Tyndall°Centre
for Climate Change Research

# *Shale gas: a provisional assessment of climate change and environmental impacts*

*A research report by The Tyndall Centre*
*University of Manchester*


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Report commissioned by The Co-operative

January 2011 (Final)

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# Executive Summary

This report, commissioned by The Co-operative, provides a provisional review and assessment of the risks and benefits of shale gas development, with the aim of informing The Co-operative's position on this '*unconventional'* fuel source.

The analysis within the report addresses two specific issues associated with the extraction and combustion of shale gas. Firstly, it outlines potential UK and global greenhouse gas (GHG) emissions arising from a range of scenarios building on current predictions of shale gas resources. Secondly, it explores the health and environmental risks associated with shale gas extraction. It should be stressed that a key issue in assessing these issues has been a paucity of reliable data. To date shale gas has only been exploited in the US and, while initial estimates have been made, it is difficult to quantify the possible resources in other parts of the globe, including the UK. Equally, information on health and environmental aspects is of variable quality and only now is there any systematic effort being undertaken to better understand these issues. Therefore, 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.

It is clear however, that while shale gas extraction, at a global level, does not involve the high energy and water inputs at the scale of other unconventional fuels, such as oil derived from tar sands, it does pose significant potential risks to human health and the environment. Principally, the potential for hazardous chemicals to enter groundwater via the extraction process must be subject to more thorough research prior to any expansion of the industry being considered. Additionally, while being promoted as a transition route to a low carbon future, none of the available evidence indicates that this is likely to be the case. 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 lead to an additional 11ppmv of $CO_2$ over and above expected levels without shale gas – a figure that could rise if more of the total shale gas resource were to be exploited than envisaged in the scenarios. This would be compounded if investment in shale gas were to delay the necessary investment in zero and very low carbon technologies.

## Key conclusions: general

**Evidence from the US suggests shale gas extraction brings a significant risk of ground and surface water contamination and until the evidence base is developed a precautionary approach to development in the UK and Europe is the only responsible action.** The depth of shale gas extraction gives rise to major challenges in identifying categorically pathways of contamination of groundwater by chemicals used in the extraction process. An analysis of these substances suggests that many have toxic, carcinogenic or other hazardous properties. There is considerable anecdotal evidence from the US that contamination of both ground and surface water has occurred in a range 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). Action has also been taken at State level, for example, on 11

December 2010 the New York State Governor issued an Executive Order requiring further review and analysis of high-volume hydraulic fracturing in the Marcellus Shale and cessation of fracturing until 1 July 2011 at the earliest. The analysis in this report clearly demonstrates that the risks associated with the cumulative impact of drilling sufficient wells to provide any meaningful contribution to the UK's energy needs cannot be dismissed, however low they might be at the individual well level. Given the requirement for EU member states to apply the precautionary principle, shale gas exploitation should be delayed until at least after the EPA has reported and, depending on the findings, perhaps longer.

**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.** Measured across their respective lifecycles the $CO_2$ emissions from shale gas are likely to be only marginally higher than those from conventional gas sources. Nevertheless, there is little evidence from data on the US that shale gas is currently, or expected to, substitute, at any significant level for coal use. By contrast, projections suggest it will continue to be used in addition to coal in order to satisfy increasing energy demand. If carbon emissions are to reduce in line with the Copenhagen Accord's commitment to 2°C, urgent decarbonisation of electricity supply is required. This need for rapid decarbonisation further questions any role that shale gas could play as a transitional fuel as it is yet to be exploited commercially outside the US. In addition, it is important to stress that shale gas would only be a low-carbon fuel source if allied with, as yet unproven, carbon capture and storage technologies. If a meaningful global carbon cap was established then the impact of a price of carbon could facilitate some substitution of coal for shale gas in industrialising (non-Annex 1) countries.

**Without a meaningful cap on emissions of global GHGs, the exploitation of shale gas is likely to increase net carbon emissions.** In an energy-hungry world, where GDP growth continues to dominate political agendas and no effective and stringent constraint on total global carbon emissions is in place, the exploitation of an additional fossil fuel resource will likely increase energy use and associated emissions. This will further reduce any slim possibility of maintaining global temperature changes at or below 2°C and thereby increase the risk of entering a period of 'dangerous climate change'. If uptake of shale gas were to match that used in the global scenarios associated increases in emissions would result in additional atmospheric concentration of $CO_2$ of 3-11ppmv by 2050.

**Rapid carbon reductions require major investment in zero-carbon technologies and this could be delayed by exploitation of shale gas.** The investment required to exploit shale gas will be substantial. In relation to reducing carbon emissions this investment would be much more effective if targeted at genuinely zero- (or very low) carbon technologies. If money is invested in shale gas then there is a real risk that this could delay the development and deployment of such technologies.

## Key conclusions: specific to the UK

**Requirements for water in shale gas extraction could put considerable 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.

**Exploiting shale gas within the UK is likely to give rise to a range of additional challenges.** The risk of aquifer water supply contamination by the hazardous chemicals involved in extraction is likely to be a significant source of local objections. Additionally, the UK is densely populated and consequently any wells associated with 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 example: drilling will require many months if not years of surface activity leading to potentially intrusive noise pollution; high levels of truck movements during the construction of a well-head will have a major impact on already busy roads; and the considerable land-use demands of shale gas extraction will put further pressure on already scarce land-use resources.

# 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[1].

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 in the US and potentially elsewhere and it 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 natural gas or coal). As an unconventional source of gas, 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, to date, has not been considered in detail 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 of shale gas (or otherwise), the drilling and hydraulic fracturing technologies required for shale gas production also bring with them a number of negative environmental impacts and risks. 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 heavy metals, organic chemicals, and naturally occurring radioactive materials (NORMS); hazardous waste generation and disposal; resource issues including abstraction of significant 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

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

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[2] that is expected to provide initial results towards the end of 2012. Some state regulators are moving towards 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 hydraulic fracturing for the extraction of natural gas or oil until 15 May 2011 (and to suspend the issuance of new permits for such drilling). On 11 December 2010, the New York State Governor vetoed the Bill and 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". The Executive Order requires that high-volume, horizontal hydraulic fracturing would not be permitted until 1 July 2011 at the earliest.

Clearly, then, the potential environmental GHG benefits that may (or may not) be gained from developing shale gas are also associated with a number of environmental risks and costs that need to be considered alongside as part of a complex risk-cost-benefit equation. 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.

## 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 to inform its position on the issue. It is looking for information both generally and also more particularly for the UK (and within the EU) where there is some (as yet limited) interest in the possibilities for the future gas supply from shale reserves and some exploration activity. The overall objective is to draw on available information (in particular from the US, where shale gas production is growing 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.

As such, issues for consideration in the study include:

- the likely carbon footprint (i.e. lifecycle emissions) 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 $CO_2e$ from extracting and burning recoverable shale gas reserves; and
- key environmental risks and impacts associated with shale gas development including: water consumption; ground and surface water contamination from

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

hydraulic fracturing chemicals and other contaminants; and any other issues that may be of concern from a UK sustainability perspective.

## 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.

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 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. In the past these have been regarded merely as relatively impermeable source rocks and seals for gas that migrates to other deposits such as permeable sandstone and carbonate reservoirs that are the target of conventional commercial gas production. With advances in drilling and well stimulation technology (originally developed for conventional production), however, 'unconventional' production of gas from these, less permeable, shale formations can be achieved.

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).

Based on US experience, this section provides detail on the modern processes involved in the production of shale gas 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

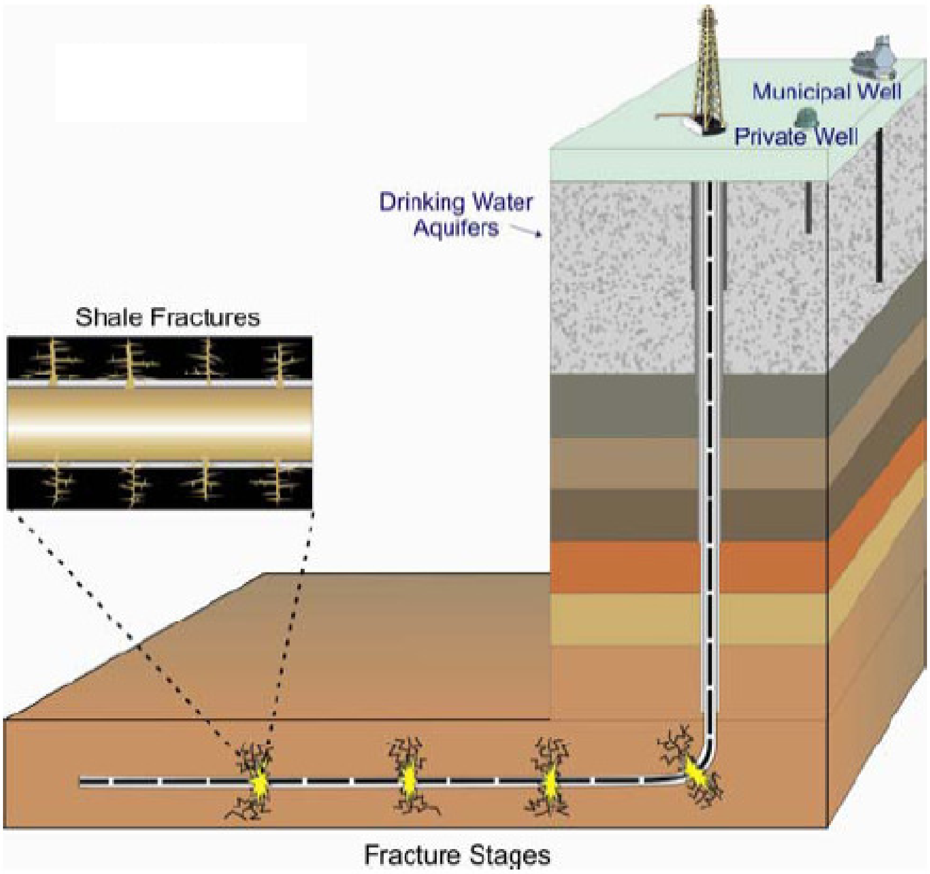
### 2.2.1 Introduction to shale gas processes

As noted above, horizontal drilling and hydraulic fracturing are the two technologies that, in combination with one another, 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 injection well 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. Between 15% and 80% of the injected fluids are recovered to the surface (US EPA, 2010).

Directional/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. This 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[3].

**Figure 2.1: Schematic diagram of hydraulically fractured horizontal well – not to scale** (US EPA Hydraulic Fracturing Research Study – Scoping Backgrounder, 2010)




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, and 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

[3] It should be noted that Figure 2.1 illustrates particular points and does not represent potential overground impacts.

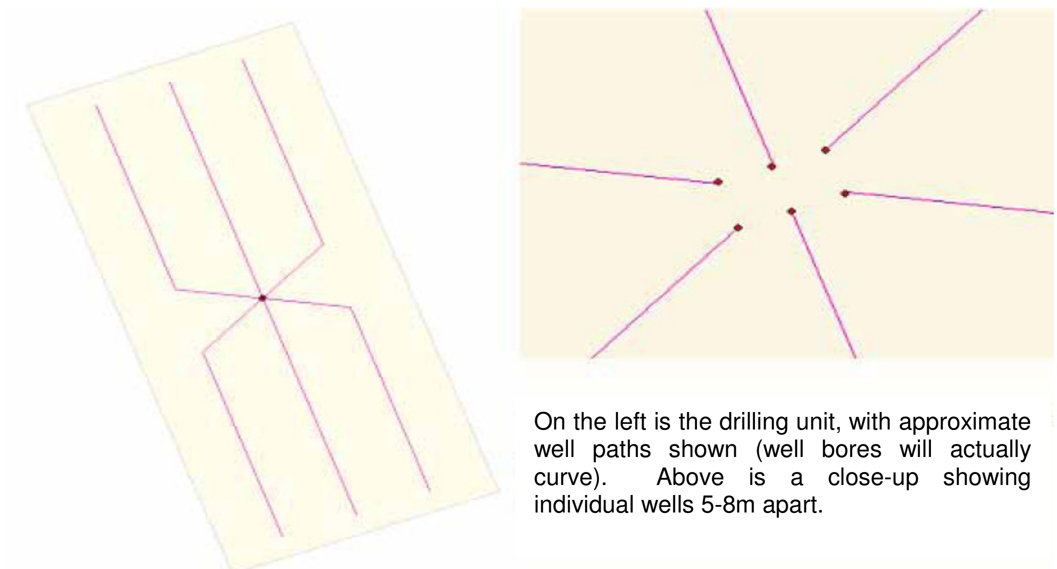
clustering of several wells on ‘multi-well’ pads, horizontal drilling from each well and multi-stage ‘slickwater’ fracturing.

| **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. It is reported that up to sixteen but more commonly six or eight wells are drilled sequentially in parallel rows from each pad, each well typically being around 5-8m apart. Each horizontal wellbore may typically be around 1-1.5km in lateral length but can be more.

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



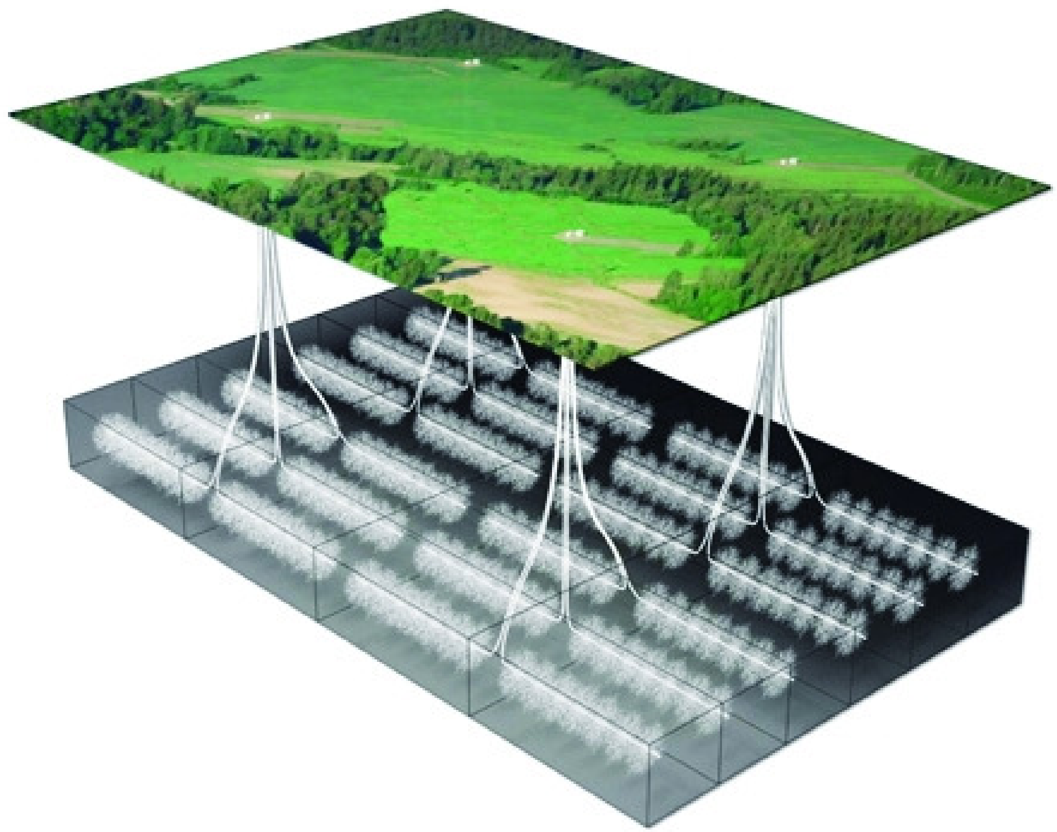
On the left is the drilling unit, with approximate well paths shown (well bores will actually curve). Above is a close-up showing individual wells 5-8m apart.

### *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[4][5]).

In terms of spacing of well pads, New York State (2009) identifies a maximum spacing of nine pads per square mile (2.6km$^2$). This is equivalent to around 3.5pads/km$^2$. In the UK, Composite energy has estimated that 1-1.5pads/km$^2$ should be sufficient in a UK setting[6].

**Figure 2.3: Illustration of the arrangement of arrays of multi-well pads over target formations**



### *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.

[4] http://www.theengineer.co.uk/in-depth/the-big-story/unlock-the-rock-cracking-the-shale-gas-challenge/1003856.article#
[5] It should be noted that Figure 2.3 illustrates particular points and does not represent potential overground impacts.
[6] http://www.composite-energy.co.uk/shale-challenges.html

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. This provides information on what is involved in development and production from construction of well pad though to decommissioning.

### 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.

***Drilling***

Vertical drilling depth will vary based on target formation and location and, typically, wells will be drilled vertically through rock layers and aquifers to a depth of about 150m above the top of a target layer formation whereupon, a larger horizontal drill rig may be brought onto the location (where separate equipment for vertical and horizontal portions of the wellbore are being used) to build angle for the horizontal portion of the wellbore (known as 'kicking off').

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 that uses drilling mud may be used. For such equipment mud is needed 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. For comparison, a conventional well[7] 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 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

[7] 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.

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 ground water 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);

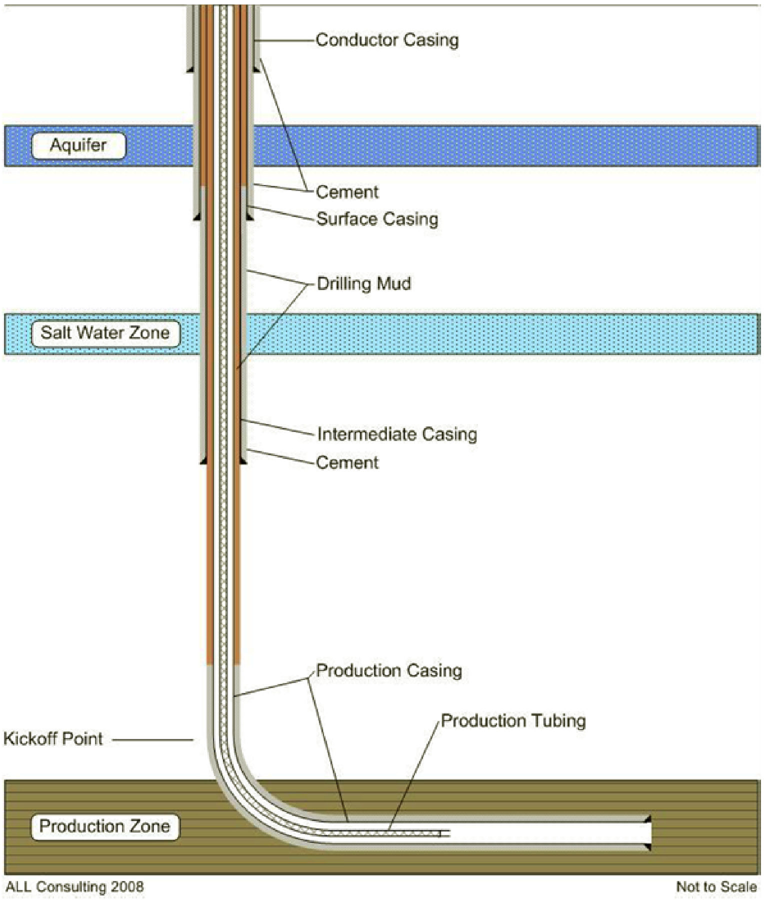
- ***Cementing in of production casing:*** GWPC note that, although some states require complete circulation of cement from the bottom to the top of the production casing, most states require only an amount of cement calculated to raise the cement top behind the casing to a certain level above the producing formation[8]. 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.

[8] 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 injection well 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 after injected fluids (flowback water) are recovered 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 product 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.

**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. |

### *Fracturing procedure*

The fracturing procedure is carried out sequentially (one well after another) and often in multiple stages for each well. 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 13 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 170-350 times the pressure used in a car tyre. It is 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.

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.

### *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$^3$ (9-29megalitres) 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. In terms of source water, 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 containers being 1-1.5m$^3$ high-density polyethylene (HDPE) steel caged cube shaped.

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’. Flowback fluid recovered from wells is reported to be between 9% and 35% of the fracturing fluid pumped from horizontal Marcellus wells in the northern tier of Pennsylvania range but 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, 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. 1,300–23,000m$^3$/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.

Storage of flowback water allows operators to re-use as much of it as possible 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 water from a single well fracturing operation, namely between 1,300–23,000m$^3$.

One operator reports a typical pit volume of 750,000gallons (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 water, 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 water 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 2.4 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 multi-well pad is 500-1,500days of activity, assuming no overlap between activities (in practice, there is some limited potential for overlap).

**Table 2.4: 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, brine tanks. Earthmoving equipment. | Well flaring and monitoring. Truck trips to empty brine 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 2.5 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 2.5: Truck visits**

| Purpose | Per well | | Per pad | |
|---|---|---|---|---|
| | Lo | Hi | Lo | Hi |
| 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 | 2400 | 3600 |
| Hydraulic Fracture Sand | 20 | 25 | 120 | 150 |
| Flow Back Water Removal | 200 | 300 | 1200 | 1800 |
| **Total** | | | **4315** | **6590** |
| ***...of which associated with fracturing process:*** | | | ***3870*** | ***5750*** |
| | | | ***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 2,800Million cubic feet (Mcf)/d declining to 900 Mcf/d
- Years 2 to 4 – 900 Mcf/d declining to 550Mcf/d
- Years 5 to 10 – 550 Mcf/d declining to 225Mcf/d
- Year 11 and after – 225 Mcf/d declining at 3%/year

### *Re-fracturing*

As can be seen from the production from a well, production 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. This may occur within five years of completion but may be less than one year or greater than ten and may occur more than once for the same well.

It is difficult to make generalisations concerning re-fracturing other than that, where it occurs, the same procedures, equipment, resources and waste water will be generated.

### 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 brine.

### 2.2.7 Resource consumption to deliver the equivalent 10% of UK gas consumption

Tables 2.6 and 2.7 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 2.6: Summary of resources (no refracturing)**

| | **Activity** | **Six well pad drilled vertically to 2000m and laterally to 1,200m** | |
|---|---|---|---|
| **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 |
| | Fracturing chemicals volume (@2%) - $m^3$ | 1,080 | 3,480 |
| | Flowback water volume - $m^3$ | 7,920 | 137,280 |
| | Flowback water chemical waste content (@2%) - $m^3$ | 158 | 2,746 |
| **Surface Activity** | Total duration of surface activities pre production – days | 500 | 1,500 |
| | Total truck visits – Number | 4,315 | 6,590 |

<table>
<tr><th colspan="4">Table 2.7: Summary of resources for re-fracturing scenario</th></tr>
<tr><th></th><th>Activity</th><th colspan="2">Six well pad drilled vertically to 2000m and laterally to 1,200m</th></tr>
<tr><td>Pre- production</td><td>As above</td><td colspan="2">As above</td></tr>
<tr><td rowspan="6">Refracturing Process<br><br>(assuming an average of 50% wells re-fractured only once)</td><td>Water volume - m<sup>3</sup></td><td>27,000</td><td>87,000</td></tr>
<tr><td>Fracturing chemicals volume (@2%) - m<sup>3</sup></td><td>540</td><td>1,740</td></tr>
<tr><td>Flowback water volume - m<sup>3</sup></td><td>3,960</td><td>68,640</td></tr>
<tr><td>Flowback water chemical waste content (@2%) - m<sup>3</sup></td><td>79</td><td>1,373</td></tr>
<tr><td>Total duration of surface activities for re-fracturing – days</td><td>200</td><td>490</td></tr>
<tr><td>Total truck visits for re-fracturing – Number</td><td>2,010</td><td>2,975</td></tr>
<tr><td rowspan="10">Total for 50% re-fracturing</td><td>Well pad area – ha</td><td>1.5</td><td>2</td></tr>
<tr><td>Wells</td><td colspan="2">6</td></tr>
<tr><td>Cuttings volume - m<sup>3</sup></td><td colspan="2">827</td></tr>
<tr><td>Water volume - m<sup>3</sup></td><td>81,000</td><td>261,000</td></tr>
<tr><td>Fracturing chemicals volume (@2%) - m<sup>3</sup></td><td>1,620</td><td>5,220</td></tr>
<tr><td>Flowback water volume - m<sup>3</sup></td><td>11,880</td><td>205,920</td></tr>
<tr><td>Flowback water chemical waste content (@2%) - m<sup>3</sup></td><td>237</td><td>4,119</td></tr>
<tr><td>Total duration of surface activities pre production - days</td><td>700</td><td>1,990</td></tr>
<tr><td>Total truck visits - Number</td><td>6,325</td><td>9,565</td></tr>
</table>

Much of the discussion above concentrates on the activities occurring at individual wells and multi-well pads (based on six wells per pad). Shale development to deliver significant volumes of gas, however, will require multiple wells and well pads.

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 (annual gas consumption in the UK in 2008 was around 90bcm). 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[9].

In terms of the lifetime of a well, productivity decreases very 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 only 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.

[9] 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 output at 9bcm/year. Over a 20 year period, between 2,600 and 3,000 wells (or around 430 to 500 well pads) would need to be developed to deliver sustained annual output equivalent of 9bcm/year. Table 2.8 provides the total resources required to deliver this quantity. The total land area covered by the required level of shale development is also estimated. Here, as identified in Section 2.2.1, distribution of 1.25-3.5 pads/km$^2$ over the shale formation is required and this range has been applied to the number of pads required to deliver the 9bcm/year.

**Table 2.8: Resource requirements to deliver 9bcm/year for 20 years (10% of UK gas consumption in 2008)**

| | **Assuming No Re-fracturing** | | **Assuming a Single Re-fracturing on 50% of Wells** (delivering an assumed 25% increase in productivity for those wells) | |
|---|---|---|---|---|
| Area -km$^2$ | 141 | 396 | 123 | 346 |
| Well pad area - ha | 743 | 990 | 648 | 864 |
| Wells | 2,970 | | 2,592 | |
| Well pads | 495 | | 432 | |
| Cuttings volume - m$^3$ | 409,365 | | 357,264 | |
| Water volume - m$^3$ | 26,730,000 | 86,130,000 | 34,992,000 | 112,752,000 |
| Fracturing chemicals volume (@2%) - m$^3$ | 534,600 | 1,722,600 | 699,840 | 2,255,040 |
| Flowback water volume - m$^3$ | 3,920,400 | 67,953,600 | 5,132,160 | 88,957,440 |
| Flowback water chemical waste content (@2%) - m$^3$ | 78,210 | 1,359,270 | 102,384 | 1,779,408 |
| Total duration of surface activities pre production – days | 247,500 | 742,500 | 302,400 | 859,680 |
| Total truck visits – Number | 2,135,925 | 3,262,050 | 2,732,400 | 4,132,080 |

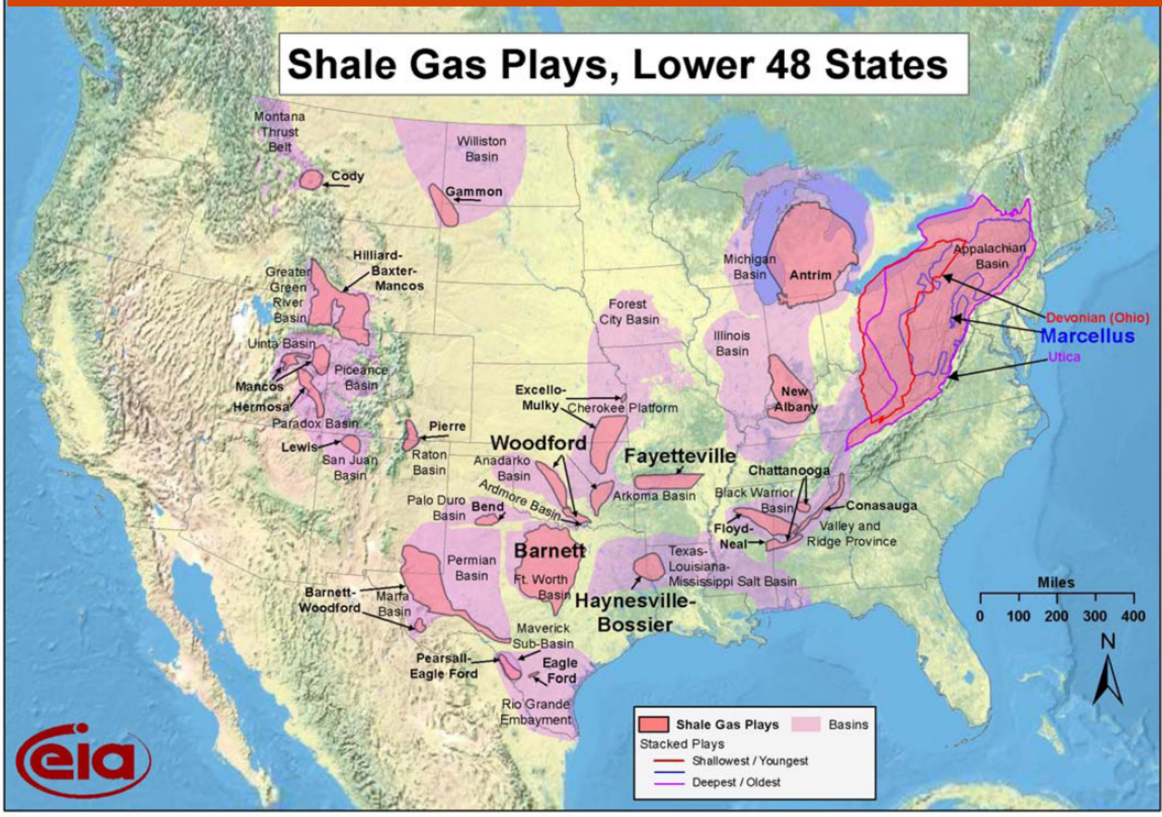
These figures can be compared with the fact that only 2000 conventional onshore wells have been drilled in the UK (DECC, 2010).

## 2.3 Shale gas production and reserves in the US

### 2.3.1 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 illustrated in Figure 2.6, shale basins are spread across a number of states in the US.

**Figure 2.6: Major US shale basins**




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

Estimates of the size of the overall US reserve are divided into and defined in terms of those reserves that are[10]:

- **proved** – estimated quantities that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions; and
- **technically recoverable** – resources in accumulations producible using current recovery technology but without reference to economic profitability.

Technically recoverable resources themselves consist of:

- **proved reserves** – as defined above;
- **inferred reserves** – that part of expected ultimate recovery from known fields in excess of cumulative production plus current reserves; and
- **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.

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

### *Estimates of US technically recoverable reserves*

A number of estimates have been made of the size of the technically recoverable shale gas resource in the US and these are summarised in Table 2.9 supplemented with US Energy Information Administration (EIA) estimates in the 2008, 2009 and 2010 Annual Energy Outlooks, along with an estimate from the 2011 Annual Energy Outlook early release overview. Depending on both publication source and year, estimates vary considerably primarily due to no assessment of some areas along with smaller variations between estimates for assessed areas.

As might be expected for such a relatively new resource, estimates have been revised upwards year on year. As is demonstrated by the annual federal assessments undertaken by the EIA, 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 early release of the 2011 figures sees an increase of over 100% on the 2010 estimate. This clearly suggests that the full potential volume of the resource is highly uncertain and is likely to increase in future.

**Table 2.9: Summary of estimates of technically recoverable shale gas resources** (various sources)

| | **Publication Date** | **Shale Gas – bcm** |
|---|---|---|
| **USGS National oils and gas assessment*** | 2002 | 2,407 |
| **2003 National Petroleum Council Gas Study*** | 2003 | 991 |
| **2008 Clear Skies Mean*** | 2008 | 7,767 |
| **2009 Clear Skies Max*** | 2008 | 23,837 |
| **ICF Assessment*** | 2008 | 10,913 |
| **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, early release overview** | 2010 | 23,427 |

As noted above, estimates of technically recoverable resources comprise 'proved', 'inferred' and 'undiscovered technically recoverable resources'. The figure from the EIA 2010 assessment (EIA, 2010a) of 10,432bcm of technically recoverable reserve (in Table 2.9) is broken down by region in Table 2.10[11].

[11] As an early release overview, EIA (2010b) does not contain all the information to found in a full report. Hence it is not possible to fully update all the figures and tables.

**Table 2.10: Technically recoverable US natural gas resources, January 1, 2008 (bcm)**

| Shale Gas | Proved Reserves | Inferred Reserves | Undiscovered Technically Recoverable Resources | Total Technically Recoverable Resources |
|---|---|---|---|---|
| Northeast | 170 | 2,073 | 0 | 2,243 |
| Gulf Coast | 187 | 2,557 | 0 | 2,744 |
| Midcontinent | 42 | 1,444 | 0 | 1,487 |
| Southwest | 212 | 1,685 | 0 | 1,897 |
| Rocky Mountain | 6 | 612 | 0 | 620 |
| West Coast | 0 | 0 | 1,441 | 1,441 |
| **Total** | **617** | **8,371** | **1,441** | **10,432** |

### *Proved US reserves*

Data from Table 2.10 suggest that total proved US shale gas resource is 617bcm, representing some 6% of the total technically recoverable reserve. However, the annual EIA assessments of US Crude Oil, Natural Gas, and Natural Gas Liquids Reserves[12] revise this upwards to 974bcm for the end of 2008 and 1,716bcm for the end of 2009. Clearly the updates to the technically recoverable reserve in EIA (2010b) will further affect this. These changes are summarised in Table 2.11. The revisions upwards again illustrate the rapidly changing context of shale gas and estimation of total shale gas reserves.

**Table 2.11: Changes to proved reserves of dry natural gas by source (bcm)**

| | | |
|---|---|---|
| **Reserves** | Year-End 2007 | 615 |
| **Discoveries** | 2008 | 252 |
| **Revisions & Other Changes** | 2008 | 119 |
| **Reserves** | Year-End 2008 | 974 |
| **Reserves** | Year-End 2009 | 1,716 |

## 2.3.2 Historical and projected future production and consumption of shale gas

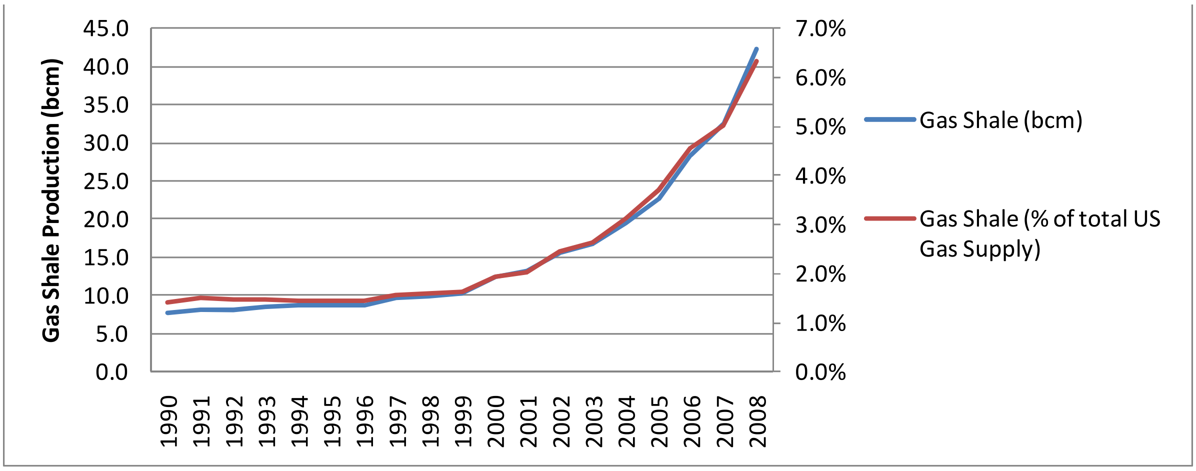
EIA AEO for 2010 provides data on consumption of shale gas (as well as other fuels and sources of energy) in the US and also projects future resource use up to 2035.

### *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)[13].

[12] http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/cr.html, November, 2010.
[13] As mentioned previously EIA (2010b) provides updated figures for 2009 of 93bcm (14.3% of total US gas supply), however as an early release report it does not update all the figures from EIA (2010a). Therefore this figure reflects data from EIA (2010a).

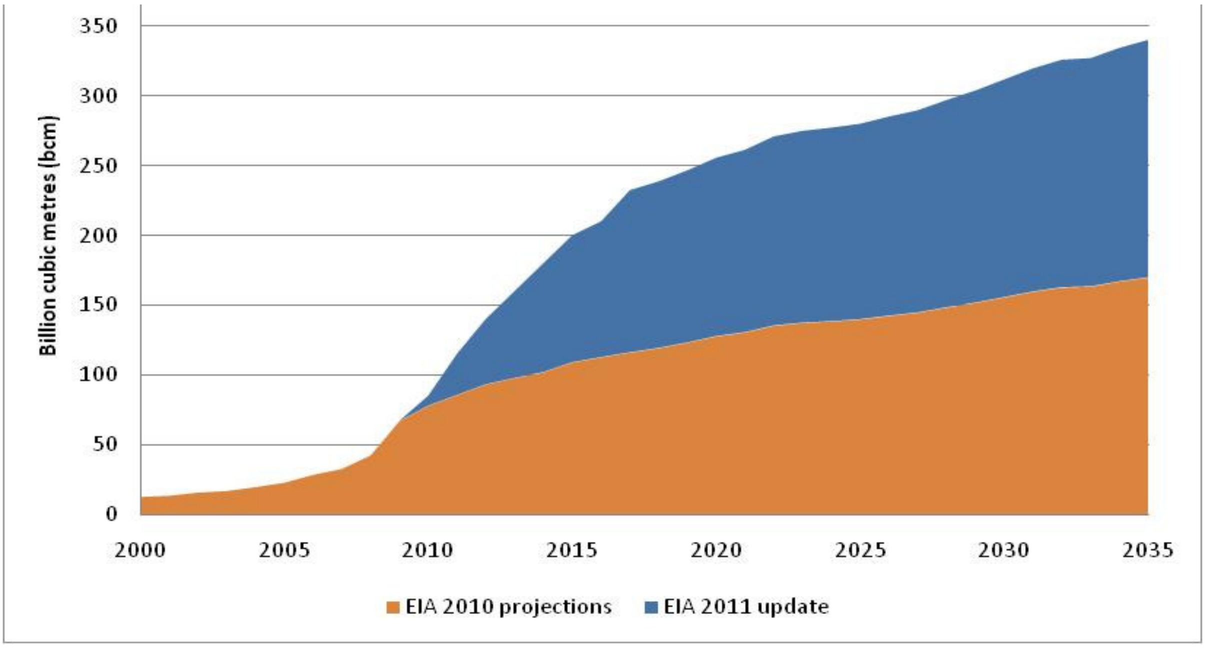
**Figure 2.7: Growth in US shale gas production 1990-2008** (US EIA AEO, 2010a)




### *EIA projections for future production and consumption to 2035*

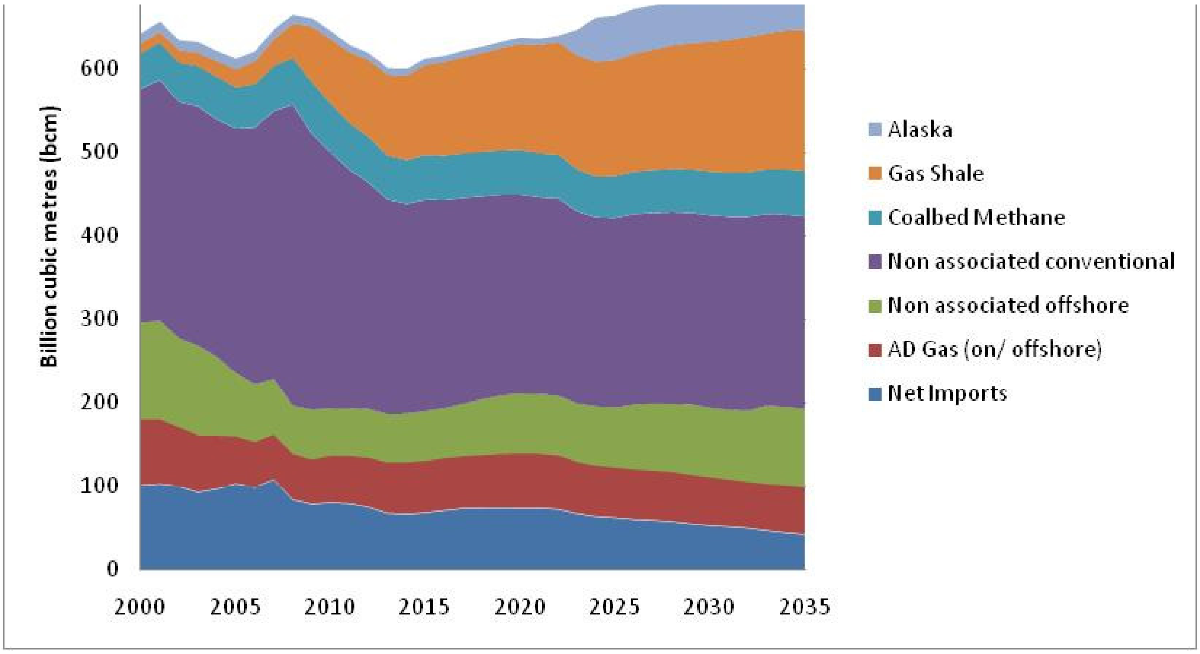
Figure 2.8 shows EIA data on actual production and projections to 2035 for both EIA (2010a) and the updated figures from EIA (2010b).

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



In the projections, expansion in shale gas is accompanied by contractions in other gas supplies including conventional and imports. Figure 2.9 shows historical and anticipated supply of natural gas and the contribution of gas by source to 2035 taken from EIA (2010a). This suggests an increase in the contribution of shale gas to overall gas supply from around 6% in 2008 to around 24% in 2035. EIA (2010b) suggests that this will change to 45% of overall gas supply by 2035[14].

**Figure 2.9: US natural gas supply 2000-2035** (US EIA AEO, 2010a)




EIA projections also predict the overall primary energy mix to 2035. Figure 2.10 shows historical and anticipated US primary energy consumption and the contribution of shale gas to 2035[15].

[14] Figure 2.9 has not been updated to take account of the updated figures in EIA (2010b).
[15] Figure 2.9 has not been updated to take account of the updated figures in EIA (2010b).

**Figure 2.10: US primary energy consumption and role of shale gas 2000-2035** (US EIA AEO, 2010a)

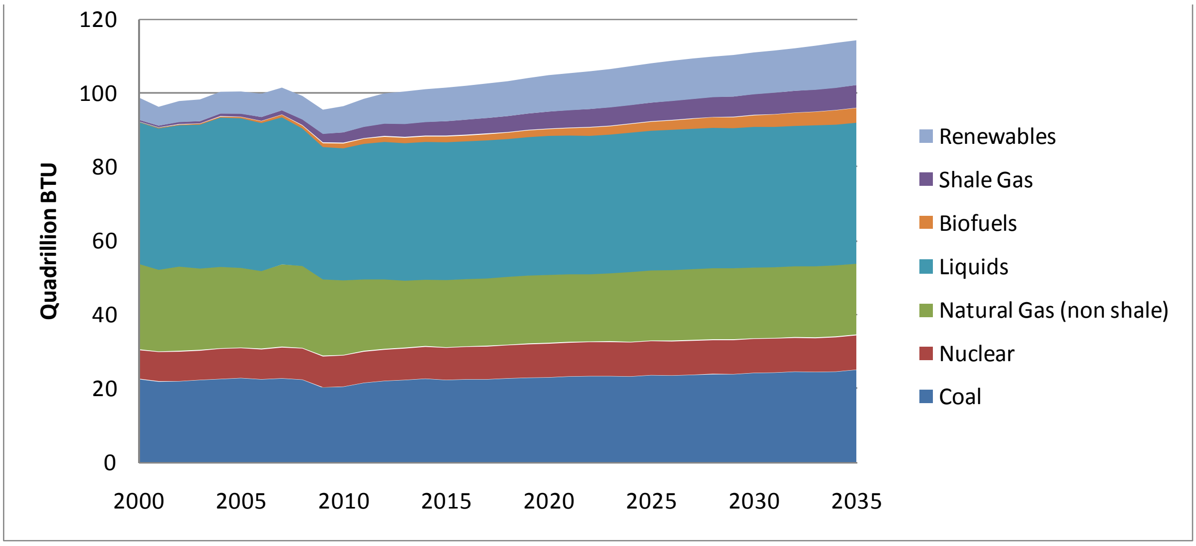



Table 2.12 summarises percentage changes in primary energy sources in the US EIA data plotted in Figure 2.10. As can be seen from the table, EIA predict that overall annual energy consumption is projected to rise by 15% by 2035 with the main changes being in shale, biofuels and, to a much lesser extent, renewables. The role of coal within the overall mix drops by only 1% by 2035 but actual consumption increases by 12% by the same year. Based on the EIA projections set out in Figure 2.11[16], the best that one could (optimistically) argue is that shale gas may curb the rate of growth in coal, consumption of which is still set to increase by 12% by 2035.

**Table 2.12: Change in US primary energy source 2008-2035 (EIA, 2010a)**

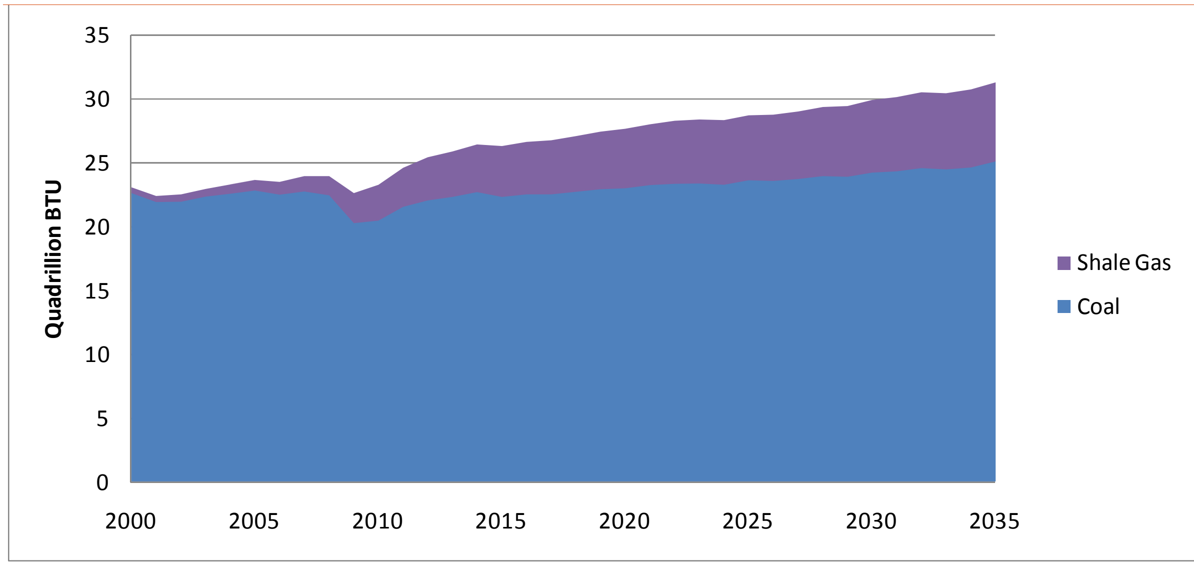
| | US Primary Energy Mix 2008 | US Primary Energy Mix 2035 | % Change | % Increase in each energy source 2008 vs 2035 |
|---|---|---|---|---|
| Coal | 23% | 22% | -1% | 12% |
| Nuclear | 9% | 8% | 0% | 11% |
| Natural Gas (non shale) | 23% | 17% | -6% | -13% |
| Shale Gas | 2% | 5% | 4% | 310% |
| Liquids | 37% | 33% | -4% | 3% |
| Biofuels | 1% | 3% | 3% | 372% |
| Renewables | 7% | 11% | 4% | 88% |
| **Total** | | | | **15%** |

In relation to the assumption that shale gas could be a bridging fuel as a transitional step to a low carbon economy, the EIA data suggests that, even if shale GHG

16 Figure 2.9 has not been updated to take account of the updated figures in EIA (2010b).

intensity was substantially lower, substitution of coal, for example, does not appear to be the intention.

**Figure 2.11: US primary energy consumption of coal and shale gas 2000-2035** (US EIA AEO, 2010a)




## 2.4 Development of shale gas in the UK

### 2.4.1 Shale potential in the UK

At present there are no shale developments in the form of well pads and horizontal shale wells in the UK. There is, however, ongoing preliminary exploration of deposits with a view to further development.

According to the British Geological Survey (BGS)[17], the UK has abundant shales at depth but their distribution is not well known. BGS is investigating the location, depth and properties of the shale as well as the processes that lead to accumulations of gas. According to the December 2010 report by BGS on behalf of the UK Department of Energy and Climate Change (DECC, 2010), "*the UK shale gas industry is in its infancy, and ahead of drilling, fracture stimulation and testing there are no reliable indicators of potential productivity*" (p.1).

However, making some assumptions and applying analogies with similar producing shale gas plays in America, BGS estimates UK shale gas reserve potential at 150bcm. At the same time BGS note that the US analogies used to produce this estimate may ultimately prove to be invalid, adding a number of caveats including

[17] http://www.bgs.ac.uk/research/energy/energy_exploitation.html

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 follows:

- ***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:*** *r*eserves 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.

For comparison with the BGS 150bcm estimate, according to DECC[18], the central estimate of gas reserves remaining based on proven plus probable reserves now stands at 601bcm. Proven gas reserves (remaining) at the end of 2008 (when gas production for the year was 68bcm) stand at 292bcm. At the maximum level, remaining gas reserves, based on a total of proven, probable and possible reserves, are 907bcm.

### 2.4.2 Shale developments in the UK

Despite the lack of knowledge concerning the nature and location of shale deposits in the UK, there are the beginnings of activity and interest in the development of shale resources in the UK and also in other parts of Europe. Known activity in the UK is comprised of the following:

***Cuadrilla Resources***

In November 2009 planning permission for an exploratory drill site at Preese Hall Farm, Weeton, Preston Lancashire (Eastings: 337500, Northings: 436600 PR4 3HT) was granted to Cuadrilla Resources by Fylde Borough Council.

Communication with the Council and the Environment Agency suggests that no environmental assessment was required but that plans for the drill were developed in conjunction with groundwater protection officers at the Agency.

According to the planning application and other documentation, the purpose of the exploratory drill is to identify whether the formation can produce gas at economic levels and, if the results prove positive, any further development will be subject to a further planning application.

[18] https://www.og.decc.gov.uk/information/bb_updates/chapters/reserves_index.htm

According to the most recent Activity Update Report[19] (7 December 2010), drilling at Preese Hall was completed on 8 December 2010 and the rig is to be relocated to a second drilling site at Grange Hill (some 15km from Preese Hall) where drilling will commence in January 2011. A full hydraulic fracturing test at the Preese Hall site is expected to commence in January 2011.

Preparations for a third exploratory well at Anna's Road are underway and a planning permit was approved on 17 November 2010.

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

### *Island Gas Limited*

Island Gas Limited (IGL) identifies itself as "*a coal bed methane (CBM) company seeking to produce and market methane gas for industrial and domestic use from virgin coal seams within its onshore UK acreage*"[20].

IGL has ownership interests ranging from 20-50% in eight Petroleum and Exploration Development Licences ("PEDLs") and 50% ownership of three onshore blocks held under one seaward petroleum production licence (SPPL) in the UK. These Licences cover a gross area of 1,000km$^2$.

On 15 February 2010, the company announced that it had identified a significant shale resource within its acreage. The reserves identified (using existing borehole logs in the locality) potentially extend over 1,195km$^2$ with an expected average thickness of 250m. These shales are understood to be hydrocarbon bearing as they have been locally demonstrated to be the source rock for hydrocarbons in the Liverpool Bay area. IGL has now identified independent consultants to review the hydrocarbon potential of these shales and the potential to produce gas and will be reporting findings once work is complete.

### *Composite Energy*

Composite Energy was initially focused solely on CBM but also has shale resources and conventional oil and gas within its current license portfolio and expects to add to that potential in 2010-11. Composite reports that it has identified shale potential within its licenses and is working to establish approaches to shale operations in a UK and European context[21].

[19] http://member.afraccess.com/media?id=CMN://2A616426&filename=20101207/AJL_01130036.pdf
[20] http://www.igasplc.com/
[21] http://www.composite-energy.co.uk/our-history.html

# 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. Instead, 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 utilising conventional sources of gaspoints. The analysis is based on non-peer reviewed data from a limited number of site measurements. The GHG data is therefore subject to high level uncertainty and may change significantly over time as the industry develops.

## 3.2 GHG emissions - gas from shales verses conventional sources

This section provides an overview of the additional $CO_2$e 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 dependent on the attributes of the reservoir. Due to these variations and inconsistent information a direct comparison between shale versus a conventional well is not recommended.

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

The purpose of this section is therefore to quantify the amount of greenhouse gases released during the main stages of the extraction process per well, which are unique to shale gas sites. 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; HIS CERA, 2010).

As discussed in Section 3.2.2, the main difference between extracting from shale versus a conventional reservoir is the horizontal drilling and hydraulic fracturing processes, which are essential to the successful extraction of gas. A potential additional point of departure for the two forms of extraction is the transportation of water and chemicals to the well site for hydraulic fracturing and the removal of this waste water/chemical mix after fracturing.

### 3.2.1 '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 are emissions of natural gas that escape unintentionally during the well construction and production stages; and
3) Vented emissions result from natural gas that is collected and combusted onsite or vented directly to the atmosphere in a controlled way.

This section focuses on the first of these, as this is the primary difference between shale and conventional sources. Fugitive and vented emissions of methane will depend on the control measures and operational procedures employed at each site.

#### *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 to drill to depths of below 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. The 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 ranging 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 that emitted during vertical drilling. ARI (2008) assume diesel fuel consumption in vertical well drilling of 1.5gallons (5.7litres)/ft drilled[22]. This figure would equate to an emission factor of 15kg $CO_2$/ft drilled (49kg $CO_2$/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 15–75tonnes $CO_2$ 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 49-73.5tonnes $CO_2$ at that site.

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

| Reservoir | Type | Depth (m) | Source |
|---|---|---|---|
| Marcellus USA | Shale | 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 | Shale | 150 – 750 | Aurora Oil and Gas Corp cited in Wagmen, D. (2006) |
| Antrim Shale | Shale | 75-450 | Aurora Oil and Gas Corp cited in Wagmen, D. (2006) |
| Fort Worth Basin | Shale | 600-2,400 | Bankers Petroleum cited in Wagmen, D. (2006) |
| Supply Region: Northeast | Conventional | Average well depth: 1,350 | ARI, 2008 (assumptions based on the use of the "ICF Hydrocarbon Supply Model) |
| Midcontinent | Conventional | 1,950 | |
| Rocky Mountain | Conventional | 1,050 | |
| Southwest | Conventional | 2,550 | |
| West Coast | Conventional | 1,950 | |
| Gulf Coast | Conventional | 3,150 | |

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

### *Pre-production – hydraulic fracturing phase*

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. The core source of onsite emissions is due to the blending of fracturing materials (pumping 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 will be carried out by diesel engines, however, alternative lighter fuels or electricity could also 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[23]. The total fuel use given is 29,000gallons of diesel fuel, equating to 325tonnes $CO_2$/well. In metric, this equates to 110,000litres diesel fuel and 295tonnes $CO_2$/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 3.5million gallons (13.2million litres) of water are required per well for hydraulic fracturing with existing technologies, and New York State (2009) give a figure of between 9-29million litres/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 commercially confidential. Conventional sites may use hydrochloric acid to enhance recovery rates[24].

Waste water or 'brine' 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 brine 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 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 use 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 and raw water mains supply; 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

[23] ALL Consulting, 2009, Table 11 p10
[24] http://www.naturalgas.org/naturalgas/well_completion.asp

location. This may require permission from local water authorities. Pumping will also have GHG emissions associated with it and may also require planning permission to put the pipework in place. After fracturing, the brine would be disposed of by transporting it by truck to a waste water 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 brine 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), assuming water transported is from a source 30km away (60km round-trip by road to the shale site (with a 983.11grams $CO_2$/km emission factor (assuming the use of a Rigid HGV, motorway driving from National Atmospheric Emissions Inventory, 2010). Furthermore, the recovered brine (15-80% of that injected) is assumed to be transported the same distance to a waste water treatment plant. At the plant, 0.406tonnes $CO_2$/million litres is released to the atmosphere when treating the brine (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 is specific to the geology and comprises a mix of methane, other heavier hydrocarbons and $CO_2$. The composition will part 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.

There is conflicting commentary on this issue:

> *"There is a paucity of data on the chemical composition of emerging unconventional natural gas plays….Natural gas production from the Barnett and other emerging shale tends to be "wet", meaning that the ratio of heavier components ($C_2$ or ethane and higher components such as propane and butane) to methane is high and the heating value is high. The $CO_2$ content in shale gas tends to be low. An exception is the Antrim Shale in the Michigan Basin -- the biogenic source of the methane produces $CO_2$ as well as methane.*

> *The composition of Barnett Shale production varies significantly in terms of natural gas wetness and liquid yield across the productive area. The play exhibits a gradation from dry gas to wet gas, to oil and gas. ….This change in composition can be correlated with thermal maturity as measured by vitrinite reflectance. The term thermal maturity refers to the level of alteration of a source bed in the process of forming oil and gas through geologic time. Vitrinite reflectance is a specific measure of thermal maturity. Areas of higher vitrinite reflectance in the eastern portion of the play are more thermally mature and have a dry gas with a lower heating content. Both the overall wetness of the Barnett and the lateral variability of wetness are significant in terms of natural gas processing infrastructure needs. This is because the liquids must be stripped from the gas before they can be accepted for long distance transport by transmission pipelines. Where existing gas processing capacity is not adequate, development of the gas resource may be restricted."* (INGAA, 2008)

However, ALL (2008) cite that shale gas is typically dry gas of over 90% methane:

> *"In terms of its chemical composition, shale gas is typically dry gas composed primarily of methane (90% or more methane). While there are some shale gas formations that do produce gas and water, the Antrim and New Albany Shales being the largest examples , they are the exception based on data from those plays with active development"* (Boyer et al, 2006).

***Summary assessment I: shale versus conventional natural gas per well***

Table 3.2 provides an overview of the additional 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. Furthermore, there may be additional fugitive emissions of natural gas during the hydraulic fracturing and flowback stage that are not quantified. Any such emissions would need to be measured onsite and would be affected by the use or otherwise of measures to limit leakage.

| Table 3.2: Key additional emissions associated with shale gas extraction | | | |
|---|---|---|---|
| | Combustion | Assumptions | Data Source |
| | tonnes $CO_2e$ | | |
| 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 and flowback | 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 | |
| Fugitive emissions[b] during fracturing | - | 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. |
| Brine 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. |
| Waste water treatment | 0.33-9.4 | Based on 9-80% 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 one 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.
b: there may also be additional vented and/or fugitive emissions associated with the drill site and drill tailings however, there is no reliable data to enable these to be quantified. Furthermore, there is likely to be vented/fugitive emissions associated with conventional natural gas extraction, again with similar uncertainties. It should be noted that there are a number of technical solutions to reduce fugitive emissions and reduce the need for venting, which are available for both conventional and shale sites.

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

The significance of an additional 348-438tonnes $CO_2$ on the emissions intensity for 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.

The implications of the fracturing stage emissions on the overall emissions per Terra Joule (TJ) of energy extracted were estimated. We have used the above table 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 3.3: Estimated $CO_2$e emissions/TJ of energy extracted per well lifetime**

| Gas shale basin | Total production | Additional $CO_2$e emissions (50% re fracture once)[25] | Source of Well Production Rate Information |
|---|---|---|---|
| | $m^3$/well | tonnes $CO_2$e/TJ[a] | |
| 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 3.3 of $CO_2$e emissions/TJ 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) and in the case of the shale, increase the emissions impact from fracturing. Additional emissions associated from fugitive sources during fracturing and the transportation on and off the site of fracturing materials would also increase the emissions. However, for a gas shale well with a high production rate (for example the Marcellus Shale given in Table 3.3), the overall impact of the emissions associated with the fracturing on emissions could be minimised. In addition there are a number of mitigation measures that can be taken (see Section 3.2.5) that can reduce the emissions from gas extraction further.

[25] Given the assumption of a well life of 8 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).

The gas initially in place (estimated measure of gas in a reservoir), and consequently reserves, is expected to vary from site to site, Table 3.4 summarises this along with the production rate per well for several gas shale basins. Note the size of the Marcellus shale basin compared to the other sites. DECC assume that by analogy with similar producing shale gas plays in America, the UK shale gas reserve potential could be as large as 150 bcm (DECC, 2010).

**Table 3.4: Comparison of gas initially in place and production rate for US sites** (ALL Consulting, 2008) and for the UK (DECC, 2010)

| Gas shale basin | Gas initially in place | | Reserves | | Estimated production | |
|---|---|---|---|---|---|---|
| | Trillion cubic feet (tcf) | bcm | Tcf | bcm | Thousand cubic feet/well/day | $m^3$/well/day |
| US | | | | | | |
| Barnett | 327 | 9260 | 44 | 1250 | 338 | 9571 |
| Faylleville | 52 | 1470 | 41.6 | 1180 | 530 | 15008 |
| Haynesville | 717 | 20300 | 251 | 7110 | 1213 | 34349 |
| Marcellus | 1,500 | 42500 | 363-500 | 10300 - 14200 | 3100 | 87783 |
| Woodford | 52 | 1470 | 11.4 | 323 | 415 | 11752 |
| Antrim | 76 | 2150 | 20 | 566 | 163 | 4616 |
| New Albany | 160 | 4530 | 19.2 | 544 | N/A | N/A |
| UK | | | | 150 | | |
| Weald[a] | | | 0.2 | 5.66 | | |
| Wessex[a] | | | 0.03 | 0.85 | | |
| Pennine[b] | | | 4.7 | 133 | | |
| Cambrian[c] | | | 0.3 | 8.5 | | |

[a] Based on analogy with Antrim shale productivity (47mmcf/$km^2$) in US (DECC, 2010)
[b] Based on analogy with Barnett shale productivity (268mmcf/$km^2$) in US, but considered unlikely that Pennine productivity will match this (DECC, 2010)
[c] Based on analogy with Barnett shale productivity (20mmcf/km2) in US, but considers a conservative productivity for the Cambrian basin (DECC, 2010)

In terms of comparing the production rates in Table 3.4 to conventional gas sources, the literature provides some insights into the returns per well of different gas sources and their future direction. A report from Massachusetts Institute of Technology (MIT) suggest it is possible to extract far more of the gas initially in place (GIIP) from a conventional source compared to shale or similar formations (MIT, 2010).

> *"Conventional resources generally exist in discrete, well-defined subsurface accumulations (reservoirs), with permeability values greater than a specified lower limit. Such conventional gas resources can usually be developed using vertical wells, and often yield economic recovery rates of more than 80% of the Gas Initially in Place (GIIP). By contrast, unconventional resources are found in accumulations where permeability is low. Such accumulations include "tight" sandstone formations, coal-beds, and shale formations. Unconventional resource accumulations tend to be distributed over a much larger area than conventional accumulations and usually require well stimulation in order to be economically productive; recovery factors are much lower — typically of the order of 15% to 30% of GIIP"* (MIT, 2010).

Evidently, the ultimate volume of gas initially in place in a reservoir is of key importance, "*Estimated ultimate recoveries (EURs) of wells in continuous [e.g. shale] accumulations are generally lower than the EURs for wells in conventional gas accumulations"*(US Geological Survey National Oil and Gas Resource Assessment Team, 1995)

However comparisons made in 1995 (or even today) may not hold in the future, as the size of newly discovered conventional sources is reportedly declining, although the extent to which this is due to the increasing exploration of unconventional sources distorting the collated statistics is unclear as found by the US Geological Survey (2002):

> *"Average daily production of US gas wells peaked in 1971 at about 435 thousand cubic feet of gas/day/well (MCFG/D/W) and declined to about 160 thousand cubic feet per day per well in 1985 and continued at the 1985 level through 1999. The average gas well today produces one third that of gas wells producing in the early to mid 1970s. The decrease in well productivity may be partly due to increased drilling of continuous-gas accumulations which generally have lower EUR's than wells drilled in conventional gas accumulations."*

The US Geological Survey's findings are supported by data from Texas reported by Swindell (1999) and updated in 2005. The information in Table 3.5 is taken from Swindell (2005) who examined the depletion rates of gas wells in Texas. The study highlights the decline in the gas recovered from gas wells in Texas between 1971 and 2005 and provides data on the first year decline rate (the rate at which production from a well declines from the 1st to 2nd year of production) in 1971 as 10% compared to 61% in 2005. Similarly trends worldwide suggest a tendency towards smaller conventional gas finds that are more difficult to extract.

**Table 3.5: Average gas recovered per well, Texas** (Swindell, 1999, 2005)

| | Projected Ultimate Recovery Million cubic feet / well | Projected Ultimate Recovery million cubic metres / well |
|---|---|---|
| Texas Oil Field 1971 | 6,245 | 176.8 |
| Texas Oil Field 1980 | 1697 | 48.1 |
| Texas Oil Field 1990 | 1568 | 44.4 |
| Texas Oil Field 2000 | 1,491 | 42.2 |
| Texas Oil Field 2005 | 1,033 | 29.2 |

In summary

- The estimates presented here are not based on fully peer reviewed emissions data;
- DECC's reserve potential for the UK of 150 bcm is based on analogy with similar producing shale gas plays in the US;

- The emissions from hydraulic fracturing are based on data from eight hydraulic fracturing processes at the Marcellus Shale, there is insufficient data as to whether the Marcellus experience is transferable to sites found in the UK;
- The main determinant appears to be the rate of return per well, thus the larger the amount of natural gas that can be extracted from a shale well, the lower the contribution the fracturing process makes to the emissions/TJ of extracted energy;
- Although the rate of return per well is not quoted for UK basins, it is thought that additional $CO_2e$ emissions per well would be at the higher end of estimates in Table 3.3 as UK reserve potential is low in comparison to the US basins outlined in Table 3.4; and
- Making 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 may be higher than for conventional gas extraction they are unlikely to be markedly so.

### 3.2.3 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 at 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. Furthermore, 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) and a gas fired power station ranges between 40 to 60% (POST, 2005).

| Table 3.6: Direct emissions from natural gas and coal compared to the additional emissions associated with extracting natural gas from shale | |
|---|---|
| | **tonnes $CO_2e/TJ$** |
| **Natural Gas**[b] | 57 |
| **Additional emissions associated with extraction from shale** | 0.14 – 1.63[a] |
| **Coal**[b] | 93 |

a: these figures are the upper and lower bounds of the emission estimates from Table 3.3, the figures depend on the amount of gas extracted per well and the assumed number of refracturing steps taken per well. Please note the figures represent the extremes of the data and assumptions used here and are not representative of all shale sites.
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.

### 3.2.5 Mitigating the emissions associated with natural gas extraction

The major opportunities for minimising the emissions associated with extracting natural gas are: to use lower carbon energy sources instead of diesel for pumps, compressors and transportation and; to fit all gas processing equipment on site with technology aimed to minimise leaks. Both options will deliver savings proportionally from both conventional and shale sources.

## 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 main 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 The UK scenarios

For the UK four scenarios have been developed:

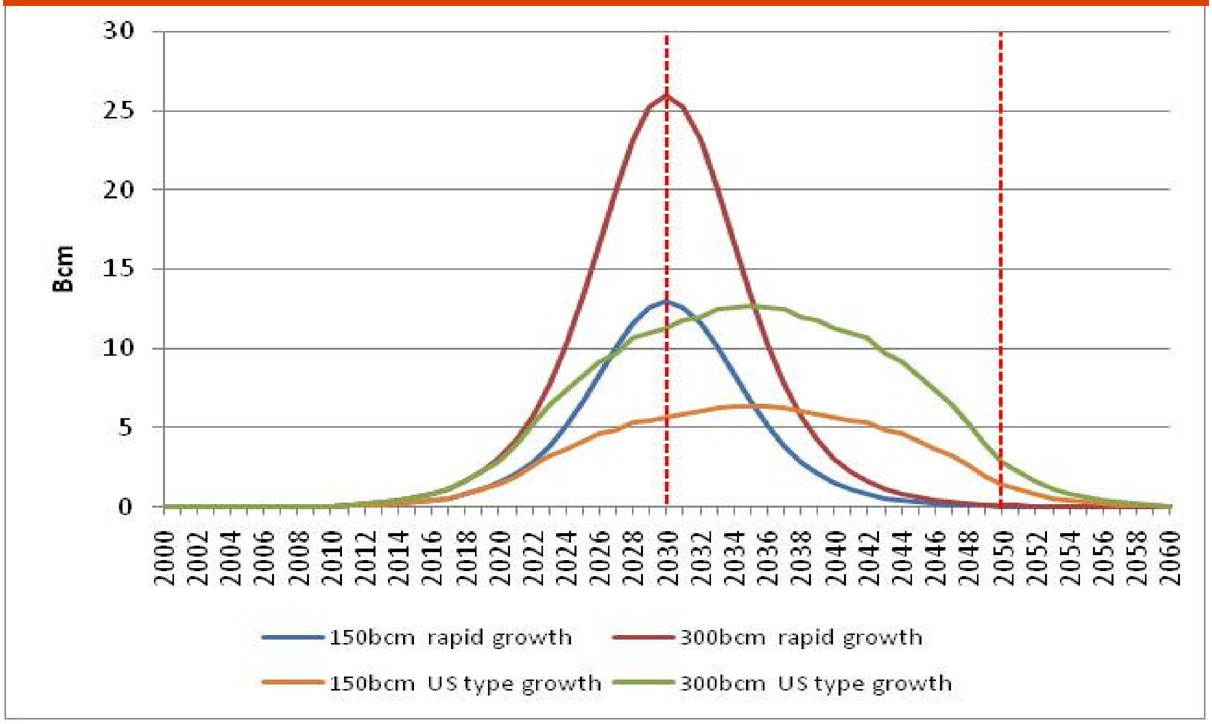
- 150bcm – rapid growth
- 150bcm – US type growth
- 300bcm – rapid growth; and
- 300bcm – US type growth.

As was outlined in section 2.4 the recent report published by DECC has suggested 150bcm as a potential figure for the shale gas reserve in the UK (DECC, 2010). Hence this has been taken as a starting point for the scenarios. However, if we look at the situation in the US we find that estimates of technically recoverable reserves have been revised upwards by significant amounts over recent years (See Table 2.9). For example, the estimates provided in the EIA Annual Energy Outlook 2011 pre release report are over 100% larger than those given in the EIA Energy Outlook 2010 report (EIA, 2010b). Given this scale of uncertainty, a figure of 300bcm for the UK shale gas resource is used as a conservative upper end of a range of possible outcomes.

Given that shale gas is yet to be commercially produced in the UK it was decided that the scenarios should cover 2 different rates of exploitation. The first of these, termed 'rapid growth', assumes that the shale gas is exploited rapidly, with the resource exhausted in a relatively short space of time. This kind of exploitation approximates to a Hubbert type curve[26]. The second, termed 'US type growth', 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 production figures for shale gas in 2009[27], suggest that current growth may be more rapid than this figure suggests. Some commentators have proposed that US exploitation rates will be much more rapid than the EIA projections with a peak between 2020 and 2025, effectively following a Hubbert like curve (Roper, 2010).

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

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




[26] M King Hubbert predicted that oil production over an geographical area would follow a bell curve, rising rapidly before dropping off equally rapidly. Using this idea he predicted that US oil production would peak around 1970 – a prediction that proved correct. A 'Hubbert curve', a derivative of a logistics curve, is often used as an approximation of the production rate of a resource over time. See e.g. Laherrère, 2000

[27] See http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm.

Using these scenarios it is then possible to explore the potential implication of shale gas exploitation on carbon emissions (Table 3.7 below).

**Table 3.7: Outcomes of UK scenarios**

| | Cumulative amount of shale gas produced (bcm) | | Cumulative $CO_2$ emissions from shale gas, 2010-2050 ($MTCO_2$) | % of UK domestic action budget[28] (2010-2050) |
|---|---|---|---|---|
| | 2030 | 2050 | | |
| 150 bcm - rapid growth | 81 | 150 | 305 | ~2.2% |
| 150 bcm - US type growth | 47 | 145 | 284 | ~2.0% |
| 300 bcm - rapid growth | 163 | 300 | 609 | ~4.3% |
| 300 bcm - US type growth | 93 | 289 | 589 | ~4.2% |

As is clear from Figure 3.1 and Table 3.7 the majority of shale gas is extracted before 2050. Over the 2010-2050 time period, using this gas would result in between 284-609 $MTCO_2$ being emitted, which equates to between 2% and 4.3% of the total UK $CO_2$ 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 with lower 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 associated with that use[29]. 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 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, carbon capture is as yet unproven and to date significantly less effort has been put into gas CCS compared to coal; given this we must consider the possibility that it may never play a significant role.

It is not possible to make meaningful and robust predictions of how any shale gas produced in the UK may be used and the subsequent impact that this might have on overall emissions levels. However, from the perspective of addressing climate change, it is hard to foresee any positive arguments. While it is possible that shale gas could substitute for coal, within the UK, this would likely be counteracted by

[28] The 2010-2050 budget was calculated based on updated figures from Committee on Climate Change (2010), p.135.
[29] It should be noted that even under the 300bcm – rapid growth scenario, even at its peak, shale gas would only contribute around 30% to total gas demand so imports would still have a role to play. Given the rapid rise and drop in this scenario any substitution for imported gas would only be temporary.

global use of coal *and* shale gas. 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 pressing requirement for the UK is to find ways to reduce fossil fuel use, not to exploit more. However, and building on earlier, even 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 would just be used elsewhere with an associated increase in global emissions. Put directly, whilst world demand for fossil fuels remains high, any new sources of fossil fuel (even if relatively low carbon per unit of useful energy) will be purchased, combusted and consequently add to the global emissions burden. It will not substitute for other fossil fuels and in this regard claiming shale gas as a viable low-carbon option for the UK cannot be reconciled with the spirit of UK commitments on climate change.

### 3.3.2 The global scenarios

As with the UK, the potential shale gas that could be exploited is highly uncertain. The only estimate for the global resource that has been found is provided in a report for the US National Petroleum Council (NPC, 2007). This suggests a figure of around 450,000 bcm global shale gas resource. Using this as a starting point three scenarios were then developed:

- High extraction – this assumed that 40% of the total resource is actually recoverable;
- Medium extraction – this assumed that 20% of the total resource is actually recoverable; and
- Low extraction – this assumes that 10% of the total resource is actually recoverable.

For each of these scenarios it is assumed that 50% of the total recoverable resource is extracted by 2050, with the 100% of the recoverable resource extracted by 2100. In the absence of any substantive and effective policies to reduce significantly global emissions and with continuing growth in demand for energy, it is entirely possible that that any resources would be exploited on a much shorter timescale, hence this is likely to be a conservative estimate. The outcomes of the scenarios are presented in Table 3.8 below.

**Table 3.8: Outcomes of the global scenarios**

| | **% resource recovered** | **Amount of shale gas exploited by 2050 (bcm)** | **Cumulative emissions associated with shale gas ($GTCO_2$) (2010-2050)** | **Additional ppmv $CO_2$ associated with shale gas emissions (2010-2050)** |
|---|---|---|---|---|
| **High extraction** | 40% | 90000 | 183 | 11 |
| **Medium extraction** | 20% | 45000 | 92 | 5 |
| **Low extraction** | 10% | 22500 | 46 | 3 |

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 46-183 $GTCO_2$, equating to an additional atmospheric concentration of $CO_2$ of 3-11ppmv[30]. 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.

[30] This assumes an airborne fraction of emissions of 45%. See, for example, Le Quere et al (2009)

# 4. Human health and environmental considerations

## 4.1 Introduction

### 4.1.1 Background

The processes involved in the production of shale gas have been described in detail in Section 2.2 of this report and the level of resources for the development of a well pad summarised in Tables 2.6 and 2.7

### 4.1.2 Importance of cumulative impacts

Perhaps unsurprisingly, the processes and operations involved in the extraction of shale gas from wells are not without their human health and environmental implications. For example, as is discussed in more detail later, the human health and environmental risks associated with hydraulic fracturing in particular have risen in 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[31].

However, 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 highly 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 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 2.8 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 spread over some 140-400km$^2$ and some 27 to 113million tonnes of water.

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

### 4.1.3 Key risks and impacts

The key risks and impacts of shale gas and shale gas processes and development can be divided as follows:

- contamination of groundwater by fracturing fluids/mobilised contaminants arising from:
    - wellbore/casing failure; and/or
    - subsurface migration;
- pollution 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 water;
- water consumption/abstraction;
- waste water treatment;
- land and landscape impacts;
- impacts arising during construction:
    - noise/light pollution during well drilling/completion;
    - flaring/venting; and
    - local traffic impacts.

## 4.2 Pollution impacts

### 4.2.1 Introduction

Pollution impacts from shale gas development are closely connected with the hydraulic fracturing process, the fracturing fluid chemicals used, transformation products and subsurface contaminants that are mobilised during the process.

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 recent expansion of the shale gas industry and increasing concerns raised by the US public, media and Congress, the US EPA announced in March 2010 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. US EPA notes that "*there are concerns that hydraulic fracturing may impact ground water and surface water quality in ways that threaten human health and the environment*" and is re-allocating $1.9 million for the study in the financial year 2010 and requesting funding for 2011 in the president's budget proposal.

US EPA is still in the early stages of the hydraulic fracturing research program and initial results will only be available towards the end of 2012. Whilst it, and other assessments, are being completed some regulators are moving towards moratoria on hydraulic fracturing. In New York State, for example, on 3 August 2010 the State Senate passed a Bill to suspend hydraulic fracturing for the extraction of natural gas or oil until 15 May 2011 (and to suspend the issuance of new permits for such drilling). On 11 December 2010, the New York State Governor vetoed the Bill and 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". The Executive Order requires that high-volume, horizontal hydraulic fracturing would not be permitted until 1 July 2011 at the earliest..

The issue of hydraulic fracturing and environmental and human health risks is, then, under the spotlight in the US. In the meantime, however, there is a paucity of information and data on which to base a quantified assessment of environmental and human health risk.

That said, this short study seeks to draw together what information is available and provide an overview of key issues, concerns and challenges from a UK perspective, in particular.

### 4.2.2 Fracturing fluids and flowback water

As will be recalled from 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 chemical additives of up to 2% by volume, around 180-580 $m^3$ of chemical additives (or 180-580tonnes based on relative density of one). After fracturing, a proportion of the fluid returns as flowback water.

#### *Chemical 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 is typically comprised of around 98% water and sand (as a proppant) with chemical additives comprising 2% (see Table 2.3).

Owing to the fact that US Federal law currently exempts the underground injection of fluids for hydraulic fracturing purposes from regulation, there is no 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 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 >10,000pounds (4.5t) 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 CAS numbers that have been extracted from chemical compositional information for 197 products as well as Material Safety Data Sheets submitted to the NYSDEC.

A review of this list has been undertaken by cross checking CAS numbers in the NYS list with the following lists on the European chemical Substances Information System (ESIS)[32] (see Annex 1 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 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:

- 15 substances are listed in one of the four priority lists;
- 6 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));
- 2 are present on the first list of 33 priority substances (Naphthalene and Benzene);

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

- 17 are classified as being toxic to aquatic organisms (acute and/or chronic);
- 38 are classified as being acute toxins (human health);
- 8 are classified as known carcinogens (Carc. 1A=1, Carc. 1B = 7);
- 6 are classified as suspected carcinogens(Carc. 2 = 6);
- 7 are classified as mutagenic (Muta. 1B); and
- 5 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.

All first fracturing operations (i.e. without re-fracturing) on a single six well pad require a total of around 1,000-3,500$m^3$ of chemicals. Based on 1.25-3.5pads/$km^2$, 3,780-12,180$m^3$ (or 3,780-12,180tonnes based on relative density of one) of fracturing chemicals would be required per $km^2$ of shale development.

Based on the data in Table 2.8, around 140-400$km^2$ of shale development comprising 2,500-3,000 horizontal wells would be required to deliver 9bcm/year (10% of UK gas consumption in 2008). This, in turn, represents high pressure injection of around 0.5-2.2million $m^3$ (or tonnes based on relative density of one) of fracturing chemicals.

***Flowback water***

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, for the UK, it is difficult to predict what the composition of flowback fluid is likely to be. In terms of example compositions, New York State (2009) provides limited sample data on composition of flowback fluids (see Annex 1, Table A.2 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 from a single well can also change within a few days of the well being fractured.

When visually compared with substances in fracturing fluids the data on flowback water would tend to suggest mobilisation and presence of elevated concentrations of:

- heavy metals (of varying types);
- radioactivity and NORMs;
- total dissolved solids; and
- perhaps, hydrocarbons including benzenes (unclear whether this represents mobilised hydrocarbons or fracturing additives).

Altogether, the toxicity profile of the flowback fluid is likely to be of greater concern than that of the fracturing fluid itself, and is likely to be considered as hazardous waste in the UK. 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, 5-89million $m^3$ of hazardous waste water would be recovered and would require treatment or storage. Importantly, the same water use and percentage recovery ranges would 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 shale development**

| | | | | |
|---|---|---|---|---|
| | **Assuming No Re-fracturing** | | **Assuming a Single Re-fracturing Operation on 50% of Wells** | |
| % Fracturing Fluid Recovery | 15% | 80% | 15% | 80% |
| **Per Well Pad** | | | | |
| Wells | 6 | 6 | 6 | 6 |
| Flowback water volume - $m^3$ | 7,920 | 137,280 | 11,880 | 205,920 |
| Flowback water chemical waste content (@2%) - $m^3$ | 158 | 2,746 | 237 | 4,119 |
| **For delivery of 9bcm/ year of Shale Gas Production** | | | | |
| Wells | 2,970 | | 2,592 | |
| Area -km2 | 141 | 396 | 123 | 346 |
| Flowback water volume - $m^3$ | 3,920,400 | 67,953,600 | 5,132,160 | 88,957,440 |
| Flowback water chemical waste content (@2%) - $m^3$ | 78,210 | 1,359,270 | 102,384 | 1,779,408 |

### 4.2.3 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 grounded 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 Southern England, groundwater supplies up to 80% of needs (Environment Agency, 2010)[33].

Owing to its importance as both a source of drinking water and as source for rivers and wetlands, preventing its pollution is vital. If it becomes contaminated and pollution runs deep it can lead to long-term deterioration.

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/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 ground 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.

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

### ***Wellbore failure/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. Owing to this, the wellbore itself probably provides the single most likely route of pollution 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, 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 ground water zone but not all ground water 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*".

New York State (2009) ignores the role and significance of cementing (and, particularly, the initial cementing work) when considering groundwater pollution. 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* $2 \times 10^{-8}$ *(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 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 potential freshwater aquifers, particularly since the probability of contamination of aquifers given is the probability per well. As thousands of shale 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 ground and surface waters with contaminants such as brine, unidentified chemicals, natural gas, sulphates, and hydrocarbons such as benzene and toluene[34]. 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 natural gas was observed bubbling into a stream bed. In addition to natural gas, groundwater samples revealed that concentrations of benzene exceeded 200micograms/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 nearly 4,000ft (1,200m) and horizontally 2,000ft (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 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.

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

2) in 2007, a well that had been drilled almost 4,000ft into a tight sand formation in Bainbridge, Ohio 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[35];

3) groundwater contamination from drilling in the Marcellus shale formation was reported in 2009 in Dimock, Pennsylvania, 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 (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.*" The investigation is ongoing (Riverkeeper);

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);

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);

[35] 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, WY, 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); and

8) on 3 June 2010 a gas well blowout in Clearfield County sprayed natural gas and wastewater into the air for 16hours. 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 40days[36].

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. Here GWPC report[37] 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 media 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*".

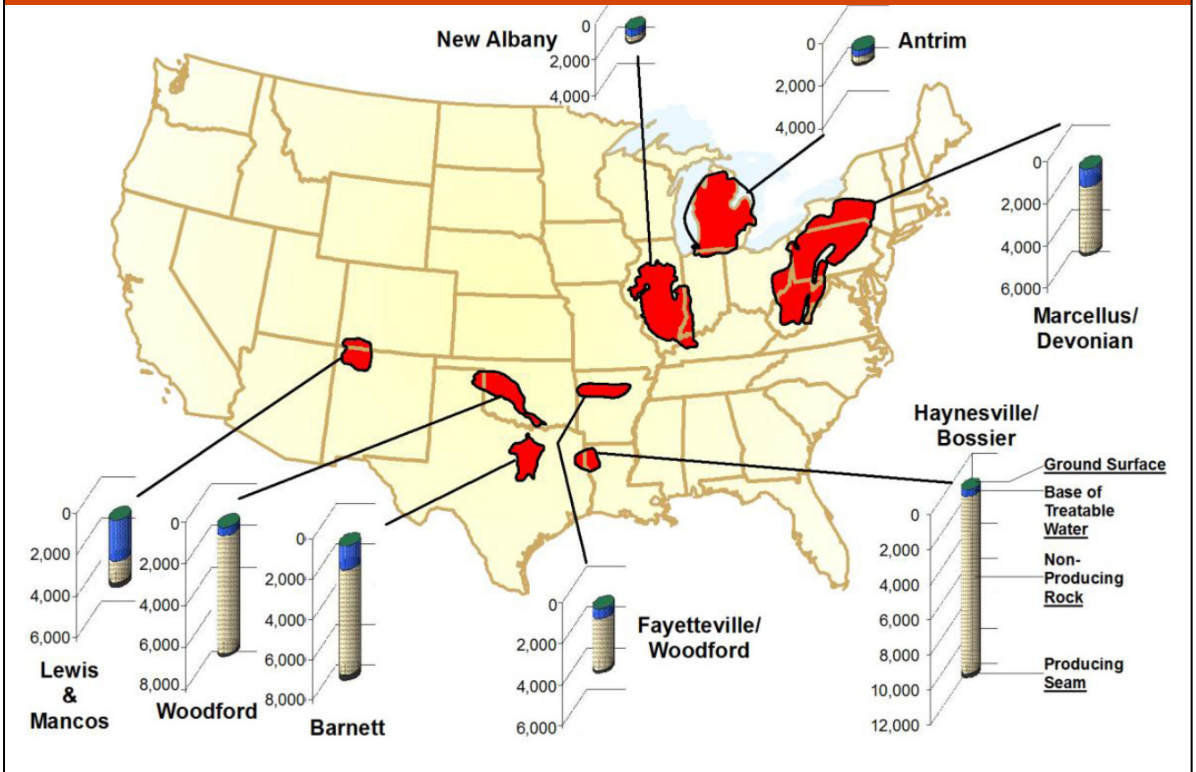
### *Sub-surface migration of contaminants*

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

The GWPC provide data on depths of formations and treatable water (see Figure 4.1) and identify that, outside New Albany and the Antrim, wells are expected to be drilled at depths greater than 3,000ft (900m) below the land surface. On the basis of this 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.

[36] http://www.circleofblue.org/waternews/2010/world/fracking-regulations-vary-widely-from-state-to-state/
[37] State Oil and Gas Regulations Designed to Protect Water Resources – Groundwater protection Council, US Dept. of Energy, National Energy Technology Laboratory May 2009

**Figure 4.1: 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 including the following can, and do, act together to result in contamination of groundwaters via:

- 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.

### 4.2.4 Routes of exposure – surface water and land contamination

Routes of exposure of land and surface waters, and via both to groundwater, are more straightforward.

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 be summarised as follows:

- well cuttings/drilling mud: a single well drilled vertically to a depth of 2km and laterally by 1.2km generates around 140m$^3$ of cuttings. A six well pad will generate around 830m$^3$ of cuttings. These are typically stored in pits before transport offsite;

- transport and temporary storage hydraulic fracturing additives: based on 2% content of fracturing fluid and water volumes provided previously, around 180-580m$^3$ of chemical additives (or 180-580tonnes based on relative density of one) are required for each well. At the level of a well pad some 1,000-3,500m$^3$ of chemicals (or 1,000-3,500tonnes based on relative density of one). As noted in Section 4.2.1, the exact composition of such fracturing fluids is not disclosed but analysis of chemical identities suggests a significant number of substances with hazardous properties and priority substance status in the EU;

- flowback fluid: each well on a multi-well pad will generate between 1,300–23,000m$^3$ of flowback waste fluid containing water, fracturing chemicals and subsurface contaminants mobilised during the process (including toxic organic compounds, heavy metals and naturally occurring radioactive materials or NORMs). According to New York State (2009) approximately 60% of the total flowback occurs in the first four days after fracturing and this may be collected via:

  (a) unchecked flow through a valve into a lined pit;
  (b) flow through a choke into a lined pit; and/or
  (c) flow to tanks.

  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 water from a single well fracturing operation, namely between 1,30–23,000m$^3$.

  New York State (2009) notes that one operator reports a typical pit volume of 750,000gallons (2,900m$^3$). Based on a pit depth of 3m, the surface footprint of a pit would be around 1000m$^2$ (0.1ha). It also notes that, owing to the high rate and potentially high volume of flowback water, 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 water from one fracturing operation on a single well.

In terms of overall flowback water volume for a six well pad the data suggest a total of 7,900-138,000m$^3$ of flowback water per pad for a single fracturing operation (with fracturing chemicals and subsurface contaminants making up to 2%, or 160-2,700m$^3$).

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.

In addition to the many onsite hazards listed above, the pooling and subsequent treatment and discharge of hazardous waste water generated by well pads, and the possible need for additional industrial wastewater treatment works, contributes to an increase in the risk of contamination through this route. The likelihood of each of these adverse events occurring varies from one hazard to another as do the consequences. Given the toxic properties of fracturing/flowback fluids (or constituents), however, any spillage onto land or surface water is likely to be of concern.

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. Investment in permanent physical containment to the standard of other hazardous installations is unlikely.

Given that the development of shale gas requires the construction of multiple wells/well pads, the probability of an adverse event leading to contamination increases accordingly. As such, 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. As might be expected, there have been a number of incidents reported in the US including (Riverkeeper, 2010):

- in September 2009 in Dimock, PA. 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;

- in Monongalia County, West Virginia 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;

- in Dimock, PA, 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; and

- on December 12, 2006, PA 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.

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[38] for citizens to report non-emergency suspicious activity related to oil and natural gas development.

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

## 4.3 Water consumption

As noted in Sections 2.2 and 4.1, 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.

As such, large quantities of water must be brought to and stored on site. Local conditions will dictate the source of water and 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 3-4/square kilometre. As each fracturing phase of the operation lasts around 2-5days/well, the provision of dedicated pipelines to each well pad would appear unlikely in the UK situation and transport via truck or abstraction is the most likely means of providing source water.

For provision of 9bcm/year shale gas for 20 years, it is estimated that total water consumption is 27,000-113,000megalitres. Averaged over the 20 year period, this is equivalent to an annual water demand of 1,300-5,600megalitres. Annual abstraction by industry (excluding electricity generation) in England and Wales is some 905,000megalitres/year. As such, development of shale reserves at levels sufficient to deliver gas at a level equivalent to 10% of UK gas consumption would increase industrial water abstraction across England and Wales by up to 0.6%.

Clearly, this comparison relates to total abstraction across the whole of England and Wales and shale development will be focussed in a much smaller area. Sourcing such significant quantities of water sustainably from local sources will be difficult owing to existing pressure on UK water resources. 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 (and, incidentally, just on the boundary of the flood zone). 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'.

## 4.4 Other impacts of and constraints on shale development

### 4.4.1 Overview

In addition to the very real issues surrounding shale gas development, chemical pollution and abstraction, there are a number of other impacts that, from a UK perspective, are likely to be significant. These impacts include:

- noise pollution;
- landscape impacts; and
- traffic and road damage.

Of all of the impacts, these are likely to present the greatest constraint on development of shale gas in the UK, whether at a local level or over a significant area.

### 4.4.2 Noise and Visual/Aesthetic Impacts

In terms of noise impacts, Table 2.4 provides a summary of activities required at well pads prior to production. On the basis of this, it is estimated that each well pad requires a total of around 500-1,500days 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[39]. 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 1.25-3.5 pads/km$^2$ the noise impacts on a locality are likely to be considerable and prolonged.

### 4.4.3 Landscape Impacts

In terms of visual impacts, each well pad will be around 1.5-2ha in size and will be equipped with access roads (New York State, 2009). During construction well pads will 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 430-500 well pads would be required to deliver 9bcm/year of shale gas, it is likely that in a UK context visual impacts will be contentious. As there is little that can be done to alleviate the levels of visual intrusion (individually or collectively), these impacts, along with noise and construction, may provide the greatest constraints on development in the UK.

### 4.4.4 Traffic

In addition to impacts onsite, construction of well pads requires a significant volume of truck traffic. Table 2.5 provides truck movements per well pad (based on a six well pad) from New York State (2009). This suggests a total number of truck visits 4,300-6,600 for the construction of a single well pad. Local traffic impacts for 1.25-3.5 pads/km$^2$ 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 similar rule where the increased funds are needed to repair roads not designed for the intense truck traffic associated with industrial gas drilling[40].

[39] http://www.composite-energy.co.uk/shale-challenges.html
[40] Riverkeeper, Inc. - Industrial Gas Drilling Reporter - Vol. 9, August 2010.

# 5. Conclusions

## 5.1 Background

### 5.1.1 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 injection well 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 6 individual wells. These well pads are sited 1-3.5 in every square kilometre.

To date shale gas has only been exploited in the United States, where production of shale gas has expanded from around 1.4% of total US gas supply in 1990 to greater than 6% of total US gas supply in 2008. 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.

### 5.1.2 The UK case

At present there are no active shale developments in the form of well pads and horizontal shale wells in the UK. There is, however, ongoing preliminary exploration of deposits with a view to further development. 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 [41].

The only active development of shale in the UK has been by Cuadrilla Resources, which received planning permission for an exploratory drill site at Preese Hall Farm, Weeton, Preston Lancashire in November 2009. Drilling at Preese Hall was completed on 8 December 2010 and the rig is to be located a second drilling site at Grange Hill (some 15km from Preese Hall) where drilling will commence in January 2011. A full hydraulic fracturing of Preese Hall is expected to commence in January 2011.

Preparations for a third exploratory well at Anna's Road are underway and a planning permit was approved on 17 November 2010.

[41] 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.

## 5.2 GHG emissions

### 5.2.1 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 natural gas.

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

- Horizontal drilling;
- Hydraulic fracturing and flowback;
- Fugitive emissions during fracturing (these emissions are unknown and have not been included);
- Transportation of water;
- Transportation of brine; and
- Waste water treatment.

The combination of emissions from these processes gave an estimate per well of 348-438tonnes $CO_2$e. This figure will increase if the well is refractured, something which could happen up to 5 times and the DECC report goes on to suggest that refracturing could happen every 4-5 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 $CO_2$e emissions associated with the processes above account for between 0.14-1.63tonnes $CO_2$e/TJ of gas energy extracted. The value depends on 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.

Given that during combustion 1TJ gas would produce around 57tonnes $CO_2$, the additional emissions from the shale gas extraction processes identified represent only 0.2-2.9% of combustion emissions. Similarly to conventional gas there will be some further emissions associated with processing, cleanup and distribution.

These 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 93tonnes $CO_2$/TJ. Clearly even with additional emissions associated with shale gas, the emissions from gas would be considerably lower. 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).
- Considering extraction and combustion, carbon emissions from shale are not significantly more than for conventional gas and are lower than for coal. It should be noted however, that it has not been possible to assess fugitive emissions that may be associated with shale extraction.

### 5.2.2 Impacts on total emissions

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

For the UK four scenarios were used; two assuming the amount of shale gas produced correlates with the figure provided in DECC (2010) – 150bcm; and two that assumed double this. For both the 150 and 300 bcm scenarios two different rates of extraction were used; one based on a Hubbert type curve (a bell curve) that is often used as an approximation for resource extraction, which sees rapid increase in production followed by a rapid drop in production; the other based on the kind of growth rates that are predicted for the US by the EIA (e.g. EIA, 2010b). All four 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 284-609 $MTCO_2$. To give this some context this amounts to between 2.0 to 4.3% of the total emissions for the UK 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.

The starting point for the global scenarios is an estimate for the global reserves of shale gas taken from a report by the US National Petroleum Council (NPC, 2007). Three scenarios were then developed assuming that differing proportions of the total resource are actually exploited (10, 20 and 40%). Assuming that 50% of this resource is exploited by 2050, these scenarios give additional cumulative emissions associated with the shale gas of 46-183 $GTCO_2$, resulting in an additional atmospheric concentration of $CO_2$ of 3-11ppmv for the period 2010-2050. 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 increase carbon emissions by potentially considerable amounts.
- Shale gas exploitation could lead to an increase in atmospheric concentration of $CO_2$ of 3 to11ppmv
- Shale gas exploitation could increase the difficulty of attaining set targets for carbon reductions through, for example, substituting for renewable energy.
- Providing that any carbon caps are strictly adhered to then shale gas would make no difference as the source of emissions would be inconsequential.

## 5.3 Environmental impacts of shale gas production

### 5.3.1 Groundwater pollution

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. While awaiting the results of this study New York State has introduced a moratorium on any new wells.

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 as study by ICF International; however, this assessment was based on an analysis of risk from *properly constructed wells.* History tells us that it 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 eliminated.
- The US EPA research should provide important new evidence in understanding this issue.

### 5.3.2 Surface pollution

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.

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

### 5.3.3 Water consumption

Shale gas extraction requires very significant amounts of water. To carry out all fracturing operations on a six well pad takes between 54-174million litres of water, which is equivalent to about 22-69 Olympic size swimming pools of water. 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 1300-5600million litres. This compares with current levels of abstraction by industry (excluding electricity generation) of 905,000million litres. Shale gas exploitation at this level would therefore increase abstraction by up to 0.6%. 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.

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

### 5.3.4 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 500-1500days (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 well head would require between 4300-6500 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. Well pads take up around 1.5-2ha and the well pads will be spaced between1.25-3/$km^2$. As has been mentioned previously, to produce 9bcm of gas annually in the UK over 20 years would require 430-500 well pads and would need to cover an area of 140-400$km^2$. For comparison 400$km^2$ is about equivalent to the Isle of Wight. This level of activity is likely to face considerable opposition at the local level and may well be seen as unacceptable more widely.

- 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, and landscape impacts being exacerbated.

## 5.4 Final comment

It is important to stress that one of the main findings of this work is that there is a real paucity of information on which to base an analysis of how shale gas could impact on 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. If we look at the US, there is little evidence that shale gas is currently, or expected, to substitute for coal. 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, 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 lead to an additional 11ppmv of $CO_2$ over and above expected levels without shale gas – a figure that will rise as and when the additional 50% of shale gas is exploited. It should be stressed that shale gas is not like oil from tar sands. The extraction process does not result in significant emissions itself compared to conventional extraction but 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 were the case, given the radical reduction in emissions required and the need for a decarbonised electricity supply within two decades[42], 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 (and even this would only permit around a 60-80% capture rate). 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

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

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.

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# Annex 1

**Table A.1: Chemical constituents of products used in fracturing fluid (table uses information 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: 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 |