Shale gas: an updated assessment of environmental and climate change impacts

Tyndall°Centre
for Climate Change Research

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Report commissioned by The co-operative

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November 2011

This report was commissioned by The Co-operative. It is non-peer-reviewed and all views contained within are attributable to the authors and do not necessarily reflect those of researchers within the wider Tyndall Centre.

Please cite this report as: Broderick. J., et al: 2011, *Shale gas: an updated assessment of environmental and climate change impacts.* A report commissioned by The Co-operative and undertaken by researchers at the Tyndall Centre, University of Manchester

CONTENTS

Tables

Executive Summary

This report, commissioned by The Co-operative, is an update on our January report, *Shale gas: a provisional assessment of climate change and environmental impacts* (Wood et al 2011). Whilst some of the analysis remains relatively unchanged from the original document, other areas having undergone important revision, not least because industry estimates of shale gas reserves at the UK and global scales have markedly increased. For example in the UK industry reserve estimates published for a single licensing area are an order of magnitude greater than national estimates published by DECC in December 2010. New papers detailing fugitive emissions have also emerged raising concerns that shale gas production may involve greater greenhouse gas emissions than previously thought.

The analysis within this new report addresses two specific issues associated with the extraction and combustion of shale gas. Firstly, it explores the environmental risks and climate change implications arising from shale gas extraction. Secondly, it outlines potential UK and global greenhouse gas (GHG) emissions arising from an updated range of scenarios built using the latest predictions of shale gas resources.

Since our earlier analysis, a range of reports and journal articles on shale gas have been published, giving the impression of a substantial increase in meaningful data alongside a more developed understanding of the issues. However, whilst the knowledge base has certainly improved, closer scrutiny of the 'new' information reveals that much of it builds on similar and very provisional data sources, and accordingly represents only a small improvement in the robustness of earlier analyses. Consequently, and despite there now being a much wider literature on shale gas, the earlier report's cautionary note, "that a key issue in assessing… shale gas ... has been a paucity of reliable data", still holds.

To date the only significant development and exploitation of shale gas has been in the United States (US). However, even there significant environmental issues remain unresolved, and reserve estimates show little sign of stabilising (increasing seven times in the last four years). Inevitably therefore, assessments of the environmental impacts, reserve potential and subsequently the greenhouse gas emissions for the European Union (EU) and the UK's fledging shale gas sector, remain subject to significant levels of uncertainty. In view of continued ambiguity as to the robustness of quantitative data, considerable effort has been made to ensure the veracity of the information in this report. Ultimately however, the analyses can only be as accurate as the information and the assumptions upon which it draws.

Despite these uncertainties, several clear conclusions arise and can be used to inform decisions on the appropriateness or otherwise of developing a shale gas industry within the UK. It is evident that shale gas extraction does not require the high energy and water inputs at the scale of other unconventional fuels, such as oil derived from tar sands. Nevertheless, there are several routes by which shale gas extraction may pose potentially significant risks to the environment. Concerns remain about the adequacy of current UK regulation of groundwater and surface water contamination and the assessment of environmental impact. Although amenable to stringent regulatory control, risks of contamination cannot be fully eliminated.

Consequently, if shale gas is to make a significant contribution to the UK's energy mix, a rigorous monitoring regime is essential to contain the risks of contamination, from thousands of wells, within 'acceptable' levels. Similarly, fugitive emissions arising from the hydraulic fracturing process and emitted around the wellhead could be significant and increase the footprint of shale gas substantially, although with effective capture and process technologies, emissions levels not dissimilar from those associated with natural gas extraction appear possible in principle. If fugitive emissions are to be kept to 'acceptable' levels and not significantly skew the balance between upstream and point of use emissions, it is again paramount that appropriate regulatory, monitoring and enforcement regimes are developed and in place prior to full scale extraction.

Turning to the climate change implications of shale gas extraction and combustion, the report demonstrates that in an energy-hungry world (e.g. EIA energy demand projections 2011)[1] and in the absence of a stringent global emissions cap, large-scale extraction of shale gas cannot be reconciled with the climate change commitments enshrined in the Copenhagen Accord (2009). This is principally an issue of the very short time frames remaining in which to reduce emissions to levels, "consistent with the science", and which would "hold the increase in global temperature below 2 degrees Celsius". Given the Accord also stipulates mitigation efforts need to be on the "basis of equity", the constraints of the Accord are germane particularly to the industrialised (Annex 1) nations. Shale gas subject to best practice extraction and subsequently combusted in high efficiency combined cycle gas turbine (CCGT) powerstations will deliver power at lower emissions per unit of electricity generated than is possible from coal fired generation. However, even if there were to be a rapid transition from coal to shale gas electricity, this could still not be reconciled with the UK's 2°C commitments under either the international Copenhagen Accord or its own national Low Carbon Transition Plan. If instead, conservative rates of recovering shale gas from the latest estimate of global reserves were achieved and only half subsequently combusted by 2050, shale gas could occupy *over a quarter* of the remaining CO_2 emissions budget associated with a reasonable chance of avoiding 2°C of warming. Atmospheric carbon dioxide levels would be expected to rise by between 5 and 16 parts per million by volume (ppmv), with a mid-range of 11ppmv.

Whether shale gas substitutes for higher carbon energy supply or meets new energy demand in the UK, it risks doing so at the expense of investment in much lower carbon supply. Energy companies, investment markets and broader UK institutions are all familiar with fossil fuels, and any short-term financial benefit that may accrue to shale gas heating and electricity risks reinforcing lock-in to established supply routes. This has two further implications. Firstly, it reduces the drive for innovation and the scope for 'learning by doing', with the UK subsequently less well equipped to compete in renewable and low-carbon markets elsewhere. Secondly, any investments in shale gas infrastructure over the coming decade would rapidly become a stranded economic asset if the UK were to respect its 2°C commitments. Alternatively, government may be persuaded to withdraw from national and international obligations, and instead sanction continued use of existing high capital value, and high carbon, shale gas infrastructure. This report illustrates how a £32bn

[1] EIA Annual Energy Outlook 2011, http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf

capital investment in shale gas could potentially displace up to 12GW of offshore or 21GW of onshore wind capacity and raise the prospect of the UK not meeting its renewable energy obligations.

To summarise: Irrespective of whether UK shale gas substitutes for coal, renewables or imported gas, the industry's latest reserve estimates for just one licence area could account for up to 15% of the UK's emissions budget through to 2050. Therefore, emissions from a fully developed UK shale gas industry would likely be very substantial in their own right. If the UK Government is to respect its obligations under both the Copenhagen Accord and Low Carbon Transition Plan, shale gas offers no meaningful potential as even a transition fuel. Moreover, any significant and early development of the industry is likely to prove either economically unwise or risk jeopardising the UK's international reputation on climate change. Against such a quantifiable and stark evaluation, it is difficult to conclude other than the UK needs to invest in very low carbon energy supply if it is to both abide by its international obligations *and* support economically sustainable technologies.

Key conclusions and discussion: Climate Change

There is little to suggest that shale gas will play a key role as a transition fuel in the move to a low carbon economy. With effective capture of fugitive methane from flowback, greenhouse gas emissions from shale gas are likely to be only marginally higher than those from conventional gas sources per unit energy. At the global level, against a backdrop of energy growth matching, if not outstripping, that of global GDP and where there is currently no carbon constraint, the exploitation of shale gas will most likely lead to increased energy use and increased emissions resulting in an even greater chance of dangerous climate change. While for individual countries that have a carbon cap, for example in the UK, there may be an incentive to substitute shale gas for coal, the likely result would be a fall in the price of globally-traded fossil fuels and therefore an increase in demand. Consequently, there is no guarantee that the use of shale gas in a nation with a carbon cap would result in an absolute reduction in emissions and may even lead to an overall increase.

If UK carbon emissions are to reduce in line with its 2°C commitments under the Copenhagen Accord, rapid and urgent decarbonisation of the electricity supply network is required. The UK's Government's Committee on Climate Change (CCC) concluded "that any path to an 80% reduction by 2050 [another of the UK Government's climate change commitments] requires that electricity generation is almost entirely decarbonised by 2030";[2] and even this relates to emission budgets well in excess of those commensurate with the Accord's framing of 2°C.[3] Given shale gas is yet to be exploited commercially outside the US, it is very unlikely it could provide other than a marginal contribution within the UK by 2020. Subsequently, unless allied with carbon capture and storage technologies as yet unproven at a large scale, all new shale gas powerstations would need to cease generating within five to fifteen years of construction, and at the latest be decommissioned by 2030.

With regards to using shale gas for heating purposes, the CCC note that as the grid decarbonises it is significantly "more carbon efficient to provide hot water and space heating with electricity than with gas burned in a condensing boiler".[4] Combining this with the UK's emission constraints derived from the Copenhagen Accord and national Low Carbon Transition Plan make clear that shale gas cannot contribute meaningfully to any UK energy future beyond 2030; whether in terms of electricity or heating.

UK Government commitments on climate change require major investment in zero and very low carbon technologies; this is likely to be delayed significantly by the exploitation of shale gas. The investment required to exploit shale gas and

[2] http://www.theccc.org.uk/pdf/7980-TSO Book Chap 5.pdf p. 173.
[3] Anderson, K., and Bows., A., 2011, Beyond dangerous climate change: emission pathways for a new world, Philosophical Transactions of the Royal Society A, 369, 20-44, DOI:10.1098/rsta.2010.0290
[4] http://www.theccc.org.uk/pdf/7980-TSO Book Chap 2.pdf. p.66.

to develop the associated generating capacity and/or gas distribution networks would be substantial.[5] Given limited financial and labour resources along with infrastructural and institutional constraints, funding and constructing a new shale gas industry inevitably will reduce the build rate and, probably, the absolute capacity of genuinely low or zero carbon energy supply alternatives. If investments in shale gas were to be sanctioned, this would result in substantial stranded assets[6] or conversely induce government to surrender its 2°C obligations under pressure to maintain 'affordable' energy supply. Either way, directing scarce financial and labour resources towards shale gas development over the coming decade is very likely to displace overall investment in very low-carbon energy supply.

Without a meaningful cap on *global* carbon emissions, the exploitation of shale gas is likely to increase total emissions. There remains little evidence to suggest other than an ongoing and rapid increase in energy use in the near-to-medium term, with the IEA's central scenario estimating a one-third increase in world primary energy demand by 2035.[7] With coal having *"accounted for nearly half of the increase in global energy use over the past decade"* there is also little to suggest a significant appetite for stringent carbon constraints in the near term.[8] Consequently, in this energy-hungry world, with GDP growth dominating political agendas and no effective and stringent constraint on total global carbon emissions, the exploitation of an additional fossil fuel resource will likely feed increased energy use and an associated rise in emissions.

If just half of the latest estimates of technically recoverable shale gas resource are extracted at conservative rates of recovery, the CO_2 from their combustion is estimated to occupy a substantial proportion, up to 29%, of an emissions budget associated with a better than 50:50 chance of avoiding 2°C warming (Anderson and Bows 2011). This may be equated with an additional atmospheric concentration of CO_2 of between 5 and 16ppmv[9] by 2050.

Key conclusions and discussion: Environmental Risks

Evidence from the US suggests shale gas extraction brings a significant risk of groundwater and surface water contamination and until the evidence base is developed a precautionary approach to development in the UK and EU is recommended. The depth of shale gas extraction gives rise to major challenges in identifying categorically pathways of contamination of groundwater by chemicals used, and mobilised, in the extraction process. An analysis of substances that have been used in the US suggests a significant number with toxic, carcinogenic, radiological or other hazardous properties. There is considerable anecdotal evidence

[5] If the argument that shale gas is to substitute for coal within the UK is to hold, new gas infrastructure will be necessary. If however, shale gas is only to substitute for imported gas, then no significant low-carbon claim, even with the UK's national boundary, can be justified.
[6] Even should retro-fit options for CCGT plant become available, it is very unlikely to deliver the level of CO2/kWh that is called for by the CCC
[7] http://www.iea.org/weo/docs/weo2011/factsheets.pdf
[8] http://www.worldenergyoutlook.org/docs/weo2011/key_graphs.pdf
[9] This assumes an airborne fraction of emissions of 45%. See, for example, Le Quere et al (2009)

from the US that contamination of both groundwater and surface water has occurred in a number of cases. This has prompted the US Environmental Protection Agency (US EPA) to launch a research programme to improve understanding of this risk (timetabled to provide initial results towards the end of 2012, with final conclusions in 2014). The view of the UK Government witnesses to the House of Commons Energy and Climate Change Committee is that UK regulation is "well-designed with clear lines of responsibility among several different bodies including DECC, the HSE, the respective Environment Agency, and Local Planning Authority" (2011; para 32) and that the UK has a "robust regime which is fit for purpose" that will ensure that unconventional gas operations are carried out in a "safe and environmentally sound manner" (2011; para 92). This study has reviewed the key regulatory instruments that are in place in the UK and EU. It appears that there are some aspects of current UK exploration where enforcement may not yet be strictly in accordance with EU directives, on chemical safety and environmental impact assessment, requiring clarification in future.

Requirements for water in commercial scale shale gas extraction could put pressure on water supplies at the local level in the UK. Shale gas extraction requires high volumes of water. Given that water resources in many parts of the UK are already under pressure, this water demand could bring significant and additional problems at the local level. Conversely volumes of contaminated wastewater returning from wells will require careful disposal.

Exploiting shale gas within the UK is likely to give rise to a range of additional challenges. The UK is densely populated and consequently wells associated with commercial scale shale gas extraction will be relatively close to population centres. The proximity of such extraction will give rise to a range of local concerns for instance, high levels of truck movements on already busy roads and the potential for seismic disturbances, that require meaningful engagement, assessment, regulation and enforcement.

1. Introduction

1.1 Background

With conventional natural gas reserves declining globally shale gas has emerged as a potentially significant new source of 'unconventional gas'. In the United States (US), production of shale gas has expanded from around 7.6billion cubic metres (bcm) in 1990 (or 1.4% of total US gas supply) to around 93bcm (14.3% of total US gas supply) in 2009 (EIA, 2010b). Energy forecasts predict that shale gas is expected to expand to meet a significant proportion of US gas demand within the next 20 years.

In large measure this expansion is possible because of significant advances in horizontal drilling and well stimulation technologies and refinement in the cost-effectiveness of these technologies. 'Hydraulic fracturing' is the most significant of these new technologies[10].

This new availability and apparent abundance of shale gas in the US (and potentially elsewhere) has led some to argue that shale gas could, in principle, be used to substitute (potentially) more carbon intensive fuels such as coal in electricity generation. On this basis it has been argued that expanding production of shale gas could represent a positive transitional step towards a low carbon economy and has been referred to as a 'bridging fuel'.

Whether shale gas is able to provide such benefits, however, depends on a number of factors including the greenhouse gas (GHG) intensity, or "carbon footprint", of the novel extraction process required in the production of shale gas and how this compares with other primary energy sources such as conventional gas or coal. As an unconventional source, requiring additional inputs and processes for different rates of (gas) return, it cannot simply be assumed that 'gas is gas' and that the GHG intensity of (unconventional) shale gas is similar to that of (conventional) gas and, by the same token, significantly less than fuels such as coal. This is an aspect that has been considered with limited empirical data and, accordingly, it is not immediately clear what the impact of a switch to unconventional shale gas will be on GHG emissions.

In addition to outstanding questions concerning the magnitude of any potential GHG benefits, or otherwise, of shale gas, the drilling and hydraulic fracturing technologies required for shale gas production also bring with them a number of issues. Various concerns have been raised about environmental and human health risks and other negative impacts associated with processes and technologies applied in the extraction of shale gas. These include: surface and groundwater contamination associated with chemicals used in the hydraulic fracturing process and the mobilisation of sub-surface contaminants such as methane, heavy metals, organic chemicals, and naturally occurring radioactive materials (NORMS); hazardous waste generation and disposal; resource issues including abstraction of significant

[10] http://www.api.org/policy/exploration/hydraulicfracturing/shale_gas.cfm

quantities of water for hydraulic fracturing processes; and land use, infrastructure and landscape impacts.

The environmental risks associated with hydraulic fracturing in particular have risen in prominence in the US. There have been a number of incidents and reports of contamination from shale gas developments and the process has, since March 2010, been the subject of a detailed US Environmental Protection Agency (US EPA) investigation and research programme into the safety and risk implications[11] which is expected to provide initial results towards the end of 2012 and final results and conclusions in 2014. Some state regulators have implemented temporary *de facto* moratoria on hydraulic fracturing while risks are assessed. In New York State, for example, on 3 August 2010 the State Senate passed a Bill to suspend issuance of new permits for hydraulic fracturing for the extraction of natural gas or oil. This was superseded on 11 December 2010, when the New York State Governor issued an Executive Order directing the Department of Environmental Conservation (DEC) to "conduct further comprehensive review and analysis of high-volume hydraulic fracturing in the Marcellus Shale". NYS DEC issued a revised draft Supplemental Generic Environmental Impact Statement (SGEIS) on 7 September 2011, providing further information and setting the context for permitting future wells. A public comments and review period is due to close on 11 January 2012. A decision on permitting hydraulic fracturing is anticipated after this date.

In the UK, Cuadrilla Resources began test drilling and hydraulic fracturing in Lancashire in late 2010 and into 2011. Limited early data is therefore available to frame analysis for the development of the industry in the UK. The company temporarily ceased operations in May 2011 to address concerns that their operations triggered seismic activity.

Clearly then, the potential environmental GHG benefits that may (or may not) be gained from developing shale gas need to be considered alongside a number of qualitatively different environmental risks and costs. In addition to the direct costs, risks and (potential) benefits from the development of shale gas there is also the potential for indirect costs from investing in and developing shale as a 'bridging fuel'. Here there is the potential for development of shale to divert attention and investment away from the renewable energy solutions that are the basis for a low carbon economy.

[11] http://yosemite.epa.gov/opa/admpress.nsf/0/BA591EE790C58D30852576EA004EE3AD

1.2 Study objectives

As part of its continuing work on 'unconventional fuels', The Co-operative has commissioned this short study to provide a review and assessment of the risks and benefits of shale gas development. The overall objective is to draw on available information (in particular from the US, where shale gas production has grown rapidly) to consider the potential risks and benefits of shale gas and reflect on development of shale reserves that may be found in the UK and globally.

As such, issues for consideration in the study include:

- the likely carbon footprint (i.e. GHG intensity) of shale gas relative to other primary energy sources such as coal and conventional natural gas;
- the magnitude of known resources and the likely contribution to total atmospheric CO_2 arising from the extraction and burning of recoverable shale gas reserves;
- key environmental risks and impacts associated with shale gas development including: water consumption; ground and surface water contamination from hydraulic fracturing chemicals and other contaminants; and any other issues that may be of concern from a UK sustainability perspective; and
- the scope and functioning of regulation in the UK/EU and its likely effectiveness as a means of controlling risks and impacts.

1.3 Structure of the report

Section 2 of the report describes shale gas production processes and considers development and production of reserves in the US. It also discusses activity on shale gas in the UK.

Section 3 considers the GHG implications of shale gas development for the UK and globally, its interaction with the wider UK energy system, and the potential investment relative to renewable energy technologies.

Section 4 reviews and assesses environmental impacts and risks associated with shale development and the cumulative impacts and issues of delivering a significant volume of shale gas in the UK.

Section 5 discusses the European regulatory framework within which shale gas exploration and production will be governed. It considers groundwater protection, regulation of fracturing chemicals and a number of wider environmental impacts.

Section 6 summarises and draws conclusions concerning the risks, costs and benefits of shale development in the UK in particular.

2. Shale gas production and reserves

2.1 Overview

Gas shales are formations of organic-rich shale, a sedimentary rock formed from deposits of mud, silt, clay and organic matter. Shales have historically been regarded by gas producers as relatively impermeable source rocks and seals over permeable sandstone and carbonate reservoirs. However, with advances in drilling and well stimulation technology, originally developed for conventional production, 'unconventional' production of gas from these, less permeable, shale formations is possible.

Development and combined application of horizontal drilling and hydraulic fracturing have unlocked the potential for production of gas from these 'tighter' less permeable shale formations and, as noted in Section 1, to date the most rapid and significant development of shale gas and associated processes has been in the US. There, shale gas production has expanded from around 7.6bcm in 1990 (or 1.4% of total US gas supply) to around 93bcm (14.3% of total US gas supply) in 2009 (EIA, 2010b)[12].

To date, significant shale gas development has been restricted to the US. This section provides detail on the modern processes involved in the production of shale gas in the US and an overview of estimated reserves and levels of historical (and future) production in the US. It also provides information on the known status of any reserves and reserve development in the UK and EU, where development of shale gas is in its very earliest and exploratory stages.

2.2 Shale gas production processes

2.2.1 Introduction to shale gas processes

As noted above, horizontal drilling and hydraulic fracturing are the two technologies that, in combination, deliver the potential to unlock tighter shale gas formations.

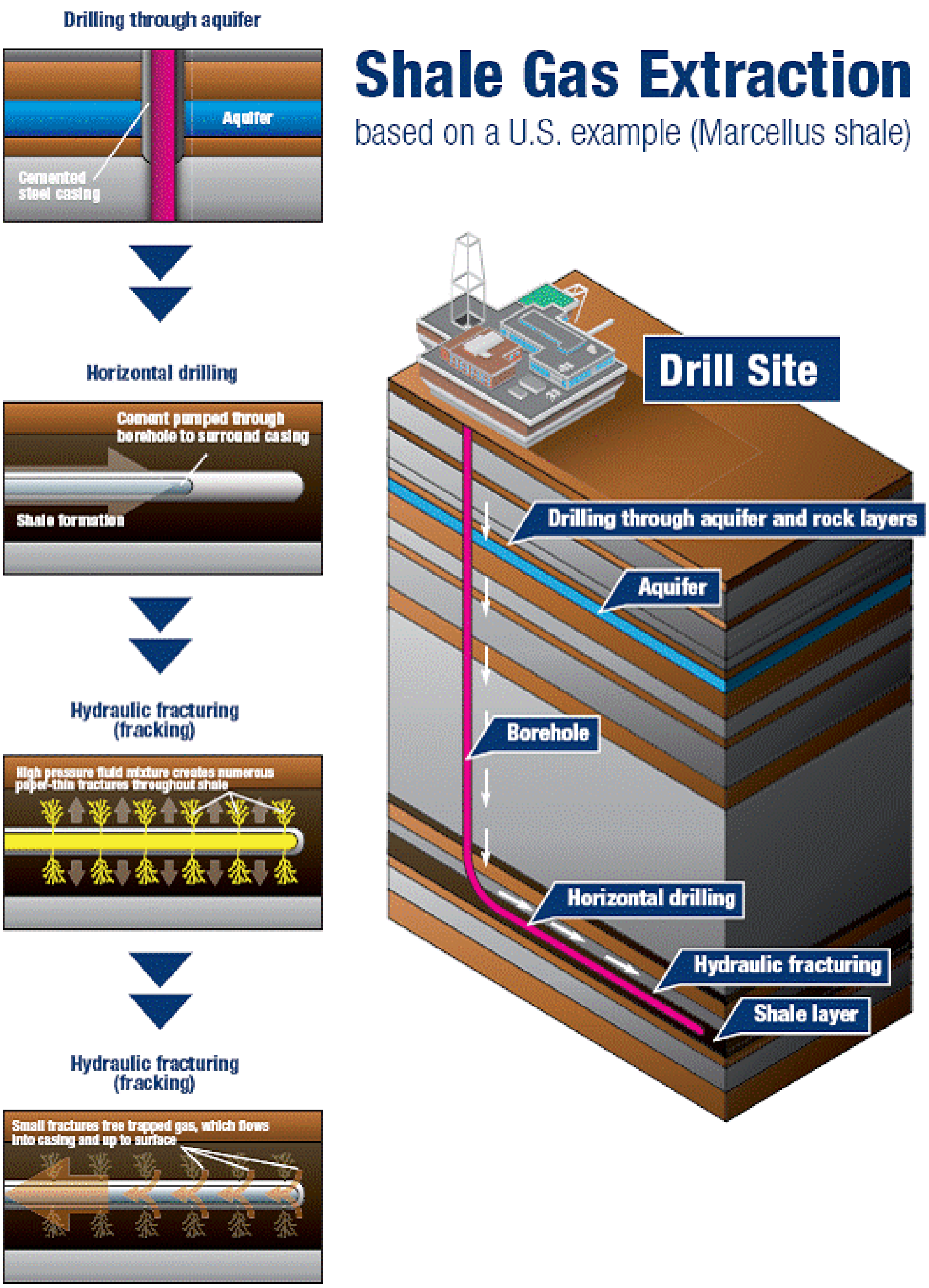
Hydraulic fracturing (also known as 'fracking') is a well stimulation technique which consists of pumping a fluid and a propping agent ('proppant') such as sand down the wellbore under high pressure to create fractures in the hydrocarbon-bearing rock. These fractures start at the horizontal wellbore and extend as much as a few hundred metres into the reservoir rock. The proppant holds the fractures open, allowing hydrocarbons to flow into the wellbore. Recovery of the injected fluids is highly variable, ranging between 15% and 80% (US EPA, 2010).

Horizontal drilling allows the well to penetrate along the hydrocarbon bearing rock seam, which may be less than 90m thick in most major US shale plays. In the UK, Cuadrilla Resources believe that the shale within its licence is much thicker,

[12] This is the year of the latest complete data available.

reportedly 1000m thick, and part of the reason for its large resource estimate[13]. Horizontal drilling maximises the rock area that, once fractured, is in contact with the wellbore and, therein, maximises well production in terms of the flow and volume of gas that can be obtained from the well. Figure 2.1 illustrates a hydraulically fractured horizontal well.

Figure 2.1: Schematic diagram of hydraulically fractured horizontal well – not to scale (The Co-operative, 2011)



13 http://www.bloomberg.com/news/2011-09-21/riverstone-backed-cuadrilla-makes-u-k-s-largest-shale-gas-find.html

Except for the use of specialised downhole tools, horizontal drilling is performed using similar equipment and technology as vertical drilling and, indeed, the initial drilling stages are almost identical to vertical wells typically used in conventional gas production. Other than the vertical portion of drilling and the final production well head, however, development and extraction processes differ between conventional gas and unconventional shale gas production. Whilst some conventional gas wells have been stimulated using hydraulic fracturing methods, hydraulic fracturing and horizontal drilling is more of an absolute requirement for shale wells to be sufficiently productive to provide a financial return.

The requirement to use horizontal drilling and hydraulic fracturing also results in differences in the distribution of wells above the target formations. The processes involved in shale production have developed over time to increase efficiency of operations. As shown in Table 2.1, from the earliest experiments with shale gas in the early 20th century, the modern process has developed into one typified by the clustering of several wells on 'multi-well' pads, with horizontal drilling from each well and multi-stage 'slickwater' fracturing[14].

Table 2.1: Shale gas technological milestones (New York State, 2009)

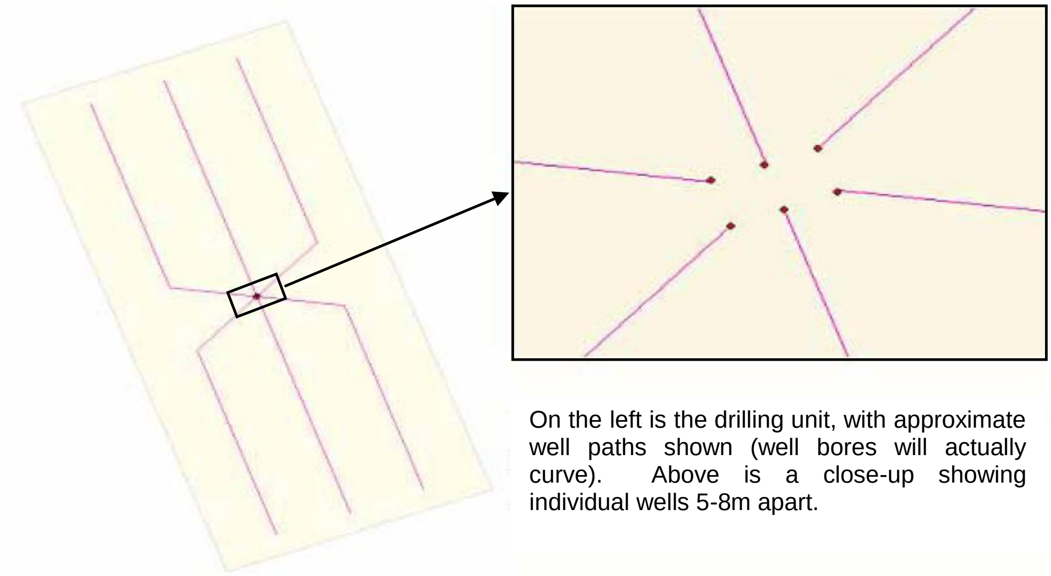
Early 1900s	Natural gas extracted from shale wells. Vertical wells hydraulically fractured with foam
1983	First gas well drilled in Barnett Shale in Texas
1980-1990s	Cross-linked gel fracturing fluids developed and used in vertical wells
1991	First horizontal well drilled in Barnett Shale
1996	Slickwater fracturing fluids introduced
1998	Slickwater fracturing of originally gel-fractured wells
2002	Multi-stage slickwater fracturing of horizontal wells
2003	First hydraulic fracturing of Marcellus shale
2007	Use of multi-well pads and cluster drilling

Multi-well pads

Horizontal drilling from multi-well pads is now the common development method employed in, for example, ongoing development of Marcellus Shale reserves in the northern Pennsylvania. Here a 'well pad' is constructed typically in centre of what will be an array of horizontal wellbores similar to that shown in Figure 2.2. Up to sixteen, but more commonly six or eight wells, are drilled sequentially in parallel rows from each pad, each well typically being around five to eight metres apart. In the UK, Cuadrilla Resources report that its well pads will each have ten wells. Each horizontal wellbore may typically be around 1-1.5km in lateral length but can be more.

[14] Slickwater refers to hydraulic fracturing with chemicals additives to alter the viscosity of the hydraulic fluid and frictional losses with the well bore. This enables faster pumping, with lower power demands, and greater penetration of proppants into microfractures. Example additives include polyacrylamide. It may be used in both vertcal and horizontal well stimulation. Not all hydraulic fracturing is performed with slickwater.

Figure 2.2: Schematic diagram of horizontal wells drilled from a single multi-well pad (New York State, 2009)



On the left is the drilling unit, with approximate well paths shown (well bores will actually curve). Above is a close-up showing individual wells 5-8m apart.

Multiple arrays of multi-well pads

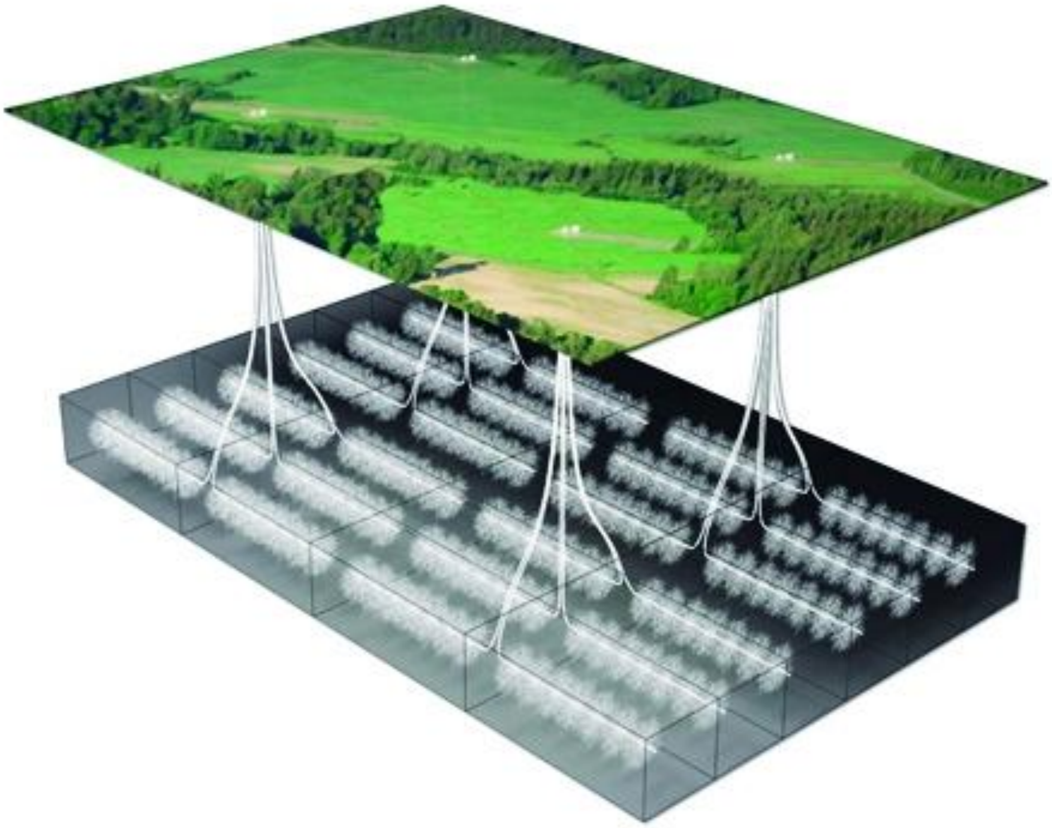
As the array of wells drilled from each well pad is able to access only a discrete area of the target formation, shale gas development also requires an array of well pads arranged over the target formation, see for example, Figure 2.3.

In terms of spacing of well pads, New York State (2009) identifies a maximum spacing of nine pads per square mile. This is equivalent to around 3.5 pads per square km. In the UK, Composite energy has estimated that 1-1.5 pads/km^2 should be sufficient in a UK setting[16]. If Cuadrilla Resources develops 200-800 well pads evenly across it's Lancashire licence area spacing will be much lower. However, even spacing does not account for geological and above ground constraints.

[15] http://www.theengineer.co.uk/in-depth/the-big-story/unlock-the-rock-cracking-the-shale-gas-challenge/1003856.article# It should be noted that Figure 2.3 illustrates particular points and does not represent all potential over ground impacts.

[16] http://www.composite-energy.co.uk/shale-challenges.html

Figure 2.3: Illustration of the arrangement of arrays of multi-well pads over target formations[14]



Key sources of difference between conventional gas and unconventional shale gas production processes

Owing to the differences in production processes between unconventional shale gas production and conventional gas production from permeable reservoirs, there are accompanying differences in the level of effort, resource use and waste generated. Accordingly, whilst the gas produced from shale is broadly identical to that produced using conventional methods, there are some significant differences.

The remainder of this section (Section 2.2) provides a detailed description of the processes involved in the development of shale wells charting the construction of well pads, through drilling, hydraulic fracturing, production and eventual plugging and decommissioning of the well, based on US experience.

2.2.2 Pre-production - Initiation and drilling phase

Well pad construction

As described above, horizontal drilling from multi-well pads is now the common development method with six or eight wells drilled sequentially from a single pad. Each pad requires an area sufficient to accommodate fluid storage and equipment associated with the high-volume fracturing operations as well as the larger equipment associated with horizontal drilling.

According to New York State (2009), an average sized multi-well pad is likely to be 1.5-2ha in size during the drilling and fracturing phase, with well pads of over 2ha possible. Average production pad size (if partial reclamation occurs) is likely to average 0.4-1.2ha. In the UK, the well pads planned by Cuadrilla for exploration and production from the Bowland Shale are approximately 0.7ha, and will contain 10 wells (Regeneris Consulting, 2011). It is unknown how operations at other UK sites may proceed.

Drilling

Vertical drilling depth will vary based on target formation and location. Typically, wells will be drilled vertically through rock layers and aquifers to a depth of about 2km, halting 150m above the top of a target layer formation whereupon, a larger horizontal drill rig may be brought onto the location to build angle for the horizontal portion of the wellbore. This transition is known as 'kicking off' with the horizontal section typically running on for 1.2km.

The vertical portion of each well, including the portion that is drilled through any fresh water aquifers, will typically be drilled using either compressed air or freshwater mud as the drilling fluid.

In contrast to vertical sections, horizontal drilling equipment requires drilling mud for:

- powering and cooling the downhole motor used for directional drilling;
- using navigational tools which require mud to transmit sensor readings;
- providing stability to the horizontal borehole while drilling; and
- efficiently removing cuttings from the horizontal hole.

Some operators may also drill the horizontal bore on air, using special equipment to control fluids and gases that enter the wellbore (New York State, 2009).

In terms of cuttings, a single well drilled vertically to a depth of 2km and laterally by 1.2km would generate around 140m^3 of cuttings. A six well pad will, then, generate around 830m^3 of cuttings. On the same basis, Cuadrilla's planned well pads, containing ten wells, might be expected to generate 1,400m^3 of cuttings. For comparison, a conventional well[17] drilled to the same depth (2km) would generate around 85m^3.

Well casings

A variety of well casings may be installed to seal the well from surrounding formations and stabilise the completed well. Casing is typically steel pipe lining the inside of the drilled hole and cemented in place. There are four casing 'strings', each

[17] Conventional wells are not clustered on multi-well pads and so there are likely to be differences in the number and distribution of wells per unit gas produced.

installed at different stages in drilling. The different types of casing that may be used are described in Table 2.2.

Table 2.2: Well casings	
Conductor casing	During the first phase of drilling, a shallow steel conductor casing is installed vertically to reinforce and stabilise the ground surface.
Surface casing	After installation of the conductor casing, drilling continues to the bottom of freshwater aquifers (depth requirements for groundwater protection vary from state to state), at which point a second casing (surface casing) is inserted and cemented in.
Intermediate casing (not usually required)	A third (intermediate) casing is sometimes installed from the bottom of the surface casing to a deeper depth. This is usually only required for specific reasons such as additional control of fluid flow and pressure effects, or for the protection of other resources such as minable coals or gas storage zones. For example, in New York, intermediate casing may be required for fluid or well control reasons or on a case specific basis; while in Wyoming, intermediate casing can be required where needed for pressure control.
Production casing	After the surface casing is set (or intermediate casing when needed), the well is drilled to the target formation and a production casing is installed either at the top of the target formation or into it (depending upon whether the well will be completed "open- hole" or through perforated casing).

Notably, requirements for installation of casings and other safety measures vary from State to State as follows:

- ***Depth of surface casing in relation to aquifers:*** whilst most states require the surface casing to extend to below the deepest aquifer, some do not. A Ground Water Protection Council (GWPC, 2009) survey of 27 States found that 25 required the surface casing to extend below the deepest aquifer;

- ***Cementing in of surface casing:*** a method known as 'circulation' may be used to fill the entire space between the casing and the wellbore (the annulus) from the bottom of the surface casing to the surface. Here, cement is pumped down the inside of the casing, forcing it up from the bottom of the casing into the space between the outside of the casing and the wellbore. Once a sufficient volume of cement to fill the annulus is pumped into the casing, it is usually followed by pumping a volume of fresh water into the casing to push cement back up the annular space until the cement begins to appear at the surface. According to GWPC (2009), circulation of cement on surface casing is not a universal requirement and in some states cementing of the annular space is required across only the deepest groundwater zone but not all ground water zones;

- ***Blowout prevention:*** once surface casing is in place, some (but not all) states may require operators to install blowout prevention equipment (BOPE) at the surface to prevent any pressurized fluids encountered during drilling from moving up the well through the space between the drill pipe and the surface casing (Worldwatch, 2010);

- ***Cementing in of production casing:*** GWPC note that, although some states require complete circulation of cement from the bottom to the top of the production casing, most states require only an amount of cement calculated to raise the cement top behind the casing to a certain level above the producing formation[18]. As noted in the GWPC report, there are a number of reasons why full cement circulation is not always required including the fact that, in very deep wells, the circulation of cement is more difficult to accomplish as cementing must be handled in multiple stages which can result in a poor cement job or damage to the casing if not done properly; and

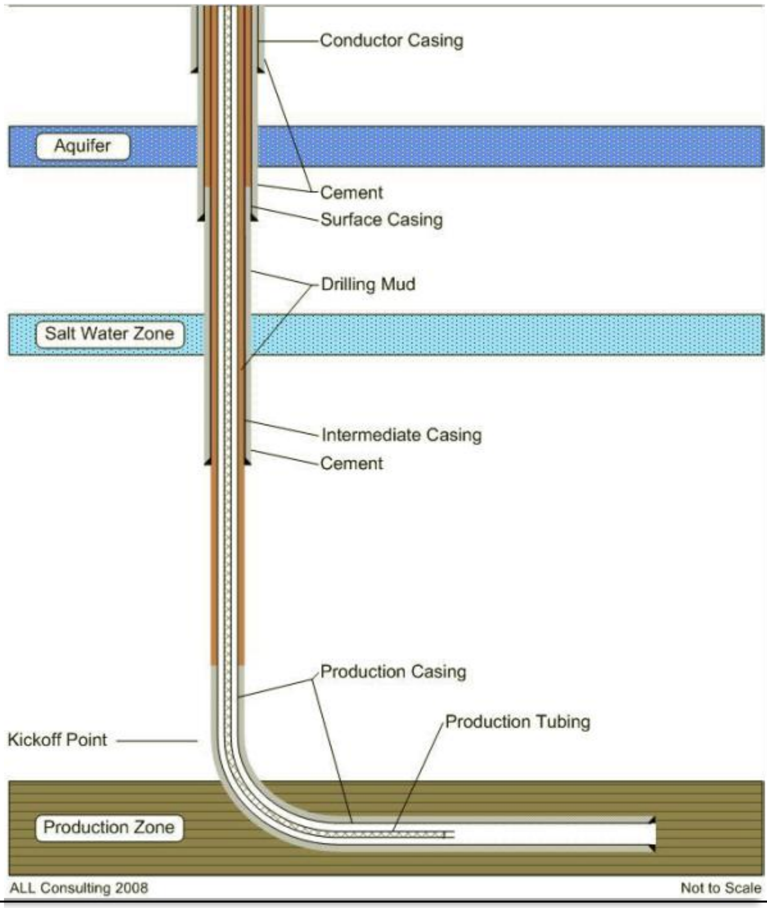
- ***Well tubing:*** a few states also require the use of well tubing inserted inside the above described casings. Tubing, like casing, typically consists of steel pipe but it is not usually cemented into the well.

Figure 2.4 illustrates a horizontal well constructed with casing and production tubing.

The last step prior to fracturing is installation of a wellhead (referred to as a "frac tree") that is designed and pressure-rated specifically for the fracturing operation. As well as providing the mechanism for pumping and controlling fluid pressure, the frac tree incorporates flowback equipment to handle the flowback of fracturing fluid from the well and includes pipes and manifolds connected to a gas-water separator and tanks.

[18] For example, in Arkansas, production casing must be cemented to two-hundred-fifty feet above all producing intervals.

Figure 2.4: Horizontal well casings and tubing – note that the diagram depicts a well with all possible casings. Not all of the casings or tubing are present in most cases (GWPC, 2009).



2.2.3 Pre-production - hydraulic fracturing phase

As has already been described, hydraulic fracturing consists of pumping a fluid and a propping agent ('proppant') such as sand down the wellbore under high pressure to create fractures in the hydrocarbon-bearing rock. These fractures start at the horizontal wellbore and extend as much as a few hundred metres into the reservoir rock. The proppant holds the fractures open, allowing hydrocarbons to flow into the wellbore and so to the surface. Figure 2.5 shows a well site during hydraulic fracturing.

Figure 2.5: A well site during a single hydraulic fracturing operation (New York State, 2009)

1. Well head and frac tree with 'Goat Head'	11. Frac additive trucks
2. Flow line (for flowback & testing)	12. Blender
3. Sand separator for flowback	13. Frac control and monitoring center
4. Flowback tanks	14. Fresh water impoundment
5. Line heaters	15. Fresh water supply pipeline
6. Flare stack	16. Extra tanks
7. Pump trucks	17. Line heaters
8. Sand hogs	18. Separator-meter skid
9. Sand trucks	19. Production manifold
10. Acid trucks	

Fracturing fluid

The composition of the fracturing fluid varies from one operator to another and the design of the fluid varies depending on the characteristics of the target formation and operational objectives. However, the fracturing fluid used in modern slickwater fracturing is typically comprised of around 98% water and sand (as a proppant) with chemical additives comprising 2% (GWPC, 2009b). A description of the role of different chemical additives is provided in Table 2.3. The identity and toxicity profile of chemical constituents is not well publicised (or known) but is discussed in more detail in Section 4. Some are not exclusive to shale gas wells, for instance, conventional sites may use hydrochloric acid to enhance recovery rates[19].

Table 2.3: Types of fracturing fluid additives	
Additive	**Purpose**
Proppant	"Props" open fractures and allows gas / fluids to flow more freely to the well bore.
Acid	Cleans up perforation intervals of cement and drilling mud prior to fracturing fluid injection, and provides accessible path to formation.
Breaker	Reduces the viscosity of the fluid in order to release proppant into fractures and enhance the recovery of the fracturing fluid.
Bactericide / Biocide	Inhibits growth of organisms that could produce gases (particularly hydrogen sulfide) that could contaminate methane gas. Also prevents the growth of bacteria which can reduce the ability of the fluid to carry proppant into the fractures.
Clay Stabilizer / Control	Prevents swelling and migration of formation clays which could block pore spaces thereby reducing permeability.
Corrosion Inhibitor	Reduces rust formation on steel tubing, well casings, tools, and tanks (used only in fracturing fluids that contain acid)
Crosslinker	The fluid viscosity is increased using phosphate esters combined with metals. The metals are referred to as crosslinking agents. The increased fracturing fluid viscosity allows the fluid to carry more proppant into the fractures.
Friction Reducer	Allows fracture fluids to be injected at optimum rates and pressures by minimising friction.
Gelling Agent	Increases fracturing fluid viscosity, allowing the fluid to carry more proppant into the fractures.
Iron Control	Prevents the precipitation of metal oxides which could plug off the formation.
Scale Inhibitor	Prevents the precipitation of carbonates and sulfates (calcium carbonate, calcium sulfate, barium sulfate) which could plug off the formation.
Surfactant	Reduces fracturing fluid surface tension thereby aiding fluid recovery.

In the UK, the only hydraulic fracturing to have taken place to date, November 2011, has been conducted at one site by Cuadrilla Resources. The composition of the fracturing fluid used, as listed on their website, is reproduced in Table 2.4.

Table 2.4: Composition of Fracking Fluid for Preese Hall Well 1. Total of 6 frack stages[20]			
Additive	**Detail**	**Quantity**	**Percentage by volume**
Water	United Utilities mains water	8,399m^3	97.93%
Proppant	Congleton Sand	108.1tonnes	0.473%
Proppant	Chelford Sand	354.6tonnes	1.550%
Friction Reducer	Polyacrylamide emulsion	3.7m^3	0.043%
Chemical Tracer	Sodium Salt (not identified)	0.425kg	0.00043%

[19] http://www.naturalgas.org/naturalgas/well_completion.asp
[20] http://www.cuadrillaresources.com/cms/wp-content/uploads/2011/02/Chemical-Disclosure-PH-1.jpg

Fracturing procedure

The fracturing procedure is carried out sequentially (one well after another) and often in multiple stages for each well on a well pad. A multi-stage procedure involves successively isolating, perforating the production casing (when present) and fracturing portions of the horizontal wellbore starting with the far end (or toe) by pumping fracturing fluid in and maintaining high pressure. A multi-stage fracturing operation for a 1.2km lateral well typically consists of eight to thirteen fracturing stages.

In terms of pressures applied, New York State (2009) identifies that anticipated Marcellus Shale fracturing pressures range from 5,000psi (345bar) to 10,000psi (690bar) – equivalent to around 170 to 350 times the pressure used in a car tyre. It also suggests that, before perforating the casing and pumping fracturing fluid into the well, the operator pumps water or drilling mud to test the production casing to at least the maximum anticipated treatment pressure. Test pressure may exceed the maximum anticipated treatment pressure, but must remain below the casing's internal yield pressure.

Water and chemical additive requirements

Each stage in a multi-stage fracturing operation requires around 1,100-2,200m^3 of water, so that the entire multi-stage fracturing operation for a single well requires around 9,000-29,000m^3 (9-29 million litres) of water and, with chemical additives of up to 2% by volume, around 180-580m^3 of chemical additives (or 180-580tonnes based on relative density of one).

For all fracturing operations carried out on a six well pad, a total of 54,000-174,000m^3 (54-174megalitres) of water would be required for a first hydraulic fracturing procedure and, with chemical additives of up to 2% by volume, some 1,000-3,500m^3 of chemicals (or 1,000-3,500tonnes based on relative density of one).

As such, large quantities of water and chemical additives must be brought to and stored on site. Local conditions dictate the source of water and operators may abstract water directly from surface or ground water sources themselves or may be delivered by tanker truck or pipeline. New York State (2009) reports that liquid chemical additives are stored in the containers and on the trucks on which they have been transported and delivered with the most common being 1-1.5m^3 high-density polyethylene (HDPE) steel caged cube shaped containers.

Water and additives are blended on site in a truck mounted blending unit. Hoses are used to transfer liquid additives from storage containers to the blending unit or the well directly from the tank truck. Dry additives are poured by hand into a feeder system on the blending unit. The blended fracturing solution is immediately mixed with proppant (usually sand) and pumped into the wellbore.

Fluid return

Once the fracturing procedure itself is completed, fluid returns to the surface in a process stage referred to as 'flowback'. The US EPA (2010) notes that "estimates of the fluids recovered range from 15-80% of the volume injected depending on the site".

Accordingly, each well on a multi-well pad will generate between 1,300–23,000m^3 of flowback waste fluid containing water, methane, fracturing chemicals and subsurface contaminants mobilised during the process, including toxic organic compounds, heavy metals and naturally occurring radioactive materials (NORMs). Similarly, any flowback fluid that is not recovered remains underground where there is concern that it is, or may become, a source of contamination to other formations including aquifers. Volumes remaining underground are equivalent to the inverse of volumes recovered, i.e. 1,700-24,400m^3 per well.

Approximately 60% of the total flowback occurs in the first four days after fracturing and this may be collected via:

- unchecked flow through a valve into a lined pit;
- flow through a choke into a lined pit; and/or
- flow to tanks.

In principle, storage of flowback fluid allows operators to re-use much of it for future fracturing operations, for example, in other wells on the well pad. This would require dilution with freshwater and application of other treatment methods necessary to meet the usability characteristics. It is not known what level of water re-use is possible and this is likely to vary from one situation to another.

The dimensions and capacity of on-site pits and storage tanks are likely to vary but, based on volumes calculated above, total capacity would have to be in excess of the expected volumes of flowback fluid from a single well fracturing operation, namely between 1,300–23,000m^3.

One operator reports a typical pit volume of 2,900m^3. Based on a pit depth of 3m, the surface footprint of a pit would be around 1,000m^2 (0.1ha). Owing to the high rate and potentially high volume of flowback fluid, additional temporary storage tanks may need to be staged onsite even if an onsite lined pit is to be used. Based on the typical pit capacity above, this implies up to around 20,000m^3 of additional storage capacity for flowback fluid from one fracturing operation on a single well (New York State, 2009).

In terms of overall flowback, water volume for a six well pad is suggested to be 7,900 to 138,000m^3/pad for a single fracturing operation, with fracturing chemicals and subsurface contaminants making up to 2% or 160-2,700m^3. Approximately 60% of the total flowback occurs in the first four days after fracturing, continuing and tailing off over a period of two weeks or so.

2.2.4 Pre-production - duration of pre-production surface operations and transport requirements

Table 2.5 summarises operations, materials, activities and typical duration of activities prior to production from a multi-well pad. Based on the duration of activities, the total pre-production duration of activities for a six well pad is 500-1,500 days of activity, assuming no overlap between activities (in practice, there is some limited potential for overlap).

Table 2.5: Summary of mechanical operations prior to production (New York State, 2009)

Operation	**Materials and Equipment**	**Activities**	**Duration**
Access road and well pad construction	Backhoes, bulldozers and other types of earthmoving equipment.	Clearing, grading, pit construction, placement of road materials such as geotextile and gravel.	Up to 4 weeks per well pad
Vertical drilling with smaller rig	Drilling rig, fuel tank, pipe racks, well control equipment, personnel vehicles, associated outbuildings, delivery trucks.	Drilling, running and cementing surface casing, truck trips for delivery of equipment and cement. Delivery of equipment for horizontal drilling may commence during late stages of vertical drilling.	Up to 2 weeks per well; one to two wells at a time
Preparation for horizontal drilling with larger rig		Transport, assembly and setup, or repositioning on site of large rig and ancillary equipment.	5-30 days per well
Horizontal drilling	Drilling rig, mud system (pumps, tanks, solids control, gas separator), fuel tank, well control equipment, personnel vehicles, associated outbuildings, delivery trucks.	Drilling, running and cementing production casing, truck trips for delivery of equipment and cement. Deliveries associated with hydraulic fracturing may commence during late stages of horizontal drilling.	Up to 2 weeks per well; one to two wells at a time
Preparation for hydraulic fracturing		Rig down and removal or repositioning of drilling equipment. Truck trips for delivery of temporary tanks, water, sand, additives and other fracturing equipment. Deliveries may commence during late stages of horizontal drilling.	30-60 days per well, or per well pad if all wells treated during one mobilisation
Hydraulic fracturing procedure	Temporary water tanks, generators, pumps, sand trucks, additive delivery trucks and containers, blending unit, personnel vehicles, associated outbuildings, including computerised monitoring equipment.	Fluid pumping, and use of wireline equipment between pumping stages to raise and lower tools used for downhole well preparation and measurements. Computerized monitoring. Continued water and additive delivery.	2-5 days per well, including approximately 40-100 hours of actual pumping
Fluid return (flowback) and treatment	Gas/water separator, flare stack, temporary water tanks, mobile water treatment units, trucks for fluid removal if necessary, personnel vehicles.	Rig down and removal or repositioning of fracturing equipment; controlled fluid flow into treating equipment, tanks, lined pits, impoundments or pipelines; truck trips to remove fluid if not stored on site or removed by pipeline.	2-8 weeks per well, may occur concurrently for several wells
Waste disposal	Earth-moving equipment, pump trucks, waste transport trucks.	Pumping and excavation to empty/reclaim reserve pit(s). Truck trips to transfer waste to disposal facility.	Up to 6 weeks per well pad
Well cleanup and testing	Well head, flare stack, waste water tanks. Earthmoving equipment.	Well flaring and monitoring. Truck trips to empty waste water tanks. Gathering line construction may commence if not done in advance.	0.5-30 days per well
Overall duration of activities for all operations (prior to production) for a six well multi-well pad			**500-1,500 days**

New York State (2009) also provides estimates of truck visits to the site. These are summarised in Table 2.6 giving trips per well and per well pad (based on a six well pad). This suggests a total number of truck visits of between 4,300 and 6,600 of which around 90% are associated with the hydraulic fracturing operation.

Table 2.6: Truck visits over lifetime of six well pad

Purpose	Per well		Per pad	
	Low	High	Low	High
Drill pad and road construction equipment			10	45
Drilling rig			30	30
Drilling fluid and materials	25	50	150	300
Drilling equipment (casing, drill pipe, etc.)	25	50	150	300
Completion rig			15	15
Completion fluid and materials	10	20	60	120
Completion equipment (pipe, wellhead)	5	5	30	30
Hydraulic fracture equipment (pump trucks, tanks)			150	200
Hydraulic fracture water	400	600	2,400	3,600
Hydraulic fracture sand	20	25	120	150
Flow back water removal	200	300	1,200	1,800
Total			**4,315**	**6,590**
...of which associated with fracturing process:			***3,870***	***5,750***
			90%	***87%***

2.2.5 Production phase

Production

Once drilling and hydraulic fracturing operations are complete, a production wellhead is put in place to collect and transfer gas for subsequent processing via a pipeline. Production from a well on a given well pad may begin before other wells have been completed.

In terms of production volumes, an operator postulated long-term production for a single Marcellus well in New York State (New York State, 2009):

- Year 1 – Initial rate of 79,300m^3/d declining to 25,500m^3/d
- Years 2 to 4 – 25,500m^3/d declining to 15,600m^3/d
- Years 5 to 10 – 15,600m^3/d declining to 6,400m^3/d
- Year 11 and after – 6,400m^3/d declining at 3%/year

Re-fracturing

As outlined above, the production from a well tails off significantly after five years or so. It is reported in a number of documents (including New York State, 2009) that operators may decide to re-fracture a well to extend its economic life, sometimes more than once.

2.2.6 Well plugging and decommissioning

When the productive life of a well is over, or where it has been unsuccessful, wells are plugged and abandoned. Proper plugging is critical for the protection of groundwater, surface water bodies and soil.

Well plugging involves removal of downhole equipment. Uncemented casing in critical areas must be either pulled or perforated, and cement must be placed across or squeezed at these intervals to ensure seals between hydrocarbon and water-bearing zones. Downhole cement plugs supplement the cement seal that already exists from the casings described earlier (New York State, 2009).

Intervals between plugs must be filled with a heavy mud or fluid. For gas wells, in addition to the downhole cement plugs, a minimum of 15m of cement must be placed in the top of the wellbore to prevent any release or escape of hydrocarbons or waste water.

2.2.7 Resource consumption

Tables 2.7 and 2.8 summarise the data provided in the discussion above concerning the activities and resources required for development of shale gas pads for no-refracturing and refracturing scenarios respectively.

Table 2.7: Summary of resources, no refracturing scenario

	Activity	**Six well pad drilled vertically to 2000m and laterally to 1,200m**	
		Low	**High**
Construction	Well pad area (ha)	1.5	2
Drilling	Wells	6	
	Cuttings volume (m^3)	827	
Hydraulic Fracturing	Water volume (m^3)	54,000	174,000
	Flowback fluid volume (m^3)	7,920	137,280
Surface Activity	Total duration of surface activities pre production (days)	500	1,500
	Total truck visits	4,315	6,590

Table 2.8: Summary of resources, re-fracturing scenario			
	Activity	**Six well pad drilled vertically to 2000m and laterally to 1,200m**	
Pre- production	As above	As above	
		Low	**High**
Refracturing Process Assuming an average of 50% of wells re-fractured only once	Water volume (m^3)	27,000	87,000
	Fracturing chemicals volume, @2% (m^3)	540	1,740
	Flowback fluid volume (m^3)	3,960	68,640
	Total duration of surface activities for re-fracturing (days)	200	490
	Total truck visits for re-fracturing	2,010	2,975
Total for 50% re-fracturing	Well pad area (ha)	1.5	2
	Wells	6	
	Cuttings volume (m^3)	827	
	Water volume (m^3)	81,000	261,000
	Fracturing chemicals volume, @2% (m^3)	1,620	5,220
	Flowback fluid volume (m^3)	11,880	205,920
	Total duration of surface activities pre production (days)	700	1,990
	Total truck visits	6,325	9,565

2.3 Shale gas production and reserves

2.3.1 Terminology

Terminology varies between sources when quantitatively describing oil and gas fields. *Reserves* are a subset of the overall *resources* that may be present within a geographic area. Resource is a broad category and represents a total quantity of hydrocarbon potentially available but which may never be recovered.

- **Technically recoverable resources** – resources in accumulations producible using current recovery technology but without reference to economic profitability.

- **Undiscovered technically recoverable resources** – located outside oil and gas fields in which the presence of resources has been confirmed by exploratory drilling. They include resources from undiscovered pools within confirmed fields when they occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions.

In the US, estimates of the size of the reserves are divided into and defined by the EIA as[21]:

- **Proved reserves** – estimated quantities that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in

[21] http://www.eia.doe.gov/oiaf/aeo/assumption/oil_gas_footnotes.html

future years from known reservoirs under existing economic and operating conditions; and

- **Inferred reserves** – that part of expected ultimate recovery from known fields in excess of cumulative production plus current reserves;

The above definitions largely map onto the internationally recognised Petroleum Resources Management System (PRMS)[22]. It classifies reserves on two independent criteria; the potential for reaching commercial development and the technical uncertainty in quantitative estimates. In terms of reserves, i.e. the part of the resource with justified for commercial development, DECC's UK estimates use the following distinctions:

- ***Proven:*** reserves which on the available evidence are virtually certain to be technically and commercially producible, i.e. have a better than 90% chance of being produced;

- ***Probable:*** reserves which are not yet proven, but which are estimated to have a better than 50% chance of being technically and commercially producible; and

- ***Possible:*** reserves which at present cannot be regarded as probable, but which are estimated to have a significant but less than 50% chance of being technically and commercially producible.

Terminology referring to smaller physical scales is also used. Gas Initially In Place (GIIP), or Gas In Place (GIP) for the remainder if production has commenced, refers to the total gas resource that is present in a reservoir or gas field and is a resource rather than a reserve measure. Estimated Ultimate Recovery (EUR) refers to a given well or field over its lifetime and accounts for its production to date and anticipated total recovery. This measure is closer in sense to a reserve.

2.3.2 Estimated global reserves of shale gas

The potential volume of shale gas that could be exploited globally is highly uncertain and substantially reliant upon expert judgements across large scales. The most recent estimate of technically recoverable resource has been made by the US EIA at 187,535bcm (EIA, 2011b) but Russia and Central Asia, Middle East, South East Asia, and Central Africa are not considered in this figure. However, it is a similar order of magnitude to the 204,000bcm estimate presented in the IEA Golden Age of Gas supplement to the World Energy Outlook (2011).

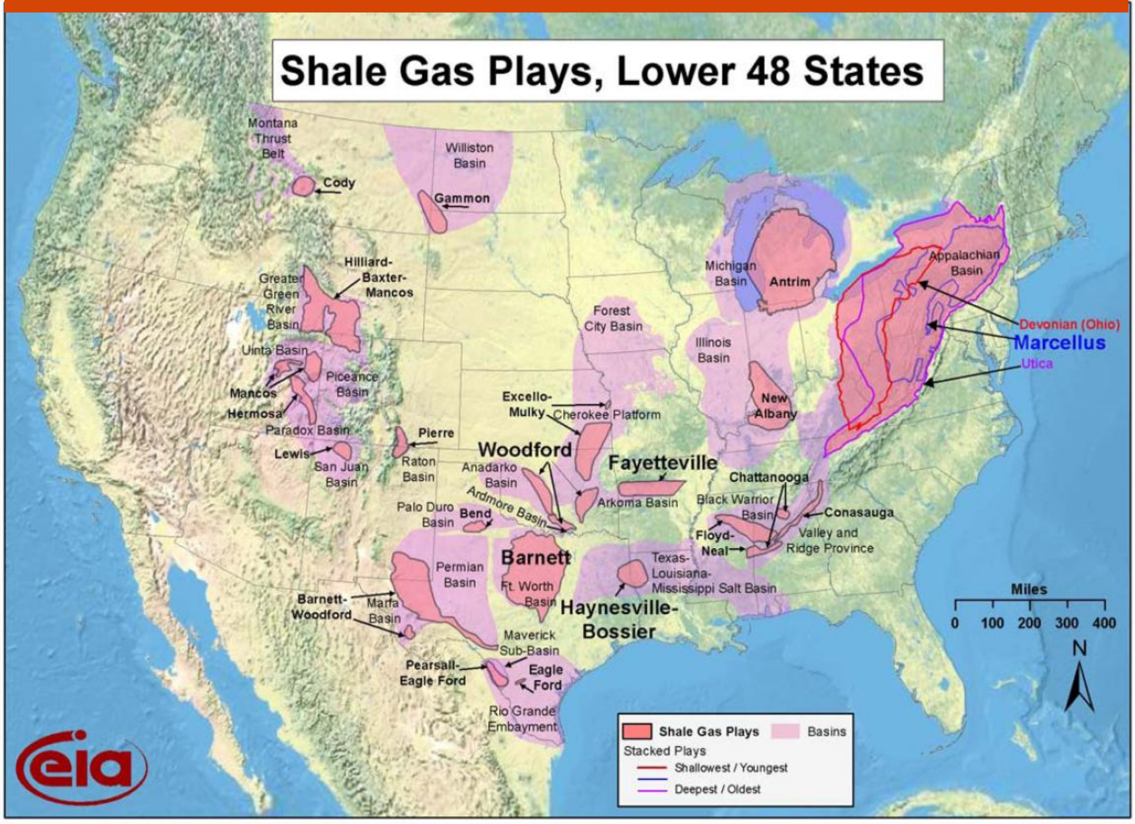
2.3.3 Estimated US reserves of shale gas

To date, the most rapid development, and indeed only really significant development, of shale gas processes and resource extraction has been in the US where shale gas production has expanded from around 7.6bcm in 1990 (or 1.4% of total US gas supply) to around 93bcm (14.3% of total US gas supply) in 2009 (EIA, 2010b). As

[22] http://www.spe.org/spe-site/spe/spe/industry/reserves/PRMS_guide_non_tech.pdf

illustrated in Figure 2.6 shale 'plays', geologically related fields, are spread across a number of states in the US.

Figure 2.6: Major US shale basins and plays



Source: Energy Information Administration based on data from various published studies.
Updated: March 10, 2010

Estimates of US technically recoverable and proved reserves

A number of estimates have been made of the size of the technically recoverable shale gas resource in the US. Depending on both publication source and year, estimates vary considerably due to lack of assessment of some areas and variations between estimates for assessed areas.

The Energy Information Administration (EIA) estimates from the 2008, 2009, 2010 and 2011 Annual Energy Outlook reports are presented as a time series in Table 2.9. Estimates have been revised upwards year on year, as new geological and productivity data are gathered and technologies refined. The upward trend is rapid and the estimates indicate a threefold increase in the estimate of technically recoverable reserve between 2008 and 2010 inclusive, while the release of the 2011 figures sees a further doubling of the 2010 estimate[23]. The full potential volume of the resource is regarded as highly uncertain by the EIA and seems likely to increase in future.

[23] This data was prefaced by the Annual Energy Outlook early release overview in December 2010 (EIA 2010b).

Table 2.9: Summary of estimates of technically recoverable shale gas resources (various sources)		
Source	**Publication Date**	**Shale Gas (bcm)**
Energy Information Administration: Supporting materials for the 2008 Annual Energy Outlook	2008	3,539
Energy Information Administration: Supporting materials for the 2009 Annual Energy Outlook	2009	7,568
Energy Information Administration: Supporting materials for the 2010 Annual Energy Outlook	2010	10,432
Energy Information Administration: Annual Energy Outlook 2011, Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays	2011	24,395

As noted above, estimates of technically recoverable resources comprise 'proved' and 'inferred' reserves and 'undiscovered technically recoverable resources'. The figure from the EIA 2011 assessment (EIA, 2011b) of 24,395 bcm of technically recoverable reserve is broken down by region in Table 2.10. Total proved US shale gas reserve is 994 bcm, representing 4% of the total technically recoverable reserve.

Table 2.10: Technically recoverable US natural gas resources, January 1, 2009				
Shale Gas	**Proved Reserves (bcm)**	**Inferred Reserves (bcm)**	**Undiscovered Technically Recoverable Resources (bcm)**	**Total Technically Recoverable Resources (bcm)**
Northeast	122	13,382	0	13,504
Gulf Coast	45	2,981	0	3,026
Midcontinent	207	1,772	0	1,979
Southwest	606	2,457	0	3,063
Rocky Mountain	11	1,223	413	1,650
West Coast	0	0	1,172	1,172
Total	**994**	**21,816**	**1,585**	**24,395**

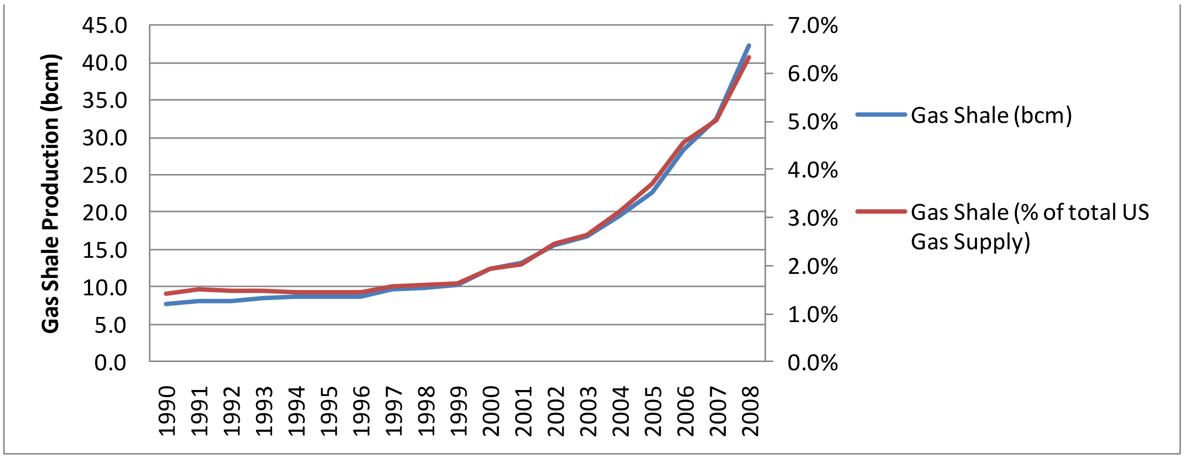
2.3.3 Historical and projected production and consumption of shale gas in the US

As well as reserve estimates, production of shale gas has grown increasingly quickly over recent years. From 2000 to 2006 the average annual increase was 17% but from 2006 to 2010 the average rate of increase has grown to 48% per year (EIA 2011). EIA Annual Energy Outlook for 2010 provides detailed data on consumption of shale gas (as well as other fuels and sources of energy) in the US and also projects future resource use up to 2035.

Historical and Current Shale Gas Production

Figure 2.7 provides data on the growth in the production of shale gas in the US from 1990-2008 taken from EIA (2010a).

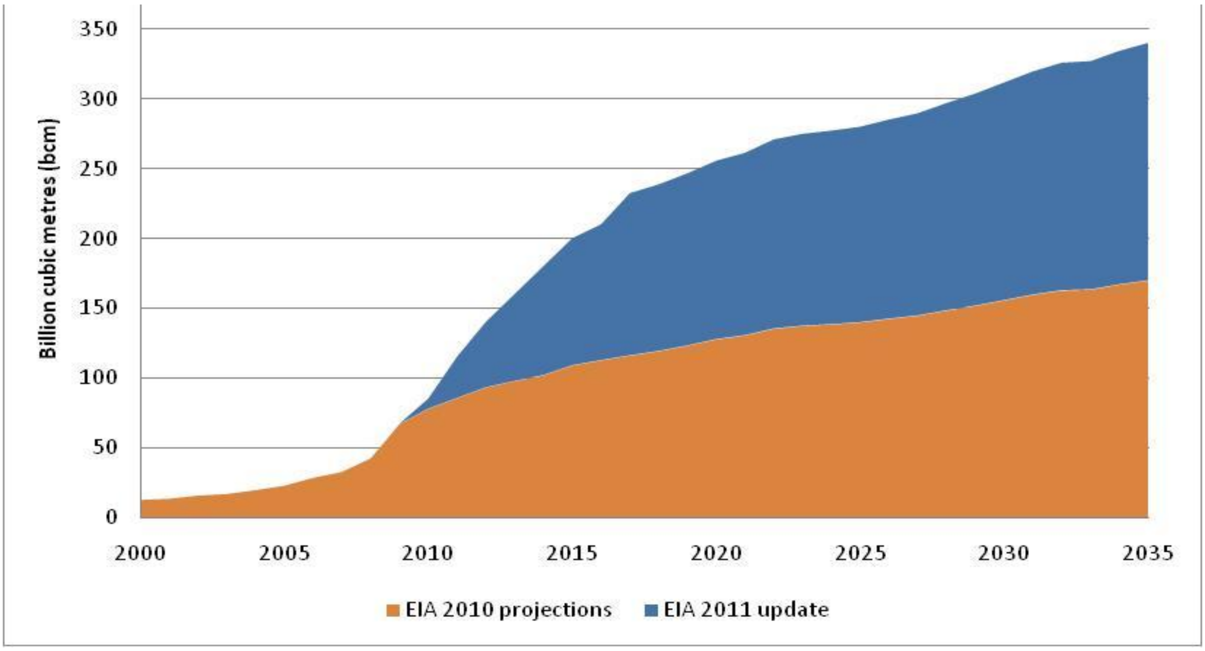
Figure 2.7: Growth in US shale gas production 1990-2008 (US EIA AEO, 2010a)



EIA projections for future production and consumption to 2035

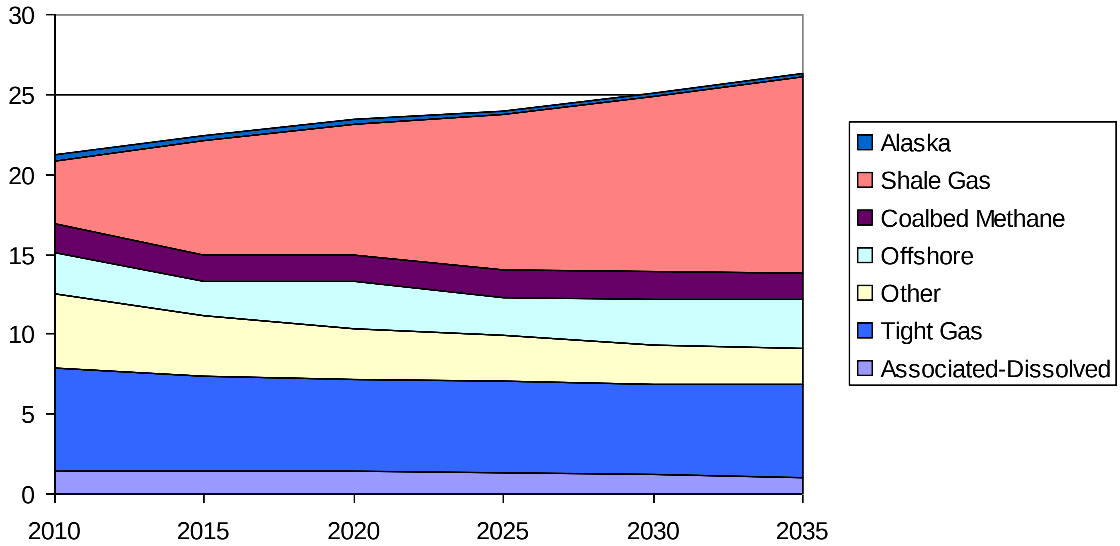
Figure 2.8 shows EIA data on actual production and projections to 2035 for both EIA (2010a) and the updated figures from EIA (2010b).

Figure 2.8: US shale gas production 2000-2035 (US EIA AEO, 2010a and 2010b)



In the EIA projections, expansion in shale gas is accompanied by contractions in other US gas production. Figure 2.9 shows anticipated supply of natural gas and the contribution of gas by source to 2035 taken from Annual Energy Outlook reference scenario (EIA 2011). These projections suggest an increase in the contribution of shale gas to overall gas consumption from around 14% in 2009 to 46% in 2035.

Figure 2.9: US natural gas supply 2010-2035 (EIA 2011)



EIA projections also predict the overall primary energy consumption mix to 2035. Figure 2.10 shows the composition of anticipated US primary energy consumption remaining broadly the same as at present with an overall increase in absolute quantities consumed.

Figure 2.10: US primary energy consumption by source 2010-2035 (EIA 2011)

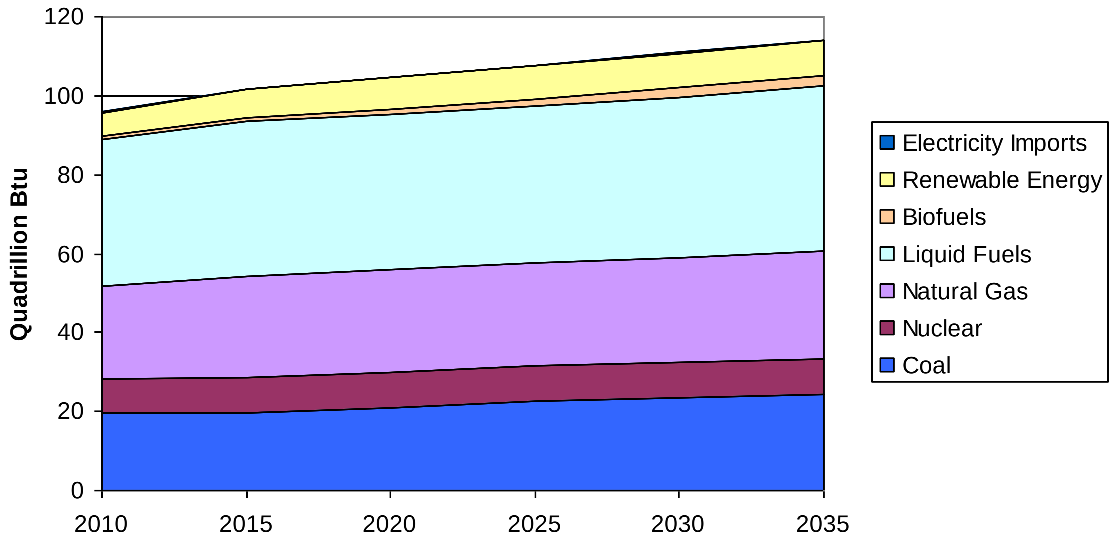


Table 2.11 summarises percentage changes in primary energy consumption in the US EIA data plotted in Figure 2.10. As can be seen from the table, EIA's reference projection is that total annual energy consumption will rise by 20% by 2035. The largest relative changes in consumption are in liquid fuels, biofuels and renewables. Natural gas consumption is expected to fall slightly in relative terms despite the transition to shale production. The expected role of coal within the overall mix is a relative increase of 0.5% by 2035 and an absolute consumption increase of 23% by the same year. Based on the EIA projections set out in Figure 2.11, one might argue that, given present regulatory conditions, shale gas may at best curb the rate of growth in coal consumption, which is still set to increase by 23% by 2035.

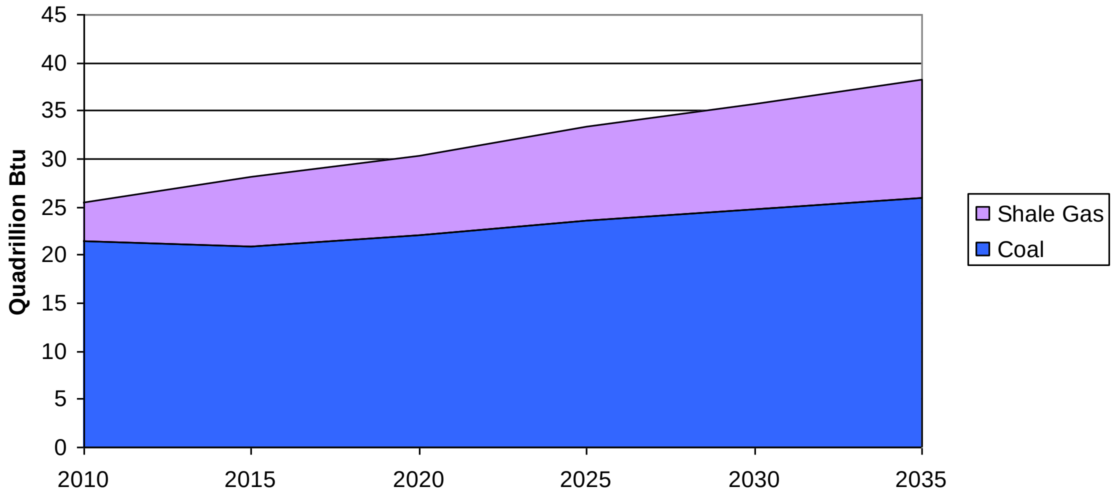
Table 2.11: Change in US primary energy consumption by source 2009-2035 (EIA, 2011)

	US Primary Energy Mix 2009	**US Primary Energy Mix 2035**	**% Change in relative proportion**	**% Increase in absolute energy consumption 2009 vs 2035**
Coal	20.8%	21.3%	0.5%	23%
Nuclear	8.8%	8.0%	-0.8%	9%
Natural Gas	24.6%	23.9%	-0.7%	17%
Liquid Fuels	38.7%	36.6%	-2.1%	14%
Biofuels	0.7%	2.2%	1.5%	282%
Renewable Energy	6.2%	7.9%	1.7%	55%
Total				20%

In relation to the assumption that shale gas could be a bridging fuel as a transitional step to a low carbon economy, even if shale GHG intensity was substantially lower than coal, the EIA projections suggest that substitution cannot be assumed in the

US. Further, to date there seems to be little sign that shale gas has substituted for coal use at the global level. Within the US the recent rapid increase in shale gas extraction and use has been accompanied by a reduction in the proportion of coal-based electricity generation, although absolute consumption of coal has not altered significantly.[24] At the same time, the US export of coal has increased markedly, net exports trebling from 2007 to 2010, and is anticipated to grow with increasing exports to China and the wider Asian markets.[25]

Figure 2.11: US production of coal and shale gas 2010-2035 (EIA, 2011)



2.4 Development of shale gas in the UK

2.4.1 Shale potential in the UK

Estimates of Total UK Shale Reserve Potential

In terms of shale gas potential, according to the British Geological Survey (BGS)[26], the UK has abundant shales at depth but their distribution is not well known. BGS and the UK Department of Energy and Climate Change (DECC) published the report *Unconventional Hydrocarbon Resources of Britain's Onshore Basins - Shale Gas* in December 2010. Making some assumptions and applying analogies with similar producing shale gas plays in America, BGS estimated the UK shale gas reserve potential at 150bcm. The report identified significant potential areas in northern England, including the Widmerpool Gulf near Nottingham and a large area centred on the Elswick Gasfield, near Blackpool.

In relation to the 150bcm estimate in the 2010 report, BGS noted that the US analogies used to produce the estimate may ultimately prove to be invalid, adding a

[24] http://www.eia.gov/electricity/annual/
[25] http://www.eia.gov/cneaf/coal/quarterly/html/t4p01p1.pdf
[26] http://www.bgs.ac.uk/research/energy/shaleGas.html

number of caveats including that the gas content of UK shale deposits is unknown, that environmental impacts of the processes are likely to limit development and that, in contrast to the US (where landowners benefit financially from developments), in the UK there are fewer/no local people with any vested interest in the success of projects.

Clearly, at present, estimates of the size of the UK's gas reserves do not include shale gas. UK gas reserves are categorised as per the scheme outlined on p32. For comparison with the BGS 150bcm estimate, according to DECC[27], the central estimate of conventional gas reserves based on proven plus probable reserves was 520bcm at the end of 2010 with proven conventional gas reserves of 267bcm and net production of 54.5bcm per annum. At the maximum level, remaining conventional gas reserves, based on a total of proven, probable and possible reserves, are 781bcm. The US Energy Information Administration estimates UK technically recoverable shale gas resources, a broader definition, to be a lower quantity at 566bcm (EIA 2011b).

Estimates from Individual Licence Areas

In terms of estimates from individual licence areas, four companies have provided estimates of reserve potential and one additional company has identified that shale gas deposits may lie in its licence area.

Cuadrilla Resources

Cuadrilla Resources is currently exploring the potential for commercial shale gas extraction within the Bowland Shale in Lancashire. The company's UK Petroleum Exploration and Development Licence (PEDL) was granted in September 2008[28]. Work on the first test well started in August 2010 at Preese Hall farm, a second was started in late 2010 at Grange Hill Farm and drilling commenced on a third near the village of Banks in August 2011. To date, fracking has only taken place at Preese Hall farm. Cuadrilla has now begun feasibility assessments for a potential detailed geophysical survey off the Fylde area, with a view to commencing in March 2012.

Based on data from this initial exploration, Cuadrilla Resources announced its first estimate of the volume of gas within its licence area on the 21st September 2011. It estimated a total gas initially in place of 5,660bcm gas of which, assuming 20% is recoverable, translates to around 1,132bcm of recoverable resource.

Island Gas Limited

Island Gas Limited, IGL, and its subsidiary IGas Resources PLC, operate in the north of England and north Wales. On 15 February 2010 it announced that it had identified a significant shale resource within its acreage. The reserves identified

[27] https://www.og.decc.gov.uk/information/bb_updates/chapters/reserves_index.htm
[28] A PEDL is the terrestrial equivalent of a traditional offshore production licence. It is awarded for six years initially, on the basis of the applicant demonstrating technical and financial competence and an awareness of environmental issues. The licensee is also required to demonstrate that they have obtained access rights from relevant landowners and complied with other statutory planning laws.

(using existing borehole logs in the locality) were identified as potentially extending over 1,195km^2 with an expected average thickness of 250m.

In October 2010 IGL gave a range of values for gas initially in place (GIIP) as between 2.5bcm and 131bcm, with a risk factor of 50%, for its North Wales licence areas. No estimate was made/published of recoverable volume. IGL identifies that, although it intends to conduct further work to better understand the potential of its shale holding, it has no plans to develop it at the moment[29].

Eden Energy

On 30 May 2011 Eden Energy announced unrisked prospective UK shale resource estimates to the Australian Securities Exchange. This identifies that Eden commissioned an independent expert report from RPS Ltd in respect of prospectivity in the 806 km^2 of the 7 PEDLs in South Wales where the Namurian Measures are interpreted as occurring. RPS calculated the following unrisked shale gas resource volumes at 90% probability of recovery (P90):

- Volume of gas initially in place (GIIP) - 968bcm; and
- Recoverable Volume - 362bcm.

Greenpark Energy

Greenpark Energy has licences to explore both coal and shale formations across 3000km^2 in the UK. Its operations are primarily concerned with coal bed methane (CBM) stimulated by a nitrogen foam fracking process, however, it has indicated that it may investigate shale formations within the same areas. The respective split in reserve estimates between the two sources is not clear. In early November 2011 it was reported that Greenpark has received permission to use hydraulic fracturing in wells at Canonbie, Dumfries and Galloway, a 25km^2 area that it has been test drilling since 2009. The company also lodged an application with the Scottish Environmental Protection Agency (SEPA) to use the technique at a second site.

Composite Energy

In the first version of this report, January 2011, we noted that Composite Energy had reported that it had identified shale potential within its licenses and was working to establish approaches to shale operations in a UK and European context. Composite Energy has since been taken over by Dart Energy, a company primarily oriented towards coal bed methane extraction with 15 licences across the UK. However, they note that their PEDL 1333 licensed area contains shale as well as coal formations with an estimated 34 bcm of gross gas initially in place.[30]

Comments on Comparability of BGS and Other Estimates

Clearly, when compared to the BGS estimates for the UK, the estimates of reserves provided by licence holders suggest much larger reserves. BGS estimates were

[29] http://www.igasplc.com/shale.aspx
[30] http://www.dartenergy.com.au/page/Worldwide/United_Kingdom/United_Kingdom/

based on the relative size of US basins and an assumed data comparison with UK and as such used no measured data on the gas content of the rock (as none were available). In terms of estimates from licence holders, only those of Cuadrilla Resources are informed by measured data, from two wells. In personal communications BGS identified that it does not have access to these measured data (and the announcement came after publication of the BGS estimate) and noted that the higher estimate is associated with extrapolation of these data to a greater number of (perhaps three) formations of greater thickness over the whole licence area. BGS also noted, however, that only more extensive drilling can determine whether this extrapolation is valid, highlighting the case of the offshore Falklands where early drilling revealed only dry oil wells and resulted in the reserve being written off, before subsequent discoveries by Rockhopper Exploration reversed this conclusion.

In terms of other estimates, BGS did not calculate figures for Carboniferous shales that haven't sourced conventional hydrocarbon fields as, without measured data, it is too early to know whether they can make a contribution. Eden Energy estimates for South Wales fit into this category. In terms of all estimates from licence holders, it should be noted that these licence holders need to appeal to shareholders and, as such, estimates may be optimistic.

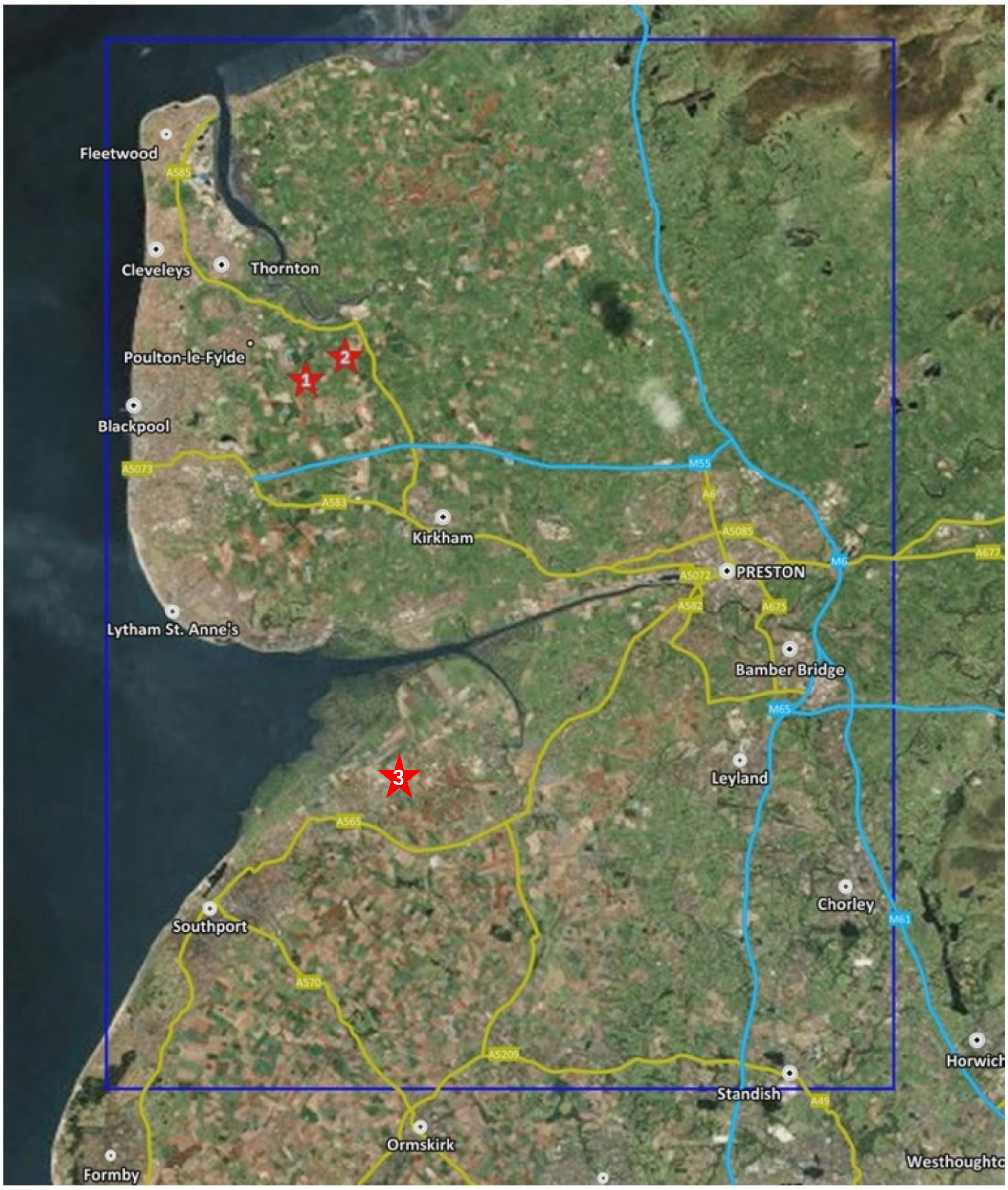
2.4.2 Exploratory and Commercial Development in the UK

At present, Cuadrilla Resources is the only company with shale gas infrastructure in place in the UK. It has five exploratory well pads with planning permission and of these exploratory drilling has taken place at three; Preese Hall, Grange Hall Farm, and Banks. Figure 2.12 provides a map of the 437 square mile (1,130 km^2) licence area and the location of the three drilled wells.

As noted above, based on data from its two wells, Cuadrilla has estimated a total gas initially in place of 5,660bcm of which, assuming 20% is recoverable, translates to around 1,132bcm of recoverable resource. Before a decision on commercial development can be made, however, further exploration is required to verify the resource potential.

A report on economic benefits of exploitation (prepared for Cuadrilla by Regeneris Consulting) provides information on Cuadrilla’s future plans under a range of development scenarios. This report identifies that in the region of four to twelve test wells will be required as part of the exploration phase, roughly proceeding at the pace of three test wells per annum. The precise location of the future test wells within the licence area has not yet been confirmed. If the exploratory phase identifies sufficient commercially exploitable reserves, a commercial development phase will follow by 2013, subject to the necessary national and local licensing and planning approvals. Regeneris Consulting (2011) detail three commercialisation scenarios (low, medium and high), described in Table 2.12, for the development of 190, 400 and 810 wells over 6, 9 and 16 years respectively.

Figure 2.12: Cuadrilla Resources' Licence Area and Test Wells (Regeneris Consulting 2011)



Note: 1: Preese Hall; 2: Grange Hill Farm. The blue boundary represents the Bowland Shale licence area. Source: Microsoft Bing Maps/Pitney Bowes Mapinfo.

Source: Regeneris Consulting (2011) supplemented to include site 3 near Banks.

Table 2.12: Commercialisation Scenarios for Cuadrilla Resources, Bowland Shale (Regeneris Consulting, 2011)

	Well Construction over time (number of wells completed)		
Year	**Low**	**Central**	**High**
2013	20	20	20
2014	30	30	30
2015	40	40	40
2016	40	60	60
2017	40	60	60
2018	20	60	60
2019		60	60
2020		40	60
2021		30	60
2022			60
2023			60
2024			60
2025			60
2026			60
2027			40
2028			20
Total Wells	**190**	**400**	**810**
Wells per pad	10	10	10
Total Pads	20	40	80
Duration of activity (years)	6	9	16
Peak activity (wells drilled per year)	40	60	60

Gas Production

In terms of estimated gas production associated with these development scenarios, Figure 2.13 provides an estimate based on the typical well production values given in Section 2.2.5. As can be seen, production ramps up in the first few years of production before tailing off. Table 2.13 provides summary data on estimated cumulative, average annual and min/max gas production over the period. As can be seen from this, the commercial development of the resource would provide an annual average of 0.7 to 2.8bcm of gas. Annual UK gas consumption in 2010 was 91bcm (DUKES, 2010), so this equates to around 0.8% to 3.2% of UK consumption in 2010. Cumulative production to 2040 is estimated at between 19.7 and 76.7bcm depending on the scenario. This represents between 1.7% and 6.8% of the estimated 1132bcm recoverable resource.

Figure 2.13: Estimated gas production to 2040 under Cuadrilla Commercialisation Scenarios

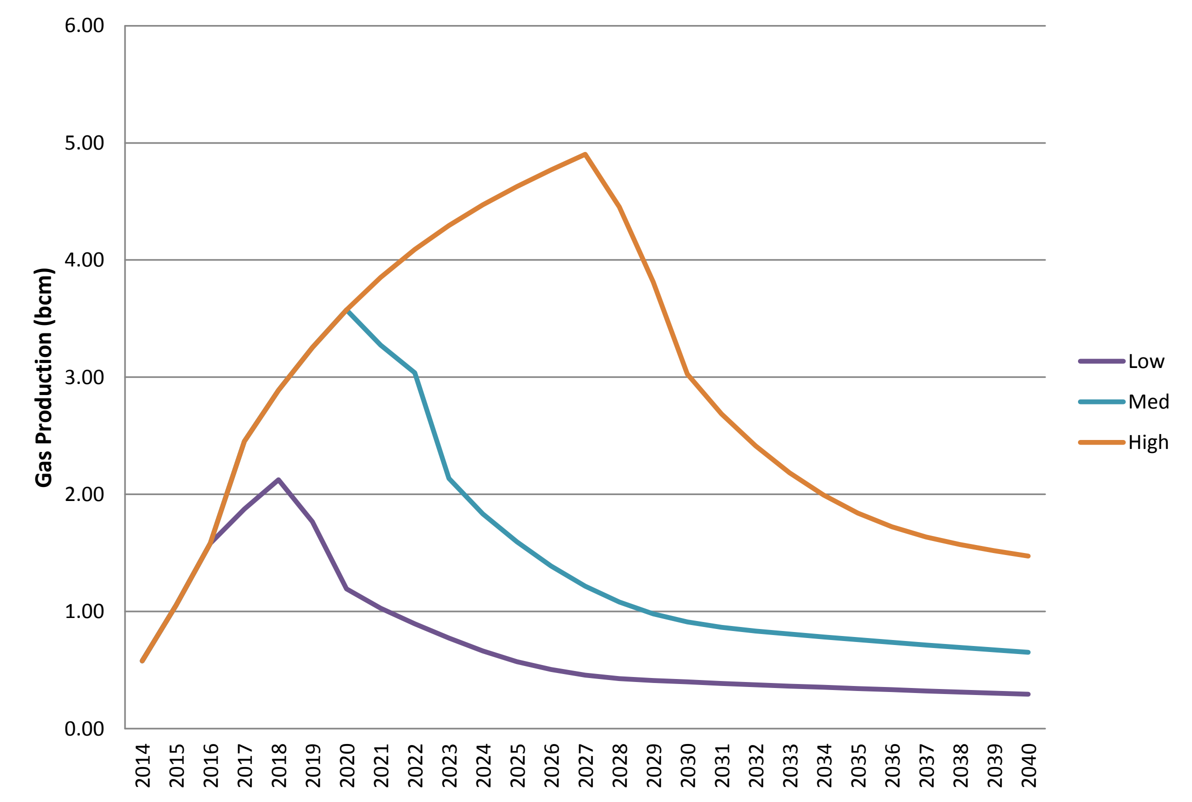


Table 2.13: Estimated Gas Production Statistics under Cuadrilla Commercialisation Scenarios (2014–2040)

	Low	Medium	High
Cumulative Production (bcm)	19.7	40.3	76.7
Cumulative as a percentage of estimated recoverable resource (1132 bcm)	1.7%	3.6%	6.8%
Average annual production (bcm)	0.73	1.49	2.84
Average annual production as a percentage of UK consumption in 2010 (91bcm)	0.8%	1.7%	3.2%
Min production in single year (bcm)	0.29	0.58	0.58
Max production in single year (bcm)	2.12	3.57	4.90

Resource Use

In terms of resources used in well construction and operation, Table 2.8 collates data based on typical wells in the US. However, disclosure of chemicals and water use by Cuadrilla Resources suggests that, to date, fracturing methods applied in the UK have used much smaller quantities of chemical additives with 3.7m^3 polyacrylamide friction reducer used in the Preese Hall 1 well. Water use (at 8,399 cubic metres per well) is also at the lowest end of the range reported on in Table 2.7. Combining the two, and assuming that resource use on exploratory wells and commercial wells is the same, provides the implied resource use per well.

Table 2.14: Resource Requirements per well under Cuadrilla Development Scenarios (based on a combination of Cuadrilla data (Regeneris Consulting, 2011) and US data in Table 2.6)

	Resources Use per Well	
Wells	1	
Well pads	0.1 (i.e. 10 wells per pad)	
Well pad area (ha)	0.7	
Water volume (m^3)	8,399	
Fracturing chemicals volume (m^3)	3.7	
Cuttings volume (m^3)	138	
Incorporating US data from Table 2.8:		
	Low Estimate	**High Estimate**
Flowback fluid volume (m^3)	1,232	6,627
Total duration of surface activities pre production /days	83	250
Total truck visits	719	1,098

Applying these data to Cuadrilla's commercial development scenarios provides the estimates of total resource use under each scenario in Table 2.15. As noted above, this assumes that resource requirements of exploratory wells and commercial wells are the same and that chemical inputs continue at the same rate as declared for the first hydraulic fracturing. Operational and geological conditions will clearly influence outcomes and these figures provide only an approximate indication of range.

Table 2.15: Estimated Resource Requirements under Cuadrilla Development Scenarios

	Scenario					
	Low		**Medium**		**High**	
Average annual production (2014-2040) (bcm)	0.73		1.49		2.84	
Cumulative Production (2014-2040) (bcm)	19.68		40.34		76.72	
Wells	190		400		810	
Well pads	19		40		81	
Cuttings volume (m^3)	27,567		55,133		110,267	
Water volume (m^3)	1,679,800		3,359,600		6,719,200	
Fracturing chemicals volume (m^3)	740		1,480		2,960	
Range	**Low**	**High**	**Low**	**High**	**Low**	**High**
Flowback fluid volume (m^3)	246,371	1,325,304	492,741	2,650,609	985,483	5,301,217
Total truck visits	143,833	219,667	287,667	439,333	575,333	878,667

2.4.3 Further Commercial Development in the UK

As can be seen from Table 2.13 the higher scenario involving development of 810 wells is estimated to provide a cumulative total of 76.7bcm of gas to 2040. In terms of current UK gas consumption, this total sum of production is equivalent to 10 months of UK consumption. This suggests that to achieve a meaningful quantity of gas production for UK consumption requires the development of significantly more wells than the number being considered in the Blackpool area.

Based on typical volumes of single well production given in Section 2.2.5, it is possible to calculate the minimum number of wells and well pads necessary to deliver sustained annual production, over a period of 20 years, equivalent to 10% of the UK's annual consumption[31].

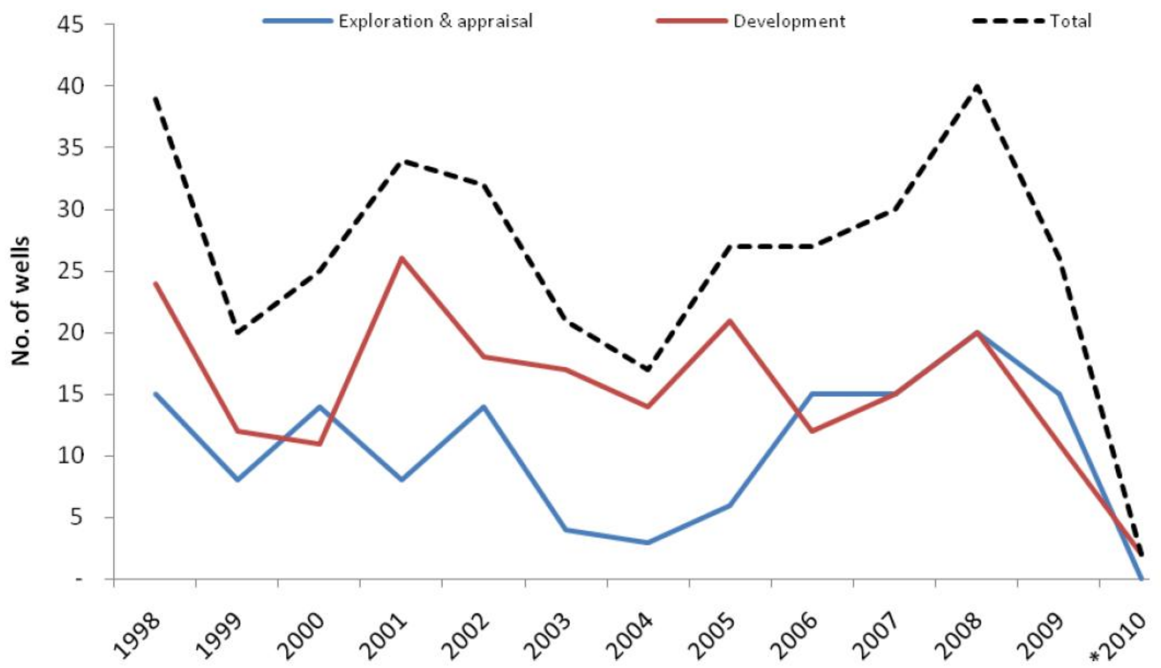
This has been achieved by calculating how may wells would need to be online in Year 1 to achieve 9bcm output (based on production in the first year), how many additional (new) wells would need to come online in Year 2 to counteract the decline in output from those that came online in Year 1, how many new wells would need to come online in Year 3 to counteract the decline in those that came online in Years 1 and 2, etc. over a 20 year period[32].

In terms of the lifetime of a well, productivity decreases rapidly over the first 5 years. An analysis of Barnett shale wells (Berman, 2009), for example, suggests that the average lifetime of horizontal shale well is around 7 years (and that the mode is 4 years). As such, it has been assumed that wells are no longer economical in years 8 onwards and production ceases.

[31] Annual gas consumption in the UK in 2010 was around 91bcm (DUKES, 2010)
[32] For the refracturing scenario it has been assumed that 50% of wells are fractured once and outputs from these are 25% higher than unfractured wells.

The rapid decline in production from one year to the next means that new wells and well pads need to be constantly developed to sustain an output of 9bcm/year. Over a 20 year period, between 2,600 and 3,000 wells (or around 260 to 300 well pads) would need to be developed to deliver sustained annual output equivalent of 9bcm/year. This represents an average of between 130 and 150 wells constructed per year. For comparison, DECC (2010a) identifies that 2000 onshore wells have been drilled in the UK to date and, as shown in Figure 2.14, around 25 onshore wells have been drilled per year in the UK for the last decade. Annual onshore well completion in the UK would have to increase by a factor of between 5 and 6 times to deliver 10% of UK consumption from shale gas.

Figure 2.14: Number of Onshore Wells Drilled 1998-2010 (DECC, 2010a)
*2010 figures for first quarter only



Resource Use

Based on the combined Cuadrilla and US data (in Table 2.14), Table 2.16 provides the total resources required to deliver 9bcm per year, equivalent to 10% of UK consumption in 2010.

Table 2.16: Resource requirements to deliver 9bcm per year for 20 years

	Assuming No Re-fracturing		**Assuming a Single Re-fracturing on 50% of Wells** (delivering an assumed 25% increase in productivity for those wells)	
Wells	2,970		2,592	
Well pads	297		259	
Cuttings volume (m^3)	409,365		357,264	
Water volume (m^3)	24,945,030		32,655,312	
Fracturing chemicals volume (m^3)	10,989		14,386	
	Low	**High**	**Low**	**High**
Flowback fluid volume (m^3)	3,658,604	19,680,768	4,789,446	25,763,915
Total truck visits	2,135,925	3,262,050	2,732,400	4,132,080

2.4.4 Shale potential in Europe

Within Europe, Poland, France, Norway, Sweden and Ukraine are estimated to possess large technically recoverable resources (EIA 2011b). Of these, Poland and France have the greatest potential, and whilst exploration has commenced in earnest in Poland with drilling, hydraulic fracturing and seismic surveys, the French parliament passed a ban on hydraulic fracturing on 30 June 2011.[33] Poland has granted more than 90 exploration licences to major and independent oil and gas companies and anticipates to be producing commercially from 2014[34]. There have been calls by MEPs to develop EU wide regulations on hydraulic fracturing, however, this has been publically disputed by the Polish government.[35]

[33] http://www.lemonde.fr/planete/article/2011/06/30/gaz-de-schiste-le-parlement-interdit-l-utilisation-de-la-fracturation-hydraulique_1543252_3244.html
[34] http://www.reuters.com/article/2011/09/18/poland-shale-idUSL5E7KI0BZ20110918
[35] http://www.euractiv.com/energy/poland-lobbies-eu-shale-gas-regulation-news-508136

3. Estimation of GHG implications of shale gas

3.1 Introduction

This section responds to three key questions:

1) How much energy and GHG emissions are associated with the extraction and processing of shale gas compared to gas derived from conventional sources?
2) Assuming there are additional GHG emissions associated with the extraction of natural gas from shale, do these additional emissions outweigh the direct emissions savings from combusting natural gas rather than coal?
3) What contribution could the combustion of shale gas make to UK and global emissions?

There is limited verifiable data available to answer these questions in detail, therefore an attempt has been made to highlight the GHG emissions associated with key production points for shale gas that are additional to any processes required for extracting conventional gas. The analysis is based on non-peer reviewed data from a limited number of site measurements. The GHG data is the best publicly available at present but is subject to high level uncertainty and may change significantly over time as the industry develops.

3.2 GHG emissions - gas from shales versus conventional sources

This section provides an overview of the additional GHG emissions associated with extracting natural gas from shale compared to a conventional source. There is limited publicly available information that is suitable for carrying out an in-depth life cycle assessment of shale gas compared to conventional gas extraction. As in the case of conventional gas sources, the size of the emissions associated with extraction is, in part, dependent on the attributes of the reservoir.

It is assumed that the combustion of natural gas emits the same amount of CO_2 whether it comes from shale or conventional sources. In the UK, natural gas extracted from gas shales is also likely to use the same distribution methods as that from conventional sources, and is therefore subject to the same distribution losses.

The main points of difference between the GHG emissions associated with shale compared to conventionally sourced gas lie in the extraction and production processes.:

- The horizontal drilling and hydraulic fracturing processes, which are essential to the successful extraction of gas.
- the transportation of water and chemicals to the well site for hydraulic fracturing
- the removal of this waste water/chemical mix after fracturing.

Data on expected emissions from extraction at the Marcellus Shale in the US is drawn from a report by the New York State Department of Environmental Conservation (2009) supplemented with guidance from others (Al Armendariz, 2009; Worldwatch Institute 2010; IHS CERA, 2010).

3.2.1 Comparator studies of GHG footprint of unconventional gas and key issues arising

Two top-down assessments of the footprint of electricity produced in the US from natural gas have been presented during 2011, one in the academic literature (Venkatesh et al, 2011), the other a consultancy report (DBCCA, 2011). Both consider emissions from the US gas system as a whole, including gas associated with oil wells, LNG imports, shale gas and conventional sources. These methodologies do not discriminate between conventional and unconventional production and as such have limited applicability to an assessment of the potential impact of UK unconventional versus conventional gas production.

Two bottom-up assessments of the greenhouse gas emissions from unconventional gas production in the US have been published in the peer reviewed literature in the same period (Howarth et al, 2011; Jiang et al, 2011). A third bottom-up assessment from the U.S. National Energy Technology Laboratory has also been released, which although from a reputable body does not clearly identify its input data (Skone et al 2011).

Key issues raised by these studies and accounting for much of the variation between their findings are:

- the absolute quantities of fugitive methane emissions from flowback following hydraulic fracturing;
- the Global Warming Potential (GWP) chosen to compare climate change impact of methane, the major component of natural gas, with carbon dioxide; and
- well productivity estimates, against which emissions estimates are normalised

In our earlier report (Wood et al, 2011) we found that whilst there may also be additional vented and/or fugitive emissions associated with the drill site and drill tailings, there was no reliable data available to enable these to be quantified. Our analysis is now updated in Section 3.2.4 to reflect the findings of these new studies and integrate them with our previous work.

3.2.2 'Additional' emissions associated with the extraction from shale on a per well basis

The extraction of natural gas from conventional sources and shale reservoirs on land-based wells follow many of the same procedures as outlined in Section 2.2. Emissions during extractions can be divided into three main sources:

1) Combustion of fossil fuels to drive the engines of the drills, pumps and compressors, etc, required to extract natural gas onsite, and to transport equipment, resources and waste on and off the well site;
2) Fugitive emissions of natural gas that escape unintentionally during the well construction and production stages; and
3) Vented emissions resulting from natural gas that is collected and combusted onsite or vented directly to the atmosphere in a controlled way.

Section 3.2.3 focuses on the first of these, whilst Section 3.2.4 discusses fugitive and vented emissions of natural gas. Section 3.2.5 provides a comparison of the impacts of shale with conventionally sourced natural gas per unit of extracted energy. Finally, these issues are brought together in Section 3.2.6 and discussed in relation to other fossil fuels.

3.2.3 Combustion of fossil fuels during extraction

Emissions during well pad construction

The main sources of GHG emissions from these steps are from the transport fuels used to transport drilling equipment and materials to the site, and onsite equipment used to provide power to operations. This step is common to both conventional and non-conventional sources. Part of the rig setup is the 'prime mover' that provides power to the rig. Prime movers are usually powered by diesel but engines running on natural gas or petrol are also available. Alternatively, rigs may be powered by electricity, produced onsite with a gas or petrol reciprocating engine or sourced directly from the grid. The size of prime mover depends on the depth required to be drilled and ranges from 500hp for shallow drilling rigs to over 3,000hp for depths approaching 6,000m (Naturalgas.org, 2010). Emissions associated with these stages will depend on the depth required for drilling and the number of wells drilled per site (see Section 2.2.2).

Emissions from drilling

As noted in Section 2.2.1 the initial drilling stages for gas shales are almost identical to vertical wells typically used in conventional gas production. Table 3.1 provides a comparison of the depths of conventional and shale wells in the US. However, the available data does not give a clear indication of whether shale is typically deeper or shallower than conventional sources. A recent DECC report states that one of the key criteria for successful shale gas sites in the USA is a well depth from the surface of between 1,000–3,500m (DECC, 2010). For the purposes of this study, emissions associated with vertical drilling are assumed to be similar for both shale and conventional sources. It should be noted that while some conventional gas wells have been stimulated using hydraulic fracturing methods, hydraulic fracturing and horizontal drilling is an absolute requirement for shale wells.

The emissions associated with the horizontal drilling are, without more specific data, assumed to be the same as those emitted during vertical drilling. ARI (2008) assume diesel fuel consumption in vertical well drilling of 18.7litres/m drilled[36]. This figure would equate to an emission factor of 49kgCO_2/m.

The additional fuel required to employ horizontal drilling is site specific. Assuming the same emissions from vertical drilling, additional horizontal drilling of between 300–1,500m (ALL Consulting 2008) could lead to an extra 15–75tCO_2 being emitted compared to a conventional well that does not use horizontal drilling. Figures from Marcellus Shale suggest a lateral length of 1-1.5km, this equates to 49-73.5tCO_2 per well at that site.

Table 3.1: Comparison of vertical well depth of example shale reserves compared to conventional sites

Type	Reservoir	Depth (m)	Source
Shale	Marcellus USA	1,500 - 2,400	"Gas well Drilling and Development, Marcellus Shale, June 12 2008 Commission Meeting" www.srbc.net cited in Delaware Riverkeeper,2010.
	New Albany Shale	150 – 750	Aurora Oil and Gas Corp cited in Wagmen, D. (2006)
	Antrim Shale	75 - 450	Aurora Oil and Gas Corp cited in Wagmen, D. (2006)
	Fort Worth Basin	600-2,400	Bankers Petroleum cited in Wagmen, D. (2006)
Conventional (supply region)	Northeast	1,350 (average)	ARI, 2008 (assumptions based on the use of the "ICF Hydrocarbon Supply Model)
	Midcontinent	1,950	
	Rocky Mountain	1,050	
	Southwest	2,550	
	West Coast	1,950	
	Gulf Coast	3,150	

[36] www.arb.ca.gov/ei/areasrc/ccosmeth/att_I_fuel_combustion_for _petroleum_prodiction.doc).

Emissions from hydraulic fracturing process

It is in this stage where one of the main sources of additional emissions required for extracting gas from shale compared to conventional sources can be found. These arise from the blending of fracturing materials (pumped from storage vessels of water, chemicals and sand) followed by the compression and injection of the fracturing material into and out of the well.

Currently, much of this is carried out by diesel engines. However, alternative lighter fuels or electricity could be used to reduce emissions during this stage. New York State (2009) reports the emissions from the use of high-pressure volume pumps based on average fuel usage for hydraulic fracturing on eight horizontally drilled wells in the Marcellus Shale[37]. The total fuel use given equates to 110,000litres diesel fuel producing 295tCO_2 per well.

During the completion stage, transportation is required to and from the site of the chemicals and water used for fracturing. All require clean up and/or storage post use. INGAA Consulting (2008) and www.Naturalgas.org (2010) suggest up to 13,200m^3 of water are required per well for hydraulic fracturing with existing technologies, and New York State (2009) give a figure of between 9,000 and 29,000m^3 per well. Emissions associated with the use of water and chemicals will depend on the water source and type of chemicals used, which are often site-specific, depending on the geology of the formation and are often treated as commercially confidential.

Wastewater disposal is an additional burden for shale gas reservoirs, as noted in Section 2.2.2 estimates of the fluids recovered range from 15-80% of the volume injected depending on the site (US EPA, 2010). In the US, many operators inject the waste liquid from fracturing into saline aquifers, this is not the only option and increasingly, water recycling is likely to be used. A number of pilot projects at Barnett Shale have recycled water for use in further fracturing; distilling and separating the water from the remaining wastewater onsite ALL Consulting (2008b) citing Railroad Commission of Texas (2010). The heat required to recycle water using distillation methods is likely to be high given the large volume of liquid involved, however more innovative methods may reduce the energy intensity of this step.

In the UK, access to water is not as restricted as for some shale sites in the US and two broad options exist as to how water can be delivered to the shale site and waste water can be treated after fracturing. The choice of water source and disposal affect both the cost to the shale site owner and the GHG emissions released, and depends on three key factors: the duration of time that the water supply is to be required at a site; the location of site in comparison to reservoirs, rivers, raw water mains supply and wastewater treatment facilities; and the volume of water required at the site.

The first and perhaps preferable option is to use water from local reservoirs, rivers or raw mains supply and either transport it by truck or pump it depending on the specific location. This may require permission from local water authorities. Pumping will also

[37] ALL Consulting, 2009, Table 11 p10

have GHG emissions associated with it and may require planning permission to put the pipework in place. After fracturing, the wastewater would be disposed of by transporting it by truck to a wastewater treatment plant. The second option is to use potable water and either pump it from a local source or transport it by truck to the site. Potable water is more energy intensive to produce, more expensive and has higher GHG emissions associated with it. The wastewater could be cleaned on site and the water recycled for future hydraulic fracturing. This would mean less fresh potable water is required from the mains supply, reducing the overall energy intensity. However, chemicals and other wastes may still have to be transported to a waste water treatment site. In this report, the first option is considered, as it is deemed the most appropriate for the UK.

Emissions from the transportation of fracturing materials have been estimated using the numbers of truck visits estimated per well (see Table 2.5). At the plant, 0.406tCO_2 per thousand cubic metres is released to the atmosphere when treating the waste water (Water UK, 2006).

Additional emissions during well production

The final stage in natural gas extraction is to process and compress the gas for distribution. The chemical composition of the gas extracted from a shale formation is specific to the geology and comprises a mix of methane, other heavier hydrocarbons and CO_2. There is conflicting commentary on the respective ratio of longer chain hydrocarbons to methane and other constituents (ALL, 2008; INGAA, 2008). The composition will partly determine the energy and therefore emissions intensity of the production stage.

During the production stage, heavier hydrocarbons, and CO_2 if present, are removed and the remaining methane (or mix of gases according to national standards for the UK gas network) is compressed for distribution. The same steps are required whether the gas is sourced from a conventional site or from shale. The main difference in this stage will be the difference in the composition of gas evolved from shale versus conventional sites.

Summary assessment I: fossil fuel combustion emissions of shale versus conventional natural gas per well

Table 3.2 provides an overview of the additional fossil fuel combustion emissions associated with extracting gas from a shale reserve. To make a comparison with a conventionally sourced well, we assume all emissions would be equivalent with the exception of the processes involved in hydraulic fracturing and flowback stage.

Table 3.2: Key additional fossil fuel combustion emissions associated with shale gas extraction			
Process	**Emissions (tCO_2)**	**Assumptions**	**Data Source**
Horizontal drilling	15 – 75	Horizontal drilling of 300-1500m; 18.6 litres diesel used per metre drilled	Fuel consumption from: ALL Consulting (2008) Emission factor from DUKES (2010)
Hydraulic fracturing	295	Based on average fuel usage for hydraulic fracturing on eight horizontally drilled wells in the Marcellus Shale The total fuel use given is 109777 litres of diesel fuel	Cited from ALL Consulting "Horizontally Drilled /High-Volume Hydraulically Fractured Wells Air Emissions Data", August 2009, Table 11 p 10 by New York State (2009). Emission factor from DUKES (2010)
Hydraulic fracturing chemical production[a]	-	Unknown	
Transportation of water	26.2 – 40.8	Based on HGV emission factor of 983.11 g CO_2/km and 60km round trip	Emission factor from NAEI (2010). Truck numbers from Table 2.5.
Wastewater transportation	11.8 – 17.9	Based on HGV emission factor of 983.11 g CO_2/km and 60km round trip	Emission factor from NAEI (2010). Truck numbers from Table 2.5.
Wastewater treatment	0.33 – 9.4	Based on 15-80% recovery of 9-29 million litres of water that is required per fracturing process and emission factor 0.406t CO_2/ML treated	Emission factor from Water UK - Towards sustainability (2006). Water use and flow back rates from Section 2.2.3.
Total per well	**348-438**	**Based on single fracturing process**	

a: a further potential source of additional emissions may be the production of chemical used in the fracturing process. However, the level of these emissions is difficult to ascertain as: conventional wells may also include various chemicals in drilling mud and any fracturing activities so claiming shale creates additional emissions via this route is problematic; and LCA data for these chemicals is highly specialised and is not typically publically available data.

3.2.4 Fugitive and vented emissions of methane from hydraulic fracturing flowback and its impact on GHG footprint estimates

Fugitive emissions from well completion and refracturing were set aside in our previous accounting exercise due to insufficient reliable data (Wood et al, 2011). However, Howarth et al (2011), Jiang et al (2011) and Skone et al (2011) each include an estimate of this source in their analyses, presenting new data or inferring fugitive emissions from the pre-production and production characteristics of unconventional wells.

After fracturing, a proportion of the hydraulic fluid that that has been injected into the well at high pressure returns to the surface and is known as flowback. Natural gas from the formation, predominantly methane, also returns with this fluid at increasing concentrations over time. This process can occur over a period of days to weeks, the fluid being collected in an open pit of or enclosed tanks (EPA, 2010). The gas may be flared, i.e. combusted immediately in an open flame, or cold vented, i.e. directly released to the atmosphere, until such a time as the flow is deemed of adequate quality for capture and processing for sale.

Flaring reduces fire hazard on site and, in transforming methane and other volatile organics to carbon dioxide, reduces the climate change impact of the operation. However, flaring has been associated with local environmental impacts including air quality (NO_x, SO_2, Volatile Organic Compounds), light and noise intrusion and there are efforts to reduce its use in the oil industry (Sanchez et al., 2008; Christen, 2004).

The amount of gas respectively vented, flared or processed depends upon specific local operations and can be complicated by a number of additional factors (IHS CERA, 2011) including that:

- gas produced during flowback may be contaminated with carbon dioxide or nitrogen injected as part of the hydraulic fracturing or well completion;
- an inconsistent and low flow rate may make it difficult to sustain a flame on traditional flare stack;
- pipeline connections may not be ready at the well completion and shutting the well may be detrimental to its subsequent productivity. Sustained flaring may therefore be preferred by the operator;
- methane may not only return in the gas phase but also dissolved in the flowback fluid. Open pit collection necessarily allows this gas to be released, enclosed tanks afford the opportunity of collection for flaring.
- differening regulatory regimes

There are a number of remedial techniques such as gas/liquid separators that can be installed at the wellhead to retain gas for processing and sale. To this end, the US EPA Natural Gas STAR programme is a voluntary partnership promoting technology transfer and methane emission reduction[38].

The data provided by Howarth et al (2011) is gathered from five US wells and cited as originating in industry reports or EPA workshops. Three of the five are for tight sand rather than shale wells although it is argued that these are comparable processes with reference to EPA (2010). No account of remediation or capture technology is given, although other sources indicate that these data arise from capture operations and not venting (Barcella et al. 2011). The highest and lowest estimates are shown in Table 3.3 below. It should be noted that the highest estimate is an order of magnitude greater than the other four, however, this is a high productivity Haynesville well and whilst not such an outlier when normalised, flowback emissions are still said to represent 3.2% of lifetime production.

[38] http://www.epa.gov/gasstar/

Jiang et al (2011) do not provide any primary measurements of fugitive emissions from completion but simulate anticipated flows of gas at typical initial production rates based upon NY DEC (2009) and PA DEP (2010), for between 4 and 15 days. The analysis concludes with a very wide possible range, 38 to 1,470 thousand cubic meters of methane per completion and used a statistical uncertainty analysis to investigate different ratios of vented to flared gas. Although not made explicit, it is assumed, for the purposes of this report that the full range of figures in Table 3.3 is incorporated into the statistical uncertainty analysis presented by Jiang et al (2011). When normalised per terajoule (TJ) of gas produced, Jiang et al (2010) figure 3 illustrates a mean of 1.15 tCO_2e/TJ with a confidence interval from near zero to 4.6 tCO_2e/TJ. In this analysis, well completion emissions are by far the greatest absolute contributor to preproduction emissions and also those with the greatest statistical stated range.

Skone et al (2011) use a figure of 330,000m^3 of methane emissions per well completion and although they include a substantial reference list they do not specify the source of this figure. Their analysis shows that a substantial proportion of upstream emissions are attributable to well completion, 8.6% on the assumption that 15% of flowback emissions are captured and flared, but that a greater share of upstream emissions, 30.3%, is associated with well refracturing[39].

The US EPA also released new estimates of fugitive emissions and revised methodologies in 2011. Its latest figures are a substantial increase on previous 1996 estimates and derive emissions factors for well completions from four studies presented at Natural Gas STAR technology transfer workshops (EPA, 2010, p86). Each study has a range of underlying individual measurements from three to over a thousand. The EPA background technical document combines these studies to identify a figure of 260,000m^3 of fugitive methane emissions per well completion.

This figure and approach has received criticism from industry analysts IHS CERA concerning the assumptions used for regional patterns of venting, flaring and capture (Barcella et al. 2011). They argue that free venting from high productivity wells would lead to a substantial fire hazard on site which would not be tolerated by the industry or health and safety regulators. This claim requires empirical validation as with good site ventilation and limited sources of ignition it is plausible that cold venting large volumes of methane need not pose a fire hazard. IHS CERA also suggest that an alternative maximum estimate of 162,000m^3 of methane per completion can be calculated by taking the total production from the 18,672 gas wells drilled in the US in 2010 as 0.303bcm per day and assuming that each vents freely for the first 10 days of production. This method does not, however, distinguish unconventional from conventional wells, which may have different initial productivities and does not include any account of refracturing.

[39] A producing well may be subjected to further rounds of hydraulic fracturing to stimulate production.

Table 3.3: Summary of flowback fugitive emissions estimates			
Study	**Fugitive emissions from flowback (thousand m^3)** *tight sand well		**Methods, data sources, assumptions**
	Low	**High**	
Howarth et al 2011	140*	6,800	Five industry presentations, empirical data, lifetime emissions per well
Jiang et al 2011	38	1,470	Figures are given per flowback event. They are the upper and lower boundaries of an uncertainty model, not empirical data.
Skone et al 2011	132*	330	Data source not clearly identified. Figures are given per flowback event, re-fracturing assumed to be equivalent to completion
EPA 2010	19	566	Four industry reports, empirical data based on thousands of wells but synthesis opaque, refracturing assumed to be equivalent to completion

Appropriate metric for comparison of methane and carbon dioxide

A conversion factor is required to relate the climate change impact of fugitive methane emissions to the carbon dioxide emissions from other activities. A number of metrics are available to compare the consequences of releasing different greenhouse gases to the atmosphere. A gas's contribution to global warming depends upon its absorption of infrared radiation, its longevity and its ability to influence other atmospheric components physically and chemically. The most widely used metric is the Global Warming Potential (GWP) which is the ratio of the change in radiation balance from a pulse release of a given gas, integrated over a specified future time period, against the same change for a release of the same mass of carbon dioxide. GWP is frequently used in climate policy as a way of comparing well mixed, long lived greenhouse gases like carbon dioxide, nitrous oxide and methane. Typically a one hundred year time period is used for the calculation and revised estimates of GWPs are prepared as atmospheric science progresses.

It is important to note that a GWP is not an inherent property of the gas molecules themselves; a GWP is a function of the atmospheric model and its parameters, for instance the anticipated gas composition over time. However, they are often treated as "black box" figures without scrutiny as they are important to the operation of other systems that require stability, such as carbon trading schemes and national inventories (MacKenzie, 2009). The choice of timescale is a convention rather than a material fact; one hundred years was chosen for the Kyoto Protocol as it approximated to what was then considered the atmospheric lifetime of carbon dioxide emissions and was also a period relevant to social and political decision making. There are arguments for the use of shorter periods if we are concerned that positive feedbacks will be activated in the climate system in the near term.

In their abstract Howarth et al (2011) conclude that the GHG footprint of shale gas is substantially greater than that of conventional gas and comparable with coal, due to substantial methane emissions. This conclusion is quite different to Jiang et al (2011) who report substantial reductions in emissions intensity of shale gas relative to coal. The major difference in the conclusions that they draw relates to the choice of GWP timescale and source, Howarth et al (2011) emphasising a 20 year time horizon and a model including indirect radiative forcing, whilst Jiang et al (2011) adopt the more widely used 100 year horizon and IPCC AR4 report figure which includes direct forcing only. It is worth considering this divergence as it could substantially alter analytical conclusions, in absolute and relative terms, with ramifications for policy making.

Firstly, considering time period, whilst it is plausible that short term warming agents could have important climatic consequences, the consensus position is that cumulative emissions of carbon dioxide are the best indicator of climate change (Allen et al, 2011). Without compelling evidence for near term non-linearities, it seems appropriate to continue with the 100 year GWP (GWP_{100}) in policy decision making at present.

Secondly, the issue of indirect radiative forcing and the choice of GWP is not discussed fully in these bottom up assessments despite the difference between the AR4 figure, GWP_{100} of 25, and the Shindell et al (2009) figure cited by Howarth, GWP_{100} of 33, being over 30%. The main underlying reason for the difference is the inclusion of indirect radiative forcing, however, these processes are not yet well supported by a robust set of computer models[40].

In conclusion, it seems prudent to scale all LCA estimations to the IPCC AR4 GWP_{100} of 25, whilst recognising the potential for methane to have a greater warming effect in the short term.

3.2.5 Comparison of shale with conventionally sourced natural gas per unit of extracted energy

The significance of an additional 348 to 438 tonnes of CO_2 plus potential fugitive methane emissions for the emissions intensity of the extraction of shale compared to conventionally sourced gas is dependent on the rate of return per well. Again this is site specific; the larger the volume of natural gas that is extracted per well, the lower the significance of the additional fracturing emissions is on the whole system. If the absolute quantity of fugitive emissions from flowback at completion and subsequent fracturing events is divided over a comparatively low productivity then the difference between conventional and unconventional gas production will be pronounced, the converse being the case for high productivity wells.

[40] Direct radiative forcing is the change in energy balance in the atmosphere attributable to absorption by the specified gas's own molecules. Shindell et al (2009) also try to account for indirect radiative forcing; the change in radiative balance due to secondary chemical and physical changes attributed to the gas in question. The composition-climate model used, G-PUCCINI, incorporates gas and aerosol chemistry within a global circulation model (GCM), however, due to the high uncertainties in the model its GWP_{100} figure is not statistically different to the AR4 findings at the 95% confidence level. Further, there are substantial differences between models in their responses to sulphur processes (Goto et al. 2011) and aerosol interaction is an area of active research yet to reach a robust consensus (Hallquist et al. 2009; Reisinger et al. 2010).

The implications of the fracturing stage emissions on the overall emissions per terajoule (TJ) of energy extracted were estimated. We have used the data in Table 3.4 of emissions per well and data from the literature for different shale well sizes. The emission rates should be treated with caution, as they are based on a number of assumptions many of which are based on findings for one shale gas field. The extent to which they are applicable to other shale gas reservoirs is unknown.

Table 3.4: Estimated CO_2e emissions per TJ of energy extracted per well lifetime

Gas shale basin	**Total production (m^3/well)**	**Additional CO_2e emissions (50% re-fracture once)[41] (tonnes CO_2e/TJ[a])**	**Source of Well Production Rate Information**
Antrim Shale (high)	22,653,600	0.65 - 0.81	Aurora Oil and Gas Group cited in Wagmen (2006)
Antrim Shale (low)	11,326,800	1.30 - 1.63	Wagmen (2006)
Barnett (ultimate)	67,960,800	0.22 - 0.27	Wagmen (2006)
Barnett (high-risk area)	31,148,700	0.47 - 0.59	Wagmen (2006)
Fayetteville (high)	48,138,900	0.30 - 0.38	Wagmen (2006)
Fayetteville (low)	36,812,100	0.40 - 0.50	Wagmen (2006)
Marcellus Shale	104,000,000	0.14 - 0.18	New York State (2009)
New Albany Shale (High)	33,980,400	0.43 - 0.54	Wagmen (2006)
New Albany Shale (Low)	19,821,900	0.74 - 0.93	Wagmen (2006)
Palo-duro	42,475,500	0.35 - 0.43	Wagmen (2006)
Woodford (high)	70,792,500	0.21 - 0.26	Wagmen (2006)
Woodford (low)	56,634,000	0.26 - 0.33	Wagmen, D (2006)

[a]Using net calorific value 35.6 MJ/m^3 (DUKES, 2010)

The results in Table 3.4, estimated CO_2e emissions per terajoule of natural gas that is extracted from different reservoirs highlights the importance of the production rate on the overall impact of the additional hydraulic fracturing step. With a low production rate, the emissions evolved during extraction make a higher contribution to total emissions/TJ (with a boundary around emission sources as described above).

With the publication of empirical data sources, outlined in Table 3.3, it is now possible to tentatively supplement our earlier calculation (Wood et al, 2011) of additional emissions arising from unconventional production. Given the acknowledged uncertainty within the data used by EPA (2010), Skone et al (2011), Jiang et al (2011) and Howarth et al (2011), and the limited knowledge of sampling and distributions within each, a simple upper and lower bound is calculated. It seems reasonable that the quantity of emissions during flowback will be positively correlated with the productivity of the well and will therefore produce unrealistic outcomes if

[41] Given the assumption of a well life of eight years (see Section 2.2.7) it has been assumed that the well is only refractured once. If the life of the well were to be extended further through additional fracturing then there would be additional emissions associated with each fracturing episode. This is further supported by DECC, which state in their report that refracturing could occur every 4-5 years in successful wells (DECC, 2010).

absolute flowback emissions from one group of wells are normalised against the productivity of another. We have therefore taken the upper and lower percentage of lifetime production of methane that is potentially emitted during flow back and applied this to our cases in Table 3.4.

Of the studies examined, these data are presented only in Howarth et al (2011), the range being 0.6% to 3.2%. It is not clear if this proportion emitted is per fracture event, of which there may be several, or the whole lifetime of the well. It is assumed to be the latter as total lifetime productivity is cited.

Additional CO_2e emissions due to flowback releases of methane calculated this way represent the same proportional impact for each well in Table 3.4. Normalised to the units used elsewhere in this study and, with a GWP_{100} for methane of 25, unmitigated this source adds 2.87 – 15.3 tCO_2e/TJ of gas produced.

Skone et al (2011) present a figure of $88m^3$ per completion with 1.1 refracturing events (workovers) during the lifetime of a conventional gas well. This is three or four orders of magnitude less than the data presented for shale gas. On this basis it is assumed that all the emissions from flowback are additional and distinctive to unconventional production.

Significance of fugitive emissions from hydraulic fracturing flowback

It is clear that there is the potential for substantial differences between the quantities of fugitive emissions arising from the flowback process in well completion. Capture of a large proportion of the methane from well completion is technically feasible. Indeed some US states mandate that such gas not be intentionally vented, for instance in Wyoming a “Green Completion” permitting scheme has been in operation in some areas since 2004, requiring producers to use specified best management practices (Corra, 2011). Skone et al (2011) notes that there is limited data available on the effectiveness of such measures at completion and refracturing. If such measures are not undertaken or prove to be ineffective then fugitive emissions from well completion and refracturing may add a substantial burden over conventional gas, out weighing the additional emissions from site operations. Further, the studies examined here do not find data available for fugitive emissions of gas from between the well casing and the ground, nor the possibility of leaks to the surface away from the wellhead (Osborn et al ,2011).

The calculations presented in Section 3.2.4 are based upon a small dataset from US wells and operations. Should shale gas exploration and exploitation continue to develop in the UK it seems prudent to require best management practices to minimise this potentially substantial source of emissions with a robust compliance and monitoring regime.

Summary assessment II: total GHG emissions of shale versus conventional natural gas per well

Table 3.5: Additional emissions associated with extracting natural gas from shale	
	(tCO_2e/TJ, equivalent to gCO2e/MJ)
Additional emissions associated with extraction operations from shale	0.14 – 1.63[a]
Possible additional fugitive emissions from hydraulic fracturing flowback	2.87 – 15.3[b]
Total possible additional shale gas emissions	3.01 – 16.9

[a] These figures are the upper and lower bounds of the emission estimates from Table 3.4, the figures depend on the amount of gas extracted per well and the assumed number of refracturing steps taken per well. In this case data is shown for one refracturing event with 50% additional operational emissions. Please note the figures represent the extremes of the data and assumptions used here and are not necessarily representative of all shale sites. Emissions associated with chemical production are not included due to poor availability of data.
[b] This assumes fugitive emissions from flowback over the lifetime of a well are predominantly vented, i.e. that wellhead gas separation technology is not employed at well completion and refracturing. Also assumes that methane has a GWP_{100} of 25 and no leakage of methane from below ground operations to the surface away from the wellhead.

In summary:

- The productivity estimates presented here are not based on fully peer reviewed emissions data.
- The emissions from hydraulic fracturing operations are based on data from eight hydraulic fracturing processes at the Marcellus Shale. It is unclear whether the Marcellus experience is directly transferable to sites found in the UK.
- Fugitive emissions from flowback estimates are based on empirical data from the US reported on a voluntary and ad hoc basis. The transferability of these estimates to UK geological features and fracturing practices is unknown. Technologies are available to reduce the fugitive emissions during flowback and there are precedents for their mandatory use in certain US states, but take up rates are unknown.
- Systematic data gathering would substantially improve the veracity and relevance of bottom-up assessment exercises to the UK, although the need for policy decisions as to an appropriate metric for methane would remain.
- The main determinants of proportional GHG impact appear to be the total return per well and the quantities of flowback methane emissions.
- The larger the amount of natural gas that can be extracted from a shale well, the lower the contribution a given fracturing event makes to the emissions/TJ of extracted energy. Multiple re-fracturing may increase both productivity and emissions but it is unknown to what extent.
- Although the return per well is not available for UK basins, it is thought that additional CO_2e emissions per well would be at the higher end of estimates in Table 3.4 as UK reserve potential is low in comparison to the US basins; it is not clear how the release of the first data from Cuadrilla's hydraulic fracturing operation in the Bowland Shale change this.
- Direct comparisons between shale and conventional gas sources into the future may not hold as conventional sources decline.

From this it is possible to conclude that while emissions from shale gas extraction will be slightly higher than for conventional gas extraction they are unlikely to be markedly so unless there is substantial release of methane during well completions and re-fracturing operations.

3.2.6 Comparison of shale gas extraction emissions with the direct emissions from coal combustion

The final question asked is at what point would the additional energy required to extract natural gas from shales outweigh the CO_2 benefits that natural gas has over coal to the end user. To carry out the assessment the life cycle emissions should ideally be compared between the three sources, however, sufficient data is not available for this to be robust.

The additional emissions associated with gas extraction from shale are compared to the direct emissions from the combustion of coal and natural gas (Table 3.6). The relatively small size of these additional emissions is dwarfed by the size of direct emissions associated with the combustion of conventional natural gas and coal. Fugitive emissions of methane have the potential to make a meaningful impact. However, they may be technically remediable.

It should be noted that methane losses during transport, distribution and storage are subject to uncertainty and maybe substantially larger than previously thought. The largest component of fugitive emissions in the Howarth et al (2011) analysis, 1.4% to 3.6% of methane produced over the lifecycle of a well, is associated with transport, distribution and storage of gas which is common to both conventional and unconventional sources. This quantity of emissions derived from industry data is comparable with an earlier estimate (Hayhoe et al 2002) and Skone et al (2011), however, it is greater than the EPA figure of 2% used by Jiang et al (2011). It is therefore possible that the emissions intensity of electricity produced from all sources of natural gas is an underestimate.

However, additional benefits arise from the use of natural gas rather than coal when converting the fuel to usable energy, due to the efficiencies of conversion. A coal fired electricity plant has a thermal efficiency ranging between 36% (Pulverised Fuel) to 47% (New supercritical plant) whilst a gas fired power station ranges from 40% to 60% (POST, 2005).

Even if converted to common units and GWP, the estimated GHG footprints of unconventional gas calculated in Howarth et al (2011), Jiang et al (2011) and Skone et al (2011) are problematic to compare because of the different assumptions and analytical boundaries drawn by each study. All identify the emissions of natural gas, predominantly methane, from hydraulic fracturing activities as the largest potential source of increased GHG impact over conventional methods. Further, all studies note well productivity and the actual quantity of these fugitive emissions as major sources of uncertainty and sensitivity in the estimates. As such we believe it is more appropriate to present an emissions range rather than a single figure at this stage.

Table 3.6: Direct emissions from natural gas and coal compared to the additional emissions associated with extracting natural gas from shale

	(tCO_2e/TJ, or gCO2e/MJ)
Natural gas[b]	57
Coal[b]	93
Additional emissions associated with extraction operations from shale	0.14 – 1.63[a]
Possible additional fugitive emissions from hydraulic fracturing flowback	2.87 – 15.3[c]
Total possible shale gas additional emissions	3.01 – 16.9

[a] These figures are the upper and lower bounds of the emission estimates from Table 3.4, the figures depend on the amount of gas extracted per well and the assumed number of refracturing steps taken per well. In this case data is shown for one refracturing event with 50% additional operational emissions. Please note the figures represent the extremes of the data and assumptions used here and are not necessarily representative of all shale sites. Emissions associated with chemical production are not included due to poor availability of data.
[b] Whilst including the extraction and production emissions associated with conventional national gas and coal would be beneficial, as previously stated in Section 3.2, there is limited publically available data and the size of emissions associated with such processes are heavily dependent on the size and additional attributes of the reservoir, making any meaningful general comparison difficult to make.
[c] This assumes fugitive emissions from flowback over the lifetime of a well are predominantly vented, i.e. that wellhead gas separation technology is not employed at well completion and refracturing. Also assumes that methane has a GWP_{100} of 25 and no leakage of methane from below ground operations to the surface away from the wellhead.

3.3 Potential impact of shale gas use on global emissions

While the previous section has focused on emissions associated with the extraction of shale gas, the following provides a sense of the potential impact that the use of shale gas may have in terms of carbon emissions at both UK and global levels.

In order to explore this issue two sets of scenarios have been developed; one focused on the UK and one taking a global perspective. It should be noted that these scenarios are in no way a prediction of what might happen, they simply explore the outcomes if particular amounts of shale gas were to be exploited.

3.3.1 UK scenarios

For the UK three scenarios have been developed. Each of these is based on a different estimate for the amount of technically recoverable shale gas in the UK.

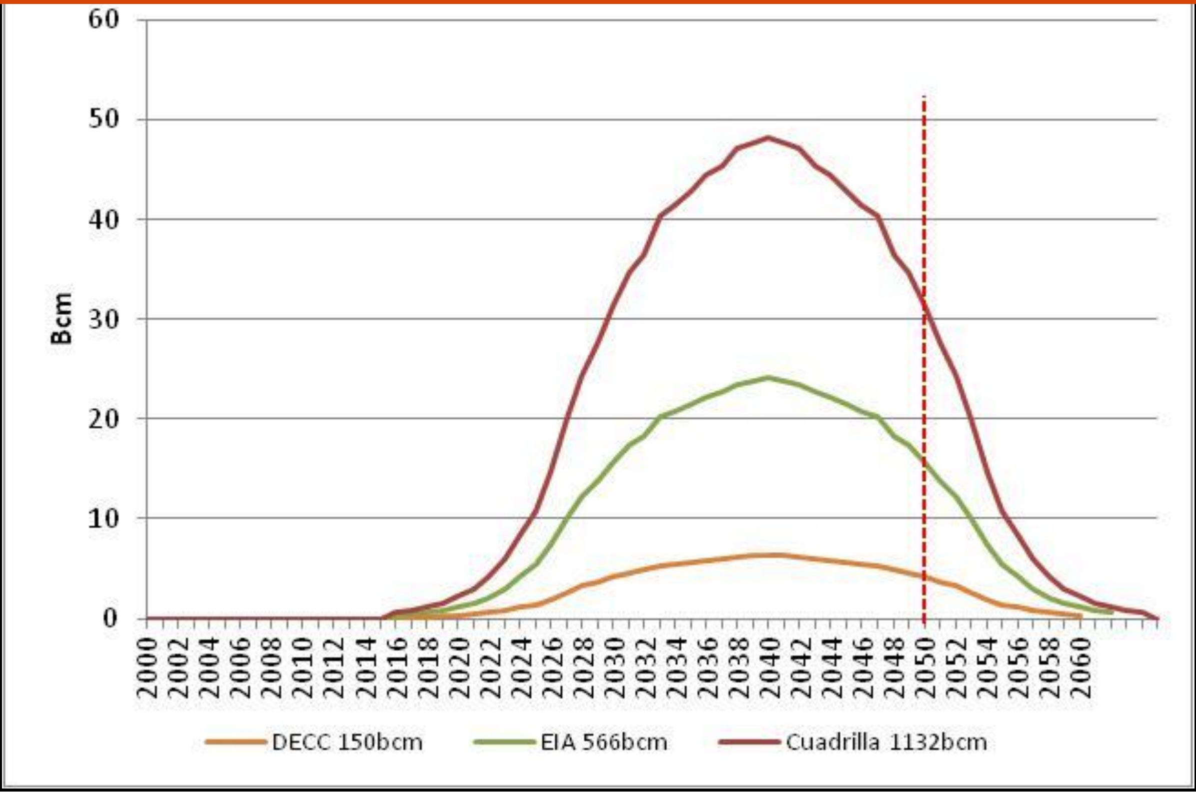
The first scenario is based on the figure of 150bcm outlined in the report by DECC discussed earlier (DECC, 2010). The second uses a figure of 566bcm from a recent report by the US EIA (EIA, 2011). The third scenario is based on the figures released by Cuadrilla stating that, in the areas where they are licensed to drill, they estimate 5,660bcm of gas in place. Assuming that only 20% is recoverable[42] gives a figure of 1,132bcm. It is of course possible that the early figures from Cuadrilla could prove to be an overestimate. It is also possible that the full amount of resource may not be recoverable in practice[43]. However, it should also be noted that the area of Cuadrilla's license represents only 5% of the Bowland shale, suggesting that the total amount of recoverable shale gas could be much higher if the Cuadrilla estimate proves to be correct. Given this uncertainty and in the absence of any other information, for the third scenario it has been assumed that this 1,132bcm figure is the amount recovered for the UK as a whole.

Following Geny (2010), in each of the scenarios production does not start in the UK until 2016 and is limited before 2020. As the US is the only market where shale gas has been exploited to date, the rate of growth assumed in the scenarios is based on *current* projected rates of growth for shale gas production in the US. It is important to note, however that there is considerable uncertainty in these growth figures. As the estimated amount of technically recoverable resource has doubled so have the assumed production figures for 2035. Figure 2.8 shows how this changes the growth of shale gas production. Even this may be an underestimate as US production figures for shale gas in 2009[44], suggest that current growth may be more rapid than this figure indicates. Some commentators have proposed that US exploitation rates may be much more rapid than the EIA projections with a peak in growth rates between 2020 and 2025 (Roper, 2010).

[42] EIA (2011) suggests average recoverability of between 20-30%
[43] For example, a report from the Potential Gas Committee (2009) reports probable reserves as 23% of technically recoverable resources in the US. This "probable" figure is based on an assumption of the amount of the resource for which there is a 50% or more probability of recovery.
[44] See http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm.

Figure 3.1 below shows the shale gas production under each of these scenarios.

Figure 3.1: Shale gas production in the UK under three different scenarios



Using these scenarios, and assuming that all gas recovered is used domestically, it is then possible to explore the potential implication of shale gas exploitation on carbon emissions (Table 3.7 below). Emissions are calculated as CO_2 from combustion only and do not include any estimate of other associated sources such as fugitive methane emissions from well completions, refracturing, processing or distribution. This is a conservative assumption on the basis of a well regulated industry with full deployment of best practice.

Table 3.7: Outcomes of UK scenarios

	Cumulative amount of shale gas produced (bcm)		Cumulative CO_2 emissions from shale gas, ($MtCO_2$)	% of UK Domestic Action budget[45]
	2030	2050	2010-2050	2010-2050
DECC 150bcm	21	132	264	1.9%
EIA 566bcm	79	499	1,015	7.3%
Cuadrilla 1,132bcm	157	997	2,029	14.5%

As is clear from Figure 3.1 and Table 3.7 the majority of shale gas is extracted before 2050 (88%). Over the 2010-2050 time period, using this gas would result in

[45] The 2010-2050 budget was calculated based on figures from the Committee on Climate Change (2010), p.135.

between 264-2029 $MTCO_2$ being emitted by 2050, which equates to between 1.9% and 14.5% of the total UK greenhouse gas budget.

Assuming that the UK carbon budgets are adhered to then additional emissions associated with shale gas would need to be offset by emissions reductions elsewhere. This could be through shale gas substituting for coal, which, given the lower emissions associated with gas fired power generation would enable more electricity to be produced for equivalent emissions. It could be the case that shale gas substituted for imported gas resulting in no additional UK gas use and hence, no additional emissions, or emissions benefits, associated with that use[46]. However, in a market led system it is also possible that a drop in the price of gas, potentially triggered by increasing UK and global reserves of shale gas, could leave gas-fired power stations substituting for renewable generation, putting still further pressure on efforts to meet climate change targets.

A further risk to emissions reductions could be that the prospects of shale gas being produced in the UK encourages additional investment in fossil fuel based power generation with the expectation that carbon capture and storage (CCS) will render this much lower carbon. However, CCS is as yet unproven and to date significantly less effort has been put into gas CCS compared to coal (Mander 2011 *pers comm*); given this we must consider the possibility that it may never play a significant role. Within the UK, the time scales for meeting emission targets are such that coal (without CCS) is likely to be phased out irrespective of whether shale gas is produced.

The role of shale gas exploitation in the UK has potential ramifications for world energy markets. While it is possible that shale gas could substitute for coal, within the UK, this could be counteracted by global use of coal *and* shale gas. If shale gas resulted in no additional emissions in the UK, (e.g. it substituted for imported gas), in an energy-hungry world any gas not imported to the UK will likely be available at a lower cost to be used elsewhere, with an associated increase in global emissions. World demand for fossil fuels remains high and is projected to increase further in the absence of binding international agreements to limit greenhouse gas emissions (IEA, 2009; EIA, 2011). Based on the these projections any new sources of fossil fuel, even if relatively low carbon per unit of useful energy, are likely to be combusted and consequently add to the global emissions burden. See, for instance, EIA projections for US shale gas and coal consumption to 2035, Figure 2.11.

3.3.2 Global scenarios

As with the UK, the potential shale gas that could be exploited globally is highly uncertain. The most recent estimate of technically recoverable resource has been made by the US EIA at 187,535bcm (EIA, 2011b) which is a similar order of magnitude to estimates presented in the IEA Golden Age of Gas publication (2011), 204,000bcm. In calculating this figure, the EIA generally used a recovery rate of between 20-30%. In order to provide three global scenarios here, it is assumed that

[46] Under the Cuadrilla scenario in the peak year of production over half of current UK gas demand could be supplied by shale gas.

the EIA figure is based on a recovery rate of 20%, with two additional scenarios of 30% and 10% recovery rates also considered.

It should be stressed that Russia and Central Asia, Middle East, South East Asia, and Central Africa are not considered in this report primarily because "...there was either significant quantities of conventional natural gas reserves noted to be in place (i.e., Russia and the Middle East), or because of a general lack of information to carry out even an initial assessment." (EIA, 2011b, p.6). Reserve estimates and their implications for GHG emissions may therefore be under estimated.

For each of the scenarios it is assumed that 50% of the total recoverable resource is extracted by 2050, with 100% of the recoverable resource extracted by 2100. In the absence of any substantive and effective policies to significantly reduce global emissions, and with continuing growth in demand for energy, it is entirely possible that any resources would be exploited on a much shorter timescale, hence this is likely to be a conservative estimate of emissions. Emissions are calculated as CO_2 from combustion only and do not include any estimate of other associated sources such as fugitive methane emissions from well completions, refracturing, processing or distribution. This is a conservative assumption on the basis of a well regulated industry with full deployment of best practice.

The outcomes of the scenarios are presented in Table 3.8 below.

Table 3.8: Outcomes of the global scenarios

	Resource recovery rate	Amount of shale gas exploited by 2050 (bcm)	Cumulative emissions associated with shale gas ($GtCO_2$) (2010-2050)	% of global emissions budget with >50% chance of ≤2°C warming[47]	Additional ppmv CO_2 associated with shale gas emissions (2010-2050)[48]
EIA global estimate low recovery	10%	46,884	95	9.5%	5
EIA global estimate	20%	93,768	190	19.0%	11
EIA global estimate high recovery	30%	140,651	286	28.6%	16

[47] A series of emissions pathways with a cumulative twenty-first century CO_2 budget of 1,321$GtCO_2$ have previously been assessed using the PRIMAP tool (Meinshausen et al.) and are estimated to have an approximately 36 per cent probability of exceeding 2°C (Anderson and Bows 2011). If emissions to 2009 are subtracted, including those from deforestation aviation and shipping, then this leaves approximately 1,000Gt of 'safe' emissions space for the remainder of the century.

[48] Assumes an airborne fraction of emissions of 45%, see for example Le Quere et al (2009), and that 1ppmv CO_2 = 2.13Gt carbon.

Given continuing growth in global energy demand it is likely that any additional fossil fuel resources that are exploited will be used in addition to existing resources. Without significant pressure to reduce carbon, it is difficult to envisage that gas would substitute for coal rather than being used alongside it. Looking at the three global extraction scenarios, this additional fossil fuel use would result in additional cumulative emissions over the time period 2010-2050 of 95-286 $GtCO_2$, equating to an additional atmospheric concentration of CO_2 of 5-16ppmv. Cumulative emissions budgets are regarded as a more robust means of associating GHG emissions with mean surface temperature changes (Allen et al, 2009). The CO_2 emissions from burning shale gas are estimated to occupy a substantial proportion, over a quarter, of a budget associated with a better than 50:50 chance of avoiding 2°C warming (Anderson and Bows 2011). Clearly this only represents half the resource being exploited and these figures would double for the period up to 2100 if all the recoverable resource were to be exploited.

3.4 UK investment scenarios for gas and renewable electricity supply

A substantial move to exploit shale gas reserves could attract investment that might otherwise go to renewable energy. The House of Commons Energy and Climate Change Committee (2011) concluded that *"shale gas has the potential to shift the balance in the energy markets that the Department has tried to create away from low carbon electricity generation".*

In order to explore this issue, we estimate the capital costs of drilling shale gas wells to supply 10% of current UK gas consumption and the equivalent Combined Cycle Gas Turbine (CCGT) power stations that would be required to burn it. This capital cost is then compared to the build cost of wind power to see what capacity the same level of investment would deliver. Given the need for low carbon generation, the costs of gas CCGT with carbon capture and storage (CCS) must also be considered.

The analysis only looks at capital costs, not operating costs, which will favour gas substantially. Wind has much lower operating costs as a percentage of total costs[49]. Costs of transmission and distribution infrastructure for both gas and electricity are also excluded.

3.4.1 Capital costs of infrastructure

The capital costs for gas, with and without CCS, and wind have been drawn from two reports commissioned by the Department for Energy and Climate Change; Parsons Brinkerhoff (2011) and Arup (2011), respectively, and are detailed in Table 3.9.

Table 3.9: Capital costs of generation technologies per gigawatt

Generation technology	Capital cost (£m/GW)
Gas CCGT[50]	669
Gas CCGT with CCS[51]	1,634
Onshore Wind[52]	1,524
Offshore Wind[53]	2,722

Regeneris Consulting (2011) assessed US precedents and Cuadrilla's existing costs in the UK, suggesting that commercial extraction wells will each cost £8.97million in the long term. This figure is used in their estimates of the local economic impact of shale gas development in the north west of England and is incorporated here for a sequential programme of well construction.

[49] For example, if we look at the levelised costs (with 10% discount rate) for gas CCGT (Parsons Brinkerhoff, 2011) we find that the operating costs (including fuel costs) account for 88% of the total cost/MWh. In contrast, Arup (2011) indicates that for wind, operating costs make up only 6% of total costs.
[50] Parsons Brinkerhoff (2011), p.18, medium value
[51] Parsons Brinkerhoff (2011), p.19, medium value, first of a kind
[52] Arup (2011), p.19, median value for site >5MW
[53] Arup (2011), p.44, median value for site >100MW

3.4.2 Capital cost estimates of electricity generation from shale gas

As outlined in Section 2.4.3 the development of significantly more wells than the number being considered in the Blackpool area is necessary to achieve gas production equivalent to 10% of annual UK consumption. Based on typical volumes of single well production given in Section 2.2.5, it is possible to calculate the minimum number of wells and well pads necessary to deliver sustained annual production, over a period of 20 years, equivalent to 10% of the UK's annual consumption[54].

The rapid decline in gas production per well from one year to the next means that new wells and well pads need to be constantly developed to sustain an output of 9bcm/year. Over a 20 year period, approximately 3,000 wells would need to be developed to deliver sustained annual output equivalent of 9bcm/year. This represents an average of between 130 and 150 wells constructed per year. The capital cost of this pattern of well construction is discounted at commercial (10%) and HM Treasury Green Book (3.5%) rates for comparison.

If all 9bcm of shale gas production is used in CCGTs then it would supply sufficient gas to operate approximately eight 1GW powerstations, assuming 50% efficiency and a 70% load factor. However, given the urgent need for low carbon electricity generation it is reasonable to assume that if major new investment were to be made in gas generation then that would have to, as soon as is possible, be made with CCS capability. This substantially increases capital costs and the possible substitution for renewable capacity. It is also unlikely that CCS would be 100% effective at reducing carbon emissions. Because of the increased fuel consumption due to the CCS process it is assumed that 7GW of installed capacity would consume the same quantity of gas as 8GW of unabated gas capacity. In the absence of large scale demonstration plants there are considerable uncertainties in the cost and efficiency parameters of CCS.

Table 3.10: Capital costs of electricity production from shale gas

Discount rate	10% Discount rate		3.5% Discount rate	
Costs	**CCGT**	**CCGT +CCS**	**CCGT**	**CCGT +CCS**
Power plant (£m)	5,352	11,438	5,352	11,438
Gas Wells (£m)	13,722	13,722	20,222	20,222
Total	19,074	25,160	25,574	31,660

3.4.3 Alternative investment in renewable capacity

If a straight substitution relationship is assumed between renewable energy and gas power generating capacity and supplied by shale reservoirs – i.e. that any money invested in gas and shale no longer available to invest in renewable energy – it is possible to demonstrate the degree to which a move towards shale gas could displace renewable energy.

[54] Annual gas consumption in the UK in 2010 was around 91bcm (DUKES, 2010)

Considering the capital costs only, 8GW of CCGT plus gas well infrastructure could displace 12.5GW of wind capacity, equivalent to over 4000 large onshore turbines, assuming a 10% discount rate for the shale infrastructure. The same investment could also provide 7.0GW of capacity offshore, equivalent to 1400 large turbines. Operating without CCS over this period would place greater pressure on other parts of the economy to decarbonise, or risk gas powerstations without CCS becoming 'stranded assets'.

With a 3.5% discount rate, and the inclusion of CCS technology, potential displacement increases to approximately 21GW of installed onshore wind capacity or approximately 12GW offshore. Either would be expected to generate approximately equivalent quantities of electricity as the gas option even given the lower load factor of wind turbines.

Table 3.11: Investment equivalents in gas and renewable capacity

	10% Discount rate		3.5% Discount rate	
	CCGT	**CCGT +CCS**	**CCGT**	**CCGT +CCS**
Onshore wind (GW)	12.5	16.5	16.8	20.8
Onshore wind (3MW turbines)	4,172	5,503	5,594	6,925
Offshore wind (GW)	7.0	9.2	9.4	11.6
Offshore wind (5MW turbines)	1,401	1,849	1,879	2,326

As mentioned above, these costs do not include operating costs, and, given that the operating cost component of total costs for gas is much higher, the results are more favourable towards gas.

3.5 Timescales for decarbonisation of UK energy system

In this section we argue that the development of shale gas in the UK will occur too slowly to contribute meaningfully to near term climate change mitigation targets and obligations and will likely maintain high emissions infrastructure in the medium term.

The UK and other Copenhagen Accord (2009) signatories have identified 2°C as the upper limit of acceptable climate change. The EU maintains that it "must adopt the necessary domestic measures… to ensure that global average temperature increases do not exceed preindustrial levels by more than 2°C" (European Commission 2007) and this objective is reiterated in the UK's Low Carbon Transition Plan (DECC 2009a).

Cumulative emission analysis indicates that, allowing for an emissions floor for agriculture and aiming for a 50% chance of not exceeding 2°C warming, then CO_2 emissions from the energy system must tend to zero by 2050 (Anderson & Bows 2008; Anderson & Bows 2011). It is therefore appropriate for UNFCCC Annex 1 countries, OECD nations such as the UK, to decarbonise much sooner, given their historical responsibility and greater resources.

The Committee on Climate Change (CCC, 2010) has advised the UK Government that decarbonisation of the electrical supply is an effective way of rapidly reducing emissions; renewable technologies with very low associated emissions are available now that are compatible with existing infrastructure. Further, there is the possibility of increasing the efficiency of transport and heating through the deployment of new electric vehicle and heat pump technologies respectively. The timescale outlined by the CCC is that transition to a very low carbon grid, with an intensity of the order of 50g CO_2/kWh, would take place by 2030, on the way to a zero carbon grid soon after. It is worth noting that the CCC acknowledge a low probability of keeping below 2°C of warming on the basis of their budgets.

Shale gas is promoted as a transition fuel offering security of supply and low carbon electricity when combusted in efficient CCGT power stations. It has been argued that the substitution of coal for shale gas in the production of grid electricity will assist in meeting emissions reductions targets. Gas fired power stations typically have a lifespan of over 25 years. Were a new round of stations to be completed in the next ten years they would become "stranded assets" or require expensive retro fitting with as yet untested carbon capture and storage (CCS) technology. To our knowledge there are as yet no large scale CCGT plants with CCS in testing or under construction worldwide.

Green Alliance scenarios (2011) indicate that if there is a second "dash for gas", emissions from the grid could still be 302gCO_2/kWh in 2030 necessitating 95% deployment of CCS to meet our fourth period emissions budgets (2023-2027). CCS will always add costs to electricity production as it reduces the efficiency of the power station and requires additional energy input in transportation and injection of the captured carbon dioxide. CCS therefore increases the net quantity of upstream emissions of gas or coal production. Reduced efficiency means that greater quantities of fuel must be used for equal electricity output, multiplying emissions over and above those from fuel combustion. For unconventional gas these have the potential to be significant if mitigation is not in place (see Section 3.2).

Further, the physical and infrastructure constraints on the large scale production of shale gas suggest that it may not be available in meaningful quantities in the UK until the end of the decade (Geny 2010). If construction of CCGT stations locks the UK into gas and detracts from investment in genuinely low carbon electricity generation then there is a low likelihood of achieving 2^{o}C climate objectives and the UK Government's expressed commitments.

A precise and accurate value of the life cycle GHG impact, either per unit of shale gas produced or per unit of electricity from shale gas, is not necessary to draw this conclusion. The absolute necessity of decarbonisation means that technologies with orders of magnitude lower emissions are required to provide energy to UK households and industry in the short to medium term.

4. Human health and environmental considerations

4.1 Introduction

4.1.1 Background

The processes, operations and resources involved in the extraction of shale gas from wells are not without their human health and environmental implications. These risks associated with hydraulic fracturing have risen to prominence in the US. Here there have been a number of incidents and reports of contamination from shale gas developments and, on 3 March 2010, the US EPA announced that it will conduct a comprehensive research study to investigate the potential adverse impact that hydraulic fracturing may have on water quality and public health[55]. This review is still ongoing and is expected to first report in 2012 with further outputs out to 2014. In the meantime, however, there remains a paucity of information and data on which to base a quantified assessment of environmental and human health risk.

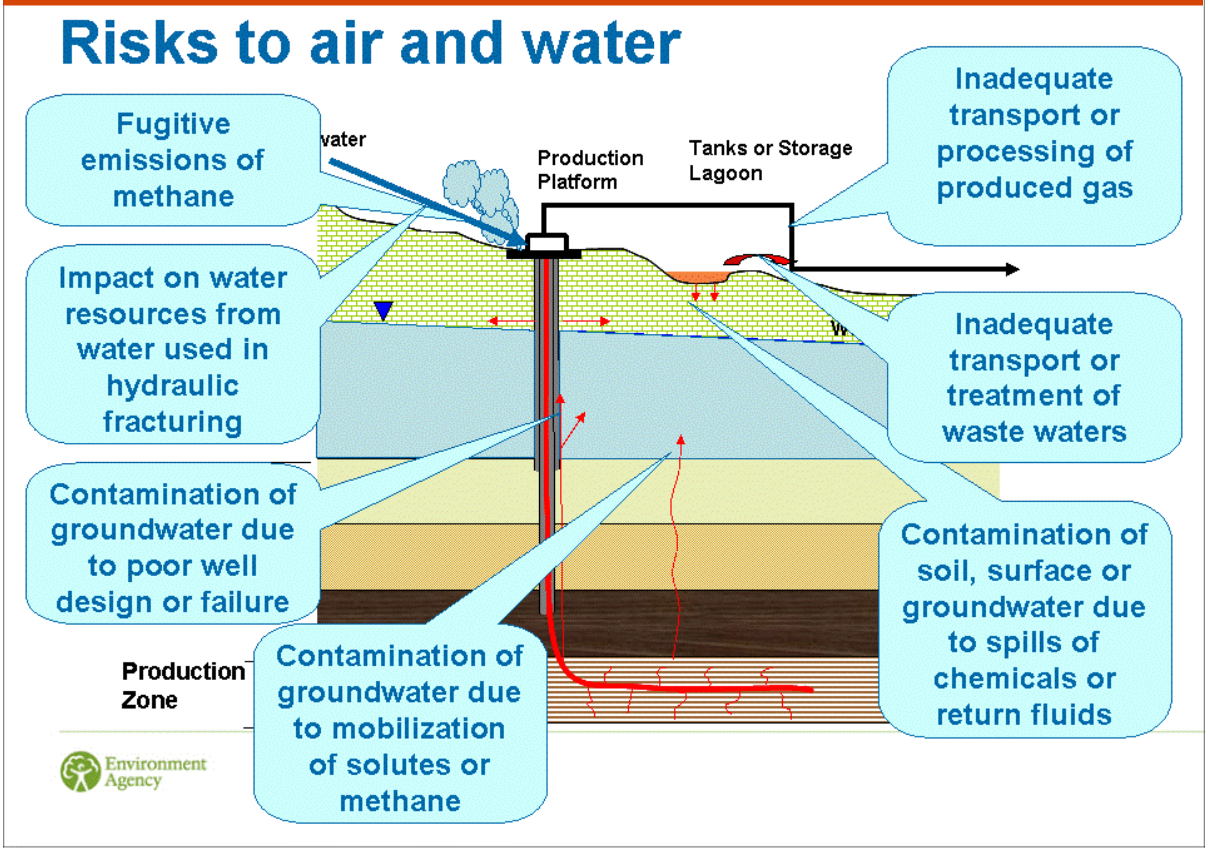
4.1.2 Key risks and impacts

The key risks and impacts of shale gas and shale gas processes and development are illustrated in figure 4.1 and can be divided as follows:

- contamination of groundwater by fracturing fluids or mobilised contaminants arising from:
    - wellbore/casing failure; and/or
    - subsurface migration;
- contamination of land and surface water, and potentially groundwater via surface route, arising from:
    - spillage of fracturing additives; and
    - spillage/tank rupture/storm water overflow from liquid waste storage, lagoons/pits containing cuttings/drilling mud or flowback fluid;
- water consumption/abstraction;
- wastewater storage, transport and treatment;
- land and landscape impacts from;
    - drill rig and well pad
    - storage ponds or tanks
    - access roads
- impacts arising during construction and pre-production:
    - noise/light pollution during well drilling/completion;
    - local traffic impacts;
- seismic impacts

[55] http://yosemite.epa.gov/opa/admpress.nsf/0/BA591EE790C58D30852576EA004EE3AD

Figure 4.1: Pollutant pathways associated with hydraulic fracturing (Environment Agency 2011)



4.2 Fracturing fluids and flowback fluid

As detailed in Section 2, a multi-stage fracturing operation involves injecting fracturing fluids at very high pressure into the wellbore to generate fractures in the target rock formation. Fracturing of a single well requires a considerable volume of water and, with reported chemical additives of up to 2% by volume, around 180-580 cubic metres of chemical additives (or 180-580tonnes based on relative density of one). After fracturing, a proportion of the fluid returns to the surface as flowback fluid.

Composition of fracturing fluids

The composition of the fracturing fluid varies from one product to another and the design of the fluid varies depending on the characteristics of the target formation and operational objectives. Fracturing fluid used in modern slickwater fracturing in the US is reported to be typically comprised of around 98% water and sand (as a proppant) with chemical additives reported to comprise 2% (see Table 2.3).

At present, there is little information available on fracturing additives and risks associated with hydraulic fracturing. US Federal law currently exempts the underground injection of fluids for hydraulic fracturing purposes from regulation (Congressional Research Service, 2009) and a significant number of formulations have been justified as trade secrets as defined and provided by Public Officers Law (New York State, 2009).

Owing to the fact that US Federal law currently exempts the underground injection of fluids for hydraulic fracturing purposes from regulation, there is very little information on the identity and concentration of substances in hydraulic fracturing formulations. Disclosure of the identity of chemicals used in hydraulic fracturing may be required on a case by case basis and, in New York State, for example, the Department of Environmental Conservation (NYSDEC) requires operators to disclose chemicals as part of the permitting procedure. However, the New York State (2009) also notes that full disclosure of chemicals and composition of formulations is not possible owing to trade secrets exemptions from public disclosure. In this way, and as is identified in comments on New York State (2009) by New York City, “involved stakeholders such as City and local health departments do not have any knowledge of the chemicals that are released into the environment near water supplies”.

In terms of disclosure to the wider public, operators are required to produce Material Safety Data Sheets (MSDSs) of chemicals stored in quantities of over 4.5tonnes under the US Emergency Planning and Community Right to Know Act of 1986 (EPCRA). However, this is unlikely to provide full coverage of chemical composition nor does it provide data on concentration of substances.

Owing to the lack of detailed information on chemical composition, this assessment must rely on information extracted from the MSDSs submitted by operators to regulators. Here New York State (2009) provides a list of 260 chemical constituents and their Chemical Abstracts Service (CAS) numbers that have been extracted from chemical compositional information for 197 products as well as MSDSs submitted to the NYSDEC.

A review of this list has been undertaken by cross checking CAS numbers in the NYSDEC list with the following lists on the European chemical Substances Information System (ESIS)[56] (see Annex 1, Table A1 for the full list):

- ***toxicity classification***: for the purposes of classification and labelling (according to Annex VI of Regulation (EC) No 1272/2008 and the Globally Harmonised System);
- ***presence on List 1-4 of priority substances***: since 1994, the European Commission has published four lists of substances requiring immediate attention because of their potential effects to man or the environment. There are 141 substances on the lists;
- ***presence on the first list of 33 priority substances***: established under Annex X of the Water Framework Directive (WFD) 2000/60/EC - now Annex II to the Directive on Priority Substances (Directive 2008/105/EC). Member States must progressively reduce pollution from priority substances; and
- ***presence on the PBT list:*** substances which have been subject to evaluation of their PBT properties under the Interim Strategy for REACH and the ESR

[56] http://ecb.jrc.ec.europa.eu/esis/

program. For substances which are persistent, bioaccumulative and toxic (PBT) or very persistent and very bioaccumulative (vPvB) a "safe" concentration in the environment cannot be established with sufficient reliability.

This analysis suggests that 58 of the 260 substances have one or more properties that may give rise to concern and:

- fifteen substances are listed in one of the four priority lists;
- six are present in list 1 (Acrylamide, Benzene, Ethyl Benzene, Isopropylbenzene (cumene), Naphthalene, Tetrasodium Ethylenediaminetetraacetate);
- one is currently under investigation as a PBT (Naphthalene bis (1-methylethyl));
- two are present on the first list of 33 priority substances (Naphthalene and Benzene);
- seventeen are classified as being toxic to aquatic organisms (acute and/or chronic);
- thirty eight are classified as being acute toxins (human health);
- eight are classified as known carcinogens (Carc. 1A=1, Carc. 1B = 7);
- six are classified as suspected carcinogens(Carc. 2 = 6);
- seven are classified as mutagenic (Muta. 1B); and
- five are classified as having reproductive effects (Repr. 1B=2, Repr. 2=3).

It is clear that the presence of a number of the substances in fracturing fluids may present cause for concern, particularly given the intended use and the volumes being used. The level of risk associated with the use of these substances will be related to the quantity and concentration of substances, their fate, and routes of exposure of people and the environment, the latter of which is considered in subsequent sections.

In the UK Cuadrilla Resources is the only operator to have conducted drilling and hydraulic fracturing. The chemicals and their quantities, presented in Table 2.4, have been disclosed to the public and this suggests a much smaller quantity of chemical use (3.7m^3 per well).

Based on the data in Table 2.16 (which is based on Cuadrilla's operations), around 2,500-3,000 horizontal wells would be required to deliver 9bcm/year (10% of UK gas consumption). This, in turn, represents high pressure injection of around 11,000-14,500m^3 (or tonnes based on relative density of one) of fracturing chemicals. In terms of Cuadrilla's commercial development scenarios within its licence area in Lancashire, the central estimate of 400 wells would require some 1,480 cubic metres of fracturing additives.

Composition of flowback fluid

Some 15-80% of injected fluid returns to the surface as flowback (and, by implication, 20-85% remains underground). Whilst flowback fluids include the fracturing fluids pumped into the well, it also contains:

- chemical transformation products that may have formed due to reactions between fracturing additives;
- substances mobilised from within the shale formation during the fracturing operation; and
- naturally occurring radioactive materials (NORMs).

The nature and concentrations of different substances will clearly vary from one shale formation to another and it is difficult to predict what the composition of flowback fluid is likely to be. The UK Environment Agency (EA) has undertaken a mineral analysis of flowback fluid from exploratory drilling by Cuadrilla Resources (the only shale gas operation that has conducted hydraulic fracturing in the UK to date). The analysis found notably high levels of sodium, chloride, bromide and iron, as well as higher values of lead, magnesium and zinc and elevated levels of chromium and arsenic compared with the local mains water that is used for injecting into the shale. The flowback fluid is very saline with chloride concentration being four times that of seawater. The mineral analysis data is provided in Annex 1 as Table A.2.

The analysis also showed the presence of low but still significant levels of NORMS with radium 226 as the radioactive material present at the highest levels (between 14 and 90 Becquerel per litre). Other naturally occurring isotopes present included potassium 40 and radium 228. The radiological analysis data is reproduced in Annex 1 as Table A.3 (Environment Agency, 2011).

In terms of other example compositions including analysis of organics, New York State (2009) provides limited sample data on composition of flowback fluids (see Annex 1, Table A.4 for full breakdown) This analysis was based on limited data from Pennsylvania and West Virginia. The analytical methods and detection levels used were not uniform across all parameters and it is noted that the composition of flowback fluid from a single well can also change within a few days of the well being fractured.

As with the UK EA analysis, when visually compared with substances in fracturing fluids the data on flowback fluid suggest mobilisation and presence of elevated concentrations of:

- heavy metals (of varying types);
- radioactivity and NORMs; and also
- total dissolved solids;

Altogether, the toxicity profile of the flowback fluid is likely to be of greater concern than that of the fracturing fluid itself, and, depending on constituents, may require an environmental permit in the UK. After the initial analysis of flowback fluid at the Cuadrilla test wells in the UK (and new limits being specified in Schedule 23 of the Environmental Permitting Regulations 2010 on 1 October 2011) the Environment Agency has determined that a permit is now required and as part of the application for a permit a radiological impact assessment will be needed. Future needs for waste water permitting will depend on site by site assessment.

The issue of NORMs in waste water is acknowledged in the US with a risk that they become concentrated in sludge after treatment (New York State, 2011). There is, however, a "current lack of data on the level of NORM concentration that may take place" (New York State, 2011; p.6-59). A recent article in the New York Times, based on internal documents obtained from the US EPA, suggested that wastewater radioactivity was higher than the operating treatment plants were able to handle and discharge safely.[57]

Volumes of waste generated and associated requirements for storage and industrial waste water treatment are also large. Table 4.1 provides ranges based on recovery of 15-80% of fracturing fluid as flowback (accounting also for the range in values of volumes of fracturing fluid used). This suggests that, for shale development delivering 9bcm/year, 3.6-26million cubic metres of potentially hazardous wastewater would be recovered over a 20 year period requiring storage, transport and treatment. Importantly, the same water use and percentage recovery ranges also imply that, if 15-80% of fluid is recovered, then between 20-85% of fluid is not recovered and, therefore, remains underground.

Table 4.1: Flowback fluid waste generated at varying levels of UK shale development

For delivery of 9bcm/year of shale gas production				
	Assuming no re-fracturing		**Assuming a single re-fracturing on 50% of wells** (delivering an assumed 25% increase in productivity for those wells)	
Wells	2,970		2,592	
Well pads	297		259	
Flowback fluid volume (m^3)	3,658,604	19,680,768	4,789,446	25,763,915

Blackpool Area (Cuadrilla commercialisation scenarios)						
	Low		**Medium**		**High**	
Wells	200		400		800	
Well pads	20		40		80	
Flowback fluid volume (m^3)	246,371	1,325,304	492,741	2,650,609	985,483	5,301,217

[57] http://www.nytimes.com/2011/02/27/us/27gas.html?_r=1

4.3 Groundwater contamination

Significance of groundwater pollution

Groundwater is water that collects in rock formations known as aquifers. Water naturally fills the aquifer from the bottom upwards, occupying rock spaces with water and creating what is known as the saturated zone of the aquifer, towards the bottom, and in the upper sections (where rock spaces contain air and water) an unsaturated zone. The boundary between saturated and unsaturated zones is the 'water table'. Groundwater is not stationary but flows through and along rock crevices from the area where water enters the aquifer (recharge zone) to an area where water leaves the aquifer (discharge zone). Where this is near the surface, springs occur and support the flow of rivers and wetlands such as fens and marshlands.

Groundwater quality is generally high and requires little or no treatment before use as drinking water. In England and Wales groundwater provides a third of drinking water on average and also maintains the flow of many rivers. In parts of Southern England, groundwater supplies up to 80% of needs (Environment Agency, 2010)[58]. Owing to its importance as both a source of drinking water and as source for rivers and wetlands, preventing its contamination is vital.

The fracturing and flowback fluids (including transformation products and mobilised subsurface contaminants) contain a number of hazardous substances that, should they contaminate groundwater, are likely to result in potentially severe impacts on drinking water quality and/or surface waters and wetland habitats. The severity will depend on, for example, the significance of the aquifer for abstraction; the extent and nature of contamination; the concentration of hazardous substances; and connection between groundwater and surface waters.

Routes of exposure

The most obvious routes for exposure of groundwaters to contamination from shale wells are:

- catastrophic failure or full/partial loss of integrity of the wellbore (during construction, hydraulic fracturing, production or after decommissioning); and
- migration of contaminants from the target fracture formation through subsurface pathways including:
    - the outside of the wellbore itself;
    - other wellbores (such as incomplete, poorly constructed, or older/poorly plugged wellbores);
    - fractures created during the hydraulic fracturing process; or
    - natural cracks, fissures and interconnected pore spaces.

[58] For more information on UK groundwaters see http://www.environment-agency.gov.uk/business/topics/water/38597.aspx

Groundwater contamination through wellbore failure or loss of integrity

Owing to the relatively significant depth of shale resources, wellbores are likely to be drilled through several aquifers. At all stages in the lifetime of a well, the wellbore therefore provides a continuous physical link between the target formation (where high pressure hydraulic fracturing and subsequent extraction occurs), other rock formations/saline aquifers, freshwater aquifers and the surface. The wellbore itself probably provides the single most likely route for contamination of groundwater.

To reduce the likelihood of contamination via the well itself, casings are installed to isolate the well from the surrounding formations (see Section 2.2).

Notably, just as depth requirements vary from state to state in the US, so do requirements for cementing in of casings. As noted in Section 2.2, a method known as 'circulation' may be used to fill the entire space between the casing and the wellbore (the annulus) from the bottom of the surface casing to the surface. However, according to the GWPC:

- circulation of cement on surface casing is not a universal requirement and in some states cementing of the annular space is required across only the deepest groundwater zone but not all groundwater zones;

- although some states require complete circulation of cement from the bottom to the top of the production casing, most states require only an amount of cement calculated to raise the cement top behind the casing to a certain level above the producing formation; and

- in very deep wells (as is often the case for horizontally drilled shale wells), the circulation of cement is more difficult to accomplish as cementing must be handled in multiple stages which can result in a poor cement job or damage to the casing if not done properly.

Clearly, once installed, wellbore casings provide the primary line of defence against contamination of groundwater. As such, the loss or initial lack of integrity of the well casing arrangement (at any point along the wellbore) has the potential to result in contamination of rock formations including aquifers.

Anything from the catastrophic failure of a well casing (for example during high pressure fracturing) through to partial loss of integrity of poor cement seals is likely to result in a pollution event. The severity of such events will depend on the nature of the loss of integrity, the contaminants and the receiving environment.

In terms of events linked to loss of casing integrity, contamination resulting from the flowback of fracture fluids through the casing itself could occur but would require physical failure of both steel casing and cement. More likely is upward flow via the cemented annulus between the casing and the formation which, in GWPC's view, presents the greatest risk of groundwater contamination during hydraulic fracturing.

"It is the cementation of the casing that adds the most value to the process of ground water protection...consequently, the quality of the initial cement job is the most critical factor in the prevention of fluid movement from deeper zones into ground water resources" (GWPC, 2009b)

New York State[59] (2009) ignores the role and significance of cementing (and, particularly, the initial cementing work) when considering groundwater contamination. It largely dismisses the issue by referring to a study it commissioned from ICF International, which used an upper bound estimate of risk from a 1980s study by the American Petroleum Institute (API). The API study analysed the risk of contamination from properly constructed Class II injection wells to an Underground Source of Drinking Water (USDW) due to corrosion of the casing and failure of the casing cement seal. Using this, the ICF study (and New York State, 2009) identified that the "probability of fracture fluids reaching a USDW due to failures in the casing or casing cement is estimated at less than 2×10^{-8} (fewer than 1 in 50million wells)". On this basis the ICF study concludes that "hydraulic fracturing does not present a reasonably foreseeable risk of significant adverse environmental impacts to potential freshwater aquifers".

Examination of this suggests that both the estimate and the conclusion may be problematic on a number of counts. Most notable is that a thorough analysis of process risk requires consideration of all (reasonably conceivable) circumstances, events and failure nodes that could potentially result in adverse impacts. As such, focussing only on an estimate of the risk of failure of properly constructed wells, fails to account for the risk of failure of improperly constructed wells. Whilst improper construction of wells may be unintended, it does occur and has resulted in pollution events (see later). As the study of risk requires the study of unintended consequences, this is a serious omission particularly as poor construction is known to represent the most significant risk to groundwater.

Another issue is the comparison between injection wells and hydraulically fractured shale wells. Whilst the ICF study notes the difference between the two, it implies that risk from shale wells is likely to be lower because injection wells work under sustained pressure and hydraulically fractured shale wells are pressurised only during hydraulic fracturing (after which pressure within the casing is less than the surrounding formation). Whilst the operational differences are true, at 5,000-10,000psi (345-690bar) the pressures applied in hydraulic fracturing are both higher and are applied several times during fracturing and re-fracturing of a well. This means that the well and casings are put under repeated episodes of high pressure followed by total pressure release, and negative pressure relative to surrounding rocks. Thus, it could equally be argued that the stress on well casings and cement seals from repeated 'inflation and deflation' may be significantly higher, and damage and subsequent loss of casing integrity is more likely for hydraulically fractured shale wells.

Given these issues, it would appear problematic to conclude that there is no reasonably foreseeable risk to freshwater aquifers, particularly since the probability of contamination of aquifers given is the probability per well. As thousands of shale

[59] Note that a new Draft SGEIS was released in September 2011 and is reported to be more robust in its treatment of risks. Time constraints on this study mean that its contents are yet to be included in the text of this report.

wells in the US are drilled through aquifers the figure presented as the probability of contamination of a USDW should have been presented as a factor of thousands higher than the one provided.

Interestingly, New York State (2009) identifies that natural gas migration "is a more reasonably anticipated concern with respect to potential significant adverse impacts" owing to:

- inadequate depth and integrity of surface casing to isolate potable fresh water supplies from deeper gas-bearing formations;

- inadequate cement in the annular space around the surface casing, which may be caused by gas channelling or insufficient cement setting time; and

- excessive pressure in the annulus between the surface casing and intermediate or production casing. Such pressure could break down the formation at the shoe of the surface casing and result in the potential creation of subsurface pathways outside the surface casing. Excessive pressure could occur if gas infiltrates the annulus because of insufficient production casing cement and the annulus is not vented in accordance with required casing and cementing practices.

Thus, on the one hand, the assessment of hydraulic fracturing in New York State (2009) dismisses the possibility of contamination owing to poor construction but, on the other, the possibility of the same poor construction is identified as "a more reasonably anticipated concern".

The omission is highlighted by the fact that there are a number of documented examples of pollution events owing to poor construction and operator error. There are reports of incidents involving contamination of groundwater and surface waters with contaminants such as brine, unidentified chemicals, natural gas, sulphates, and hydrocarbons such as benzene and toluene[60]. In many cases the exact cause or pathway of the contamination is yet to be identified owing to the difficulty in mapping complex subsurface features (Hazen and Sawyer, 2009) but there are also several where causes such as poor construction have been identified. These include the following:

1) In 2004 in Garfield County Colorado, US, natural gas was observed bubbling into a stream bed. In addition to natural gas, groundwater samples revealed that concentrations of benzene exceeded 200micrograms/litre and surface water concentrations exceeded 90micrograms/litre (also 90 times the state water quality limit). The operator had ignored indications of potential problems while drilling, failed to notify the regulators as required by the drilling permit, and failed to adequately cement the well casing. This, in conjunction with the existence of a network of faults and fractures led to significant quantities of formation fluids migrating vertically nearly 1,200m and horizontally 600m, surfacing as a seep. Although remedial casings installed in the well reportedly reduced seepage, the resulting benzene plume has required remediation since 2004. Subsequent

[60] see, for example, Riverkeeper case studies impacts and incidents involving high-volume hydraulic fracturing from across the country and http://www.riverkeeper.org/

hydrogeology studies found that ambient groundwater concentrations of methane and other contaminants increased regionally as gas drilling activity progressed, and attributed the increase to inadequate casing or grouting in gas wells and naturally occurring fractures.

2) In 2007, a well that had been drilled almost 1,200m into a tight sand formation in Bainbridge, Ohio, US, was not properly sealed with cement, allowing gas from a shale layer above the target tight sand formation to travel through the annulus into an underground source of drinking water. The methane eventually built up until an explosion in a resident‘s basement alerted state officials to the problem[61];

3) Groundwater contamination from drilling in the Marcellus Shale formation was reported in 2009 in Dimock, Pennsylvania, US, where methane migrated thousands of feet from the production formation, contaminating the freshwater aquifer and resulting in at least one explosion at the surface. Migrating methane has reportedly affected over a dozen water supply wells within an area of 9miles^2 (23km^2). The explosion was due to methane collecting in a water well vault. Pennsylvania Department of Environmental Protection (PA DEP) has since installed gas detectors and taken water wells with high methane levels offline at impacted homes to reduce explosion hazards. The root cause remains under investigation and a definitive subsurface pathway is not known;

4) In July 2009 in McNett Township, the Pennsylvania DEP discovered a natural gas leak involving a drilled well. Two water bodies were affected by the release of methane gas which also impacted numerous private drinking water wells in the area and one resident was forced to evacuate. A subsequent PA DEP report identified that the “suspected cause of the leak is a casing failure of some sort.” (Riverkeeper, 2010);

5) In April 2009 in Foster Township, PA, drilling activities impacted at least seven drinking water supplies. Stray gas became evident in numerous wells and residents complained. Two of the affected water supplies contained methane and five had iron and manganese above established drinking water standards. After investigating, the PA DEP found that “the stray gas occurrence is a result of 26 recently drilled wells, four of which had excessive pressure at the surface casing seat and others that had no cement returns” (Riverkeeper, 2010);

6) On December 12, 2006, PA DEP issued a cease and desist order to two companies which had “continued and numerous violations” of Pennsylvania law and had “shown a lack of ability or intention to comply with the provisions of the commonwealth’s environmental laws.” Among the violations cited in the order were “over-pressured wells that cause gas migration and contaminate groundwater; failure to implement erosion and sedimentation controls at well sites which has caused accelerated erosion; unpermitted discharges of brine onto the ground; and encroachments into floodways and streams without permits” (Riverkeeper, 2010);

[61] Ohio Department of Natural Resources, Division of Mineral Resources Management, — Report on the Investigation of the Natural Gas Invasion of Aquifers in Bainbridge Township of Geauga County, Ohio,” (Columbus, OH: 1 September 2008 reported in Worldwatch 2010).

7) In Fremont County, Wyoming, US, in response to complaints of foul odours and taste in residential wells, EPA Region Eight funded an investigation into the source and nature of the contamination. The report considered data collected from residential and municipal wells in Pavillion, Wyoming in March and May 2009. The report found heightened levels of hazardous contaminants in a number of drinking water wells, including the same chemicals used in a nearby hydraulic fracturing operation (Riverkeeper, 2010). Further data from sampling in 2010 was released by the EPA on 9 November 2011 and a research report is due in late November 2011[62]; and

8) On 3 June 2010 a gas well blowout in Clearfield County, PA, sprayed natural gas and wastewater into the air for sixteen hours. The blowout reached as high as 75ft, according to press accounts, before an emergency response team flown in from Texas was able to cap the well. The blowout was blamed on untrained personnel and improper control procedures, and the well operators were fined $400,000 and ordered to suspend all well operations in the state for forty days[63].

In addition to the evidence that contamination of groundwater via this route can (and does) occur, the fact that voluntary action on the use of some toxic substances in fracturing fluid has been taken on the basis of 'unnecessary risks' implies that there is a risk of potential concern. GWPC report[64] that diesel was cited as a principal constituent of concern by the Oil and Gas Accountability Project (OGAP) because of its relatively high benzene content. An agreement was reached to discontinue its use as a fracture fluid constituent in coalbed methane (CBM) projects in zones that qualify as USDWs. This action, then, also conflicts with the general conclusion that "hydraulic fracturing does not present a reasonably foreseeable risk of significant adverse environmental impacts to potential freshwater aquifers".

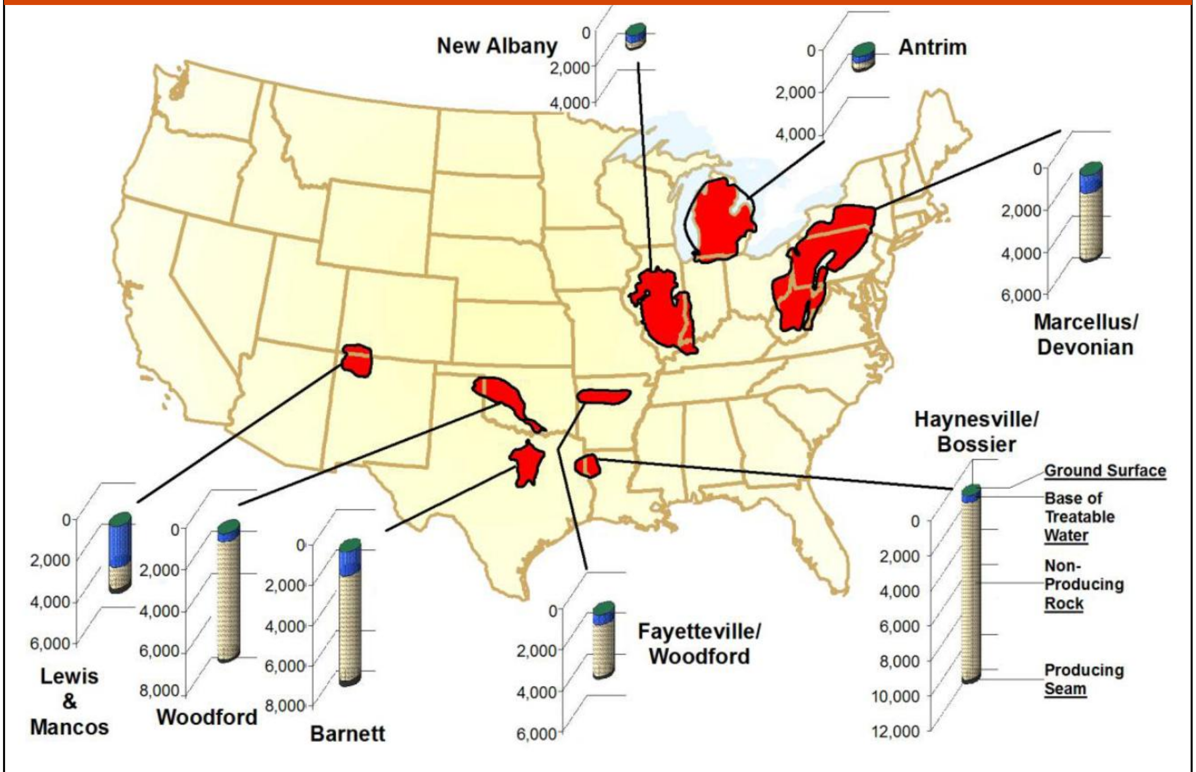
Sub-surface migration of contaminants

The exposure routes outlined above may combine with other routes, for example, via man-made or natural fractures, to produce contamination of groundwater or surface waters.

The GWPC provide data on depths of formations and treatable water (see Figure 4.2) and identify that, outside New Albany and the Antrim, wells are expected to be drilled at depths greater than 900m below the land surface. Some commentators seek to dismiss the potential for water contamination on the basis that target formations frequently lie at significant depths below aquifers and contaminants must migrate through the intervening rock.

[62] http://www.epa.gov/region8/superfund/wy/pavillion/
[63] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=12818&typeid=1
[64] State Oil and Gas Regulations Designed to Protect Water Resources – Groundwater protection Council, US Dept. of Energy, National Energy Technology Laboratory May 2009

Figure 4.2: Comparative depth of formations and groundwater



Here, for example, reports such as New York State (2009) identify that the objective of hydraulic fracturing is to limit fractures to the target formation as excessive vertical fracturing is undesirable from a cost standpoint. The expense associated with unnecessary use of time and materials is cited, as well as added costs of handling produced water and/or loss of economic hydrocarbon (should adjacent rock formations contain water that flows into the reservoir formation). Whilst this may be true, it does not negate the possibility of fractures extending vertically beyond the target formation and thereby creating or enhancing the pathways between previously isolated formations. For example, New York State (2009) cites an ICF report that identifies that, despite ongoing laboratory and field experimentation, the mechanisms that limit vertical fracture growth are not completely understood.

Incidents such as those highlighted above serve to demonstrate that a combination of exposure routes can, and do, act together to result in contamination of groundwaters.

4.4 Surface water and land contamination

Surface water is water collected above ground in streams, rivers, lakes and ponds.

The operations conducted at individual well pads requires the transport of materials to the site; use of those substances; generation of wastes; storage of wastes; and subsequent transport of wastes generated. For an individual well pad these can accumulate to substantial amounts, as detailed in Tables 2.8, 2.14, and 2.16.

The key operational hazards in these processes at an individual well pad site include (but are not limited to) the following:

- spillage, overflow, water ingress or leaching from cutting/mud pits owing:
    - limited storage capacity;
    - operator error;
    - storm water or flood water ingress; or
    - poor construction or failure of pit liner;
- spillage of concentrated fracturing fluids during transfer and final mixing operation (with water) that occurs onsite owing to:
    - pipework failure;
    - operator error;
- spillage of flowback fluid during transfer to storage owing to:
    - pipework or frac tree failure during the operation;
    - insufficient storage capability and overflow;
    - operator error;
- loss of containment of stored flowback fluid owing to:
    - tank rupture;
    - overfilling of lagoons due to operator error or limited storage capacity;
    - water ingress from storm water or floods;
    - poor construction or failure of liner;
- spillage of flowback fluid during transfer from storage to tankers for transport owing to:
    - pipework failure; or
    - operator error
- spillage of flowback fluid during transport to wastewater treatment works

Many of these hazards and routes of exposure are well known from other industrial processes and action can be taken to reduce the likelihood of such events occurring. Usually such risks persist in dedicated industrial facilities with significant investment having been built into the design to reduce the impacts should incidents occur. In contrast, the activities and hazards at well pads identified above are part of the construction of the pad and, hence, occur over a short time relative to the lifetime of the pad itself. Therefore, investment in permanent physical containment to the standard of other hazardous installations is unlikely.

The likelihood of each of these adverse events occurring varies from one hazard to another as do the consequences. Given the toxic properties of some fracturing and flowback fluids (or constituents) spillage onto land or surface water is likely to be of concern.

The likelihood of pollution incidents associated with wider development of shale increase from the 'possible' end of the spectrum at the level of a well pad through to the 'probable' as the number of wells and pads increases. There have been a number of incidents reported in the US including:

1. in September 2009 in Dimock, Pennsylvania, US, a two liquid gel spills occurred at a natural gas well pad polluting a wetland and causing a fish kill. Both involved a lubricant gel used in the high-volume hydraulic fracturing process and totalled over 30,000litres. The releases were caused by failed pipe connections (Riverkeeper, 2010);

2. in Monongalia County, West Virginia, US, in September 2009 a substantial fish kill along the West Virginia-Pennsylvania border was reported to the West Virginia Department of Environmental Protection. Over 30 stream miles were impacted by a discharge, originating from West Virginia. The DEP had received numerous complaints from residents who suspected that companies were illegally dumping oil and gas drilling waste into the waterway (Riverkeeper, 2010);

3. in Dimock, Pennsylvania, US there have been two reports of diesel fuel leaking from tanks at high-volume hydraulic fracturing drilling operations. The first leak was caused by a loose fitting on a tank and resulted in approximately 3,000 litres of diesel entering a wetland. The second leak resulted in approximately 400 litres of diesel causing in soil contamination (Riverkeeper, 2010); and

4. on December 12, 2006, Pennsylvania DEP issued a cease and desist order to two companies owing to continued and numerous violations. Among the violations cited in the order were unpermitted discharges of brine onto the ground (Riverkeeper, 2010).

A number of such incidents relate to failure to implement or conform to regulatory controls and the provision of sufficient regulatory oversight to so many individual sites and processes is both difficult and costly.

The lack of sufficient regulatory control has been an issue of concern in the US and on 27 January 2010, the US EPA announced the opening of the 'Eyes on Drilling' Tipline[65] for citizens to report non-emergency suspicious activity related to oil and natural gas development.

UK and EU Regulation is reviewed in Section 5 of this report.

[65]http://yosemite.epa.gov/opa/admpress.nsf/0/E4BFD48B693BCF90852576B800512FF2

4.5 Water consumption

As noted in Sections 2.2 and 4.1, in the US, each stage in a multi-stage hydraulic fracturing operation requires around 1,100-2,200m^3 of water so that the entire multi-stage fracturing operation for a single well requires around 9,000-29,000m^3 (9-29megalitres). For all fracturing operations carried out on a six well pad, a total of between 54,000-174,000m^3 (54-174megalitres) of water would be required for a first hydraulic fracturing procedure.

In the UK, Cuadrilla Resources is the only operator to have conducted drilling and hydraulic fracturing. It has disclosed the identities of chemicals and the volume of water required (Table 2.4). This suggests water use slightly lower than the lowest value in the range described above for the US at around 8,400m^3 per well and 84,000m^3 for the (proposed) 10 well pads.

To conduct hydraulic fracturing, large quantities of water must be brought to and stored on site. Local conditions will dictate the source of water and, in the US, operators may abstract water directly from surface or ground water sources or it may be delivered by tanker truck or pipeline. However, as has been noted elsewhere, well pads themselves are spaced out in an array over the target formation, with around three to four per square kilometre. As each fracturing phase of the operation lasts around two to five days per well, the provision of dedicated pipelines to each well pad would appear unlikely in the UK and transport via truck or abstraction are the most likely means of providing source water (note that abstraction in the UK is tightly regulated).

As detailed in Section 2.4.3 for the provision of 9bcm/year shale gas for 20 years in the UK, using Cuadrilla data, it is estimated that total water consumption is 25-33 million cubic metres (Table 2.16). Averaged over the 20 year period, this is equivalent to an annual water demand of 1.25 to 1.65 million cubic metres.

This compares with current levels of abstraction by industry (excluding electricity generation) of 905 million cubic metres. While 1.25 to 1.65 million cubic metres appears to be a small additional level of abstraction, a number of points need to be made:

- This gives annual average water requirement assumed over the whole country. Clearly actual water requirements will be focused in the areas where shale gas is being extracted and this could add a significant additional burden in those areas. By way of example, the (as yet exploratory) drilling being undertaken by Cuadrilla resources at Preese Hall in Fylde, UK, is within the River Wyre catchment. The catchment covers some 578km^2 and the Environment Agency's Catchment Abstraction Management Strategy (CAMS) for the Wyre identifies that all zones are classified as either 'over licensed', 'over abstracted' or 'no water available'. As noted earlier, water abstraction is tightly regulated in the UK. For the exploratory well Cuadrilla sourced its water from the utility company.
- Water resources in the UK are already under a great deal of pressure making additional abstraction difficult; and

- The impacts of climate change may put even greater pressure on water resources in the UK.

Given that the water is mainly used over a short period of time during initial fracturing the most likely means of getting this water to the site in the UK would probably be by truck or abstraction.

4.6 Other impacts of and constraints on shale gas production

4.6.1 Noise and Visual/Aesthetic Impacts

In terms of noise impacts, Table 2.14 provides a summary of activities required at well pads prior to production. On the basis of this, it is estimated that each well pad (assuming 10 wells per pad) requires a total of around 800-2,500days of noisy surface activity. Of all of these activities, drilling of wells is likely to provide the greatest single continuous noise (and, light) pollution as drilling is required 24 hours a day. Here, New York State (2009) estimates that each horizontal well takes four to five weeks of 24hours/day drilling to complete. The UK operator Composite Energy estimates 60 days of 24 hour drilling[66]. On the basis of this, each well pad will require 8-12 months of drilling day and night. This would be significant even if it were only a single pad that was being developed, but with development of multiple pads in a locality, the noise impacts to be locally considerable and prolonged.

4.6.2 Landscape Impacts

In terms of visual impacts, each well pad will be around 1ha in size (based on Cuadrilla's activities) and will be equipped with access roads. During construction well pads may comprise storage pits, tanks, drilling equipment, trucks, etc. making the installations difficult to develop in a way that is sympathetic with surrounding landscapes.

Given that 300 well pads would be required to deliver 9bcm/year of shale gas, assuming 10 wells per pad, it is likely that in a UK context visual impacts will be contentious. At a local level, Cuadrilla's commercialisation scenario indicates construction of 40 well pads in the medium scenario (80 in the high). As there is little that can be done to alleviate the levels of visual intrusion (individually or collectively), these impacts, along with noise and truck movements, may provide the greatest constraints on development in the UK.

4.6.3 Traffic

In addition to impacts onsite, construction of well pads requires a significant volume of truck traffic. Table 2.14 provides truck movements per well from New York State (2009). Scaled up, this suggests a total number of truck visits of 7,000-11,000 for the construction of a single ten well pad in the UK. Local traffic impacts for construction of multiple pads in a locality are, clearly, likely to be significant, particularly in a densely populated nation such as the UK.

In the US traffic damage to roads has been an issue. For example, it is reported that West Virginia Department of Transportation has increased the bonds that industrial gas drillers must pay from $6,000 to $100,000/mile. Pennsylvania is considering a

[66] http://www.composite-energy.co.uk/shale-challenges.html

similar rule where the increased funds are needed to repair roads not designed for the intense truck traffic associated with industrial gas drilling[67].

4.6.4 Seismicity

Hydraulic fracturing is known to sometimes cause seismic events. For example, the British Geological Society (BGS)[68] identify that any process that injects pressurised water into rocks at depth will cause the rock to fracture and possibly produce earthquakes. It adds that it is well known that injection of water or other fluids during processes such as oil extraction, geothermal engineering and shale gas production can result in earthquake activity.

NYC (2011)[69] highlights a number of examples of seismic events induced by human activity. The report details how an increased incidence of seismic events was linked to the high pressure injection of fluid for solution mining of brine. An evaluation of the events concluded that “fluids injected during solution mining activity were able to reach the Clarendon-Linden fault and that the increase of pore fluid pressure along the fault caused an increase in seismic activity” (p.4-33).

Hydraulic fracturing may induce seismic activity in two ways: the energy released in fracturing the rocks can create micro-seismic events that are only detectable by sensitive monitoring equipment – this is a normal part of the fracking process; the second type is a “felt” event that can be detected by humans on the ground surface. While the potential link is acknowledged, looking at hydraulic fracturing activity in the US, the NYC (2011) report finds no evidence of any seismic events caused by the process.

In the UK, hydraulic fracturing was halted at the Cuadrilla Resources’ Preese Hall exploratory site after a magnitude 1.5 earthquake on 27 May in the Blackpool area and in the light of a preceding magnitude 2.3 earthquake on 1 April 2011. At the time the British Geological Survey (2011) commented:

“We understand that fluid injection, between depths of two to three kilometres, was ongoing at the Preese Hall site shortly before both earthquakes occurred. The timing of the two events in conjunction with the fluid injection suggests that they may be related. It is well-established that fluid injection can induce small earthquakes. Typically, these are too small to be felt.”[70]

Cuadrilla Resources commissioned an independent report on the events with a view to establishing cause and mitigation (de Pater and Baisch, 2011). The report concludes that it is highly probable that the hydraulic fracturing at Preese Hall-1 well triggered the recorded seismic events. The two events reported by BGS and 48 much weaker events that were detected make it hard to dismiss them as an isolated incident. The report observes that the larger events are two orders of magnitude

[67] Riverkeeper, Inc. - Industrial Gas Drilling Reporter - Vol. 9, August 2010.
[68] http://www.bgs.ac.uk/research/earthquakes/BlackpoolMay2011.html
[69] This is a revised version of their 2009 report on the same topic.
[70] http://www.bgs.ac.uk/research/earthquakes/BlackpoolMay2011.html

stronger than normally observed from hydraulic fracturing induced seismicity and estimates any future event would be of maximum of around magnitude 3 on the Richter scale as a worst-case scenario.

In terms of future events, the report identifies that it is unlikely that a future worst case event at such a depth would cause structural damage on the surface. However, this does not negate the possibility of structural damage to the wellbore and loss of well integrity. Here, for example, the report discusses the fact that the Preese Hall 1 well was deformed from a circular shape to an oval shape from approximately 2,580m to 2,630m down the wellbore after the second of six hydraulic fracturing stages in April 2011. The casing above and below that interval was not observed to be significantly deformed. It was determined that the deformed casing did not affect the overall wellbore integrity, and posed no risk to any shallow groundwater zones and, as such, the decision was made to proceed with the Stage 3 fracturing treatment.

It is clear, then that seismic events can be caused by hydraulic fracturing and, whilst these are unlikely to be of a sufficient magnitude to cause structural damage on the surface, structural damage to the wellbore itself (and in all likelihood other wellbores in the vicinity) is possible and has been documented in this case.

According to a statement from Charles Hendry (UK Energy Minister) on 2 November 2011, the UK Government will look at the report carefully with the assistance of independent experts and regulators before deciding whether hydraulic fracturing operations should resume[71].

[71] http://www.decc.gov.uk/en/content/cms/news/cuadrilla_hend/cuadrilla_hend.aspx

4.7 Importance of cumulative impacts

Whilst the new risks associated with hydraulic fracturing of wells may be the subject of debate, such risks and impacts are not the only potential drawback of shale exploration, particularly when considering relatively densely populated countries such as the UK.

Here, whilst there is the temptation to focus on the risks associated with individual processes involved in shale gas production and reported incidents, it is also important to consider the impact of shale gas as a whole.

More ‘run of the mill’ impacts including vehicle movements, landscape, noise or water consumption, may be of significant concern, particularly in more densely populated countries where there is greater competition for resources, such as the UK.

Cumulative impacts may be a particular issue too, when one considers the development of shale gas at a scale sufficient to deliver gas at meaningful volumes. To set the cumulative nature of impacts in context, Table 2.16 provides estimates of the resources required to deliver shale gas production at a rate of 9bcm/year (equivalent to 10% of UK gas consumption in 2008) for 20 years. To sustain this level of production for 20 years in the UK would require around 2,500-3,000 horizontal wells and some 25 to 33 million cubic metres of water. A proportionately large quantity of wastewater, requiring treatment if hazardous, and transport to licensed treatment works must also be considered.

5 European regulatory framework

5.1 Introduction

The view provided by DECC to the Energy & Climate Change Committee is that UK regulation is "well-designed with clear lines of responsibility among several different bodies including DECC, the Health and Safety Executive (HSE), the respective Environment Agency, and Local Planning Authority" (DECC, Para 32) and that the UK has a "robust regime which is fit for purpose" and will ensure that unconventional gas operations are carried out in a "safe and environmentally sound manner" (Para 92).

In addition, the perception is that the regulatory framework that operates in the UK/EU is likely to be much more robust than that operating in the US[72] where issues and problems have been reported. From a regulatory perspective, many of the problems experienced in the US have been blamed on the US federal Energy Policy Act of 2005 which excluded hydraulic fracturing from the Safe Drinking Water Act, effectively delegating it to State responsibilities to protect groundwater.

This study has reviewed the key regulatory instruments that are in place in the UK and EU to identify the extent to which these views hold true and, therein, the extent to which the current regulatory framework and its application has (and will) provide adequate control of risks and impacts.

5.2 Groundwater protection

5.2.1 UK Regulation

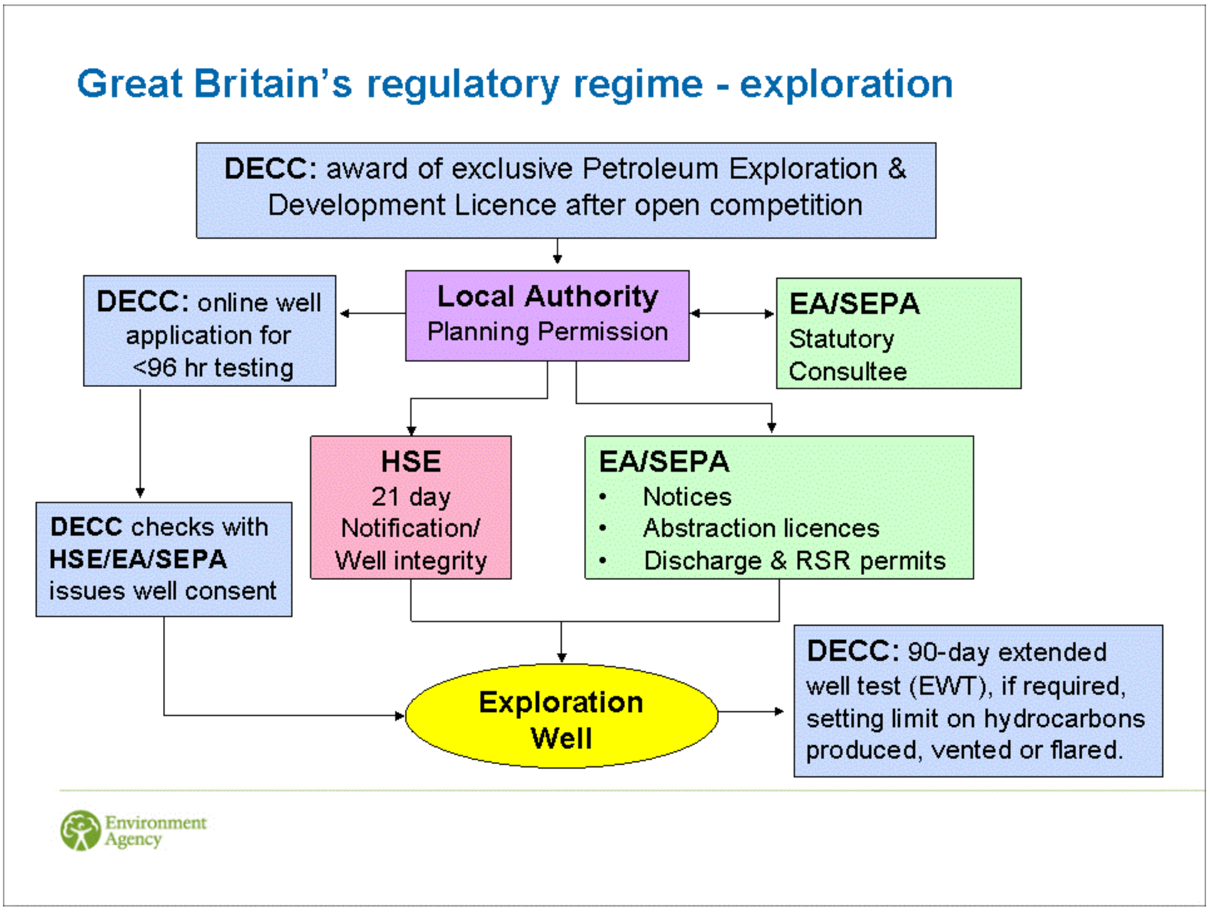
When considering the powers and responsibilities provided by the implementation of EU Water Framework Directive (WFD) and Groundwater Directives the view of the UK Government, in theory at least, holds true for groundwater.

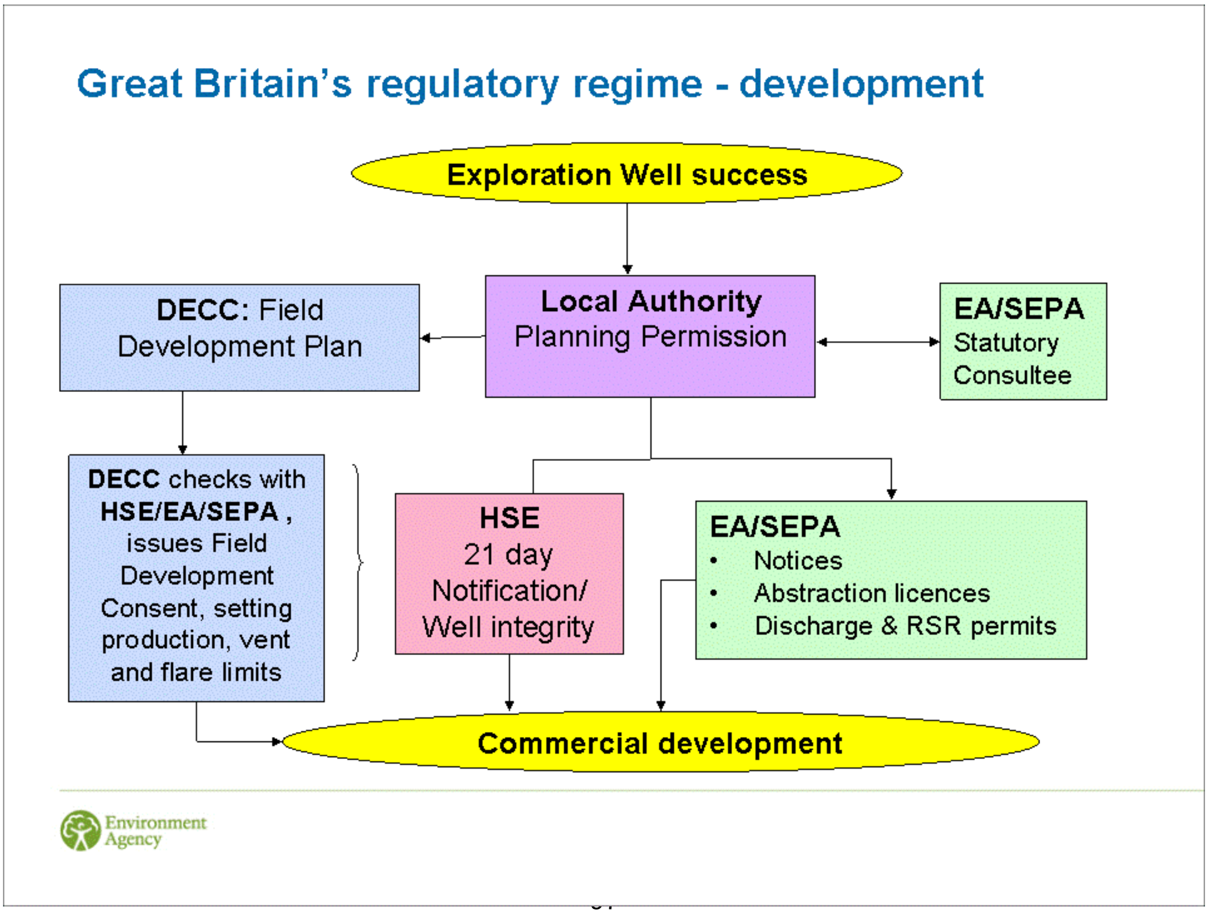
When properly implemented and applied, these powers permit regulators to require the application of necessary measures for the protection of groundwater from shale gas operations. These powers can be applied to management of risk from both 'normal' operations and 'abnormal' operations (such as full/partial loss of well integrity).

However, in order to ensure that unconventional gas operations are carried out in a "safe and environmentally sound manner" there is a need to apply the full suite of powers (and responsibilities) available.

[72] See for example paragraphs 94 and 108 and recommendation 12 and 22 of the E&CCC report.

Figure 5.1: Flow diagrams identifying relevant bodies in UK regulatory regime and respective processes for exploration and development. (Environment Agency 2011a)





In the case of existing operations in the UK, the EA considered the specific activities at the locations and, considering their 'normal operation' determined they would not lead to an input of a pollutant to water and so did not constitute "groundwater activity". On this basis, it has determined that no environmental permit was required. With regard to environmental permitting of future developments, the Environment Agency has identified that it is not expecting to routinely require environmental permits in relation to "groundwater activity" for the same reasons[73]. Figure 5.1 Illustrates the current permitting sequence and regulatory responsibilities for different aspects of UK exploratory drilling.

Importantly, the EA's current position appears to consider only 'normal operations' at such installations and, as such, risks to groundwater from 'abnormal' operations from, for example, full or partial loss of wellbore integrity, are not explicitly considered in the decision as to whether or not to require a permit for groundwater activity.

This position is based on the presumption that wells and well casings will be properly designed and constructed and, as such, there will be no release of fluids from wells and no risk to groundwater or other receiving environment. In turn, the basis for this presumption is that other UK regulation, under the remit of HSE, seeks to ensure that they are.

The well provisions of this latter regulation identify that operators shall ensure that wells are designed and constructed and operated at every stage such that, "so far as is reasonably practicable, there can be no unplanned escape of fluids from the well". On first inspection, then, this presumption might appear to be a fair one.

Further inspection, however, highlights that the well design and construction regulation considers only health and safety risks. The issue of environmental risk is not one that is considered by the regulator (HSE) and, hence, is not an aspect that is considered when determining what constitutes design and construction to ensure that there can be no unplanned escape of fluids from the well "so far as is reasonably practicable".

The terms 'so far as is reasonably practicable' (SFAIRP) and 'as low as reasonably practicable' (ALARP) have a specific (and interchangeable) meaning in health and safety regulation. What constitutes 'reasonably practicable' involves assessment of the risks to be avoided and of the sacrifice, in money, time and trouble, involved in taking measures to avoid those risks. Comparison of the two determines what risk reduction measures are 'reasonably practicable' as well as what measures would be grossly disproportionate.

[73] Note that permitting for groundwater activity should not be confused with that for other activities such as disposal of flowback fluid. Here, after initial analysis of flowback fluid at the Cuadrilla test wells and new limits being specified in Schedule 23 of the Environmental Permitting Regulations 2010 on 1 October 2011 the Environment Agency has determined that a permit is now required. Based on initial analysis of the radioactivity in the flowback fluid Cuadrilla will also require an Environmental Permit to store and dispose of the flowback fluid and as part of the application for a permit a radiological impact assessment will be required. Future needs for waste water permitting will depend on site by site assessment.

At present, because the UK well design and construction regulation focuses only on health and safety risks to people, what currently determines 'reasonably practicable' measures for well design and construction is restricted to the consideration of the health and safety risks avoided and associated costs. In other words, because environmental risks of unplanned escape of fluids are not part of the equation, they, and the associated environmental costs, are not currently part of the equation for determining what measures to prevent unplanned release of fluids constitute 'reasonably practicable'.

Clearly, then, consideration of environmental risks avoided alongside the health and safety risks avoided would tend to increase the level of investment that is justified beyond that which is considered reasonable/justifiable at present (by consideration of the health and safety risks alone).

From this it can be concluded that, whilst the UK's well design and constriction regulation is indeed likely to help ensure that there is no unplanned escape of fluids, the standard of 'reasonably practicable' protection afforded by it is likely to be lower than it should be. Thus, in order to ensure the *environmental* risks of full or partial loss of well integrity are considered, it appears that either the Environment Agency must consider 'abnormal' operations and therefore require an environmental permit for "groundwater activity" relating specifically to suitable design standards, or regulations and associated standards relating to well design and construction need to be revised to address the shortfall.

In either case, standards need to be developed to more adequately address the issues peculiar to shale gas development both in terms of the processes themselves and the cumulative impact of development. In relation to the former, in a recent report on shale gas, the Institution of Gas Engineers and Managers (IGEM, 2011) identifies that, for new technologies such as horizontal directional drilling and hydraulic fracturing, there is a "distinct lack of standards for these processes". There are no British Standards covering the hydraulic fracturing procedure itself and a standard on directional drilling is still under development. In contrast, IGEM report that in the US there are API (American Petroleum Institute) ANSI-accredited (American National Standards Institute) standards and guidance documents including four standards that apply specifically to Hydraulic Fracturing (Well Construction and Integrity Guidelines, Water Management, Mitigating Surface Impacts and Isolating Potential Flow Zones). In light of these issues, IGEM has recommended that "standards are needed within the UK and internationally to ensure the consistency of safety measures and to guarantee that environmentally damaging or dangerous practices such as have been recorded in the US do not occur within the UK".

In terms of cumulative issues, future standards should also address the cumulative nature of the environmental (and human health) risks associated with shale gas wells when compared to the conventional wells that the regulations are, broadly, designed to address. For example, a given shale well pad (such as those proposed in commercial development scenarios over the Bowland Shale) is likely to have ten wells drilled to down to the target formation at any single location as opposed to one in the case of conventional wells. As it only takes the full/partial loss of integrity of a single one of these wells to produce an adverse impact, the risk of contamination at this location is ten times higher than that of a single conventional well drilled at the same location. By implication, then, the design standards that apply to shale gas wells need to offer many times the level of protection as would apply to a conventional well in order for there to be parity of risk between the two cases.

5.2.2 Regulation in the EU

Whilst this study finds that the powers and responsibilities provided by the implementation of EU WFD and Groundwater Directives, when properly implemented and applied, will permit regulators in all Member States to require the application of necessary measures for the protection groundwater from shale gas operations, the case of the UK illustrates that Member States may fall back on existing domestic regulation on well design and construction to address risks from full or partial loss of well integrity.

The adequacy of this has been discussed above and in the main text and in Annex 2. What is important from an EU perspective, however, is that there are currently no harmonised EU requirements as regards the proper design and construction of wells. As such, any other EU Member State that takes a similar view to that of the UK may also depend on its own existing domestic regulations to address this set of risks.

Without examining the suite of domestic regulation operating in Member States (which beyond the scope of this study), it is not possible to judge the adequacy, or otherwise, of such domestic regulation. However, the lack of harmonised requirements in relation to well design and construction means that there is likely to be variation in the extent to which the risks of groundwater contamination through full or partial loss of well integrity will be addressed in different Member States.

In relation to different standards operating in different countries, as noted above, IGEM has recommended that “standards are needed within the UK and internationally to ensure the consistency of safety measures and to guarantee that environmentally damaging or dangerous practices such as have been recorded in the US do not occur within the UK”. It is also interesting to note the comments of Cuadrilla CEO Mark Miller to IGEM (2011) that “API (American Petroleum Institute) sets a lot of standards but we don’t really follow a rigid API Standard. Most of the industry worldwide has API standards but they have standards developed for each country. So there are some things we do here that are unique to the UK that aren’t really required in North America, but to us they are Industry Best Practice and add another level of safety to what we do”.

In relation to the implications of this for future shale gas development in the EU, the perception is that the regulatory framework that operates in the UK and EU is likely to be much more robust than that operating in the US where it is acknowledged that there have been problems and issues. From a regulatory perspective, many of the problems experienced in the US have been blamed on the US federal Energy Policy Act of 2005 which excluded hydraulic fracturing from the Safe Drinking Water Act, effectively delegating it to State responsibilities to protect groundwater.

From this perspective, then, the regulatory situation in the EU is not so very different. Whilst there are harmonised requirements for the protection of groundwater across all Member States, there is variation in interpretation of how these requirements are to be met and powers applied. Most significantly, in relation to one of the key sources of risk, that of full/partial loss of well integrity, the issue may well be delegated to Member State domestic regulations on well design and construction – a situation that is not dissimilar to that which is blamed for many of the problems in the US.

Finally, it should be strongly noted that regardless of the regulation and the strength of the measures applied to the construction and operation of wells, a residual risk will always remain. Just because a well may be designed and constructed such that the risk of unplanned release is as low as reasonably practicable does not mean an unplanned release will not happen. Regulatory measures may make it less likely – but the risk cannot be eliminated. Thus, even a small probability per well, once multiplied across all wells, becomes a correspondingly larger probability that an adverse event will occur somewhere at some point in time. For example, if regulation reduces the likelihood of 'something going wrong' to 1 in 1,000 per well, then, when one constructs 3000 wells, as would be required to deliver 10% of current UK gas consumption, there is a 95% chance of an incident. If one constructs a few tens of thousands of wells, which would certainly be required for meaningful production in the EU, then at least one failure becomes close to certain and multiple failures become highly probable. On this basis, while regulation must inevitably look at individual circumstances and control risks on a case by case basis it is the role of policy to take into account the limits of regulation of the relevant risks.

5.3 Regulation of substances used in fracturing fluids

5.3.1 EU Regulation

The use of any substance in hydraulic fracturing fluid must ultimately be registered with the European Chemicals and Health Agency (ECHA) under the REACH (Registration, Evaluation, Authorisation and restriction of Chemicals) Regulations that came into force on 1st June 2007.

REACH is still being phased in but at the present time, the use of any substances fitting the following criteria should have already been registered with an associated chemical safety assessment (CSA) for that use:

- 1000 tonnes per annum (tpa) or;
- 100 tpa and classified under Chemicals (Hazard Information and Packaging for Supply) Regulations 2009 (CHIP) as very toxic to aquatic organisms or;
- 1 tpa and classified under CHIP as Cat 1 or 2 carcinogens, mutagens or reproductive toxicants.

The Directorate Generale (DG) for the Environment of the European Commission has supplied us with a statement on the position with regard to REACH and fracturing chemicals. This statement notes that "shale gas operators are not allowed to use a substance which does not fulfill REACH requirements in their activities. Shale gas operators must in any case comply with requirements applicable to downstream users under Regulation (EC) No 1907/2006 on the registration, evaluation and authorisation of chemicals (REACH). Should they fail to comply with such requirements, they would face penalties for non-compliance from Member State enforcement authorities".

The European Chemicals Agency (ECHA) has examined the exposure scenarios (Chemical Safety Reports) of the REACH registration dossiers for a selected number of chemical substances likely to be used in shale gas and found no evidence that the dossiers for the selected substances contain reference to shale gas (and other related search terms). This does not mean that no substances have been registered for that use, simply that none have been identified to date.

In terms of enforcement, the Commission notes that "it is up to Member State enforcement authorities to ensure that shale gas exploration and exploitation projects fully comply with REACH requirements and subject operators to penalties in case of non-compliance. The Commission has not been informed so far of cases of non-compliance by shale gas operators".

In terms of regulatory coverage, then, REACH should, in principle, provide suitable coverage of the issues regarding use of any substance in fracturing fluid. In addition, Member States have powers to require disclosure of chemicals being used in hydraulic fracturing as part of undertaking their duties under the WFD and Groundwater Directives.

5.3.2 UK Regulation

The UK enforcement regime for REACH is established under the 2008 REACH Enforcement Regulations. The competent authority for REACH in the UK is HSE but the enforcement regime established by the REACH Enforcement Regulations 2008 is a multi-agency one.

Hydraulic fracturing has been carried out in the UK as part of exploration by Cuadrilla Resources. The substances to be used in the hydraulic fracturing process were fully and voluntarily disclosed by the operator to the Environment Agency before hydraulic fracturing took place. As such, any possible non-compliance with REACH requirements on use of these substances for hydraulic fracturing should have been identified by the Environment Agency according to its duties under the REACH and the REACH Enforcement Regulations.

However, the ECHA study on behalf of the Commission identifies that, for one of the substances used in the UK, polyacrylamide, there is no evidence that hydraulic fracturing is a registered use and hence, evidence of potential non-compliance with REACH. The European Commission has been made aware of the use of polyacrylamide for hydraulic fracturing in the UK and of possible non-compliance with REACH. DG Environment informs us that the European Commission is currently looking into the issue but, for the time being, is not in a position to provide any further information on this.

If it is found that use of polyacrylamide, or any other substance, for hydraulic fracturing in the UK or elsewhere did not comply with regulations then, given that substances were declared to the authorities in advance of their use, this represents a failure on the part of the multi-agency UK enforcement authorities to take the appropriate action. This, in turn, would appear to question the view of the UK Government witnesses to the Energy and Climate Change Committee that UK regulation is "well-designed with clear lines of responsibility among several different bodies including DECC, the HSE, the respective Environment Agency, and Local Planning Authority" (House of Commons, 2011; para 32).

5.4 Wider environmental impacts

5.4.1 EU Regulation

In addition to the environmental and contamination risks surrounding shale gas development, there are a number of other impacts that are likely to be significant. Consideration of the wide range of environmental impacts from individual installations/development comes under the scope of the Environmental Impact Assessment Directive (Directive 85/337/EEC, as amended by Directives 97/11/EC and 2003/35/EC). This sets out a requirement for member States to require an EIA of installations with significant environmental impacts.

Annex I of the Directive identifies installations which will always require EIA. Based on the criteria for projects requiring EIA under Annex I of the EIA Directive, a shale gas well pad would always require an EIA if it produced 5,000 cubic metres per day or more of gas. This study finds that a proposal to develop a shale gas well pad is extremely unlikely to constitute an Annex I project under the EIA Directive and so will not automatically require an EIA.

Annex II of the EIA Directive identifies projects that are subject to Article 4(2) of the Directive which identifies projects that may require an EIA, where this includes descriptors that would cover shale gas development. Accordingly, the Directive requires that, for shale gas development, Member States should:

- "determine through (a) a case-by-case examination, or (b) thresholds and criteria set by the Member State whether the project shall be made subject to an assessment…. ….Member States may decide to apply both procedures referred to in (a) and (b)"; and

- "When a case-by-case examination is carried out or thresholds or criteria are set….. the relevant selection criteria set out in Annex III shall be taken into account", where these require member States to consider the sensitivity of project locations and potential impacts, as well as the characteristics of projects, in deciding whether EIA is needed. This includes consideration of impacts of cumulation with other projects (including other wellpads), accidents and complexity of the impacts.

According to recent ECJ rulings reported by the European Commission, "Member States are obliged to take account of all the relevant selection criteria listed in Annex III when establishing criteria or thresholds for Annex II projects. A Member State that has established thresholds and/or criteria that take account only of the size of projects, without taking all the criteria listed in Annex III into consideration, would exceed the limits of its discretion under the Directive".

The Directive, then, leaves it to Member State screening procedures to identify whether or not EIA will be required for a given shale project and, so, whether shale gas development will be subjected to EIA depends on the screening procedures operating in Member States (which must comply with the Directive's requirements).

There is substantial evidence that screening procedures are not consistent between Member States and that they may not adequately screen projects. For example, in its report on the application and effectiveness of the EIA Directive[74], the European Commission identifies a number of concerns regarding Member State screening procedures including:

- Member States often exceed their margin of discretion, either by taking account only of some selection criteria in Annex III or by exempting some projects in advance;

- the number of EIAs carried out by different Member States varies considerably even when comparing Member States of a similar size and the levels at which thresholds have been set (to screen in or screen out certain projects) has clear implications for the amount of EIA activity; and

- there is a lack of harmonised practices for public participation and no common reference point for the beginning of the consultation. In several Member States, the public is already consulted at an early stage (at the screening stage or at the scoping stage). However, in most cases, the public is consulted for the first time on the information gathered pursuant to Article 5, which corresponds to the minimum requirement laid down by the Directive.

On the basis of this the Commission's report identifies that the screening mechanism should be simplified and clarified, for example, by detailing the selection criteria listed in Annex III and by establishing Community thresholds, criteria or triggers.

In addition to issues over screening, the report also identifies a number of other weaknesses. In relation to cumulative effects, the Commission report identifies that there are still several cases in which cumulative effects are not taken into account and problems when it comes to eliminating 'salami-slicing' practices, where

[74] COM(2009) 378 final: Report from the Commission to the Council, the European Parliament, the European Economic and Social Committee and the Committee of the Regions on the Application and Effectiveness of the EIA Directive.

developers deliberately reduce a project into smaller units to avoid thresholds set for EIA consideration.

We therefore conclude that the impacts of shale gas projects are unlikely to be considered adequately or consistently in different Member States. Part of this conclusion is based on application of EIA in the UK, as well as the Commission's own findings.

5.4.2 UK Regulation

In the UK, the EIA Directive is implemented by the Town and Country Planning (Environmental Impact Assessment) (England and Wales) Regulations 1999 which set out which types, scale and location of projects may require an EIA and where applicants may need to apply to the Local Authority for a screening opinion on whether an EIA is required.

To date, development of five exploratory shale gas wellpads has been permitted in the Northwest of England. All were submitted as separate applications and none has been required to undertake EIA nor undergo formal screening by the Local Planning Authority (LPA) to identify whether one would be required.

The shale gas wellpads were declared to the LPA as covering an area of 0.99ha such that they did not meet the UK criterion of more than 1ha requiring "deep drilling" projects (under Annex II) to have a formal screening to identify whether EIA was required. As such, no further consideration was given to the issue.

However, the LPA could have required the same projects to undergo formal screening for EIA under UK regulations for the category "*surface industrial installations for…the extraction natural gas*", where the area of the development exceeds 0.5 hectare. As such, the LPAs decision appears to fail to implement the UK regulations and the EIA Directive properly.

The failure of the LPA to take these facts into consideration places the existing shale developments in some jeopardy from a legal challenge. As the 2009 Baker case highlighted, any concerned individual or group can request that the Secretary of State make a screening direction in relation to a project and there is no obstacle to challenging the decision of LPAs. There are also examples of successful challenges that have led to planning permissions being quoshed because LPAs have not or have not adequately, screening proposals.

From the perspective of the proper implementation of the EIA Directive, the LPA's decision can be questioned on a number of levels. Most obviously, it appears not to have considered whether the development constituted development under an appropriate category.

More importantly, however, the decision to rule out the developments from even being considered for EIA because they were not of a sufficient area to meet the UK criterion appears to conflict with recent ECJ rulings reported by the European

Commission. As noted above, these explicitly identify that "Member States are obliged to take account of all the relevant selection criteria listed in Annex III when establishing criteria or thresholds for Annex II projects. A Member State that has established thresholds and/or criteria that take account only of the size of projects, without taking all the criteria listed in Annex III into consideration, would exceed the limits of its discretion under the Directive".

Whilst the UK appears confident about the robustness of its environmental regulations and their ability to address issues from shale gas development, as with other aspects described in this report, there appear to be significant failings in relation to both EIA regulation (i.e. the use of 'size only' trigger thresholds) and its implementation (i.e. the consideration of appropriate categories and criteria). As a result of these, based on a thorough review of experience to date in the UK, to date shale gas development has 'slipped under the radar' of EIA in the UK because of a combination of the thresholds/criteria being applied, the small size of individual projects, and poor interpretation and enforcement of these criteria.

Whether this is a situation that is shared by other Member States is not known at present (and further research would be required). However, the concerns of the European Commission set out in its report[75] (and described earlier) suggest that this inadequacy in screening procedures may be an issue shared by a number of other Member States and so not limited to the UK. This suggests that action is required at Community level to ensure that other Member State screening procedures (including thresholds and criteria) will flag up the possibility of significant impacts from shale gas development and, in particular, the cumulation of projects and the prevention of 'salami slicing' practices. If appropriate action is not taken in this regard, there is a very real possibility that shale gas development may slip below Member State screening thresholds/criteria and the wide ranging impacts of shale gas developments may not be fully considered under the terms of the EIA Directive.

[75] COM(2009) 378 final: Report from the Commission to the Council, the European Parliament, the European Economic and Social Committee and the Committee of the Regions on the Application and Effectiveness of the EIA Directive.

6. Conclusions

6.1 Background

6.1.1 Exploitation of shale gas

Gas shales are formations of organic-rich shale, a sedimentary rock formed from deposits of mud, silt, clay, and organic matter. In the past these have not been seen as exploitable resources, however, advances in drilling and well stimulation technology has meant that 'unconventional' production of gas from these, less permeable, shale formations can be achieved. Extraction of the gas involves drilling down and then horizontally into the shale seam. A fluid and a propping agent ('proppant') such as sand are then pumped down the wellbore under high pressure to create fractures in the hydrocarbon-bearing rock (a process known as hydraulic fracturing). These fractures start at the horizontal wellbore and extend as much as a few hundred metres into the reservoir rock. Gas is then able to flow into the wellbore and onto the surface. Wells are usually grouped into well pads containing around six to ten individual wells. In the United States (US) these well pads are sited 1 to 3.5 in every square kilometre.

To date shale gas has only been exploited in the US, where production of shale gas has expanded from around 1.4% of total US gas supply in 1990 to greater than 14.3% of total US gas supply in 2009. From 2000 to 2006 the average annual increase was 17% but from 2006 to 2010 the average rate of increase has grown to 48% per year (EIA 2011). Resource estimates have also grown substantially in this time. The upward trend is rapid and EIA report a threefold increase in the estimate of technically recoverable reserve between 2008 and 2010 inclusive, while the release of the 2011 figures sees a further doubling of the 2010 estimate[76]. Energy forecasts predict that shale gas is expected to expand to meet a significant proportion of US gas demand within the next 20 years with an increase in production from 93bcm in 2009 to 340bcm in 2035, a 266% increase.

6.1.2 The UK case

At present the only shale developments in the form of well pads and horizontal shale wells in the UK are exploratory. The most advanced drilling has been by Cuadrilla Resources, which received planning permission for an exploratory drill site at Preese Hall Farm, Weeton, Lancashire in November 2009. Drilling at Preese Hall was completed in December 2010 and hydraulic fracturing has been conducted from January to May 2011. As of November 2011 drilling, but not yet hydraulic fracturing, had been undertaken at two further sites, Grange Hill Farm and Banks, both in Lancashire[77].

[76] This data was prefaced by the Annual Energy Outlook early release overview in December 2010 (EIA 2010b).
[77] www.cuadrillaresources.com/what-we-do/locations

There is a high level of uncertainty around the potential reserves of shale gas in the UK but, drawing assumptions from similar producing shale gas plays in America, BGS estimates UK shale gas reserve potential at 150bcm [78]. However, based on data from its initial exploration, on the 21st September 2011 Cuadrilla Resources announced its first estimate of the volume of gas within its licence area in Lancashire. It estimated a significant total of 5,660bcm gas initially in place which, assuming that 20% is recoverable, translates to around 1,132bcm of recoverable resource, from an area of just 437 square miles.

6.2 GHG emissions

6.2.1 Differences with conventional gas

It has been assumed in this report that the direct emissions associated with the combustion of shale gas will be the same as gas from conventional sources. In considering the UK, the distribution of shale gas would be the same as conventional gas and therefore subject to the same losses. This means that the main difference between shale and conventional gas is likely to be from emissions that arise from the differing extraction processes. The limited verifiable data available made assessment of these extraction emissions problematic. However, it was possible, using data on expected emissions from the Marcellus Shale in the US, to estimate the likely emissions associated with the different processes that occur in extracting shale gas compared to conventional gas.

The report has estimated emissions associated with a number of processes:

- Horizontal drilling;
- Hydraulic fracturing;
- Transportation of water;
- Transportation of wastewater; and
- Wastewater treatment.

The combination of emissions from these processes gave an estimate per well of 348-438tCO_2e. A potentially larger quantity of fugitive methane emissions from flowback must be added to this sum if not controlled effectively. This figure will increase if the well is refractured, something which could happen up to five times and a recent DECC (2010) report has suggested that refracturing could happen every four to five years for successful wells.

The significance of these emissions is dependent on the rate of return for the well – something which is site specific. Looking at examples of expected total production for shale basins in the US we can estimate that, on average, the additional CO_2e emissions associated with the processes above account for 0.14 to 1.63 tCO_2e/TJ of

[78] At the same time BGS note that the US analogies used to produce this estimate may ultimately prove to be invalid. Hence it is possible that the shale resource could be larger.

gas energy extracted, with a further potential for 2.87 to 15.3 tCO_2e/TJ from fugitive methane emissions during flowback.

These values depend upon the total amount of gas that is extracted per well and the number of times it is refractured. Examining the UK in particular, although the rate of return per well is not quoted for UK basins, it is thought that additional CO_2 emissions per well would be at the higher end of estimates compared to the US, as UK reserve potential is low in comparison to the US basins. It is unknown how applicable the estimates provided by Cuadrilla Resources are to other formations.

Given that during combustion 1TJ of gas would produce around 57tCO_2e the additional emissions from the shale gas extraction processes identified represent 0.2-2.9% of combustion emissions excluding flowback emissions and 5.3-29.7% if they are not captured. Similarly to conventional gas, there will be further emissions associated with processing, cleanup and distribution.

The technical possibility of relatively low levels of additional emissions suggest that there would be benefits in terms of reduced carbon emissions if shale gas were to substitute for coal. Combustion of coal produces around 93tCO_2e/TJ. Clearly even with additional emissions associated with shale gas, the emissions from gas would be lower, assuming that gas losses during transport, distribution and storage are minimal. These losses are subject to substantial uncertainty at present, although a range from 1.4% to 3.6% does not appear unreasonable (Howarth et al, 2011). The benefits increase when the higher efficiencies of gas fired power stations compared to coal fired power stations are considered.

- Emissions associated with additional processes needed for the extraction of shale gas are small (0.2-2.9% of combustion emissions).
- The potential for fugitive methane emissions during flowback could increase this substantially if not managed on site. This may be up to 30%, however, empirical data is limited.
- Considering extraction and combustion alone, carbon emissions from shale are not significantly more than for conventional gas and are lower than for coal.

6.2.2 Impacts on total emissions

In order to examine the potential impact of shale gas, CO_2 emission scenarios were developed for both the UK and globally.

For the UK, three scenarios have been developed. Each of these is based on a different estimate for the amount of technically recoverable shale gas in the UK. The first scenario is based on the figure of 150bcm outlined in the report by DECC discussed earlier (DECC, 2010). The second uses a figure of 566bcm from a recent report by the US EIA (EIA, 2011). The third scenario is based on the figures released by Cuadrilla stating that, in the areas where they are licensed to drill, there are shale gas reserves of 5,660bcm, 20% of which was assumed to be recovered.

All three scenarios see the majority of shale gas being exploited before 2050 and the cumulative emissions associated with the use of this shale gas ranged from 264-2,029 $MtCO_2$. To give this some context, it amounts to between 1.9% and 14.5% of the total UK greenhouse gas emissions budget to 2050 under the intended budget proposed by the UK Committee on Climate Change. Assuming that the carbon budget is adhered to then this should not result in additional emissions in the UK. For example, it is possible that UK produced shale gas could substitute for imported gas, although it would not negate the need for imports. However, it is also possible that extracting additional fossil fuel resources could put pressure on efforts to adhere to our carbon budget by reducing gas prices and directing investment away from renewable energy. It is also important to note that in a market led global energy system where energy demand worldwide is growing rapidly, even if shale gas were to substitute for imported gas in the UK, leading to no rise in emissions, it is likely that this gas would just be used elsewhere, resulting in a global increase in emissions.

As with the UK, the potential shale gas that could be exploited globally is highly uncertain. The most recent estimate of technically recoverable resource has been made by the US EIA at 187,535bcm (EIA, 2011). In calculating this figure, a recovery factor of between 20-30% was generally used. In order to provide three global scenarios, it was assumed that the EIA figure is based on a recovery rate of 20%. Two additional scenarios are then used with recovery factors of 10% and 30%.

Assuming that 50% of this resource is exploited by 2050, these scenarios give additional cumulative emissions associated with the shale gas combustion of 95-286 $GtCO_2$, resulting in an additional atmospheric concentration of CO_2 of 5-16ppmv for the period 2010-2050. These emissions would occupy a substantial proportion, up to 29%, of an emissions budget associated with a better than 50:50 chance of avoiding 2°C warming (Anderson and Bows 2011).

However, in an energy hungry world it is possible that exploitation would be more rapid than this. What we can say with more certainty is that without a meaningful cap on global carbon emissions, any emissions associated with shale gas are likely to be additional, exacerbating the problem of climate change.

- Without a meaningful cap on carbon emissions the utilisation of shale gas will likely increase carbon emissions by potentially considerable amounts.
- Shale gas exploitation could lead to an increase in atmospheric concentration of CO_2 of 5 to 16ppmv and occupy up to 29% of a 2°C emissions budget.
- Shale gas exploitation could increase the difficulty of attaining set targets for carbon reductions through, for example, substituting for renewable energy.
- If global carbon caps were to be agreed and if they were strictly adhered to, then it is possible that shale gas would make no difference as the source of emissions would be inconsequential. However, this would require a very significant deployment of as yet unproven large scale carbon capture and storage (CCS).

6.2.3 Investment in shale gas compared to renewables and implications for decarbonisation

A substantial move to exploit shale gas reserves has the potential to impact upon investments in renewable energy. In order to explore this, we estimated the capital costs of drilling shale gas wells to supply 10% of current UK gas consumption and the equivalent Combined Cycle Gas Turbine (CCGT) power stations that would burn it. Given the need for low carbon generation, the costs of gas CCGT with CCS was also considered. It is estimated that such a programme over the next twenty years would cost between £19bn and £32bn.

If a straight substitution relationship is assumed between electricity from renewables and gas then, considering the capital costs only, 8GW of CCGT plus gas well infrastructure could displace 12.5GW of wind capacity, equivalent to over 4,000 large onshore turbines, at a commercial discount rate. With a 3.5% social discount rate, and the inclusion of CCS technology, potential displacement increases to approximately 21GW of installed onshore wind capacity or 12GW offshore. Either would be expected to generate approximately equivalent quantities of electricity as the gas option even given the lower load factor of wind turbines.

There is also a matter of timing of possible substitution between shale gas and coal. The Committee on Climate Change has argued that transition to a very low carbon grid, of the order of 50gCO_2/kWh, should take place by 2030, on the way to a zero carbon grid soon after. Were a new round of stations to be completed in the next ten years they would become “stranded assets” or require expensive retro fitting of as yet untested CCS technology. As such it seems likely that shale gas would “lock in” high emissions infrastructure in the medium term.

A precise and accurate value of the life cycle GHG impact, either per unit of shale gas produced or per unit of electricity from shale gas, is not necessary to draw this conclusion. The absolute necessity of decarbonisation means that technologies with orders of magnitude lower emissions are required to provide energy to UK households and industry in the short to medium term.

- Substantial investment in shale gas wells and power plant would be required to produce gas sufficient for 7-8GW of electricity generating capacity, even more so with the addition of CCS.
- This same investment could deliver approximately 21GW of onshore wind capacity or 12GW offshore, when assessed at social discount rates appropriate for policy decisions.
- Gas powerstations built in the near to medium term will require retro fitting of CCS capability or become ‘stranded assets’ if the UK keeps to its climate change objectives.

6.3 Environmental impacts of shale gas production

6.3.1 Groundwater contamination

The potential for contamination of groundwater is a key risk associated with shale gas extraction. Although there is limited evidence it appears that the fluid used in hydraulic fracturing contains numerous chemical additives, many of which are toxic to humans and/or other fauna. Concerns that the fracturing process could impact on water quality and threaten human health and the environment have prompted the US EPA to instigate a comprehensive research study into the issue. The New York State Senate and Governor have moved separately to suspend the issuance of new permits for hydraulic fracturing, in effect a *de facto* moratorium. The New York State Department of Environmental Conservation (DEC) issued a revised draft Supplemental Generic Environmental Impact Statement (SGEIS) on 7 September 2011, providing further information and setting the context for permitting future wells. A public comments and review period is due to close on 11 January 2012. A decision on permitting hydraulic fracturing is anticipated after this date.

Groundwater pollution could occur if there is a catastrophic failure or loss of integrity of the wellbore, or if contaminants can travel from the target fracture through subsurface pathways. The risks of such pollution were seen as minimal in a study by ICF International; however, this assessment was based on an analysis of risk from properly constructed wells. History tells us that it is rarely the case in complex projects that mistakes are never made and the risk of groundwater pollution from improperly constructed wells also needs to be considered.

The dismissal of any risk as insignificant is even harder to justify given the documented examples that have occurred in the US, seemingly due to poor construction and/or operator error. These examples have seen high levels of pollutants, such as benzene, iron and manganese, in groundwater, and a number of explosions resulting from accumulation of gas in groundwater.

- There is a clear risk of contamination of groundwater from shale gas extraction.
- It is important to recognise that most problems arise due to errors in construction or operation and these cannot be entirely eliminated.
- The US EPA research should provide important new evidence in understanding this issue. Full conclusions are expected in 2014.

6.3.2 Surface water and land contamination

While it may not always be possible to pinpoint the exact cause of groundwater contamination, identifying the source for land and surface water pollution is more straightforward. There are a number of potential sources of pollution including: well cuttings and drilling mud; chemical additives for the fracturing liquid; and flowback fluid – the liquid containing toxic chemicals that returns to the surface after fracturing. There numerous routes by which these potential sources can cause pollution incidents including failure of equipment and operator error. Unsurprisingly, a number of incidents have been reported in the US.

While these hazards are similar to those found in numerous industrial processes, for shale gas extraction, they occur over a short period of time during the construction of the pad and initial drilling. This means that investment in physical containment, as would be expected in many cases with such hazards, is perhaps less likely.

- High standards of hazard management will need to be maintained at all times if surface pollution is to be avoided.

6.3.3 Water consumption

Shale gas extraction requires very significant amounts of water. Based on US data, to carry out all fracturing operations on a six well pad takes between 54,000 and 174,000 cubic metres of water. Based on water volumes used in Cuadrilla Resources' operations, if the UK were to produce 9bcm of shale gas each year for 20 years this would equate to an average annual water demand of 1.3 to 1.6 million cubic metres. This compares with current levels of abstraction by industry (excluding electricity generation) of 905 million cubic metres. While this appears to be a small additional level of abstraction, a number of points need to be made:

- This gives annual average water requirement assumed over the whole country. Clearly actual water requirements will be focused in the areas where shale gas is being extracted and this could add a significant additional burden in those areas;
- Water resources in the UK are already under a great deal of pressure making additional abstraction difficult; and
- The impacts of climate change may put even greater pressure on water resources in the UK.

Given that the water is mainly used over a short period of time during initial fracturing the most likely means of getting this water to the site in the UK would probably be by truck or abstraction.

- Significant amounts of water are required to extract shale gas and this could put severe pressure on water supplies in areas of commercial exploitation.
- The impacts of climate change may further exacerbate this problem.

6.3.4 Other issues

In considering the potential extraction of shale gas in the UK it is important to recognise the different circumstances compared with the US, which gives rise to a number of other areas that should be considered.

Noise pollution

Given the high population density and the likelihood that any shale gas extraction may be located relatively close to population centres, noise pollution may be an important consideration. Activities such as drilling mean that each well pad requires around 800-2,500days (and nights) of noisy surface activity.

Traffic

Linked to noise is the issue of increases in traffic associated with shale gas extraction. It is estimated that the construction of each wellpad would require between 7,000-11,000 truck visits. This could clearly have a local impact on roads and traffic in the locality of shale gas well heads. Damage to roads not suited to the levels of truck traffic associated with gas drilling has been an issue in the US.

Landscape impacts

The construction of well pads is an industrial activity and requires access roads, storage pits, tanks, drilling equipment, trucks etc. As has been mentioned previously, to produce 9bcm of gas annually in the UK over 20 years would require around 300 well pads. In the Blackpool area alone, commercialisation by Cuadrilla resources suggests between 40 to 80 pads (for the medium and high scenarios) with production only sufficient for the equivalent of 5 to 10 months of UK gas consumption.

Seismic impacts

It is well known that injection of water or other fluids during processes such as oil extraction, geothermal engineering and shale gas production can result in earthquake activity. Hydraulic fracturing was stopped at the Cuadrilla Resources' Preese Hall exploratory site after a magnitude 1.5 earthquake on 27 May in the Blackpool area and in the light of a preceding magnitude 2.3 earthquake on 1 April 2011. An investigation concluded that it is highly probable that the hydraulic fracturing at Preese Hall-1 well triggered the recorded seismic events (de Pater and Baisch, 2011). The two events reported by BGS and 48 much weaker events that were detected make it hard to dismiss them as an isolated incident. The report also discusses the fact that the Preese Hall 1 well was deformed from a circular shape to an oval shape from approximately 2,580m to 2,630m down the wellbore. The casing above and below that interval was not observed to be significantly deformed and it was determined that the deformed casing did not affect the overall wellbore integrity, posing no risk to any shallow groundwater zones.

It is clear, then that seismic events can be caused by hydraulic fracturing and, whilst these are unlikely to be of a sufficient magnitude to cause structural damage on the surface, structural damage to the wellbore itself (and in all likelihood other wellbores in the vicinity) is possible and has been documented in this case.

Cumulative impacts

Cumulative impacts may be a particular issue, when one considers the development of shale gas at a scale sufficient to deliver gas at meaningful volumes. To sustain a 9bcm level of production for 20 years in the UK would require around 2,500-3,000 horizontal wells. This would require some 25 to 32 million cubic metres of water and scale up other per well impacts and risks to a similar degree.

- For the UK, high population density and the likely proximity of wells to population centres could result in certain impacts such as noise pollution, traffic, landscape and seismic impacts being exacerbated.

6.4 European regulatory framework

6.4.1 Overview

The view of the UK Government witnesses to the House of Commons Energy and Climate Change Committee is that UK regulation is “well-designed with clear lines of responsibility among several different bodies including DECC, the HSE, the respective Environment Agency, and Local Planning Authority” (2011; para 32) and that the UK has a “robust regime which is fit for purpose” and will ensure that unconventional gas operations are carried out in a “safe and environmentally sound manner” (2011; para 92).

In addition, the perception is that the regulatory framework that operates in the UK and EU is likely to be much more robust than that operating in the US where it is acknowledged that there have been problems and issues. From a regulatory perspective, many of the problems experienced in the US have been blamed on the US federal Energy Policy Act of 2005 which excluded hydraulic fracturing from the Safe Drinking Water Act, effectively delegating it to State responsibilities to protect groundwater.

This study has reviewed the key regulatory instruments that are in place in the UK and EU to identify the extent to which these views hold true and, therein, the extent to which the current regulatory framework and its application has (and will) provide adequate and consistent control of risks and impacts of exploratory and commercial shale gas development. The conclusions of this can be summarised succinctly as follows in relation to each of the areas examined.

6.4.2 Groundwater

In the UK: The Environment Agency's intention is not to routinely require an environmental permit, suggesting that shale gas operations do not constitute groundwater activity. Only 'normal' operations are considered when determining whether to require an environmental permit. 'Abnormal' operations such as from full or partial loss of well integrity are not considered in this decision. As such, regulation of these risks is via domestic health and safety regulation with regard to well construction and design. As this regulation does not include environmental risk in the consideration of what measures are justified to reduce risk "so far as is reasonably practicable"; the study finds that this set of regulation is inadequate and needs to be updated if it is to be used to control environmental risks in the place of an environmental permit. The current approach (which considers only health and safety risks avoided) is considered unlikely to provide the same level of construction and design standard as one that considers ALL of the risks avoided by proper well design and construction. As such, either well design and construction regulation needs to be updated if it is be used for this purpose, or all development should be covered by environmental permits to build in the additional controls. In a recent report on shale gas (IGEM, 2011), the Institution of Gas Engineers and Managers (IGEM) identifies that, for technologies such as horizontal directional drilling and hydraulic fracturing, there is a "distinct lack of standards for these processes". It has recommended that "standards are needed within the UK and internationally to ensure the consistency of safety measures and to guarantee that environmentally damaging or dangerous practices such as have been recorded in the US do not occur within the UK".

In the EU: The experience of the UK suggests that, for control of environmental risks from 'abnormal' operations, domestic regulation on well design and construction may be used instead of permitting under the Groundwater Directive. As there is no harmonised regulation on well design and construction in the EU, any Member State doing the same will be relying on its domestic regulation. This means that the risks associated with abnormal operations, such as from full or partial loss of well integrity, may not be consistently controlled across Europe and may rely on procedures and regulations operating in the Member State concerned, where these may or may not offer an adequate standard of risk control.

6.4.3 Chemicals used in fracturing fluids

In the EU and UK: the REACH regulations should, in theory, provide adequate control and oversight of chemicals used in fracturing fluid given proper enforcement. However, recent work by the European Chemicals and Health Agency suggests that none of the substances that it has examined has yet been registered for use in fracturing fluids. One of these substances has already been used in hydraulic fracturing operations in the UK. The European Commission is currently investigating whether this use failed to comply with the REACH regulations despite its use having been declared to the regulator in advance. As such, whilst the regulations have the power to ensure that any substance must be registered for that use, and associated chemical safety assessments undertaken, the possible non-compliance of the UK underlines the necessity of careful enforcement.

6.4.4 Wider environmental impacts

In the EU: Environmental impacts of projects come under the scope of the Environmental Impact Assessment (EIA) Directive which lists two categories of projects for EIA. Those in Annex I always require EIA but we conclude that the volumes of gas production from individual project units (well pads) are too low to allow them to be included as Annex I projects. They do, however, fit the description of Annex II projects that require Member States to consider whether full EIA is required based on the characteristics and locality of the projects and associated impacts. This requires consideration of cumulation of projects (i.e. impacts of one project in the context of similar ones in the same locality) amongst other matters in what is known as a 'screening procedure'.

In its ongoing review of the EIA Directive, the European Commission has expressed concern that Member State screening procedures are not adequate and are inconsistent with one another. There have also been European Court of Justice rulings on the use of criteria based only on the size of a project, where this is deemed not to be satisfactory and non-compliant.

In the UK: No EIAs of existing wellpads have been undertaken because the Local Planning Authority (LPA) determined that the projects were outside the area based (size only) criteria in the UKs implementing regulation. As such, none of the existing projects have been fully considered as is indicated by the EIA Directive. In addition, the LPA failed to identify a lower area criterion that also fits the description of the project. This places the existing developments at risk from legal challenge.

Overall: Given the specific example of the failure to properly consider shale gas projects under Annex II of the EIA directive, combined with the European Commission's existing concerns about the adequacy and consistency of Member State screening procedures, the study finds that shale gas projects are unlikely to be consistently required to undertake EIA in the EU. Here, again, whether EIA will be undertaken rests with procedures operating in individual Member States.

6.4.5 General conclusion

As noted above, from a regulatory perspective, many of the problems experienced in the US have been blamed on the US federal Energy Policy Act of 2005 which excluded hydraulic fracturing from the Safe Drinking Water Act, effectively delegating the responsibility to protect groundwater to individual states. From this perspective, then, the regulatory situation in the EU is not so very different. Whilst there are harmonised requirements for the protection of groundwater, environmental impacts and chemicals across all Member States, there is variation in interpretation of how these requirements are to be met and powers applied as well as different regulation (particular with regard to well design and construction). This means that in the EU also, control of risks and impacts may be delegated to Member State domestic regulation, interpretation and enforcement – a situation that is not dissimilar to that which is blamed for many of the problems in the US.

6.5 Final comment

It is important to stress that one of the main findings of this work is that there is a paucity of information on which to base an analysis of how shale gas could impact GHG emissions and what environmental and health impacts its extraction may have. While every effort has been made to ensure the accuracy of the information in the report, it can only be as accurate as the information on which it draws. In itself, this lack of information can be seen as a finding, as along with the growing body of evidence for ground and surface water contamination from the US and the requirement for the application of the precautionary principle in the EU, shale gas extraction in the UK must surely be delayed until clear evidence of its safety can be presented. The US EPA study on risks to groundwater will hopefully add to knowledge on the subject. With this considerable uncertainty surrounding the environmental impacts of shale gas extraction it seems sensible to wait for the results of the US EPA investigation to bring forward further information.

The argument that shale gas should be exploited as a transitional fuel in the move to a low carbon economy seems tenuous at best. EIA projections for the US do not anticipate that shale gas will substitute for coal in the medium term. Further, in the UK currently, a little under two thirds of coal consumption is imported from the global coal market; accordingly any reduction in coal demand from the UK will, *ceteris paribus*, trigger reductions in global coal prices. The supply-demand relationship of relatively liberalised markets makes clear that a reduction in the price for coal will facilitate increased demand elsewhere. Consequently, whilst the UK may be able to reduce its national emissions through indigenous shale gas consumption, this risks triggering a net increase in global emissions; with the atmosphere receiving relatively unchanged emissions from coal *and* additional emissions from shale gas.

It is possible that some level of substitution may occur in other countries but, in the current world where energy use is growing globally and expected to continue to do so, without a meaningful constraint on carbon emissions, there is little price incentive to substitute for lower carbon fuels. It is difficult to envisage any situation other than shale gas largely being used *in addition* to other fossil fuel reserves and adding a further carbon burden. This could occupy over a quarter of the remaining carbon budget for keeping below 2^{o}C warming, and lead to an additional 16ppmv of CO_2 over and above expected levels without shale gas – both figures that will rise as and when the additional 50% of shale gas is exploited. It should be stressed the extraction process does not necessarily result in significant emissions itself compared to conventional extraction but there is the potential for substantial fugitive emissions. However, given the urgent and challenging requirements facing us with regards to carbon reductions, any additional fossil fuel resource just adds to the problem.

The idea that we need 'transitional' fossil fuels is itself open to question. For example, in the International Energy Agency scenario that outlines a path to 50% reduction in carbon emissions by 2050, fuel switching coupled with power generation efficiency, only accounts for 5% of the required reductions (IEA, 2010). If globally we are to achieve the considerable reductions in carbon emissions that are required then it is energy efficiency, carbon capture and storage, renewable energy etc that will make the difference.

While a strong case could be made for the domestic extraction of shale gas from an energy security basis – replacing a proportion of imported gas with domestic production, this is not the focus of this report. Within the UK shale gas could substitute for coal and thereby reduce the UK's emissions, however, with a carbon budget in place, coal (without CCS) is likely to be phased out anyway – shale gas is not required to make this happen. Even if this was the case, given the radical reduction in emissions required and the need for a decarbonised electricity supply within two decades[79], it would risk being a major distraction from transitioning to a genuine zero-carbon grid. Given the investment in infrastructure required to exploit these resources there is the danger of locking the UK into years of shale gas use, leaving unproven carbon capture and storage, as the only option for lower carbon electricity. Consequently, this investment would be better made in real zero-carbon technologies that would provide more effective long-term options for decarbonising electricity.

At the global level, against a backdrop of energy growth matching, if not outstripping, that of global GDP and where there is currently no carbon constraint, the exploitation of shale gas will most likely lead to increased energy use and increased emissions resulting in an even greater chance of dangerous climate change. While for individual countries that have a carbon cap, for example in the UK, there may be an incentive to substitute shale gas for coal, the likely result would be a fall in the price of globally-traded fossil fuels and therefore an increase in demand. Consequently, there is no guarantee that the use of shale gas in a nation with a carbon cap would result in an absolute reduction in emissions and may even lead to an overall increase.

In addition to concerns about groundwater and GHG emissions, it is also important in considering possible shale gas extraction in the UK to recognise that high population density is likely to amplify many of the issues that have been faced in the US. If meaningful amounts of gas were to be extracted in the UK (the example of 9bcm has been used in the report but the scenarios see annual production rising above this level for periods of time) then this could have a considerable impact on scarce water and land resources.

[79] The Committee on Climate Change has suggested that electricity will need to be effectively decarbonised by 2035 (CCC, 2010).

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Annex 1

Table A.1: Chemical constituents of products used in fracturing fluid
Information drawn from http://ecb.jrc.ec.europa.eu

CAS Number	Substance	Priority list	PBT or Listed on First Priority List	Aquatic Toxicicy (Chronic and/or Acute	Acute Toxicity	Carcinogen	Mutagen	Repro
2634-33-5	1,2 Benzisothiazolin-2-one / 1,2-benzisothiazolin-3-one			Yes	Yes			
95-63-6	1,2,4 trimethylbenzene			Yes	Yes			
123-91-1	1,4 Dioxane	2				Carc 2		
52-51-7	2-Bromo-2-nitro-1,3-propanediol			Yes	Yes			
111-76-2	2-Butoxy ethanol	4			Yes			
107-19-7	2-Propyn-1-ol / Progargyl Alcohol			Yes	Yes			
51229-78-8	3,5,7-Triaza-1-azoniatricyclo[3.3.1.13, 7]decane, 1-(3-chloro-2-propenyl)-			Yes	Yes			
108-24-7	Acetic Anhydride				Yes			
79-06-1	Acrylamide	1			Yes	Carc 1B	Muta 1B	Repr 2
1336-21-6	Ammonia			Yes				
12125-02-9	Ammonium Chloride				Yes			
1341-49-7	Ammonium hydrogen-difluoride				Yes			
7727-54-0	Ammonium Persulfate / Diammonium peroxidisulphate				Yes			
7664-41-7	Aqueous ammonia			Yes	yes			
71-43-2	Benzene	1	1st Priority list			Carc 1A	Muta 1B	
10043-35-3	Boric acid	4						
71-36-3	Butan-1-ol				Yes			
10049-04-4	Chlorine Dioxide			Yes	Yes			
10049-04-5	Chlorine Dioxide			Yes	Yes			
7758-98-7	Copper (II) Sulfate			Yes	Yes			
111-46-6	Diethylene Glycol				Yes			
107-21-1	Ethane-1,2-diol / Ethylene Glycol				Yes			
100-41-4	Ethyl Benzene	1			Yes			

Table A.1: Chemical constituents of products used in fracturing fluid (cont)

CAS Number	Substance	Priority list	PBT or Listed on First Priority List	Aquatic Toxicicy (Chronic and/or Acute	Acute Toxicity	Carcinogen	Mutagen	Repro
9003-11-6	Ethylene Glycol-Propylene Glycol Copolymer (Oxirane, methyl-, polymerwithoxirane)							
75-21-8	Ethylene oxide				Yes	Carc 1B	Muta 1B	
50-00-0	Formaldehyde				Yes	Carc 2		
75-12-7	Formamide							Repr 1B
111-30-8	Glutaraldehyde			Yes	Yes			
7647-01-0	Hydrochloric Acid / Hydrogen Chloride / muriatic acid				Yes			
7722-84-1	Hydrogen Peroxide	2			Yes			
5470-11-1	Hydroxylamine hydrochloride			Yes	Yes	Carc 2		
98-82-8	Isopropylbenzene (cumene)	1						
64742-95-6	Light aromatic solvent naphtha					Carc 1B	Muta 1B	
67-56-1	Methanol				Yes			
8052-41-3	Mineral spirits / Stoddard Solvent					Carc 1B	Muta 1B	
141-43-5	Monoethanolamine				Yes			
64742-48-9	Naphtha (petroleum), hydrotreated heavy					Carc 1B	Muta 1B	
91-20-3	Naphthalene	1	1st Priority list	Yes	Yes	Carc 2		
38640-62-9	Naphthalene bis(1-methylethyl)		PBT					
64742-65-0	Petroleum Base Oil					Carc 1B		
64741-68-0	Petroleum naphtha					Carc 1B	Muta 1B	
1310-58-3	Potassium Hydroxide				Yes			
107-98-2	Propylene glycol monomethyl ether	4						
7631-90-5	Sodium bisulfate				Yes			
3926-62-3	Sodium Chloroacetate			Yes	Yes			
1310-73-2	Sodium Hydroxide	4						

Table A.1: Chemical constituents of products used in fracturing fluid (cont)

CAS Number	Substance	Priority list	PBT or Listed on First Priority List	Aquatic Toxicicy (Chronic and/or Acute	Acute Toxicity	Carcinogen	Mutagen	Repro
7681-52-9	Sodium hypochlorite	2			Yes			
1303-96-4	Sodium tetraborate decahydrate							Repr 1B
5329-14-6	Sulfamic acid			Yes				
533-74-4	Tetrahydro-3,5-dimethyl-2H-1,3,5-thiadiazine-2-thione (a.k.a. Dazomet)			Yes	Yes			
64-02-8	Tetrasodium Ethylenediaminetetraacetate	1			Yes			
68-11-1	Thioglycolic acid				Yes			
62-56-6	Thiourea			Yes	Yes	Carc 2		Repr 2
108-88-3	Toluene	2						Repr 2
5064-31-3	Trisodium Nitrilotriacetate	3			Yes	Carc 2		
1330-20-7	Xylene				Yes			

Table A.2: UK Environment Agency mineral analysis of flowback fluid from Cuadrilla Resources site, Preese Hall

SITE	Cuadrilla Drill Rig	Cuadrilla Drill Rig	Cuadrilla Drill Rig	Cuadrilla Drill Rig	Cuadrilla Drill Rig	Mains water (from United Utilities web data) average concentration
DATE	**07/04/2011**	**14/04/2011**	**28/04/2011**	**18/05/2011**	**14/06/2011**	
TIME	**13:20**	**13:30**	**11:10**	**14:00**	**09:55**	
Conductivity at 25oC μs/cm	–	–	–	150614	133730	299
pH	–	–	–	6.35	7.06	7.54
Lead (filtered) μg/l	179	<20	<2	<40	<40	
Lead - as Pb μg/l	600	<10	<10	<40	44.9	<0.417
Mercury (filtered) μg/l	0.01	<0.01	0.013	<0.01	<0.01	
Mercury - Hg μg/l	0.024	<0.01	<0.01	<0.01	0.012	<0.0127
Cadmium (filtered) μg/l	0.674	<1	1.47	<2	<2	
Cadmium - Cd μg/l	1.29	<0.5	<0.5	<2	<1	<0.04
Bromide mg/l	–	–	242	854	608	<0.444
Chloride Ion mg/l	15400	34400	22200	75000	64300	13.5
Sodium (filtered) mg/l	7950	15100	9330	28400	>200	
Sodium - Na mg/l	no bottle	15100	9380	28400	23600	22.9
Potassium (filtered) mg/l	23.2	46.4	37.8	82.1	>20	
Potassium - K mg/l	28.8	52.3	40.6	–	–	
Magnesium (filtered) mg/l	177	>50	397	–	–	
Magnesium - Mg mg/l	no bottle	586	401	1470	1350	9.21
Phosphorus - P mg/l	1.28	0.0771	<0.02	<0.1	<0.5	
Chromium (filtered) μg/l	< 3	<5	0.565	28	<10	
Chromium - Cr μg/l	25	4.03	<3	20.5	53.9	<0.349
Zinc – (filtered) μg/l	297	<50	53.6	142	411	
Zinc - as Zn μg/l	565	51.5	<30	173	435	
Nickel – (filtered) μg/l	13.8	<10	21.5	<20	<20	
Nickel - Ni μg/l	20.3	<5	<5	<20	<20	1.2
Silver (filtered) μg/l	< 10	<5	<10	<20	<10	
Silver μg/l	–	–	<1	<20	<10	

Table A.2: UK Environment Agency mineral analysis of flowback fluid from Cuadrilla Resources site, Preese Hall

SITE	Cuadrilla Drill Rig	Cuadrilla Drill Rig	Cuadrilla Drill Rig	Cuadrilla Drill Rig	Cuadrilla Drill Rig	Mains water (from United Utilities web data) average concentration
Aluminium (filtered) µg/l	< 50	<100	<10	<200	<200	
Aluminium-Al µg/l	596	<50	<50	<200	<100	<8.04
Arsenic (filtered) µg/l	5.1	<1	<1	<1	<1	
Arsenic – As µg/l	6.2	<1	<1	1.2	2.6	0.309
Iron (filtered) µg/l	36600	82800	35800	70700	106000	
Iron - as Fe µg/l	66600	80700	51800	78600	112000	<7.62
Cobalt (filtered) µg/l	< 10	<5	<10	<20	13.3	
Cobalt µg/l	–	–	4.96	<20	<50	
Copper (filtered) µg/l	27.5	<10	12.4	36	<20	
Copper - Cu µg/l	936	8.04	<5	37.6	34.4	0.025
Nitrogen - N mg/l	10.7	52.5	33.4	98.8	77.8	
Vanadium - Filtered µg/l	< 20	<10	<20	<40	<20	
Vanadium - V µg/l	< 4	<10	<2	<40	<100	

Table A.3 Radiological analysis (gamma spectrometry) of flowback fluid from Cuadrilla Resources site, Preese Hall (Becquerels per kg, or Becquerels per kg equivalent for solids) (Environment Agency 2011)

LGC Ref.	L3004801		L3005184		L3005769	
Sample Ref	Water Sample B 14/04/11	Solids from Sample L3004801	Water Sample B 03/05/11	Solids from Sample L3005184	Bottle A Rec'd 23/05/11	Solids from Sample L3005769
Analysis Date	21-04-11	21-04-11	09-05-11	18-05-11	24-05-11	31-05-11
^{40}Potassium	< 1.0	< 1.0	3.5 ± 1.1	< 1.0	3.3 ± 1.9	< 1.0
^{60}Cobalt	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1
^{137}Caesium	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1
^{228}Actinium	1.7 ± 0.4	< 0.1	2.6 ± 0.5	0.4 ± 0.1	2.9 ± 0.6	1.4 ± 0.3
^{228}Thorium	< 4.0	< 4.0	< 4.0	< 4.0	< 4.0	< 4.0
^{224}Radium	< 4.0	< 4.0	< 4.0	< 4.0	< 4.0	< 4.0
^{212}Lead	0.4 ± 0.1	< 0.5	0.9 ± 0.1	< 0.5	0.7 ± 0.1	< 0.5
^{212}Bismuth	< 0.5	< 0.5	< 0.5	< 0.5	< 0.5	< 0.5
^{208}Thallium	< 0.5	< 0.5	< 0.5	< 0.5	< 0.5	< 0.5
^{234}Thorium	< 2.0	< 2.0	< 2.0	< 2.0	< 2.0	< 2.0
^{226}Radium	14 ± 2.1	< 0.2	16 ± 2.1	2.5 ± 0.4	17 ± 2.3	7.2 ± 1.5
^{214}Lead	1.4 ± 0.2	< 0.5	6.0 ± 0.7	1.6 ± 0.2	2.3 ± 0.3	2.6 ± 3.3
^{214}Bismuth	0.9 ± 0.2	< 0.5	5.1 ± 0.6	1.3 ± 0.2	2.1 ± 0.3	2.3 ± 0.3
^{235}Uranium	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1
^{227}Thorium	< 0.5	< 0.5	< 0.5	< 0.5	< 0.5	< 0.5
^{223}Radium	< 0.5	< 0.5	2.1 ± 0.6	< 0.5	< 0.5	< 0.5
^{241}Americium	< 0.2	< 0.2	< 0.2	< 0.2	< 0.2	< 0.2

Table A.4: Analysis of flowback fluid composition (information from New York State (2009)

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
	1,4-Dichlorobutane	1	1	198	198	198	%REC
	2,4,6-Tribromophenol[91]	1	1	101	101	101	%REC
	2-Fluorobiphenyl[92]	1	1	71	71	71	%REC
	2-Fluorophenol[93]	1	1	72.3	72.3	72.3	%REC
00056-57-5	4-Nitroquinoline-1 -oxide	24	24	1422	13908	48336	mg/L
	4-Terphenyl-d14 [94]	1	1	44.8	44.8	44.8	%REC
00067-64-1	Acetone	3	1	681	681	681	µg/L
	Alkalinity, Carbonate, as CaCO3	31	9	4.9	91	117	mg/L
07439-90-5	Aluminum	29	3	0.08	0.09	1.2	mg/L
07440-36-0	Antimony	29	1	0.26	0.26	0.26	mg/L
07664-41-7	Aqueous ammonia	28	25	12.4	58.1	382	mg/L
07440-38-2	Arsenic	29	2	0.09	0.1065	0.123	mg/L
07440-39-3	Barium	34	34	0.553	661.5	15700	mg/L
00071-43-2	Benzene	29	14	15.7	479.5	1950	µg/L
	Bicarbonates [95]	24	24	0	564.5	1708	mg/L
	Biochemical Oxygen Demand	29	28	3	274.5	4450	mg/L
00117-81-7	Bis(2-ethylhexyl)phthalate	23	2	10.3	15.9	21.5	µg/L
07440-42-8	Boron	26	9	0.539	2.06	26.8	mg/L
24959-67-9	Bromide	6	6	11.3	616	3070	mg/L
00075-25-2	Bromoform	29	2	34.8	36.65	38.5	µg/L
07440-43-9	Cadmium	29	5	0.009	0.032	1.2	mg/L
07440-70-2	Calcium	55	52	29.9	5198	34000	mg/L
	Chemical Oxygen Demand	29	29	1480	5500	31900	mg/L
	Chloride	58	58	287	56900	228000	mg/L
00124-48-1	Chlorodibromomethane	29	2	3.28	3.67	4.06	µg/L
07440-47-3	Chromium	29	3	0.122	5	5.9	mg/L
07440-48-4	Cobalt	25	4	0.03	0.3975	0.58	mg/L
	Color	3	3	200	1000	1250	PCU
07440-50-8	Copper	29	4	0.01	0.035	0.157	mg/L
00057-12-5	Cyanide	7	2	0.006	0.0125	0.019	mg/L
00075-27-4	Dichlorobromomethane	29	1	2.24	2.24	2.24	µg/L
00100-41-4	Ethyl Benzene	29	14	3.3	53.6	164	µg/L
16984-48-8	Fluoride	4	2	5.23	392.615	780	mg/L
07439-89-6	Iron	58	34	0	47.9	810	mg/L
07439-92-1	Lead	29	2	0.02	0.24	0.46	mg/L
	Lithium	25	4	34.4	55.75	161	mg/L
07439-95-4	Magnesium	58	46	9	563	3190	mg/L
07439-96-5	Manganese	29	15	0.292	2.18	14.5	mg/L
00074-83-9	Methyl Bromide	29	1	2.04	2.04	2.04	µg/L
00074-87-3	Methyl Chloride	29	1	15.6	15.6	15.6	µg/L
07439-98-7	Molybdenum	25	3	0.16	0.72	1.08	mg/L
00091-20-3	Naphthalene	26	1	11.3	11.3	11.3	µg/L
07440-02-0	Nickel	29	6	0.01	0.0465	0.137	mg/L
	Nitrogen, Total as N	1	1	13.4	13.4	13.4	mg/L
	Oil and Grease	25	9	5	17	1470	mg/L
	o-Terphenyl [96]	1	1	91.9	91.9	91.9	%Rec
	pH	56	56	1	6.2	8	S.U.
00108-95-2	Phenol	23	1	459	459	459	µg/L
	Phenols	25	5	0.05	0.191	0.44	mg/L
57723-14-0	Phosphorus, as P	3	3	0.89	1.85	4.46	mg/L
07440-09-7	Potassium	31	13	59	206	7810	mg/L
07782-49-2	Selenium	29	1	0.058	0.058	0.058	mg/L
07440-22-4	Silver	29	3	0.129	0.204	6.3	mg/L
07440-23-5	Sodium	31	28	83.1	19650	96700	mg/L

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
07440-24-6	Strontium	30	27	0.501	821	5841	mg/L
14808-79-8	Sulfate (as SO4)	58	45	0	3	1270	mg/L
	Sulfide (as S)	3	1	29.5	29.5	29.5	mg/L
14265-45-3	Sulfite (as SO3)	3	3	2.56	64	64	mg/L
	Surfactants [97]	3	3	0.2	0.22	0.61	mg/L
00127-18-4	Tetrachloroethylene	29	1	5.01	5.01	5.01	µg/L
07440-28-0	Thallium	29	1	0.1	0.1	0.1	mg/L
07440-32-6	Titanium	25	1	0.06	0.06	0.06	mg/L
00108-88-3	Toluene	29	15	2.3	833	3190	µg/L
	Total Dissolved Solids	58	58	1530	93200	337000	mg/L
	Total Kjeldahl Nitrogen	25	25	37.5	122	585	mg/L
	Total Organic Carbon [98]	23	23	69.2	449	1080	mg/L
	Total Suspended Solids	29	29	30.6	146	1910	mg/L
	Xylenes	22	14	16	487	2670	µg/L
07440-66-6	Zinc	29	6	0.028	0.048	0.09	mg/L
--	Gross Alpha	8	8	22.41	--	18,950	pCi/L
--	Gross Beta	8	8	62	--	7,445	pCi/L
7440-14-4	Total Alpha Radium	6	6	3.8	--	1,810	pCi/L
7440-14-4	Radium-226	3	3	2.58	--	33	pCi/L
7440-14-4	Radium-228	3	3	1.15	--	18.41	pCi/L