

Life-Cycle Assessment of Greenhouse Gas Emissions from Unconventional Gas in Scotland

Main Report, August 2014

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NOTE: A non-technical summary – Life-cycle Assessment of Greenhouse Gas Emissions from Unconventional Gas in Scotland: Non-Technical Summary can be found on the CXC website at [http://www.climatexchange.org.uk/files/9214/1258/6142/Life-cycle Assessment of Greenhouse Gas Emissions from Unconventional Gas in Scotland Non-Technical Summary.pdf](http://www.climatexchange.org.uk/files/9214/1258/6142/Life-cycle%20Assessment%20of%20Greenhouse%20Gas%20Emissions%20from%20Unconventional%20Gas%20in%20Scotland%20Non-Technical%20Summary.pdf)

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Foreword

In its regulatory guidance on coal bed methane and shale gas published in 2012, SEPA identified that “there is a lack of real field data (on greenhouse gas emissions)” and noted that different assertions exist as to the extent of fugitive emissions of methane during shale gas operations compared, for example, to conventional gas extraction. Until this dispute is resolved by collection and analysis of actual data SEPA will remain neutral but requires operators to make full use of technologies that capture the gas prior to escape in order to reduce fugitive methane emissions.

SEPA requested this research to help them and others involved in regulating unconventional gas developments to understand the potential sources and scale of greenhouse gas emissions. While this study does not collect and analyse new data, it is intended to help to bridge knowledge gaps and to identify where mitigation measures may be necessary.

1. Introduction

This report presents a life-cycle assessment (LCA) of greenhouse gas (GHG) emissions associated with the extraction of two unconventional gas resources currently being considered for development in Scotland: coal bed methane (CBM) and shale gas.

The term ‘unconventional gas’ refers to natural gas obtained from rocks that are not amenable to ‘conventional’ exploitation. In conventional gas production, wells can be expected to produce freely after they access permeable reservoirs. In contrast, much more needs to be done to get unconventional gas to flow from the rocks into wells. Thus Cook et al. (2013) describe unconventional gas resources as distinguished by both the geological properties of the reservoir rock, and the technologies and processes necessary to produce the gas¹. These geological properties make the gas too difficult or uneconomic to extract without technological advances such as horizontal drilling and hydraulic fracturing. Unconventional gas resources include shale gas, tight gas, coal bed methane (CBM) and methane hydrates. These resources are composed predominantly of methane (Cook et al., 2013), there is no difference in the chemical processes of generation of natural gas extracted by conventional and unconventional methods. Underground coal gasification² uses different technologies and does not produce natural in-situ methane.

Advances in technologies for unconventional gas extraction over the past twenty years have led to a boom in unconventional gas exploitation. Currently the USA is the global leader for onshore shale gas development, and the largest CBM operations are in the USA, Canada, China, India and Indonesia. The generation of large volumes of gas in the USA has resulted in very low energy prices and enhanced energy security. These changes have induced debate on energy issues, often described in terms of the ‘energy trilemma’, in which environmental impacts (especially climate change), energy security and energy costs (fuel poverty) need to be reconciled. For shale gas the term ‘energy quadrilemma’ may be more appropriate with socioeconomic impacts forming a fourth element, including societal impacts, risk-benefit inequity, and trust in governance (e.g. Perry, 2012; Jacquet, 2012 and 2014).

Natural gas has less associated greenhouse gas (GHG) emissions when burned for fuel than coal or oil, and flexible operation of gas-fired combined cycle electricity generation is possible without large efficiency or GHG penalties, unlike conventional coal or oil-fired steam turbine generation. Thus in the short term, gas-fired energy generation, using the combined cycle technology, supports a cleaner energy system by enhancing the integration of renewables and displacing coal-fired generation (IEA Energy Technology Perspectives 2014)³. Gas from unconventional resources may therefore play a role in the transition to clean energy generation of the future; with the potential to support the Scottish Government’s ambitions

¹ Unconventional gas is not defined solely by the techniques required for economic extraction since these techniques are also been applied to so-called conventional gas fields to optimise their recovery.

² <http://coal.decc.gov.uk/en/coal/cms/publications/mining/gasification/gasification.aspx>

³ Indeed, the enhanced availability of cheap gas from shale in the USA has led to decreased CO₂ emissions from energy generation. However, it is important to consider gas in the context of global energy markets. In the case of the USA, the unconventional gas boom and subsequent increased gas-fired generation made USA coal cheaply available. Consequently, exports of USA coal surged, driving down global coal prices and leading to increased coal use in Europe (and elsewhere) which is incompatible with global climate change objectives.

for a low carbon economy, and help achieve the emission reduction targets of the Climate Change (Scotland) Act 2009.

However, in order to establish the potential of unconventional gas in the transition to clean energy generation, the environmental implications of developing these resources must first be examined. This report contributes to this process by providing an assessment of the GHG emissions associated with exploiting potential shale gas and CBM resources in Scotland, and identifying potential options for minimising or mitigating these emissions.

1.1 Report Scope and Approach

This report presents a life-cycle assessment (LCA) of the estimated greenhouse gas (GHG) emissions associated with the exploration and extraction of onshore coal bed methane (CBM) and shale gas in Scotland. These two unconventional gas resources have been developed elsewhere in the world and have promising potential in Scotland. In this context, the LCA carried out refers to the aggregate quantity of GHG emissions, including direct emissions and significant indirect emissions, from exploration to the point of production of a fuel product (“cradle to gate”) - but not the distribution and use of that fuel. Figure 1 shows the different steps in the production and use of unconventional gas, and highlights the boundaries of our LCA. The mass values for all GHGs associated with each stage of the LCA have been adjusted to account for their relative global warming potential (GWP) relative to CO₂ using the most up-to-date figures from the IPCC (see section 4.1.1).

Within the scope of this LCA for unconventional gas, GHG emissions could be associated with a range of activities:

- **Direct GHG emissions** - from the exploration and production activities, which would include the direct release of produced gas to atmosphere (from controlled venting or venting of fugitive emissions, i.e. leakage); the combustion of produced gas as part of controlled flaring or to power onsite machinery; and combustion of other fuels to power onsite machinery or to transport equipment and materials to and from the site.
- **Indirect GHG emissions** - that are a consequence of the exploration and production activities and gas processing, for example removal of peat to build well pads, electricity consumption, or the emissions embedded in the sourcing of purchased materials and fuels, and outsourced activities (such as waste treatment and disposal).

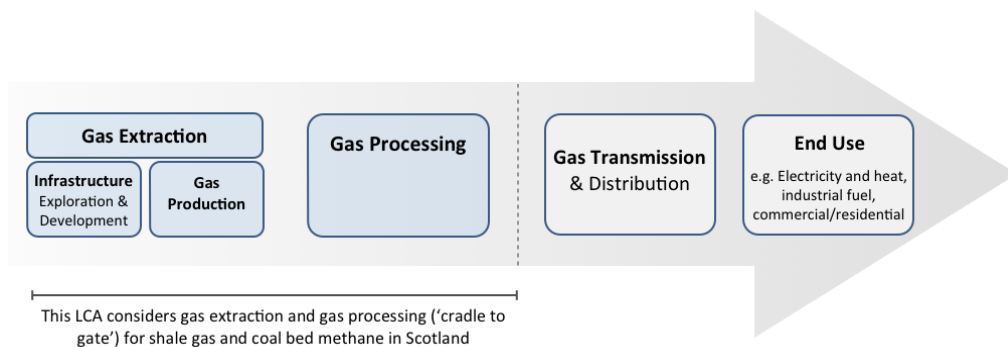


Figure 1. The boundaries of the ‘cradle to gate’ life-cycle assessment. The stages considered in this report (Gas Extraction and Gas Processing) are shaded blue on the left hand side of the figure.

Given the infancy of the modern unconventional gas industry in Scotland (and the UK) almost all of the published evidence for GHG emissions from shale gas and CBM operations refer to international operations, mainly in North America and Australia. Several aspects of unconventional gas extraction in Scotland (and the UK) would differ from these international operations due to:

- a) *Country-specific factors*: for example, regulation (influenced by societal factors), geological and geographical setting, infrastructure and procurement, and public acceptance.
- b) *Technological factors*: advances in, and adoption of, Best Available Techniques (BAT) mean that some operational practices that were considered realistic for previous LCAs are now out-dated, or were not adopted in the countries for which LCAs have been completed. Non-adoption of BAT would not be an option in Scotland due to the stringency of the regulatory regime (see section 2.6).

As such, we review and consider the relevance of existing published evidence in the context of operations in Scotland based on current knowledge. We consulted industry, regulatory and academic expertise⁴ on geological, technological and planning and policy aspects to inform our report.

This desk-based study provides a useful context and starting point to gauge the potential GHG emissions associated with each stage of shale gas and CBM exploitation in Scotland. The framework of the LCA, including the assumptions, and the information sources, are outlined in section 3, with the key inputs for our LCA detailed in section 4. However there are many unknown factors that must be defined, or refined, before the GHG estimates reported could be confidently applied. In particular the embryonic nature of the unconventional gas industry in the UK, which is still far from a commercial operation, means that the calculations are based on assumptions from other countries that may not be wholly applicable for unconventional gas resource exploitation in Scotland. Where relevant, elements of importance beyond the scope of this report are discussed, and in section 6 we highlight key areas for future refinement, including uncertainty and sensitivity analysis, of the life-cycle assessment.

The work in this report was commissioned in December 2013 and sent out for peer review in early June 2014. Therefore no papers or reports published after the start of June 2014 are considered in the report with the exception of the BGS detailed geological investigation into shale gas resources in the Central belt (Monaghan 2014, published 30/6/2014), which provided information to constrain some of our key assumptions.

This cradle-to-gate LCA conforms to ISO14044. The functional unit is MJ of energy.

1.2 Context with respect to existing LCAs

Many previous LCA studies have been published for unconventional gas exploitation in the US, and Australia, and have been adapted to understand the potential GHG emissions from

⁴ The companies and individuals contacted are detailed in the text and are listed in the acknowledgements.

unconventional gas exploitation in Europe. These studies span the 20 years of experience of both developing the technology for drilling and fracturing horizontal wells and exploiting unconventional oil and gas resources. During this time environmental and safety regulations, operating practices, and best available technology have matured so that several of the assumptions made for these LCAs, reflect past practice and so are not applicable today even for the countries for which they were made.

The LCA presented here is for potential operations in Scotland, which is a new province for unconventional gas exploration. Any future Scottish unconventional gas developments can draw on a pre-existing oil and gas industry centred in the North Sea, which has a well-developed research and engineering infrastructure and which deploys the latest technology in a challenging environment. This industry is well connected with the technology used in other unconventional gas provinces because many companies operate internationally. In addition, Scotland, and the UK, have a well-developed environmental, health and safety culture that has created a high-performance operating environment in the North Sea and has enabled oil and gas field development to be undertaken with minimal negative impact in environmentally and economically sensitive areas (such as the Wytch Farm oil field in Dorset). This legacy will facilitate the application of the latest technology and best operating practice for gas exploration and extraction activities onshore Scotland.

For these reasons, this LCA draws on the previous published studies where applicable for operations that are similar (such as drilling, water processing, materials and transport and site preparation) but will defer to new technology and best operating practices that are applicable today for well testing, hydraulic fracturing and production clean-up. Previously published LCA studies were performed for unconventional gas exploration in provinces where the geology and reservoir properties are known and therefore the borehole design (vertical and horizontal well length, pipe size and weight, fracturing pressures and likely volumes of produced gas) are well constrained. Mackay and Stone (2013) performed a meta-analysis of previously published LCAs to place them into the UK context. Here we adapt the work of Mackay and Stone (2013) and others to produce an LCA that is relevant to potential unconventional gas plays in Scotland. The adaptations are based on a desk study of what is known of the Scottish geology, regulations, infrastructure, and social-political context.

1.3 Report Structure

The report is structured as follows:

- [Section 2](#) explains what shale gas and CBM are, where they could be found in Scotland, and their key attributes with respect to potential exploration and production.
- [Section 3](#) describes and discusses the assumptions of the LCA presented in the context of Scottish geology, geography, infrastructure, and regulatory framework, comparing these as appropriate to global practices. These assumptions are highlighted in the context of stages in the LCA workflow of exploration through production to decommissioning.
- [Section 4](#) presents the key inputs into our LCA of GHG emissions, in the context of our Scottish Scenario.
- [Section 5](#) is an analysis of the LCA results and a comparison of the emissions with other natural gas resources.

- [Section 6](#) presents some initial conclusions and recommendations for further refinement of the LCA.

2. Unconventional Gas Resources in Scotland

2.1 Shale Gas

2.1.1 What is shale gas?

Shale gas refers to natural gas trapped within very fine-grained low permeability sediments, such as shales, mudstones and silty mudstones. These were typically deposited in aquatic environments (lakes and seas) and are rich in organic material such as the remains of plants, animals and micro-organisms. The organic matter contains organic chemical compounds (kerogens) that could transform into hydrocarbons when the rock is heated and pressurised, first transforming to oil and then to gas as temperature increases (the rocks become more thermally mature). The gas then remains trapped within the impermeable shale rocks.

The presence of shale formations is not the only factor in determining where shale gas resources might occur in Scotland. The shale rocks need to have been buried deep enough and long enough to have been heated and pressured sufficiently to convert the organic matter to gas. Therefore, determining if a given source rock is likely to be mature for gas requires modelling its burial history. A further element for consideration in Scotland is the presence of volcanic igneous rocks, which may have created local thermal anomalies that brought otherwise immature rocks to maturity (Monaghan 2014).

2.1.2 How is shale gas extracted?

Shale gas is produced by drilling vertically into, and then horizontally along layers of shale. Because the gas is trapped within the pore space of the rock, the rock needs to be fractured to provide pathways for the gas to escape. The fractures create permeability in the rocks. This requires a technique called 'hydraulic fracturing' (fracking), whereby fluids such as water are pumped into horizontal wells through the shales at pressures high enough to induce fractures in the rock. These hydraulic fractures are 'propped' open by proppant materials, such as sand, which are pumped into the well as particles suspended in the fracture fluid. Post-fracturing, the pressure at the well head is dropped by pumping any water from the borehole (clean-up) and the gas flows into the 'propped' fractures and on into the well bore where it is extracted along with the fracture fluids. The produced gas is collected at the wellhead, processed if necessary, and then either combusted to generate electricity, used for petrochemical feedstock or fed into the national gas grid. The process of shale gas extraction is described in more detail in section 2.4, table 1.

2.1.3 Where is the potential shale gas in Scotland?

The rocks with the highest potential for recoverable shale gas lie across the Central Belt of Scotland (DECC 2011, Monaghan 2014). As this is an area with a history of hydrocarbon extraction from shales, as well as coal and other mining, there is a relatively rich set of subsurface geological data to draw conclusions from including: mine plans, borehole and

geophysical data. Other areas with potential unconventional gas resources are the Orcadian Basin of Caithness, Orkney and Shetland, and the Jurassic rocks of the Inner Hebrides and Moray Firth, both of which have proven petroleum resources, some of which is already extracted offshore. Though there is no current commercial onshore production (in 2014), there is currently one onshore licenced area on the northern side of the Moray Firth in Caithness (see section 2.3, figure 3).

The sub-surface extent of the rock formations of interest and their maximum depth is constrained by a mixture of surface outcrop, well and seismic data. For the central belt of Scotland this information is reported and discussed in Underhill et al. (2008) and Monaghan (2013). Monaghan (2013) created 3D sub-surface models from available data to show the predicted depth and extent of the top of the Strathclyde Group of rocks (the main rocks of interest for unconventional gas) across the Central Belt (figure 2). The combination of the lateral extent and depth of the formations allows an initial assessment to be made of potential gas-prone areas. The most up-to-date report in Scottish shale gas resources by Monaghan (2014) conducts a detailed survey of data from the Central Belt to determine gas-in-place resource estimates of 49.4 - 134.6 tcf (1.4 – 3.81 tcm).

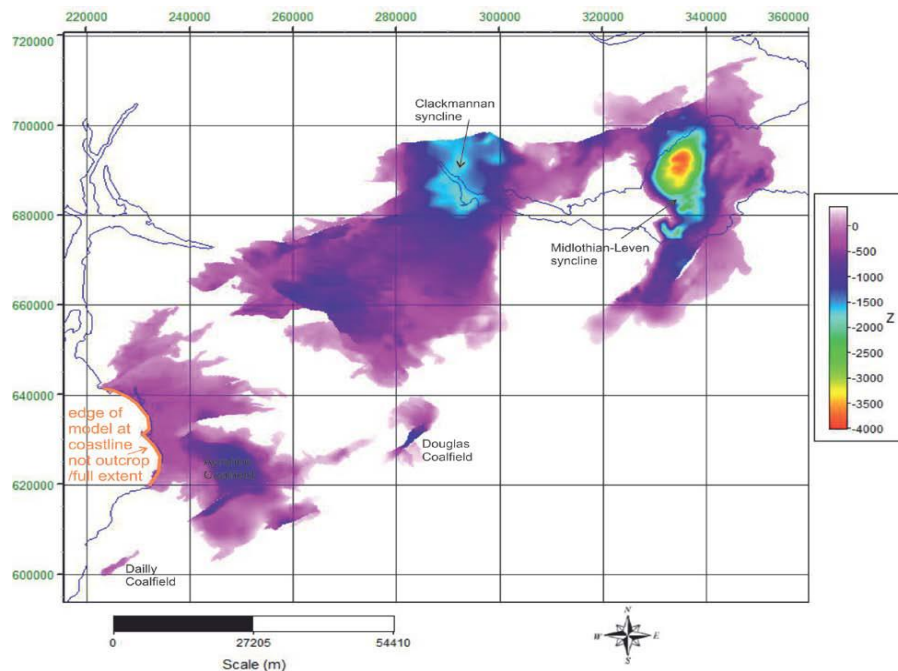


Figure 2. Depth map to the top of the Strathclyde Group (which includes the West Lothian Oil Shale Formation) from Monaghan (2013). The Strathclyde Group is the rock formation most likely to contain rock units of interest for shale gas and CBM. Depths (Z on the colour-scale) are in meters. The coast of Scotland is outlined in black. The locations of two major folds are annotated – the Midlothian-Leven syncline in the East and the Clackmannan syncline in the West, note that these correspond to locations where rocks have been buried to greater depths, and are therefore likely to be more mature for gas. No equivalently detailed map exists for other potential shale gas or CBM areas of Scotland.

2.1.4 Comparison to other potential shale gas areas in the UK

As of 2014 there is no shale gas being extracted in Scotland. Given the geological context of the shale gas potential in Scotland it is worth making a few comments with regard to comparisons that may be made to other potential shale gas areas in the UK and abroad. Various experts have noted that the UK shale gas-hosting rock formations are different to

those in North America. Indeed, every shale gas formation is unique and poses distinct exploration and production challenges. Notable contrasts between the geology of the Central Belt of Scotland and other potential shale gas sites in the UK include:

- Lake deposits – with many inter-bedded layers of sands in between the shales. This is distinctly different from the thick marine shale sequences in the Bowland shale of Northern England, and may have consequences for the production strategy for the gas.
- Non-marine formation – for which organic matter tends to form gas with associated heavy hydrocarbons (wet gas), which would have consequences for the processing of the gas and the economic feasibility of the resource. This is very unusual. The other potential UK source rocks are marine, and only one of the major shale basins in the USA contains this type of organic matter (the Green River Formation).
- Potential for former volcanic activity to have caused local heating and therefore localised highly productive areas (sweet spots), in otherwise under-mature shales.

These differences have implications for the assumptions that go into an LCA as discussed in section 4.

2.2 Coal Bed Methane

2.2.1 What is coal bed methane?

Coal bed methane (CBM) (also called Coal Seam Gas in Australia) refers to natural gas adsorbed within coal seams. This is different from Coal Mine Methane (CMM), which is natural gas extraction from worked coal seams. Natural gas extraction by CMM is currently operational onshore at several sites in England, but CMM is not considered within this life cycle assessment. Methane is also often extracted in traditional coal mining to reduce explosion hazards.

Coal is a rock formed from the burial, compaction and heating of layers of ancient plant matter (accumulated in swamps) that have been solidified ('lithified') through burial resulting in compaction and heating. Natural gas forms from the organic matter as it transforms into coal but remains trapped in the coal seam by several mechanisms, including adsorption onto organic particles in the coal, dissolution in the formation waters, and/or held within small fractures, called cleats, within the coal.

2.2.2 How is coal bed methane extracted?

Coal bed methane is produced by drilling vertically into and then horizontally along coal seams. Depending on the geology of the coal seam, there are two options for CBM extraction:

- If the coal seams are thin, shallow, or already fractured there is no need to hydraulically fracture the seam. Gas is extracted by 'dewatering' the seam. The coal seam is drained by pumping out the formation water, which allows the methane to flow from the coal bed. It is not possible to subsequently hydraulically fracture coal from a well that has been designed for dewatering, without first refilling cleats with water and re-designing the well completion.

- If the coal seams are thicker, deeper, or less fractured, then hydraulic fracturing may be required to release the gas. This requires a different well design and more horizontal wells to be drilled. Hydraulically fracturing coal seams requires less pressure than that required for shale gas, and therefore less water. In CBM, a foam is often more effective as a fracturing fluid and reduces the volumes of water used in the process.

The produced gas is collected at the surface, processed if necessary, and then either combusted to generate electricity on site, or fed into the national gas grid.

The following describes extraction operations by Dart Energy⁵, and has been adapted from the Dart Energy Scotland website⁶.

- Production wells are drilled using two wells - a vertical well from which the gas is produced and a horizontal well that targets the coal seams.
- Firstly, a vertical well is drilled to approximately 100m below the lowest targeted coal seam. This operation takes around 14 days to complete.
- Then a second 'surface-to-inseam' (SIS) well is drilled approximately 400m away. The rig first drills vertically towards the targeted coal seams then, when the well reaches the coal seam, the well trajectory is turned to drill horizontally within the coal towards the first well. The SIS well intersects the vertical well, then continues drilling horizontally along the coal seam for up to 1000m. The 6-inch (15.24 cm) wide drill bit is steered using electro-magnetic technology transmitted wirelessly to an engineer on the surface. This operation takes approximately 90 days to complete.
- Additional horizontal wells are then drilled, branching off from the initial SIS wellbore, intersecting the vertical production well, and following along target coal seams at different depths.
- At the bottom of the vertical well there is a submersible pump to produce the gas and water.

Potential CBM resources could be found at depths as shallow as 300m but are typically around 800 - 1000m deep. At even greater depths the gas becomes more difficult and expensive to extract.

2.2.3 Where is the potential CBM in Scotland?

The potential CBM resource in Scotland mostly covers the same area as the potential shale gas resource, within the Central Belt of Scotland (figure 2). The coal-bearing strata that are being considered for CBM are generally younger (higher in the rock sequence) than the formations of interest for shale-gas. CBM resources in the Central Belt are shallow, in the top 1000m of rock, than the shale gas resource. Around the Firth of Forth the rock units of interest (the Limestone Coal formation and Scottish Coal Measure group) are buried to 3 km

⁵ Now wholly owned by Igas, May 2014.

⁶ <http://www.dartenergyscotland.co.uk/>

and 2 km respectively (Monaghan 2013). There are also potential CBM resources near Canonbie in Dumfries and Galloway.

The British Geological Survey published a report in 2004 outlining the UK’s coal resources that have the potential for exploitation with ‘new technologies’, including an overview of the Scottish coal resource (Jones et al., 2004). The UK Government’s Department of Energy and Climate Change (DECC) published a review in 2011 of the CBM resources of Britain’s onshore basins (DECC, 2011).

2.2.4 Comparison to other potential CBM areas in the UK

Scotland is currently leading the way in the exploitation of CBM in the UK, therefore comparison to other sites in the UK is not particularly informative.

2.3 Development Status of Unconventional Gas in Scotland

As of 2014, there are six Petroleum Exploration and Development Licences (PEDL) held in Scotland, covering nine local authority areas (figure 3). Of these the majority are held by Dart Energy, who have three PEDL in the greater Central Belt area, and another near Canonbie in Dumfries and Galloway. The PEDL license allows a company to pursue a range of hydrocarbon exploration activities (subject to necessary permits and regulations), including exploration and development of shale gas and CBM.

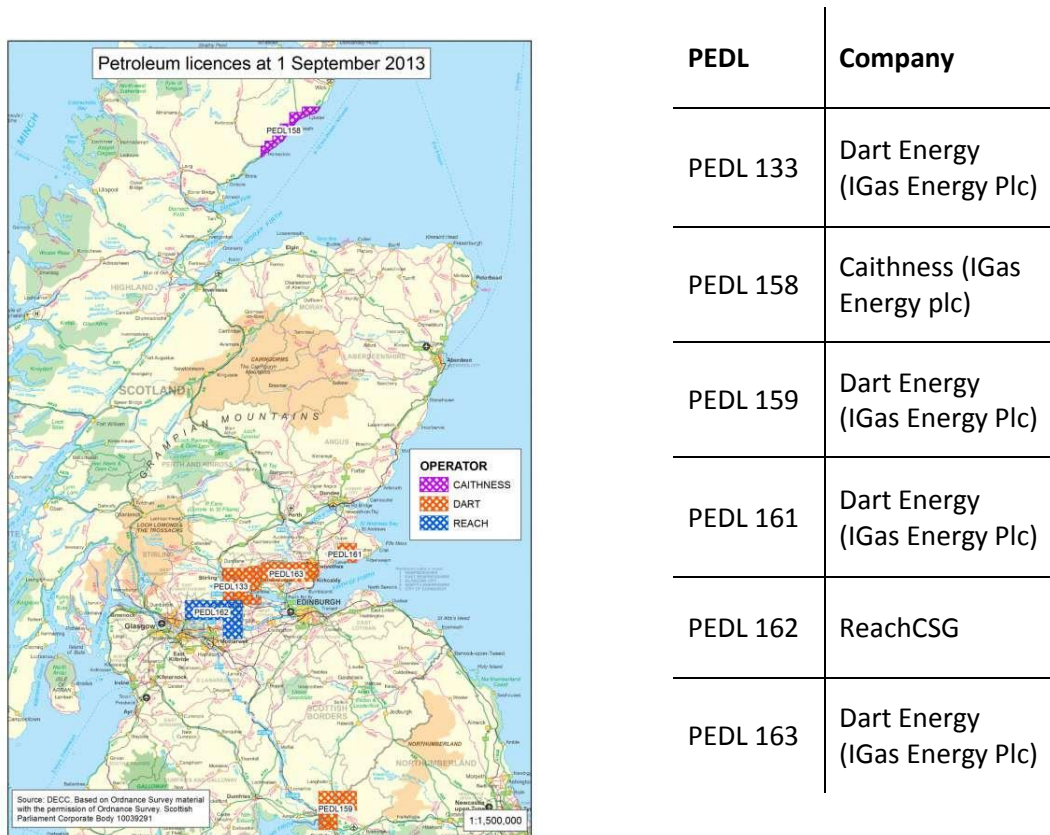


Figure 3. Petroleum Exploration and Development Licences (PEDL) for unconventional gas in Scotland (as of Sept 2013). Data and image from SPICE briefing document (Reid, 2013). PEDLs cover all hydrocarbon activities, so it is

not appropriate to equate any of these six PEDLs simply as being for CBM or shale gas. As of May 2014 – Dart Energy is owned by IGas Energy plc.

PEDL licenses are awarded by DECC in Licensing Rounds which usually take place every few years. In the last License Round in 2008, 55 new licenses were awarded across the UK. DECC launched the 14th onshore oil and gas licensing round in July 2014 (DECC, Strategic Environmental Assessment, 2013a). Figure 4 shows the areas that are under consideration for licences in the 14th onshore oil and gas licensing round, which include licence blocks across the Central Belt of Scotland⁷.

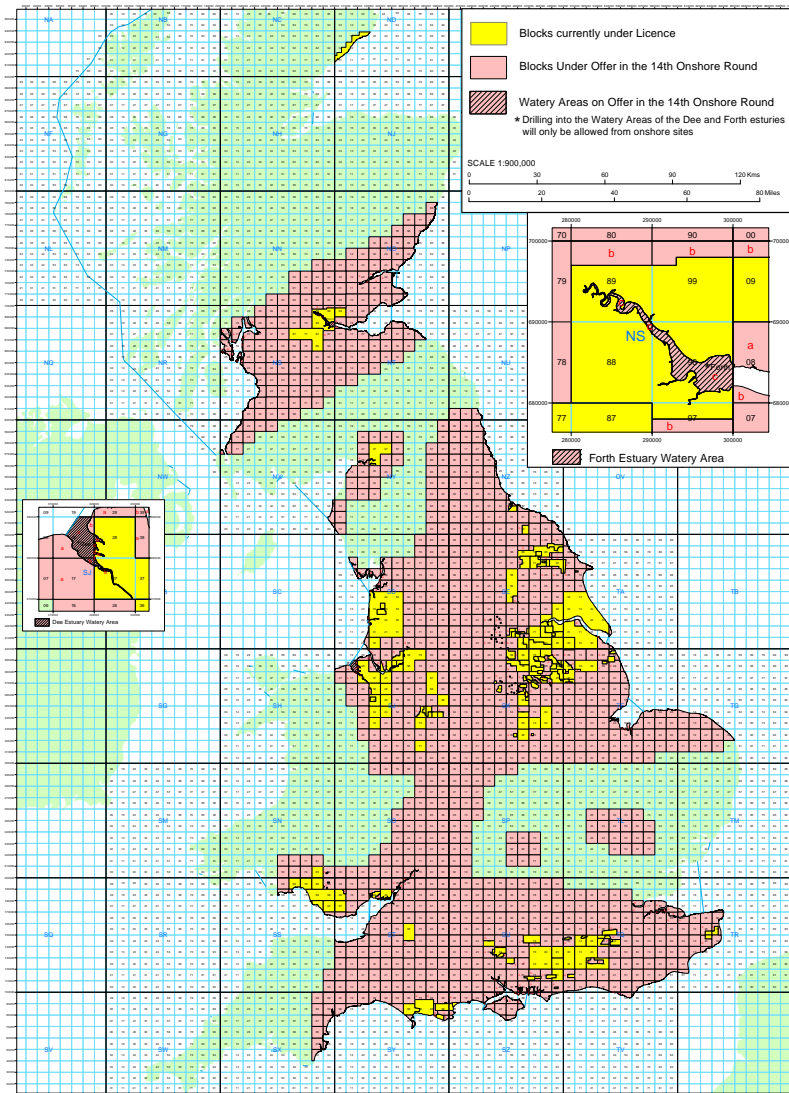


Figure 4. Existing licenses to explore for oil and gas in Great Britain (yellow) and areas under consideration for new licenses as part of the 14th onshore licensing round (pink). Adapted from DECC.

⁷ <https://www.gov.uk/oil-and-gas-licensing-rounds#th-landward-licensing-round> - Accessed July 2014

2.4 Stages of Unconventional Gas Exploration and Development

There are several progressive stages of resource development for unconventional gas, which apply to both shale gas and CBM. The main stages and associated activities are outlined in table 1, modified from Forster and Perks (2012). Each stage of the resource development from initial exploration to site abandonment and reclamation would produce associated GHG emissions. Understanding the breakdown of emissions at each stage helps to understand where the maximum benefits could be gained in terms of GHG mitigation. These stages of exploration and development have been used to inform the inputs into this LCA, and to structure this report.

	Stage	Example activities and potential GHG emission sources
1	Non-intrusive exploration	<ul style="list-style-type: none"> • Securing of necessary development and operation permits. • Site identification, selection, characterisation • Exploration surveys (seismic etc)
2	Intrusive exploration	<ul style="list-style-type: none"> • Establishing baseline conditions (geochemical, microseismic) • Land preparation (land use change) • Access road construction • Equipment transportation (including water) • Exploration well pad construction
3	Appraisal	<ul style="list-style-type: none"> • Exploration drilling: vertical well design and construction. • Appraisal drilling: horizontal well design and construction. • Logging, and well testing • Hydraulic fracturing (including flaring) for shale gas. • Well completion • Dewatering (for CBM) • Flow testing, and gas (& oil) production (and processing) • Disposal of construction and drilling wastes, and water treatment.
4	Production development	<ul style="list-style-type: none"> • Monitoring baseline conditions (e.g. geochemical, microseismic) • Land preparation (land use change) • Construction of road and pipeline connections • Equipment transportation • Development well pad and facility construction and installation. • Well design construction and completion • Disposal of construction and drilling wastes • Water treatment (or recycling)
5	Production operation and maintenance	<ul style="list-style-type: none"> • Gas/oil production and processing • Well work-overs and integrity testing • Environmental monitoring
6	Well plugging and abandonment	<ul style="list-style-type: none"> • Well plugging and testing • Site equipment removal • Pre-relinquishment survey and inspection • Site restoration and reclamation. • Environmental monitoring




Table 1. Stages of the life cycle for unconventional gas exploration and production, modified from Forster and Perks (2012). Example activities that have potential GHG emissions at each stage of the life cycle are annotated. Well plugging and abandonment (stage 6) would occur after exploration or appraisal, if the outcome of the exploration stage shows no resource or a non-economic resource.

2.5 Scottish Geology: Implications for the LCA

The geological factor that has greatest effect on the emissions associated with drilling is the depth to the target rock horizon. Depth determines the length of the vertical borehole, and so affects the quantity of borehole construction materials, drilling fluids, cement, and drilling waste, all of which have embedded carbon. The energy and time required for drilling (and fracturing) deeper rocks are also greater.

Until more geological information is established by exploratory drilling we can only estimate potential borehole depths from existing information.

Other geological factors can affect production strategies and therefore have an impact on the potential greenhouse gas emissions. Such factors include:

- 1) *In situ* stress and rock strength. These affect the ease with which rocks could be hydraulically fractured. *In situ* stress would also control the permeability of natural fractures in shale and coal. The stress and rock strength of shale rocks in Scotland are poorly documented and are likely to be variable. The strength of the rock has implications for the quantities of materials required for fracturing the rock as well as the pressures required.
- 2) The thickness of the rock layers influences the volume of gas in a target layer, and therefore how economic it is to produce, and so affect the production strategy. For shale gas, the shale thickness influences the way that fractures propagate and so would affect the design of the fracturing strategy. The coal seam thickness in Scotland is variable, but the most prospective shales in Scotland are thinner than the Bowland Shale and some shales in the USA.
- 3) The degree of geological complexity (structural and stratigraphic) would affect the level of detail required for site characterization surveys, and the type and amount of well logs used in appraisal boreholes. In general, Scottish target rock formations have a higher degree of structural complexity than many of those in the USA.
- 4) The maturity and types of organic material in the shales would determine the hydrocarbon type and composition that could be produced and the degree of processing required to remove Natural Gas Liquids (NGL), like propane and butane, sour gases like carbon dioxide and hydrogen sulphide, and other contaminants such as salts and mercury.

All of these geological factors would vary from site to site. Therefore, this LCA uses a single Scottish scenario, based on the geology and infrastructure of the Scottish Central Belt to which the LCA is compared. Section 3 outlines this Scottish Scenario.

The possibility of direct leakage to the atmosphere from individual hydraulic fractures propagating to the surface is vanishingly small. Davies et al. (2012) collated data on fracture heights from the US and showed that the probability of a hydraulic fracture extending vertically for over 350m is 1%. In their estimate of the Scottish shale gas resource, the BGS considered a minimum depth of resource to be 805m based on a depth cutoff of 500m plus an additional 305m to account for the likely vertical extent of hydraulic fracture heights Monaghan (2013).

2.6 Scottish Regulation of Unconventional Gas

Previous LCA reports from the USA and Australia have been based on assumptions that would not be relevant in Scotland, because the regulations are different. DECC in their response to the MacKay and Stone report (DECC 2014) accepted all eight recommendations from the report. Particularly important for emissions reduction is the acceptance that Best Available Techniques (BAT) including green completions of boreholes, designed to minimise any escape of gas (fugitive emissions) from the borehole, are to be adopted in the UK. Nevertheless, there are occasions when venting or flaring may have to take place for limited periods due to health and safety considerations. Venting and flaring of gas is regulated by DECC under license conditions or under powers in the Energy Act (1976), and these mean in practice that operators must use green completion techniques where this is possible, as regulations bind operators to minimise emissions.

Regulations and permits/permissions for unconventional gas development in the UK involve several regulators. DECC issue Petroleum Exploration and Development Licenses (PEDLs). The Local Planning Authority is responsible for granting planning permission (under the Town and Country Planning (Scotland) Act 1997) for surface works associated with borehole construction, fracturing operations and wellhead development. As part of this, operators may need to submit a waste management and an environmental impact assessment. The Scottish Environment Protection Agency (SEPA) is a statutory consultee on planning applications. Under the Climate Change (Scotland) Act (2009) SEPA has a duty to consider how Scotland could reduce the greenhouse gas emissions from regulated industry and businesses.

The Health and Safety Executive (HSE), through The Borehole Sites and Operations Regulations (1995), place a duty on operators to ensure that no operational well modifications, that would involve a risk of accidental release of fluids from the well, are carried out unless they have notified the HSE at least 21 days in advance. The HSE could serve improvement notice requiring modifications to the plan if they are not satisfied with the well design and changes must be made before drilling operations could commence. Finally, any operation that intersects, disturbs or enters coal seams must have prior written permission from the Coal Authority.

The permitting and regulation pathway for shale gas and coal bed methane in Scotland is shown in SEPA's guidelines for unconventional gas (2012) and DECC's Regulatory Roadmap (DECC 2013b). SEPA will regulate abstractions, impoundments, engineering works and point source discharges through CAR and PPC also detailed in SEPA (2012).

2.7 Scottish Regulations: Implications for the LCA

SEPA believes that current regulations provide a high level of protection against the potential environmental impacts of unconventional gas exploitation (SEPA, 2012). Although the current regulatory environment is complex (there are various regulators involved and many different regulatory powers that may be invoked), the legislative powers to protect against greenhouse gas emissions associated with unconventional gas are in place. Regulations cover activities, not individual industries, so the same degree of regulatory complexity exists for other industries. DECC (2014) has also committed to developing research into improved extraction

techniques and greenhouse gas mitigation technologies. In each of the LCA stages outlined in section 3, we give details of the relevant legislation.

3. Stages of Exploration and Production of Unconventional Gas: The Scottish Scenario

This section details the cradle-to-gate life cycle activities for shale gas and CBM in Scotland (see figure 1). We outline important country-specific and technological factors or uncertainties that would influence these activities, and their implications for life cycle emissions.

Because there has been no detailed exploration for unconventional gas in Scotland, geological factors such as depth to the target formation, formation thickness and stress field are poorly defined. There are significant uncertainties in the geology at depth even within the Central Belt where the BGS have published their detailed survey (Monaghan 2014). Because there are even less data outside the Central Belt, the geological uncertainties are much higher for other areas of Scotland. Infrastructure, such as road networks and water sources also vary. We have therefore defined a ‘Scottish Scenario’ based on the geology and infrastructure of the Central Belt of Scotland. The Central Belt of Scotland was chosen for two reasons. Firstly, because of its long history of hydrocarbon and coal production and secondly there is evidence (well tests, core, log data) of significant extractable hydrocarbons; therefore it is the region most demonstrably likely to support commercial unconventional gas production. Secondly, the majority of license areas that were included in the Strategic Environmental Assessment (SEA) for the 14th round of onshore licensing, which opened in July 2014, are in the Central Belt with a few in Dumfries and Galloway and none in northern Scotland (figure 4).

The BGS and the Department of Energy and Climate Change published a detailed study in 2014 of the shale gas rocks in the Central Belt of Scotland, to directly inform those interested in exploiting the potential resource. The main gas-bearing rock formations that the BGS report highlights as being prospective have a maximum depth of 4 km, but are mostly around 2 km deep (see figure 66 of Monaghan 2014).

In the following six sections (3.1-3.6), one for each stage shown in figure 5, the common assumptions of published LCAs are discussed, and put into the context of Scotland.



Figure 5. Schematic workflow for the exploration and production of unconventional gas. See table 1 for a breakdown of the activities at each stage, and sections 3.1 – 3.6 on the main assumptions made at each stage for the LCA.

It is worth noting the differences in infrastructure requirements between the key stages of Exploration and Appraisal and Production Development for unconventional gas. These infrastructure requirements, outlined in table 2 below, have implications for the associated GHG emissions at each stage.

Table 2. Summary of the key likely infrastructure differences between the Exploration and Appraisal stages and the Production Development stage.

Factor	Exploration/Appraisal	Production Development
Number of wells	Single well	Multi-well, stacked multi-lateral pad
Water transport to site	Tanker Truck (or temporary pipeline)	Pipeline/ Tanker Truck
Waste water treatment and transport	On site (tanker truck/pipeline)	Onsite (pipeline) Off site (pipeline)
Gas processing	Onsite	Offsite (pipeline)
Gas Use	Generator on site	National Gas Grid

3.1 Stage 1: Non-Intrusive Exploration

3.1.1 Site identification, selection and characterisation

A desk-based spatial exploration is first undertaken to determine the likely geological units in the subsurface. Existing information (e.g. from previous boreholes or surveys, mines and geological models) is used, normally at the scale of the regional geology (kilometre-scale). In some cases new non-invasive surveys may be carried out to locate subsurface geological structures (e.g. seismic⁸ and micro-seismic surveys). This information is used to decide whether it is of economic interest to drill an exploration borehole and where best to locate it.

3.1.2 Baseline Monitoring and Permits

Baseline environmental monitoring prior to exploration drilling is required by regulations such as The Water Environment (Controlled Activities) (Scotland) Regulations 2011 (CAR). The monitoring strategy would be informed by a site-specific risk assessment and should be sufficient to characterise the natural variability of the groundwater system.

As a minimum under CAR, for boreholes with depths greater than 200m:

- Boreholes that would be fully cased and cemented require 3 months water environment monitoring prior to commencement of drilling.
- Boreholes that would not be fully cased and cemented and are intended to be left open for more than 7 days require 6 months water environment monitoring prior to commencement of drilling. In addition, uncased and un-cemented wells must be decommissioned within 6 months after completing drilling.

⁸ The internal geological features of thick shale rich rock units are difficult to image by 3D seismic techniques, though the top and bottom of thick units could be defined.

- Boreholes that would abstract groundwater require 12 months water environment monitoring prior to the commencement of groundwater abstraction (such as to dewater coal seams, see section 4.3).

The Local Authority may require an Initial Site Condition Report. This includes a site report and a baseline report in which any soil and groundwater contamination at the site are described and the potential for any contamination by the exploration activities are outlined. For gas exploration activities this baseline report would likely include geochemical information about the background soil methane conditions, as well as air and noise conditions.

3.2 Stages 2 and 3: Intrusive Exploration and Appraisal

The intrusive exploration stage includes physical sub-surface exploration: the drilling of boreholes and their associated infrastructure. Exploration drilling for unconventional gas may involve several stages, but could be thought of as consisting of two main components:

- a) *Drilling of an exploration borehole.* A vertical well is normally drilled first to establish the subsurface rock strata, the hydrocarbon content of formations (by taking core samples, or analysing drill cuttings), any natural fracture information, stress information and performing some open-hole borehole tests⁹.
- b) *Appraisal of the flow properties of the rocks cut by the borehole.* The vertical exploration borehole and perhaps horizontal off-shoots could be subjected to flow tests to determine if gas is present and could be extracted commercially. The orientation and magnitude of the in-situ stress may be assessed by a 'mini-frac' test. Hydraulic fracturing tests for shale gas, or dewatering tests for CBM may be performed.

Vertical drilling for exploration boreholes would have similar GHG emissions to vertical drilling for an appraisal or full production well. GHG emissions associated with the stages of drilling, cementing, well completion and waste disposal are outlined in section 4.

3.2.1 Pad construction

To prepare the site for drilling a well pad is first constructed. This involves the following:

- The top soil is removed to reveal the subsoil, and the excavated surfaces are compacted (e.g. using a vibrating roller or vibrating plate). In the case of peatland, the peat soils must be removed to bedrock or suitable load bearing substrate. Much of Scotland's peat overlies glacial till, which usually has as good load-bearing properties as bedrock. Bulldozers and excavating equipment are required.
- A concrete blinding pad is prepared. The British Standard for water-retaining structures requires that at least 75mm of blinding concrete is first placed directly over the

⁹ Open hole borehole tests may include down-well logs for resistivity, spectral Gamma ray, density, neutron, multi-pole sonic, electrical image log, packer formation tests and fluid sampling.

prepared surface¹⁰ to level it. Structural concrete is then poured onto a polythene slip membrane placed on top of the blinding concrete.

- Reinforced masonry bunds must be built to protect inundation from flood events or to prevent chemical spillage from polluting the surrounds. The bunding requirements would be site-specific. SEPA requires oil storage tanks to have bunding up to 3.5 metres wide and 1.2 metres high, built from reinforced block work walls or reinforced brickwork and rendered with impermeable coating¹¹.
- High security protective fencing and gates would likely be erected around the site to protect against potential damage from trespass. In addition, the site would have sound walls (baffles) constructed to keep noise pollution to a minimum¹².

The well pad must be large enough to host facilities for storing water and other materials required for drilling, as well as to host the drilling infrastructure. The site would also require facilities for workers such as port-a-cabins and toilets, and a power supply, likely to be a diesel generator in the exploration stage, though gas powered generators (which are quieter) are an option.

For exploration drilling the area cleared for site preparation would be smaller than for a borehole drilled for subsequent appraisal and/or development (see section 3.2.3).

3.2.2 Construction of access roads

At the exploration stage, any new access roads built would be designed to be temporary and may include some extension or resurfacing of existing roads to make them suitable for use by heavy trucks. Construction of new access roads to the site would require vegetation clearance and would likely be made with locally-derived rubble fill or of floating construction in the case of peatlands. The length of these access roads would depend on the road density at each location.

For the Central Belt of Scotland, any new roads are likely to be much smaller in length compared to many areas in the USA and Australia. The values for GHG emissions from road construction would be correspondingly lower than those calculated for LCAs in the USA. Most LCAs do not consider emissions from access road construction at the exploration stage but in any case at the following Production Development stage these tend to be very small (Forster and Perks, 2012), see section 3.3.1.

3.2.3 Land use change

Land use change as a result of the removal of vegetation for well pad preparation, access road construction, and pipeline connections, could lead to GHG emissions. The extent of the emissions associated is dependent on the area cleared and the type of vegetation cover. Most

¹⁰ Hardcore concrete could be used to level the ground surface where compaction is such that the infrastructure could be supported without any long-term adverse effect.

¹¹ CIRIA Report 163 "Construction of bunds for oil storage tanks" Pollution Prevention Guidelines (PPG) : Notes : Masonry Bunds

¹² From the edge of the well site, operations must not exceed 55dB in the day-time and 42dB at night.
<http://www.ukoog.org.uk/knowledge-base/community-kb/what-will-onshore-oil-and-gas-exploration-mean-for-me>

vegetation types sequester carbon, with the exception of croplands because crop vegetation would be consumed or incorporated in the soil and decomposed each year.

Many of Scotland's soils are characterised by having high carbon content, for example, blanket peat covers over 23% of Scotland's land area (fig 6a). The organic (carbon) content of peatland is very high and varies from anything above 20-25% organic matter for peaty soil types (as opposed to mineral soil), to more than 50-60% for peat (Bruneau and Johnson, 2014). The typical carbon content of UK peat is 52% carbon (dry weight) (Bruneau and Johnson, 2014), and the average peat depth (thickness) in Scotland ranges between 0.5 - 3 meters, though depths can reach up to 8 meters. The excavation of peat around the pad and roads and the associated drainage causes the carbon in the exposed or drained peat to oxidise and so the peat decomposes. This process results in the release of greenhouse gases to the atmosphere, as well as loss of photosynthesis in the area affected. Other upland soil types common in Scotland, such as heathland store more carbon per hectare than grassland and this carbon can also be released as a result of the land use change associated with unconventional gas exploration and extraction. There is considerable peat and organic soil cover within the rural areas of the Central Belt (figure 6b and c).

Previous published LCAs calculate the emissions associated with site preparation (including land use change) to be small (MacKay and Stone, 2013). For example, Santoro et al. (2011) estimate emissions from land use to be 167.5 tCO₂/ha, which becomes negligible when compared to emissions in the full life cycle. These LCAs do not consider land use change for exploration pad construction. In our LCA we follow this example assuming that exploration pads would be created large enough to become development pads, so all GHG emissions associated with pad construction are accounted for in the development and production stages. In addition, we consider the scenario of constructing pads on peatland for various peat depths, which has not been included in previous LCAs.

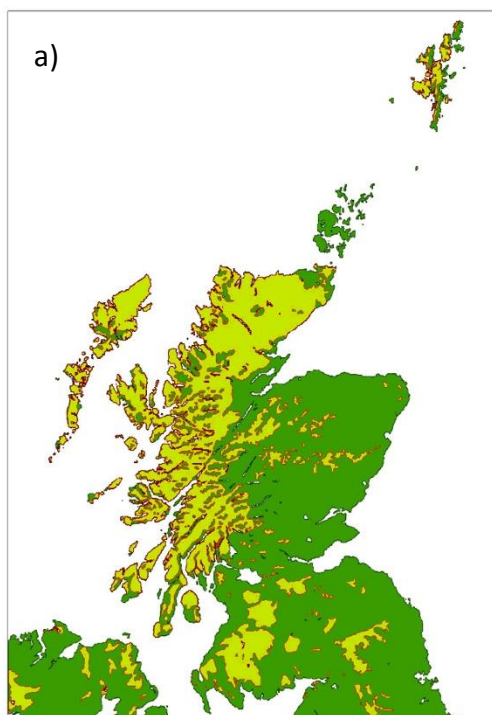
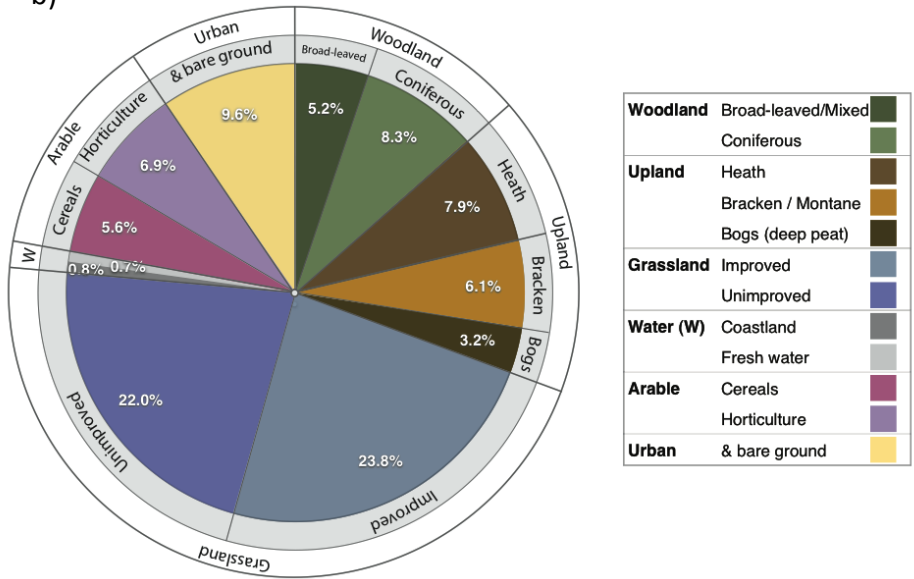


Figure 6.

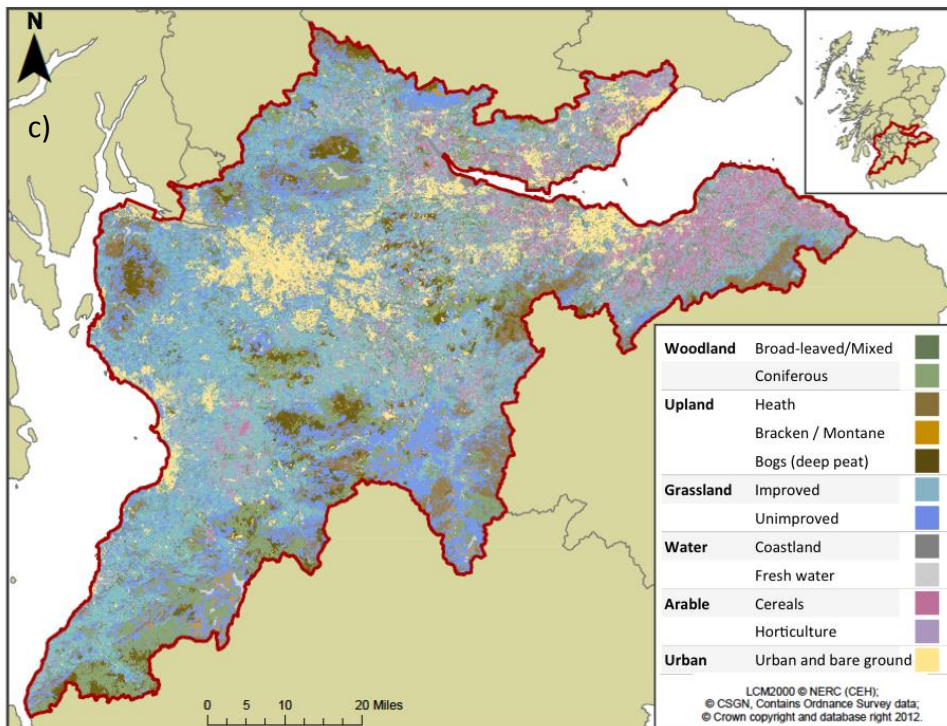
a) Map showing the distribution of peat soils as the dominant soil type in Scotland (yellow). Map is 1 km resolution. This figure does not show the depth of peat, which is a key variable for GHG emissions.

Source: Harmonized World Soil Data (JRC 2013), available at http://eussoils.jrc.ec.europa.eu/esdb_archive/Soil_Data/Global.htm

b)



b) The percentage of each land use type in the Central Belt of Scotland. Upland land use types have high organic carbon content, particularly deep peat. Land use change in these areas could lead to GHG emissions.



c) Geographical distribution of land use types in the Central Belt of Scotland.

Source (for a-b): Central Scotland Green Network (CSGN) Activity Area boundary (2014) - available at: <http://www.centuralscotlandgreennetwork.org/resources/data/data-download>.

3.2.4 Equipment transport

The emissions associated with equipment transport would depend on several location-specific factors including the emissions specifications of the trucks (e.g. fuel use and efficiency), the number of trucks required (determined by the quantity of materials for transport), transport distances and road congestion factors.

Construction and drill equipment would mostly be transported onto site by road, except in Caithness where it may first be shipped by sea to the local ports of Wick or Scrabster. As there are currently very few rigs in the UK that are suitable for drilling horizontal wells that would be hydraulically fractured (EY 2014), these rigs would initially be imported from overseas, similar to the case in Australia (Cook et al., 2013). This would increase emissions from transporting the drill rig. In the USA, 'factory drilling', where the same equipment is used repeatedly at the same site, reduces the needs for trucking equipment between well pads.

Truck specification: Specification for trucks in the UK are different to the USA, where trucks are larger and so the numbers of trucks required to transport the same volume of water would be larger than those for USA operations, but may have lower-emissions. Horizontal drilling rigs are bigger than vertical rigs, and in the UK are transported by articulated trucks, as abnormal loads. Emissions from transport of the drilling rig have been calculated but are negligible compared to other site preparation emissions (MacKay and Stone, 2013).

Water transport: For exploration drilling, the water required for drilling and appraising the well would likely be transported by tanker truck or temporary pipeline. These pipelines might be a flexihose from the nearest fire hydrant or other mains water source, or surface-routed HDPE pipelines from the mains supply, and would be routed along ditches, and only temporarily buried, for example when crossing a road. These temporary pipelines would then be removed after use.

Transport distances: In the USA the transport distances are typically much greater than they would be in the UK due to differences in infrastructure density. For example in the LCA for shale gas in the USA for the development stage, Santoro et al. (2011) assume average distances of 321 km (200miles) per truckload for drilling and completion equipment and an average of 201 km (125 miles /per truckload) for water chemicals and wastes. In contrast, Broderick et al. (2011) assume a 60 km round trip for trucks carrying water in the UK setting. In Scotland, water for exploration activities would likely be transported by a temporary pipeline, or by bowser trucks.

3.2.5 Exploration Drilling

Exploration boreholes are generally vertical, to document the rock stratigraphy, but could include horizontal sections to appraise the shale gas or coal bed methane resource potential. Vertical drilling follows conventional practice. At the surface, a blow-out preventer (BOP) is connected to the casing to control pressure while drilling. The BOP would automatically shut down flow in the wellbore should there be any sudden or uncontrolled escape of fluids (Mair et al., 2012).

Exploration borehole density - In the USA, it is common for many small diameter exploration boreholes to be drilled to locate the most productive shale horizons ('sweet spots'). In the UK, the differences in planning legislation, land use and public acceptability of development make such practice unlikely (MacKay and Stone, 2013). Instead exploration wells are likely to be designed to become production wells to minimise the number of pads required.

Exploration borehole lengths - The length of the vertical and horizontal boreholes would vary from site to site. For a model exploration borehole in Scotland we assume a vertical depth of 2.5 km, for both shale gas and CBM exploration activities. This approximates to the depth of the base of the Strathclyde group shale rocks (see section 2, figure 2). Less is known about the subsurface geology in Caithness, however outcrop studies suggest that a depth of 2.6 km would represent the maximum likely well depth for shale gas exploration in this region. Most of the coals are located at shallower depths than the shale rocks, and the techniques used to extract CBM mean it is likely that the focus for extraction of this resource would be shallower than for shale gas. So a borehole depth of 2.5 km represents a maximum depth for CBM in Scotland.

Exploration borehole tests - During and after the drilling of exploration boreholes tests, the information they provide would be used to decide whether to progress to further appraisal and production. The majority of these tests would have little to no greenhouse gas emissions associated but there is no available data for these. The exploration stage does not include drilling a horizontal section and performing hydraulic fracturing or dewatering-tests since these activities would classify the well to be an appraisal well.

Exploration borehole emissions - Any methane produced during tests in the exploration stage would normally be flared because, as outlined in section 2.6, routine venting is not permitted due to pollution regulations and explosion and asphyxiation hazards (but may take place in an emergency i.e. to mitigate a blow out or explosion at the well head by venting through a flue stack). At the exploration stage, these releases are regulated by DECC as a requirement of the PEDL license and Local Authorities under the Management of Extractive Waste Regulations. MacKay and Stone (2013) note that there is little information available on emissions associated with exploration but that the emissions from drilling and well testing are expected to be small. Previous published LCAs have not included emissions from exploration drilling (Forster and Perks, 2012).

The procedure for water treatment and waste management for exploration wells would follow the same procedure as appraisal and development wells, which is detailed in section 3.4.10

3.2.6 Appraisal well drilling and tests

If the exploration well tests suggest that there is economically recoverable gas, the exploration could be developed into an appraisal well, or a new appraisal well would be drilled. These are likely to be drilled to the same specifications as production development wells (detailed in Section 4.4).

Appraisal wells for shale gas and CBM would likely include drilling a horizontal well, of up to 1.5 km, that would be subjected to flow testing. This includes hydro-fracture tests in the case of shale and dewatering tests in the case of CBM. The GHG emissions and associated

assumptions for hydro-fracturing, testing and dewatering are detailed under Production Development (section 4.4). Previous LCAs do not consider the emissions associated with appraisal wells.

3.3 Stage 4: Production Development

Once exploration and appraisal have determined that there is a viable commercial unconventional gas resource, production wells would be planned and drilled. As is the case for exploratory drilling activities, baseline water and air environment monitoring would be determined by the site-specific risk assessment for the planned development (see section 3.1.2).

Well drilling and completion typically takes several weeks, and involves a sequential process of drilling, insertion of steel casing strings which progressively decrease in diameter, cementing each one and testing. The drilling and completion technology is similar to conventional wells¹³.

Multi-well development: It is now common practice for shale gas wells to have multi-well pads, where from the same well pad up to 16 wells are drilled in parallel rows for up to 2 km in the same rock horizon (Broderick et al., 2011). The horizontal well-heads are spaced between 5 - 8m apart, their orientation dictated by the direction of minimum stress. Due to the thickness of the shales in the UK, and the thin layers of shale with high organic content in Scotland, it is likely that both shale gas and CBM development would have multiple horizontal sections at different depths (this could be multiple lateral drains from one well) in the prospective rock units (see figure 7). The use of multi-well pads significantly reduces the surface footprint (and cost) of the development compared to multiple single-well pads, minimising the visual impact and the disturbance of wildlife habitats and associated human amenity value of the landscape (as has been achieved at Wytch Farm in Dorset, England). Therefore this is likely to be the preferred approach in areas such as Scotland's Central Belt and in rural areas in Caithness and the Southern Upland South flank where there is either valuable agricultural land or peat-dominated landscapes.

The activities associated with production development are outlined in more detail in the following subsections.

¹³ Many conventional oil and gas wells are horizontally drilled and hydrofractured.

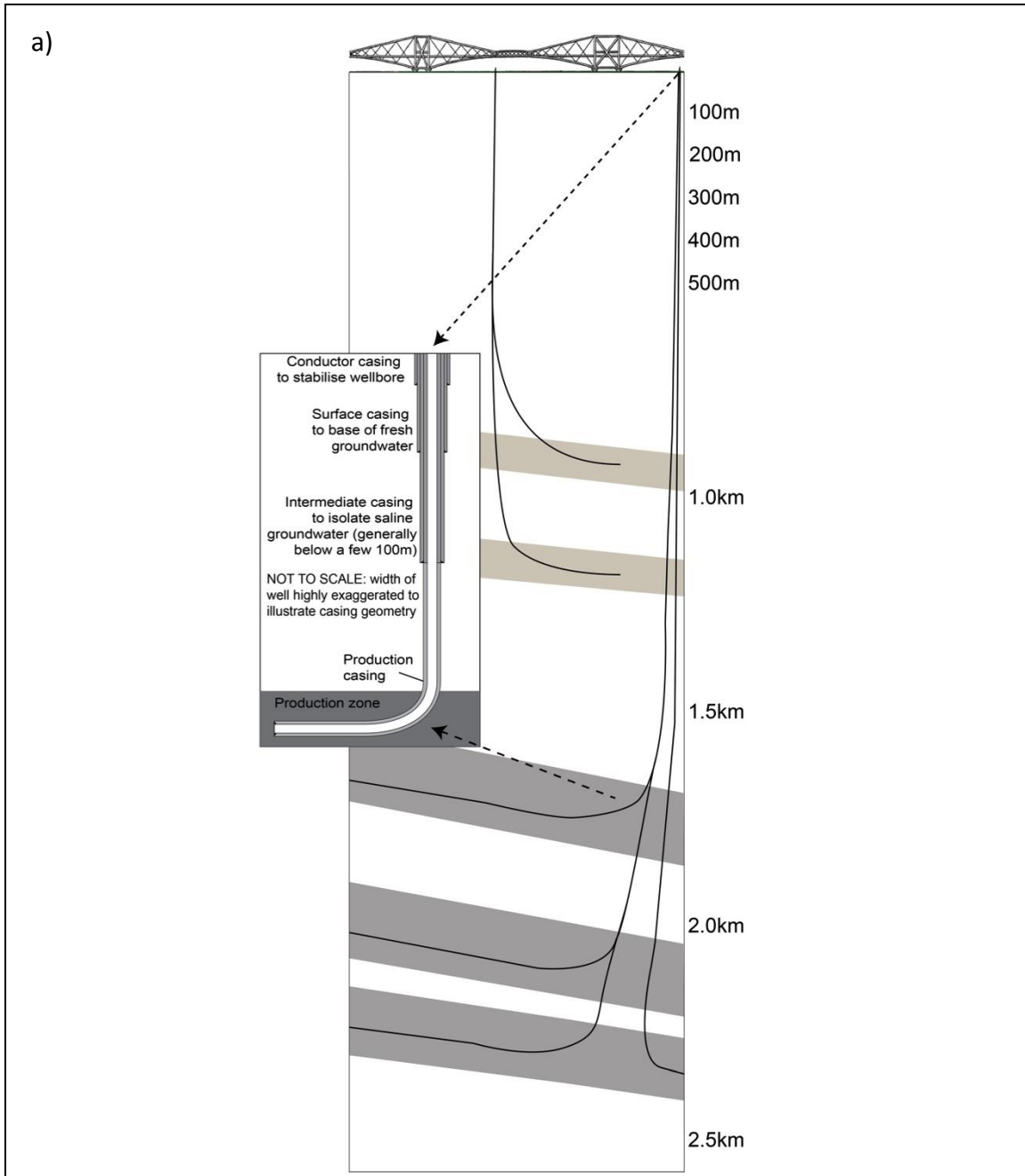
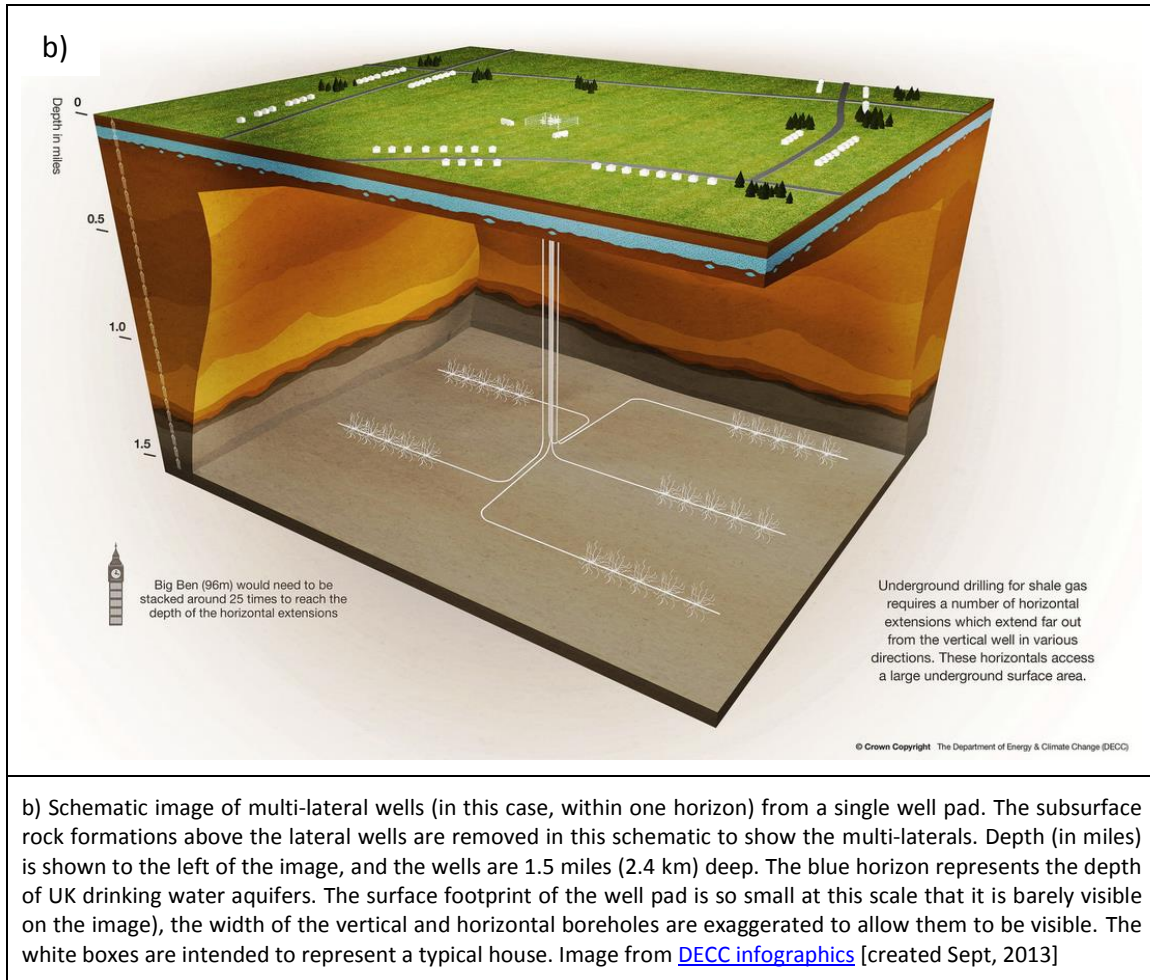


Figure 7. a) Scale drawing of wells (black lines) coming from a stacked (multi-depth) multi-well, multi-lateral shale gas well pad (right hand side) and a CBM well pad (left hand side). Drill rig is about 10m tall [note that a workover rig could be up to 20m tall]. Image of the 110m high Forth Rail Bridge from 1911 Encyclopedia Britannica ([licenced under Creative Commons](#)) is provided for scale. The width of the black lines representing the wellbores in this image are wider than the wellbores would be at this scale - the diameter of the production casing is typically of the order of 14cm. Note that the geology is deliberately simplified: in the Central Belt prospective shale units are 2-3m thick and packaged within thicker interlayered units of “sandstones and shales” (Monaghan 2013, 2014, Underhill et al. 2008). The depths of the laterals in the image show the typical depths of the appropriate rock units in the Central Belt. The details of the geology of other prospective areas in Scotland will remain unclear until such time as any exploration drilling takes place. The inset shows a typical well design (after RS/RAE, 2012). Conductor casing is set for a depth of approximately 30 meters to stabilise the hole. The surface casing runs from the surface to beyond the lowest freshwater-bearing rocks. The intermediate casing isolates the borehole from non-freshwater zones. The production casing runs all the way to the production zone. At each stage cement is pumped into the wellbore and up between the casing and the rock until it reaches the surface. Geophysical tools are run down the hole to test for cement integrity before the next wellbore is drilled and cased. Horizontal wells for CBM will typically be at shallower depths than shale gas wells.



3.3.1 Development pad construction

Pads designed for development and production are larger than exploration well pads, so that they could accommodate multiple wells and the production facilities around the well-head. The well pads would have facilities for storing water, chemicals and other materials (e.g. proppants) required for well operations, as well as for storage of flowback/produced water and gas treatment and compression facilities. The site would also require power supply networks.

Size of the well pad area - The size of the well pad area is determined by factors such as site topography, number of wells and the presence of additional infrastructure such as workers offices, gas or water treatment machinery. A review of shale gas operations in the Marcellus Shale (USA) by Forster and Perks (2012) found multi-well pad areas for well pad and access roads ranged from 2.4 – 2.6 ha. MacKay and Stone (2013) note that at the present early stage of exploration in the UK, it is difficult to know how the spatial footprint of production operations would compare to those in the USA. Broderick et al. (2011) use Cuadrilla's planning application for a 0.7 ha pad (for ten wells) whereas Taylor et al. (2013) estimate that one well pad would require 2 ha (the size of a football pitch). This is approximately the same size as the well pads estimates used for LCAs in the USA. If the development well pad is utilizing an exploration or appraisal well site, only the additional emissions from extending the well pad need to be accounted for. Pads for CBM development can be smaller as they do

not need to accommodate a large set of fracturing equipment and its associated tanks etc. It is worth noting that much of the cleared land may be reclaimed once the well is operational. Santoro et al. (2011) estimate that two-thirds of the well pad area may be re-seeded within 9 months of being cleared. However, for a Scottish peatland scenario it would not be possible to remediate the peat in a short-time scale. There are no engineering processes that can reproduce the natural fabric of waterlogged peat once disturbed. Alternative uses of the excavated peat should therefore be considered. Further information on alternative uses of peat can be found in SEPA's "[Position Statement - Developments on peat](#)"¹⁴.

Access roads - Any temporary access roads or local roads that were not designed for high volume, heavy truck and tanker traffic would need to be upgraded at the development stage. The estimated area of land clearance for new access roads in the USA range between 0.6 ha (Jiang 2011) and 0.44 ha (Santoro et al. 2011). Santoro et al. (2011) also estimate that ~ 1.6 km roads per well pad would need to be upgraded for high volume traffic. In addition, need for road repairs would be more frequent than standard. In Scotland, road density is likely to be greater than the USA, and so the GHG emissions for new road construction would likely be less. The road traffic is very heavy during the well construction and completion but during production would be very small with mainly light vehicles.

Pipeline - Santoro et al. (2011) estimate 1609 m of pipe per well pad requiring land clearance of 15 meters (2.46 ha in total), which would be an adequate width to allow machinery access. It is assumed that this land is not wholly reclaimed.

3.3.2 Drilling appraisal and development wells

Vertical drilling follows the process as outlined in section 4.3.2. For horizontal drilling, a down-hole drilling motor and measurement-while-drilling (MWD) instrument¹⁵ and geosteering tools (tools that image the rock around the well) are added to the drilling assembly. Directional drilling, to create horizontal segments, usually starts approximately 150m above the target formation, and is drilled to the horizontal (or bedding plane inclination) with an approximate ~150m radius of curvature. The orientation of the lateral (i.e the horizontal component) is determined by the in-situ underground stress regime. The wells horizontal section could be completely horizontal, or toe-up (where the end of the lateral well is higher than where it originally deviated from the vertical well), or toe-down, the actual trajectory being adjusted during drilling to track along the shale or coal layer using geosteering tools (Cook et al., 2013).

The length of the vertical and horizontal wells would vary from site to site. Previous LCAs of shale gas operations in the Marcellus Shale (USA) assume average well depths of approximately 2.6 km with a 1.2 km lateral (Forster and Perks, 2012). In the UK, Broderick et al. (2011) assume up to 1.5 km horizontal drilling, vertical drilling is excluded from their calculations, but Cuadrilla have suggested vertical wells in the Bowland Shale of up to 3 km depth (Forster and Perks, 2012). See Box 5 on page 54 for assumptions about likely depths for

¹⁴ http://www.sepa.org.uk/waste/waste_regulation/idoc.ashx?docid=0999acc5-4c77-4e75-a6fc-0bf582e6d115&version=-1

¹⁵ Measurement while drilling (MWD) techniques include Resistivity, Spectral Gamma ray, Density, Neutron logging.

Scottish wells. The length of the horizontal part of the well has significant implications for GHG as emissions because as well length increases the emissions associated with the surface facilities would likely become a smaller fraction of the total well emissions.

The energy required to drill the well is dependent on several factors, including the depth of the target shale or coal horizon (and so pressure conditions), the length of the horizontal well, the strength of the rock units to be drilled through, and the in-situ stresses in the rocks. The drilling rigs are usually powered by diesel (or diesel-electric AC or DC) but engines running on natural gas or electricity are also available (Broderick et al., 2011). It is worth noting that powering a rig using gas would have lower associated GHG emissions than powering a rig using electricity from the UK grid, given the present energy mix and power loss during transmission.

Jiang et al. (2011) estimate that the total emissions for drilling in the USA range from 610-1100 tCO₂ eq per well (assuming drilling rig powered by diesel, and the well is 2,600 metres deep, with lateral length of 1,200 metres). In practice laterals are normally somewhere between 1-3 km long, see the following section.

3.3.3 Drilling fluid

There are different types of drilling fluid.

Drilling mud - On a drilling rig, mud is pumped from a mud storage tank down into the well to lubricate and cool the drill bit, control pressure within the well, stop losses of fluid into porous zones and transport the rock cuttings to surface. The cuttings are separated from the drilling mud at the surface, and the mud is then returned to the mud storage tank, reconditioned and pumped down the well again in a closed cycle (Cook et al., 2013). Drill mud could be water based or oil based - where the oils are usually non-toxic and biodegradable. Water based mud is typically water mixed with ~1% bentonite clay, ~2-3% barium sulphate (barite) and <0.1% of several other food grade or biodegradable additives¹⁶. Water-based mud would be used for CBM wells which tend to aim for solids-free drilling to preserve the coals permeability. For drilling shale gas wells, water-based mud would be used in shallower stages to reduce contamination issues in the case of small leaks. In deeper sections that require greater pressure control, oil based mud may be used (Cook et al., 2013) and there are options for air based drilling, where air replaces oil or water based fluids. Air drilling is not an option through coal seams in the UK, due to the risk of combustion. As long as there are no coal seams involved, air drilling with down-the-hole hammers can offer much faster drilling for vertical sections.

Water for drilling - Previous LCAs rarely differentiate between the quantities of water required for drilling and the quantities of water required for hydraulically fracturing the well. However here it is assumed that water is either trucked from the nearest mains water supply

¹⁶ For example, the drilling mud at Cuadrilla's Becconsall well was 95.8% water, 1.1% bentonite clay, 2.5% barite, 0.14% starch, 0.15% cellulose, 0.05% xanthan gum, 0.03% sodium bicarbonate, 0.02% caustic soda, 0.006% biocide, 0.02% citric acid, and 0.04% sodium bicarbonate. <http://www.cuadrillaresources.com/wp-content/uploads/2012/09/Drilling-Fluid-Disclosure-Sheet-Becconsall-Totals.pdf>

or in the case of the well pad being in close proximity a water mains a connection pipe would be laid to the well pad for both drilling and fracturing purposes.

Air and water based drilling mud would have lower embedded emissions than oil based drilling mud; the latter also adds cost to the treatment and disposal of drill cuttings. Forster and Perks (2012) note that most previous LCAs do not consider emissions from drilling mud. Only Jiang et al. (2011) calculate emissions from sourcing the water and bentonite (which is mined in few places in the world). Forster and Perks (2012) assume these materials are transported 100 km to the drilling site.

3.3.4 Drilling waste

Drill cuttings are flushed from the borehole and separated from the drilling mud and then studied (e.g. for geological information and to measure physical and chemical properties), and stored for disposal in a specially constructed poly-lined container or pit. It is standard for drilling mud to be recycled, but contaminated or spent mud would likely go for commercial disposal (and be pre-treated if necessary).

Oil based mud and associated cuttings must be treated before disposal to reduce the oil content (e.g. by composting, incineration, thermal desorption) at facilities such as those in Aberdeen which are set up to receive similar materials from the offshore industry. Water-based cuttings may not require treatment, depending on their compositions, and may go straight to landfill as inert waste. There are other options for disposal of cuttings¹⁷, for example they could be reused for construction materials, disposed by land-farming or put back down the well bore, if it is to be decommissioned.

3.3.5 Well casing and cement

All production wells for shale gas and CBM would be fully cased and cemented as standard, and SEPA would require proof of well integrity which should also conform to the HSE's requirement for audited well construction details. Well casings and cement provide a multi-layered barrier to seal the well from surrounding formations and stabilise the completed well. Casing is typically a series of steel cylinders lining the inside of the drilled hole, which are joined together by gas-tight threaded connections with a metal to metal seal, to form continuous 'strings' and cemented in place (see figure 8). Each section of casing weighs ~230 kg, and so for deep, long horizontal wells the casing assembly could weigh close to 90 tonnes (Cook et al., 2013).

If there is a blow out and the BOP closes, the well casing has to contain the well pressure. To ensure that well casing would be robust, a well integrity test is carried out after each casing string has been cemented. The cement, sourced from the UK, is typically Portland cement¹⁸ with small quantities of additives to improve the performance of the cement, including:

¹⁷ International Association of Oil & Gas Producers (2003) Report 342: Environmental aspects of the use and disposal of non aqueous drilling fluids associated with offshore oil & gas operations. <http://www.ogp.org.uk/pubs/342.pdf>

¹⁸ There are several Portland cement producers in the UK, and many more distributors.

- **Magnesium Oxide** - to make the cement expand when drying, since pure Portland cement contracts, causing tiny fractures to form that could jeopardise the integrity of the seal.
- **Polypropene** - to make the cement more flexible, and so reducing the risk of cement fracturing. This is particularly important for shale gas wells that would be hydraulically fractured.
- **Polyacrylamide** - to make the cement self-healing, so that any cracks that do form would close up.

It is best practice to perform a cement bond log (CBL) or ultrasonic cement evaluation log inside well casings to acoustically detect the bond strength of the cement to both the pipe and the formation wall for each cemented string (Mair et al., 2012). Casing and cement manufacture have high associated GHG emissions, and so are considered in many of the published LCAs for shale gas. MacKay and Stone (2013) adopt calculations by Forster and Perks, (2012) based on Santoro et al. (2011) who consider the mass of cement and steel required and their production/manufacture to estimate total GHG emissions associated with casing and cementing the well. Suitable cements are manufactured in the UK and so are likely to be delivered to the well site by road.

3.3.6 Well tests

Well tests are performed to determine *in situ* rock and fluid properties, well bore conditions, and gas potential. If the well needs more than 96 hours of testing, the operator must apply to DECC for an 'extended well test' permit. To appraise gas flow rates adequately and establish commerciality, shale gas and CBM wells would require approximately 60 - 90 days of testing. The permit limits the quantities of gas to be produced and captured or flared during the extended well testing period. If gas production facilities are not in place, the gas would have to be flared (Forster and Perks, 2012).

Open hole tests

The majority of open hole well tests are to establish the rock properties.

- **Coring**: Rocks cores are likely to be taken during vertical drilling operations. Coring is done incrementally. The cores would then be analysed by a series of techniques.
- **Logging**: Before the casings are installed, a series of logging tools¹⁹ would be lowered down the well on an electric cable, though some of these measurements could be made while drilling.
- **Formation tests**: e.g. a drill-stem test (DST) which could be performed on open or cased wells. The drill bit is replaced by the DST tool, packers²⁰ to isolate the formation of interest, and the well head valve closes, reducing pressure in the well and causing formation fluids to flow into the well. DSTs provide information on the rock

¹⁹ Open hole logging include Resistivity, Spectral Gamma ray, Density, Neutron, Multi-pole Sonic, Electrical Image Log, Packer Formation Tester.

²⁰ 'Packer' equipment makes a seal between the wall of the borehole and the drill.

permeability (including the permeability of cleats in coal) and allow the formation fluids to be analysed for their gas or geochemical properties.

Few emissions would be associated with coring and logging besides the emissions embedded in the equipment devices and their operation, which would be marginal. Small quantities of methane may be released from drilled coal seams, and the time required to perform the open hole tests could lead to some small fugitive releases from gas bearing rock horizons, but normal practice would be to bullhead (i.e. push under pressure) the fluids in the test string back into the formation to avoid emissions at the surface and hydrocarbon collection and disposal issues.

Cased hole tests

- **Well integrity testing:** After each casing string has been cemented a well integrity test is performed to ensure that the casing is robust. Integrity testing typically involves pressurising the well bore with water (~70 MPa) for approximately 10 minutes, though the test details are dependent on casing and well design. An inflow test could also be made by depressurizing the casing to observe leaks from the formation into the casing.
- **Mini-frac testing:** The rock fracture properties are usually determined²¹ by a 'mini-frac' test, in which a small fracture is created in the test formation, and the closure of this fracture is observed by measuring the pressure decline in the well (this is when the pressure decline rate approaches zero), which could take a few hours to several days depending on the formation properties. Multiple mini-frac tests may be performed for different rock units in a vertical well, or different sections of a horizontal well. The mini-frac test is important since the rock fracture properties derived from the test are used to design the hydraulic fractures for production. There are different ways to perform these fracture tests, but essentially a fracturing fluid (without proppant) is pumped down the well at high pressure to induce a small fracture. Then the wellhead valve is closed and the fluid pressure decrease is recorded either at the wellhead or in the borehole and this data is analysed to determine the fracture properties²².

²¹ Properties the mini-frac could inform, include the formation permeability, reservoir pressure, fracture closure pressure, fracture gradient and fluid leakoff coefficient

²² <http://www.fekete.com/SAN/TheoryAndEquations/WellTestTheoryEquations/Minifrac.htm> [accessed March 2014]

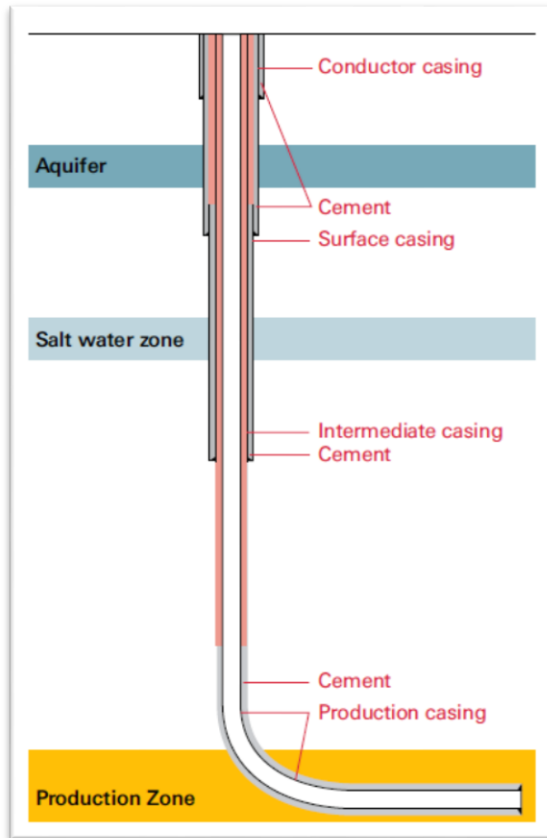


Figure 8. Schematic image showing multiple well casing in a standard UK well, from Mair et al., (2012). Note some wells in the USA are not cased to this standard. This image is not to scale, the real depth of the horizontal portion of the well is likely to be at 1-3 km depth in Scotland, with aquifers in the first few 100m. See figure 7 on page 30 for a scaled image.

Both well integrity testing and mini-frac tests require small amounts of water (with some chemical additives, likely), and pressure pumps for fluid injection. These tests would therefore have associated GHG emissions, but these are poorly constrained.

3.3.7 Well completion

Well completion is a generic term for the process of connecting a cased well to the surrounding rock formation, and so making a well ready for production or injection once drilling has concluded and the drill rig is removed. To connect the well to the gas-containing formation a perforating gun loaded with shaped charges is lowered into the well to perforate the casing and its cement seal, creating holes into the rock (Forster and Perks, 2012). This is the same as for conventional wells. Well completion also includes any subsequent hydraulic fracturing for shale gas appraisal.

There are widely varying estimates of well completion GHG emissions for shale gas, mainly due to the method of disposal of methane produced during flowback of the fracturing fluid. If the gas produced is flared it has a much lower Global Warming Potential (GWP) than if the gas is vented and enters the atmosphere as methane (see Section 4.1). Very little is known about the GHG emissions from drilling and preparing wells for CBM (Cook, et al., 2013), though the emissions associated with well completion for CBM wells in the USA are reportedly orders of magnitude less than estimates for shale gas wells (Skone et al., 2012). Published LCAs based on USA shale gas operations include the GHG emissions associated with flowback when calculating emissions from well completion, which could be significant. Previous LCAs have variable assumptions based on practices in the USA: Howarth et al.,

(2011) assume all methane is vented; O'Sullivan and Paltsev (2012) assume 70% of methane is captured, 15% vented and 15% flared; Jiang et al. (2011) assume 76% flaring and 24% venting (ACOLA, 2013).

The range in these estimates, and the different geological and regulatory context of the UK makes it challenging to estimate emissions from well completion in UK, where green completion techniques including gas recovery and flaring (rather than venting) would be regulated at both CBM and shale gas sites. Mackay and Stone (2013) note that while data on well completions from USA operations is a useful guide, more reliable estimates for the UK could be established only by appropriate field measurements at future UK operations. As a reference case, operations at the Wytch Farm oil field ensure that flaring is only used in exceptional circumstances. Venting is not permitted and so does not occur, and all other fugitive sources of methane are, where possible, captured and utilised. The quantity of gas combusted in a single flare event or during well completion at conventional hydrocarbon reservoirs will likely be greater than any flaring events from shale gas operations. This is because the gas in conventional hydrocarbon reservoirs is typically overpressured, unlike shale gas or CBM, and production wells that access overpressured gas reservoirs will release methane more vigorously than wells accessing reticent unconventional reservoirs (Thorogood and Younger, 2014).

3.3.8 Hydraulic fracturing

Some exploration wells for shale gas may be hydraulically fractured for flow testing. To hydraulically fracture the rock, fracturing fluids and proppant materials are pumped into horizontal wells in the shales at high pressures (over ~50 MPa) by an array of trucks with high pressure pumps.

GHG emissions associated with the fracturing process mostly include the emissions embedded in the fracturing fluids (water and chemicals), the energy consumed in pumping of fracturing fluids down (and back out of) the well, and the release of methane from flowback fluids once the section has been fractured.

The power demand for fracking pumps is significant, though it varies according to the pressures required to hydraulically fracture the rock, which itself is dependent on the well depth and geological factors such as rock strength and the prevailing stress regime (see section 2). The pumps are most commonly fuelled by diesel but could be powered by natural gas or electricity. To reduce GHG emissions and minimise public health concerns it may be preferable to avoid using diesel-powered pumps.

3.3.9 Fracturing fluid

There are several options for fracturing fluid, depending on the nature of the fracture that operators wish to create:

- **Slickwater:** Slickwater is the most common fracturing fluid and is approximately ~95% fresh water and c.~5% proppant with <1% additive chemicals (Mair et al., 2012), including friction reducing gels that give rise to the name 'slick'. Water and additives are blended on site in a truck-mounted blending unit where dry additives are poured into a feeder system on the blending unit, then the fracturing solution is mixed with

proppant and pumped into the wellbore (Broderick et al., 2011). Slickwater creates complex fracture networks.

- **Gels:** Cross-linked gels are shear-thinning to allow the gels to be pumped into the formation, and the higher viscosity improves suspension of the proppant. Less fluid volume is required to reach the fracture pressures than with slickwater. Gels create larger, simpler fracture networks.
- **Hybrid:** It is becoming increasingly common in the USA to first use slickwater to create a complex network of fractures, and then use gels to enhance these fractures, by lengthening and propping.
- **Saline water:** Saline water with some additives, requires larger volumes to induce fractures than slickwater.

The average volume of fracturing fluids required to fracture a shale gas well depends on the depth of the well and the subsurface properties such as rock strength, stress field and depth. In the USA, the average quoted volume ranges between 4.0 - 6.1 million US gallons (15.14 - 23.1 thousand m³) per well depending on the region (Goat and Grimshaw, 2012).

Hydraulic fracturing of coal for CBM requires significantly less fracturing fluids, fracturing chemicals, and fracture pressures since coal is naturally more brittle than shale (Cook et al., 2013).

Broderick et al. (2011) estimated the emissions from pumping to be 295 tCO₂eq per well, based on the needs of the average horizontal well in the Marcellus Shale (assumes 109,777 litres of diesel, with emission factors of 2.64 kg CO₂/litre).

Transport of fracturing water, if needed, could be by trucks or pipeline.

Additive chemicals - Typical fracture fluid additive chemicals are: scale inhibitor, acid, biocide, friction reducer and surfactant (Mair et al., 2012). These chemicals have embedded carbon in their manufacture and transport and storage infrastructure since the safe transport, storage and handling requires specialist containers - the most common being 1-1.5 m³ high-density polyethylene (HDPE) steel caged cubic containers (Broderick et al., 2011). The carbon embedded in fracturing chemicals has been calculated by Jiang et al. (2011) to be 300 tCO₂ eq per well for the USA.

Proppant - Proppants are typically sand, but could be sintered bauxite (Cook et al., 2013). The quantity of proppant varies according to the design of the fracture operation. In Cuadrilla's Preese Hall fracturing operations, ~ 77 tonnes of sand proppants were used per fracturing stage.

There are GHG emissions embedded in the sourcing and transport of proppants. For their Lancashire wells Cuadrilla sourced sand quarried locally (Cheshire). There are several sand quarries active in the Central Belt of Scotland²³, thus limiting emissions from transport operations. For the South flank of the Southern Uplands sand could be sourced in

²³ <http://www.scotland.gov.uk/Resource/Doc/178913/0050918.pdf>

Lancashire/Cheshire and for Caithness it could be shipped into Wick or Scrabster by sea from the most convenient source.

The design of the hydraulic fracturing operation, including the volume of fracturing water required and the types and quantities of additives needed are dependent on the geological situation and other engineering and planning factors. Considering the geological uncertainties regarding well depth, rock strength, hardness, subsurface pressure and stress regime, it is difficult to say how much a typical Scottish hydraulic fracturing treatment would require.

If alternative fracturing techniques were applied, such as the use of foam as a fracturing fluid, the GHG emissions associated with this activity would change.

3.3.10 Produced water and other fluids

After hydraulic fracturing a period of controlled production, called clean-up, is required during which time the fracturing fluids return from the rock along with formation fluids. It could take from 2 to 20 days before the first gas is produced; this is dependent on the local geological conditions (Cook et al., 2013).

Between 15-80% of the hydraulic fracturing fluid is recovered during flowback and as produced waters (Broderick et al., 2011). The flowback fluids contain the additive chemicals, some proppant, dissolved methane and other formation fluids, and some naturally occurring radioactive materials (NORMs) from the rock formation. Proppant is separated from the fracturing fluids, and then the fracture fluid and proppant are stored for re-use or disposal. The quantity of flowback water decreases rapidly over the first few days following the hydraulic fracturing (during the clean-up phase), and then decreases more gradually as the well goes into production.

Reported recycling rates for produced fluids vary between 10% and 77% (DECC, 2013a). Cuadrilla has suggested that flowback fluids, if uncontaminated by liquid hydrocarbons or highly saline formation water, could be reused, significantly reducing the volume of water required to be transported onto site (MacKay and Stone, 2013).

Most LCAs use gas production flow rates to calculate the potential GHG emissions from the well completion phase. Previous LCAs assume maximum total gas from flowback fluids to be equivalent of up to 10 days gas production at the initial well flow rates (Broderick et al., 2011; Jiang et al., 2011; US EPA, 2009). This is because the typical clean-up period for wells accessing the Marcellus Shale lasts between 3-10 days (Eshlman and Elmore, 2013).

The proportion of these potential emissions that is released to atmosphere is dependent on management practice at the site. Until recently in the USA, unseparated flowback fluids were stored in open pits where the methane associated with the produced waters degassed to atmosphere and in some cases caused contamination problems due to accidental leakage (Bamberger and Oswald, 2012; Adgate et al., 2014). This practice is becoming less common in the USA due to the health and safety, and environmental problems it poses. In the UK, flowback fluids must be stored in closed tanks before recycling and re-use or disposal.

The GHG emissions associated with flowback are also dependent on whether the flow-back methane is vented, flared or recovered (captured). For example, 'green completion' or 'reduced emissions completion' (REC) practices to recover gas from flowback fluids are

considered best practice. For the UK these BATs will be employed at the outset. In the USA, where shale gas extraction has been in progress for some time, shale gas operators are beginning to employ these new BATS and green completion will be mandatory from 2015 (Mair et al., 2012). This recovered gas could either be added to the produced gas for processing, or used to power on-site equipment or flared.

For CBM, dewatering the coal seam produces saline water, the volume of which depends on the volume of cleats in the coal. Produced water from CBM often contains contaminants from the coal seam, and could include NORMs and inorganic/organic substances. This water is steadily pumped from the seam over the production life of the well. Gas is separated from the produced water, before the water is treated and disposed of.

3.3.11 Water treatment and disposal

Hydraulic fracturing and CBM extraction produce large quantities of wastewater. Flowback water from hydraulic fracturing could be reused, but would need to be disposed of eventually. Produced water from CBM tends to be highly saline and would be treated differently. The UK has a history of effectively treating mine waters which are similar to those produced from CBM (e.g. Younger and Sapsford 2004).

In Scotland discharges that are likely to have an impact on the water environment require authorisation under the Water Environment (Controlled Activity) (Scotland) Regulations 2011 (CAR). However the re-injection of flow-back water for disposal is forbidden under CAR because it does not comply with the Water Environment (River Basin Management Planning: Further Provision) (Scotland) Regulations 2013. In addition to controls under CAR, because flow-back water is classed as extractive waste it is regulated by the local authority by planning controls and Extractive Waste Regulations.

The GHG emissions associated with wastewater treatment and disposal in the UK was calculated by Broderick et al. (2011), to be between 0.3 - 9.4 tCO₂e per well. MacKay and Stone (2013) assume emissions from treating flowback water to be higher, at 16 t CO₂e per well.

3.4 Stage 5: Production Operation and Maintenance

3.4.1 Equipment for continued production

At the stage when operations on site are purely focused on production of gas a manifold is fitted to the well. Most wells undergo a single workover during which tubing and other components (e.g. valves) are replaced and/or tested. Less than 12% of unconventional gas wells are re-fractured during a workover (Skone et al. 2011) but some wells have been re-fractured up to 5 times (IEA, 2011).

Previous LCAs assume that emissions from well workovers are similar to emissions from well completion (Skone et al. 2011; Broderick et al. 2011; MacKay and Stone 2013), and most studies assume one workover per well. The same level of intervention is unlikely for CBM wells, and so workovers are probably less frequent than for shale gas.

3.4.2 Gas processing

The composition of unprocessed natural gas varies depending on the geological source of the gas. On average, shale gas in the USA contains 86% methane, 4% ethane, 1% propane, 3% CO₂ and 7% nitrogen (Cook et al., 2013). Whether the produced gas would be used to generate energy on site or would be prepared for addition to the UK national gas grid, some processing would be necessary. Indeed, the UK national gas grid has particular compositional requirements that must be met (see table 3).

Table 3. Gas composition required for the UK National Grid.

Hydrocarbon	%	Other	%
Methane (CH ₄)	>95	Nitrogen (N ₂)	1.6
Ethane (C ₂ H ₆)	0.025	Carbon Dioxide (CO ₂)	0.7
Propane (C ₃ H ₈)	0.002	Hydrogen Sulphide (H ₂ S)	trace
Butane (C ₄ H ₁₀)	0.0006	Water (H ₂ O)	trace
Pentanes + (C ₅ H ₁₂ + C ₁₀ H ₂₂)	0.0002		

The stages of gas processing are as follows (adapted from Cook et al., 2013):

- *Gas-oil separator*: gravitational separation of light and heavy hydrocarbons (oil = C₁₂+))
- *Condensate separator*: mechanical separation of condensates (condensates = C₂ to C₁₂)
- *Dehydrator*: water removal from the gas
- *Contaminants*: removal of hydrogen sulphide (sweetening), carbon dioxide, oxygen and helium, typically using amine absorption. The products are vented, sequestered or stored and sold in the case of helium.
- *Nitrogen extraction*: Separation of nitrogen, which is then vented.
- *De-methaniser*: separation of methane from heavier gas components and lighter liquids
- *Fractionator*: separates Natural Gas Liquids (NGLs) using their different boiling points.

Gas processing infrastructure may be located on site or off site, in which case the gas would likely be transported by pipeline. The greater the processing demands the greater the GHG emissions associated with the gas treatment process, particularly if the process has high energy demands, for example requires gas compression or heating/cooling.

Processing gas from CBM

In general, gas produced from CBM has very high methane content with few impurities – although this would vary between different sites. If high purity CBM gas is being used to generate energy on site then the produced gas may only need to be dehydrated before it enters the generator. However, if the high purity CBM gas is being added to the national gas grid, propane and other heavier hydrocarbons may need to be added so that the gas meets the required standards.

Processing gas from shale

Gas from shale could contain natural gas liquids (NGLs) such as ethane, propane and butane. These NGLs are more difficult to extract than methane and thus may require more hydraulic fracturing stages in order to recover them (AEA, 2012 and Forster and Perks, 2012). The NGLs must be separated from the lighter hydrocarbons (by a fractionator) and captured.

The high economic value of NGLs means that they are likely to be captured and sold rather than disposed of. For example, the global chemical company INEOS has signed a supply contract to refine NGLs from USA shale gas, which will supply Grangemouth refinery. The nature of the organic content of Scottish shale rocks suggest that unconventional gas produced from shale would likely contain NGL's. The transport and processing of these NGLs would add to the GHG emissions associated with gas processing.

Greenhouse gas emissions from processing

Most previously published LCAs do not distinguish emissions from processing from overall emissions during production (Forster and Perks, 2011). MacKay and Stone (2013) use a single figure for conventional offshore gas production that wraps up gas processing with fugitive emissions from production and transmission to onshore terminals for processing. We chose not to use this approach since transmission over the distances of offshore operations is much greater than for onshore unconventional gas in Scotland, and also this would double-count fugitive emissions (since we estimate these from the EUR).

Gas compressors are required to transport the gas to the processing facility, and also to maintain particular gas flow/pressure conditions in the processing unit. Forster and Perks (2011) summarise results from NYESDEC (2011) that calculate fuel consumption for compressors emits 5,591 tCO₂ per year for a single well.

3.4.3 Gas compression

Gas must be compressed to 85 atmospheres (85 times normal atmospheric pressure, 8.6 MPa) before entry to the National Grid. While generators could operate with uncompressed gas, experience at Dart Energy CBM operations in Airth found that it is preferable to compress the gas prior to entering the generator. This is because gas flow variation causes operational issues (malfunction/low efficiency). During compressor down-time due to malfunction or maintenance, gas is often flared. Therefore optimised compressors would keep GHG emissions to a minimum.

The power demand for compressors could be significant, depending on the required pressure and the gas flow rates. Compressors could be fuelled by diesel or natural gas. Diesel compressors could have associated public health concerns due to both noise pollution and particulate and ozone pollutants which affect air quality. To reduce GHG emissions and minimise public health concern gas powered compressors may be preferred, particularly at the development stage.

The GHG emissions associated with gas compressions for transport to and from the processing site or to the generator will vary with gas recovery volumes, the necessary pressure and transport distances.

3.4.4 Fugitive emissions

According to the IPCC (2007) fugitive emissions from oil and gas extraction activities may occur due to: fugitive equipment leaks; process venting; evaporation losses; disposal of waste gas streams (e.g., by venting or flaring), and accidents and equipment failures. More recently the term 'fugitive' has been used to refer to unintentional gas leaks that are difficult to quantify and control (MacKay and Stone, 2013). This more recent definition of 'fugitive methane', which we adopt, therefore does not include the disposal of waste gas streams by venting or flaring of the methane associated with well completion, which in this report we refer to as part of the flowback fluid or 'clean-up gas'.

Fugitive emissions are variably accounted for in other studies, and which stems from variation in the definition of the term 'fugitive emissions', differences in assumed management practices, and a lack of clarity over the actual emissions. As such, previously published LCAs assume that fugitive methane leakage during production, processing and transport of unconventional gas would be similar to that of conventional natural gas (Skone et al, 2011; Jiang et al., 2011; Cook et al., 2013; MacKay and Stone, 2013), and varies with EUR. In the US, fugitive emission rates from extraction alone are estimated to be ~ 0.54% of the methane that is extracted at the wellhead (US EPA, 2011; Skone et al., 2011), and a further 0.66% is lost fugitively during gas processing and transport. Forster and Perks (2012) assume that 0.1% of gas throughput is fugitively vented during pipeline transmission. In the UK, fugitive gas lost during processing and transport is equivalent to 100 tCO₂e per 1 million m³ of produced gas (MacKay and Stone, 2013).

The results of recent studies at shale gas sites in the USA indicate that methane emissions from shale gas operations are uncertain and need refining. For example, direct emissions measurements at natural gas production sites in the USA presented by Allen et al. (2013) found that emissions from pneumatic controllers and equipment leaks are higher than EPA inventory estimates, but also that that emissions from well completion are lower than previously estimated. Additionally, aircraft-based measurements of atmospheric methane above shale gas sites performed by Caulton et al. (2014) find methane emissions from drilling activities in Pennsylvania to be orders of magnitude larger than the inventory estimates suggest, and overall methane emissions from shale gas operations (well completion, pipelines etc.) may be as much as 2.8 – 17.3% of total production.

3.4.5 Environmental monitoring

On-going environmental monitoring would be required as part of various permits and permissions. There are no published estimates of GHG emissions from environmental monitoring, although we would expect them to be very low, relating mainly to the transport emissions from field staff and the emissions associated with energy use in laboratories.

3.5 Stage 6: Decommissioning

On completion of drilling operations a well may either be suspended for future testing or, if there is no commercially viable gas resource, it would be abandoned²⁴ and the site would be decommissioned. This involves:

Well abandonment: The well is plugged by filling sections of the well with cement to ensure it is structurally stable and that no fluids would flow into the well (Mair et al., 2012; Cook et al., 2013). The well is often then cut off below the surface and then buried so there is no surface footprint.

Removal of surface installations: All equipment and waste must be transported off-site, and the well pad and access roads removed. UK planning guidance requires consultation with the landowner to see if any of the roads and/or hard standings are to be left for future use, which would lower emissions. Previous LCA have assumed that the roads and hard standings remain.

Restoration of the site: The land must be returned to the same conditions, or better conditions, than it was prior to the construction of the exploration well.

SEPA would not allow any relevant permits to be surrendered if the borehole is not decommissioned to their satisfaction²⁵. To surrender the CAR permit, the operator must provide confirmation of any potential environmental impacts associated with abandoning the borehole, and demonstrate how they proceed in a manner that removes the risk to the groundwater environment. Surrender of a PPC permit requires a closure report in which the condition of the site is described and any changes from the baseline condition are identified. This report will also include a description of the steps taken to avoid pollution risks from the site, or to return the site to a satisfactory condition.

MacKay and Stone (2013) note that from their review of LCAs for shale gas, that data on GHG emissions for the abandonment phase stage is sparse, but the main source would be from the concrete infill to seal the well, with some negligible emissions from infrastructure removal and site restoration. If the well is not abandoned appropriately and the well integrity is compromised, some fugitive emissions may occur, though this would be far more likely (albeit still very rare) in the case of (over-pressured) conventional reservoirs than it would be in the case of (under-pressured) unconventional reservoirs (Thorogood and Younger, 2014). Considine et al. (2013) examine drilling violations for companies operating in the Marcellus Shale (USA), and found two cases of subsurface gas migration from a dataset of 3,500 wells.

²⁴ The site must be decommissioned in accordance with the latest Oil and Gas UK standard - DECC Onshore UK Oil and Gas and SEPA

²⁵ Regulatory Guidance for Coal bed methane and shale gas (Version 121119) Paragraph. 30.

4. LCA Assumptions and Inputs

The assumptions and input parameters of the LCA for unconventional gas in Scotland are presented in this section. In general we refer to the meta-study prepared for DECC by MacKay and Stone (2013) who examined typical shale plays in the USA to define those analogous to the Bowland Shale in Northern England. MacKay and Stone (2013) made a statistical analysis of published LCA studies to estimate GHG emissions associated with the development of these shales in the context of the UK regulatory framework. To help us to compare potential unconventional gas operations in Scotland with operations and practices considered in previous published LCAs we constructed a 'Scottish Scenario' (see section 4.1) based on a Scottish Central Belt unconventional gas reservoir. Here, the LCA we present builds on this work by adapting it for Scotland by:

- (i) Assessing how appropriate the assumptions of MacKay and Stone (2013) and the publications it draws from are for Scotland – including the geology, infrastructure and regulation in Scotland.
- (ii) Calculating the GHG emissions for land use change due to building access road and the well pad. This includes peat habitat loss, which has not been previously included in any unconventional gas LCA but is particularly relevant to Scotland.
- (iii) Estimating the GHG emissions from exploration, appraisal and development and production of a Scottish unconventional gas resource.
- (iv) Comparing the above for both shale gas and for CBM.
- (v) Considering how unconventional gas production may vary in different locations in Scotland (Central belt, southern flank of the Southern Uplands and NE Scotland) – and the consequences for the GHG emissions associated with developing the resource.

We present the Scottish scenario before outlining the overarching approach to this work and the assumptions for each stage of the LCA.

4.1 LCA Assumptions: Scottish Scenario

In our LCA we largely refer to the MacKay and Stone (2013) meta-study prepared for DECC. We consider the development of an unconventional gas reservoir in the Central Belt of Scotland. We call this the "Scottish Scenario", and we consider scenario development for both shale gas and CBM. This scenario for development simply assesses the relevance to the Scottish context of assumptions in published LCA studies that MacKay and Stone (2013) reviewed. The scenario well does not affect the input calculations for the LCA, with the exception of the calculations we perform for GHG emissions from land use change.

The Scottish Scenario well would be targeting rocks in the Clackmannan Syncline, the onshore location in the Central Belt where the shale rocks are deepest. This scenario was chosen because such deep drilling would represent the largest economic expenditure to explore and develop the gas resource, and also the scenario with the largest GHG emissions associated with exploration and development due to the additional materials and energy needed for drilling (see section 2.4). The recently published study on the shales of the Midland Valley (Monaghan et al., 2014) reports that the majority of the gas-bearing rocks onshore are

between 1 - 2 km depth (rarely deeper). The Scottish Scenario we model here will likely exceed the average drilling depth for shale gas, and for CBM since the coal formations will likely be shallower (see section 4.1.2). We may therefore consistently overestimate the potential GHG emissions from unconventional gas exploration and development compared with a median case for Scotland.

4.1.1 The Scottish Shale resource

The prospective well depths and the overall rock formation thickness of Scottish shale is similar to the Marcellus Shale (USA) and Barnett Shale formations, and the wells proposed by Cuadrilla in the Upper Bowland Shale in Northern England.

The Barnett is considered to be a good analogy to the UK Carboniferous shales by the BGS and MacKay and Stone (2013). However, in contrast to these shales, which range from 20-240m thick, the shales of interest in Scotland form a series of thin organic shale beds interlayered with thicker limestone, sandstone, tuff and shell beds. Indeed, the organic shales only make up 10% of the formation and so the individual target layers are much thinner in the Scottish rocks than those targeted for unconventional gas in the USA and England. This has implications for any comparison with the emissions associated with the Marcellus/Barnett developments:

- Drilling horizontal wells in the shales will depend on the hardness contrast between the shales and the intercalated rocks and may be problematic if the shale rocks are harder than the intercalated rock units.
- Hydrocarbons may have migrated out of the shale and into intercalated rock units that are more porous. It is possible that these intercalated rocks may be the productive zones (rather than the shales), in which case the rock permeability may be enough to allow gas extraction without hydraulic fracturing. If this is not the case, fracturing the formation may be difficult due to the permeability contrast between the shales and the permeable intercalations.
- If the intercalated rock units are more permeable than the shales and are water-saturated, which is highly likely then the hydraulically induced fractures must be limited to the thin shale layers. This is because fracturing the more permeable rock units could result in water production instead of hydrocarbon production.

These subtleties will be highly site-specific and therefore cannot be accounted for in this over-arching LCA. They will impact on the style and design of development infrastructure, and therefore will have implications for the total GHG emissions associated with unconventional gas in Scotland.

4.1.2. The Scottish Coal Bed Methane resource

For this LCA we assume that exploration and development of CBM in the Central Belt will be similar to that for shale gas, with multiple horizontal wells at several depths, although the coal rocks will generally be at shallower depths than the shales. The wells for CBM will differ from those for shale gas since drilling fluids will be water-based rather than mud-based, to preserve the natural permeability of the coal rocks, and the coals will not normally need to be

hydraulically fractured. Therefore, the water requirements for developing CBM will be less than for shale, but will require significant pumping to dewater the coal layers.

CBM wells drilled in the Canonbie area will be similar to those in the Central Belt since the geology is comparable, though the depths cannot be specified without further geological investigations.

4.2 Overarching LCA Inputs

4.2.1. Global warming potential of methane

This LCA uses the latest IPCC and EC standards for calculating GHG emissions, and the 100 year time span for calculating global warming potential (GWP). The standard numbers for GWP were revised in November 2013²⁶ for the newly published IPCC AR5. These standards have increased the GWP for fossil methane from 25 (reported in IPCC, AR4) to 36.

MacKay and Stone (2013) use the IPCC AR4 value of 25, which most of the LCAs in their meta-analysis also apply, aside from Howarth et al (2011) who use GWP of 33, which MacKay and Stone (2013) modify accordingly to put the work of Howarth et al (2011) into the context of their own work. Box 1 shows the summary of global warming potential.

Box 1. Summary: Global warming potential.

1Mg CO₂ is 0.2728 Mg C

100 year time span for global warming.

Methane GWP = 36

4.2.2. Units for GHG emissions intensity

It is conventional to express the carbon intensity (CI) of a fuel in terms of the total GHG emission per MJ of energy. The carbon intensity of burning methane is 13.46 g CO₂ eq C MJ⁻¹, without considering any of the emissions from producing the gas (such as the exploration infrastructure, gas processing facilities, fuel transport etc.). To represent the carbon intensity of the fuel while taking the emissions associated with fuel production into account, the total

²⁶ In the new IPCC, AR5 publication, (11/11/2013) Climate Change 2013: The Physical Scientific Basis from IPCC, (AR5) the GWP values have changed from previous assessments due to new estimates of lifetimes, impulse response functions and radiative efficiencies. These are updated due to improved knowledge and/or changed background levels. Because CO₂ is used as reference, any changes for this gas will affect all metric values via AGWP changes. Relative to AR4 the CH₄ AGWP has changed due to changes in perturbation lifetime, a minor change in RF due to an increase in background concentration, and changes in the estimates of indirect effects. The indirect effects on O₃ and stratospheric H₂O are accounted for by increasing the effect of CH₄ by 50% and 15%, respectively. The ozone effect has doubled since AR4 taking into account more recent studies. Together with the changes in AGWP for CO₂ the net effect is increased GWP values of CH₄. In addition due to the different C isotope ratios there is a distinction between recycled C methane from the biosphere and fossil methane. When climate-carbon feedbacks are included for both the non-CO₂ and reference gases, all metric values increase relative to the methodology used in AR4, sometimes greatly. Though the uncertainties range for these metric values is greater, as uncertainties in climate-carbon feedbacks are substantial, these calculations provide a more consistent methodology.

'up-front' emissions associated with the development of the unconventional gas resource are calculated and then averaged or 'amortised' over the total amount of gas that is extracted at the site (the EUR, see section 4.2.3). Therefore the GHG emissions in this report are presented in grams of CO₂ equivalent Carbon per MJ of energy of combustion (g CO₂ eq C MJ⁻¹). The physical constants and conversion factors used to calculate the carbon intensity per unit of energy are listed in box 2.

Box 2. Summary: carbon intensity per unit of energy	
Combustion energy of methane:	55.5 MJ kg ⁻¹
Density of methane:	0.659 g/l (at STP) 25°C and 1 atm.
1Mg of CO ₂ :	0.2728 Mg Carbon
1 KWh:	3.6MJ

4.2.3. Estimated Ultimate Recovery (EUR)

The EUR is dependent on the quality of the gas reserve, as well as the gas price and the production cost²⁷. Previous LCAs have found that the majority of GHG emissions are associated with development activities (drilling and well completion), and since these emissions are amortised over the lifetime of the well, its productivity has an important consequence on the carbon intensity of the gas produced (which is expressed per unit of energy, see section 4.1.2).

For the UK, MacKay and Stone (2013) report that EUR below 2 bcf (57 Mm³) of gas would be uneconomic. Since so little is currently known of the UK unconventional gas reserves, MacKay and Stone model three scenarios to investigate the role of EUR on the GHG emissions of UK shale gas (see table 4). We adopt these EUR estimates for our Scottish Scenario for ease of comparison with MacKay and Stone and because their economic arguments are as relevant for Scotland as they are for the rest of the UK. It is likely that the EUR for CBM could be less and yet be economic to exploit since production and processing costs are expected to be lower for CBM than for shale gas.

Table 4. Production Scenarios from MacKay and Stone (2013).

Scenario	Well Life Production			
	<i>Bcf</i>	<i>Mm³</i>	<i>Energy PJ</i>	<i>Gg CO₂ eq C</i>
Low EUR	2	57	2.085	28.061
Central EUR	3	85	3.109	41.845
High EUR	5	140	5.120	68.921

Mm³ = million cubic meters

²⁷ The EUR increases with gas price, but decreases with production cost which is which is dependent on geological and technological factors, and development design.

4.2.4 Disposal of methane

On-site methane disposal infrastructure is necessary for safety reasons, and the processes that may require such practice include maintenance operations and well completion (making a well ready for production) and workovers. Advances in BAT now enable most emissions from e.g. well completion and workovers to be collected and utilised (Skone et al, 2011) which UK operators are expected to apply as part of the licensing agreement (see section 2.6).

The method of methane disposal from these processes has important consequences for GHG emissions since flaring drastically reduces the GWP of the released gases compared to venting because the GWP for CO₂ is 36 times smaller than for methane. In the US, flaring converts ~98% of methane to CO₂ (Skone et al. 2011). In the UK, silent flaring technology allows 100% efficient burning of methane and so we assume that all methane that is flared is converted to CO₂.

Assumptions on the percentage of gas vented, flared or captured is therefore critical to the outcome of the LCA. We model three scenarios to investigate the sensitivity of GHG emissions to the method of methane disposal during well completion:

- **100% capture:** in Scotland, this is most likely at the development stage
- **100% flaring:** in Scotland, this may occur at the exploration stage, although capture would be more favourable.
- **100% venting:** in Scotland this would never be permitted, but this scenario enables comparison with previous published LCAs as a worst-case and stressing the importance of enforcing BAT application.

The method we use to estimate the quantity of methane associated with well completion is outlined in Box 5 (f) in section 4.3.4.

4.2.5. Land use in Scotland

Since Scotland's soil represents a major carbon sink (section 3.2.3) we calculate the GHG emissions associated with land use change for well pad and transport infrastructure (access roads and pipelines) for three soil types in the Central Belt: peatland, arable land, and grassland. We assume that no more than 1.5 m of soil would be removed for construction purposes because this is the maximum that would be excavated for roads. We also assume that areas of deep peat would be avoided for well pad construction which would require excavation to bed rock or suitable load bearing substrate. Deforestation is not considered in this LCA.

Calculations are performed by adapting a model developed to calculate the GHG emissions associated with the construction of wind turbines on peat soil (Nayak et al., 2010; version 2.7.5 of the Scottish Government Wind-farm Carbon Assessment tool). The specific inputs to our land use change model are details in Section 4.3.2 (Box 4b) below.

4.2.6 Infrastructure in Scotland

Proximity to the industrial infrastructure in Scotland compared to the USA will enable roads and pipelines to be shorter and minimise transportation. We estimate the maximum distance

from a road is c. 30 km in the Central Belt and use these figures as an absolute worst-case scenario; the average is more likely to be 10 km or less.

The proximity of the site to a mains water source (or hydrant) and gas distribution infrastructure will reduce transport costs. The area around Canonbie would benefit from proximity to English industrial areas and proximity to exploitation of the Bowland Shales. In Caithness there is a limited water and gas grid and it is relatively remote by road and rail transport. However there are the two ports of Wick and Scrabster for the sea shipment of heavy equipment and consumables and this would reduce the transportation emissions²⁸. The PEDL 158 license area is close to the main road to Wick port.

4.3 LCA Assumptions

The LCA assumptions we have used for each stage of the unconventional exploration and production workflow are summarised in boxes, along with a comparison of how the Scottish Scenario impacts on the relevance of these assumptions.

For each stage we take the example case as shale gas and note any differences for CBM. Some of the stages of unconventional gas exploration and production share several similar activities, and there are little differences between shale gas and CBM, but where these exist we comment on their relevance.

4.3.1 Stage 1: Initial site investigations

Our LCA does not take into account emissions from the site investigation phase. The LCA assumptions are summarised in box 3.

Box 3. LCA assumptions for Stage 1: Non-Intrusive Exploration

Stage 1 emissions are not included in this or any existing LCA.

The GHG emissions associated with spatial exploration and baseline monitoring for shale gas or coal bed methane are not considered. These would include emissions from office-based desk study, field data collection and analysis. No published data exists for these activities, and it is likely that the associated emissions would be minimal.

4.3.2 Stages 2 and 3: Exploration and appraisal

Previous LCAs do not calculate the emissions from stages 2 and 3 alone. In our LCA we could estimate the GHG emissions associated with drilling and site preparation in both the exploration and appraisal stages. Assumptions for stages 2 and 3 are summarised in box 4.

²⁸ GHG emissions for transportation in gCO₂ eq C per tonne mile for road, rail and ship are 160, 104 and 40 respectively

Box 4. LCA assumptions for Stages 2 and 3: Intrusive Exploration and Appraisal

We calculate emissions from land use change from site clearance for the exploration well pad and access roads. We assume that in exploration and appraisal, one vertical and one horizontal well is drilled. The appraisal well for shale gas is hydraulically fractured once. For CBM the appraisal well dewateres the coal seam. Water is transported to and from the site by truck. Any gas produced at this stage is captured and flared or utilised.

a) Assumptions for area of site clearance for exploration activities

New access roads associated with exploration: We assume that 30 km of new access road would be built. These roads are 6.54m-width single track with passing places, as used in the Wind Farm Carbon Assessment Tool (Nayak et al., 2010). This is the maximum likely road length for the Central Belt of Scotland. We have calculated the GHG emission impact of vegetation clearance and the excavation and drainage of top soils (see b, below), but not GHG emissions specifically associated with construction. For a Scottish Scenario we would expect any roads constructed at this stage to be rubble filled with local material.

Well pad area: The area cleared to construct the exploration and appraisal well pad is assumed to be 1 ha.

The total area cleared for new access roads is 19.6 ha. This is considered to be a very conservative estimate since the exploration pad size is likely to be smaller and the road lengths are likely to be shorter.

b) Assumptions for calculating emissions from land use change:

To estimate the carbon emissions from land use change (incl. excavation and drainage of top soils for well pad and access road constructions) we model the following soil types:

- Soil carbon content of 55% peat (with density of 0.25 g/cc) for peat depths of 1.5 m.
- Mineral soils with arable use.
- Mineral soils with grassland use.

The loss of photosynthetic absorption of atmospheric CO₂ into the peat during the 30 year life of the pad is also estimated. This is assumed to be zero for grasslands and arable lands as the vegetation is consumed and respired. Drainage is kept to a minimum and borrow sites are remediated after pad construction. We calculated this by adapting a model developed to calculate the GHG emissions associated with the construction of wind turbines on peat soil (Nayak et al., 2010; version 2.7.5 of the Scottish Government Wind-farm Carbon Assessment tool).

c) Scenario for site construction and equipment transport in the exploration phase

We adopt MacKay and Stone's (2013) reported GHG emissions associated with site construction for development. These estimates consider the hard standing, fencing etc and equipment transport by truck. For a Scottish Scenario we would expect such equipment, and any water, would be transported by trucks at the exploration and appraisal stage.

d) Scenario for exploration and appraisal drilling - We adopt MacKay and Stone's (2013) reported GHG emission associated with drilling a single vertical exploration well and horizontal appraisal well. For more detail on these see Box 5. Well tests would be performed and wells would be cemented and completed as standard.

The Scottish Scenario exploration well would be a single vertical exploration well drilled to 2400m (depth of the base of the Strathclyde Group in the Clackmannan

syncline) to represent a typical well for shale gas in the central belt. We use the same depth for CBM and for shale gas. The Scottish Scenario appraisal well would be a single horizontal of 1.5 km length from the exploration well.

- e) **Scenario for appraisal activities:** For shale gas we assume the appraisal well would be hydraulically fractured once, and for CBM the coal seam would be dewatered. We assume that water would be transported to and from site by truck with the same specifications as outlined in MacKay and Stone (2013), and would be treated off site. Besides the water required for drilling, CBM appraisal only requires water transport from the site during dewatering.
- f) **Scenario for flowback and fugitive emissions:** Any produced gas during appraisal would be captured and flared which would be a worst-case scenario since the gas may be captured and used. We assume the potential methane quantities associated with flowback or dewatering, and potential fugitive emissions are the same for development wells. See **box 5** for assumptions about estimating methane quantities associated with flowback.
- g) **Scenario for abandonment:** We assume that the exploration well pad is developed for production.

4.3.3 Stage 4: Production development

The development of unconventional gas sites in Scotland would likely see a relatively small number of multiple well pads with multiple wells at multiple depths in the prospective rock units (compared to the widely publicised “factory drilling” with closely spaced wells in some areas of the USA. This is due to the multi-layered inter-bedded nature of the shale and coal rocks in Scotland, as well as social factors since multi-well sites minimise the surface footprint. MacKay and Stone (2013) present the overall estimated GHG emissions (tCO₂e per well) from the drilling and hydraulic fracturing together rather than a breakdown of the emissions associated with the activities that the drilling and hydraulic fracturing require. To allow comparison of the GHG emissions associated with CBM and shale gas for this LCA we separate the drilling and fracturing steps.

To calculate methane associated with well completion we have taken a similar approach to previous LCAs, we assume that methane produced during well completion is a function of the initial flow rates at the well and use production decline curves for USA shale gas published by Browning et al (2013). We model three scenarios to investigate the sensitivity of GHG emissions to the method of methane disposal during well completion which are 100% capture, 100% flaring and 100% venting (see section 4.2.4).

The LCA assumptions of Stage 4 (production development) are summarised in box 5.

Box 5. Stage 4 Production Development: LCA assumptions

GHG emissions calculated for Stage 4 activities assume the exploration well pad is developed into a 10 well pad with 3 EUR scenarios. Emissions from land use change from new road construction and for gas and water pipelines are calculated for three vegetation scenarios. We adopt the GHG emissions estimates for drilling and hydraulic fracturing published in MacKay and Stone (2013), and adapt these to calculate emissions for dewatering of coal seams. Each of the production wells are hydraulically fractured once. Water is transported to and from the site by pipeline. Any gas produced at this stage is captured and flared or utilised. We assume a 30 year life span of the production site.

- a) **Scenario for well pads and wells** - We assume a 10 well pad (10 development wells are drilled from a single pad). For the Scottish scenario development pad this would mean 5 wells in each direction, all parallel to the axis of minimum horizontal stress, draining an area of reservoir 0.7 to 1 by 1.5 to 2.5 km. This scenario is a multi-well pad which develops a single rock horizon near the maximum likely depth for shale gas and CBM in Scotland. The likely well pad area for the Scottish scenario is 2.5 ha (hard standing and 10 well cellars and mud and water pits). We do not explicitly consider the GHG emissions related to bunding or security infrastructure.
- b) **Scenario for access road and pipelines** - We have assumed 10 km of new access road, equating to 6.54 ha. The new road would be permanent and designed to carry heavy loads. Over peat land it would be a floating construction. We assume that 10 km of new pipeline are constructed for water, on the assumption that water would be taken from the mains rather than abstracted. In addition, we assume 10 km of new gas pipe will transport the gas produced to the mains and/or to the processing site. These assumptions inform the area of vegetation clearance in (c) below. We do not calculate the GHG emissions specifically associated with construction of roads and pipelines.
- c) **Assumption for land use change** - We assume the same soil scenarios as outlined in Box 5 (b) to calculate the GHG emissions from land use change from vegetation clearance from access road and pipeline construction. We assume that pipelines are buried, and so account for land use change from their construction. The total area of land that is cleared to enlarge the well pad, entrench the pipes and create 10 km new access road is equivalent to the area of land cleared in the development stage (~21- 22 ha).
- d) **Assumptions for site preparation** – Since the exploration well pad is extended for development, we use the emissions outlined in Box 4 (c).
- e) **Drilling production wells** - The water and mud requirements for each horizontal well would be the same as drilling the vertical well. We adopt the GHG emissions estimates for drilling and hydraulic fracturing published in MacKay and Stone (2013), and adapt these to calculate emissions for drilling the wells (500m³ from the total water, 90% of the remaining total emissions). We assume the emissions from transportation of the drill rig are 15 tCO₂ per well.

Drilling for shale gas will use bentonite mud and water. Drilling for CBM, to preserve permeability, water based drilling fluid will be used - which may use more water but since no drilling mud will be used we assume the GHG emissions associated with drilling are the same for CBM and shale gas. In the Scottish scenario we would expect that drilling mud is reconditioned and reused for next well, but do not consider this explicitly here.

- f) **Well completion** - We assume that methane produced during well completion relates to initial gas production at the wellhead. We use the production decline curves for USA shale gas published by Browning et al (2013) to calculate the volume of methane produced in the first 9 days for the three EUR scenarios. This is a conservative estimate. We assume

that potential methane associated with flowback and dewatering are the same, though in reality the initial gas production rates for CBM would be much lower and so the emissions associated with well completion should be considerably less.

We model three scenarios to investigate the sensitivity of GHG emissions to the method of methane disposal during well completion which are 100% capture, 100% flaring and 100% venting (see section 4.2.4) and assume that flaring converts all gas to CO₂.

- g) **Hydraulic fracturing** - For shale gas wells, each horizontal well would be hydraulically fractured once. We assume that wells drilled for CBM do not require hydraulic fracturing. We use estimates of 300 tCO₂e per well for hydraulic fracturing additives as calculated by Jiang et al. (2011). We assume the emissions from transportation of the hydraulic fracturing drill rig are 15 tCO₂ per well. We adopt the GHG emissions estimates for drilling and hydraulic fracturing published in MacKay and Stone (2013), and adapt these to calculate emissions for fracturing the wells (14,500m³ water, 10% of the total emissions for drilling and hydraulic fracturing stage to account for pumping fracturing fluids, additive chemicals and transportation of the fracturing rig).

These estimates will be very conservative for hydraulic fracturing in the Scottish scenario since the fracturing fluid would be recycled and reused for each well, including separating and reusing any returned proppant. This would reduce the quantities of chemicals required. Furthermore, the quantities and transport distance of these additives and proppants would likely be lower for the Central Belt of Scotland than for the USA.

- h) **Dewatering**: GHG emissions from dewatering coal seams for CBM are calculated by adapting MacKay and Stone (2013) estimates for drilling and hydraulic fracturing (14,500m³ water is produced from the coal seam, and 10% of the total emissions for drilling and hydraulic fracturing stage to account for pumping the water from the coal seam).
- i) **Water requirements** - We use MacKay and Stone (2013) assumption that 15,000m³ of water is required to drill and hydraulically fracture each shale gas well (500m³ from this total is used for drilling the well). This is the average volume of water required to hydraulically fracture shales in the USA (Cook et al., 2013). The amount of water transported from the site (for both CBM and shale gas) is assumed to be the same, 15,000m³. For shale gas, this is the produced water from flowback and production, whereas for CBM this is the produced water from dewatering the seam. Without further information on Scottish rocks it is difficult to comment on the proportion of water produced from shale gas or CBM wells for the Scottish scenario. However transport and treatment of 15,000m³ of water is conservative for shale gas since although the flowback volumes for hydraulic fracturing are variable, they have never greater than 80% of the injected volumes, and the intercalated nature of the shale rocks in Scotland would suggest that flowback volumes would be lower.
- j) **Water treatment and transport** – We assume that water is transported to and from the site by temporary pipeline and adopt the MacKay and Stone (2013) calculations for the GHG emissions associated with transporting (pumping) and treating this volume of water in the UK using values from Defra (16 tCO₂e for treating 15,000m³ water). The emissions embedded in pipeline infrastructure are not explicitly considered. CBM appraisal only requires water transport from the site during dewatering and so the emissions for water transport are halved compared to shale gas.

4.3.4. LCA assumptions for Stage 5: Production operation and maintenance

We assume the development wells are operational for 30 years and model three scenarios for gas recovery (EUR scenarios, see section 4.2.2). Fugitive emissions are calculated as a function of the EUR of the well pad, and use the production decline curves of Browning et al. (2013). Calculating GHG emissions from gas processing involved such significant uncertainties that we chose to omit this step from the LCA.

MacKay and Stone (2013) use a single figure for conventional offshore gas production that wraps up gas processing with fugitive emissions from production and transmission to onshore terminals for processing. We chose not to use the approach of MacKay and Stone (2013) since transmission over the distances of offshore operations is much greater than for onshore unconventional gas in Scotland, and this would also double account for fugitive emissions (since we estimate these based on the EUR, see 4.4.2).

GHG emissions from gas processing occur from the construction of a processing facility, fugitive methane leakage in the processing infrastructure, or CO₂ emissions from fuel combustion to power compressors or the gas processing equipment. We already account for fugitive emissions and so the emissions from the processing stage will be dependent on the gas quality (and therefore processing steps) and distance transported for processing (and therefore emissions associated with gas compression). In addition, in the case of developing a new gas treatment plant, these estimates would require calculation of the GHG emissions associated with gas processing infrastructure, or for example, land use change.

As such, in the absence of information about the quality of gas produced from shale or coal in Scotland, and absence of published information about the GHG emissions specifically associated with gas processing and compression, we do not consider the emissions associated with gas processing and compression in this LCA.

The LCA assumptions of Stage 5 (production operation and maintenance) are summarised in box 6.

Box 6. LCA assumptions for Stage 5: Production Operation and Maintenance

GHG emissions associated with stage 5 consider a single workover per well and c.1% of the total gas produced to escape as fugitives.

a) **Well workovers** - we assume that each shale gas (and CBM) well has one workover to extend its lifetime. The potential emissions from well workovers are assumed to be similar to emissions from well completion, and since in Scotland the same application of BAT will be expected for well workovers, we assume the same model scenarios for methane disposal as above (section 4.2.4).

b) **Refracturing** - we do not assume that any of the wells are hydraulically fractured more than once during the operation of the well. If the shales in Scotland are particularly plastic compared to shales in the USA, re-fracturing may be necessary to extend the lifetime of the well. In this case the total GHG emissions for the fracturing process would multiply according to the number of times the well is re-fractured. This would include the GHG emissions associated with sourcing additives and proppants, and from pumping fracturing fluids.

c) **Fugitive methane** – in this LCA we distinguish point sources of methane from operations such as testing and flowback, which can be captured and used or flared, from fugitive methane that cannot be captured and therefore escapes to the atmosphere from valve and compressor operation etc. We assume that a conservative value of c.0.1% of the total gas produced over the operating life of the well escapes as fugitive emissions during the operation and maintenance of valves, pumps etc. This approximation is equivalent to 1 day of initial methane production at the well head which we calculate from the production decline curves for USA shale gas published by Browning et al (2013) (see section 4.3.4, Box 5-f). Fugitive emissions are difficult to capture and flare or utilise due to their small individual volumes and so are considered as vented methane.

d) **Gas processing** - we do not calculate the emissions from gas processing. For CBM, these will be small since gas from CBM has high methane content and may simply need dehydrating with minor compression. For shale gas the gas processing requirements are too uncertain to estimate at this stage, particularly if the gas is sour or contains NGL's, in which case, the processing costs and associated GHG emissions would be considerably higher than CBM. We do consider the estimated emissions from fuel consumption to power compression from NYESDEC (2011), which are 5,591 tCO₂e per year for a single well for production in the Marcellus Shale. These estimates are not presented in the LCA but instead inform our discussion of in section 5.1.5.

e) **Operation accidents** - the impact of accidents, blowouts, terrorist attacks and other events are not considered in this LCA. Similarly we do not consider that an individual hydraulic fracture could propagate to the surface, thereby providing a pathway for methane leakage to the atmosphere (section 2.5).

4.3.5 LCA assumptions for Stage 6: Decommissioning the well

Previous LCA, including MacKay and Stone (2013) do not tend to consider the emissions related to well plugging and site restoration activities, aside from land restoration once the unconventional gas infrastructure is removed. We assume that grass and arable land would be fully restored during abandonment after 30 years operation of the well pad, and that for peat soils the borrow sites are fully restored and that drainage around the pad and roads is minimal. However, peat soils in general are difficult if not impossible to restore and so the carbon loss from land use in peat areas would be more significant.

The LCA assumptions of Stage 6 (decommissioning) are summarised in box 7

Box 7. LCA assumptions for Stage 6: Decommissioning

Stage 6 GHG emissions associated with site decommissioning are not taken into account in this LCA.

The assumption has been made that all exploration wells would continue into the Production cycle. Fugitive methane emissions would be zero on decommissioning due to the depressurisation of formations.

4.3.6 Summary differences in assumptions for Stages 2-3 (exploration/appraisal) and Stage 4 (development).

There are some key differences in the Scottish scenario for activities during the exploration and the development stage, which we summarise in table 5 below.

Table 5. Summary of key difference between operations at the exploration and the development stage.

Assumption	Exploration well pad	Development well pad
Area cleared	30 km of new, temporary fill, access roads (19.6 ha in total) 1 ha for the well pad	10 km new road and 10 km of new gas pipeline and water pipeline 2.5 ha for the well pad
Land use change	Assumptions the same	Assumptions the same
Number of wells per pad	1 vertical, 1 horizontal.	10 horizontal wells.
Water transport	Tanker truck	Pipeline
Methane disposal during clean-up	Captured and flared	a) Captured and flared b) Captured and utilised
EUR	N/A	3 scenarios

5. Results and Discussion

5.1 Shale Gas LCA Results

Our LCA includes the production, transportation and environmental GHG emissions from producing unconventional gas in Scotland.

The estimates of the maximum, mean and minimum GHG emissions for each stage of development are shown in Figures 9a and 9b. The high, central and low estimates of carbon intensity for well construction (which includes drilling, casing and cementing) and hydraulic fracturing rely on the range of values from previously published work as outlined in section 4. Fugitive emissions and emissions from clean-up (well completion and workovers) are dependent on a well's productivity (EUR), therefore the high productivity wells have the highest fugitive emissions and vice versa. The land use change values are for arable land (minimum), grassland and for a 1.5m deep peat site (maximum). All wells are assumed to be worked-over once with equivalent emissions to the original well completion.

It is important to note that whilst the scenarios presented represent a range of recovery factors (EUR) and a range of scenarios and associated assumptions, the uncertainties in these assumptions and scenarios are not included in the calculations or represented in the graphs. We propose how uncertainties may be accounted for in the future work section 6.3.5.

Figure 9a demonstrates the relative contribution of site construction, well construction, hydraulic fracture, land use change and fugitive methane to the overall GHG cost of an unconventional gas well from which all of the clean-up methane is *flared*. This represents a worst-case scenario for an appraisal well, in all likelihood some of the methane at that stage could be captured and utilised. Figure 9b demonstrates the GHG emissions from a well where 100% of the clean-up methane is captured and *utilised*. This represents a well that has been completed using best practice (green completion).

Figure 10 shows the same charts but with land use removed to highlight the variations between the smaller contributions to overall GHG emissions for a site where all flowback methane is flared and for a site where all flowback methane is captured and utilised.

When the different factors are compared, the largest contribution to the total GHG emissions is from potential fugitive methane emissions. GHG emissions associated with land use change are greater than all other sources if peatlands are disturbed. If potential methane emissions from clean-up (during well completion and workovers) are captured and reutilised in Scotland the GHG emissions associated with this stage are negligible. Our LCA models very conservative scenarios in most steps of exploration and development, and thus GHG emissions should be overestimated. This is particularly the case for CBM, and overall GHG emissions from CBM extraction will be lower than shale gas for the same EUR scenarios.

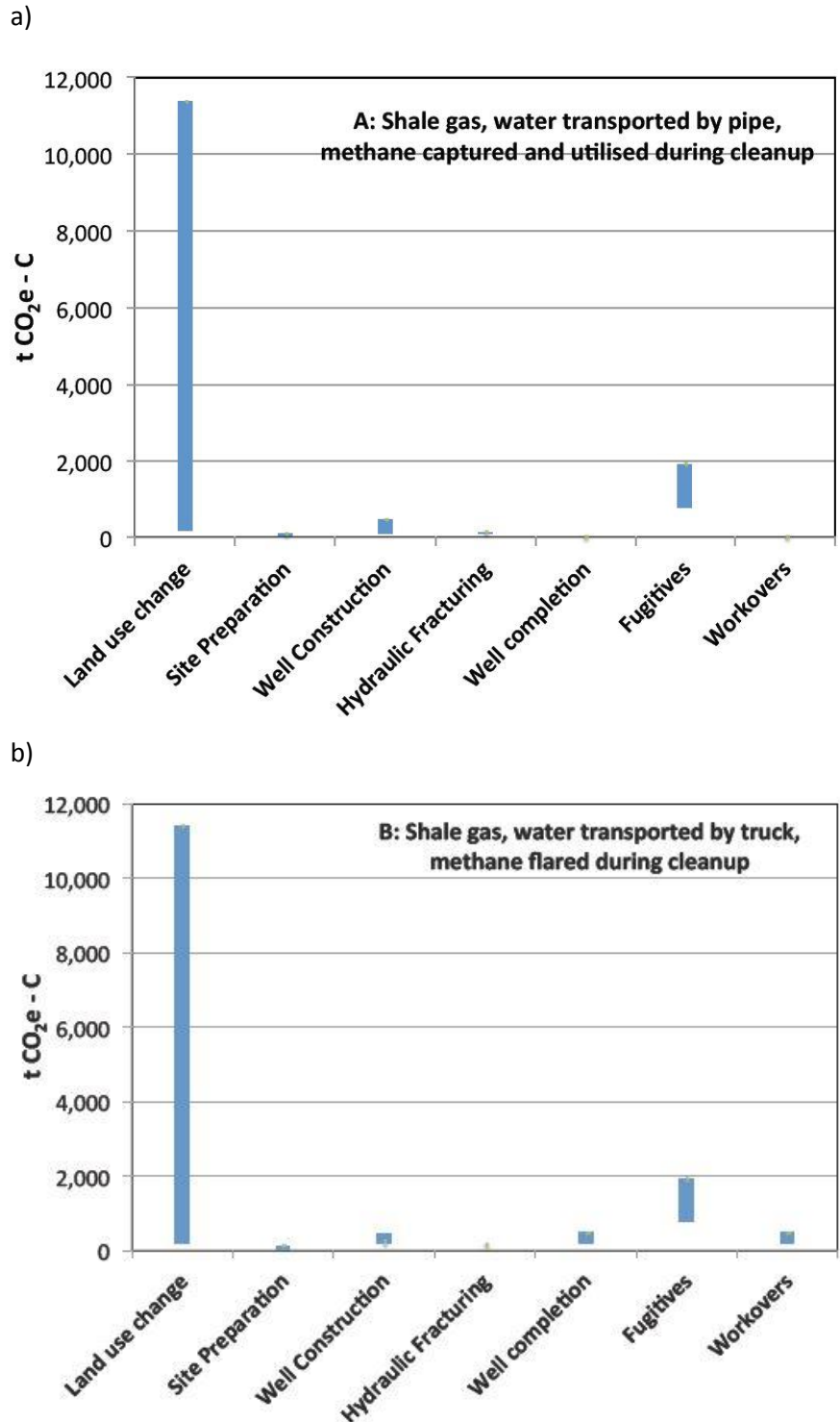


Figure 9. Comparison of GHG cost per well of different elements of the shale gas life cycle, for each element a range of emissions are modelled for high and low productivity wells. Two scenarios are presented: a) where water is transported by pipe and all of the flowback methane is captured and utilised; and b) where water is transported by truck and all of the flowback methane is flared. The largest GHG cost in both cases is for land use change in peatland and for fugitive emissions.

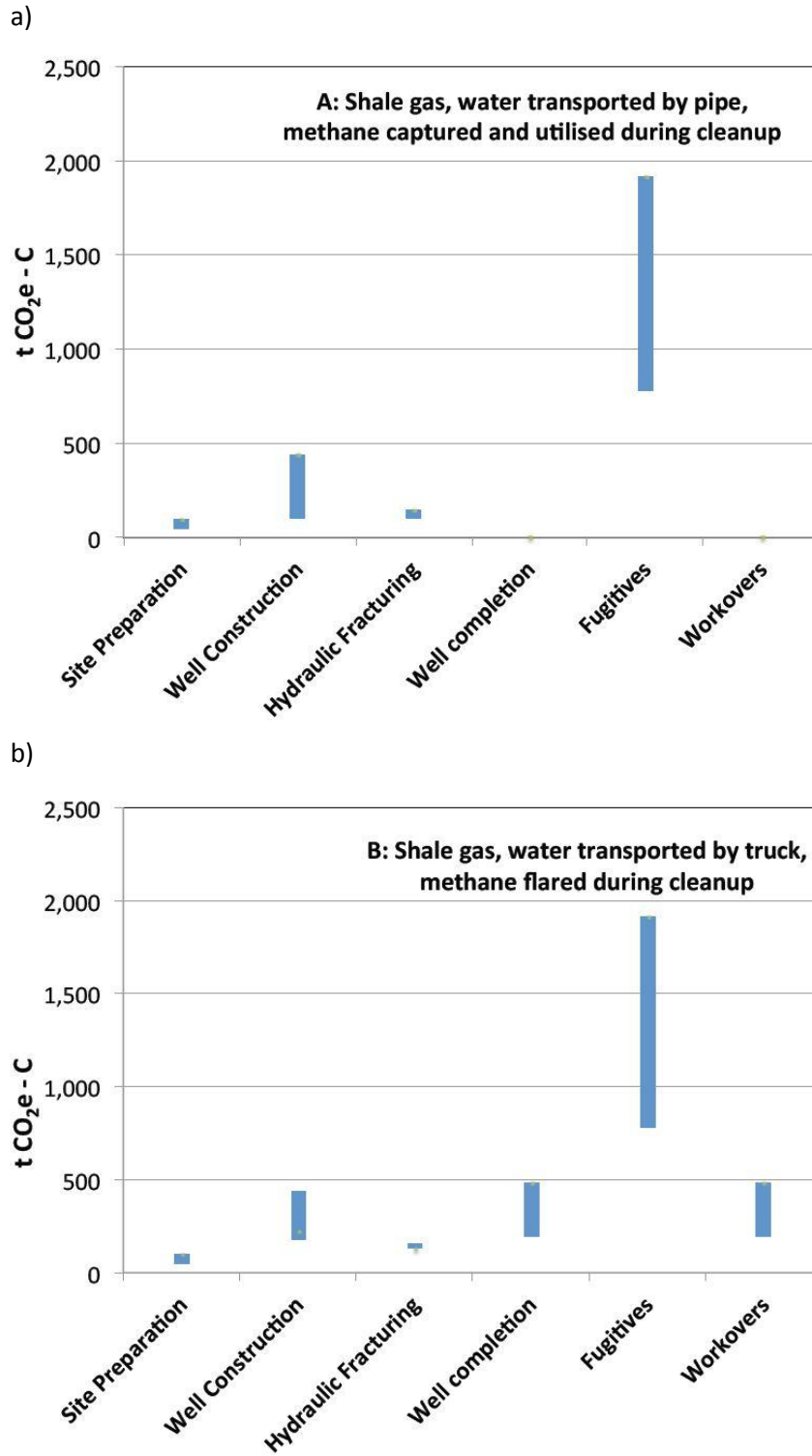


Figure 10. Comparison of GHG cost per well of different elements, *excluding land use change* in shale gas development for each element a range of emissions are modelled for high and low productivity wells. Two scenarios are presented: for: a) where water is transported by pipe and all of the flowback methane is captured and utilised (i.e. no emissions from well completions or workovers); and b) where water is transported by truck and all of the flowback methane is flared.

5.1.1. Methane capture and reuse or flaring during clean-up

There are several different disposal methods for the methane that may be associated with well completion (clean-up). Disposal options include: 1) Methane can be vented (CH_4 released to the atmosphere. This would not be permitted in the UK unless in emergencies, as outlined in section 3.3.7); 2) Methane can be captured and flared (combusted to release CO_2 and H_2O to atmosphere); 3) Methane can be captured and utilised (e.g. powering onsite machinery or re-injected into the gas grid). The disposal methods have considerable implications for the potential GHG emissions (CO_2e) associated with the clean-up process. This is illustrated in Figure 11, which shows the carbon intensity of one clean-up operation (well-completion or reworking) for different methane disposal options.

For our LCA, we consider that waste gas streams will not be 100% vented, but 100% flared as a worst-case scenario. It is Best Practice to capture and utilise as much of the 'clean-up' methane as possible prior to production. This is because 100% venting or flaring will not be permitted due to 1) the safety considerations under UK/EU regulations to avoid explosion and fire risk, and 2) the requirements to minimise GHG emissions. Though we assume capture of flowback emissions to be best practice, Figure 11 shows the GWP reduction that can be achieved by flaring gas captured during clean-up if utilisation of the gas is not possible.

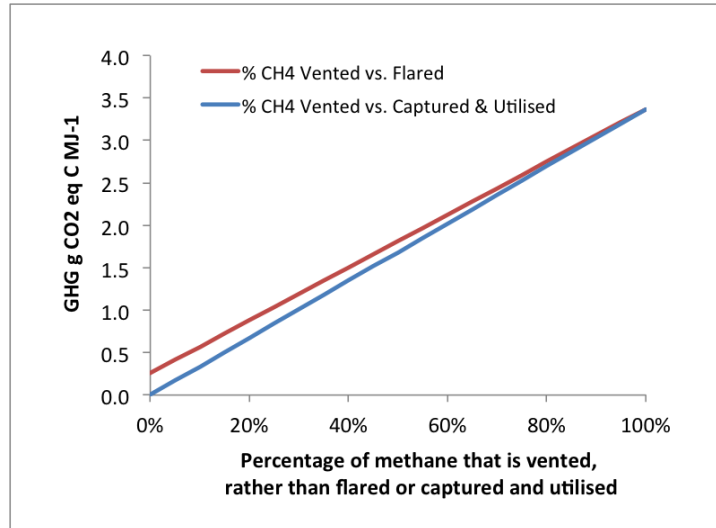
LCAs performed for US operations often assume that a significant proportion (e.g. 15 – 24%) of the clean-up gas is vented. This may have been applicable in the US where there was no previous environmental or economic regulation on methane disposal. The rise in economic value of condensates in the US means that methane or condensate disposal by venting or flaring is no longer implemented to the same extent. This is because as long as the gas and condensates have more value than the cost of a separator and burner/compressor, it makes no economic sense for an operator to vent the clean-up gas. As such, operators would strive not to vent or flare valuable gas: the 100% venting scenario considered by Howarth et al. (2011) is equivalent to venting \$1,000,000 of methane, which commercially is unlikely to happen. For the scenarios we modelled for potential quantities of methane from well clean-up, flaring 100% of this methane would be equivalent to flaring £60,000 - £150,000 of gas, which could instead be captured and used or sold²⁹.

Captured methane may be delivered to the national gas grid, and could be used in place of diesel to power on-site machinery such as pumps, heaters and compressors. If methane utilised on-site displaces diesel for powering the site then there will be an associated GHG emissions reduction, as well as a reduction in the other pollutants from diesel combustion (SO_x , NO_x , black carbon).

The assumptions and calculations we perform to calculate the potential methane associated with well clean-up are very conservative, since 9 days of initial production is towards the maximum estimate of 10 days for field data in the USA (see section 3.4.10).

²⁹ Assumes a gas price of approximately £0.43 per therm.

a)



b)

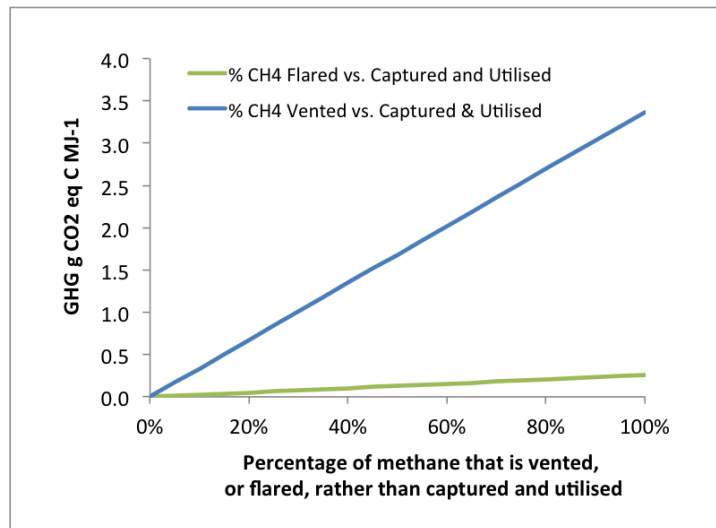


Figure 11 shows the carbon intensity of one clean-up operation (well-completion or reworking) for different methane disposal options (see text above). By mass, the GWP of methane is 36 times greater than CO₂, however because the molecular weight of CO₂ is greater than CH₄, complete combustion of 1kg of methane results in 2.75 kg of CO₂. Therefore, the overall CO₂e emissions from venting methane are 13.1 times more than if the same mass of methane was fully combusted i.e flared using BAT ($36/2.75 = 13.1$).

Figure 11 a) shows how GHG emissions increase with the proportion of methane that is disposed of by venting as opposed to flaring (red line), or being captured and utilised (blue line). 100% capture (0% venting, blue line) has zero GHG emissions – the GHG emissions associated with utilisation are outside the scope of this cradle-to-gate LCA.

Figure 11 b) shows how GHG emissions increase with the proportion of methane that is flared or vented, rather than captured and utilised. 100% venting (0% capture and utilisation, blue line) results in 13.1 times more GHG emissions than 100% flaring (0% capture and utilisation, green line).

These graphs stress how flaring rather than venting methane can vastly reduce the GHG emissions from methane disposal; a small increase in the percentage of methane that is vented instead of being captured and utilised or flared has large consequences for the GHG emission due to the high GWP of methane.

5.1.2. Fugitive emissions

Cumulative small emissions of methane from the maintenance and operation of valves, flanges and pumps over the life of the well (fugitive emissions) would individually be of such small volume that they would be difficult to capture and flare or utilise. These emissions are therefore vented – leading to GHG emissions. Our calculations estimate between 44,000 and 108,000m³ of methane would be fugitively released.

Fugitive emissions are variably accounted for in other studies, which stems from a variation in the definition of fugitive, differences in assumptions of management practice during extraction, and also lack of clarity over the actual emissions, since they are difficult to measure or monitor (see section 5.4.5). Estimates of total fugitive emissions presented by other LCAs typically include emissions from well completion (clean-up gas) together with small emissions from valves and compressor operations etc (which we refer to as fugitive sources), and in some cases, also include leakage during gas processing and distribution, which is not within the scope of our cradle-to-gate LCA. This LCA separates these potential sources of methane emissions because with BAT the clean-up gas can be captured and flared or utilised, whereas it is harder to do so for small leaks (fugitives), although improving the design and lifetime of pumps, valves, and compressors may significantly reduce these emissions.

In this LCA, we assume that, cumulatively, small leaks fugitively vent approximately 0.1% of the total gas produced per well. This is relatively conservative for a cradle-to-gate onshore scenario where BATs are applied as standard, but there is a great degree of uncertainty since this methane is difficult to estimate or calculate without an inventory of practice at UK operations.

5.1.3. Land use change

The carbon intensities for emissions associated with land use change for site preparation on rotational grassland to native peatland (assuming peat depth of 1.5 m) for the three EUR are shown in table 6.

Table 6. Emissions associated with land use change for a ten-well pad, for three production scenarios. EUR - Estimated Ultimate Recovery

Scenario	Total energy <i>PJ</i>	GHG emissions / g CO ₂ eq C MJ ⁻¹	
		<i>Peat soil (1.5 m deep)</i>	<i>Grass land</i>
<i>Low EUR</i>	2.085	5.455	0.493
<i>Central EUR</i>	3.109	3.658	0.331
<i>High EUR</i>	5.120	2.221	0.201

Preparing access roads and the well pad on peatland sites causes significant emissions. Across peatlands roads are assumed to be of a 6.94m wide floating construction³⁰, with 30 km of new road for an exploration site and 10 km road for development site (and 10 km new gas and water pipelines); any borrow sites are fully restored and that drainage around the pad and roads is minimal. For mineral soils the roads are of hardcore construction. The effect of constructing on peat is significant for GHG emissions.

5.1.4. Emissions from transport

Emissions from transport of equipment onsite are embedded in the estimates for site preparation that MacKay and Stone (2013) report. We assume that the drill and fracturing rigs would require transport on site for each well that will be drilled and hydraulically fractured, but this is unlikely since it would be most common to perform all the fracturing operations sequentially. i.e. only one on-off site movement.

We compare the emissions from transporting water to and from the site by truck or by pipeline. Trucking water has much higher emissions (91 tCO₂e per well) associated than pipeline (5 tCO₂e). Therefore pipeline transport reduces the GHG emissions. However, these estimates do not consider the carbon embedded in the pipeline infrastructure or amend the area of land use change if pipelines are not built at the development stage (which would reduce land use change associated with development of an exploration site by on third). These emissions would be minimised if HDPE surface routed pipelines were used for water supply.

5.1.5. Emissions from gas processing

Emissions from gas processing are not included as assumptions for gas processing are too uncertain at this stage. Emissions from the processing stage will be dependent on the gas quality and distance transported for processing. GHG emissions from gas production and processing occur from the construction of a processing facility, fugitive methane leakage in the processing infrastructure, or CO₂ emissions from fuel combustion to power compressors or the gas processing equipment. Scottish shale gas may also contain NGLs which will increase the processing requirements and therefore the GHG emissions associated with this stage.

Most previously published LCAs do not separate emissions from processing from the overall emissions from production, or processing and transport (Forster and Perks, 2011). MacKay and Stone (2013) use a single figure for conventional offshore gas production that wraps up gas processing with fugitive emissions from production and transmission to onshore terminals for processing. We chose not to use this approach since our cradle-to-gate LCA does not include gas transmission, this would double account for fugitive emissions (since we estimate these from the EUR), and in any case, transport over the distances of offshore operations is much greater than for onshore unconventional gas in Scotland.

³⁰ Floating roads are used on peat soils that are over 1m deep. They become increasingly expensive as peat depth increases.

Gas compressors are required to transport the gas to the processing facility, and to maintain particular gas flow/pressure conditions in the processing unit. Forster and Perks (2011) summarise results from NYESDEC (2011) that calculate fuel consumption for compressors emits 5,591 tCO₂ per year for a single well. For a well with a 30 year lifespan, this becomes 45,744 tCO₂ per year per well, which for our EUR scenarios range from 2.4 – 6.0 g CO₂-C eq per MJ. However, these values are for gas production from the Marcellus Shale in the USA, and refer to total fuel use for compressors for transport over larger distances than would be relevant for Scotland.

5.1.6. Comparison of results of other LCA's

An overall comparison of GHG emissions associated with each stage of the exploration-production workflow for shale gas is present alongside estimates from previously published LCAs in Table 7. The largest differences between our LCA results and previous work arise from our assumption that venting of gas during well completion will not be permitted.

Table 7: Estimated GHG emissions associated with each stage of shale gas production (in g CO₂ /MJ) comparing shale gas in Scotland with other published LCAs for the UK and the USA. Table adapted from Forster and Perks (2012). Note that we calculate fugitive emissions separately to emissions from clean-up (well completions and workovers), whereas for other studies the fugitive emissions are included in their estimates of gas processing and transport. The 100 year GWP for methane varies between LCAs presented in this table; our study assumes the latest IPCC (2013) value of 36, Howarth et al. (2011) assumes GWP value of 33, the other studies use 25.

	Scotland	UK			USA		
	This LCA - Shale gas	MacKay and Stone (2013)	Broderick et al. (2011)		Jiang et al. (2011)	Skone et al. (2011)	Howarth et al. (2011)
<i>gCO₂e/MJ</i>			Low	High			
EUR ³¹	Central EUR	Central EUR			Base Case*		
Site preparation	0.05 - 0.12 ³²	0.07	-	-	0.10	0.10	0.60
Drilling & Hydraulic fracturing	0.24 - 0.71 ³⁵	0.39 – 0.41 ³³	0.10	1.60	0.60	1.80	0.90
Well completion	0 - 0.34 ³⁴	0.94 - 1.12 ³⁵	2.90	15.30	1.20	1.30	21.90
Well work-overs	0 - 0.34	0.94 - 1.12	-	-	-	4.60	-
Other fugitive	1.37	-	-	-	-	-	-
Pre - production total	1.66 - 2.89	2.33 – 2.71	3.00	16.90	1.80	7.80	23.40
Gas processing	-	2.73	-	-	-	3.50	2.20
Overall	1.66 - 2.89	5.06 – 5.45	3.00	16.90	1.80	11.30	25.60

³¹ The Central Estimated Ultimate Recovery (EUR) from MacKay and Stone (2013) which we present in this table assumes 3bcf of methane is produced over the lifetime of the well. EUR assumptions differ between studies; for example, Broderick et al. (2011) assume 0.2 – 1.8 bcf, and Jiang et al. (2011) assume 2.7 bcf base case.

³² The emissions associated with land use change on arable & peat soils during the site preparation stage are not included in this table, but for the Central EUR the emissions from vegetation clearance to 1.5 m depth on grassland are 1.21 gCO₂e/MJ, and from peatsoils (55% carbon) are 13.41 gCO₂e/MJ.

³³ These estimates include GHG emissions associated with the transport (by pipeline or truck) and treatment of water required for this stage.

³⁴ We assume 100% of potential methane associated with well clean-up is captured and then flared or re-injected to the gas grid.

³⁵ This presents the Reduced Emissions Completion (REC) model from MacKay and Stone (2013), whereby 90% of potential methane associated with well clean-up is captured and then flared or re-injected to the gas grid. These values exclude the Howarth et al. (2011) Haynesville data.

5.2 Coal Bed Methane LCA Results

This LCA has been conducted for a Scottish scenario for shale gas, and for each component of the associated GHG emissions the differences for a CBM well have been highlighted. The difference in emissions is based on knowledge of the coal geology in the Central Belt of Scotland, and other factors (outlined at each workflow stage). Because we have applied the same assumptions for CBM and shale gas aside from the fracking and dewatering stage, the estimated overall LCA GHG emission for CBM is similar to those for shale gas wells (Figure 13). These assumptions are more conservative for CBM than for shale gas, so our estimate is a worse case scenario for CBM.

The minimum estimate of GHG emissions associated with well construction would be most applicable for CBM. This is because wells for CBM would generally be shorter, around 1 km vertical depth. In addition, this LCA assumes that wells for CBM are not hydraulically fractured, and so the emissions from well preparation source from dewatering the coal seam. The potential emissions associated with clean-up of CBM wells may be lower than for shale gas, and CBM wells may also require fewer workovers. However, we do not have enough information to make valid estimations of the implications or scale of these differences.

For CBM the water transport requirements are almost halved compared to shale gas since only a small amount of water is transported to the site for drilling, but a large quantity of water is transported away from the site for water treatment (whereas for shale gas, large quantities of water are transported onsite for hydraulic fracturing fluid). The wastewater from dewatering the coal seam may be treated on site, such as at Dart Energy's Airth CBM site, but then transported off site for disposal. Figure 12 compares the GHG emissions for hydraulic fracturing and dewatering.

The production rates for CBM wells would also be towards the low end of the estimated production rates of shale gas wells. Additionally, they may require a closer spacing, and consequently more wells to access the same volume of gas. Fugitive emissions and land use change would still be the largest contributing factors.

Gas from CBM will likely have high methane content and require little processing. Therefore the GHG emissions associated with processing of gas produced from coal will likely be lower than for shale.

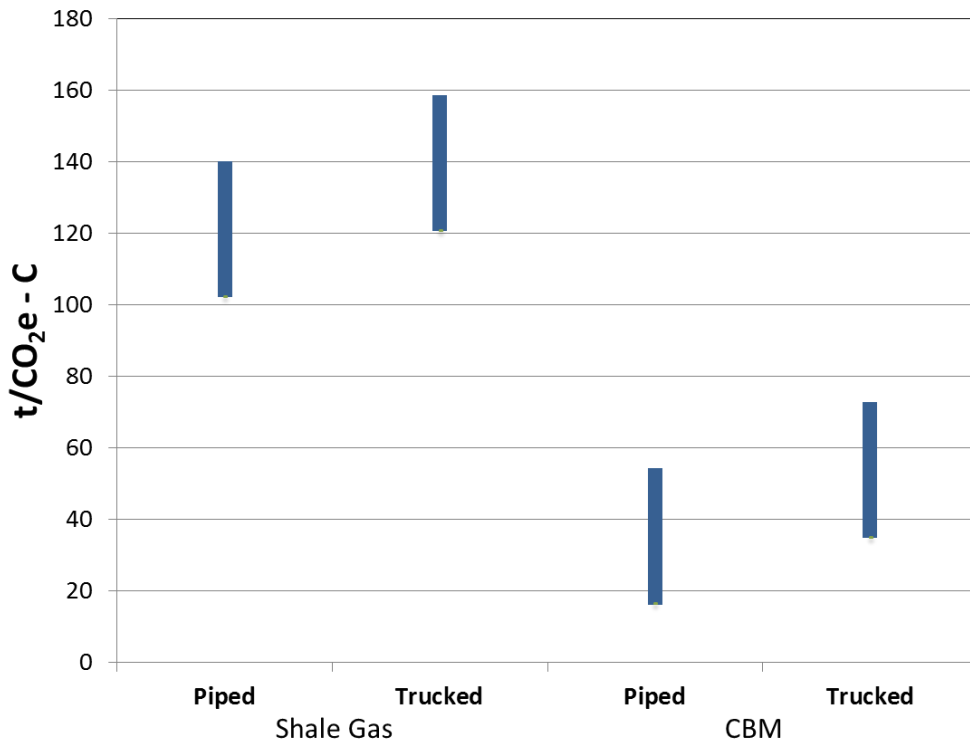


Figure 12. GHG emissions associated with the hydraulic fracturing stage of shale gas extraction compared with GHG emissions associated with the dewatering stage of CBM, for both piped (mains) and trucked water scenarios. The range of GHG emissions reflect high and low EUR recovery rates, as modelled by MacKay and Stone (2013).

5.3 Shale Gas LCA GHG Emissions - Comparison with other Gas Sources

The total development, production, transportation and land use change costs are considered for unconventional gas, as calculated in this report, based on a scenario for the Central Belt of Scotland, and compared to those of Northwest Europe offshore gas, Liquefied Natural Gas (LNG) and Non EU piped gas. For unconventional gas the grassland and peatland (1.5 m depth of peat) sites were considered for both 100% methane flaring, and 100% methane capture, for the clean-up of the flow back fluids, we assume in both these scenarios some fugitive emissions. The Northwest Europe offshore gas, Liquefied Natural Gas and Non EU piped gas values are taken from MacKay and Stone (2013). The results are shown in figure 13. To calculate the total GHG emission for combustion of this fuel, the CO₂ from combustion of 13.46 g CO₂ eq C MJ⁻¹ needs to be added to the emissions from the production, transportation and land use change emissions.

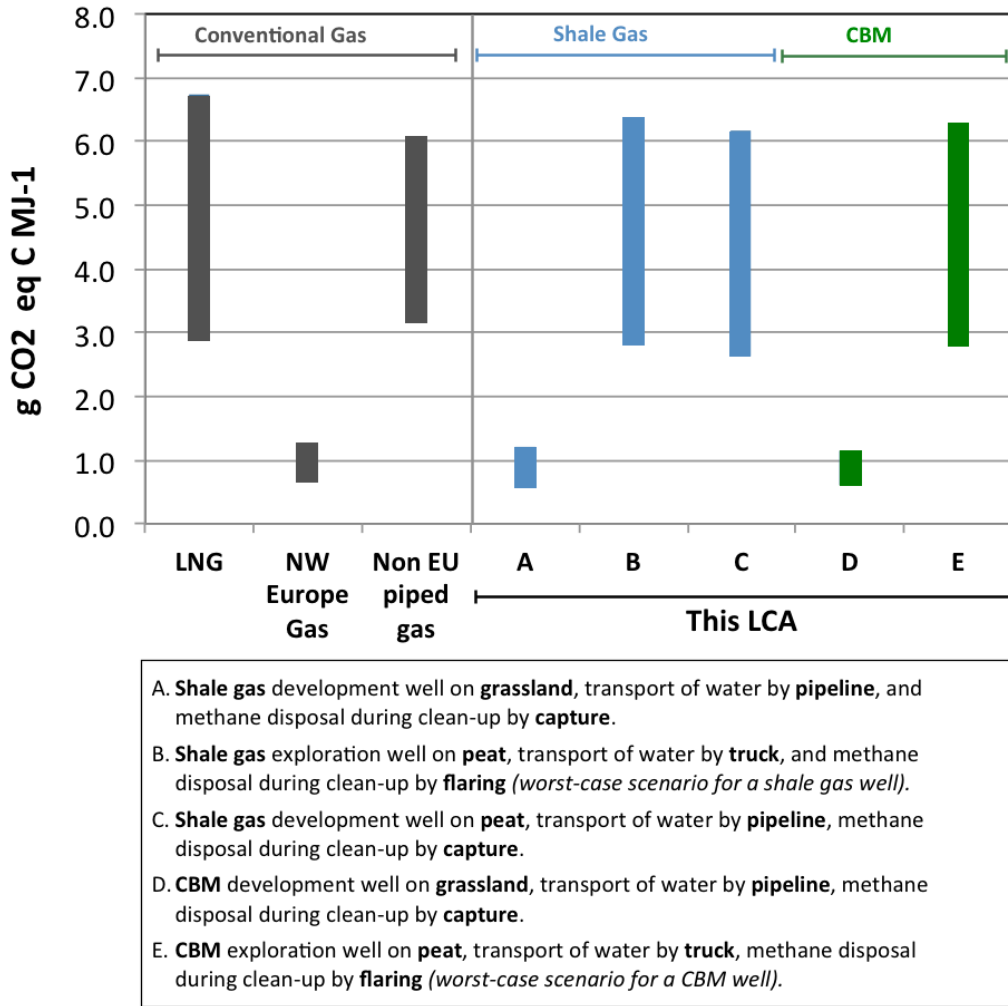


Figure 13. Comparison of the unconventional gas LCA GHG emissions from this study (A-E) with other gas sources, as reported in MacKay and Stone (2013).

NW Europe Gas has the lowest emissions according to MacKay and Stone (2013). From our calculations if Scottish unconventional gas was produced from a grassland or arable land site and all flowback methane was captured and utilised, then gas produced from shale gas would have similar emissions to conventional gas, even with the conservative development assumptions that we have made. However, if the development of shale gas or CBM disturbs peatland of over 1.5 m depth, then total emissions would be higher than emissions from imported Liquid Natural gas (LNG) and Non EU piped gas.

Considering the extreme scenario with the maximum emissions (peatland, 100% flaring of clean-up methane, minimum production level and maximum well costs), the total emission from using gas as a fuel would be similar to oil (22 g CO₂ eq C MJ⁻¹) and lower than coal (33 g CO₂ eq C MJ⁻¹).

5.4 Discussion

We have chosen to take conservative estimates of GHG emissions – i.e. to generally overestimate where there are uncertainties. However we have not completed a full uncertainty analysis or sensitivity-tested our outcomes based on these uncertainties (see section 6.3.5). We recommend that operators aim to minimise GHG emissions from operations where the health and safety and social penalties of doing so are minor. For instance if a road could be diverted away from an area of peat soils, it should be as long as the local community is not adversely affected.

5.4.1 Land use change

The assumptions we use in this LCA for land use change are deliberately conservative: for access to exploration pads we assume 30 km of new (temporary) access road; and for development pads we assume 10 km new (permanent) road, 10 km new water pipe and 10 km new gas pipe (laid together). This assumption is almost certainly an overestimate for the Central Belt, and is probably an overestimate for the other areas under consideration for unconventional gas extraction in S. Scotland and NE Scotland, given that the location of the potential resource in all three locations is close to populated areas. These populated areas have road densities considerably higher than most of the regions in the USA and Australia where unconventional gas has been developed.

Given the desk-based nature of this study we have only accounted for the direct carbon loss from the area beneath developed pads, roads and pipelines, and have modeled a depth of up to 1.5 m for peatland (which we assume to have 55% carbon content). For mineral soils with arable and grassland land use, there is a linear relationship between GHG emissions and the carbon content of soil. However for peatland this relationship is non-linear since the GHG emissions are also affected by parameters such as the depth of peat that is drained, the region of drainage, and also the soil temperatures. The scenario that we model for land use change on Scottish peat is therefore widely variable, depending on the site. It would be possible to model the GHG implications of soils with the specific carbon content for a development site, for particular different depths.

In the event that an unconventional gas industry emerges in Scotland, we would recommend that operators avoid areas of deep peatland, and that where possible existing roads be utilised, though these will have to be maintained appropriately.

5.4.2 Transport choices (roads or pipeline)

MacKay and Stone (2013) find emissions for the transport of water by trucks is 15 times higher than transport by pipeline over a distance of 20 km. These calculations do not appear to consider the embedded carbon in pipelines and/or trucks. The cost of fuel and amortization of the trucks must be considered against the pipeline construction and pumping costs. We estimate that the crossover in volume where piping costs less than trucks would be approximately 4 well's worth, but this depends heavily on the actual volumes of water required at the site and sent off-site for clean-up. This tradeoff could be incorporated into a carbon-calculator for unconventional gas.

An additional factor in deciding on the acceptable tradeoff between GHG emissions from land use change from buried pipelines vs emissions from trucks is public health and public acceptability. Access roads will be built in any case in order to transport site equipment and personnel, so building a new pipeline requires extra land clearance. However a pipeline will significantly reduce the number of trucks going past the local population and therefore the health risks associated with exhaust (e.g. particulates) and road traffic accidents. A full-scale unconventional gas industry may be able to reduce the GHG emissions, while reducing the health impacts to local populations by running spurs off existing gas and/or water pipeline networks to each well sites.

These conflicts can be minimised. Temporary surface-routed pipelines connected to the mains water (see section 3.2.4) could supply water for short-term activities (such as drilling or hydraulic fracturing). Where permanent water supply infrastructure is necessary, surface-routed water supply could minimise emissions from land use change.

5.4.3 Carbon 'front-loading' of exploration and development

All the GHG emissions incurred during exploration, appraisal, and production have to be amortised over the productive life of the wells to determine the actual carbon intensity of the gas. The productivity of the wells is therefore crucial to the overall carbon intensity. This LCA has considered that appraisal wells are turned into producers and that exploration wells are not tested to surface so emissions are small, identifying potential land use change as being more significant in terms of GHG emissions. Given the large number of production wells to be drilled in a field (compared to a small number of exploration and appraisal wells), the GHG emissions of exploration wells (when amortised over the production life) become small. This is one reason why exploration and appraisal wells are often not considered separately in previously published LCAs.

5.4.4 Multi-well and multi-lateral pads

Because of the amount of embedded emissions in constructing the well pad, access roads and any water or gas pipelines, the more wells per pad the lower the GHG 'penalty' from land use change when expressed per well. Given the difference in population density between Scotland and the areas in the USA and Australia where shale gas and CBM development has already taken place, social implications are also likely to drive operators to utilise more multi well and multi-lateral pads. Maximizing the number of wells per pad (or maximise the EUR of the resource) is extremely important in peatland.

5.4.5 Fugitive emissions

This LCA, like previous studies, estimates fugitive GHG emissions from gas production flow rates using an inventory process and engineering calculations. However, as outlined in section 3.5.5, recent studies of direct or airborne measurements at shale gas sites in the USA indicate that fugitive methane emissions may be higher than estimated through the inventory process (Allen et al., 2013; Brandt et al, 2014; Caulton et al., 2014). Further work needs to be conducted to establish the actual flowback and fugitive emissions from drilling, well completion, clean-up, on-site processing and onwards into gas transport (see section 6.3.5). Additionally, recent work by Brandt et al. (2014) highlights that individual sources of

leaks can account for a very large fraction of the overall GHG emissions for gas exploitation. These so called 'super-emitters' sources must be minimised, and so operators should work towards Leak Detection and Repair (LDAR) programmes that would permit rapid remediation of any leaks.

5.4.6 Water consumption for hydraulic fracturing

Given the thinly bedded nature of the Scottish shales in the Central Belt, with intercalated porous beds, it is likely that hydraulic fracture technology would play a potential important role. Recent presentations by hydraulic fracturing companies such as Schlumberger show that there is a large R&D effort to reduce volumes of water used in hydraulic fractures in the USA because water use is becoming a constraint in many areas for unconventional reservoir development. Although water shortage is not currently a significant issue for Scotland in the same way that it is for other areas such as the Marcellus Shale in the USA (Laurenzi and Jersey, 2013); it is clear that reducing water consumption by using techniques such as "slickwater" and foams, plus the re-use of water, are industry trends. Reducing water use has economical as well as environmental benefits. It is therefore likely that actual water use would be below the 15,000m³ per well, assumed in this LCA. However, until hydraulic fracture tests are completed in the Scottish shales it is hard to estimate a more precise water volume.

5.4.7 Gas processing

We have not explicitly included gas processing in our LCA calculations because there is significant uncertainty around the numbers. Emissions from the gas processing stage will be dependent on the gas quality and distance transported for processing. With no information on the composition of the potential gas that could be extracted from shale it is impossible to say what kind of processing would be necessary. If the produced gas has a complex composition or is very sour it will probably be too expensive to develop that resource.

For CBM the main processing requirement is likely to be for dehydration therefore with minor GHG costs. If propane or ethane are required to either dilute the impurities in the produced gas or to increase the concentration of heavier hydrocarbons to meet the national gas grid requirements then these could potentially be sourced from Grangemouth in Scotland's Central Belt.

There is a possibility that shale gas from the Central Belt could be relatively "wet", i.e. contain significant Non Gas Liquids (NGL). Although the production and treatment of NGLs was not in the scope of this LCA, these could be transported to and treated at Grangemouth, where a facility is currently being built to import NGLs from overseas including NGLs from USA shale gas fields.

While dehydration and compression can be completed on site for small wells or at the appraisal stage (like at the CBM well at Airth), most unconventional gas developments would use a centralised processing facility that would process gas from several well pads as opposed to gas from one well pad. Therefore the GHG emissions from processing infrastructure when amortised over several tens of wells will become minimal, provided that developing the processing infrastructure on peatlands is avoided.

The other major GHG emissions from gas processing are from powering compressors required to transport the gas. These compressors can run either on diesel, or be powered by gas produced at a site (Skone et al. 2011). In the Central Belt, the GHG emissions from compressors is likely to be fairly low since it is closer to markets than gas produced offshore or in other, larger counties with less infrastructure (for example, Siberian gas is piped ~4000 miles with ~ 100 compressors stations en route to Germany).

Since we do not include gas processing in our LCA the total GHG emissions are slightly lower than if this stage had been included. The GHG emissions associated with gas processing should be re-evaluated if at any future point Scottish unconventional gas is produced. In the following section further work is suggested that includes sensitivity analysis of such factors.

6. Conclusions and Recommendations

6.1 Summary of Key findings

In our study, we have shown that, by focusing on factors specific to the Central Belt of Scotland, the life-cycle greenhouse gas emissions from unconventional gas extraction are likely to be equivalent to those of conventional gas extraction, if best practice is followed and building on peat is avoided.

The study has found that the key factors influencing the lifecycle emissions of unconventional gas in Scotland are:

- Emissions from land use change associated with site clearance for the construction of well pads, roads and infrastructure in areas of peat soil.
- Fugitive methane emissions that escape from valves etc. and so are not easily captured.
- Methane emissions during well completion, which are dependent on the quantity of methane in the flowback liquid and the treatment of this methane (e.g. venting, flaring, or captured and utilised). But note that in the context of Scottish regulation for the use of BATs these will be small.

These conclusions differ in some respects to the analysis of previous LCAs by Forster and Perks (2012) which reports that the main factors affecting estimates of life cycle GHG emissions are:

- Overall lifetime shale gas production of the well;
- Methane emissions during well completion which are dependent on the quantity of methane in the flowback liquid and the treatment of this methane (e.g. venting, flaring or green completion);
- Number of re-fracturing events and the associated increase in productivity that result from these.

6.2 Recommendations

Of the two major factors influencing GHG emissions identified in our LCA, the amount of direct GHG emissions from well completions and workovers are straightforwardly minimised through regulations requiring green completions, and prioritising capture then flaring over venting, with an associated monitoring regime. There is considerable debate in the academic literature over the magnitude of fugitive emissions (Cathles 2012; Cathles et al 2012; Howarth et al 2012; Weber and Calvin, 2012; Brandt et al. 2014). According to Skone et al. (2011) “although technology is available to capture and flare virtually all of the vented gas from extraction and processing, economics and other practical concerns often prevent the implementation of such technologies”. Further research is required into the cost and practicalities of these GHG emissions reduction technologies; as well as technologies designed to detect and plug leaks in a timely manner. An ongoing research project at the Centre of Carbon Management at the National Physical Laboratory examining fugitive

emissions of methane will also help inform our understanding of fugitive emissions associated with unconventional gas exploitation in Scotland.

Given the scientific debate in the literature over fugitive emissions and the discrepancies between alternative monitoring practices and inventory calculations, further research work in this area and active monitoring of any unconventional gas sites licenced should be a priority.

The direct and indirect emission from destruction of peat is of particular importance to Scotland, and other countries, where peat-rich soils are common. This is the first time that analysis of site clearance and land use change on GHG emissions has been incorporated into an LCA of GHG emissions associated with unconventional gas. The disturbance of peat is hard to mitigate against because the structure, and therefore function, of the peat cannot be restored after it is disturbed. Measures could be put in place around site remediation and carbon-offset initiatives. Operators could be encouraged to avoid areas where peat depths are particularly large, and could include peat depth in calculations of optimal well pad sites.

We recommend that:

- Operators aim to minimise GHG emissions from operations where the health and safety and social penalties of doing so are minor.
- Operators should avoid developing well pads, access roads or new pipelines (water or gas) in areas of deep peatland.
- Where possible, existing roads should be utilised, though these will have to be maintained appropriately.
- Operators should consider running spurs off existing gas and/or water pipeline networks to well sites to minimise construction of new gas and water pipelines. Where necessary, it may be preferable to construct surface-routed (unburied) pipelines to minimise the area of land disturbance and to reduce the embedded carbon in the pipeline infrastructure. Operators should consider a centralised processing facility that would process gas from several well pads, and mechanisms for shared access to such a facility.
- Operators should work towards Leak Detection and Repair (LDAR) programmes that would permit rapid remediation of any leaks to minimise fugitive emissions.
- Operators should aim to capture and utilise the methane produced during clean-up, even at the exploration stage.
- Water and other materials (such as drilling mud, prop pant and chemicals) should be recycled where possible as Best Practice.
- Operators should maximise the number of or length of boreholes at each well pad (to access a larger volume of the subsurface from a single surface installation) to minimise the area of land that is built upon.
- Where possible, the site equipment should be powered by produced or captured natural gas rather than diesel (which is noisier and produces more black carbon pollutants) or electricity (due to transmission losses – unless generated from

renewable sources on site). Operators should consider transporting water to and from the site by surface-routed HDPE pipelines to minimise the area of land disturbance and to reduce the embedded carbon in the pipeline infrastructure.

- Where possible, material should be sourced locally to reduce transport distances (i.e. procurement should consider the embedded carbon emissions).

6.3 Future Work on Lifecycle Assessment

6.3.1 Extraction of offshore resources from onshore wells

Most of the deepest shales in the Central Belt are located under the Firth of Forth and therefore offshore and are not considered in this study. Other shales and coal beds are also likely to be found in shallow offshore areas around the coast of Scotland. It would be possible to drill long reach wells from onshore if production rates rendered such wells economical. An example is the Wytch Farm well in the south of England, which extends 11 km offshore from an Area of Outstanding Natural Beauty. Long reach wells would require different technologies and therefore different parameters that could be considered in a future LCA that considered extraction of near-shore unconventional resources.

6.3.2 Unconventional gas extraction from other parts of Scotland.

We have focussed on the Central Belt because there is a greater amount of data about the subsurface geology than the other areas of interest in Scotland. A future LCA for other regions of Scotland would require consideration of geological and non-geological factors in the LCA that may differ from the Central Belt. For instance, peat thickness in Caithness could be up to ten metres, though it is common for bedrock to emerge through the peat. Additionally, the regional road network sparser than the Central Belt, and there isn't an extensive existing gas grid, so the area of land use change maybe larger. These differences may cause the potential overall GHG emissions from land use change on peat soils to be considerably larger than in the Central Belt. Transport distances would also likely be greater in Caithness, although this factor does not significantly contribute to the overall GHG emissions.

6.3.3 LCA based on a more detailed analysis related to specific sites, practices, land use and other factors

If an unconventional gas industry develops in Scotland it could be useful to develop a carbon calculator similar to that for wind farms (Nayak et al., 2010; version 2.7.5 of the Scottish Government Wind-farm Carbon Assessment tool). This would require more detailed input on the geology, land use and transport access for specific sites. For instance it would be possible to model the GHG implications of soils with the specific carbon content for a development site, and for particular different depths. Tradeoffs between for example different transport options, including embedded carbon in pipelines and tankers could be incorporated into a carbon-calculator for unconventional gas.

6.3.4 Geological uncertainties

The data available to build geological models of rocks in the sub-surface are spatially sparse (e.g. borehole data) or at relatively low resolution (e.g. good-quality 3D seismic data cannot generally image features with a vertical resolution of less than ten metres, and are harder to collect onshore). This means that there would be uncertainty in the lateral and vertical extent of rock formations and their overall geometry (Bond et al 2007; 2012). This geological uncertainty has significant implications for resource potential and therefore estimates of potential GHG emissions associated with exploration and production of shale gas and CBM. There remain significant uncertainties in the geology of shale rocks at depth, even within the Central Belt where the BGS have published their detailed survey of Scottish shale gas resources Monaghan (2014). Exploration activities will reduce these uncertainties to inform a refinement of this study, but uncertainties would still exist.

6.3.5. Uncertainty analysis and sensitivity testing of assumptions

Each element input into the different stages of the LCA has uncertainty associated with it. One example is the range of assumptions and debate around fugitive emissions (e.g. Cathles 2012; Cathles et al 2012; Howarth et al 2012; Weber and Calvin, 2012). A recent study (Brandt et al., 2014) shows that from analyses of previous data, the amount of methane emitted during natural gas operations is consistently underestimated and that “super-emitters” (e.g. one off cases) could represent a large proportion of the total GHG emissions associated with natural gas exploration and production. A sensitivity and uncertainty analysis, similar to that carried out by Weber and Calvin (2012) for GHG emissions associated with shale gas exploitation, and the impact of these uncertainties on the LCA outcomes, would provide a useful insight into the controlling factors and highlight areas where additional research or monitoring may be required.

Sensitivity analysis could also be undertaken on the cumulative GHG effects of multiple well pad development to sustain economic productivity. Most published LCAs, including this one, are based on calculations associated with the development of a single well/well pad, with an assumed productivity (or a range of productivity scenarios – our low, mid and high EURs) that allow the emissions to be compared to other energy sources. Our knowledge of how many well pads will in fact be required to sustain economic productivity is unknown, as there are no current commercial operations on Scotland and flow rates remain untested.

6.3.6. Expert elicitation

A number of the key uncertain model assumptions and inputs in this study meet the criteria for application of expert elicitation (US EPA, 2009); including a lack of scientific consensus, the presence of significant data gaps, and the potential for estimates of individual investigators to be viewed as not-fully-informed, imprecise, or biased. Expert elicitation has been used to effect across science, including environmental health (Knol et al., 2010); conservation (Martin et al. 2012); climate change (Morgan et al. 2001; Schuur et al. 2013). In terms of the LCA outcomes presented here, the estimates for peat carbon sequestration and loss are based on limited scientific studies, yet have a major impact on the overall GHG emissions. An expert elicitation that investigated the range in expert belief on the GHG

emissions associated with peat loss would input into an uncertainty and sensitivity analysis of the current LCA, as well as potentially into a carbon calculator tool.

Some of the other key model assumptions, such as the presence or absence of a 'super-emitter' GHG emission source in a UK scenario, such as those outlined by Brandt et al. (2014), could be considered through use of expert elicitation methods.

6.3.7. Well integrity

Mair et al (2012) highlighted well integrity as being a potential pathway for contaminants. Considine et al. (2013) examine drilling violations for companies operating in the Marcellus Shale (USA). Out of 3,533 wells they found there have been two cases of subsurface gas migration, which were from improper well casing and cementing and thus could have been avoidable. In the UK, out of 143 onshore wells that were producing at the end of 2000, there is one incidence of well integrity failure (Davies et al., 2014), though these by definition do not include unconventional gas wells, which will tend to leak substantially less than conventional gas wells (Thorogood and Younger 2014). The quantity of fugitive emissions resulting from well integrity failure is unknown. Future work could include consideration of the likely long-term well integrity, but rather than using retrospective studies of the legacy well population, this needs to be done by assuming that new wells in Scotland would be constructed using BAT (Thorogood and Younger 2014).

6.3.8. Natural gas liquids

The scope of this project did not include the production of liquids associated with produced natural gas. The extraction and processing of any liquids produced alongside the gas would add to both the gas processing and to the on site separation and extraction facilities required and hence the overall GHG emissions associated with exploitation of any unconventional gas resource. Scenarios that include the production of some natural gas liquids with an associated sensitivity analysis would create a more robust LCA, that might better represent a Scottish scenario given the uncertainties in the depth of burial of the potential shale gas source rocks in Scotland, which are thought to be in places near the oil-gas transition boundary (Monaghan et al., 2014).

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Glossary

Institutional abbreviations

ACOLA	Australian Council of Learned Academies
BGS	British Geological Survey
DECC	The Department of Energy and Climate Change – British government department.
DOE/NETL	The United States Department of Energy national laboratories and technology centres - a system of facilities and laboratories for the purpose of advancing science and technology to fulfil the Department of Energy mission.
HSE	Health and Safety Executive – the UK regulator for work-related health, safety and illness.
IEA/OECD	International Energy Agency . The IEA is an autonomous organisation linked with the Organisation for Economic Co-operation and Development (OECD). It works to ensure reliable, affordable and clean energy for its 28 member countries and beyond.
SEPA	Scottish Environment Protection Agency

Units

atm	- atmospheric pressure. One atmosphere is approximately 0.1 MPa.
Bcf	- billion cubic feet
C	- Carbon.
CI	- carbon intensity; the total GHG emission per MJ of energy CO ₂ eq C MJ ⁻¹
CO_{2eq}	- Carbon dioxide equivalent, a measure used to compare the emissions from various greenhouse gases based upon their global warming potential (GWP). For example, the global warming potential for methane over 100 years is 36. This means that emissions of one million metric tons of methane is equivalent to emissions of 36 million metric tons of carbon dioxide. CO ₂ quantities are often expressed in tonnes (t), or millions of tonnes (megatonnes, Mt).
Gg	- Giga-grams, or a billion grams, which is equivalent to a megatonne.
Ha	- Hectare. One hectare is equivalent to 1000 m ²
Mg	- Mega-grams, or a million grams, which is equivalent to a tonne.
MJ	- Megajoules, a million joules. Joules (J) is a unit of energy.
Mm³	- Million cubic meters
MPa	- Megapascals, or a million pascals. Pascals (Pa) are the standard unit of pressure in the UK.
STP	- Standard temperature and pressure
Tcf	- trillion cubic feet
Tcm	- trillion cubic meters

Terms

Abandonment - To permanently close a well, usually after either logs determine there is insufficient hydrocarbon potential to complete the well, or after production operations have drained the reservoir. An abandoned well is plugged with cement to prevent the escape of methane to the surface or nearby aquifers.

Amortised - Averaged over a lifecycle. For example, to represent the carbon intensity of the fuel while taking the emissions associated with fuel production into account, the total 'up-front' emissions associated with the development of the unconventional gas resource are calculated and then averaged or 'amortised' over the total amount of gas that is extracted at the site.

Anticline - In structural geology, an anticline is a fold where strata slope downward on both sides from a common crest. The oldest rock layers are at the centre of the anticline.

BAT - Best Available Technique(s) – (see Best Management Practice)

Best Management Practice - Current state-of-the-art mitigation measures applied to oil and natural gas drilling and production to help ensure that development is conducted in an environmentally responsible manner. This is also known as Best Available Technique.

Blowout - An uncontrolled flow of gas, oil or water from a well, during drilling when high formation pressure is encountered.

BOP - Blow out preventer – A valve at the top of a well that controls the fluids in hydrocarbon wells. BOP's are of critical importance to the safety of the well.

Borehole – The hole or shaft in the earth made by a well drill; also, the uncased drill hole from the surface to the bottom of the well.

Borrow Pits - Where material from one location is excavated for use at another site. The material excavated is often sand or gravel, and is used for example as hard standing for further construction (e.g. a well pad or road).

CAR - Controlled Activities Regulations - Regulations for any activities that may affect Scotland's water environment.

Casing - Steel pipe placed in a well.

CBM - Coal Bed Methane or Coal Seam Gas (CSG). A form of natural gas extracted from coal beds. Along with tight and shale gas, CBM is considered an unconventional natural gas resource.

Cement bond log – an acoustic logging tool that is used to determine the quality of the well cement, to ensure that the cement has strongly bonded to both the casing (pipe) and the formation wall.

CMM – Coal Mine Methane - A form of natural gas extracted from coalmines.

Clean-up - Clean-up is a period of controlled production to clean out the well in advance of gas production after drilling, well completion and workovers. Clean-up removes drilling debris, drilling fluids and flowback fluids from wells that have been hydraulically fractured or or worked over. This must be done to allow dry gas to flow.

Completion - the activities and methods of preparing a well for production after it has been drilled to the objective formation. This principally involves preparing the well to the required specifications; running in production tubing and its associated down hole tools, as well as perforating and stimulating the well by the use of hydraulic fracturing, as required.

Conventional gas - Conventional gas is natural gas that is extracted from underground reservoirs using traditional exploration and production methods.

Deep peat - a peat soil with a surface organic layer greater than 1.0m deep (JNCC, 2011).

Disposal Well - A well into which waste fluids could be injected deep underground for safe disposal.

Drill bit - the tool used to drill through the rock.

Drilling Fluid - Mud, water, or air pumped down the drill string which acts as a lubricant for the bit and is used to carry rock cuttings back up the wellbore. It is also used for pressure control in the wellbore.

Drill-stem test - Well tests that are conducted with the drill-string in the borehole.

Drill-String - The combination of the drill pipe and any tools used to make the drill bit rotate and continue drilling into rock.

EIA - Environmental Impact Assessment - a formal process or procedure used to identify the future positive and negative environmental consequences of a development proposal (plan or policy), to ensure that environmental impacts are considered by decision makers.

Estimated Ultimate Recovery (EUR) – the estimated total amount of gas which is economically recoverably from a well. This is equivalent to the productivity of a well.

Flowback - The flow of fracture fluid back to the wellbore after the treatment is completed.

Flowback fluids - Liquids produced following drilling and initial completion and clean-up of the well.

Geosteering tools - Tools that image the rock around the well.

GHG - Greenhouse gases

Green completion - used to describe the Best Available Technique employed for preparing a cased well for production.

Groundwater – The supply of usually fresh water found beneath the surface usually in aquifers, which are a body of permeable rock containing water, and may supply wells and springs with drinking water.

GWP – Global warming potential.

HGV - Heavy goods vehicles

High Volume Hydraulic Fracturing - The stimulation of a well (normally a shale gas well using horizontal drilling techniques with multiple fracturing stages) with high volumes of fracturing fluid. Defined by New York State DEC (2011) as fracturing using 300,000 gallons (1,350m³) or more of water as the base fluid in fracturing fluid.

Horizontal Drilling - Deviation of the borehole from vertical so that the borehole penetrates a productive formation with horizontally aligned strata, and runs approximately horizontally.

Horizontal Leg - The part of the wellbore that deviates significantly from the vertical; it may or may not be perfectly parallel with the layers in the rock formation.

Hydraulic fracturing (aka Fracing or Fracking) - A process through which small fractures are made in impermeable rock by a pressurised combination of water, sand and chemical additives. The small fractures are held open by grains of sand, allowing the natural gas to flow out of the rock and into the wellbore.

Hydraulic Fracturing Fluid - Fluid used to perform hydraulic fracturing; includes the primary carrier fluid, proppant material, and all applicable additives.

Kerogen is a mixture of organic chemical compounds that make up a portion of the organic matter in sedimentary rocks. It is insoluble in normal organic solvents because of the high molecular weight of its component compounds.

LCA - Life Cycle Assessment

LDAR - Leak Detection and Repair

Marcellus Shale (USA) – A large play that underlies most of the U.S. Northeast, the Marcellus is a Devonian-age shale that is estimated by the Energy Information Administration to contain at least 410 tcf of unproved, technically recoverable gas. Most of the play is at the 5,000-to-8,000 foot level below the surface and was long considered too expensive to access until advances in drilling and fracturing technology.

Microseismic - The methods by which fracturing of the reservoir could be observed by geophysical techniques to determine where the fractures occurred within the reservoir.

NGLs - Non Gas Liquids - Components of natural gas that are separated from the gas state in the form of liquids.

Operator - Any person or organisation in charge of the development of a lease or drilling and operation of a producing well

Peat - a soil with a surface organic layer greater than 0.5m deep which has an organic matter content of more than 60% (JNCC, 2011)

PEDL - Petroleum Exploration and Development Licenses.

Perforate - To make holes through the casing to allow the oil or gas to flow into the well or to squeeze cement behind the casing.

Perforation - A hole created in the casing to achieve efficient communication between the reservoir and the wellbore.

Permeability - Permeability is the measure of how fluids or natural gas move through the rock (typically measured in millidarcies or mD)

PPC - Pollution Prevention and Control - is a regulatory regime for controlling pollution from certain industrial activities (PPC 2012).

Proppant – A granular substance, often sand, that is mixed with and carried by fracturing fluid pumped into a shale well. Its purpose is to keep cracks and fractures that occur during the hydraulic fracturing process open so trapped natural gas could escape.

Propping Agents/Proppants - Non-compressible material, usually sand or ceramic beads, that is added to the fracture fluid and pumped into the open fractures to prop them open once the fracturing pressures are removed.

REC - Reduced Emissions Completion.

Reclamation – The restoration of a well site to its pre-existing condition after drilling operations cease. Reclamation activities, which are governed by state, federal and local laws and regulations, could include soil replacement, compacting and re-seeding of natural vegetation.

Reduced Emissions Completion (aka green completion) - a term used to describe a practice that captures gas produced during well completions and well workovers following hydraulic fracturing. Portable equipment is brought on site to separate the gas from the solids and

liquids produced during the high - rate flowback, and produce gas that could be delivered into the sales pipeline. RECs help to reduce methane, VOC, and HAP emissions during well clean-up and could eliminate or significantly reduce the need for flaring.

Reservoir (oil or gas) - A subsurface, porous, permeable or naturally fractured rock body in which a potentially economic amount of oil or gas has accumulated. A gas reservoir consists only of gas plus fresh water that condenses from the flow stream reservoir. In a gas condensate reservoir, the hydrocarbons may exist as a gas, but, when brought to the surface, some of the heavier hydrocarbons condense and become a liquid (see shale oil).

Reservoir Rock - A rock that may contain oil or gas in appreciable quantity and through which petroleum may migrate.

Sedimentary rock - A rock formed from sediment transported from its source and deposited in water or by precipitation from solution or from secretions of organisms.

Shale - A sedimentary rock consisting of thinly laminated claystone, siltstone or mudstone. Shale is formed from deposits of mud, silt, clay, and organic matter. These are very fine-grained low permeability sediments, typically deposited in lakes and seas.

Shale gas - is a natural gas trapped within shales that are rich in un-decayed organic material (such as the remains of plants, animals and micro-organisms). The organic matter transforms into hydrocarbons when the rock is heated and pressurised, first transforming to oil and then to gas as temperatures increase. The gas then remained trapped within the impermeable shale rocks (unlike conventional gas, where it escapes migrating into the adjacent rock volume).

Shale oil - liquid hydrocarbons produced from shale.

SIS well – Surface to in seam well – a CBM well that is drilled vertically down to the coal seam, and then continues horizontally along the coal seam. The SIS well will intersect the vertical well.

Stratigraphy - The branch of geology that seeks to understand the geometric relationships between different rock layers (called strata), and to interpret the history represented by these rock layers.

Syncline - In structural geology, a syncline is a fold in the rock, where the rock layers dip inward from both sides toward the axis (center) of the fold, where the younger rock layers are located.

Tight gas - Natural gas found in reservoirs with low porosity and low permeability. It could be compared to drilling a hole into a concrete driveway—the rock layers that hold the natural gas are very dense, therefore the gas doesn't flow easily.

Tight sands - A geological formation consisting of a matrix of typically impermeable, non-porous tight sands.

TOC - Total Organic Carbon - The concentration of material derived from decaying vegetation, bacterial growth and metabolic activities of living organisms or chemicals in the source rocks.

Unconventional gas - natural gas held in rocks that are not conventionally exploited due to their geological characteristics which makes the gas too difficult or uneconomic to extract. The term includes shale gas, tight gas, coal bed methane (CBM) and methane hydrates.

Viscosity - A measure of the degree to which a fluid resists flow under an applied force.

VOC - Volatile Organic Compound. These are organic compounds that are volatile gases at standard atmospheric conditions.

Well completion - the process of preparing a cased well for production.

Well pad - A site constructed, prepared, levelled and/or cleared in order to perform the activities and stage the equipment and other infrastructure necessary to drill one or more natural gas exploratory or production wells.

Well site - Includes the well pad and access roads, equipment storage and staging areas, vehicle turnarounds, and any other areas directly or indirectly impacted by activities involving a well.

Wellbore - A borehole; the hole drilled by the bit. A wellbore may have casing in it or it may be open (uncased); or part of it may be cased, and part of it may be open.

Wellhead - The equipment installed at the surface of the wellbore. A wellhead includes such equipment as the casing head and tubing head.

Wildcat - Well drilled to discover a previously unknown oil or gas pool or a well drilled one mile or more from a producing well.

Workover - Repair operations on a producing well to restore or increase production. This may involve repeat hydraulic fracturing to re-stimulate gas flow from the well.

Zone - A rock stratum of different character or fluid content from other strata.



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