fracking process. The depth range of shales in Europe is similar to the US.

Choice of water supply will vary according to local availability. In some cases the optimum supply method will be to construct a local pipe network from a nearby lake or river. Where this is not possible the water may need to be delivered by truck, as described in section 3.3.5. In many cases, roads will need to be upgraded at the expense of the drilling companies. This will not be entirely unexpected, as the US drilling industry is frequently required to bear local infrastructure costs.

4.2.8.2 Water treatment and disposal

The problems of water disposal have been discussed in section 3.3.2. From the US experience the shale industry should already have learned that poor treatment and disposal practices soon reach the public domain and tarnish the reputation of the industry and ultimately, through the democratic process, it is the weight of public opinion that can decide whether companies drill, or not.

The dual problems of water consumption and contamination can be reduced significantly by purpose built re-cycling plants, but these could be expensive and will be measured against other disposal options.

The clear message is that the water supply, treatment and disposal problems may all require significant resources and if the authorities are adequately prepared for the nature and magnitude of the potential problems, solutions will be more easily identified.

4.2.9 Labour resources and costs

Shale gas exploitation generally requires a much greater number of wells than conventional developments to produce the same amount of gas. In North America, where much of the conventional production comprises mature onshore wells, the average production per well was already relatively low and consequently there is already a sizeable inventory of land rigs and drilling crews. However, in Europe, where the bulk of production is offshore, wells are considerably more productive, with fewer drilling crews, and very few land rigs available. Of those rigs available for onshore drilling, the inventory is ageing, and there are few that can match the state-of-the-art high powered drilling rigs that are currently achieving high rates of utilisation in the US drilling sector.

Worldwide, there is already a shortage of trained drilling crews and the shale gas boom, if it spreads across the globe, could result in a further step-change in the demand for drillers.

This raises two issues with the potential to slow the rate of progress of the unconventional gas industry in Europe:

- there is likely to be a general world shortage of trained drilling specialists. The relatively small numbers available in Europe with local language skills could find themselves being drawn towards relatively lucrative international work; and
- in order to achieve the number of onshore wells necessary for the exploitation of shale gas, drillers will need to be trained in the use of the new generation of high-powered horizontal drilling rigs. These skills might also be very attractive to the international market.

The availability of drilling rigs represents a possible bottleneck. Some 100 active land rigs were available in Europe in 2010, whereas in the US the number was 2,500. The low number of rigs will undoubtedly cause inflated prices in Europe, especially when coupled with a lack of experienced engineers and geologists.

4.2.10 Carbon regulations and footprint

CO₂ regulations remain a significant threat to investment in the European gas industry, including the unconventional sector. Where the US now sees the abundance of gas as an opportunity to reduce CO₂ in a pragmatic and economic way, there remains a significant pressure group in Europe that is ideologically opposed to the exploitation of fossil fuels, regardless of the advantages.

As a result there remains a fear in the mind of oil and gas developers that the market for gas in Europe could be squeezed to make room for green energy.

This is not without foundation. The EU has used a cap-and-trade system since 2005, and remains committed to reduce CO₂ emissions by progressively lowering the cap. At the beginning of 2013 the EU introduces phase three of the European Emissions Trading System (ETS), which is proposed to deliver two-thirds of the EU's emissions reduction target⁷. From 2013 the free allocations of CO₂ certificates will be significantly reduced as Europe is moving towards a full auctioning of certificates, and further tightening of limits.

Although we may be going through a period of relatively low price for CO₂ certificates, the ETS is undeniably impacting the investment outlook for the EU's oil and gas sector, both upstream and particularly downstream.

In addition to this, it has been proposed that the global warming potential of the shale gas in power generation is around twice that of the coal-fired industry, when looked at over a 20-year period. The issue was addressed recently in a Cornell University study⁸ that proposed as much as 8% of methane from the shale gas industry is released into the atmosphere. The report argues that as methane is a more powerful greenhouse gas than CO₂, shale gas has the potential for a much larger global warming impact than conventional gas, or coal. However, Cornell acknowledges that significantly more study is needed, as the projections for methane emissions used within their study were derived from extrapolation and estimation, and based upon low quality data.

The Cornell study clearly targets the shale industry and, in return, it has been widely criticised by the industry for its use of poor quality data. The argument by Cornell may be a timely reminder of the need for better practices in the containment of methane, but not necessarily an argument for the superiority of coal over shale gas in terms of global warming potential.

4.3 Conclusions

The contrarians have some sound arguments and it is clear that the shale operators have a vested interest in downplaying a few of the uncomfortable truths. Clearly there are some recent investments in acreage, wells and acquisitions that are sub-economic in the current economic climate.

However, this is far from evidence that the operators were dishonest in their intentions or made poor judgements at the time the investments were made. Few people, if any, in 2006 or 2007 would have forecast a natural gas price of around \$4/mmbtu in 2010-11. Furthermore, the operators have been improving their art, and it is apparent that some

⁷ The EU has committed itself to reducing CO₂ emissions to 20% below 1990 levels by 2020.

⁸ 'Methane and the greenhouse-gas footprint of natural gas from shale formations', Howarth, Santoro, & Ingraffea, Climatic Change, 2011

large players are happy to invest in new acreage at \$4/mmbtu, albeit mostly in liquids rich acreage. Operators have done well to survive a \$4/mmbtu environment and it is to their immense credit that some thrive.

The US shale gas experience is the most relevant to potential cost of producing shale gas in Europe and the rest of the world. Some observers have calculated that European shale production costs will be much higher than US costs. These views do not factor-in the likely economies of scale, and technical ingenuity that will inevitably be focused on the European experience. Our view is that the US experience will be transferable to Europe, and that European costs will fall in a similar manner to US production costs, but there will remain a premium for the European cost base.

This does not mean that all-in European costs decline to US levels. There are structural aspects in Europe that, compared to the US, increase the cost of oil and gas drilling and production activities. But, by learning from the achievements in the US, Europe will benefit from the latest technology, best practices, and prudent regulatory oversight.

5. PROSPECTS IN GREAT BRITAIN

5.1 Introduction

The potential development of unconventional gas in GB has received significant media and public attention in recent months. The potential for GB to reduce its reliance on imported gas through the development of indigenous resources would be a significant economic and political benefit.

The recent experience of the US and relatively high gas prices has focussed attention on whether GB could see a similar 'revolution' in gas supply. This section outlines GB's unconventional gas reserves and also describes current market conditions in GB, to determine whether there are barriers to large scale unconventional gas development.

Annex B provides information on the companies that are seeking to exploit GB's unconventional gas resources.

5.2 Unconventional gas resources

5.2.1 Shale Gas

The geological shale prospects of GB were recently summarised in the report 'The Unconventional Hydrocarbon Resources of Britain's Onshore Basins', published by DECC. This report was produced under contract by the British Geological Survey (BGS), based on recent analysis, together with published data and interpretations.

The BGS notes that the untested shale rock volume in the UK is very large but, with only limited geological information, and prior to extensive drilling, fracture stimulation and testing, it is not clear that UK shales have the properties to yield natural gas in commercial quantities. The three most promising plays were identified, and quantified by analogy with US shale plays as follows:

- UK Carboniferous (Upper Bowland Shale) shale gas play, with a potential yield up to 134bcm;
- UK Jurassic (Lias) shale gas play, with a potential yield of up to 6bcm; and
- UK Cambrian shale gas play (Midland Microcraton), with a potential yield of up to 4bcm.

There is additional potential in some older shales, but this comes with a higher risk. Offshore shales are also believed to be prospective, but commercial exploitation is considered unlikely in the foreseeable future (due to much higher exploitation costs offshore).

To put the upper limit quantity of gas into context, it is a volume of gas that has a market value of £40billion at a gas price of 70p/therm. It is also a sufficient volume to provide in excess of 10% of the UK's natural gas for a period of 15 years.

5.2.2 CBM

There are substantial quantities of coal remaining in GB, and much of this resource contains methane in sufficient quantities that commercial exploitation may be viable. The volumes of coal in certain strata can be reasonably estimated by measuring the thickness from core samples taken from a variety of wells over many years, and the approximate

geographical areas are known. By multiplying the area by the thickness, an approximation of the coal volume can be made. This can then be multiplied by known and estimated values of the methane content per cubic metre of coal.

Using the above methodology, recent estimates indicate that the UK CBM resource base may be in the order of 2,900bcm, but the recoverable volume is a relatively small percentage of this. As with shale gas, estimates of CBM resources need to make a range of assumptions to cover large areas where the required technical data is simply not available. A best-guess estimate used by DECC in a recent presentation is 10% of this amount is potentially recoverable.

The above estimates are for onshore resources only. There is known to be a large coal resource under the North Sea, but this is not included because commercial exploitation does not appear economic within the period studied.

5.3 Licensing regime

Petroleum Exploration and Development Licenses (PEDLs) are a relatively recent innovation, replacing the old system of sequence of licences. Instead, they are valid for a sequence of periods, called Terms which are designed to follow the typical lifecycle of a field: exploration, appraisal, and production. Each licence expires automatically at the end of each Term, unless the Licensee has made enough progress to move into the next Term. Each licence incorporates the following terms:

- exploration – 6 Years;
- appraisal – 5 Years; and
- production – 20 Years.

Progression to the second and third stages can be accelerated if the obligations are satisfied early.

The PEDL system requires a 50% acreage relinquishment at the end of the initial term, and large increases in acreage fees through the appraisal term. Together with the relatively small initial licence areas, there is a concern throughout the industry that there could be too many players with small positions. DECC is understood to be considering the need for special licence for unconventional gas development.

In order to mitigate potential environmental impacts of the 14th licensing round, DECC commissioned an environmental report, 'Strategic Environmental Assessment for a 14th and Subsequent Onshore Oil & Gas Licensing Rounds' (URN 10D/553), which was published in July 2010. DECC concluded that the appropriate path forward '...is to proceed with the licensing programme but with some licensing conditions. It is recommended that the DECC place an explicit expectation on licence applicants to demonstrate an excellent understanding of the environmental sensitivities and potential constraints on blocks both at the application stage and during any subsequent operations.'

5.4 Fiscal terms for unconventional gas production

Unconventional gas fields do not currently receive any preferential tax treatment under the UK oil & gas taxation regime.

New projects in the UK are subject to a 30% corporation tax charge, plus a 32% supplementary charge, effectively a 62% profits tax after costs have been recovered.

Unconventional projects may benefit from preferential treatment applied to smaller fields through a value allowance. Fields of less than 3.4bcm do not pay the supplementary charge on the first £75 million in revenue. For fields between 3.4bcm and 4.3bcm, the £75 million allowance is reduced on a straight line basis to zero. The allowance is subject to a cap of 20% (maximum £15 million) that can be taken in any single year.

Small fields costs can be offset against the corporation tax and supplementary tax charges.

The UK oil and gas taxation regime was designed and implemented at a time when the exploitation of unconventional gas resources was barely envisaged. It was written with the North Sea as the main target, and smaller onshore fields a relatively minor consideration. Unconventional gas developers would like to see a system that addresses the specific operating environment of their own industry. The view is that taxes are generally higher than for similar fields in the US.

Potential problems of the UK oil & gas taxation regime include:

- the definition of a 'field' does not comport with shale gas geology and exploitation practices and potentially conflicts with the licensing process and tax regime; and,
- a relatively high marginal tax rate 62% might discourage capital expenditure to boost production rates, for example mid-life well work-overs, by lengthening the payback periods.

It remains to be seen how profitable the UK unconventional gas industry could be, and an appropriate time for review might be during the appraisal terms of the licences. This is sooner for CBM than for shale gas.

5.5 Unconventional gas operating environment

Beyond the geological uncertainty, there is the equally important question as to whether the GB operating conditions are commensurate with shale operations. There are multiple aspects to this issue including:

- Population density – GB (and continental Europe) has a much higher population density than the US, and this is likely to result in greater public opposition, more restrictions, and less land available for drilling activity.
- Land rights – In GB, land owners do not own mineral rights, in contrast to the US, but must consent to land use, so there is little incentive to support development.
- Planning consents – Local authorities must grant planning consent for production sites, but do not receive royalties as in most states in the US.
- Pragmatic environmental legislation – from an EU perspective, the US is perceived to have relatively permissive environmental regulations in relation to exploration and production.
- Supportive national and local government – both forms of government are able to exercise a degree of judgement in relation to permissions for exploration and production activity: national government at a licensing level, and local government at planning permission level. Investors and operators will be observing closely the reaction of government to the environmental lobby.

- Fiscal incentives – the UK currently has no tax incentives specifically to support unconventional gas production. Taxes appear generally higher than for similar fields in the US even when royalty payments to landowners are included;
- Gas transportation – GB has a well-developed transportation network and abundant distribution networks, providing gas supply to over 90% of households. Under current regulations, gas supplies must meet National Grid specifications, but this requirement can be relaxed for small volumes. Larger volumes will require processing to meet specifications, at the producers cost. An alternative to processing is wellhead power generation, or other local usage.
- Water availability – GB has a well-developed water supply network, but local supply issues at drilling sites are an inevitable logistical problem, the severity depending on proximity to suitable mains supplies, reservoirs, lakes, or rivers. In all cases, authority to take volumes of water must be obtained from the relevant authorities. It may be that the locational distances may allow water to be transported by pipe to drilling sites rather than by road tankers. Composite Energy has drawn river water by pipe, and Cuadrilla has piped in water for its exploratory drilling. However, trucking may be the only option for disposal of contaminated water.
- Disposal of contaminated water – drillers and fracking operators will need to include their water management plans before operations can begin. According to Cuadrilla, the contaminated water, rock chips and drilling mud would be sent to landfill. Whilst this may be adequate during the exploration phase, the much larger quantities collected during commercial exploitation might require treatment and alternative disposal methods. The problems of water pollution are discussed in the context of the US in section 3.3.2.
- Availability of skilled staff – GB has a significant number of skilled drilling staff, mostly from the offshore sector, and these skills are transferable to the onshore sector. However, with the world expansion of the unconventional hydrocarbons sector, in addition to a previous shortage of skilled rig operators, there would appear to be a pressing need for increased training. The assumption that staff can simply be hired from the international markets may be correct, but ignores the upward pressure on wages.
- Availability of equipment and support services – equipment supply is a severe shortcoming in the GB onshore exploration and production sector. The onshore rig inventory is generally not suitable for high volume commercial exploitation of shale gas. The availability of hydraulic fracking pumps and operatives was recently reported as two teams operating across Europe. Whereas the offshore service sector is well developed, the onshore service sector is virtually non-existent.
- Transparent licensing system – GB is seen to have a transparent licensing system. Across Europe the licensing systems generally gave preferential treatment to state oil companies and national champions, and the legacy is still visible. Licence relinquishment systems now mean that much of the prospective unconventional gas acreage has become available to recent applicants.

- Access to geological data – the existing data is generally of limited use. The results of recent drilling activity under the PEDL licences can remain entirely confidential in the hands of the well operator for the exploration term, but is likely to be revealed if the developer moves from the exploration to the appraisal term of the licence. Therefore it can be several years before a limited indication of well test results reach the public domain. DECC is currently working on a database of well data information, and a requirement for public release after a set time period, possibly 4 or 5 years.
- Transferability of US geological expertise – it is not entirely clear how the US experience will transfer to GB. One question is whether the leading US shale companies will become involved in GB, or whether they will willingly share their extensive databases with GB operators, who might be seen as competitors.

In most of these matters the GB operating environment supports the conditions that underpin a successful commercial shale gas production industry, and there are other areas, such as rig availability that are soluble. However, there are clearly concerns over several of the issues, such as the political impact of the environmental debate. It remains to be seen how much GB environmental oversight materially constrains the exploitation of unconventional gas resources.

In terms of the development path, GB's shale industry is still in an early, cautionary exploration stage, many years behind the US in terms of the volume of useful geological data available. Appraisal of the first wells is just beginning and, although the initial results are encouraging, there is a long way to go before the first commercial exploitation. However, this depends on a wide range of conditions, all of which need to be supportive of commercial exploitation. Development is not going to happen without the support of national and local government, and the local communities. The rewards are large: at today's gas prices it has the potential to be a £40billion industry. However, investors will be keeping a close eye on developments and have the option to invest elsewhere should it become apparent that the US experience will not be replicable in GB.

5.6 Summary

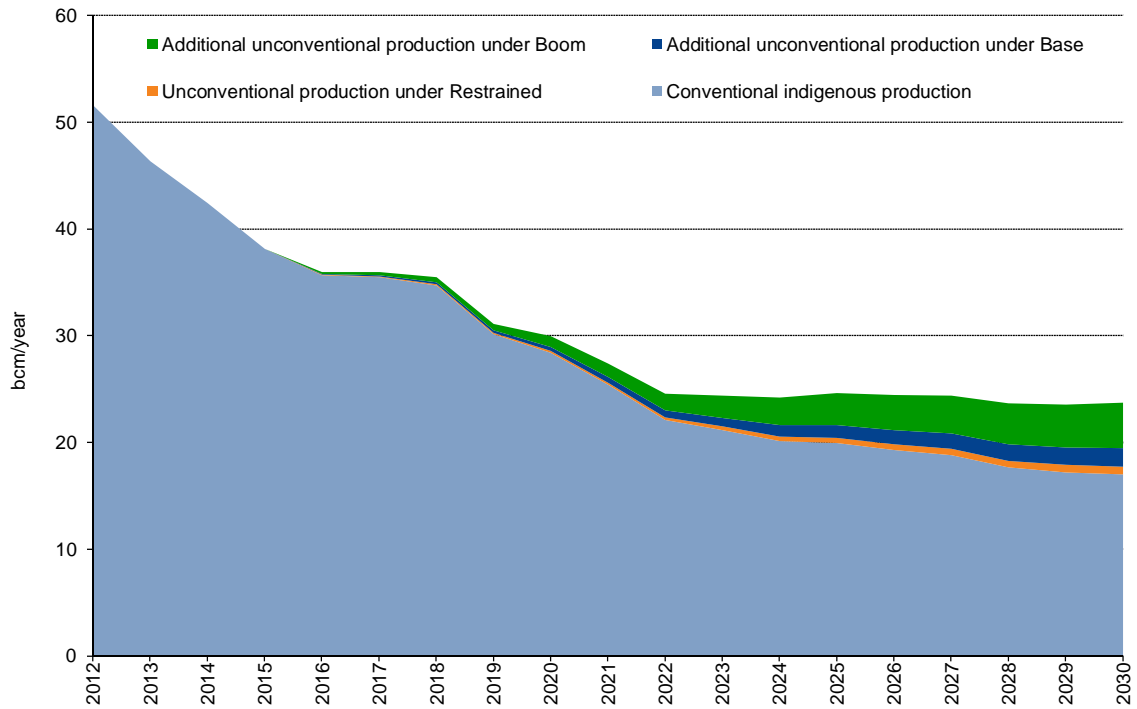
GB has the potential to develop both shale gas and CBM resources. The unconventional gas reserves could be significant in terms of the maintaining indigenous supplies. However, there are a number of issues that might prevent a US style shale gas revolution from taking place.

Not least of these issues is how NIMBYism might generate a lack of public support for onshore drilling activities. A whole host of other issues might affect the viability of large scale production of unconventional gas in GB including the fiscal, planning and environmental regimes.

In GB, unconventional gas production will be competing for market share with increasing supplies from Norway and continental Europe, via pipeline, and with shipments of LNG.

Figure 6 shows Pöyry's range of unconventional gas production assumptions for GB alongside the declining indigenous reserves. The volumes appear small but allow for indigenous production to be maintained at a reasonable level from around 2022 onwards.

Figure 6 – Declining conventional reserves and projected increased production from unconventional gas



6. PROSPECTS IN EUROPE

6.1 Introduction

Since exploration for shale gas in Europe is in its infancy, relatively little is known about the characteristics of potential gas shales. As a result, estimates of the technically recoverable shale gas remain subject to a wide range of uncertainty, and will be subject to numerous revisions as new information becomes available from the seismic and drilling programs already under way.

There are three potentially major regional shale gas plays in Europe plus a number of others with local potential. The major potential plays are:

- a lower Palaeozoic play that occurs in northwest Europe running from eastern Denmark through southern Sweden to the north and east of Poland;
- a kerogenous alum play, located in Denmark and Sweden; and
- a further lower Palaeozoic play located in Poland, which has, to date, attracted the most interest from developers.

Estimates of total shale gas resources in Europe range from Wood Mackenzie's 1.4tcm to Advanced Resources International's 4tcm. This higher estimate is approximately equal to the entire EU27 gas demand for the next 8 years. The latest EIA estimate, which includes more speculative potential plays, now stands at over 18tcm of technically recoverable resources.

This section outlines the current state of play in some key European countries.

6.2 Poland

6.2.1 Overview of unconventional gas prospects

The estimates of Poland's maximum recoverable shale gas reserves vary according to the source. Advanced Resources International has estimated Poland's reserves at 3tcm⁹. In April 2011 the EIA published its latest estimate of 5.3tcm. The EIA highlights three prospective regions for shale gas exploration in Poland:

- the Baltic region in the north;
- Lublin in the south; and
- Podlasie in the east.

Geologists have found a number of similarities between the Lublin Basin and the Barnett Shale in Texas. The thicker Silurian layers, around 1,300m thick, suggest the possibility of substantially higher reserves per acre in the Lublin Basin than the Barnett play.

Poland is currently awaiting the results of a joint survey by the US Geological Survey and the Polish Geological Institute, which is scheduled to be published in September 2011. This will give a more detailed approximation of the shale potential, but more accurate

⁹ 'Unconventional Gas: An Exportable North American Revolution?', Vello A. Kuuskraa, Advanced Resources International

estimates will only become apparent over a period of years, from data gathered on the basis of exploration.

Poland is currently the European front-runner for the early exploitation of gas shales. The Silurian shales are thought to contain large volumes of methane, and the geology is simpler than most other European plays, with fewer faults, and prospective areas covering much of the country.

The good physical conditions, hospitable terrain, access to high-value markets and attractive resource base, make Poland a compelling shale gas opportunity in the near term. It is also becoming apparent that Poland is favourable towards the shale industry for a variety of other reasons:

- the Polish government is concerned that Gazprom has a virtual monopoly on gas supply into the Polish market and has been seeking greater supply diversity for a number of years;
- the population density in prospective drilling areas is relatively low by general European standards, and shale gas activity would result in investment, jobs and money into the regions;
- the shale gas companies have made significant efforts to include the local communities as stakeholders in the shale gas industry by offering to contribute towards local infrastructure such as roads and transport and this has proved popular with the important farming community; and
- Poland is reputed to have relatively few environmental restrictions for a European country.

Hence it has been relatively easy to sway the public opinion in favour of shale gas drilling, in contrast to the sometimes hostile opposition and environmental lobbies in parts of France and Germany.

This favourable attitude is illustrated by the Polish Geological Institute, which has opened access to its database, and is reported as having been extremely helpful and co-operative to potential developers.

6.2.2 Poland's gas supply position

Poland has some indigenous gas production but depends almost entirely on Russian gas imports. Some small quantities are contracted from Germany. Poland has tried to contract gas from Norway, and more recently has signed an LNG supply contract with Qatar. It is also building an LNG terminal at Świnoujście.

State-owned gas company PGNiG forecasts that gas demand will increase by 40% over the next five years.

6.2.3 Recent activity and participants

The Polish Environment Ministry has so far granted 85 concessions for shale gas exploration, mainly in the Lublin, Mazowsze, Pomeranian and Lower Silesian regions, covering around 20% of Poland's land area.

Poland has attracted the interest of, and has awarded licences to a wide range of major international E&P players including: ExxonMobil, Chevron, ConocoPhillips, and Marathon. It has also attracted smaller independents such as Realm Energy, Lane Energy, BNK,

San Leon Energy, and Aurelian Oil & Gas. The state owned gas company, PGNiG, holds seven of these licenses, covering some prime acreage.

6.2.4 Conclusions

Poland has already been touted as the 'second Norway', in respect of its gas resources. It is clear that there is significant activity underway in Poland in order to exploit shale gas resources. Poland is an attractive prospect for a number of companies with interests in shale gas. However, the shale gas industry in Poland is still immature and there is a lack of accurate data to confirm the high expectations of some Polish officials.

If initial reports are to be believed, then commercial production could commence within two to three years, but significant volumes will probably only be produced in seven to ten years. Should Poland succeed in developing its shale resources, it could be self-sufficient in gas supply before 2030, and a production plateau of 50bcm/year has been suggested.

Producing shale gas in Poland is likely to be more expensive than in the US. However, the high cost of imported gas, additional employment, income and national security benefits may mean that shale gas is an economic alternative to pipeline gas.

6.3 Germany

6.3.1 Overview of unconventional gas prospects

Although relatively small by international standards, the onshore production sector in Germany has been active for many years and ranks third largest in the EU after the Netherlands and Romania. The EIA estimates the technically recoverable shale gas reserves at 227bcm.

The North Rhine-Westphalia region is thought to contain a sizeable proportion of Germany's shale gas reserves and the state government recently awarded exploratory drilling licenses to ten companies, including those from the US, Canada, and Australia. However, growing environmental opposition to shale drilling in Germany has led the state of North Rhine-Westphalia to ask ExxonMobil to delay test drilling in the region until the end of 2011.

Other areas in Germany are also thought to be good prospects for shale gas, including Lower Saxony, and several eastern regions that contain extensions of Polish plays.

In addition to shale gas, Germany has extensive reserves of coal, and several CBM exploration projects are under appraisal. Shell is a notable player and Australia's Queensland Gas holds CBM licences covering approximately 1,900 km². Estimated reserves of German CBM are in the region of 3tcm, of which 2tcm is concentrated in the Ruhr area.

6.3.2 Conclusions

Germany is an attractive target for potential unconventional gas developers due to the established industry, the commercial environment, the depth of knowledge in the science of geology and some attractive shale and CBM prospects. However, there has been criticism that Germany is a high-cost country in the exploration sector, and that existing players have too much control of the infrastructure and assets.

6.4 The Netherlands

6.4.1 Overview of unconventional gas prospects

The Netherlands gas market has been dominated by the giant Groningen field for a number of decades. The decline in Groningen reserves and the exploration and production sectors in general, have fuelled an increased interest in indigenous shale gas potential. The Ministry of Economic Affairs Agriculture and Innovation has made statements stressing the importance of the potential of shale gas reserves.

However, interest in CBM does not currently appear to rank highly in the Dutch energy sector, despite some former coal mining activity and known reserves.

At least three plays are reported to hold considerable shale potential:

- the Epen Shale;
- the Posidonia Shale; and
- the Kimmeridge Clay (Offshore).

The EIA estimates that the technically recoverable shale gas reserves in the Netherlands are 483bcm whilst independent research organization TNO has a much higher range from 68tcm to 312tcm.

6.4.2 Recent activity and participants

The main player in the Netherlands is Cuadrilla Resources. Cuadrilla is partnering with Energie Beheer Netherlands (EBN), which is owned by the Dutch Government.

In addition to this, Brabant Resources, a subsidiary of the Cuadrilla Resources, plans to drill the Netherlands' first unconventional gas well in the township of Boxtel in North Brabant province in July or August 2011. The municipality has issued a permit required for test drilling.

Cuadrilla also hopes to drill in the nearby communities of Helvoirt and Haaren.

There has been some, albeit muted, local opposition in Boxtel with a petition calling for a halt to the drilling gaining only 500 signatories. While activities at Boxtel only represent test drilling and a production license is still far in the future, the Dutch Ministry has stressed that the development of shale gas is in the national interest and should not be stopped by opposition at the municipality level.

6.4.3 Conclusions

Shale gas exploration is at a very early stage in the Netherlands. If commercial reserves are proved, it is likely that the Dutch government will be highly supportive of their development, although mindful of the potential environmental risks.

6.5 France

6.5.1 Overview of unconventional gas prospects

According to EIA data, France has considerable recoverable reserves of shale gas and it ranks only just behind Poland with an estimated 5.097tcm.

In March 2010, the French government issued three new permits for shale oil and three for shale gas. The shale oil permits included the right to carry out drilling work, while the permits for shale gas were for exploratory activities only. The most controversial award was the unconventional exploration permit to Total E&P France, which covers 4,327km² of land between Montélimar and Montpellier, in the heartlands of the Languedoc's wine region.

However, following strong lobbying from Europe Écologie against shale gas exploration in the Larzac area of southern France, the French government has suspended the three gas exploration permits.

The risk of water contamination is a real concern in France and the initial one month moratorium on drilling in shale was extended following the Environment minister's announcement of the creation of a commission charged with evaluating the environmental impact of shale gas production across all of France. The statement released added that "no authorisations for shale gas exploration will be given, or even considered, before the commission reports". The final report is expected in June 2011.

Licence holders that were drilling, or preparing to drill on oil shale permits awarded by the government, are understood to have voluntarily suspended new wells as well as planned fracking operations.

CBM exploration has been in progress for several years in France, with a small amount of production from de-commissioned coal mines. On a larger scale, European Gas Limited is moving slowly forwards with its Lorraine CBM project, with gas-in-place estimated at 136bcm. Other smaller projects are also under way.

6.5.2 Recent activity

Since 2004, France has issued nine exploration permits for unconventional gas exploration, including the three issued in March 2010 for shale gas exploration in the southeastern part of the country. However, these permits are currently under review, and there is a high likelihood that they will be revoked.

6.5.3 Conclusions

France has considerable reserves of shale gas, and market players are active in attempting to develop projects. However, development of these reserves may be thwarted by the powerful and influential environmental and agricultural lobbies. The recommendations of the environmental impact report, due out in June 2011, will determine the future development of shale gas in France.

6.6 Sweden

6.6.1 Overview of unconventional gas prospects

Sweden has considerable reserves of shale gas; the EIA estimates that the technically recoverable reserves are 1.16tcm; and the most attractive target is the Alum Shale of southern Sweden.

However, Sweden has relatively little gas transportation infrastructure, no indigenous supplies and total gas consumption of only around 1bcm/yr. Currently all gas is imported via a single pipeline from Denmark. The lack of a developed gas industry might make Sweden a less attractive market for shale gas development.

There is also a political divide in Sweden concerning the development of shale gas. The current Swedish government has a positive position on shale gas development whilst the opposition alliance led by the Social Democrats in partnership with the Greens and the Left Party has spoken against shale gas, making it clear that a 'red-green' government will not engage in large-scale fossil fuel extraction in Sweden. This position specifically includes Shell's planned production of gas in southern Sweden.

In the event that shale gas is developed in Sweden, the import pipeline is a possible physical constraint on maximum production. Shale gas production could displace the current import volumes, and a further 1bcm/yr could be exported via Denmark. Additionally there could be an unfulfilled potential market of around 0.5bcm/yr of industrial demand along the western coast.

6.6.2 Recent activity and participants

Shell has been exploring shale gas potential in the Southern region of Skaane. The first well was drilled in Ry, to a depth of 950m, between November 2009 and January 2010. The program of three exploration wells has now been completed and the company reports that the results are promising, and that there could be enough gas to cover Sweden's gas needs for at least 10 years.

6.6.3 Conclusions

Although Sweden potentially has considerable shale reserves, the lack of infrastructure and a gas industry may limit the role that Swedish shale gas can play in the wider European context. In the event that shale gas of a suitable quality becomes available from within Sweden, it can be assumed that there would be potential for the displacement of existing supplies and export of 1bcm/year of gas via the existing pipeline at relatively low cost. Domestic gas demand may increase as a result of additional indigenous gas supplies but any additional exports would require significant investment in infrastructure.

6.7 Austria

The Austrian company OMV has recently suggested that potential recoverable shale gas reserves in the Vienna Basin are 425bcm. Total Austrian reserves are estimated by OMV to fall between 5.7tcm and 8.5tcm.

Austria's RAG, which has been in the national exploration and production sector for over 75 years, also believes that unconventional production has significant commercial potential in Austria.

6.8 Hungary

Hungary was initially thought to have some considerable shale gas reserves with prospects being investigated in the Makó Trough. However, the companies involved in the exploration now refer only to tight gas sand or basin-centred gas prospects.

ExxonMobil and MOL both withdrew from the Makó Trough project in 2010 after results from the drilling program proved disappointing. The project appears to be shelved and is not currently considered to be economically viable. Falcon Oil and Gas, the other partner in the project continues to monitor well performance and hopes to finance a horizontal well at some point in the future.

6.9 Romania

Romania has a long-established exploration and production sector and in the event that shale gas resources are proven, there is available infrastructure and the expectation of a willingness to accommodate development.

In June 2010, the Romanian government launched the 10th Exploration Bid Round, including 10 blocks in the Pannonian Basin covering a total area of approximately one million acres, adjacent to the Hungarian border.

The Pannonian Basin has more than 40 established oil and gas fields, and is recognised to have large unconventional resource potential in shale and tight gas, as well as conventional gas possibilities.

The blocks had been relinquished by the Romanian state companies Petrom and Romgaz, but bidders anticipate that the application of modern exploration technologies, including the acquisition of state-of-the-art seismic data, will provide a better understanding of the remaining hydrocarbon potential on the blocks. Extensive work programs are proposed for each Block, including the acquisition of 2D and 3D seismic data.

The recent poor results from the Hungarian sector were undoubtedly a blow for the prospects in Romania, and this will likely diminish the enthusiasm for the unconventional gas potential in the near term. Also, there still remains the possibility that conventional targets will be more attractive in the short term, and this may delay the appraisal of unconventional plays. Romania awaits the results of unconventional gas exploration in Poland and Germany and a successful outcome would be likely to bring a much-needed injection of enthusiasm and investment.

6.10 Italy

Italy has some CBM reserves but no significant reserves of shale gas.

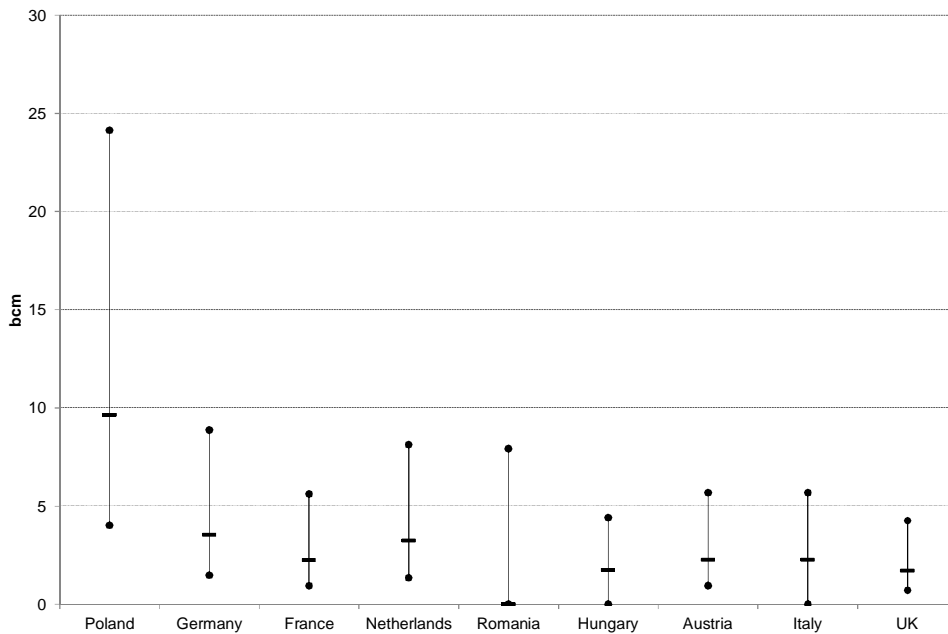
Independent Resources, is working on Italy's first CBM project, Fiume Bruna, near Grosseto in Tuscany. The Fiume Bruna permit covers 247km² in an area that was host to an active coal industry until the late 1950s, when the mines were abandoned in the wake of a major explosion. The permit carries an in-place reserves estimate of 5bcm, of which some 2.6bcm is thought to be recoverable.

6.11 Summary

There is potential within Europe for unconventional gas to become a major source of supply. Conversely, there is a real possibility environmental constraints will be too great and very little unconventional gas will be developed. For this study, we have tried to capture this range of uncertainty within our scenarios for Europe.

Figure 7 highlights the range of unconventional gas assumptions for each country, across the scenarios. It shows how we assume that Poland has the highest potential of the countries studied, accounting for nearly 30% of unconventional gas production in the Boom scenario, and over 40% in the Restrained scenario. In contrast, the UK has relatively low reserves – accounting for around 4bcm/year in the Boom scenario and 0.7bcm/year in the Restrained. Further details on our production assumptions may be found in section 8.1.

Figure 7 – Range of EU unconventional production by 2030 across scenarios



7. PROSPECTS AROUND THE REST OF THE WORLD

In this section we examine key regions around the world with substantial unconventional gas reserves that could potentially have an impact upon the European gas market, or the balance of the worldwide LNG market.

Such regions fall into three categories:

- Those exporting gas via pipeline to Europe – including Russia, Ukraine and Algeria.
- Those importing LNG via re-gasification terminals – including China and India.
- Those exporting LNG through liquefaction projects – including Indonesia, Australia and Algeria.

Other regions, such as South Africa or parts of South America also have unconventional gas potential but in the period to 2030 studied in this report, these are unlikely to commence significant production; or all unconventional gas production is likely to be consumed by their domestic markets and not impact the worldwide LNG market in a significant way.

In this section, we outline the prospects for unconventional gas developments in each of the regions considered to have significant unconventional gas potential in the period to 2030. In some of these regions we have chosen to vary their gas output between the three scenarios we have modelled in this study. Details of the assumptions made for the modelling are described in Section 8.2. In other cases, our analysis indicates that unconventional gas developments are unlikely to have a significant impact on the world gas market balance. In these cases these regions' inputs to the modelling are based upon Pöyry's Central assumptions and do not vary between the scenarios.

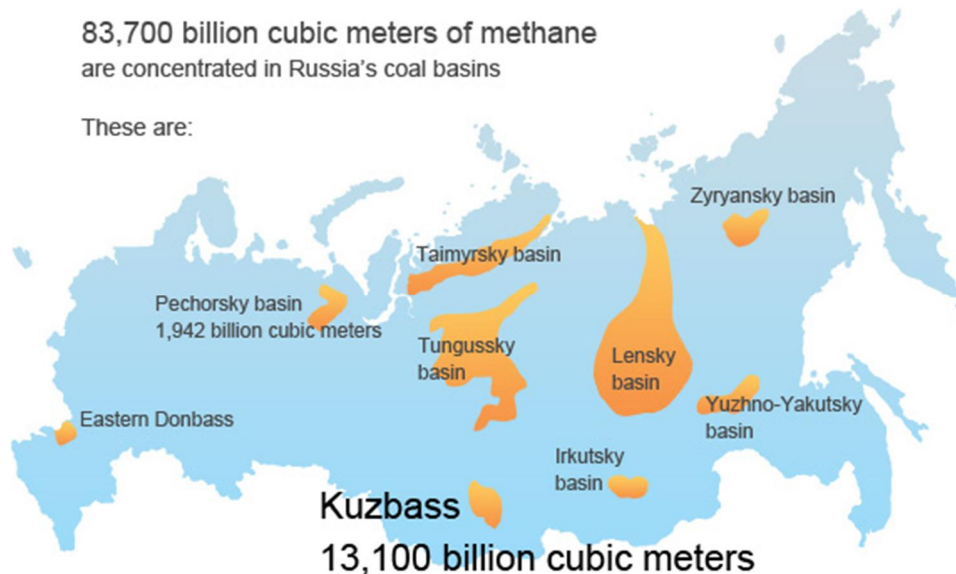
7.1 Russia

Russia currently holds the largest reserves of conventional gas in the world, around 48tcm. It also seems highly likely that Russia holds enormous resources of shale gas and the world's largest resources of CBM.

Because Russia could continue to produce conventional gas at current rates for over 60 years, there is relatively little incentive to pay much attention to unconventional gas resources. However, there are some areas where CBM might play a useful role, and the Kuzbass coal basin was chosen for a production program which started in 2010.

The potential reserves of CBM in Russia are illustrated in Figure 8, which shows the resource potential of several major coal basins in Russia, including Kuzbass. Gazprom estimates the total CBM reserves as 83.7tcm.

Figure 8 – Russia’s coal basins



Source: Gazprom

Russia’s shale basins are extensive but, outside Russia there is limited information available.

7.1.1 Key players and recent activity

7.1.1.1 CBM

Gazprom dobycha Kuznetsk, a wholly owned subsidiary of Gazprom, is the license owner in the Kuzbass basin area. The principal target is the Talda field. A pilot operation of seven exploratory CBM wells was launched in 2009 and in February 2010 the project moved into the production phase. The development plan called for 30 wells in 2010 and 128 wells per annum from 2011 onwards. During the plateau period, annual CBM production is projected to reach 4bcm/year, with a subsequent increase to 18–21bcm/year in the long-term. The gas produced will go to meet gas demand in Western Siberia’s southern regions.

7.1.2 Conclusions

Russia has enormous natural gas resources, both conventional and unconventional. The volumes that could potentially be produced far exceed the current size of the Russian and CIS gas markets, therefore unrestricted exploitation would exert considerable downward pressure on prices.

Gazprom, which is majority owned by the Russian federal government, has a near monopoly position in the Russian natural gas sector and is the sole exporter of Russian natural gas. We expect these conditions to continue. For the planning period, we expect Gazprom and the Russian government to facilitate the production of unconventional gas only for limited regional or local reasons. The economics of unconventional gas production in Russia will be pitted against the merits of conventional gas, and it currently appears that the bulk of new production is likely to be conventional.

We believe unconventional gas developments in Russia could have a positive impact on the total volume of gas available for export to Europe and our projections for these under each scenario modelled are described in Section 8.2.

7.2 Ukraine

Following the licencing of the bulk of the prospective unconventional Polish gas acreage, a number of players have turned their attention to Ukraine. The EIA currently estimates Ukraine's technically recoverable shale resources at 1,189bcm and Ukrainian experts believe the shale resources could be much larger.

The Lublin Basin shale layers in neighbouring Poland extend into Ukraine, and experts also expect sizeable shale gas and CBM reserves in the Dnieper-Donetsk Basin. The Minister of Environment and Natural Resources, Mykola Zlochevsky, considers it the biggest shale gas deposit in the world. However, this needs to be viewed in the light of on-going negotiations, and a shortage of up-to-date geological data.

7.2.1 Key players and recent activity

The Ukrainian Ministry is reported to be in initial negotiations with Chevron, Shell, ExxonMobil in order to set up a joint ventures for shale gas and CBM.

EuroGas Ukraine Ltd holds five unconventional gas concessions under joint ventures with the Ukrainian company Nadra Luganshchiny Ltd. The concessions cover an area of 512 km² and are believed to have CBM potential overlying shale potential in lower strata. One estimate of the CBM resources, published by EuroGas is that they contain 12tcm of CBM, but this remains to be independently verified, and estimates made of the potentially recoverable volumes. EuroGas also has ambitions to explore the shales underlying its concessions and is holding talks and sharing information with Total.

7.2.2 Conclusions

Due to its current dependence on Russian gas imports, the development of new gas reserves is of great importance to Ukraine. Negotiations are likely to be backed by strong political support, as confirmed by the Minister of Energy, Yuriy Boiko, who within the next five years wants to produce an additional 20bcm of natural gas from shale gas and CBM in Ukraine.

The complexity of extracting shale gas means that Ukraine will need to benefit from international help to solve the technical problems. Unfortunately, the country has a long-standing reputation for a poor investment climate for foreign players in the hydrocarbons sector. For gas companies there have been restrictions on exports, price ceilings and court challenges to their licenses. Marathon withdrew from Ukraine in mid-2008.

There are also some unresolved questions about the potential abundance of conventional gas resources. If Ukraine still has some cheap-to-develop conventional gas reserves, this will threaten investment in unconventional gas resources. Furthermore, this threat is not confined to conventional gas supplies from within Ukraine. Another risk is that a change of export policy by Russia might undermine the economics of Ukraine's unconventional gas industry. Whilst neither of these threats may materialise, they are sufficient to create some uncertainty in the minds of potential investors.

We believe, in time, it is possible unconventional gas developments in Ukraine could follow a similar pattern to that projected for Poland, and we outline our assumptions for each of the scenarios modelled in section 8.2.

7.3 China

China's unconventional gas resources appear to be fairly evenly divided between shale gas and CBM. The recent EIA study gives an estimate of 36.1tcm of technically recoverable shale gas reserves, while another source (Interfax-China) states CBM reserves of 36.7tcm. Three of the major basins, Qinshui, Ordos and Junggar are believed to hold CBM resources of 18.8tcm¹⁰.

Chinese ambitions include a rough target to produce some 10% of its total gas production from shale gas by 2020.

7.3.1 Key players and recent activity

7.3.1.1 CBM

Commercial CBM production began in China in 2005 and, at the time, the Central government announced a target of 5bcm/year of CBM production by 2010. It now appears that China has missed the target, and production only rose to around 1.2bcm/year in 2010. The principal problem appears to be the lack of adequate infrastructure to transport the gas to the existing markets. Wood Mackenzie has reported that, out of ten CBM pipeline projects due to be completed in 2010, only two were finished by the end of the year.

In the absence of pipelines, there are signs that attempts are being made to use the CBM for local power generation. The Shanxi provincial government has said that the Province will have CBM fuelled power plants with combined installed capacity of 1,000MW by 2015.

7.3.1.2 Shale

The Chinese government and US Geological Survey have recently entered into an agreement, the "US-China Shale Gas Resource Initiative", to support shale gas exploitation in China.

According to the Xinhua News Agency in March 2011, the head of China's National Energy Administration is considering pilot exploration areas for shale gas and wants to exploit the resource as early as possible.

In a parallel announcement, Shell Chief Executive, Peter Voser, announced that his company plans to spend US\$1 billion/year on shale gas in China over the next five years, provided the exploration program currently underway proves to be successful. Shell's program includes the drilling 17 wells in China, aimed at both tight gas and shale gas, in several regions including SW Sichuan, China's most prolific gas province.

Eni has also agreed to develop shale gas opportunities with China's PetroChina Co Ltd.

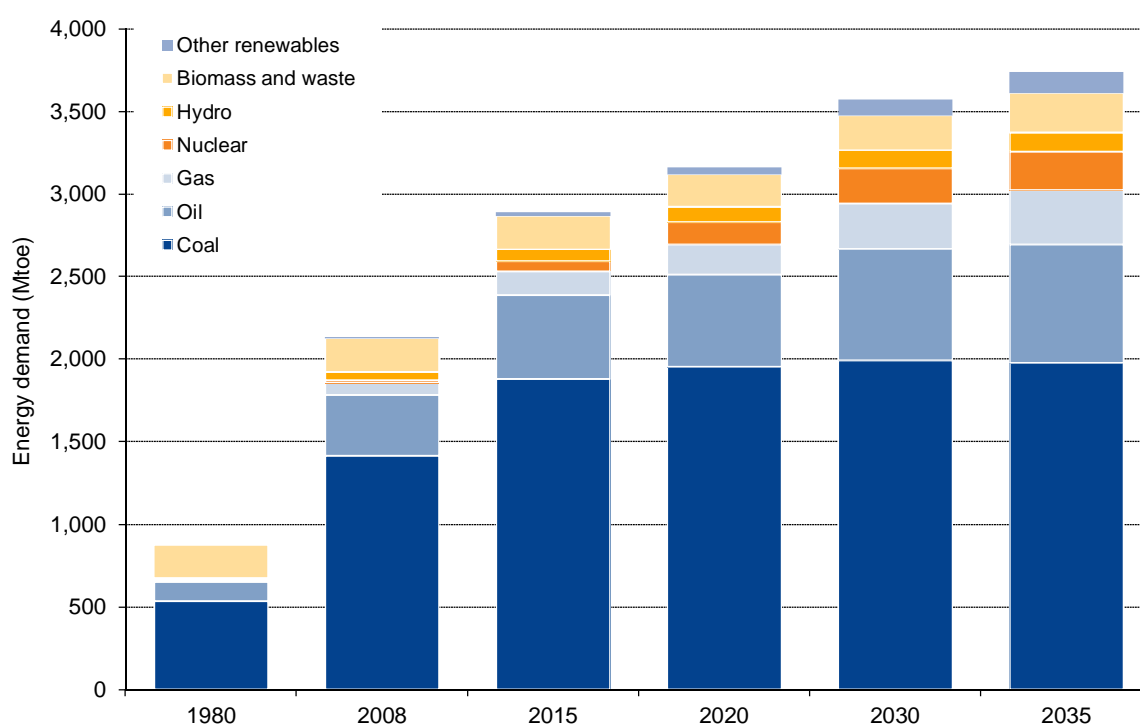
¹⁰ Oil & Gas Journal, Wood Mackenzie, Sept 2010

7.3.2 China's primary energy demand

In order to tackle the question of how Chinese unconventional gas resources may impact Chinese demand for gas from the rest of the world it is necessary to examine all of China's demand for energy. China's historical and projected primary energy demand is shown below in Figure 9 and Chinese demand for energy is set to grow substantially by 2030.

Although the use of gas is also projected to increase rapidly, its proportion of the total primary energy demand in China only reaches 8% by 2030 according to the IEA figures presented in Table 2. If more economical indigenous gas production were to become available it is likely this percentage would increase.

Figure 9 – Primary energy demand in China (Mtoe)



Calendar years. Source: IEA World Energy Outlook 2010

Table 2 – Primary energy demand in China (%)

	1980	2008	2015	2020	2030	2035
Coal	61%	66%	65%	62%	56%	53%
Oil	13%	17%	18%	18%	19%	19%
Gas	1%	3%	5%	6%	8%	9%
Nuclear	0%	1%	2%	4%	6%	6%
Hydro	1%	2%	3%	3%	3%	3%
Biomass and waste	23%	10%	7%	6%	6%	6%
Other renewables	0%	0%	1%	1%	3%	3%
Total	100%	100%	100%	100%	100%	100%

Source: IEA World Energy Outlook 2010

The proportion of primary energy demand met by coal is projected to remain over 50% beyond 2030 even though the Chinese government has ambitions to displace coal through the increased use of gas, especially in power generation. Coal-fired generation is currently creating severe environmental problems in major cities and its substitution by gas could significantly relieve these.

Pöyry anticipate China’s huge growth in demand for energy will require not only imports via its planned LNG regasification terminals, but also, any unconventional gas produced. Additional gas supplies are likely to displace coal to alleviate environmental issues.

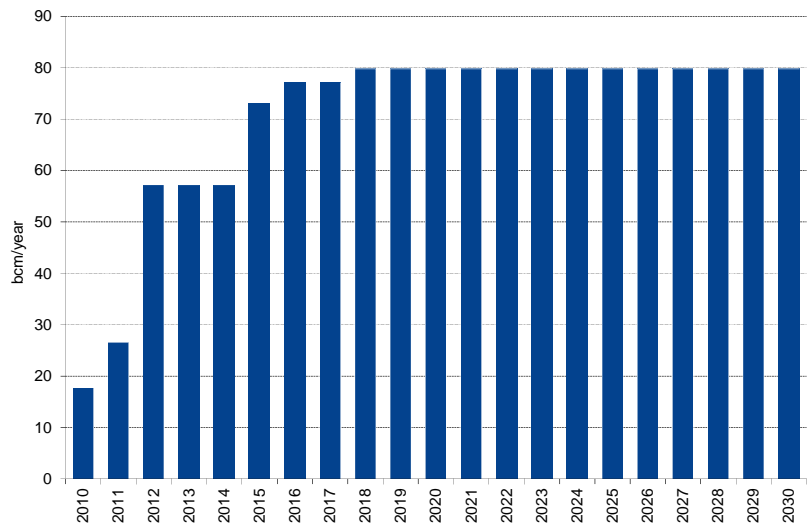
7.3.3 Conclusions

China has embarked on a path of exploitation of unconventional resources with a growing determination. Early moves faltered because adequate resources were not made available, and CBM production missed its ambitious targets. However, the rapidly increasing demand for energy, pollution problems, and new increases in world energy prices, make the development programs more important, and a renewed determination is sensed.

Even with accelerated development of unconventional gas resources, the likely production will make a relatively small impact on China’s domestic energy supply, perhaps increasing from 2020 onwards if the development programs are successful. However, because energy demand growth is so large in China and gas needs to fill an increasing portion of the supply, including the displacement of coal.

The Chinese gas market is projected to require significant new LNG re-gasification capacity over the next decade, as shown in Figure 10. At this time, Pöyry do not expect unconventional gas supplies to impact upon this requirement for LNG in China.

Figure 10 – Projected LNG re-gasification capacity into China



In summary, there are three main reasons for our maintaining China's growth in LNG re-gasification across the scenarios modelled. These are:

- Overall growth in energy demand in China will absorb any new unconventional gas resources.
- Lack of gas infrastructure means that unconventional gas is likely to be used locally for power generation in-land close to the coal fields where it is produced; while LNG will be used in the large cities close to coast and the LNG re-gasification terminals.
- Environmental concerns will cause any new unconventional gas produced to substitute for coal as a fuel in power generation.

7.4 India

India's total energy demand is moderate compared to China, although it is similar in that the economy is also heavily dependent on domestic coal. India also has some domestic gas resources which it intends to exploit, and together with imports of LNG, it hopes to increase the percentage of natural gas in primary energy demand. A CBM development policy is already in place and the government hopes that CBM will make a growing contribution to India's natural gas supply.

7.4.1 Overview of unconventional gas resources

The recent EIA study estimates India's technically recoverable shale gas reserves at 1.8tcm. Basins of preliminary shale gas interest have been identified by Indian geologists in the Cambay Basin in Gujarat, the Assam-Arakan Basin in north-east India, and the Gondwana Basin in central India.

India has a massive coal industry and the extents of coal seams are reasonably well known, so reserves of CBM are likely to be high. The Petroleum Ministry of India estimates the total CBM resource at 2.6tcm, which at current levels of consumption of around 50bcm/year equates to over 50 years of resources.

7.4.2 Key players and recent activity

7.4.2.1 Shale

In November 2010, India was reported to have signed a MoU with the US Geological Survey for technical assistance to assess the country's domestic shale gas resources. India's upstream regulator, planned to draft shale gas policy in preparation for an initial auction of blocks in 2011. However following the Environment Ministry raising questions on the potential impact on water quality, the government deferred the auction and announced a one year moratorium on shale gas drilling.

In a statement, the petroleum ministry said that it wanted to comprehensively address environmental concerns over the excessive use of water, pumping of chemicals into the earth and the larger number of wells needed for shale gas exploration.

Water is scarce in much of India and, besides the issue of contamination; the potential requirements of intensive shale exploitation exceed the quantities available. This illustrates the point that both water supply and contaminated water disposal plans are essential to the responsible development of shale gas, not only in India, but wherever the industry operates.

7.4.2.2 CBM

The CBM policy was approved in 1997 to tap this unconventional source of energy. Twenty-three CBM blocks have been awarded in the first three rounds of auction. The fourth round was launched recently with an offer of 10 blocks covering nearly 5,000km². In all, 26 blocks have been awarded – two of them under nomination basis to Oil & Natural Gas Corporation Limited (of India) – and the estimated resources in these blocks amount to 1,480bcm. Based on the current estimates and status of planned field development, CBM production in India is likely to reach 2.7bcm/year by 2012-13.

Another leading player is India-based Reliance Industries, which has three CBM blocks in the states of Madhya Pradesh, Rajasthan and Chhattisgarh. It is reported to have established over 100bcm of reserves, and the company has plans to drill around 100 wells by 2015. In its two Sohagpur CBM blocks, prolonged production testing has already been undertaken, and the blocks are expected to achieve peak production of 4.5mcm/day in 2014-15 from the existing and proposed wells.

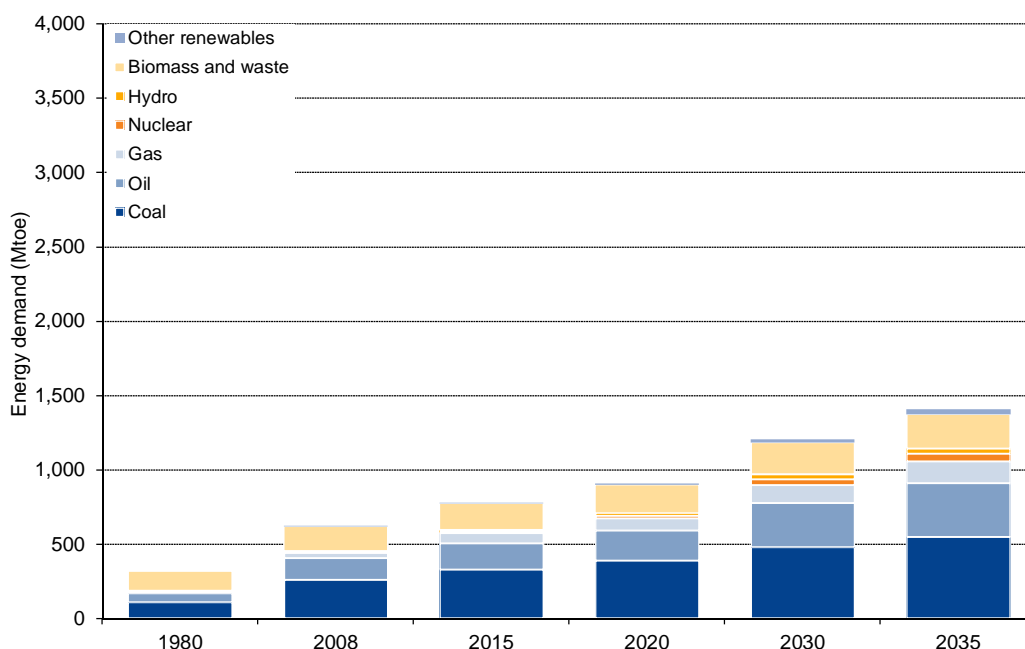
Commercial production began recently from a block in Raniganj, operated by Essar. The block, which has a potential to produce 3.5mcm/day, is supplying currently supplying local buyers. A spokesman for Essar confirmed the drilling 143 wells in the first phase has been achieved and they will be fast-tracking the drilling of new wells. The company holds five CBM blocks.

7.4.3 India's primary energy demand

As in the case of China, it is important to see the development of new sources of unconventional gas in light of the whole of India's primary energy demand, shown in Figure 11 and Table 3.

Indian total energy demand is moderate, although projected growth in demand is great, with large additions of gas and renewable energy. Use of coal and oil is projected to dominate and by 2030, gas is projected to meet only 10% of India's primary energy demand.

Figure 11 – Primary energy demand in India (Mtoe)



Calendar years. Source: IEA World Energy Outlook 2010

Table 3 – Primary energy demand in India (%)

	1980	2008	2015	2020	2030	2035
Coal	33%	42%	42%	43%	40%	39%
Oil	19%	23%	23%	23%	25%	26%
Gas	3%	6%	9%	9%	10%	11%
Nuclear	1%	1%	1%	2%	3%	4%
Hydro	2%	2%	2%	2%	3%	2%
Biomass and waste	42%	26%	23%	21%	18%	16%
Other renewables	0%	0%	1%	1%	2%	2%
Total	100%	100%	100%	100%	100%	100%

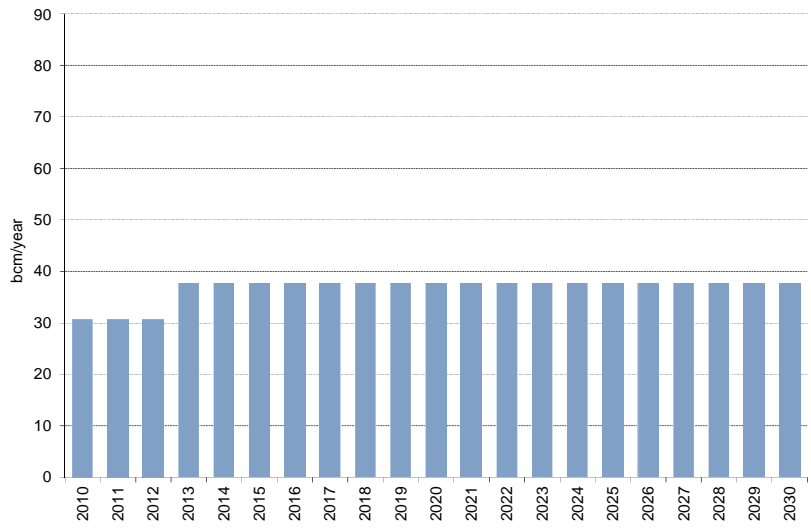
Calendar years. Source: IEA World Energy Outlook 2010

7.4.4 Conclusions

Progress with unconventional gas exploitation has been relatively slow, and the resource base not in the same league as the leading nations. Whilst production of CBM will grow steadily, and shale gas may be exploited, the overall volumes are not expected to make a decisive contribution to India’s energy balance at a national level. The volumes will be easily absorbed into India’s rapidly expanding energy balance, providing a valuable contribution to the economy.

India is only projected to add one LNG re-gasification terminal in the next decade, see Figure 12, and we do not expect unconventional gas development to influence the decision to build this terminal.

Figure 12 – Projected LNG re-gasification capacity into India



7.5 Australia

Australia has a great wealth of energy resources ranging from coal to conventional hydrocarbons, shale gas, uranium and solar potential. The leading question in energy policy is where best to place its limited investment resources.

7.5.1 Overview of resources

Australia is known to hold abundant resources of CBM and has a range of highly prospective shale strata.

Coal production has been established in Australia for over 100 years and the knowledge of the resource is well established. Rogner’s study of 1997 gave an estimate of 13tcm for the CBM resource of Australasia which, from the known extent and recent increases in reserves, looks a reasonable number.

Potential shale gas resources are much less certain as there is very little exploration of the shale layers to date. The recent EIA study gives an estimate of 13tcm of technically recoverable reserves.

7.5.2 Overview of gas production

Australia has a relatively small population, concentrated in coastal cities across thousands of miles. As a result there is no national transmission system, and closest to this is the network of pipelines connecting population centres along the East coast.

Off shore production is concentrated on the NW Shelf, and almost exclusively supplied to LNG projects for export to Asia. Small volumes are supplied to distribution networks local to the LNG liquefaction facilities. LNG projects under development will significantly increase the conventional offshore production over the next 20 years, but this will also have limited impact on the domestic market.

Onshore gas production is currently supplied almost exclusively to the domestic market. Overall gas consumption in Australia is relatively small, less than one third of the UK's gas consumption. Consumption has trended slowly upwards from 17bcm in 1990 to around 26bcm/year today¹¹.

In recent years, strong growth in CBM production has offset the declines in conventional gas, notably from the Cooper Basin in South Australia. CBM production has risen from zero in 1995 to 5bcm/year in 2009. Furthermore, CBM production is poised for take-off as onshore production has been earmarked to supply a generation of new-build LNG liquefaction plants on the east coast.

Around 97% of Australia's CBM production takes place in Queensland. The state is home to Australia's largest onshore reserves of CBM in the Bowen and Surat Basins. CBM is now an important energy resource in Queensland, where it accounts around 90 per cent of the state's domestic gas supply. The state's resources now comfortably exceed domestic requirements for the next 100 years and, as a result, Queensland is also home to a number of proposed LNG liquefaction projects intending to use CBM as feedstock.

Outside of Queensland, the remainder of Australia's CBM production takes place in New South Wales, which also has abundant coal reserves and is seen as a prime CBM growth area. Exploration for CBM is also taking place at various other locations throughout Australia.

7.5.3 Conclusions

Australia will be an increasingly important provider of LNG to the rapidly growing Asian nations, and this will have an impact on world LNG dynamics. Australia has the advantages of location, being able to ship LNG to Asia more economically than some competitors. It also has an attractive climate for exploitation and investment. Leading commentators, such as the Wall Street Journal, support the notion that Australia will surpass Qatar as the world's leading supplier of LNG over the next 20 years.

We believe it is possible that with good developments in unconventional gas technology, Australia could increase its LNG liquefaction capacity and add resources to the world LNG market. Our assumptions are outlined in section 8.2.

7.6 Indonesia

Indonesia has a large natural gas industry based on conventional resources and is a major exporter of LNG. However, the government and industry have had problems developing adequate conventional natural gas to maintain the LNG liquefaction plant at current levels of production. Conventional resources have been discovered in some areas but, because of location, they are often not suitable for commercial exploitation. It is hoped that unconventional resources can provide a new supply to LNG plants, and provide commercial gas markets with a cost-effective solution to the growing energy needs.

¹¹ excluding fuel gas for LNG liquefaction plants.

7.6.1 Overview of resources

Despite its' potentially enormous resources, neither Rogner, nor the EIA focus on Indonesia. This is likely because of the massive geographical area, geological diversity, and the fact that Indonesia is one of the least explored countries in the world.

The Ministry of Energy and Mineral Resources reports that Indonesia has massive CBM resources and a recent survey estimates its CBM reserves are 12.8tcm. The South Sumatra Basin, the largest in Indonesia, is estimated to contain in-place resources of approximately 5.2tcm.

7.6.2 Key players and recent activity

Between May 2008 and August 2009, 15 CBM production sharing contracts were granted by the Government of Indonesia, with total exploration commitments of almost US\$100 million over the next 3 years.

In December 2009, Indonesia awarded the Sanga-Sanga CBM production sharing contract to a consortium of BP and ENI, which will each hold 37.8%, with the remainder held by Opicoil and Universe Gas and Oil. The consortium is committed to a US\$38 million appraisal programme to determine the block's production capacity and refine current reserves estimates, with the aim of eventually supplying the Bontang LNG liquefaction terminal.

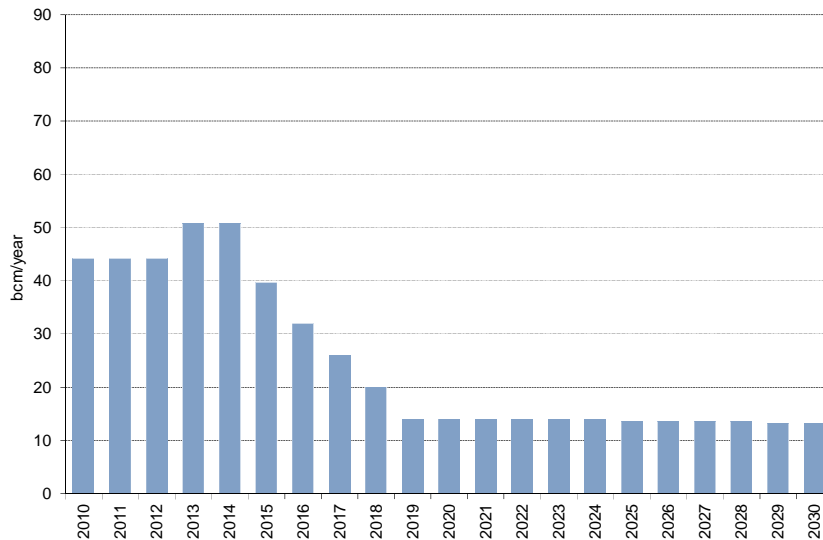
At the beginning of April 2011, the Indonesian government signed 14 exploration contracts, of which nine were for CBM, and the remainder for conventional gas and oil. The hope of the government is that the strategy of developing CBM can tackle the country's gas supply shortfall. The Ministry of Energy and Mineral Resources, under its framework for the development of CBM, is hoping that production of CBM will start in 2011, and reach a target of 1bcm/year in 2015, and 10bcm/year by 2025.

7.6.3 Conclusions

Interest in the unconventional gas resources in Indonesia has been strong, with several E&P majors involved, and the resource base appears to be large. However, the unconventional sector remains at the very early stages of development and it is difficult to estimate how far production will grow.

The government of Indonesia is drawn between the needs for feedstock gas supply into LNG export projects, and the growing needs of the domestic energy markets. It will be difficult to maintain exports from Indonesia because the domestic gas market is growing and any CBM production is likely to be absorbed into the home market. However, Indonesia covers a vast area, and geographical factors will play a key role. Resources near to population centres will be valuable in domestic markets, and those near the LNG liquefaction plants may be used as feedstock. Pöyry assume LNG exports from Indonesia fall from 2015 in all scenarios because less gas is available to export, as shown in Figure 13.

Figure 13 – LNG liquefaction capacity for export from Indonesia



7.7 Algeria

7.7.1 Overview of resources

The EIA estimate of Algeria’s technically recoverable reserves of shale gas is slightly over 6.5bcm. First fracking has taken place and early indications are that it has ten times the amount of reserves than in the US.

7.7.2 Key players and recent activity

At the present time there is very little unconventional gas activity.

In March 2011, state oil & gas company, Sonatrach, reported that shale gas prospects in Algeria very interesting, and that it already had contacts with International oil companies operating in the country. Sonatrach announced it will launch a pilot project for developing unconventional gas resources in 2012, but would not expect production before 2018-20. ENI of Italy has also announced that it plans to evaluate Algeria's shale gas opportunities.

7.7.3 Conclusions

Shale gas in Algeria remains at an early stage of development. Despite the good intentions of Sonatrach and ENI, it is likely that shale gas production will take longer to establish than in Europe. On the positive side, Algeria has large resources and a strong incentive to develop unconventional gas reserves, to meet current contractual commitments, to provide a reserve base for new projects, and to supply the increasingly energy-hungry domestic gas market, particularly in the power generation sector.

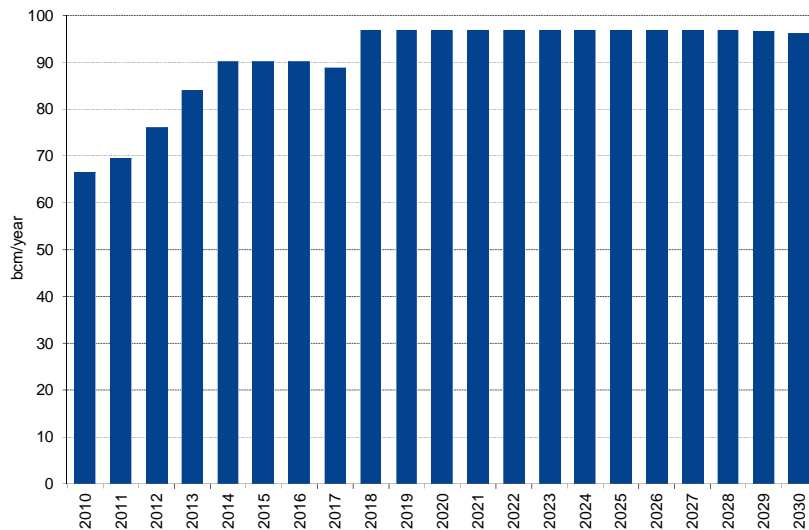
On the negative side, Algeria has a long history of low-cost conventional natural gas production, and the petroleum taxation regime is renowned as one of the least profitable for investors. It will take a paradigm change of significant proportions to adjust the investment climate for the exploitation of shale gas or CBM. Water supply must also be a

serious concern as the water resources are relatively poor and the water distribution network covers a relatively small proportion of the land area.

Tight gas may be a more realistic target for early exploitation, but this might also require significant adjustments to the petroleum taxation regime.

Pöyry assume export capacity from Algeria increases over the next seven years and after that are maintained until the end of period modelled, as shown in Figure 14.

Figure 14 – Gas export capacity from Algeria via pipeline and LNG liquefaction



7.8 Conclusions

Of the regions outside Europe and North America we have studied, we believe that unconventional gas developments in some will have an impact on the gas markets of Europe, while in others they will not. The regions we believe could have a significant impact are Russia, Ukraine and Australia, while those which will have less of an impact are China, India, Indonesia and Algeria.

Unconventional gas developments in Russia and Ukraine could increase the availability of gas for import to Europe via pipelines from the East.

Unconventional gas developments in Australia could increase the amount of LNG liquefaction available to the Worldwide LNG market.

For a variety of reasons described above we believe the gas markets of China and Indonesia will absorb any future unconventional gas production without having an impact upon the worldwide LNG market.

The development of unconventional gas in India and Algeria will be seriously restricted by the lack of water supplies and hence production in the period to 2030 will be insignificant.

8. SCENARIOS FOR UNCONVENTIONAL GAS DEVELOPMENT

This study of unconventional gas potential around the world has illustrated that there is considerable uncertainty regarding future levels of unconventional production. In order to capture the range of possible levels of production we have developed three scenarios, upon which our modelling is based. These are the Boom, the Balanced and the Restrained Scenarios, which were outlined in our Introduction and are described in detail in this section.

These scenarios are designed solely to investigate the impact of different futures for unconventional gas production and costs, all other assumptions are constant across the scenarios. The general assumptions which are consistent across the scenarios – such as, oil price and exchange rates – are based upon Pöyry's Central projections. Infrastructure assumptions are also kept constant across the scenarios, so pipeline capacities and LNG re-gasification/liquefaction capacities are the same, except in the case of Australian LNG liquefaction where unconventional gas resources could have an impact. This is described below in section 8.2.3.

8.1 The scenarios

The modelling we have carried out in the course of this study has been focused on the potential of unconventional gas developments across the world to impact upon Great Britain and North West Europe (NWE). Each scenario considers the potential of unconventional gas production in each European country and also projects the potential range in output from unconventional gas resources in key regions around the world.

In this section, we describe each scenario and present the projected unconventional gas production from individual European countries.

In Annex C, we also present the peak capacity versus the peak day demand in GB and in NWE under each scenario. Unconventional gas volumes in Europe are not projected to be highly significant to the 'supply margin' (that is, the difference between the available capacity and demand) even under our Boom Scenario. However, because our modelling includes iterations with our electricity model; price-sensitive demand from power generation varies between scenarios (this is described in more detail in Section 9). This leads to the supply margin tightening under scenarios affected by changes in demand.

Later in this section, we describe the range in unconventional gas production projections from key regions around the world, and summarise our assumptions across the scenarios.

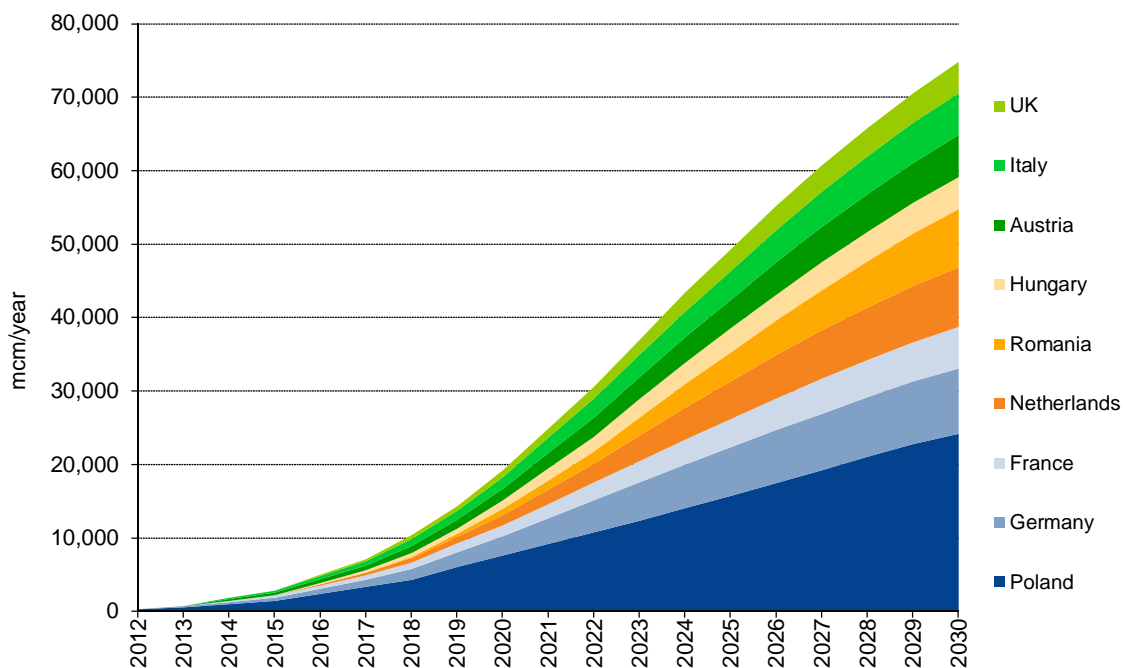
8.1.1 Boom Scenario

The Boom Scenario projects a US-style boom in unconventional gas production in Europe. It is an optimistically high case where shale gets strong political and local support. The geology proves to be good in multiple countries. Lessons from the US industry are readily adaptable to European shales and technological advances continue, which causes production costs to fall from their current levels towards the cost of US shale production. Despite this, however, there is still a premium (set at 35%) to be paid over US shale costs due to the differing costs of land ownership, environmental compliance etc. The cost assumptions and sources are described in Section 8.4 and a 35% premium on current US costs represents our low cost projection.

The latest most powerful rigs and other infrastructure and support services become available in Europe and production costs are low enough to displace other supplies. All these factors result in production of unconventional gas in Europe reaching 75bcm/year by 2030, shown in Figure 15.

Under the Boom Scenario the rig count builds to 60 state-of-the-art rigs by 2030, each drilling 2 wells per month, in pads of 8 wells each. The total well count by 2030 is 14,286 wells on 1,786 pads. About 30% of the production is in Poland, with substantial amounts in Germany, Netherlands, Romania, France, Austria and Hungary. Smaller volumes are produced in the UK.

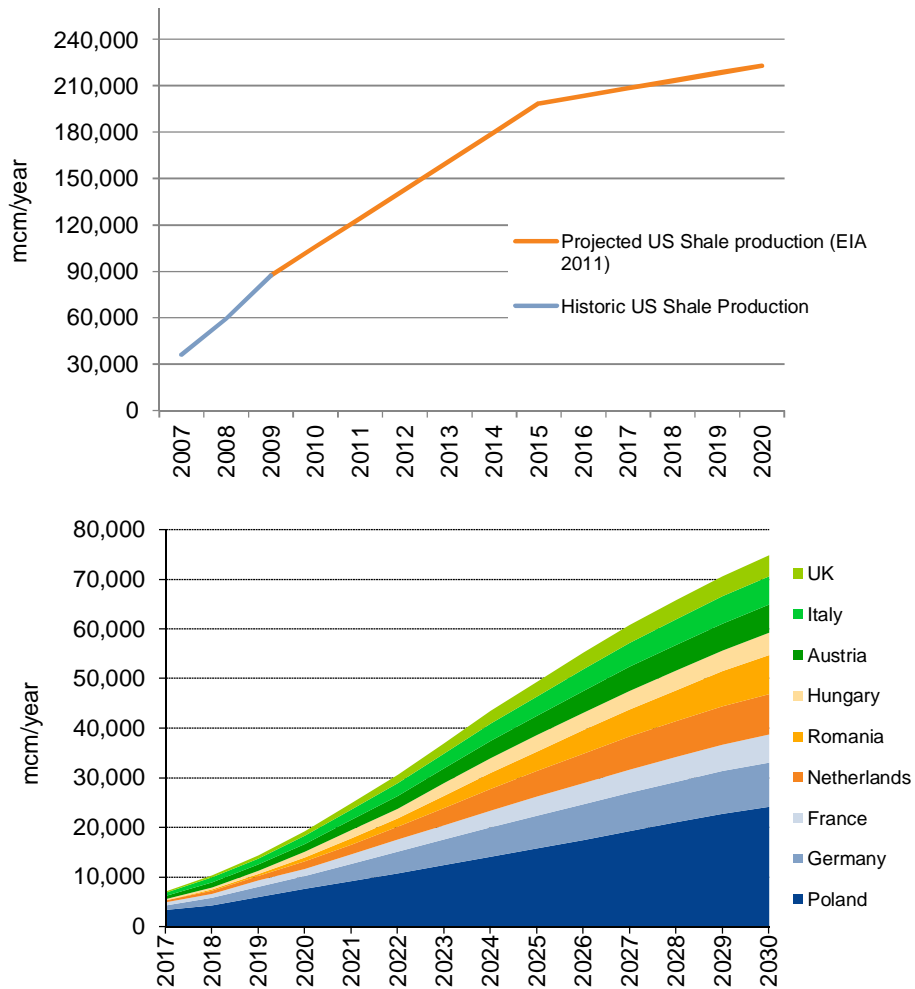
Figure 15 – Unconventional gas production in Europe under the Boom Scenario



As recently as five years ago, nobody in the US imagined that shale gas production would provide as much as 15% of US gas supply by 2010; so the Boom Scenario, although low probability, is necessary to test the impact of similar events out-turning in Europe.

It is interesting to compare recent shale gas production rates in the US and the EIA’s latest shale gas production projections from 2007 to 2020, with our projections for Europe a decade later – from 2017 to 2030. These are shown side by side in Figure 16, and although the US shale gas production is in the region of three times the projected unconventional gas production for Europe, the projected pattern of growth is very similar.

Figure 16 – Comparing US growth in shale gas production with projections for unconventional gas in Europe under the Boom Scenario



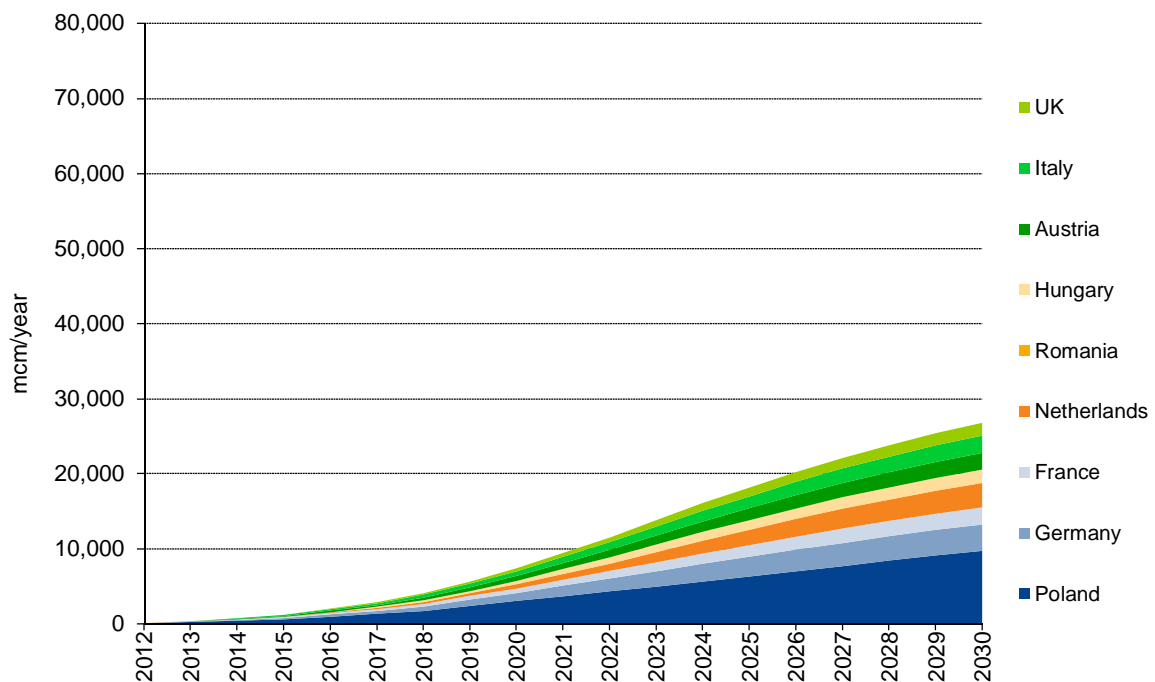
Source: EIA and Pöyry

8.1.2 *Balanced Scenario*

Under the Balanced Scenario, political support for shale development is mixed and local communities need to be convinced of the economic and social benefits. Water and environmental problems slow the approvals process. Some shales have good economics but others are sub-economic in the time scale under consideration. The US experience can be applied reasonably well, technology moves forward and results in production increases to about 27bcm/year by 2030 as shown in Figure 17.

We consider the Balanced Scenario has a moderate probability.

Figure 17 – Unconventional gas production in Europe under the Balanced Scenario



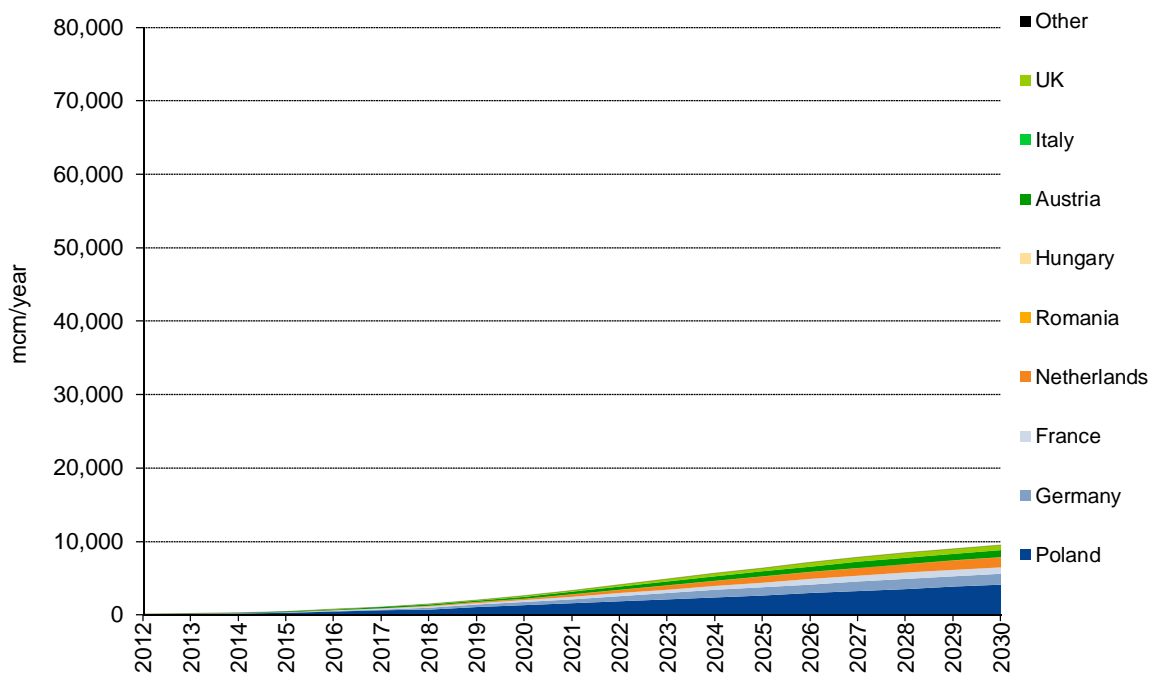
8.1.3 Restrained Scenario

Under the Restrained Scenario NIMBYism is rife and political support is poor in most countries. Early instances of pollution slow the approvals process considerably and geology is poor and few shales have significant volumes of liquids so relatively small ‘patches’ are developed.

US expertise is available but does not readily translate to European shales, equipment must meet more stringent industry standards and low volumes make this expensive, so the market is left to European manufacturers who are slow to respond with powerful rigs, low potential profits leave little cash for research funding and technology moves forward relatively slowly. Production only reaches about 9bcm/year by 2030, shown in Figure 18.

Although a pessimistic scenario, we consider the Restrained Scenario to have the same moderate probability as the Balanced Scenario.

Figure 18 – Unconventional gas production in Europe under the Restrained Scenario

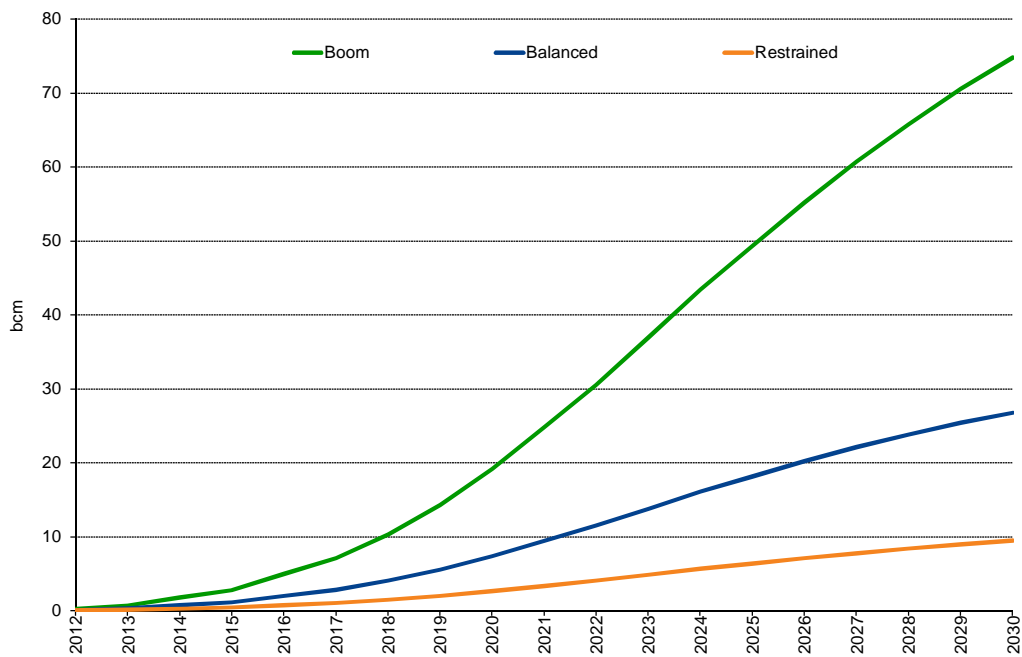


8.1.4 Unconventional gas production in Europe under each scenario

The range of projected unconventional gas production from Europe, under each scenario is shown in Figure 19.

There are two recent studies, which we can compare with our scenarios, which project European unconventional gas production. Rice University in the US presents a European case for 55bcm/year of shale gas production by 2030 – which falls between our Balanced and our Boom Scenarios. While Wood Mackenzie has said that it believes Poland could be producing 30bcm/year by 2030 – which is slightly more optimistic than our Boom Scenario which has Poland producing around 22bcm/year by 2030.

Figure 19 – Projections for unconventional gas production in Europe



8.2 Assumptions in key regions around the world

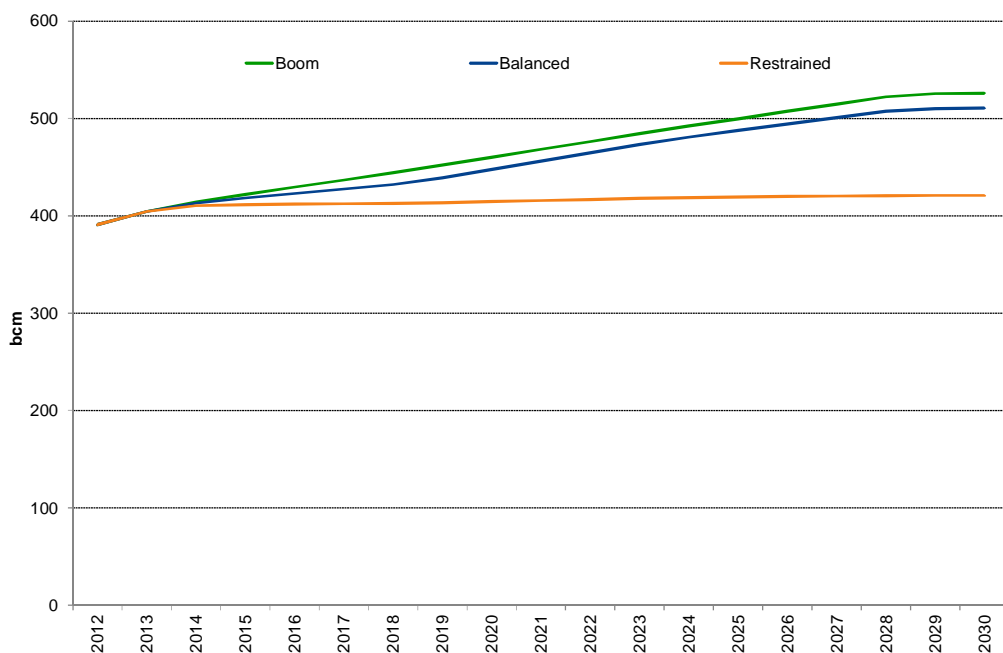
Section 7 describes unconventional gas developments in key regions of the world. In this section we summarise our projections under each of our scenarios for those regions we believe may impact the future balance of the European gas market.

8.2.1 Unconventional gas production in the US under each scenario

Our three scenarios for US unconventional gas production are shown in Figure 20. Under our Balanced Scenario we have used EIA projections for unconventional gas production in the US. We consider the EIA projections to be quite optimistic, so we have only increased our projection under the Boom scenario by a small percentage over this.

As discussed in this report, there is always the possibility that the boom in unconventional gas production in the US could falter due to unrealistic economic assumptions and the rapid increases in production could stall (see our discussion of the Contrarian view in section 4.1.1). Under our Restrained Scenario we have assumed unconventional gas production in the US plateaus after 2014.

Figure 20 – Unconventional US gas production



Note: In this case, unconventional gas includes tight gas production

8.2.2 Gas production in Russia and Ukraine under each scenario

Pöyry models production from all of Russia’s conventional gas fields and includes imports Gazprom plan to obtain from Central Asia. We also use projections of Russia’s domestic demand and demand from transit countries such as Belarus and Ukraine. Combining all these elements, we project the total Russian gas available for import to Europe.

Under our Boom scenario we assume the most optimistic production projections from Gazprom. At this time, it is not possible to project the split between conventional and unconventional sources, so we have taken a view that that under a scenario where

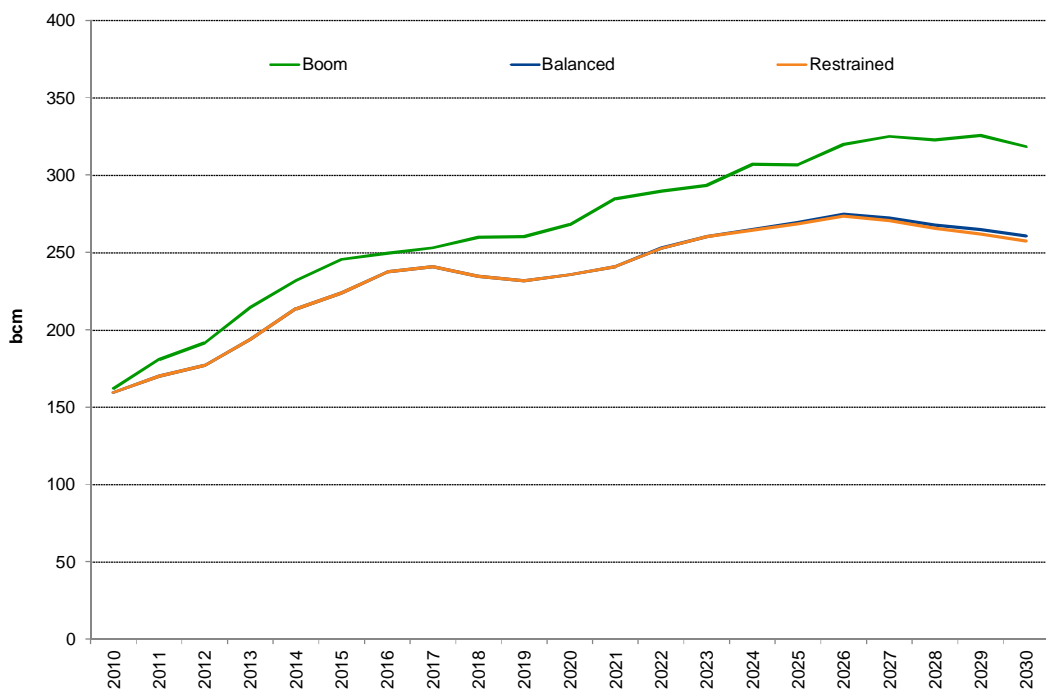
unconventional gas technology is making good progress around the world, production from Russia will be boosted by the addition of new, economic unconventional gas resources. Our other scenarios assume Pöyry’s central projection for Russian gas production, which is more conservative.

Because Russia has such huge conventional gas resources we do not project a lower availability of Russian gas for Europe due to restrictions in unconventional gas development under the Restrained Scenario.

Ukrainian unconventional gas production could take a similar, if delayed pattern to that expected in Poland – as described in Section 7.2. In our modelling we have treated Ukraine as having similar reserves to those in Poland but have delayed their development. In the Boom scenario we have assumed developments in Ukraine lag Poland by five years and production of unconventional gas reaches 17bcm/year by 2030. In the Balanced scenario, Ukraine lags Poland by 10 years and unconventional gas production reaches 3bcm/year by 2030. Under the Restrained Scenario the barriers prove too great and no unconventional gas is produced

As Ukraine is a transit country for Russian gas on route to Europe, Ukrainian gas production is netted off the total of Russian gas available to Europe shown in Figure 21. The small difference between the Restrained and the Balanced Scenarios towards the end of the period in Figure 21 is due to the difference in Ukrainian unconventional production.

Figure 21 – Total Russian gas available as imports to Europe

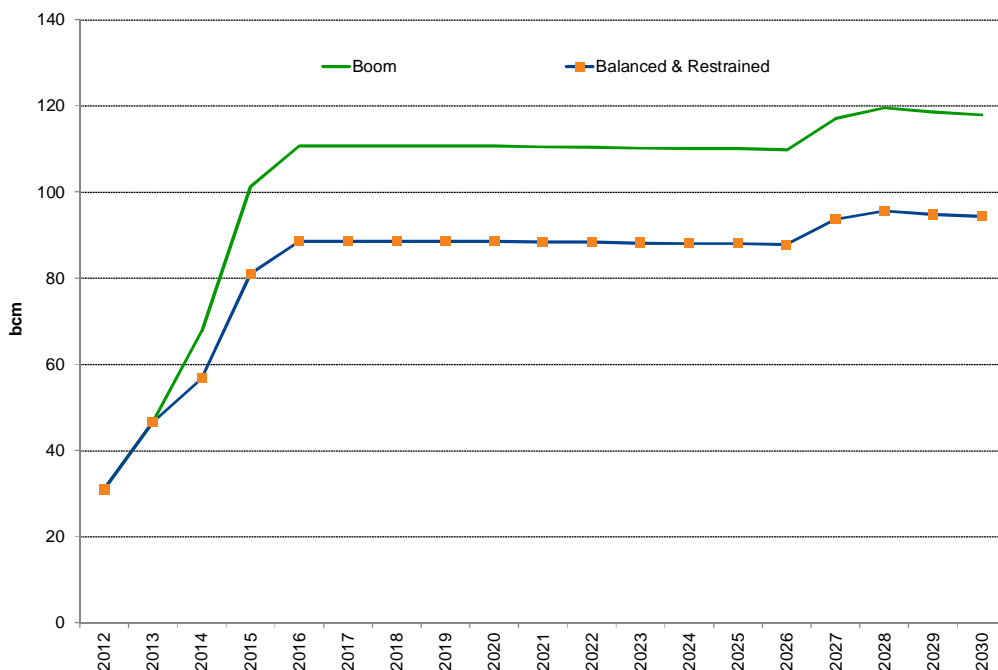


8.2.3 LNG liquefaction in Australia under each scenario

Australia is set to see a rapid growth in its LNG export capacity over the next five years. As its domestic gas demand is relatively small, as discussed in section 7.5, there is every possibility that new gas production will be exported. Plans for liquefaction capacity are well underway and we do not consider a reduction in our central projection to be likely, so it has been used in both our Balanced and Restrained scenarios.

Under our Boom scenario we have assumed that an unexpected abundance of unconventional gas sources in Australia leads to an even greater availability of gas to export than already planned. Our projection for LNG liquefaction capacity in Australia under our Boom Scenario rises to 25% over the Pöyry central projection and is shown in Figure 22.

Figure 22 – Liquefaction capacity in Australia



8.3 Summary of assumptions across the scenarios

Figure 23 shows a summary of those sources of gas supply from each of the regions which has been assumed to vary between the scenarios, in 2010, 2020 and 2030. The figure illustrates the differences between the scenarios; all other assumptions – excluding the costs of unconventional gas production – are the same. Figure 23 includes the total annual demand in NW Europe under each scenario to illustrate the comparative changes in demand, which result from different gas prices in each scenario.

In 2030 the Boom Scenario has an additional 144bcm/year of gas available when compared to the Balanced Scenario; and 255bcm/year more than the Restrained Scenario.

Figure 23 – Summary of volume differentials between the scenarios

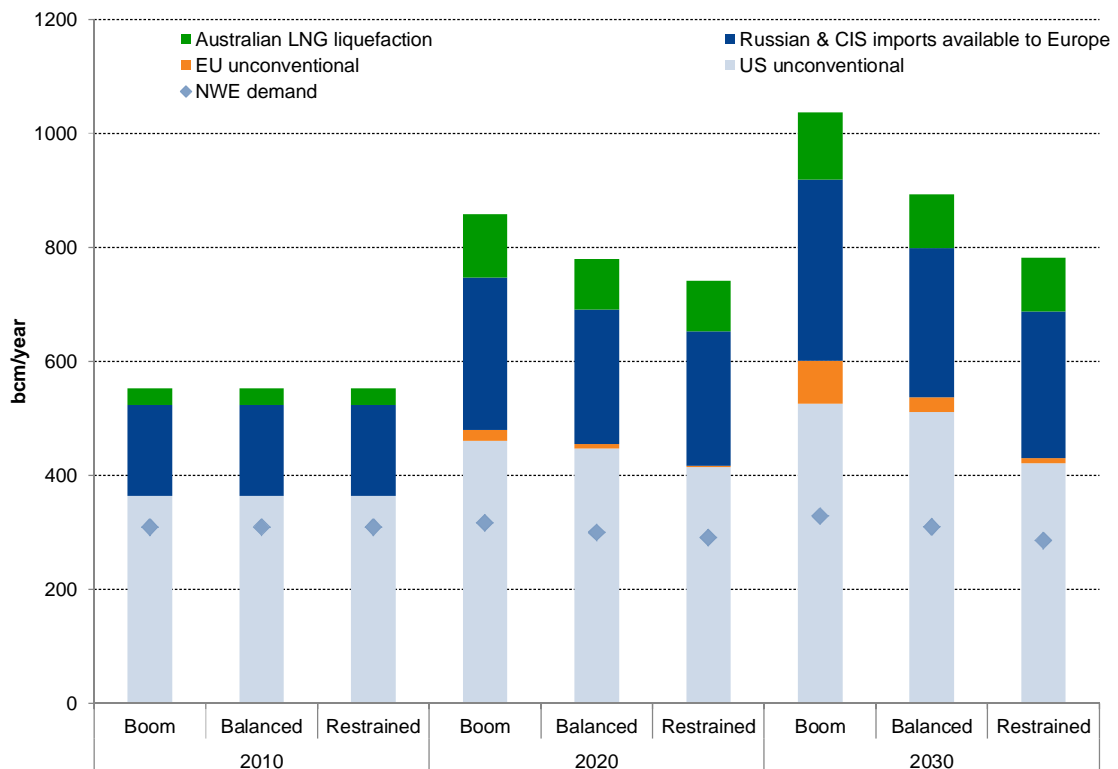


Table 4 summarises the differences between the scenarios, including the different costs assumptions for unconventional gas production. The cost assumptions are also shown in Figure 24.

Table 4 – Summary of scenario assumptions

	Boom	Balanced	Restrained
European UC production	High – reaching a maximum of 75bcm by 2030	Central – reaching a maximum of 27bcm by 2030	Low – reaching a maximum of 9bcm by 2030
US UC production	High – reaching a maximum of 526bcm by 2030	Central – reaching a maximum of 511bcm by 2030	Low – reaching a maximum of 421bcm by 2030
Russian gas available to import	High – reaching 318bcm by 2030	Central – reaching 260bcm by 2030	Central
Australian LNG liquefaction	High – 25% higher than central from 2015 onwards	Central – reaching 94bcm by 2030	Central
Ukrainian UC production	High – similar to Poland's growth rate, but delayed by five years. Reaches a maximum of 17bcm by 2030	Low – similar to Poland's growth rate, but delayed by 10 years. Reaches a maximum of 3bcm by 2030	None
UC production costs in Europe	Starting from 78p/th NWE and 64p/th for CEE, then towards US shale plus a premium of 35% by 2020	Starting from 78p/th NWE and 64p/th for CEE, then towards US shale plus a premium of 50% by 2020	108p/th NWE and 71p/th for CEE for entire period

UC = unconventional gas

8.4 Cost assumptions

The Oxford Institute of Energy Studies' (OIES) report in December 2010¹² considered European shale gas costs assumptions in detail. Based on Schlumberger Business Consulting data, they estimated costs for vertical testing and development wells, without taking into account any operational performance improvements. OIES cites the horizontal well drilled and fracked in Poland in August 2010 as costing up to around \$20 million and Aurelian Oil and Gas's 2010-11 tight gas horizontal Sikierki well in Poland as costing \$19 million.

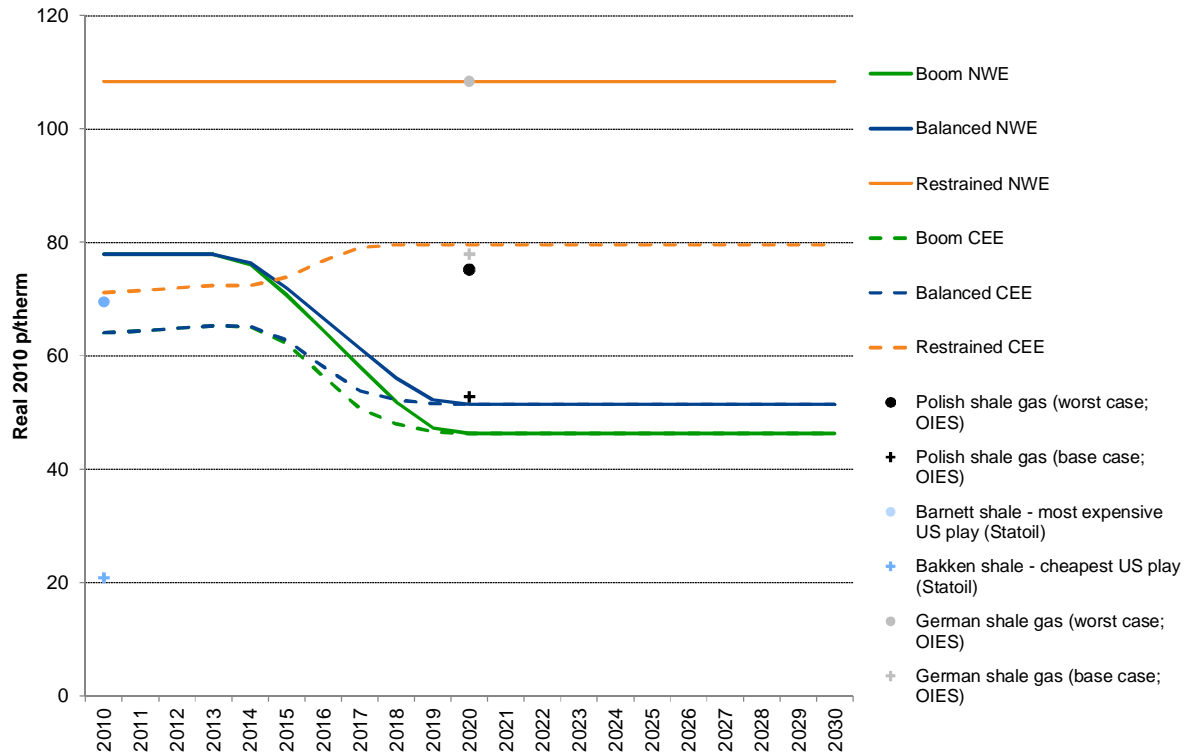
Going forward, OIES concludes that for structural reasons European unconventional gas well costs are roughly 2 to 3 times higher than in the US, and that a cost decrease of 50% is 'the best that could be expected for European drilling operations in the long run'.

Figure 24 compares Pöyry's assumptions for the cost of shale production in Europe against OIES figures and data published by Statoil. Cost assumptions are based upon the OIES figures and, under the Boom and Balanced Scenarios, fall towards US production costs. This reflects the gradual overcoming of technological barriers and economies of scale as more players enter the market. There is still a premium placed upon the costs over those from the US, due to the higher land prices and diffused nature of EU shale plays. In the

¹² <http://www.oxfordenergy.org/pdfs/NG46.pdf>.

Restrained scenario we have kept costs at the highest level to reflect continued difficulties faced by companies in exploiting shale plays Europe.

Figure 24 – Benchmarking European unconventional gas cost assumptions



NWE – North West Europe, CEE – Central Eastern Europe
 Source: Oxford Institute of Energy Studies, Statoil and Pöyry

The difference in costs between the Balanced and the Boom scenarios is not great, but, as will be seen in the next section, the volumes of the unconventional sources available makes a significant difference to the overall market prices.

9. OUTPUTS

This section describes the main outputs of our market analysis, particularly focussing on the impacts that unconventional gas production could have on production patterns, and market prices in both GB and wider Europe.

9.1 Comparing outputs from scenarios

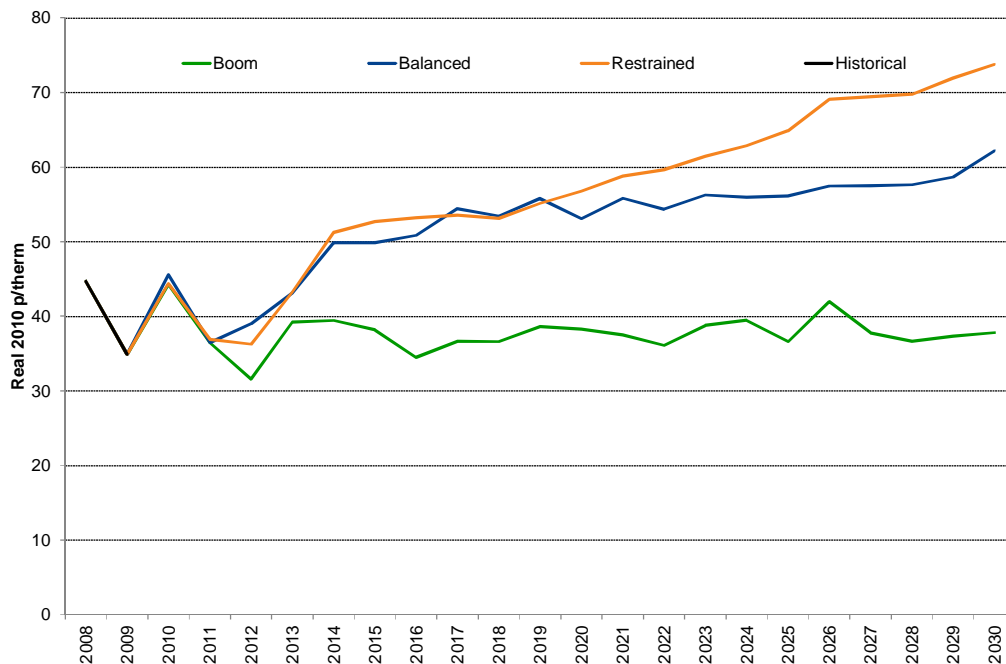
We found that GB's unconventional volumes are unlikely in themselves to have a significant impact upon the future make-up of gas supplies. However, the effect on price of increased availability of economic unconventional gas supplies displacing more expensive sources of gas could be significant. The accompanying impact upon gas demand resulting from changing gas price is also significant.

9.1.1 GB prices

The impact of unconventional gas production on the GB gas price can be seen clearly in Figure 25, which shows prices in the Boom Scenario remaining considerably lower than the other scenarios. As will be seen in Section 9.1.3, this is not directly due to unconventional production in GB, but is rather due to the large amounts of gas that become available to GB through imports, be they from the Continent, Norway or through LNG shipments. The economic production of unconventional gas in Europe makes more low cost gas available to GB, displacing expensive sources.

In the Restrained scenario, there is a smaller amount of unconventional gas available worldwide, especially in the US. This creates a much tighter supply-demand margin worldwide, with consequently smaller amounts of relatively cheap LNG available to meet GB demand. In this Scenario, prices rise throughout the period.

Figure 25 – GB prices across the three scenarios



Prices in the Restrained and Balanced scenarios are similar until around 2020 when the differences in unconventional gas production in each of the scenarios is great enough to have a significant impact on the marginal gas price of gas available in GB.

9.1.2 GB demand

Gas demand is made up of power generation demand and non-power generation demand (industrial, residential, and commercial). Whilst our non-power demand assumptions are derived from a combination of growth rates and historical data, our power generation assumptions are derived through iterations with our electricity model. We develop internally consistent assumptions¹³ around a number of key drivers, all of which have impacts on the demand, which are:

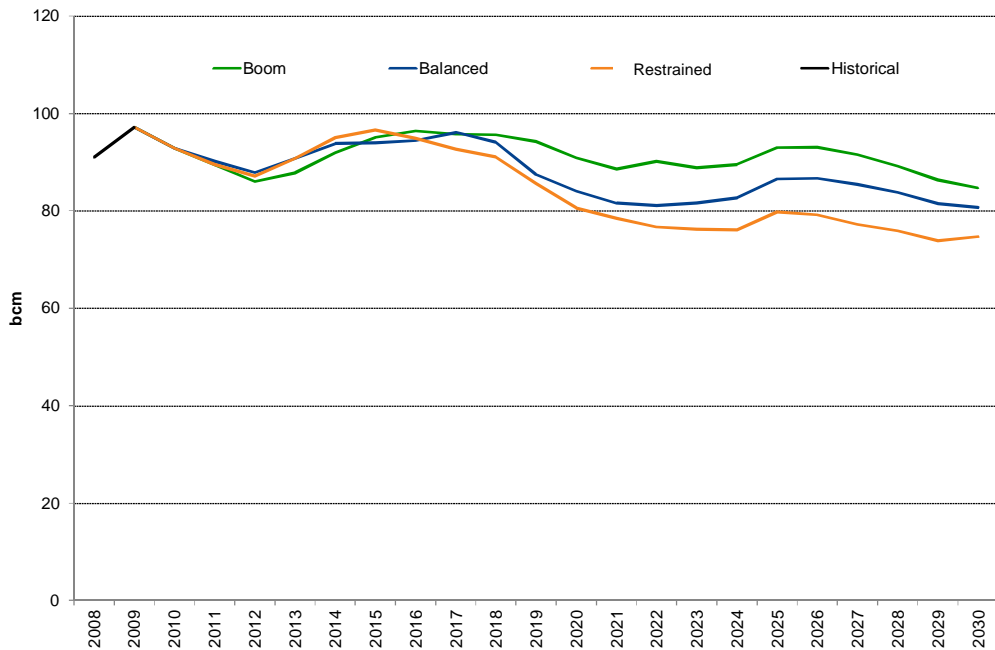
- fuel prices (coal, oil, and gas prices);
- CO₂ price assumptions;
- electricity demand;
- new power station construction and plant retirements; and
- costs and performance of new entrants.

Our fuel price assumptions and the gas prices shown above in Figure 25 are used to derive a consistent view of gas demand from power generation. This is added to the non-power demand (which does not vary between scenarios) and the result is the total GB demand projections which are shown in Figure 26.

The variation in gas price between the scenarios has a significant impact on power generation and thus the overall GB gas demand. Under the Boom Scenario when plentiful supplies of relatively cheap unconventional gas production keeps GB gas prices low, the total GB gas demand moves between 85 – 95bcm/year. At times the total GB gas demand under the Boom Scenario is nearly 20bcm/year higher than under the Restrained Scenario in which gas prices are pushed up by the stalling of US shale production tightening the world's LNG market.

¹³ For example, new entrant costs take account of fuel and CO₂ prices

Figure 26 – Total GB demand

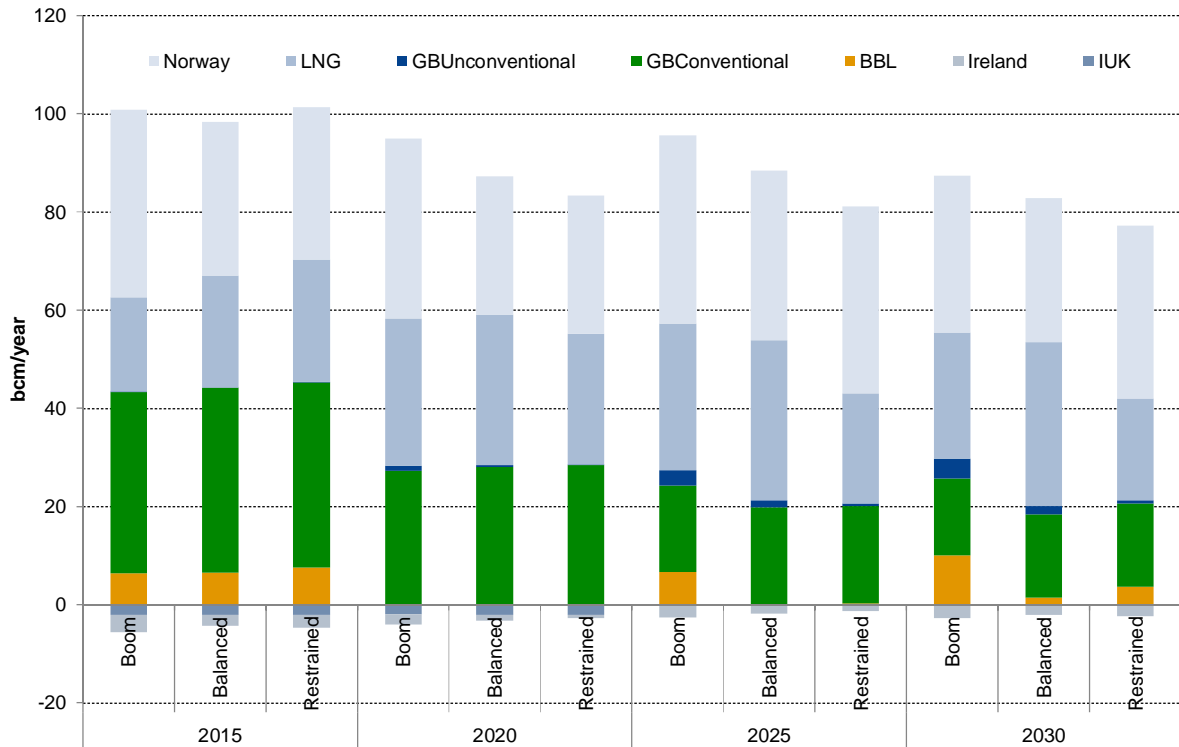


9.1.3 GB annual supply

With declining indigenous reserves, GB will become increasingly reliant on imports, both via pipelines and LNG shipments. Whilst there is potential for unconventional gas in GB, the indigenous volumes are too low to materially affect the GB supply-demand balance.

What is noticeable in the annual sources of supply to GB shown in Figure 27, is the overall demand level and the relative importance of imports from the Continent (which are highest under the Boom Scenario), and the imports from Norway versus LNG. By 2030, under the Restrained Scenario, Norway is more heavily relied upon compared to the Balanced Scenario, which pulls in more LNG. This difference is due to limited LNG supplies under the Restrained Scenario caused by the stalling of unconventional gas production in the US.

Figure 27 – Net annual sources of supply to and from GB



The net annual flows shown in Figure 18 indicate that over the whole year IUK is usually a net exporter of gas to the Continent and BBL an importer. In 2020, it is noticeable that the net imports via BBL are zero in all scenarios. This is because some large Russian gas fields are in decline and around this time Russian gas available to Europe is relatively low and the model projects the most cost effective solution is that GB would acquire more gas via Norway or LNG.

9.1.4 GB peak supply

Whilst annual supplies show how GB will source its gas into the future overall, they will not highlight any supply constraints that GB may face on a peak day. Figure 28 compares GB’s peak day sources of supply across the scenarios.

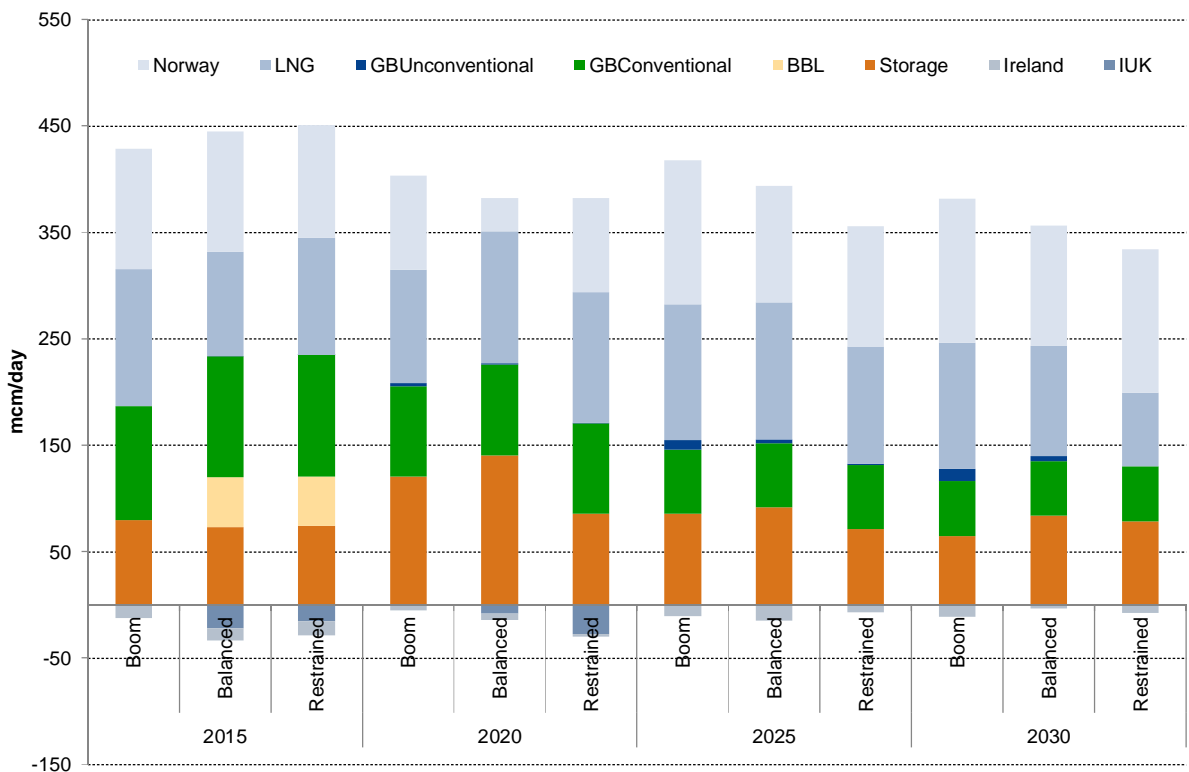
It is worth highlighting that when we model a cold day with peak demand in GB we also assume NW Europe is experiencing similar conditions, limiting import availability from the continent.

In 2015, when demands are high across all three scenarios compared to later years, use is made of the interconnector with the Netherlands under the Balanced and Restrained Scenarios.

In 2025 and 2030, despite unconventional gas production being well advanced, the impact of GB unconventional gas is limited, with volumes only making up a small percentage of peak day supplies under the Boom and Balanced Scenarios. Negligible amounts of unconventional gas are available in the Restrained Scenario.

Volumes of LNG used on a peak day in 2030 are lowest under the Restrained Scenario, but this does not impact security of supply because the overall demand level is also reduced.

Figure 28 – Net sources of supply to and from GB on a peak day



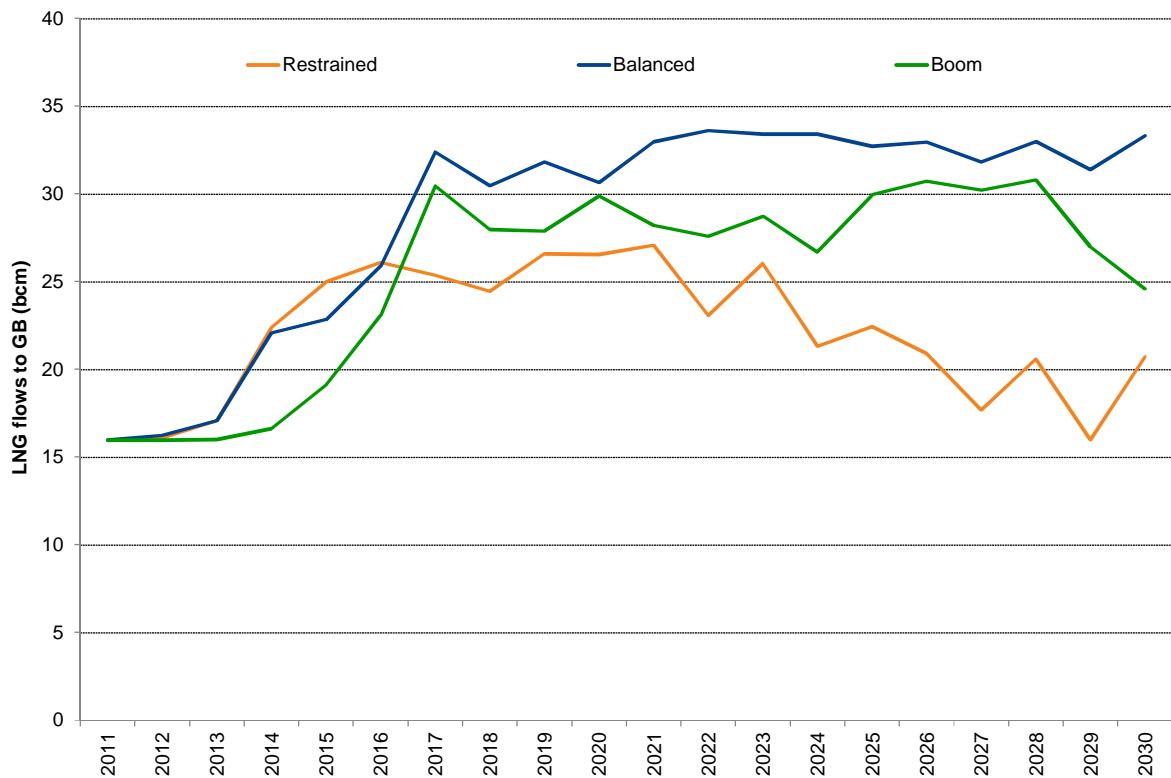
9.1.5 LNG flows

Figure 29 shows how GB's LNG regasification terminal utilisation changes across the three scenarios. Once again under the Restrained Scenario, it is the higher volumes of LNG being taken by the US that has an impact upon GB, limiting its LNG imports. High prices have also constrained GB demand so fewer imports are required overall.

Although under the Boom Scenario the world LNG market is well supplied, the amounts of unconventional gas which are being produced in Europe under this scenario push LNG out. The interconnectors between the Continent and GB also see a higher utilisation under the Boom Scenario (see Section 9.2.1).

The Balanced Scenario sees the highest utilisation of GB's LNG re-gas terminals, due to a combination of lower imports from the Continent and relatively plentiful LNG supplies.

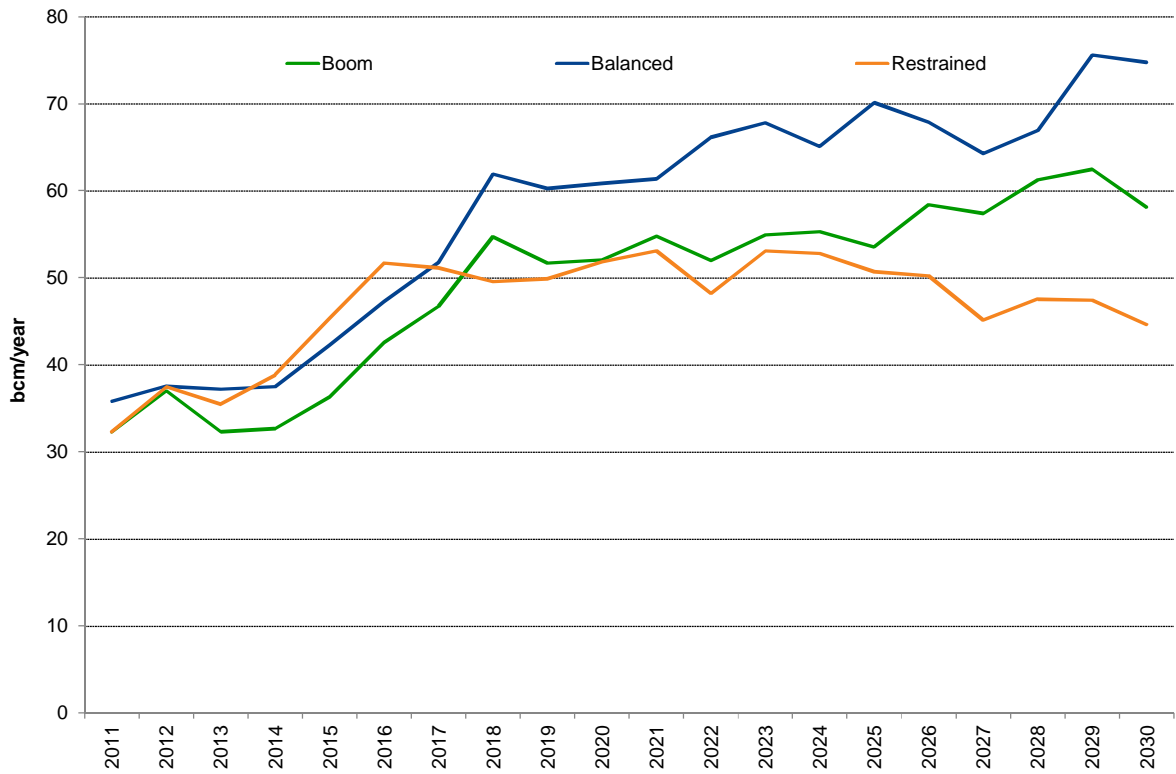
Figure 29 – Total flows across all LNG terminals in GB



The picture for NW Europe, as shown in Figure 30, is very similar. In the Boom Scenario, plentiful unconventional gas supplies squeeze out LNG supplies, decreasing the utilisation of the re-gasification terminals. Whilst under the Restrained Scenario, the demand for LNG in the US diverts LNG away from Europe.

From 2017, the Balanced Scenario sees the highest utilisation of LNG re-gas terminals in Europe, due to a combination of lower indigenous production and relatively plentiful LNG supplies.

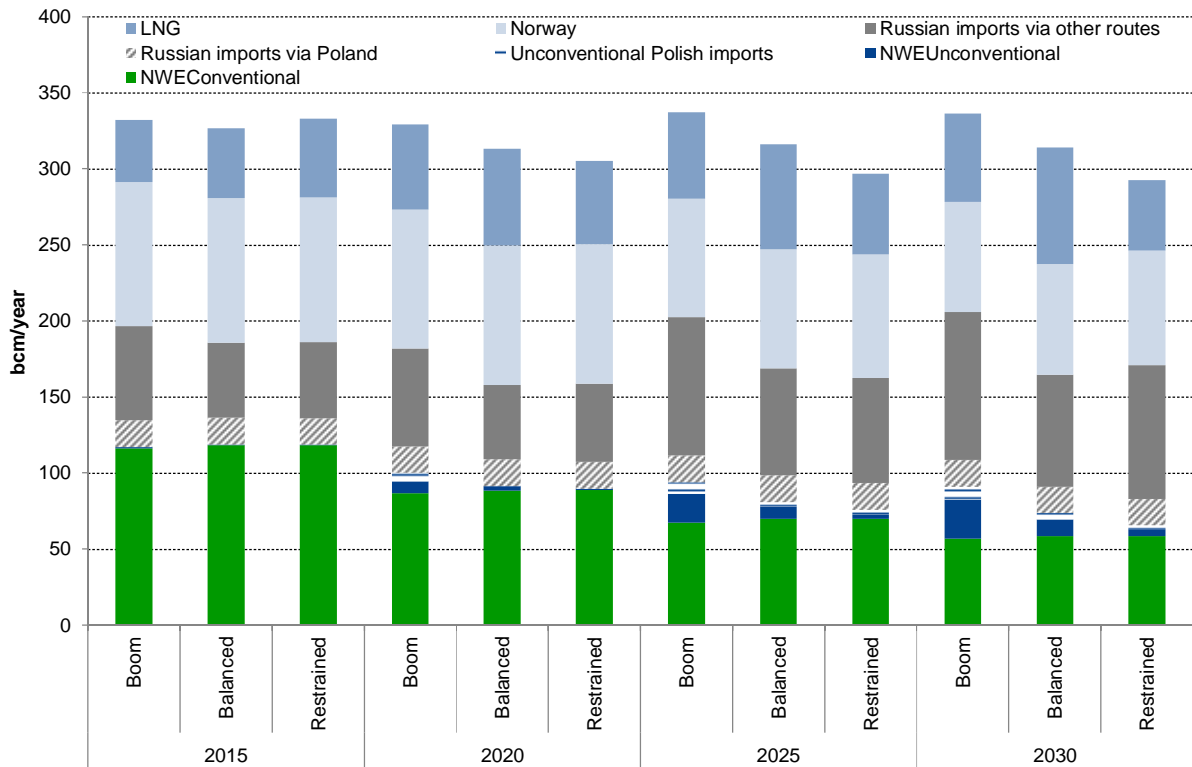
Figure 30 – Total flows in to LNG terminals in NWE



9.1.6 Sources of supply to NW Europe

The flows of gas through the LNG terminals into NWE, shown in the previous section, give an indication of the principal changes within NWE under each scenario. These are illustrated in greater detail in Figure 31, which shows all the main sources of supply to NWE.

Figure 31 – Annual sources of gas supply to NWE



Supplies of Russian gas to NWE transit either: Ukraine, Slovakia and the Czech Republic/Austria; or, Belarus and Poland. It is not possible to project the volumes of Russian gas which will transit Poland on route for Germany versus the volumes of unconventional gas which may be exported from Poland to Germany. We have estimated this figure based on transit contracts from Russia via Poland remaining stable after 2020 and, after this time, allowing unconventional imports to grow.

By 2030, under the Boom Scenario, 10% of NW European gas demand is met from unconventional sources. This percentage is only 5% in the Balanced Scenario and 2% in the Restrained Scenario.

9.2 The scenarios

In this section we examine each scenario in turn looking in a more detail at the some of the assumptions and outputs, as well as some of the more interesting results.

Firstly, we start with a comparison between the projected annual average GB market price for gas and the assumed cost of other key sources of supply under each scenario. These sources of supply are as follows:

- An expensive source of LNG to Europe (e.g. Malaysian LNG);
- A cheap source of LNG to Europe (e.g. Qatar LNG);
- New North Sea gas production;
- Projected GB unconventional gas production;
- Oil-indexed Continental contracts; and
- Central and Eastern unconventional gas production.

The costs of LNG, North Sea production and oil-indexed contracts do not vary between the scenarios, but the cost of unconventional gas production does. It is interesting to compare where the cost of unconventional gas production sits relative to the other sources of gas and how the different unconventional gas production assumptions under each scenario moves the GB gas market onto higher cost marginal gas sources.

In this section we also compare the projected gas price in GB with other key markets under each scenario. These markets were chosen for their specific importance, as follows:

- Poland, where the majority of unconventional gas in Europe is likely to be developed by 2030;
- the US, where progress in unconventional gas production continues to have a large influence on world gas prices; and
- the world LNG spot price, which gives an indication of the tightness of LNG supplies.

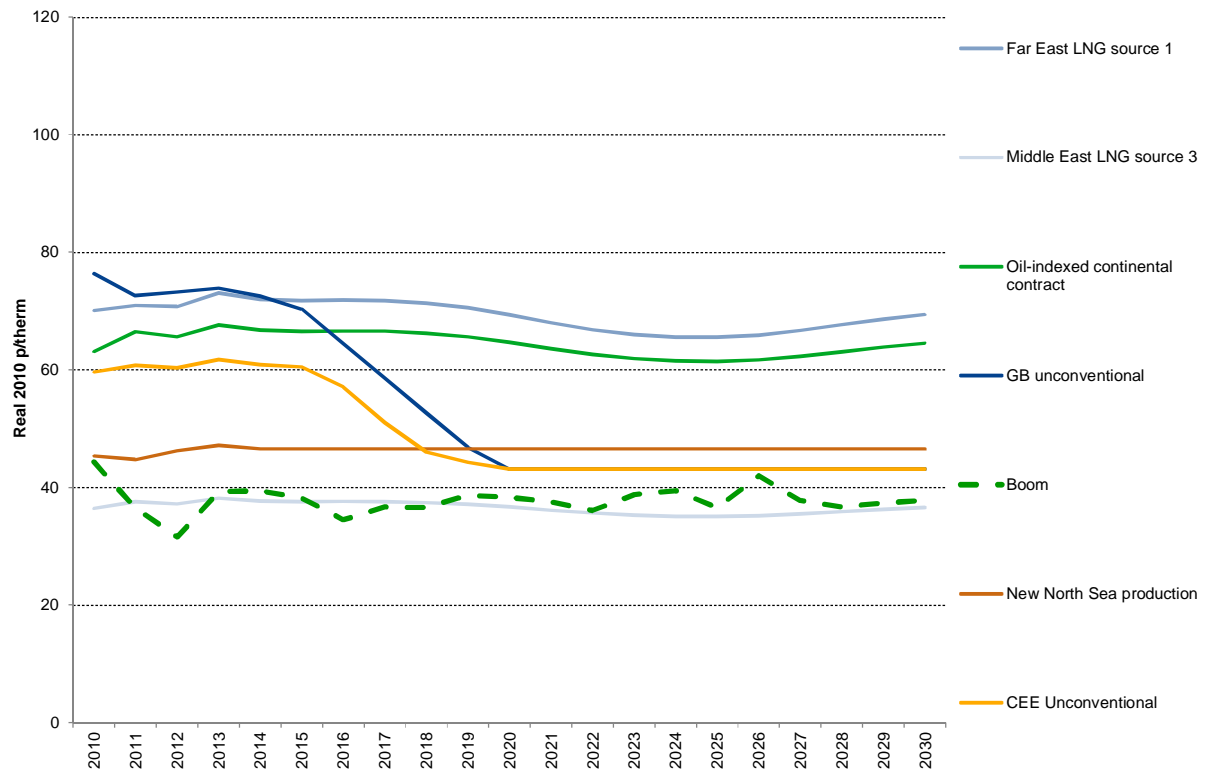
Under each scenario the picture for GB and the rest of Europe changes. For GB the balance between imports from the Continent and LNG supplies shifts; and for the rest of Europe the competition for supplies of LNG with the powerful US market is a key influence.

Under the Boom scenario there are other interesting results regarding capacity constraints within the European gas network. We also try to quantify how much unconventional gas could make its way west to GB from the production projected on the continent.

9.2.1 The Boom Scenario

Under the Boom Scenario, Figure 32 shows that unconventional gas production costs fall below new North Sea gas production costs from around 2020. The overall abundance of LNG supplies allows GB market prices to align themselves broadly with cheaper sources of LNG. In the early years GB prices fall slightly below the cost of Middle Eastern LNG, as prices are occasionally set by cheaper existing indigenous supplies.

Figure 32 – Gas year average NBP price under the Boom Scenario alongside sample source costs



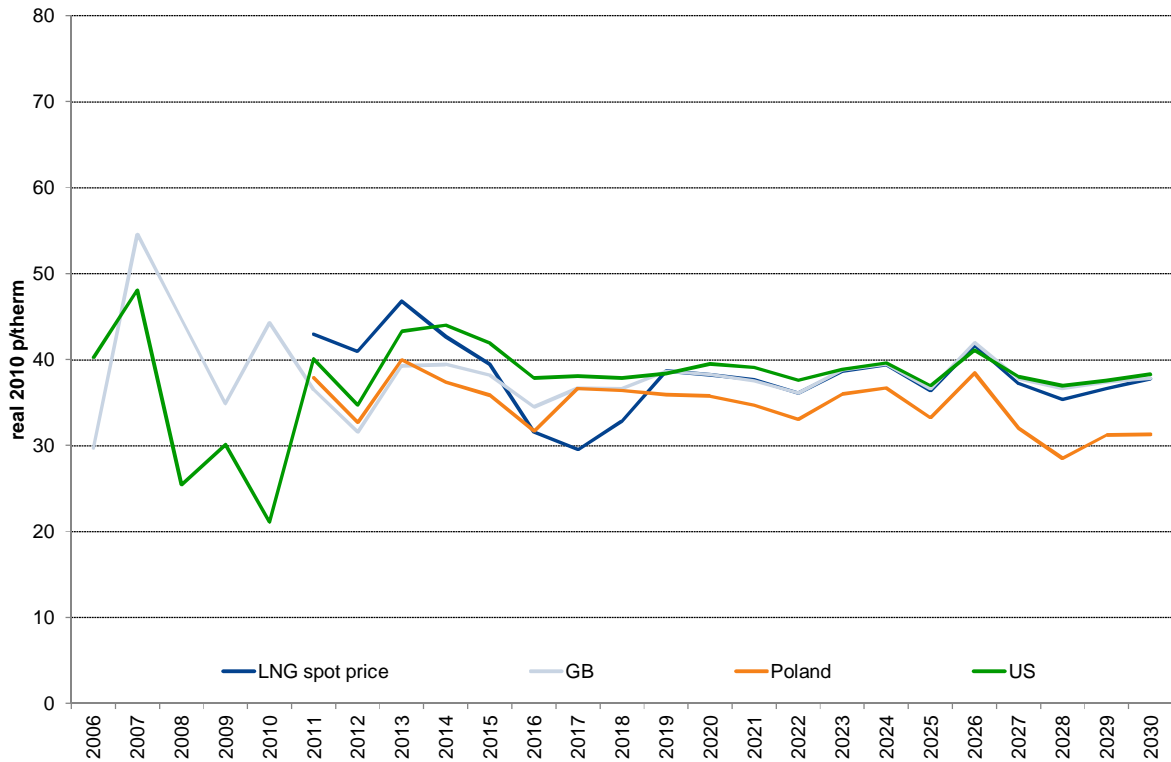
Note: The 2010 gas year price is the weighted average of historic monthly prices and projected prices until Sept 11

Figure 33 shows that under the Boom scenario, Poland has the cheapest wholesale prices in the long term. This is caused by an over-supply situation, brought on by the boom in unconventional gas production and long-term contracted gas from Russia. The price reduction is similar to that currently seen in the US.

The LNG spot price is high for the next few years, due to increased demand from Japan, but in time the abundance of LNG serves to link the other three markets and their prices converge.

US gas prices in the gas year starting in October 2010 have been very low relative to European market prices. In our model, US prices are linked to Europe via LNG shipments and are projected to rise to European levels in the gas year 2011.

Figure 33 – Prices in the Boom Scenario

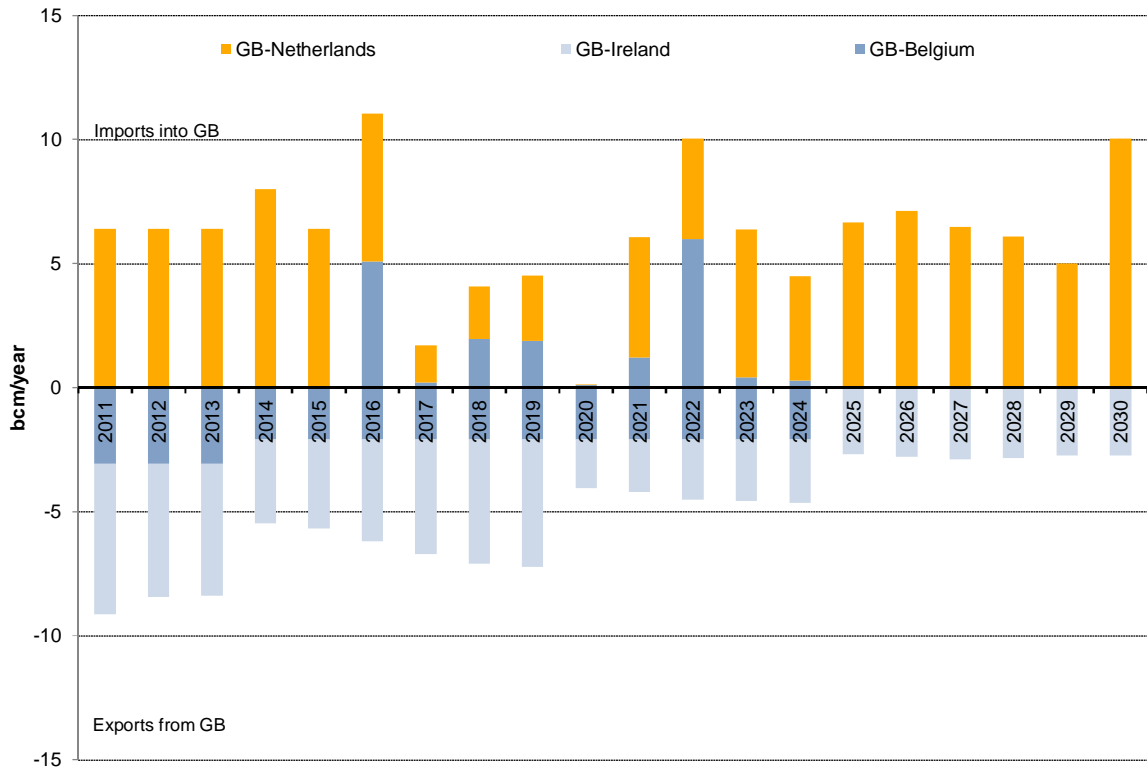


Note: Gas years 2006, 07, 08 and 09 are historical. Source: IEA Energy Prices and Taxes Q1 2011 and Heren

High production of unconventional gas on the Continent, under the Boom scenario, causes excess gas to flow into GB, as shown Figure 34. In particular, comparing the imports to GB via interconnectors from 2017 onwards under the Balanced and Restrained Scenarios (shown in Figure 40 and Figure 43), the Boom scenario makes much greater use of BBL and IUK for imports.

In 2020, there are only exports from GB to the Continent. This is due to Russian supplies reaching a low point at this time as their existing gas fields deplete, before new production takes off. Post 2020, we envisage the development of new gas supplies in Russia, increasing their availability to Europe. Therefore, GB continues to import gas from the Continent in subsequent years.

Figure 34 – Gross interconnector flows with GB in the Boom Scenario

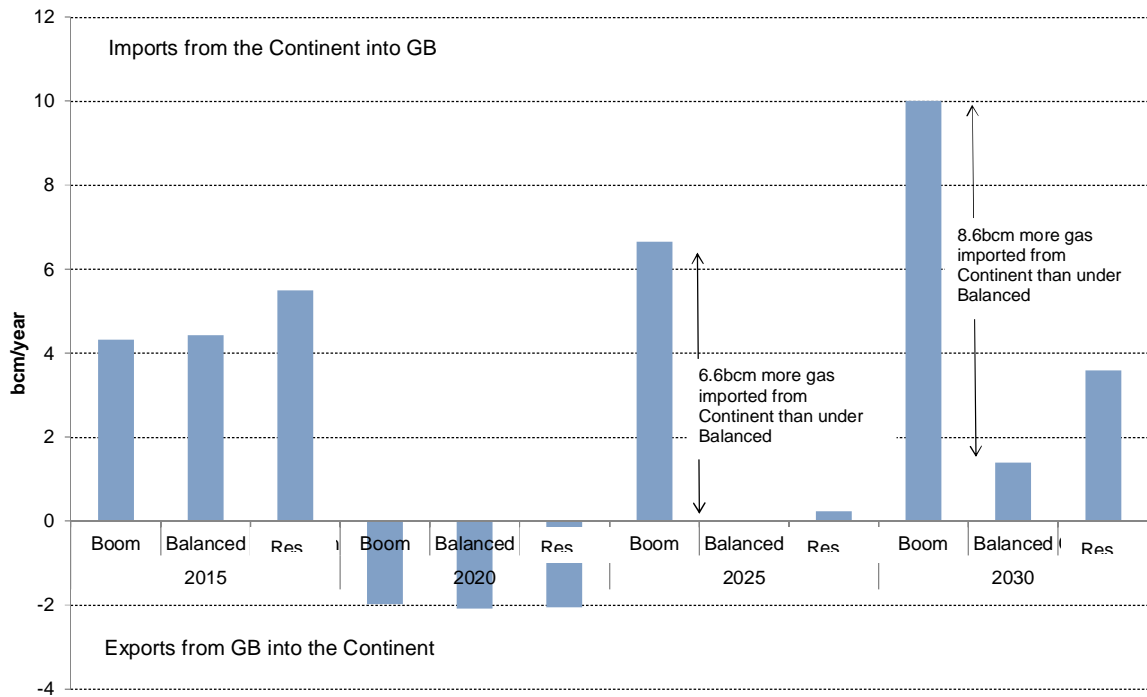


Quantifying in detail the volumes of unconventional gas which could flow from the Continent to GB is not possible because of the well-developed gas network on the Continent and the mixing of different sources of supply. However, it is possible to gain an impression of how much gas is displaced from the Continent and thus exported to GB under the Boom scenario compared with the Balanced Scenario; the key difference between the Boom and the Balanced Scenarios being the growth in unconventional gas production in Europe.

By 2025, net-exports from the Continent to GB are 6.6bcm (see Figure 35), compared to zero in the Balanced Scenario. At this time unconventional gas production on the Continent is 46bcm/year under the Boom Scenario, resulting in an additional 6.6bcm being sent towards GB.

By 2030, net-exports from the Continent to GB are 8.6bcm (see Figure 35) greater than those in the Balanced Scenario. Similarly this is likely to be the impact of significant unconventional gas production, although the actual gas molecules sent to GB could come from a number of different sources.

Figure 35 – Comparing net imports from the Continent under the scenarios



9.2.1.1 Constraints between Poland to Germany under the Boom scenario

Poland is the European country most likely to produce significant quantities of unconventional gas by 2030. Under the Boom Scenario our modelling clearly shows that Poland’s projected gas prices, shown Figure 33, fall below the other key market prices.

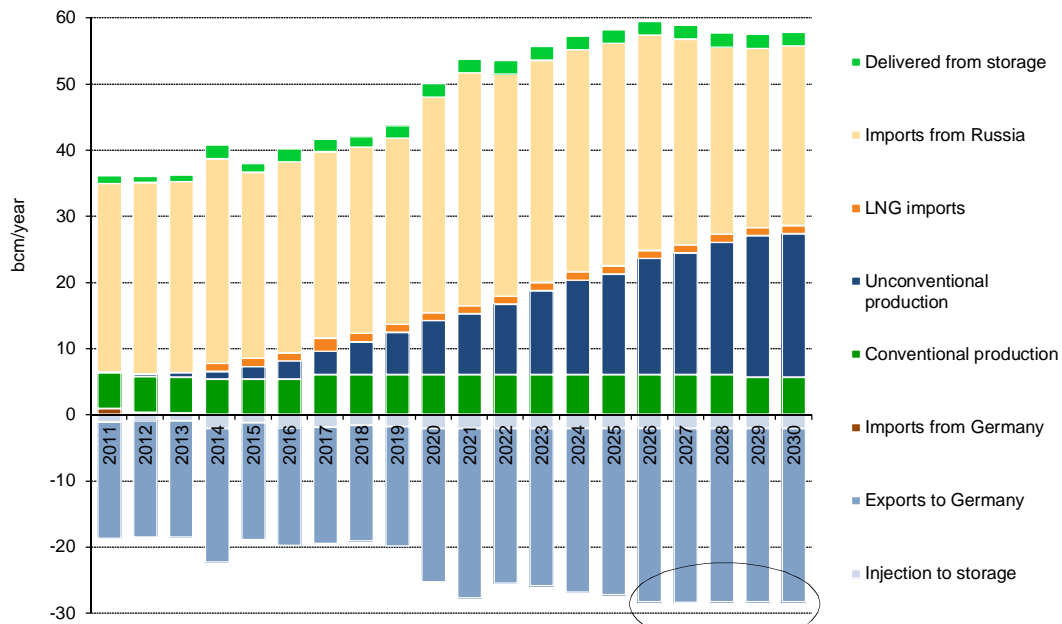
In 2009, 31.5bcm/year of Russian gas was supplied to Germany. Some of this gas will have transited via Ukraine and Slovakia and some will have transited via Belarus and Poland. Our modelling projects 18bcm transiting to Germany via Poland in the gas year 2011.

This figure rises to about 20bcm/year by 2030 in the Balanced and Restrained Scenarios, and to over 26bcm/year in the Boom Scenario, as shown in Figure 37. In fact, under the Boom scenario the interconnector capacity between Poland and Germany reaches capacity by 2026 as the contracted gas from Russia and the boom in unconventional production leaves Poland oversupplied.

In our modelling we have relaxed take-or-pay obligations from 2029 onwards, but in reality a contract renegotiation between Russia and Poland could well take place early in the 2020s if unconventional production begins to take-off.

This constraint between Poland and Germany is the only infrastructure constraint identified in the modelling during this project.

Figure 36 – Annual sources of gas supply to, and exports from, Poland under the Boom Scenario



Exports to Germany reach capacity in 2026

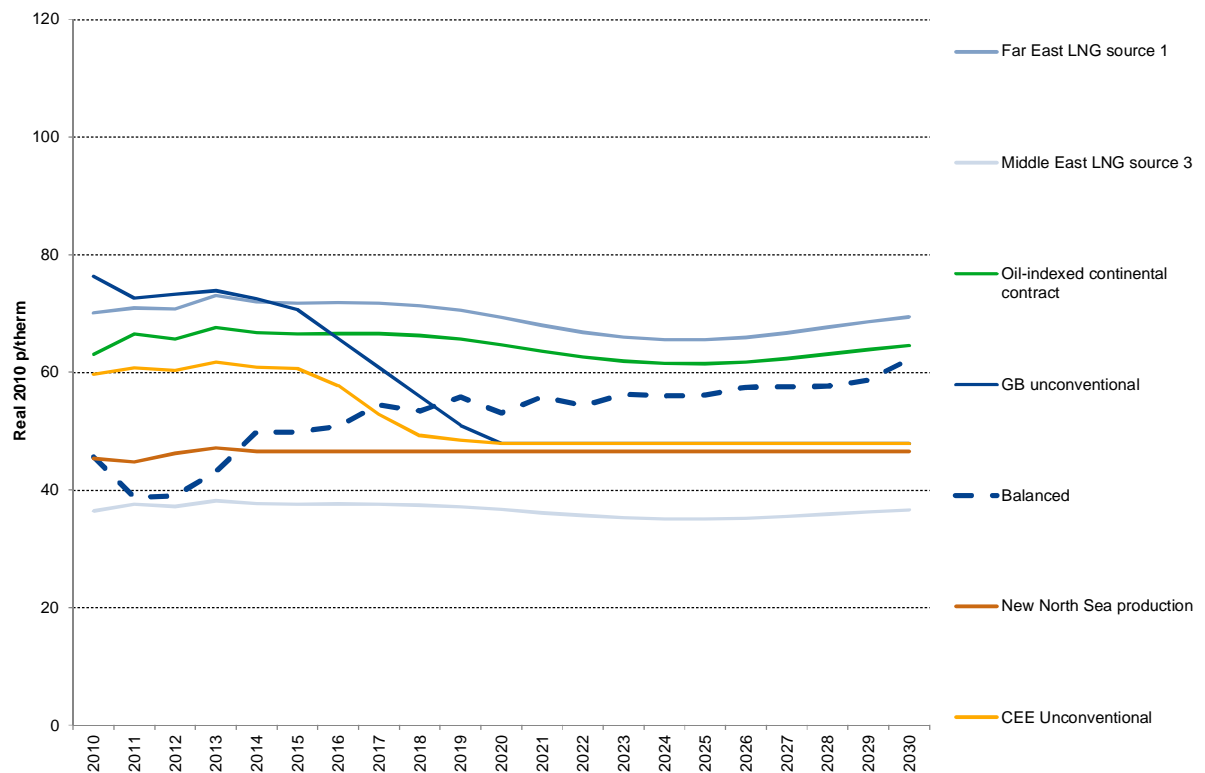
Figure 37 – Gas volumes transiting from Poland to Germany



9.2.2 The Balanced Scenario

Under the Balanced Scenario shown in Figure 38, the GB annual average market price moves from around the cost level of Middle Eastern LNG towards oil-indexed contract prices by 2030¹⁴. In our analysis the price is set on a daily basis by one of the many sources of supply (there are in the region of 100 different sources included in our model). Unconventional gas production costs under the Balanced Scenario move towards new North Sea production costs by 2020, and are below the GB market price, which is set by more expensive imports.

Figure 38 – Gas year average NBP price under the Balanced Scenario alongside sample source costs



Note: The 2010 gas year price is the weighted average of historic monthly prices and projected prices until Sept 11

Figure 39 shows the gas price in various key markets in the Balanced Scenario. They are closer together than in the Boom Scenario and GB’s prices become closely linked to the LNG spot market price due to its increased dependence on LNG imports.

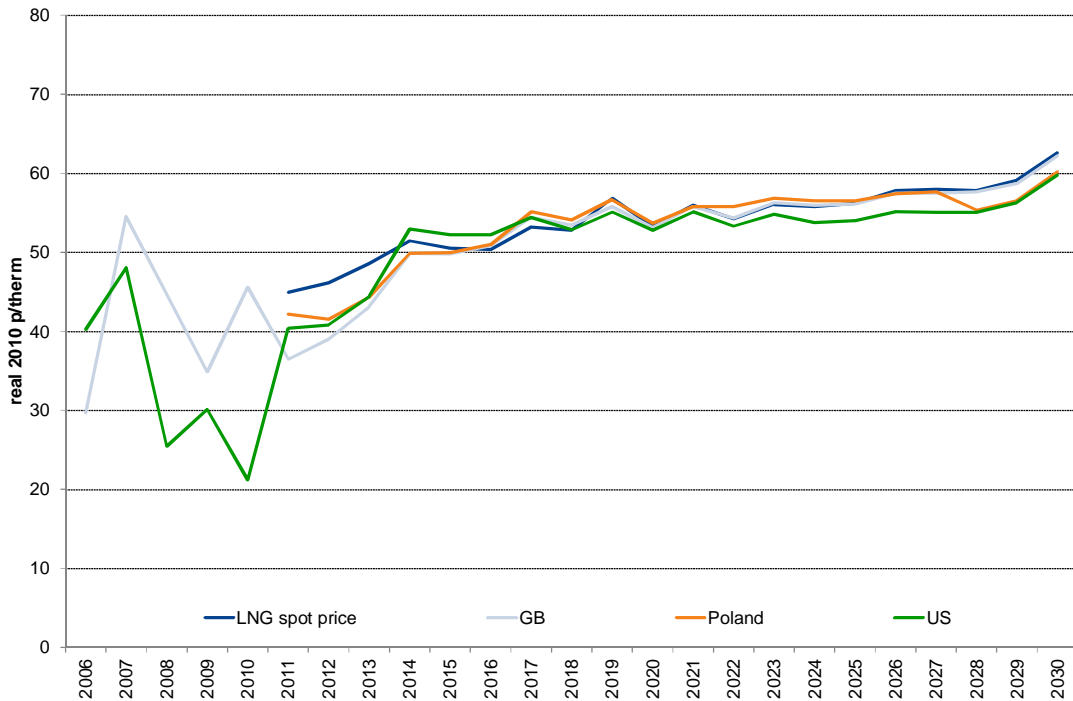
Poland and the US are closely linked to each other at the end of the period due to their reliance on unconventional gas production.

Gas flows between GB and the Continent (shown in Figure 40) become negligible from 2025 onwards. This is due to the large quantities of LNG being imported, and the delivery

¹⁴ The unrest in the Middle East, which started in February 2011, has pushed up European gas prices and the NBP rose at times in Q1 2011 to the level of oil-indexed continental contract prices. Our projections show the impact of these events receding in the 2011 gas year.

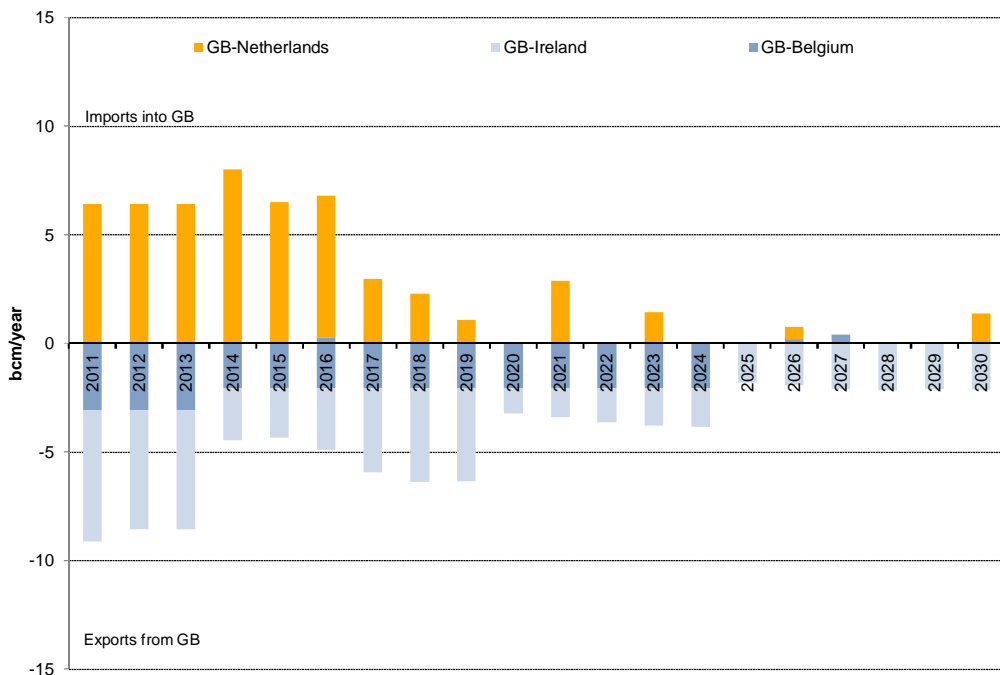
of LNG to appropriately located terminals becoming more efficient than interconnector flows between the regions.

Figure 39 – Prices in the Balanced Scenario



Note: Gas years 2006, 07, 08 and 09 are historical. Source: IEA Energy Prices and Taxes Q1 2011 and Heren

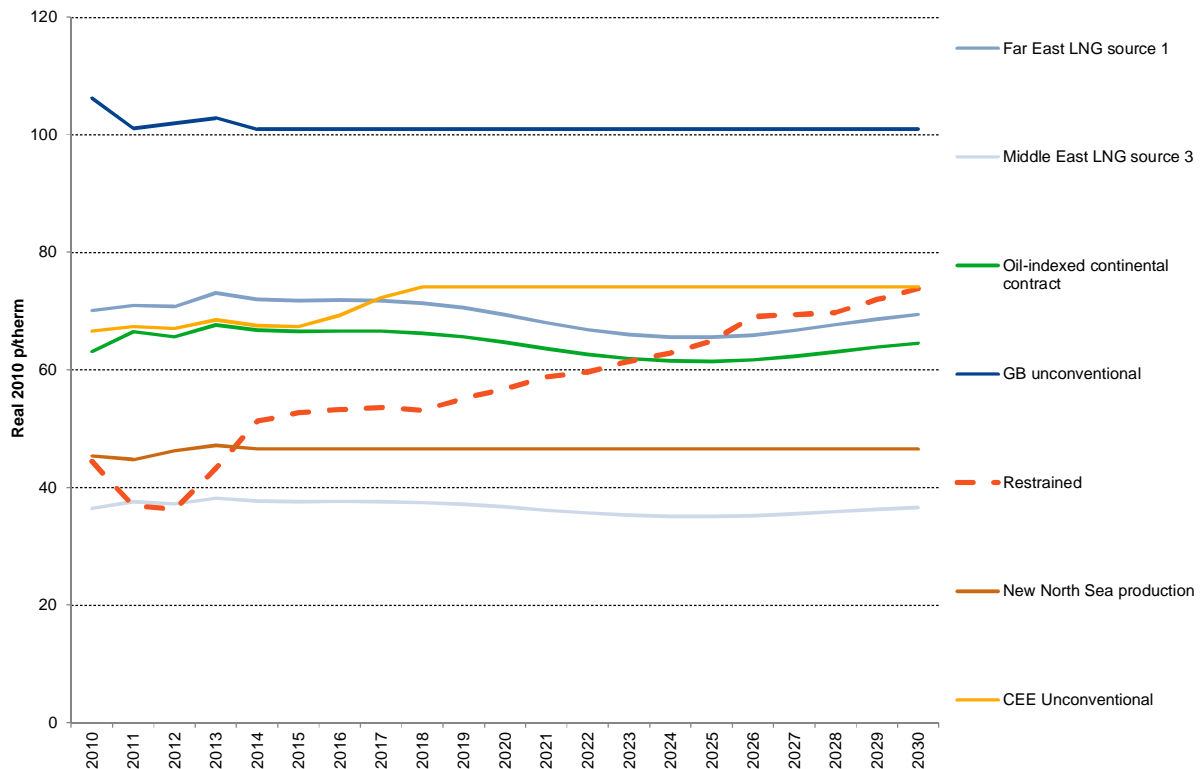
Figure 40 – Gross interconnector flows with GB in the Balanced Scenario



9.2.3 The Restrained Scenario

Under the Restrained Scenario, the cost of producing unconventional gas in GB is very high, see Figure 41. The cost of unconventional gas production in Central and Eastern Europe (CEE) is lower, but still greater than expensive LNG sources. By 2025, GB gas market prices move above oil-indexed contract prices on the Continent and approach CEE unconventional gas costs.

Figure 41 – Gas year average NBP price under the Restrained Scenario alongside sample source costs



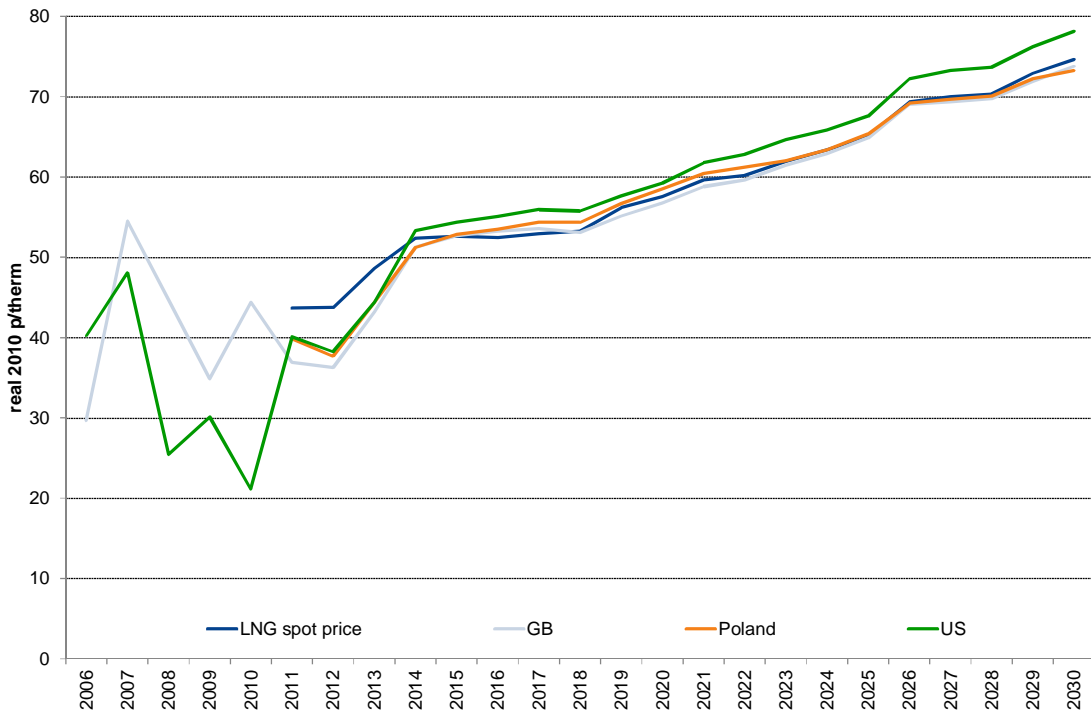
Note: The 2010 gas year price is the weighted average of historic monthly prices and projected prices until Sept 11

Figure 42 shows gas prices in key markets in the Restrained Scenario, under which US market prices become the highest of the zones around 2014, when unconventional gas production stalls. US demand growth, which is based upon the EIA’s own assumptions, is quite high and due to low growth in unconventional gas production, greater reliance on expensive LNG imports helps push prices up.

The other markets are set by the world LNG spot price, which moves up in line with the US, but remains slightly lower.

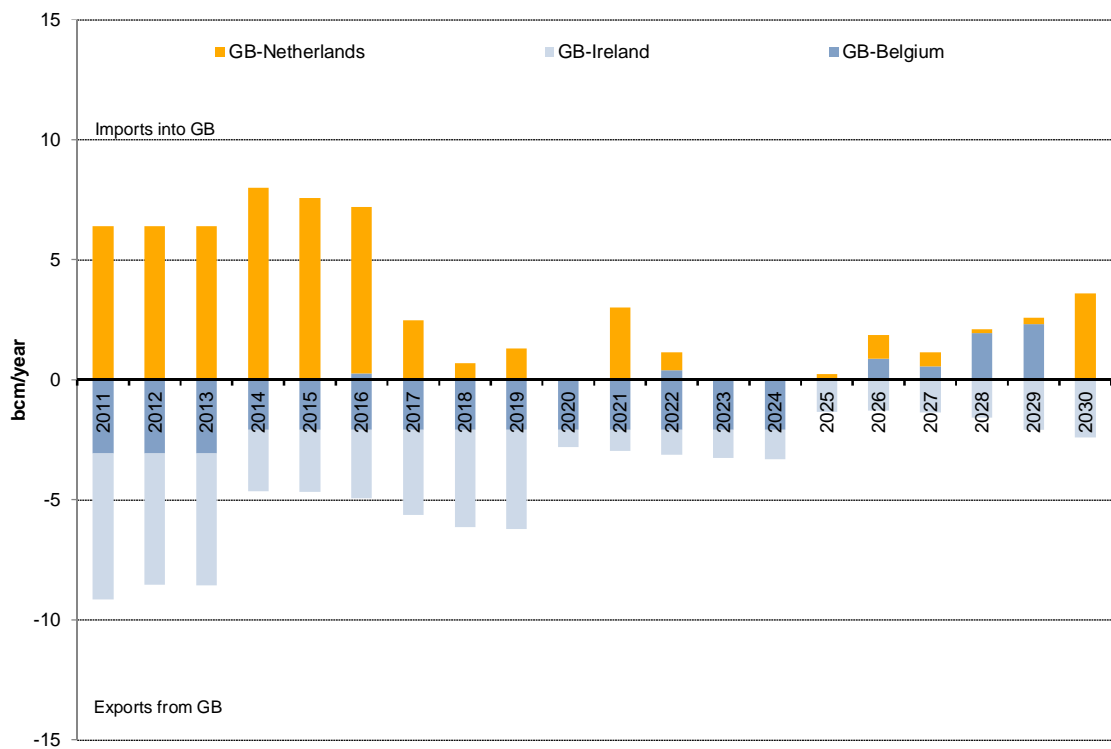
The interconnector flows under the Restrained Scenario (shown in Figure 43) are very similar to those under the Balanced Scenario, except in the later years where LNG availability becomes constrained due to demand for LNG by US market. Imports from the Continent to GB increase from 2026 onwards in this scenario.

Figure 42 – Prices in the Restrained Scenario



Note: Gas years 2006, 07, 08 and 09 are historical. Source: IEA Energy Prices and Taxes Q1 2011 and Heren

Figure 43 – Gross interconnector flows with GB in the Restrained Scenario



10. CONCLUSIONS

Environmental concerns are likely to prove a considerable hindrance to the development of unconventional gas resources in Europe, making our Boom Scenario a low probability outcome. However, large scale, low cost unconventional gas production in Poland would suppress European gas prices for some time; and even moderate development of unconventional gas resources in Europe could keep gas prices in Great Britain lower from 2020 onwards, than if no resources are developed at all.

If the governments of Europe learn their lessons well from the US experience and apply high environmental standards from the outset, backed up with well-resourced and stringent regulation, it is possible unconventional gas development in Europe could progress without significant environmental concerns further stalling exploration and production. In order to achieve the Boom Scenario, however, the geological and technical environment will also have to be favourable to keep costs low.

Water supply and disposal are key barriers which need to be overcome, and Europe could potentially develop low-cost, environmentally acceptable solutions and provide leadership for the rest of the World in best practice.

Given that the magnitude of the unconventional gas reserves in Great Britain is unlikely to match that of the US or Poland, there is limited opportunity for it to play a leading role in Europe's unconventional gas industry. However, with a pragmatic approach that recognises both the economic benefits and the need to avoid environmental problems, there is potential for the growth of sizeable UK businesses, and improved security of gas supplies.

The Polish government and people are generally supportive of shale gas development. There are numerous positives, including economic benefits, security of supply, reduced dependence on Russia, and the pride of taking European leadership of a potentially world-changing industry. There is also the possibility of providing a practical solution to the Polish problem of carbon emissions from the ageing fleet of coal-fired power plant, which is a growing embarrassment to EU carbon policy.

Environmental concerns are noticeably more muted in Poland than elsewhere in Europe, but environmental groups are beginning to make an appearance. The Polish government will have to respond in a pragmatic manner to the environmental concerns if there is to be a future for shale gas development in Europe.

This study shows that unconventional gas production may affect Europe both directly from indigenous production, but also markedly from its indirect effect on global LNG market prices. The Restrained Scenario indicates that any signs of delays to US unconventional gas development, which causes production to drop below that currently projected by the EIA, could push up the prices of gas available to Europe.

While the security of gas supply to GB and wider Europe is improved by any increase in the indigenous gas reserves, reliance on imports is inevitable. A tightening of the world LNG market due to changes in US unconventional production would not only have an impact on average prices, but would also make price spikes in times of supply difficulties more likely.

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GLOSSARY

Cleats

Cleats are natural fractures in seams, resulting from seismic stresses, which may enhance the flow of hydrocarbons through the rock. The direction of cleats may be used to determine the direction of the horizontal section of a well.

Effectiveness

Effectiveness is often quoted in terms of global-warming potential. Methane is 72 times more effective as a greenhouse warming gas than CO₂, over a 25 year time scale.

Global warming potential (GWP)

Global-warming potential (GWP) is a measure of the amount of heat trapped by a gas in relation to the amount of heat trapped by the same mass of CO₂.

Hydraulic fracturing

Hydraulic fracturing, commonly known as 'fracking', refers to the process of injecting fluid into a well under high pressure with the objective of fracturing the surrounding rock, and accelerating the release of hydrocarbons held within the rock

Liquids-rich

Liquids-rich shale is shale which not only contains natural gas also in combination with substantial quantities of hydrocarbons liquids, which are extracted together with the gas

Naturally occurring radioactive material (NORM)

Naturally occurring radioactive material (NORM) are all radioactive elements found in the environment. Long-lived radioactive elements such as uranium, thorium and potassium and any of their decay products, such as radium and radon are examples of NORM. These elements have always been present in the Earth's crust.

Porosity

Porosity is the ratio of the pore volume to the total volume of a material.

Permeability

Permeability is a measure of the ability of a porous rock to allow fluids to pass through it.

Seams

A layer of coal is known as a seam.

Shale play

A shale play is a geographical area containing a geological shale formation that is targeted by exploration and production companies for the commercial exploitation of hydrocarbons.

Sweet-spots

'Sweet spots' in a shale gas play are those areas where the characteristics, such as depth, permeability, total organic content, and thickness of the shale seam, provide the optimal conditions for the commercial extraction of natural gas. The term may also be used to describe regions which contain the more valuable liquids-rich shale.

Underground coal gasification (UCG)

UCG is a specific method of CBM extraction where injection wells are used to supply oxygen to ignite hydrocarbon underground. Through the combustion process, pressure is created within the seam, and gas is extracted to the surface through production wells drilled into the coal-seam at points distant from the combustion process.

Combustion is generally conducted at temperature of 700–900 °C. The process decomposes coal and generates carbon dioxide, hydrogen, carbon monoxide and small quantities of methane and hydrogen sulphide.

Vertical heterogeneity

Vertical heterogeneity is the degree to which shale layers vary in permeability and porosity in the vertical plane of a shale layer.

ANNEX A – BERMAN’S ANALYSIS

Berman’s study of company reports provided implied production costs shown in Figure 44.

Figure 44 – Selected Company 5-Year Production Costs

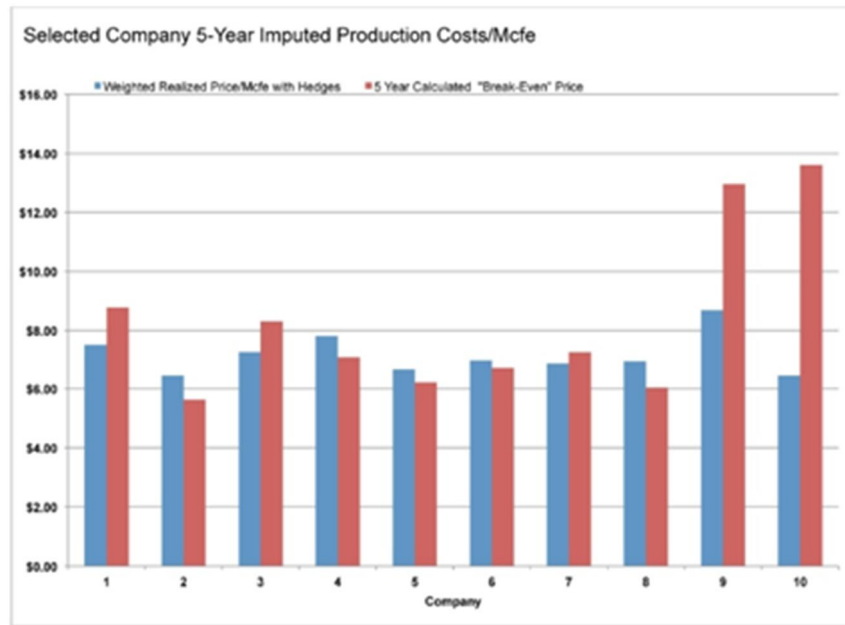
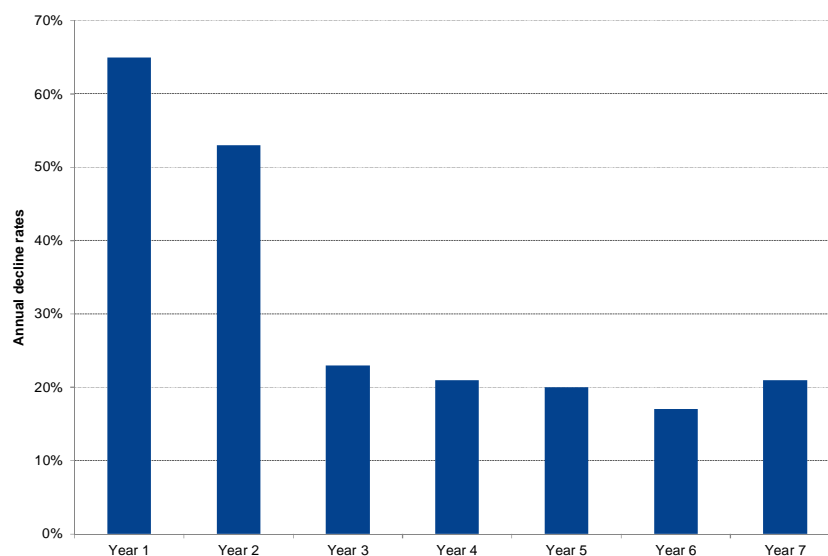


Figure 5. Selected shale company 5-year production costs and realized prices.
Source: Company files.

Source: Berman

Berman undertook an analysis of the decline rates of the first 11,500 wells drilled in the Barnett shale plays and this is shown in Figure 45.

Figure 45 – Average annual decline rates



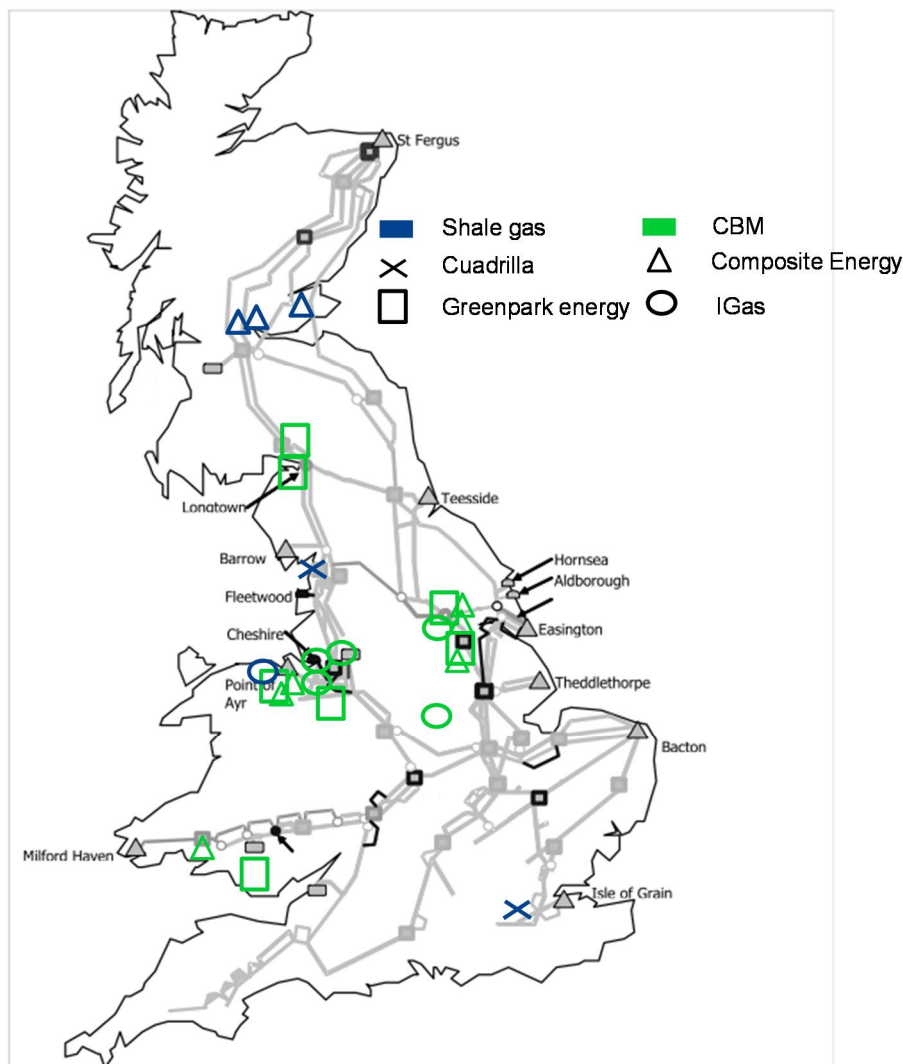
Source: Berman

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ANNEX B – COMPANIES OPERATING IN GB

There are four companies developing, or considering the development of, unconventional gas reserves in Great Britain. Most of these developments were for CBM but they now also include some shale gas deposits. The locations of the sites are shown in Figure 46. There are two main clusters of CBM developments in North Wales and Yorkshire, and a few other sites around the country. Nearly all are in regions close to the existing National Transmission System, so the connection of unconventional gas to the NTS should be straightforward, although arrangements for new entry capacity and gas quality could be an issue.

Figure 46 – Unconventional gas developments in GB



Source: Company websites, National Grid

B.1 Cuadrilla Resources

In November 2009 Cuadrilla received a planning permission for an exploratory drill site at Preese Hall Farm, Preston Lancashire from Fylde Borough Council. Cuadrilla is targeting natural gas 2,750m below the surface in the Bowland Shale which runs from Pendle Hill near Preston to the Irish Sea.

Cuadrilla completed its first well on 8 December 2010, followed by a pre-frac well test, also completed during December. Cuadrilla says its tests show that the shale seems to be much thicker than predicted by the Royal Geological Society. As a result, Preese Hall was drilled deeper than originally planned in order to encounter all of the prospective shale sections.

The Cuadrilla drilling rig was relocated to Grange Hill, approximately 15km to the South, for commencement of the second well in January 2011.

Cuadrilla Resources commenced hydraulic fracturing operations at Preese Hall in late March 2011, and the operation was expected to last 30-60 days, followed by production testing. Unfortunately, following the occurrence of a minor earthquake very close to the site, early in the morning of 1 April 2011, the company suspended its operations while investigations were made into what caused the earthquake, which measured 2.2 on the Richter scale. The epicentre was identified as between Carleton and Poulton Industrial Estate, just two miles from Preese Hall and the British Geological Survey (BGS) immediately launched an investigation. A spokesman for Cuadrilla said that no fracking operations were taking place at the time of the earthquake.

A third exploratory well in the Bowland Shale was drilled at Anna's Road under a planning permit approved on 17 November 2010.

According to Cuadrilla, results thus far have exceeded expectations, and warrant completion of the full work programme originally envisaged. Mark Miller, CEO of Cuadrilla Resources is reported to have said that they were attempting to determine if it was economically viable to proceed. Cuadrilla stated separately that they believe the Bowland Shales of Lancashire could potentially provide up to 10% of the UK's gas supply.

In addition to resources in the UK, Cuadrilla possesses resources in Holland, Poland, Hungary and Czech Republic and has a total resource of approximately 0.9 million hectares. Drilling is due to commence in Holland in 2011 following completion of Grange Hill and fracturing in Hungary is also scheduled for early 2011.

B.2 Composite Energy

Composite Energy, founded in 2004, is actively pursuing unconventional gas developments, both CBM and shale gas and, potentially, conventional oil and gas in Europe. The company holds 15 UK onshore CBM licenses, and 3 CBM licences in Poland, and is targeting additional licenses in Belgium and Germany.

In February 2011, Australian CBM developer Dart Energy Limited announced that it had agreed to acquire the 90% of Composite Energy Limited that it does not already own for approximately US\$46.7 million. At the same time, Dart took the opportunity to announce its intention to accelerate the commercialisation of the PEDL133 CBM licence in Scotland. The new owner intends to re-brand composite as Dart Energy Europe.

Composite Energy holds licences for the sedimentary basins in the Scottish Midland Valley, the East Midlands Coalfield, the Cheshire Basin and South Wales. Composite Energy has already produced gas from its Scottish Midland Valley basin.

B.3 Greenpark Energy

Greenpark Energy plans to develop its UK CBM licenses on an accelerated basis, with initial CBM production as early as the second half of 2012. The company's CBM licenses are located in mainly rural locations, thus facilitating the obtaining of requisite planning permission for its proposed production operations. Most of its licenses are also located near existing gas pipelines with unused capacity.

The company has aggressively pursued its UK test and appraisal drilling operations since 2007, having to date completed six vertical test wells and two horizontal pilot production wells which have been flow tested and which have demonstrated commercial flow rates.

B.4 Island Gas Limited (IGas)

IGas was set up to produce and market domestically sourced gas, primarily from unconventional reservoirs, particularly CBM. IGas is now producing gas from its pilot production site at Doe Green at a rate of around 1,700m³ per day in Warrington and selling electricity through its on-site generation, a UK first for CBM. Initial production rates indicate that the company should exceed its threshold for commerciality.

IGas has ownership interests of between 20% and 100% in eleven Petroleum Exploration and Development Licences in the UK, wholly owns two methane drainage licences and has a 75% interest in three offshore blocks under one Seaward Petroleum Production Licence. These licenses cover a gross area of approximately 1,756km². In a study compiled by Equipoise Solutions Ltd, an independent oil and gas appraisal group, the mid case estimate of Gas Initially In Place (GIIP) is around 100bcm, excluding any shale potential.

In a separate study, also compiled by Equipoise Solutions, the shale gas potential of the Holywell shale within certain interests held by Island Gas Limited (IGas), across the North West of England and North Wales, was estimated at about 56bcm.

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ANNEX C – PEAK CAPACITY VERSUS PEAK DEMAND

It is not possible to indicate the proportion of imports available from the Continent to GB which are from unconventional sources.

It is worth noting the peak demand level under each scenario, as these are different and influence the supply margin.

C.1 Peak capacity versus peak demand under the Boom Scenario

Figure 47 – Peak capacity versus demand in GB under Boom Scenario

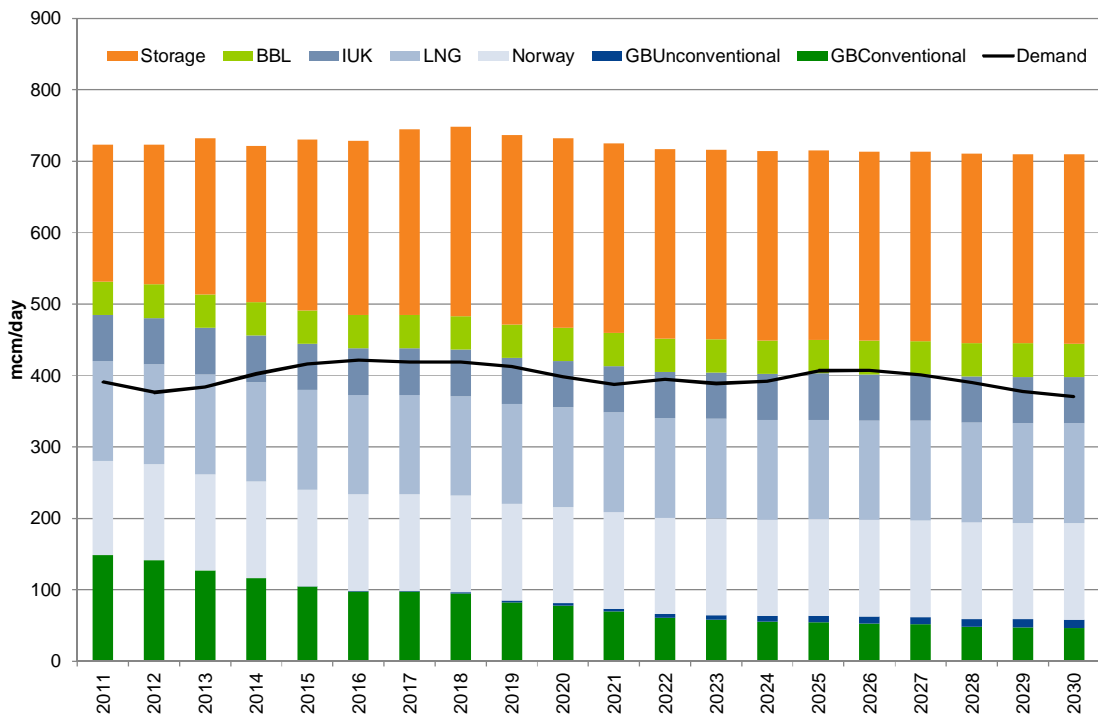
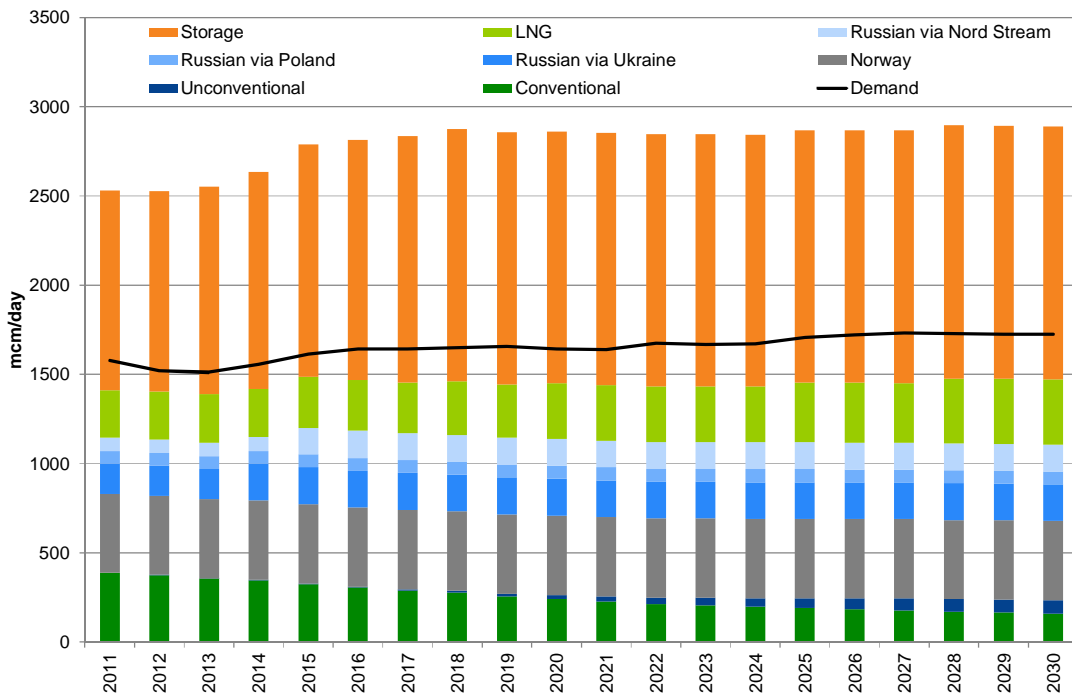


Figure 48 – Peak capacity versus demand in NWE under Boom Scenario



C.2 Peak capacity versus peak demand under the Balanced Scenario

Figure 49 – Peak capacity versus demand in GB under Balanced Scenario

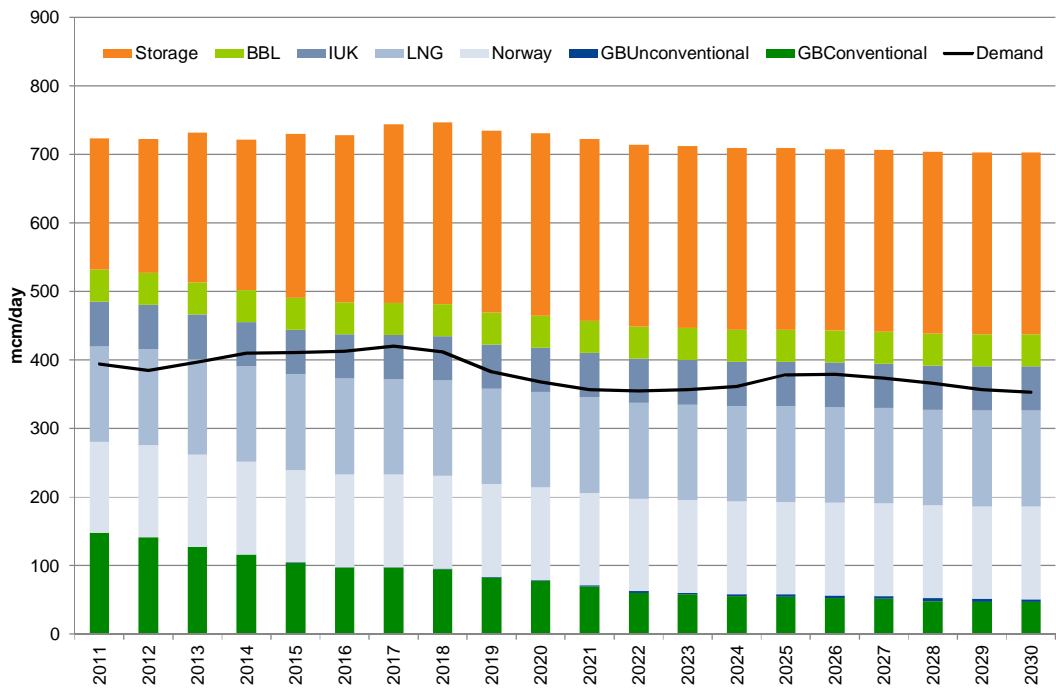
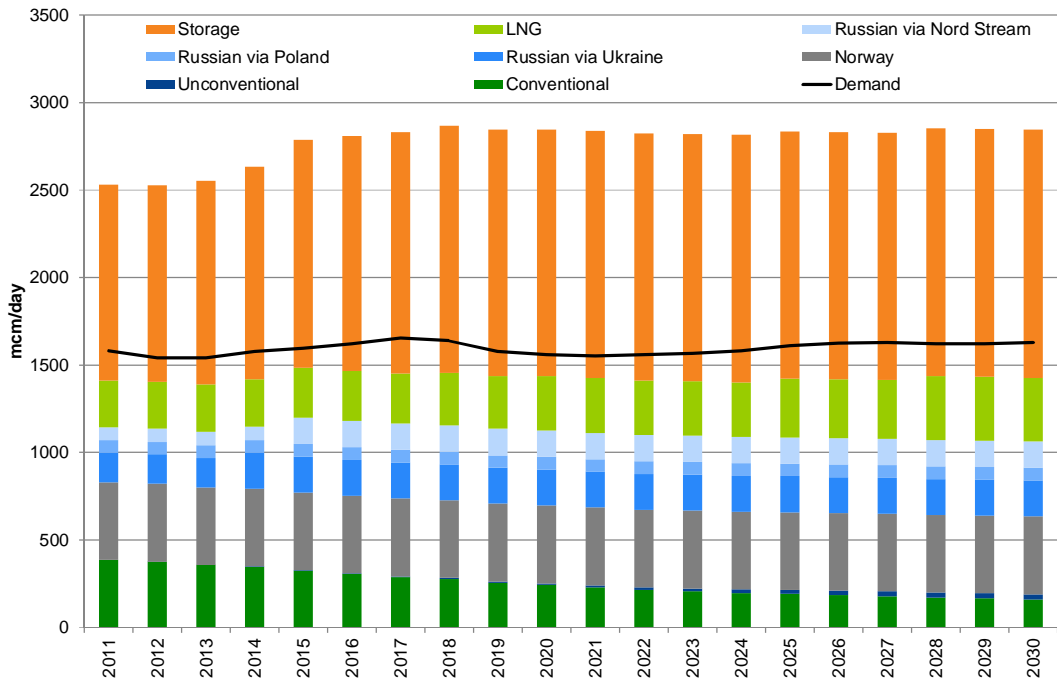


Figure 50 – Peak capacity versus demand in NWE under Balanced Scenario



C.3 Peak capacity versus peak demand under the Restrained Scenario

Figure 51 – Peak capacity versus demand in GB under Restrained Scenario

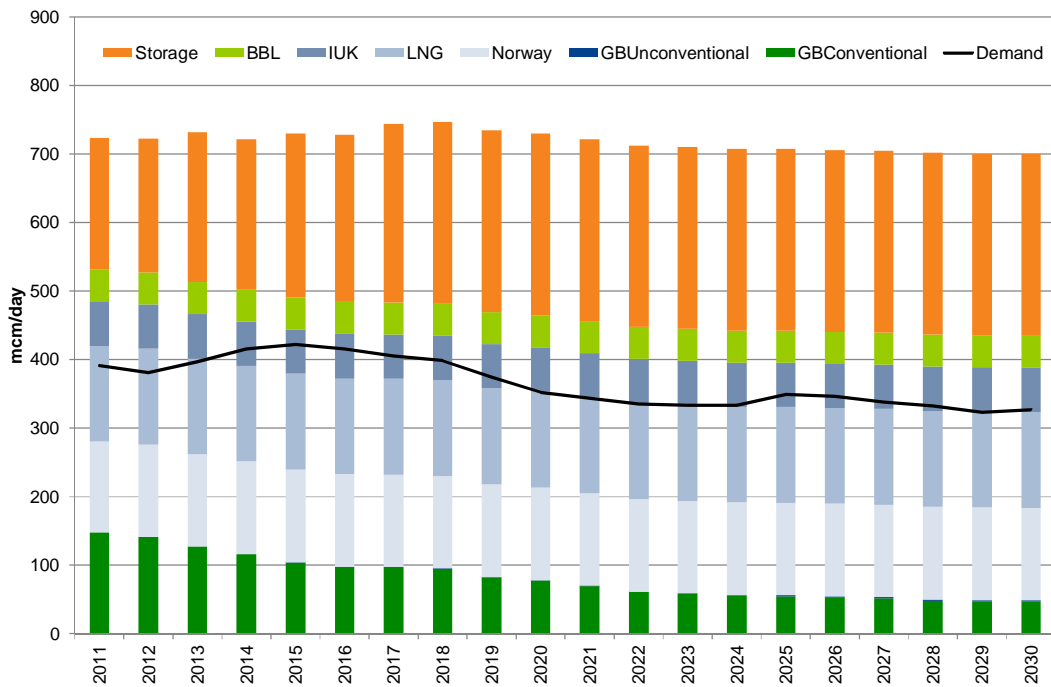
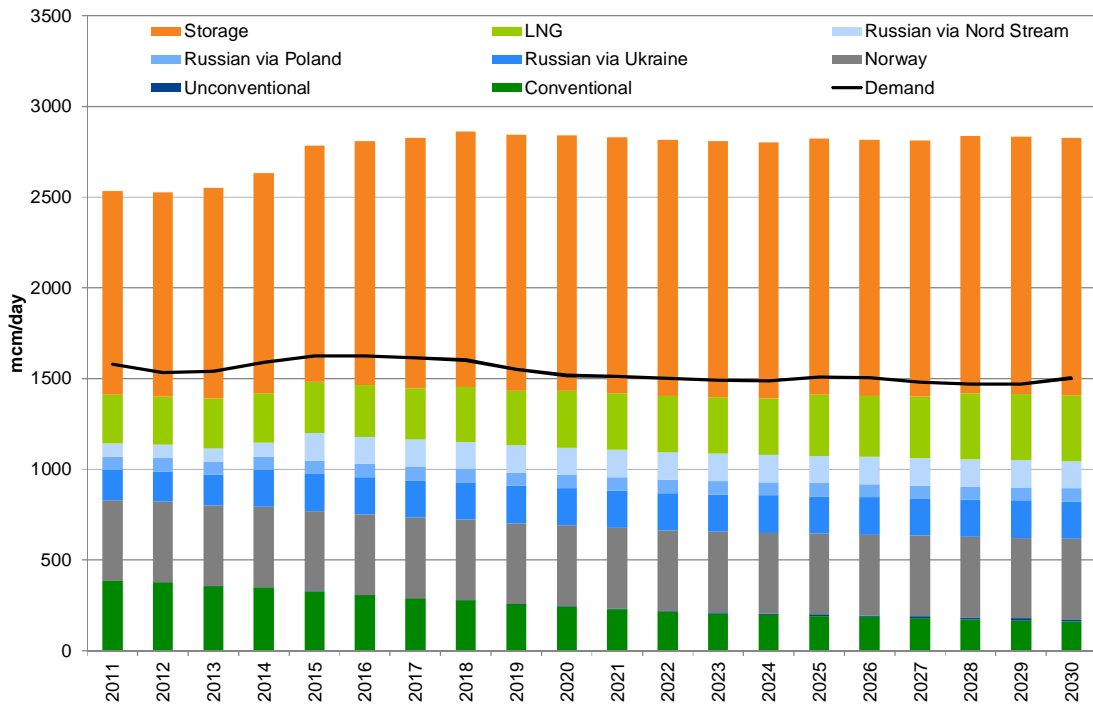


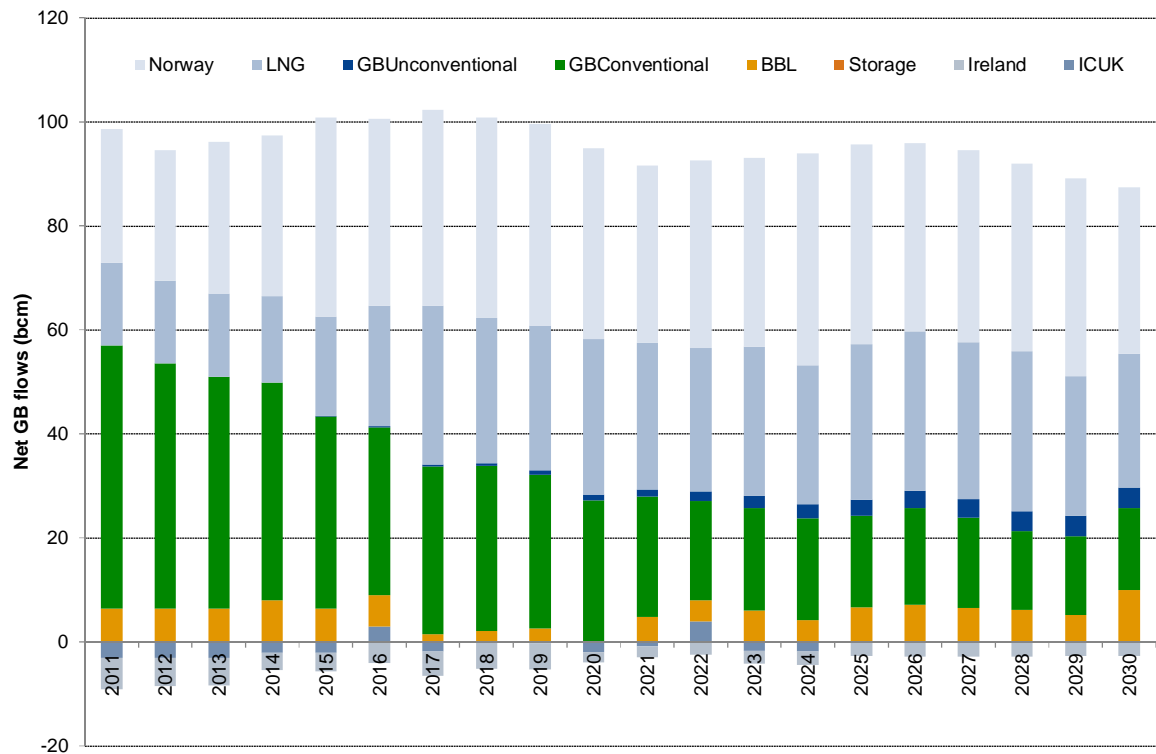
Figure 52 – Peak capacity versus demand in NWE under Restrained Scenario



ANNEX D – ANNUAL SOURCES OF SUPPLY TO GB

Figure 53 shows that, even under the Boom Scenario, GB is only supplied with 4bcm by 2030, whilst imports from the Continent and LNG reach a maximum of 7bcm and 30bcm respectively.

Figure 53 – Annual sources of gas supply to, and exports from, GB under the Boom Scenario

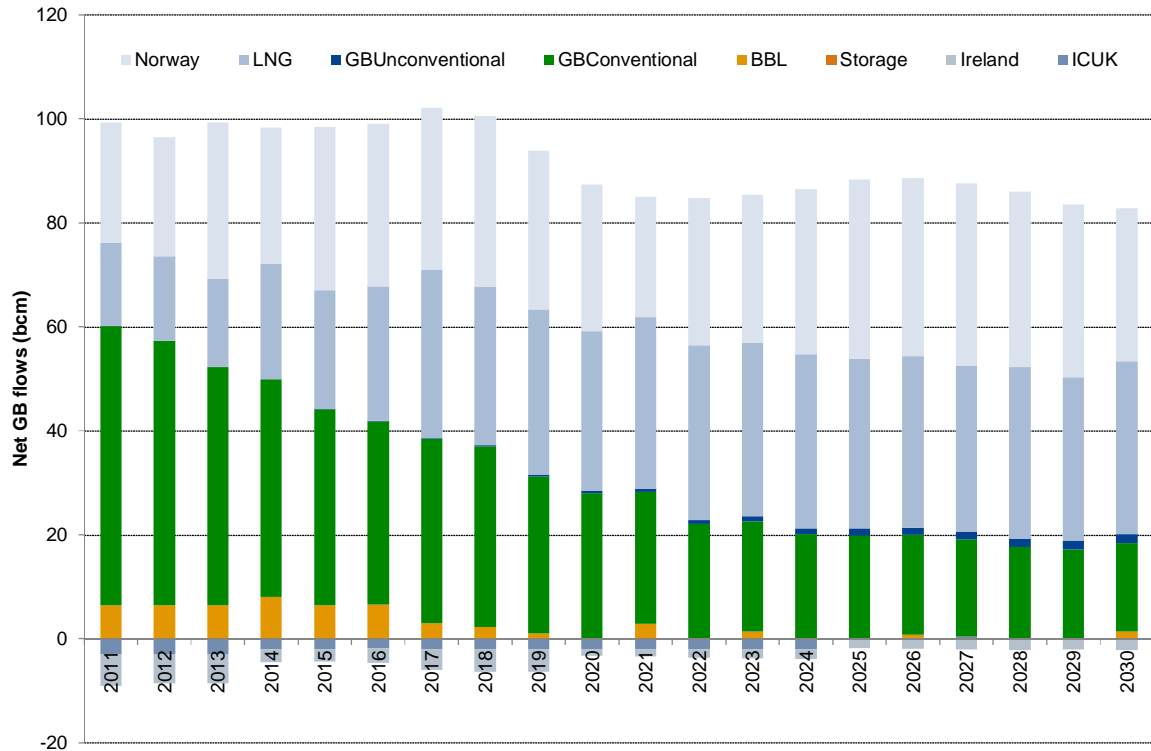


Note: Negative net flows denote net exports

In Figure 54, where we have lower volumes of unconventional gas, it can be seen that imports through the BBL pipeline fall off post-2020 when compared to Figure 53. This is due to lower levels of demand from power generation under the Balanced Scenario, which has similar levels of LNG and Continental imports on an annual basis.

Comparing Figure 53 and Figure 54, also shows increased flows from Norway in the Boom Scenario. This is due to unconventional gas production in Continental Europe pushing Norwegian gas out, which is then diverted to GB.

Figure 54 – Annual sources of gas supply to, and exports from, GB under the Balanced Scenario

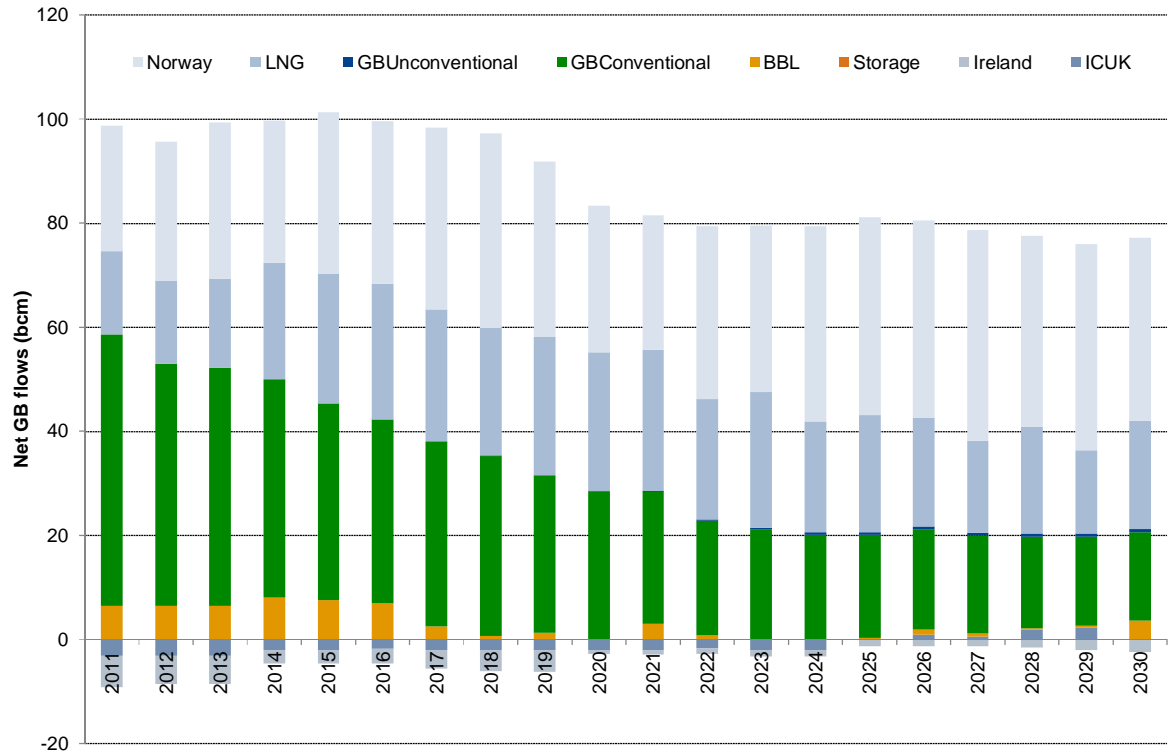


Note: Negative net flows denote net exports

Figure 55 shows flows to and from GB under the Restrained Scenario. Here, the indirect influence of unconventional gas can be seen most clearly. The lower amounts of unconventional gas, especially in the US, means that less relatively cheap LNG is available. Therefore, GB imports more gas from the Continent and Norway, especially in the long term.

However, through iterations with our electricity model, the higher gas prices under the Restrained Scenario mean that overall gas demand in GB is lower, reducing GB's requirement for imports.

Figure 55 – Annual sources of gas supply to, and exports from, GB under the Restrained Scenario



Note: Negative net flows denote net exports

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