Committee on Climate Change report on Onshore Petroleum – supporting annex on analytical assumptions

Understanding the potential for shale gas production in the UK

Both conventional and unconventional sources of oil and gas were generated over millions of years from the same source rock.

- Oil and gas was formed millions of years ago when great quantities of organic matter were buried under an increasingly thick layer of sediment. As the depth of the sedimentary layer increased the temperature and pressure exerted on the organic matter increased, eventually transforming it into hydrocarbons (a compound made up of carbon and hydrogen); oil was formed first eventually followed by gas as the temperatures increased further.
- For conventional reserves of oil and gas, some of the hydrocarbons escaped the source rock (the layer containing the organic matter) rising up through permeable rock before being trapped by a non-permeable layer, forming the oil and gas reserves we exploit today.
- With unconventional oil and gas the hydrocarbons remained locked in the low permeability source rock.

The processes for exploiting both conventional and unconventional oil and gas are similar, the main difference being how the wells are stimulated to improve the flow of the hydrocarbons. Unconventional oil and gas wells are stimulated with (high volume) hydraulic fracturing which increases the void space in the shale improving the flow of hydrocarbon up the well.

- Hydraulic fracturing is the process of pumping fluid down the well at high pressure. The fluid is mainly water, with the addition of chemicals that are used for a variety of reasons including improving the flow characteristics of the water and mitigating bacterial growth; and a proppant such as sand which prevents the fractures created from closing.
- 10% of conventional wells have been hydraulically fractured, although this is likely to have been carried out using a lower volume of fracturing fluid than those used for shale gas exploitation.

The Infrastructure Act (2015) covers shale gas wells when hydraulic fracturing is used with a relevant well to explore or exploit petroleum and more than 1,000 cubic meters of fluid is injected at each stage or more than 10,000 cubic meters in total.[1] For the purposes of this report we have not differentiated between hydraulic fracturing with different fracturing fluid volume. Our analysis and recommendations apply to all hydraulic fracturing to improve the flow of hydrocarbon from the source rock (shale, mud-rock, etc.), independent of fracturing fluid volume.

Knowledge that shale deposits contain hydrocarbons is not a recent development, although commercial exploitation of these deposits on a large scale was not possible until the development of horizontal drilling and hydraulic fracturing. A recent series of studies from the

---

[1] Analysis by Professor Stuart Haszeldine has suggested that this definition would not cover all shale gas wells in the UK.

British Geological Survey (BGS) has estimated the oil and gas in place in three shale basins: the Weald, the Bowland and Midland Valley.

- The **Weald** basin is located in South-East England. The BGS report found that the basin had no significant gas resource, mainly because the shale is not thought to have reached the geological maturity required to generate gas. The study estimates the total oil in place ranges from 2.2-4.4-8.6 billion barrels of oil (P90-P50-P10).[2]
- The **Bowland** basin is located in the North of England. Strictly, this shale basin is formed of both the Bowland shale formation and the Hodder mudstone formation and referred to as the Bowland-Hodder shale formation. BGS estimate the gas in place ranges from 4.6-7.5-12.7 tcm (49,000-80,000-130,000 TWh) (P90-P50-P10). The study from BGS does not estimate the oil in place due to inadequate geotechnical data.
- The **Midland Valley** basin is located in the central belt across Scotland. The recent BGS study estimates that the gas in place ranges from 1.4-2.3-3.8 tcm (15,000-24,000-40,000 TWh) ((P90-P50-P10). The study estimates the oil in place ranges from 3.2-6.0-11.2 billion barrels of oil (P90-P50-P10).

The BGS studies emphasised that these figures refer to an estimate for the entire volumes of hydrocarbons contained in the rock formations, not how much can be technically recovered. To start to establish the volume of gas that is technically recoverable requires a number of exploratory wells to prove commercial flows of gas are possible.

- The US Environmental Protection Agency studies estimate that technical recovery factors typically found in the US range from 20% to 30%, but caveat this by stating that a shale formation's resource potential cannot be fully determined until extensive well production tests are conducted across the formation.
- In Poland, 72 shale gas wells had been drilled by the end of 2015, with 25 fractured releasing gas.[3] However the wells only yielded at best a third of the gas required to make the wells commercial.[4]
- Both Argentina and China have started to produce shale gas commercially.
- So far only a single shale well has been flow tested in the UK, at Preece Hall near Blackpool. However, proceedings stopped when hydraulic fracturing triggered seismic movements.
- Estimates on the length of time required for exploration in the UK vary from two to ten years before estimates of the technically recoverable reserve can be formed. This is dependent on the length of time required to drill and fracture numerous wells across the resource. Between 2000 and 2010 it is estimated that over 17,000 exploratory natural gas wells were drilled in the US, at an average of 130 per month. This level of exploration is unlikely to be replicated in the UK as the area covered by shale basins is far greater in the US and they approached this in a trial and error way, which is unlikely to be replicated in the UK.

---

[2] P90, P50 and P10 refer to the estimates of probability for at least the quoted resource. For example, P90 indicates a 90% chance that the resource is at least the estimate cited.

[3] http://www.nature.com/news/can-fracking-power-europe-1.19464

[4] The reason for the poor performance of the wells is thought to be due to the presence of loam (clay) in the shale; on contact with water the loam swells reducing the gas flow.

Ultimately the productivity of a well is a function of the technical recoverability per unit length of fractured lateral and the length of the lateral. The productivity of a standard well can vary by a factor of over 10 across a shale formation.[5] As the length of a well lateral increases so does the productivity of the well, although productivity per unit length has been found to reduce as the well lateral length increases.[6]

Production from shale wells declines exponentially soon after production starts. The estimated ultimate recovery (EUR) is an estimate of the volume of gas that can be produced over the productive life of the well.[7] Whilst we have assumed a range of EURs for our analysis, these were based on the level considered necessary for a commercial industry at a range of gas prices.

It is uncertain whether the conditions which led to the dramatic increase in US shale gas production will be replicated in the UK or elsewhere. Whilst we covered various productivity scenarios in the report, these were used to give an illustration of the potential greenhouse gas emissions at various reported levels of production. All the productivity scenarios assume that shale gas can be produced economically to some degree.

In reality, this will remain highly uncertain until a sufficient level of exploratory drilling has been undertaken across the relevant shale basin to indicate whether commercial flows of hydrocarbons are achievable. Ultimately, the economics of shale gas production will come down to three key drivers; the geology, which influences the well productivity; the costs required to achieve that productivity, and the price at which the gas can be sold.

Greenhouse gas emissions assumptions

Oil and gas wells are developed over four main stages: exploration, well development, production and well decommissioning and abandonment. Greenhouse gas emissions occur at each of these stages. We have considered these emissions in our analysis in four categories:

- **Fugitive emissions**, which include both vented emissions and unintentional leaks. Vented emissions are a result of planned releases, where permitted, as a result of maintenance operations and safety concerns. Unintentional methane leaks include those from valves and pipe joints, compressors, well heads and accidental releases above and below ground from the well through to injection into the grid or before being put to use.
- **Combustion emissions** that occur from on-site burning of fossil fuels. The emissions come from engines, such as those used for drilling and hydraulic fracturing, as well as from any flaring of gas.
- **Indirect emissions** that result from transporting materials and waste to and from site.
- **Land-use change emissions**, which include the CO_2 released (e.g. from the soil) when land is converted from one use to another, as well as any emissions relating to land remediation during decommissioning.

[5] IDDRI (2014) *Unconventional Wisdom*, available at: http://www.iddri.org/Publications/Unconventional-wisdom-economic-analysis-of-US-shale-gas-and-implications-for-the-EU

[6] http://www.ogj.com/articles/print/volume-113/issue-12/drilling-production/study-forecasts-gradual-haynesville-production-recovery-before-final-decline.html

[7] It should be noted that the economic life of the well is likely to be shorter than the productive life; therefore the total volume of gas produced from the well is likely to be smaller than the EUR.

Top-down approaches to estimating methane emissions, via sampling of atmospheric methane concentrations, tend to produce higher estimates for the proportion of gas being released than bottom-up studies. However, top-down studies cannot currently attribute emissions to particular sources (e.g. shale gas production), nor do they allow detailed analysis of the opportunities for reducing these emissions.

We have therefore based our analysis on the best available bottom-up evidence base, in order to estimate ranges for potential emissions in a UK context. We have obtained estimates for the greenhouse gas emissions associated with onshore petroleum exploitation from various sources:

- **UK emissions inventory**. Greenhouse gas emissions from petroleum exploitation are estimated in the National Atmospheric Emissions Inventory (NAEI), which is produced annually under international reporting obligations. The inventory is used as the basis for reporting the UK's GHG emissions to the European Commission (EC) and United Nations Framework Convention on Climate Change (UNFCCC).
- The UK GHG inventory uses a range of generic emission factors, which have been developed by sampling the potential GHG emissions from each piece of equipment. The emissions factor is then multiplied by an activity factor, which accounts for the number of each equipment type. The accuracy of the estimated emissions depends on the quality of both emission factor and activity factor.
- We have used various sources to estimate the emissions not currently covered by the UK inventory, including emissions from unconventional oil and gas. The range of sources of onshore petroleum varies in quality and volume of information available:
    - A growing number of studies have been developed on the lifecycle analysis of natural gas supplies, with many comparing lifecycle emissions for shale gas to those for other sources of energy. Until recently the majority of these studies relied on engineering assumptions in the absence of primary data.
    - More recently, the Environmental Defense Fund, a US NGO, has funded a group of studies that measured both individual sites and entire regions.
- In September 2015, the Sustainable Gas Institute (SGI) produced a comprehensive literature review on the available evidence on GHG emissions from the exploitation of gas.[8]

We have used these sources as the basis for our emissions data (Table 1), supplemented by a few more recent studies.

[8] SGI (2015), *Methane and CO_2 emissions from the natural gas supply chain*, http://www.sustainablegasinstitute.org/publications/white-paper-1/

Table 1. Summary of emissions from different stages of shale gas extraction

		Literature ($ktCO_2e$/well)			
		Minimum	**Mean**	**Median**	**Maximum**
Pre-production	**Site preparation**	0.012	0.26	0.23	0.9
	Drilling	0.012	0.32	0.29	0.87
	Hydraulic fracturing	0.18	0.4	0.29	0.8
	Well completion	-	2.8	0.12	130
Extraction	**Normal operation**	1.7	7	5.8	18
	Liquids unloading	-	3	0.41	160
	Workovers	-	5	0.13	130
Processing		1.3	8	7	21
Total		**3.2**	**27**	**14**	**470**

Source: SGI with CCC calculations

Note: Assumes that a well provides 0.52 TWh (2 bcf) of gas

Based on this evidence, we have constructed Low, Central and High estimates for emissions at each stage of shale gas production (Table 2) before mitigation techniques and technologies are deployed:

- **Pre-completion emissions**. This includes site preparation, drilling and hydraulic fracturing. We use the median and high emissions given in literature for our range. Additionally we look at the potential GHG emissions associated with land use change which Bond et al[9] highlighted could have a major impact.
- **Well completions**. The SGI reported that the highest methane emission recorded during well completion was 537,000 m^3 which we have used for our high GHG emission[10] and

[9] Bond et al. (2014), *Life-cycle Assessment of Greenhouse Gas Emissions from Unconventional Gas in Scotland*, http://www.climatexchange.org.uk/files/2514/1803/8235/Life-cycle_Assessment_of_Greenhouse_Gas_Emissions_from_Unconventional_Gas_in_Scotland_Full_Report_Updated_8.Dec.14.pdf

[10] The highest in literature is 6,800,000 m^3 as estimated by Howarth

100,000 m^3 as our central. Methane emissions from well completions have been measured to be low as 300 m^3.

- **Normal operations**.
  - A recent study by Marchese et al.[11] measured methane emissions from 114 gathering stations in the US. They found mean methane emissions from gathering stations to be 1.2% of throughput (ignoring an obvious outlier of 69%), which represents our high value, we use the median value of 0.43% as our central value.
  - For well pad methane emissions, Allen et al.[12] measured emissions to be up to 0.2% of throughput; we use this for both our high and central values. Brantley et al[13] found emissions from the well pad to be higher than Allen, but the author suggested the difference was due to the sites measured being older with low productivity.
  - Normal operations are required to use some of the gas for the process. We have assumed this to be the equivalent of 0.1% of the throughput.
- **Liquids unloading**. There is still a significant degree of uncertainty surrounding the GHG emissions associated with liquid unloading. Some wells do not require liquid unloading whilst other wells had 7,500 liquid unloading events in a year, and high corresponding liquid unloading emissions. Allen et al estimated the upper bound for the mean methane emission to be 1,360 m^3 per event and on average there are 33 events per year, giving our high value of 45,000 m^3 per year. SGI suggest that Allen et al found the median value for methane emissions to be 28,600 m^3 per year which we have taken as our central value.
- **Workovers**. The SGI suggest that there are between 0.03 and 0.17 workovers per well per year. We have taken the high figure of 0.17, which is the equivalent of one workover every 6 years[14]. We have also assumed the corresponding methane emission for well completion for each workover.[15]
- **Processing**. SGI suggest the range in literature for fugitive methane from processing is up to 0.5% of throughput, which we have used as our high value, and on average is 0.25% of throughput, which we have used as our central value. Processing sites also use a proportion of the gas in the processing process, SGI suggest this can be as high as 9% of the gas, which provides our high value, while we have used 6% as our central value.

The literature provides ranges for the greenhouse gas emissions at each stage of development. These ranges are particularly large for well completion, liquids unloading and workover, spurring more recent studies to measure the fugitive methane emissions from these stages directly.

---

[11] Marchese et al. (2015) *Methane Emissions from United States Natural Gas Gathering and Processing*. http://pubs.acs.org/doi/full/10.1021/es5052809

[12] Allen et al. (2013) *Measurements of methane emissions at natural gas production sites in the United States*. Proc. Natl. Acad. Sci. U. S. A. 2013, 110 (44), 17768–17773. http://www.pnas.org/content/110/44/17768.short

[13] Brantley et al. (2014) *Assessment of Methane Emissions from Oil and Gas Production Pads using Mobile Measurements*. http://pubs.acs.org/doi/pdf/10.1021/es503070q

[14] We assume the average economic life of a well at 20 years.

[15] In reality we expect the emission associated with each subsequent workover to be lower due to a drop in well productivity and reservoir pressure.

Table 2. Low, Central and High estimates used in our analysis for emissions at different stages of production

	$ktCO_2e$/well	Low	Central	High
Pre-production	**Site preparation**	0.23	0.23	0.9
	Drilling	0.29	0.29	0.87
	Hydraulic fracturing	0.29	0.29	0.8
	Well completion	0.2	1.8	9.4
Extraction	**Normal operation**	2.6	5.5	9.4
	Liquids unloading	2.2	5	7.9
	Workovers	0.4	3.5	19
Processing		7.5	10.7	16
Total		**14**	**27**	**64**

Mitigation techniques and technologies

It is possible to mitigate some of these emissions through a range of techniques and technologies. US EPA's Natural Gas STAR programme has highlighted a range of cost-effective techniques and technologies to mitigate the GHG impacts of the oil and gas industry.[16] We have highlighted some of the major emissions mitigation techniques and technologies:

- **Well completion:** Completion GHG emissions can be either flared or captured using reduced emissions completion. We have assumed that it is possible to capture 98% of the methane, which Allen et al. found in his analysis and we have assumed a well-designed flare could burn 98% of the methane contained in the gas.
- **Liquid Unloading:**
  - The GHG emissions from liquid unloading could also be reduced through the installation of a plunger lift system. ICF in their report on economics emission mitigation opportunities suggest a plunger lift system could mitigate emissions by 90%. Sample figures from Allen et al. concur with this. Based on measured data we assume a 93% saving in the high case and 89% in the central case.

[16] http://www3.epa.gov/gasstar/tools/recommended.html

- The results from Allen et al. also highlights that the emissions from some automated plunger lift systems are higher than the wells where the gas is vented to the atmosphere. It is uncertain what the counterfactual for this well is if it didn't have a plunger lift system[17].and it is unclear whether the automated lift system was correctly configured. There is limited data available and this requires further investigation.

- **Monitoring:** 'Super-emitters' have been identified as a key source of GHG emissions. It has been found that a very small number of installations emit a high proportion of the fugitive emissions. ICF suggest that annual inspections and repair would reduce emissions by 40%, quarterly inspections by 60%, and monthly inspections by 80%. We have taken the central figure of 60% with quarterly inspection and repair as a potential reduction in GHG emissions over the life of the gas infrastructure.[18]
- **Compressors:** Natural Gas STAR found that use of dry seal compressors rather than standard wet seals would reduce methane emissions from compression by 97%. In the US the emissions from compression are found to be 20% of supply chain greenhouse gas emissions. It is currently uncertain how many compressors would be used in the UK shale industry so the overall saving from using dry seal compressors cannot be calculated.
- **Pneumatic devices:** The GHG emissions from pneumatic devices accounts for 14% of supply chain emissions. There are various types of pneumatic devices used, all of which vent various quantities of gas. ICF suggest it is possible to switch some high bleed pneumatic controllers to low-bleed pneumatic controllers. This switch would reduce the methane emissions from each controller by 90%. As with compressors the number of high-bleed pneumatic controllers which may be used is unknown, therefore the potential actual emission saving cannot be calculated.
- **Vapour recovery units:** When oil and liquid condensates are produced, these require storing temporarily to balance flows or before being tankered offsite. As these liquids are stored, methane entrained in with them separates out and is often vented to the atmosphere. A vapour recovery unit could capture 95% of these GHG emissions. Again there is uncertainty over the volume of associated oil and liquid condensates which may be produced, thus the number of storage tanks.

There are many other mitigation options which may be applied across shale gas development, from the well through to processing. Some of these mitigation options may be cost-effective. However, due to the nascent state of the shale gas industry further mitigation options are too early-stage to include in our analysis. Further research on potential mitigation techniques relevant to the UK should be considered.

---

[17] This well had 7,500 unloading events per year. It is unlikely that this number of events would be replicable without an automated plunger lift system.

[18] We assume that the potential for 'super-emissions' increases as the equipment ages.

Gas constants used throughout the report

Calorific value (higher heating value basis)	38.1 MJ/m^3
Methane density	0.7 kg/m^3
CO_2 density	1.97 kg/m^3

It should be noted that the calorific value and gas density will vary with temperature and pressure. The values used in this report are consistent with those used in the SGI (2015).

As previously discussed the composition of shale gas varies dramatically across each shale formation. We have assumed the average composition of raw shale gas includes 86% methane and 3% CO_2.