Environment Agency

Evidence

Monitoring and control of fugitive methane from unconventional gas operations

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Miranda Kavanagh

Director of Evidence

Preamble

This report has been produced to provide information to the Environment Agency on the methods available for monitoring and controlling fugitive methane emissions from onshore unconventional gas operations. The report focuses primarily on operations involving the hydraulic fracturing of shale to extract methane and includes some comparison with conventional gas operations. The report is based on a review of current practices, recent research and regulatory developments. It draws on published information including experience of hydraulic fracturing operations in North America.

The report is designed to help the Environment Agency identify areas where it may need to acquire more detailed information and expertise, particularly if it is required to regulate future onshore unconventional gas operations in England and Wales. It is not designed to be a definitive account of all monitoring and control methods but to give an overview of the main techniques available and of the factors that should be considered when applying them for regulatory purposes. The report is not a statement of the Environment Agency's position and it does not represent Environment Agency guidance on the matter.

Executive summary: scope and technical outline

Study scope

The Environment Agency is investigating the potential for fugitive methane to be released from unconventional gas operations to provide evidence in relation to the sustainability of unconventional gas. As part of this, the Environment Agency needs to assess what monitoring and controls may need to be applied to fugitive methane from unconventional operations as part of a regulatory regime to make unconventional gas extraction more sustainable.

The present study was commissioned to contribute to this work programme with the following components:

- (i) Outline of unconventional gas extraction techniques;
- (ii) Outline of conventional extraction for comparison with the position for unconventional extraction;
- (iii) Survey of the methods available for monitoring methane from each process and position of fugitive release identified in (i);
- (iv) Survey of the methods available for controlling fugitive emissions of methane from each process and position identified in (i);
- (v) Case studies to illustrate how monitoring and control methods have been applied to fugitive emissions from unconventional and conventional operations;
- (vi) Summary of related issues that may arise during the regulation of fugitive emissions from unconventional operations;
- (vii) Conclusions and recommendations including the identification of best practice for the control of fugitive emissions and recommendations for a cost-effective strategic programme of monitoring and emission estimation.

Technical outline

Introduction

Hydrocarbon extraction has taken place in Europe since the 19th century. The industry developed rapidly in the 1960s, following the discovery of oil and gas in the southern North Sea, and in the 1980s, following the discovery of reserves in the northern North Sea and Russia. The industry focused mainly on ‘conventional’ reserves. That is, oil and gas from high permeability rock formations, which could be more readily extracted.

After decades of growth and stability, proved gas reserves in Europe are starting to decline. This change has coincided with the development and application of techniques in the United States for extraction of gas from reserves which were previously uneconomic or impractical in Europe. These resources comprise extensive shale gas reserves along with less extensive coalbed methane reserves.

Gas shales are formations of organic-rich shale, a sedimentary rock formed from deposits of mud, silt, clay, and organic matter. The shales are relatively impermeable so that substantial quantities of natural gas are trapped within their pores. The low porosity of the rock means that the shale must be fractured to enable the extraction of natural gas.

The situation in the UK has evolved during 2011–2012 with indications that UK recoverable reserves could potentially be of a similar scale to those of Poland and France. Commercial extraction of shale gas could commence in Poland in the next few years. At present, there is a temporary suspension of the use of hydraulic fracturing for shale gas extraction in the UK to allow time for considering its environmental implications. This is especially for any implications for seismicity. Industry forecasts of shale gas well drilling suggest that up to 200 wells per year could be drilled in the UK by 2020.

Overview of hydraulic fracturing

Hydraulic fracturing is the process by which a liquid under pressure causes a geological formation to crack open. It is used to extract gas from shale formations by drilling a vertical section of a well down and then drilling horizontally through the shale formation to maximise access to gas reserves.

Once drilling is complete, the drill string is extracted and the well bore is lined with steel pipe. Cement is pumped around the outside of the pipe to lock it in place and provide a barrier to fluid transfer. Once the cement hardens, shaped charges are pushed down the pipe to the shale formation to perforate the pipework and cement layer at the required locations. Each horizontal well may be fractured at several stages.

When perforations are present at the appropriate point, fracturing fluid at high pressure is pumped into the well. Fracturing fluid normally consists of water with a range of additives to facilitate the fracturing process including 'proppants'. This is referred to as 'slickwater' fracturing. In some shale gas extraction sites in the US such as those with water sensitive components (for example, clay) and under saturated reservoirs, the fluid used for fracturing is thickened with gelling agents in order to increase its viscosity.

The proppant is forced into the fractures by the pressured water and holds the fractures open once the water pressure is released. The sources of water used during hydraulic fracturing activities include surface water and groundwater These can be supplemented by recycled water from previous hydraulic fracturing. The quantities of water used depend on well characteristics (depth, horizontal distance) and the number of times each well is fractured. Vertical shale gas wells typically use approximately 2000 m^3 of water while horizontal wells require approximately that amount of water per stage. In comparison with hydraulic fracturing in vertical wells, horizontal fracturing requires longer well lengths, higher pressures and notably higher volumes of water; it is therefore known as "high-volume horizontal fracturing".

Additives are mixed with base fluids mainly to modify fluid mechanics to increase performance of the fracturing fluid. Further chemicals are added for purposes such as prevention of corrosion to the well pipes. The fracture fluids usually consist of about 98–99 per cent water and proppant (usually sand, but other granular materials can be used) and 1–2 per cent additives.

Following the release of pressure, liquids are returned to the surface. The water which flows to the surface before the well is completed and gas extraction commences is referred to as 'flowback water'. This usually consists mainly of hydraulic fracturing fluid and is likely to contain methane.

In many cases, water continues to flow to the surface from shale gas wells during the production phase. This usually consists mainly of water from within the shale gas measures (referred to as 'formation water' or 'produced water') together with decreasing quantities of hydraulic fracturing fluid. Between 0 and 75 per cent of the injected fluid is recovered as flowback.

Operators of conventional hydrocarbon extraction processes may re-fracture a well to stimulate the flow of additional gas or oil from the same formation. In the case of shale gas, however, experience from the US is that wells are likely to be re-fractured infrequently; either once every 5–10 years or not at all.

Shale gas formations typically cover a much wider lateral extent than conventional gas reservoirs. This opens the possibility of extensive development of large gas fields. This is in contrast to conventional gas extraction, which has been localised in nature.

Coalbed methane (CBM) is methane formed through the geological process of coal generation. It is present in varying quantities in all coal. CBM can be extracted using hydraulic fracturing techniques.

'Tight gas' refers to gas which is trapped in unusually impermeable hard rock or in a sandstone or limestone formation that is unusually impermeable and non-porous (known as tight sand). In a conventional sandstone the pores are interconnected and so gas is able to flow easily from the rock. In tight sandstones there are smaller pores, which are poorly connected by very narrow capillaries resulting in very low permeability. Techniques such as hydraulic fracturing or acidising are needed to extract gas from a tight formation at economically viable flow rates.

Comparison of conventional and unconventional gas production

The UK has more extensive experience of offshore oil and gas extraction than onshore extraction. Onshore gas production represents 0.4 per cent of UK total gas production.

From the perspective of fugitive methane control, there are two main considerations that apply to onshore hydraulic fracturing for unconventional gas extraction that do not apply to conventional gas extraction:

- control of fugitive methane contained in flowback water and produced water from unconventional gas extraction;
- control of fugitive methane leaking from infrastructure that is specifically required for hydraulic fracturing activities on the extraction site.

Consideration may need to be given to minimising the risk of methane reaching the surface via pathways from the well infrastructure (for example, in the event of failures of the well liner system) or via the overlying rocks following fracturing of the shale matrix. For deeper shale gas measures release via the overlying rocks is less likely to pose a significant risk. Control of these risks will be built into the design of an unconventional gas extraction project. An appropriate pre-operational monitoring survey will be an important component of the project to ensure that any emissions via these pathways can be identified and addressed.

Methane monitoring techniques

The measurement of methane emissions is driven by safety, environmental and economic considerations. For leak detection, it is vital to assess if the released levels are in an explosive range as well as the location and rate of leak. In this situation, methane is measured using lower explosive level (LEL) measurement systems. This is not specific to methane, but includes other gaseous hydrocarbons that can form an explosive mixture.

Further away from the local production equipment, it is important to know that methane is not significantly above the background level at or beyond the plant boundary. This is often tested using fenceline monitoring.

At the fenceline and in the medium field measurements can be used for the assessment of methane flux (the mass release rate over a period of time from a particular installation). At larger scales the overall impact of multiple wells and associated infrastructure on methane concentrations and fluxes can be assessed on a regional basis.

Monitoring requirements will change over time requiring different approaches:

- Prior to any drilling, it would be very useful to characterise the background methane levels:
- During drilling and production there will be an emphasis on monitoring fugitive releases, primarily driven by safety and operational maintenance to deliver leak detection and repair programmes. Fenceline measurements can be used to evaluate the performance of an individual installation, while measurements within the wider community can be used to investigate potential environmental impacts including incident response. Wider scale methane measurements can also be used to estimate methane fluxes;
- After well closure methane monitoring can be used as part of the maintenance of capped wells.

A wide range of measurement methods are described. These include techniques for:

- assessment of leak rates;
- measurement of emissions from wellhead and associated production plant sources;
- leak detection and emission rate screening;
- discrete ambient measurements;
- path integrated optical remote sensing for concentration and flux measurements;
- tracer gas correlation;
- carbon speciation.

Combining methane measurement with additional data collection can enable methane emission rates to be estimated. The report describes the use of monitoring in conjunction with dispersion modelling to develop estimates of methane release rates from wide areas.

Control methods

Methane can be emitted from unconventional gas extraction during several steps of the gas production process. These include pre-production processes, such as hydraulic fracturing, and production processes, such as gas dehydration and compression.

Particular attention is focused on methane emissions from flowback handling during well completion. Upon completion of the fracturing step, the fracturing fluid mixture (which now contains a combination of water from the shale rocks, fracturing fluid, sand, hydrocarbon liquids and natural gas) is brought back to the surface. Standard practice has been to vent or flare the natural gas during this step and to direct the sand, water and other liquids into ponds or tanks. Methane emissions from the flowback/well completion step may be controlled through the use of reduced emission completions (RECs) – also known as green completions. This involves the installation of portable equipment specially designed to handle the high initial flow of water, sand and gas. A sand trap is used to remove the solids and is followed by a three-phase separator which separates the water from the condensate (liquid hydrocarbons) and gas. "Green completion" is the general term for the various methods used to control methane emissions during well completion; the additional methane gas collected by green completions can be sold, so that such completions are commercially advantageous for operators. Where the pipeline infrastructure is not yet in place to receive saleable gas, the gas stream may be routed to a temporary flare. The US Environmental Protection Agency (US EPA) has recently published regulations that would require the use of RECs on new hydraulically fractured gas wells and re-fractured wells.

Controls on methane emissions are also available on other sources of emissions which are common to conventional gas extraction:

- Unloading of produced liquids can be controlled by the installation of a plunger lift system;
- Venting from storage tanks can be controlled through the use of vapour recovery units and transfer to pipeline or flaring;
- Emissions from conventional glycol dehydrators can be reduced by using vapour recovery units, desiccant dehydrators and flash tank separators;
- Emissions from pneumatic devices such as liquid level controllers, pressure regulators and valve controllers can be reduced with more intensive maintenance and by using low bleed techniques;
- Emissions from compressors are a major potential source of fugitive methane emissions due to the presence of natural gas in mechanical systems at high pressure. Methane emissions can be reduced by the use of dry seals in place of wet seals and by periodic replacement of rod packing systems. Natural gas or electrically powered plant can be used to reduce emissions compared to diesel-fired plant.

Electrically powered drilling equipment can be used to reduce emissions to air of other pollutants compared to the use of diesel plant. Three-way catalytic convertors can be used to reduce emissions from diesel plant used in drilling or hydraulic fracturing.

Case studies

Five case studies were developed to illustrate good practice in control and monitoring of fugitive methane emissions from unconventional gas operations.

Case study 1: Regulation in British Columbia. Much of the natural gas production in British Columbia is from unconventional sources. The Province has implemented regulations and published guidance with the aim of eliminating venting and reducing the use of flaring. This requires operators to collect methane as soon as practicable and, if the well is within 1.5 km of the collection pipeline, the operator is required to connect to the pipeline. Operators are required to co-operate to provide economically viable methods for extraction and utilisation or flaring of dissolved gases. The regulations and guidance are supported by an inspection team and an incident response team. This approach has been effective in delivering improvements in natural gas management since 2006.

Case study 2: Reduced emissions completion, Wyoming. BP has drilled and fractured almost 1400 wells in tight sands in the Wamsutter and Jonah fields, south-west Wyoming. BP has been carrying out reduced emissions completions since 2001. The use of this technology is now widespread in the industry. However, this is not appropriate to every well. For example, it is difficult to apply at low pressure wells because of the need for additional compression. This results in an additional energy and financial cost. If inert gases have been used to support the flow of produced waters it could preclude the gas from being transferred to pipeline. Also, compressors are not well suited to operate on gas flows with variable pressures and/or volumes. BP considers that the industry will use REC techniques where it is appropriate to do so on a case-by-case basis because of the additional revenue obtained from the gas recovered in this way. Shale gas wells are typically well-suited to reduced emissions completion.

Case study 3: Agency and developer co-ordination in Greater Natural Buttes Area Gas Development Project. The Greater Natural Buttes Project Area (GNBPA) encompasses approximately 66,000 hectares in an existing gas producing area located in Uintah County in the US state of Utah. Kerr-McGee Oil & Gas Onshore LP (KMG) is developing the oil and gas resources within the GNBPA, which currently includes 1562 oil and gas wells and associated infrastructure. In the GNBPA, methane emissions are significant for both potential indirect health effects due to ozone formation, as well as potential climate effects. In 2006, KMG proposed to drill up to 3675 new gas wells, and construct the associated infrastructure. To control methane emissions from this expansion the following measures were proposed:

- Low emission dehydrators to be used at all existing and new compressor stations and wells;
- Approximately 50 per cent of the compression plant to be electrically driven;
- Emission controls to be used on existing and new condensate tanks, and other plant with significant potential for fugitive emissions;
- Low-bleed pneumatic devices to be installed at all existing and new compressor stations and production facilities;
- Green completions for all well completion activities;
- Trials of natural gas fired drilling equipment to be carried out;
- Dry seals to be fitted on new centrifugal compressors;
- An annual inspection and maintenance programme to reduce fugitive emissions;
- Reducing or ceasing drilling or using only lower emitting engines during specified periods;
- Gas turbines to be introduced for natural gas compression;
- Blowdowns to be limited or prohibited during specified periods;
- Plunger lift systems to be used;
- A monthly monitoring survey to be carried out using forward looking infrared spectroscopy;
- A direct inspection and maintenance programme to be carried out;
- Vapour recovery to be used for tank load out.

Case study 4: Bacton natural gas terminal, Norfolk. Bacton is one of the largest gas terminal complexes in the UK. Some gas clean-up and refining is carried out at the site, but it not a natural gas extraction site. However, it provides a useful case study of approaches adopted to the control of methane emissions from an operational gas processing facility in the UK, focusing on issues which arise once the gas has been extracted to pipeline.

A rolling maintenance programme is carried out by a team of qualified pressure system specialists over a 5–10 year cycle. Pipework is cleaned internally using spherical pigs to clear condensed material. The pressure within the system is monitored continually and normal tolerances are well known. If a flange leakage were to occur it would be detected by a pressure drop. The site is also inspected visually and aurally by the operational staff. Laser scanning techniques have been investigated but were not implemented at Bacton because the plant was too complex for this technique to be useful. In the event of an emergency, the operator would vent methane to the atmosphere. Flares are not used at Bacton because of the potential intrusiveness of flares in this location.

Fugitive methane emissions from Bacton are estimated using generic industry guidelines. The estimates are obtained by counting the number and type of joints and outlets in the pipework and estimating the fugitive emissions from this information and from associated gas pressures, temperatures and flow rates. These emissions are reported to the Department for Energy and Climate Change (DECC).

Case study 5: Fort Worth natural gas air quality study. The city of Fort Worth in Texas is home to extensive natural gas production and exploration as it lies over the Barnett Shale, a highly productive natural gas shale formation. Extraction of natural gas has involved exploration and production (E&P) operations in residential areas, employment areas, and near public roads and schools. Many individual citizens and community groups in the Fort Worth area were concerned that these activities could have an adverse effect on their quality of life. In response to these concerns, the Fort Worth City Council appointed an independent committee to review air quality issues associated with natural gas exploration and production.

A year-long study was carried out comprising of four main activities: ambient air monitoring; point source testing; air dispersion modelling; and a public health evaluation. This study provides a useful example of a strategic community-wide monitoring programme using a variety of techniques. Although not limited to methane, the study is indicative of reconnaissance work that could be carried out in a systematic way to identify and quantify emissions sources.

Ambient air monitoring was conducted at eight different locations around the city of Fort Worth over a two-month period in September and October 2010. Point source testing was conducted from August 2010 to February 2011 and involved testing fugitive emissions from 388 sites using a variety of techniques. The air dispersion modelling analysis was conducted to quantify downwind impacts from natural gas activities. Modelling was conducted for average and maximum emission rates from well pads and compressor stations. Finally, the public health evaluation was carried out to evaluate the ambient air monitoring data and dispersion model results. Levels of emitted substances were assessed against health-based air quality screening levels.

Related issues for methane emissions reporting

Issues that are expected to arise during the regulation and reporting of fugitive methane emissions from unconventional gas extraction operations were evaluated. Relevant guidance was considered and UK and international emissions inventory experts were consulted.

When reporting methane emissions data it is important that associated information is also provided. This covers aspects such as the activities carried out, the methods used to estimate methane emissions and any associated monitoring data.

No relevant emission factors or detailed industry datasets applicable to onshore unconventional gas exploration and production have been found from UK or EU sources. The US EPA has proposed new factors for estimating methane emissions from unconventional gas completion. These factors were reviewed and a revised approach was recommended. It was estimated that 210,000 m^3 methane (112 tonnes) are emitted per unmitigated well completion. This would be reduced by about 90 per cent with reduced emission completions. These factors are subject to ongoing discussion and industry data suggest that they may significantly overestimate fugitive methane emissions. These factors are subject to significant uncertainty and variability between sites.

Further evidence of the uncertainties in this area is shown by a separate study that compared factor-based estimates with ambient methane concentrations in a production field in the Denver-Julesburg basin of the United States. The ambient concentrations suggested that about four per cent of produced methane may be released fugitively, which is about twice the amount from factor-based estimates.

Onshore gas extraction sites that may come under future Environment Agency regulatory control are likely to be required to report annual estimates of methane release to the Pollution Inventory.

The primary source for information on fugitive methane mitigation measures for the oil and gas industry is the US EPA sponsored voluntary industry programme, Natural Gas STAR. This gives information on measures to control emissions from a range of sources associated with natural gas extraction, together with information on costs and payback times.

Recommendations

It is recommended that the Environment Agency uses the information in this report as a starting point for its regulatory programme in relation to the monitoring and control of fugitive methane from unconventional gas operations. It is recommended that further research is carried out to focus on mitigation options, different technologies and their effectiveness, scope of application and cost–benefit analysis appropriate for the UK situation.

Industry standard emission factors are widely used for estimating methane emissions in the oil and gas industry. These may not be applicable to the plant and equipment used for unconventional gas extraction, and may also reflect outdated practices in the unconventional gas industry. It is recommended that the Environment Agency should avoid relying solely on these factors and should request that operators develop emissions estimates from multiple data sources wherever possible. This may require additional measurement surveys to be carried out on representative plant if relevant data are not otherwise available.

It is recommended that the Environment Agency should require operators of unconventional gas extraction facilities to carry out surveys to measure ambient methane levels before operations commence; during drilling, hydraulic fracturing and completion; and during production.

It is recommended that a monitoring survey designed to verify methane emissions estimates from unconventional gas extraction during drilling, hydraulic fracturing, completion and production would provide useful information. This survey may be supplemented by dispersion modelling techniques to infer overall emissions from monitored concentrations.

It is recommended that the Environment Agency initiates and continues consultation with peers in regulatory agencies in the UK, across the EU and in North America to improve methods for measuring and controlling fugitive methane emissions. It is recommended that the Environment Agency reviews the findings of international inventory studies due to be published during 2012 and 2013.

Consideration may also need to be given to minimising the risk of methane reaching the surface via pathways from the well infrastructure (for example, in the event of failures of the well liner system) or via the overlying rocks following fracturing of the shale matrix.

Contents

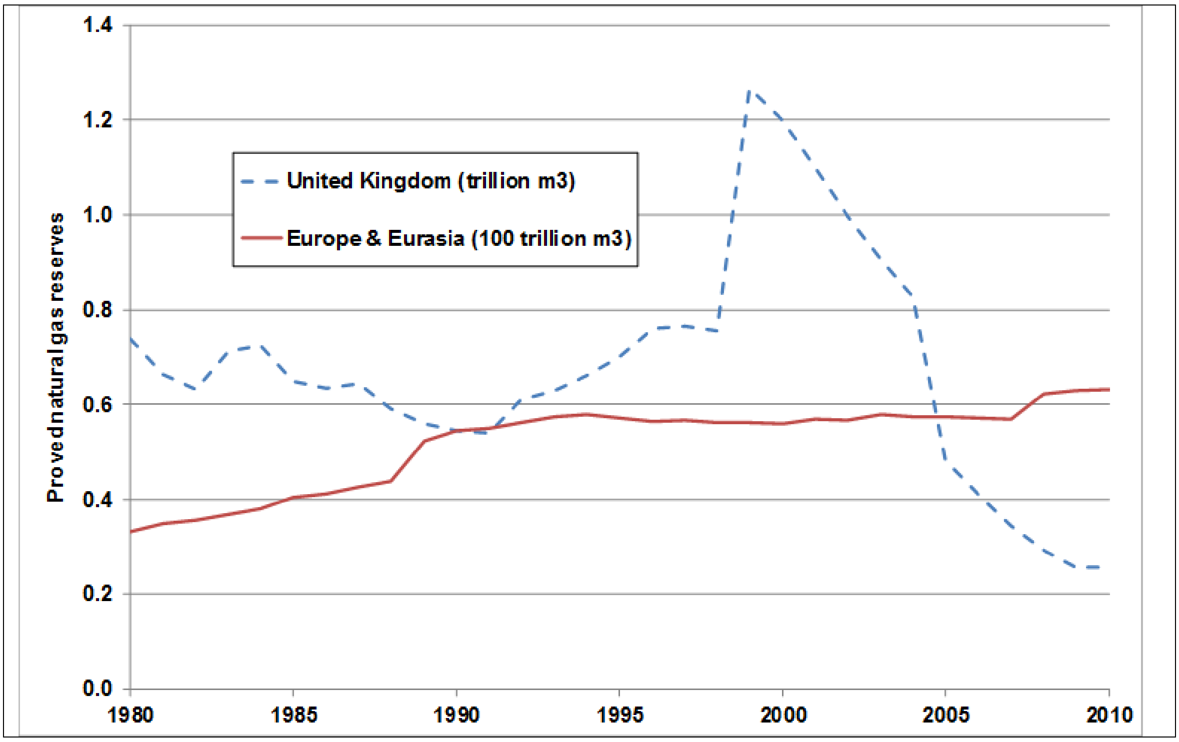
1 Unconventional gas extraction

This chapter describes unconventional gas extraction techniques and how they differ from established practice in the UK and Europe. A glossary and a list of abbreviations are provided at the end of the report before the appendices.

1.1 Market context

Hydrocarbon extraction has taken place in Europe since the 19th century. The industry developed rapidly in the 1960s following the discovery of oil and gas in the southern North Sea, and in the 1980s following the discovery of reserves in the northern North Sea and Russia. The industry focused mainly on 'conventional' reserves – that is, oil and gas from high permeability formations, which could be more readily extracted.

After decades of growth and stability, proved gas reserves in Europe may be starting to decline (Figure 1.1). In 2004, the UK returned to being a net importer of gas.



Source: BP (2012)

Figure 1.1 Proven gas reserves in the UK and Europe 1980–2011

This change has coincided with the development and application of techniques in the US for extraction of gas from reserves that were previously uneconomic or impractical. In this context, gas producers in Europe have begun to investigate unconventional oil and gas resources. In Europe, these resources consist of extensive shale gas reserves, along with less extensive coalbed methane reserves.

Gas shales are formations of organic-rich shale, a sedimentary rock formed from deposits of mud, silt, clay and organic matter. The shales are relatively impermeable so that substantial quantities of natural gas are trapped within their pores. The low porosity of the rock means that reserves must be fractured to enable the extraction of natural gas. Table 1.1 summarises estimated shale gas reserves in Europe.

Table 1.1 Estimated shale gas recoverable resources for select basins in Europe

Country	2009 natural gas market[1] (trillion m^3, dry basis)			Proved natural gas reserves (trillion m^3)	Technically recoverable shale gas resources (trillion m^3)
	Production	Consumption	Imports (exports)		
France	0.00085	0.049	98%	0.006	5.10
Germany	0.0144	0.093	84%	0.18	0.23
Netherlands	0.0790	0.049	(62%)	1.39	0.48
Norway	0.103	0.0045	(2156%)	2.04	2.4
UK	0.059	0.088	33%	0.255	0.57
Denmark	0.0085	0.0045	(91%)	0.059	0.65
Sweden	–	0.0011	100%		1.16
Poland	0.0059	0.016	64%	0.164	5.30
Turkey	0.00085	0.035	98%	0.006	0.42
Ukraine	0.020	0.044	54%	1.10	1.19
Lithuania	–	0.0028	100%		0.113
Others[2]	0.014	0.027	50%	0.077	0.54
Total	0.305	0.365		5.27	13.0

Notes: [1]Dry production and consumption
[2]Romania, Hungary, Bulgaria
Source: US EIA (2011)

The situation in the UK has evolved in the last few months, with indications that UK recoverable reserves could potentially be of a similar scale to those of Poland and France (Cuadrilla Resources 2011 and associated press reports[1]). At the same time, it is anticipated that the US Energy Information Administration (US EIA) estimates set out in Table 1.1 may be reduced in line with recent reductions in estimated shale gas reserves in the US.

Commercial extraction of shale gas could commence in Poland in the next few years. At present, there is a temporary suspension of the use of hydraulic fracturing for shale gas extraction in the UK. A recent report from the Department for Energy and Climate Change (DECC) states:

'DECC has had discussions with Cuadrilla, the operator of shale gas sites in that area, and agreed that a pause in hydraulic fracture operations was appropriate so that a better understanding can be gained of the cause of the seismic events. A geomechanical study is being undertaken, and the results of the analysis and recommendations on how to mitigate the risk of induced seismicity will be reviewed by DECC, the BGS, the Environment Agency and the Health and Safety Executive before any decision on the resumption of shale gas hydraulic fracture operations is made' (DECC 2011, p. 3).

Extraction of shale gas has also been banned in France, although this is currently subject to appeal.

[1] For example: Blair, D., 2011. Lancashire yields huge shale gas find. *Financial Times*, 21 September 2011.

As quoted in a conference presentation by the vice-president of PGNiG, the largest Polish oil and gas exploration and production company (Karabula 2011), forecasts of shale gas well drilling have been prepared by UK energy business advisors, Douglas-Westwood (2011). These forecasts are built up on a country-by-country basis, taking market trends, drivers and constraints into account. From this a demand-driven forecast for new well drilling is developed. As this approach relies on information from sector operators, it may tend to over-state the likely development of shale gas extraction. The forecast well numbers are set out in Table 1.2.

Table 1.2 Forecast numbers of new wells drilled per year 2011–2020

New wells drilled	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Argentina	0	0	0	36	121	237	344	427	500	535
Australia	0	0	36	98	179	240	292	338	382	404
Austria	0	0	0	0	0	0	0	0	7	11
Bulgaria	0	0	0	0	0	0	7	26	51	66
Canada	467	739	889	1001	1088	1137	1136	1196	1279	1324
China	115	185	218	289	369	466	578	732	929	1035
France	0	0	0	0	7	64	148	247	318	351
Germany	0	0	7	70	165	277	357	426	490	521
India	0	0	0	0	0	0	36	110	210	260
Ireland	0	0	0	0	0	0	1	2	2	2
Netherlands	0	0	0	0	0	18	46	82	107	118
Poland	0	36	164	348	541	682	807	923	1035	1090
South Africa	0	0	0	0	7	64	148	247	318	351
Sweden	0	0	0	0	0	0	0	0	0	0
Tunisia	0	0	0	0	0	0	0	73	184	276
UK	0	0	21	53	94	122	146	169	190	201
Ukraine	0	0	0	0	0	218	576	1044	1388	1545
USA	16,381	16,145	16,748	17,230	17,272	17,317	17,252	17,227	17,442	17,568
Africa	0	0	0	0	7	64	148	320	502	626
Asia	115	185	218	289	369	466	615	842	1139	1296
Australasia	0	0	36	98	179	240	292	338	382	404
Eastern Europe and former Soviet Union	0	36	164	348	541	900	1390	1993	2474	2700
Latin America	0	0	0	36	121	237	344	427	500	535
Middle East	0	0	0	0	0	0	0	0	0	0
North America	16,848	16,884	17,637	18,231	18,359	18,455	18,388	18,424	18,721	18,892
Western Europe	0	0	28	123	266	482	698	926	1106	1192
Total	16,963	17,106	18,083	19,125	19,843	20,843	21,874	23,268	24,831	25,656

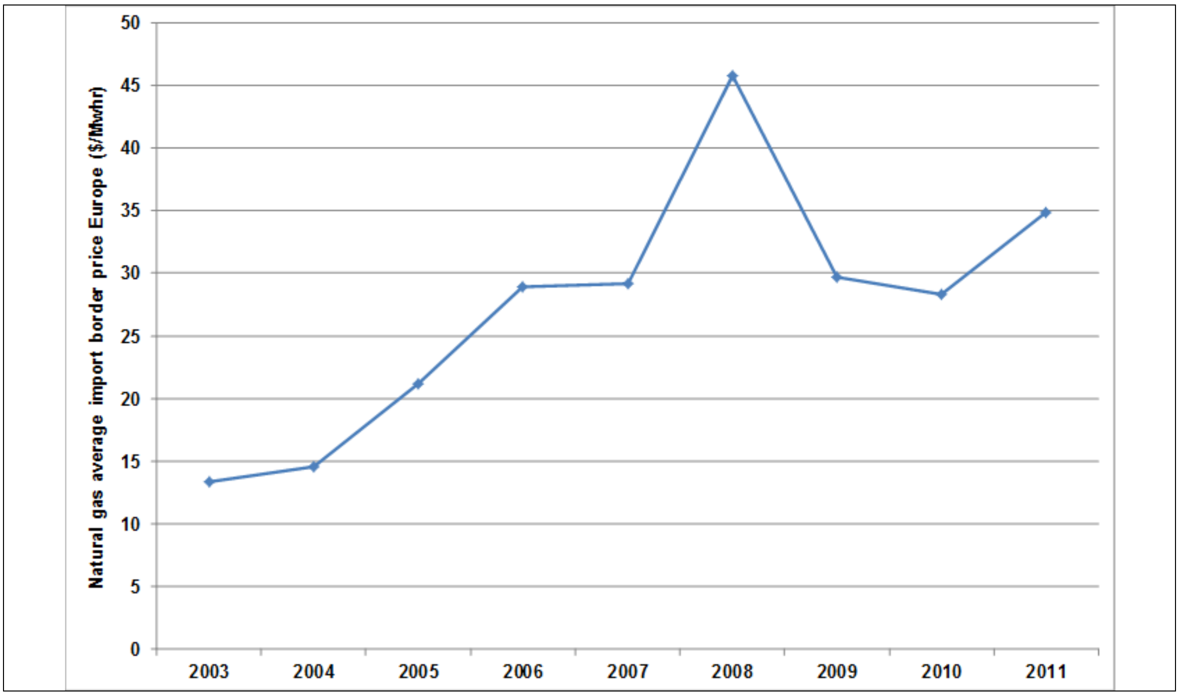
Estimated global coalbed methane (CBM) reserves are summarised in Table 1.3 (Maisonnier 2007). This information indicates that, in the European context, coalbed methane could comprise a significant proportion of unconventional gas resources. However, the industry focus and forecast expansion in Europe is currently almost exclusively linked to shale gas.

Table 1.3 Estimated world CBM reserves

Area	Estimated recoverable reserves (Tm^3)	
	Low end	High end
Asia	18.3	95.1
North America	26.9	124.1
South America	0.4	0.9
Confederation of Independent States	113.3	456.3
Europe	4.6	7.6
Africa	0.8	1.6
World	164.2	685.7

As readily accessible oil and gas reserves are becoming progressively limited, the energy supply industry is turning more to 'unconventional' reserves, defined as natural gas reserves in reservoirs with a permeability of less than 1 millidarcy (mD). The term 'unconventional' gas may not be well-defined in practice and care should be exercised in its use and interpretation.

Such reservoirs were previously considered too complex or too expensive to extract. The exploitation of these reserves will be subject to commercial considerations and shale gas is expected to become increasingly attractive as the price of conventional natural gas increases. Gas prices have fallen from their peak in 2008, which may tend to reduce the attractiveness of shale gas in Europe compared with other sources of natural gas in the short term (Figure 1.2). In order to enhance cost-effectiveness, shale gas exploration activity in the US is currently focused on areas that are expected to produce both a gas product and a condensate product.



Source: World Bank

Figure 1.2 Natural gas prices in Europe 2003–2011

1.2 Overview of hydraulic fracturing

1.2.1 Hydraulic fracturing

This section provides a description of the hydraulic fracturing process, which is common to both vertical and horizontal wells.

Hydraulic fracturing is the process by which a liquid under pressure causes a geological formation to crack open. This process is used for a number of industrial and commercial purposes. The main use of interest for the purpose of this project is its use for extraction of hydrocarbons (natural gas or oil). The process is also known as 'HF', 'fracking' or 'fracing', but is referred to as 'hydraulic fracturing' or 'fracturing' in this report.

The following description of hydraulic fracturing is adapted from a document issued by the US Environmental Protection Agency (US EPA) (US EPA 2010a, p. 1):

'During hydraulic fracturing, fluids are injected into production wells under high pressure to generate fractures in geologic formations. Fracturing fluids consist primarily of water and chemical additives that serve a variety of purposes, such as increasing fluid viscosity, inhibiting corrosion, and limiting bacterial growth. Water used for hydraulic fracturing activities may come from surface water and groundwater. Propping agents, or 'proppants' (such as sand or ceramic beads) are added to keep the fractures open after the pressure is released. The fracturing fluids (water and chemical additives) are then returned back to the surface, where they are stored, treated, and disposed of or recycled. After fracturing, natural gas will flow from pores and fractures in the rock into the well for subsequent extraction.'

The overall drilling and fracturing process is carried out as follows.

A drill string is used to drill a hole through the surface layers and into the gas play. For shale gas extraction, horizontal drilling techniques are typically used to drill horizontally through the gas play to maximise access to gas reserves.

Once drilling is complete, the drill string is typically extracted and the well bore is lined with steel pipe. In other cases, 'open hole' completions are carried out, in which the production casing is run to penetrate the top of the producing zone. It is also possible to run the production string the entire length of the well but not cement the horizontal portion. The selection of these techniques depends on the formation geology, depth, desired outcome and regulatory requirements.

Cement is pumped around the outside of the pipe to lock it in place and provide a barrier to fluid transfer. Once the cement hardens, shaped charges are pushed down the pipe to perforate the pipework and cement layer at the required locations. In some cases, pre-perforated liners are used but in-place perforation provides more accuracy for placing the perforations at the desired location.

When perforations are present at the appropriate point, fracturing fluid at high pressure is pumped into the well. Fracturing fluid normally consists of water with a range of additives to facilitate the fracturing process – this is referred to as 'slickwater' fracturing. In some shale gas plays in the US such as those with water-sensitive components (for example, clay) and under saturated reservoirs, gelled fracturing techniques are used (US EPA 2010b).

The proppant is forced into the fractures by the pressured water and holds the fractures open once the water pressure is released. For conventional fracturing, the fracture pressure gradient is typically 0.4–1.2 psi per foot (0.09–0.27 bar per metre) (derived from project team experience). For instance, for a typical 2,400 metre conventional well, this would correspond to approximately 500 bar and pressures would generally be below 650 bar. Fracture lengths can be expected to vary depending on the geological properties of the rock matrix and the fracture treatment. For example, in the Barnett Shale, fractures typically extend up to 500 metres from the shaft, but not further as with longer fractures, the costs exceed the benefits (Brunner and Smosma 2012). In the Jonah Field, Wyoming, fractures typically extend for 120–240 metres (Chipperfield 2010). The fractures allow natural gas and oil to flow from the rock into the well.

The sources of water used during hydraulic fracturing activities include surface water and groundwater, which can be supplemented by recycled water from previous hydraulic fracturing. Significant quantities of water can be used, depending on well characteristics (depth, horizontal distance) and the number of times each well is fractured. Vertical shale gas wells typically use approximately 2,000 m^3 water; horizontal wells require approximately that amount of water per stage (US DOE 2009 pp. 74–77).

Fracturing fluid additives are mixed with base fluids mainly to modify fluid mechanics to increase performance of the fracturing fluid. Further chemicals are added for purposes such as the prevention of corrosion to the well pipes. The fracture fluids usually consist of about 98 per cent water and proppant (usually sand, but other granular materials can be used) and 2 per cent additives (NYSDEC 2011, p. 5-40 and Table 5.6).

Table 1.4 Fracture fluid additives

Additive type	Description of purpose	Examples of chemicals
Proppant	'Props' open fractures and allows gas / fluids to flow more freely to the well bore.	Sand (sintered bauxite; zirconium oxide; ceramic beads)
Acid	Removes cement and drilling mud from casing perforations prior to fracturing fluid injection and provides accessible path to formation.	Hydrochloric acid (3–28%) Muriatic acid
Breaker	Reduces the viscosity of the fluid in order to release proppant into fractures and enhance the recovery of the fracturing fluid.	Peroxydisulfates
Bactericide / biocide / antibacterial agent	Inhibits growth of organisms that could produce gases (particularly hydrogen sulfide) that could contaminate methane gas. Also prevents the growth of bacteria, which can reduce the ability of the fluid to carry proppant into the fractures.	Gluteraldehyde 2,2-Dibromo-3-nitrilopropionamide
Buffer / pH adjusting agent	Adjusts and controls the pH of the fluid in order to maximise the effectiveness of other additives such as crosslinkers.	Sodium or potassium carbonate Acetic acid
Clay stabiliser/ control / KCl	Prevents swelling and migration of formation clays which could block pore spaces thereby reducing permeability.	Salts (e.g. tetramethyl ammonium chloride) Potassium chloride (KCl)
Corrosion inhibitor (including oxygen scavengers)	Reduces rust formation on steel tubing, well casings, tools, and tanks (used only in fracturing fluids that contain acid).	Methanol Ammonium bisulfate for oxygen scavengers

Additive type	Description of purpose	Examples of chemicals
Crosslinker	Increases fluid viscosity using phosphate esters combined with metals. The metals are referred to as crosslinking agents. The increased fracturing fluid viscosity allows the fluid to carry more proppant into the fractures.	Potassium hydroxide Borate salts
Friction reducer	Allows fracture fluids to be injected at optimum rates and pressures by minimising friction.	Sodium acrylate–acrylamide copolymer Polyacrylamide (PAM) Petroleum distillates
Gelling agent	Increases fracturing fluid viscosity, allowing the fluid to carry more proppant into the fractures.	Guar gum Petroleum distillates
Iron control	Prevents the precipitation of metal oxides which could plug off the formation.	Citric acid
Scale inhibitor	Prevents the precipitation of carbonates and sulfates (calcium carbonate, calcium sulfate, barium sulfate), which could plug off the formation.	Ammonium chloride Ethylene glycol
Solvent	Additive that is soluble in oil, water and acid-based treatment fluids which is used to control the wettability of contact surfaces or to prevent or break emulsions.	Various aromatic hydrocarbons
Surfactant	Reduces fracturing fluid surface tension thereby aiding fluid recovery.	Methanol Isopropanol Ethoxylated alcohol

Source: Taken from NYSDEC (2011, Table 5.6)

Following the release of pressure, liquids are returned to the surface. The water which flows to the surface before the well is completed and gas extraction commences is referred to as ‘flowback water’ (US EPA 2010b). This usually consists mainly of hydraulic fracturing fluid, and is likely to contain dissolved methane and/or bubbles of methane.

In many cases, water continues to flow to the surface from shale gas wells during the production phase. This usually consists mainly of water from within the shale gas measures (referred to as ‘formation water’ or ‘produced water’) together with decreasing quantities of hydraulic fracturing fluid – although fracturing fluid can continue to be discharged over a period of several months. Experience in the US is that between 0 and 75 per cent of the injected fluid is recovered as flowback (US DOE 2009, p. 66).

As shale formations were originally laid down in marine environments, produced water tends to be of high salinity. Flowback water and produced water may be stored in tanks or pits prior to disposal or recycling. In the US, flowback water and produced water are frequently discharged to well injection facilities or, following treatment, to surface waters. A proportion of these waters can also be re-used in some cases, although increasing salinity and presence of other contaminants limits the extent of re-use that is possible in practice.

Operators of conventional hydrocarbon extraction processes may re-fracture a well to stimulate the flow of additional gas or oil from the same formation. Re-fracturing is typically carried out when the production rates have declined beyond the expected reservoir depletion rate (ICF 2009, p. 19). Operators re-fractured Barnett shale wells when the production declined by between 50 and 85 per cent of the original production rate (ICF 2009, p. 21). In the case of shale gas, however, experience from the US is that wells are likely to be re-fractured infrequently – either once every 5–10 years or not at all (NYSDEC 2011, section 5.10). The decision to re-fracture depends on economic return (ICF 2009, p. 20).

Hydraulic fracturing is used by gas producers to stimulate wells and recover natural gas from sources such as conventional wells, coalbeds, tight sands and shale gas formations. Fracturing is also used for other applications including oil recovery and related stimulation techniques are used for geothermal energy installations. However, recent technical developments open up the possibility of using fracturing to establish of horizontal wells and of using much larger volumes of fracturing fluid as described above.

1.2.2 Use of hydraulic fracturing in horizontal wells

As discussed in Section 1.1, the primary issue of concern is the anticipated increase in the use of hydraulic fracturing for the extraction of shale gas. The development of affordable horizontal drilling over the past 20 years has made unconventional resources such as shale gas accessible on a commercially viable basis.

Directional/horizontal drilling techniques and hydraulic fracturing techniques developed in the US allow the well to penetrate along the hydrocarbon bearing rock seam and thereby enable the gas to be extracted from the shales. It had long been recognised that substantial supplies of natural gas were embedded in shale rock. In 2002–2003, hydraulic fracturing and horizontal drilling enabled commercial shale gas extraction to commence (SEAB 2011). This maximises the rock area that, once fractured, is in contact with the well bore and so maximises well production in terms of the flow and volume of gas that may be collected from the well.

To drill and fracture a shale gas well, operators first drill down vertically until they reach the shale formation. Within the target shale formation, the operators then drill horizontally or at an angle to the vertical to create a lateral or angled well through the shale rock. In the Marcellus Shale formation in Pennsylvania, for example, a typical horizontal well may extend from 600 to 2,000 metres and sometimes approaches 3,000 metres (Arthur et al. 2008). In unconventional cases, the well can extend more than a mile below the ground surface (Chesapeake Energy 2012), while the ‘toe’ of the horizontal leg can be almost two miles from the vertical leg (Zoback et al. 2010). A shale gas well can be drilled using a traditional vertical drilling rig for the vertical portion, followed by a directional drilling rig for the horizontal portion. Alternatively, the operator may use a directional rig for the entire well bore. Figure 1.3 provides an illustration of the principal stages in the hydraulic fracturing process.

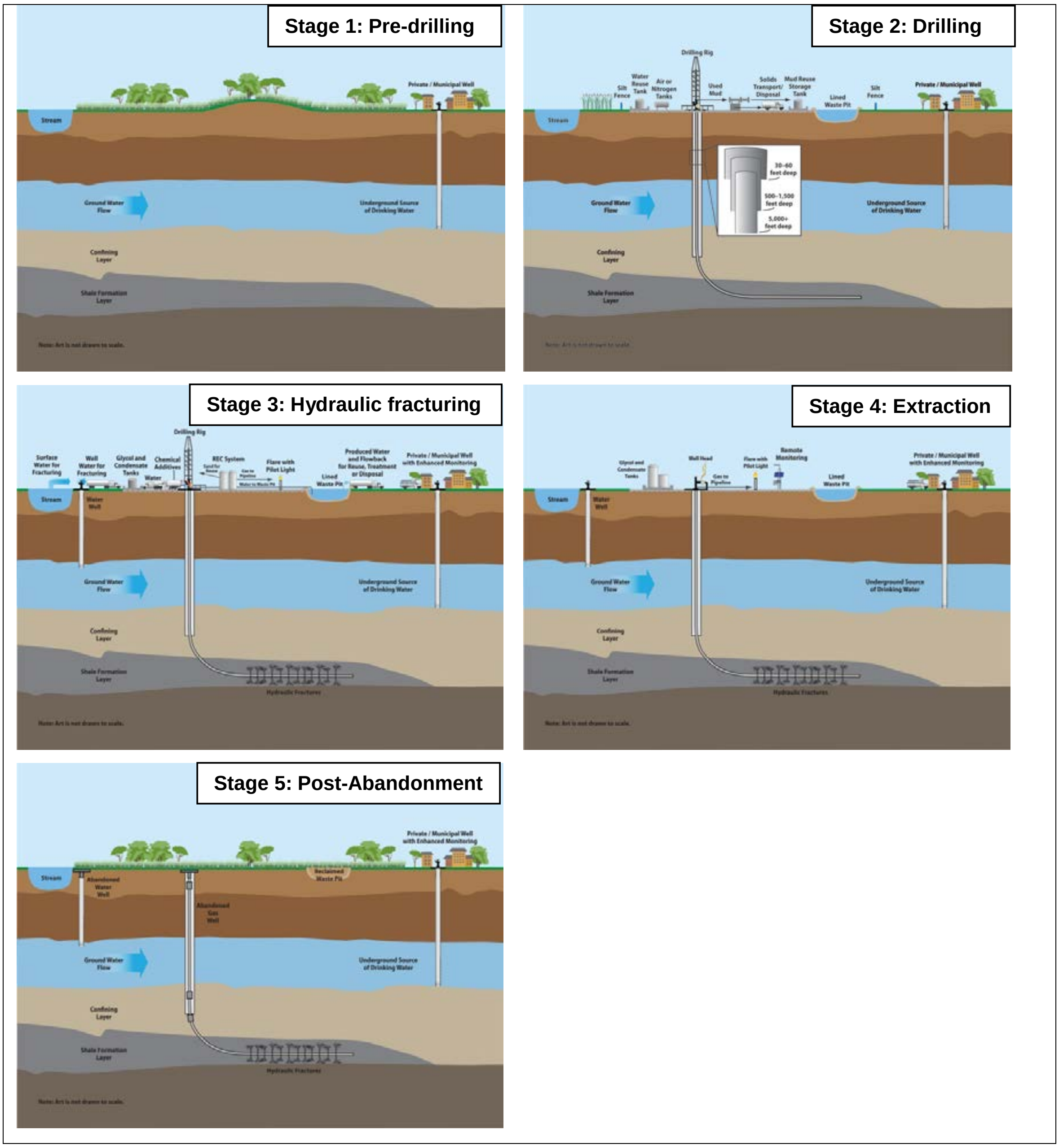


Figure 1.3 Stages in the hydraulic fracturing process

Directional drilling is also used in coalbed methane recovery. In this case, the drilling follows the coal seam and is not necessarily horizontal.

Once the directional well is complete, producers pump fracturing fluid into it at a pressure sufficient to create fractures in the rock formation. Because of the longer well lengths, higher pressures and higher volumes of water are required for horizontal hydraulic fracturing compared with conventional fracturing. This is known as high volume horizontal (or directional) fracturing. In this context, the term ‘high volume’ has been interpreted following the definition in the New York State Generic Environmental Impact Statement (GEIS) (NYSDEC 2011, section 3.2.2.1):

‘High-Volume Hydraulic Fracturing (HVHF) means hydraulic fracturing using greater than 300,000 gallons of water cumulatively in the HVHF Phase.’

This figure corresponds to 1,350 m^3. In the European context, it appears that a definition of 1,000 m^3 per stage would be a more appropriate working definition:

- For the test drillings carried out by Cuadrilla Resources Limited in Boxtel, the Netherlands, a hydraulic fracturing volume of 1,000 m^3 per hour is estimated for 1–2 hours, per stage. It is expected that the total amount of water used will be about the same as in the UK (9,000–29,000 m^3 per well (Broderick et al. 2011, p. 25). As drilling is currently on hold in the Netherlands, there are no figures as to actual fluid volumes.
- For the hydraulic fracturing carried out by Halliburton at the Lubocino-1 well in Poland, 1,600 m^3 of fluid was used.

The range of fluid pressures used in high volume hydraulic fracturing is typically 10,000–15,000 psi (700–1000 bar), and exceptionally up to 20,000 psi (1,400 bar). This compares to a pressure of up to 10,000 psi (700 bar) for a conventional well.

1.2.3 Shale gas

Conventional natural gas reservoirs form when gas migrates toward the Earth's surface from organic-rich source rock and becomes trapped by a layer of impermeable rock. Producers can access the gas by drilling vertical wells into the area where the gas is present, allowing it to flow to the surface. Shale gas resources, however, are contained within relatively impermeable source rock, meaning that the gas does not migrate out of the source rock and into a reservoir where drillers can easily access it. The gas remains in the shale beds, in which it was formed. This means that shale gas reserves differ from conventional gas reserves in terms of two key aspects:

- Shale gas formations are of much lower permeability than conventional gas reservoirs.
- Shale gas formations typically cover a much wider lateral extent than conventional gas reservoirs – for example, the Bowland Shale in northern England is widespread in the Craven Basin, including the Lancaster, Garstang, Settle, Clitheroe and Harrogate districts, south Cumbria and the Isle of Man; also in North Wales, Staffordshire and the East Midlands (BGS 2012).

Shale gas can be formed via a number of routes. When temperatures of the organic-rich sedimentary rocks exceed 120°C, oil and natural gas are formed from organic matter within the rocks (Broadhead 2004). It normally takes millions of years for the source rocks to be buried at sufficient depth for these temperatures to occur and generate sufficient volumes of oil and natural gas to form a commercially viable reservoir. If the organic materials within the source rock are mostly wood fragments, then the primary hydrocarbons generated upon maturation are natural gas. If the organic materials are mostly algae or the soft parts of land plants, then both oil and natural gas are formed. Oil and gas formed in this manner are referred to as thermogenic oil and gas. At higher temperatures, oil may break down further, forming natural gas.

Anaerobic bacterial activity in organic-rich sedimentary rocks can also result in the generation of natural gas. This process takes place at lower temperature at shallower depths than thermogenic processes. In this process, referred to as biogenic gas generation, the organic-rich source rocks are never buried very deeply and do not attain temperatures necessary for the thermogenic production of gas. Biogenic processes produce less gas per unit volume of sediment than thermogenic processes. Consequently, gas wells used for extraction from biogenic reserves tend to be low volume and relatively shallow (less than 600 metres). In contrast, thermogenic reserves tend to be at depths of 1,000–5,000 metres. Foreseeable shale gas extraction in the UK is likely to be from measures at depths of 1,000–1,900 metres (North UK Petroleum

System Bowland Shale) and 3,500–4,700 metres (South UK Petroleum System Liassic Shale) (US EIA 2011).

The low permeability of shale gas plays means that horizontal wells paired with hydraulic fracturing are required in order for natural gas recovery to be viable. The typically extensive area of shale gas formations opens the possibility of extensive development of large gas fields. This is in contrast to conventional gas extraction, which has been localised in nature.

Because its widespread extraction is relatively new, shale gas – along with tight gas and coalbed methane – is often referred to as 'unconventional' natural gas. However, in some areas such as British Columbia (Canada), the majority of gas extraction and almost all new exploration are from shale gas reservoirs, and so it is no longer considered unconventional by the industry and regulatory authorities in these areas.

Unconventional natural gas development has become an increasingly important source of natural gas in the US in recent years (US EPA 2011j). It accounted for 28 per cent of total natural gas production in 1998 (Arthur et al. 2008). This rose to 50 per cent in 2009 and is projected to increase to 60 per cent in 2035 (US EIA, 2010). At the end of 2009, the five most productive shale gas fields in the US were producing 0.24 billion cubic metres (bcm) of natural gas per day (Zoback et al. 2010).

1.2.4 Coalbed methane

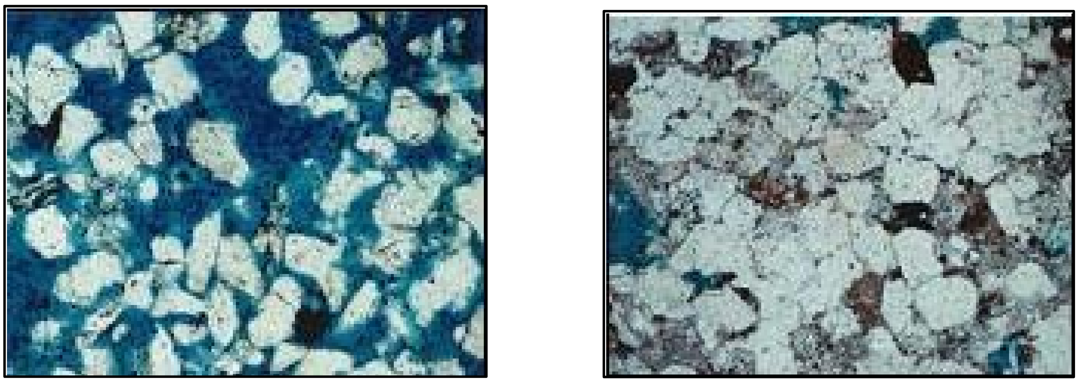
Coalbed methane (CBM) is formed through the geological process of coal generation. It is present in varying quantities in all coal and like in shale gas formations it is trapped with the strata – in this case within the coal itself with only 5–9 per cent as free gas. It is exceptionally pure compared to conventional natural gas, with the coalbed gas typically containing 90 per cent methane.

Hydraulic fracturing is used in CBM deposits to enhance extraction. The process of hydraulic fracturing is as previously described but the effect on the coalbed differs in the extent that the process results in what has been described as rock 'breakdown'. This is because coal is a very weak material and cannot take much stress without fracturing.

The process can fracture not only the coalbeds but also fracture surrounding strata within or around the targeted zones. The process sometimes can create new fractures but more typically enlarges existing fractures, increasing fracture connections in or around the coalbeds.

1.2.5 Tight gas

The term 'tight gas' refers to gas that is trapped in unusually impermeable, hard rock, or in a sandstone or limestone formation that is unusually impermeable and non-porous (known as tight sand). In a conventional sandstone, the pores are interconnected so gas is able to flow easily from the rock. In tight sandstones there are smaller pores, which are poorly connected by very narrow capillaries, resulting in the very low permeability of 1 mD or less. Figure 1.4 illustrates the differences between conventional and tight sandstones.



Notes: Conventional sandstone (left) has well-connected pores (dark blue). The pores of tight gas sandstone (right) are irregularly distributed and poorly connected by very narrow capillaries (NETL 2012).

Figure 1.4 Microscopic sandstone sections

The permeability of tight gas reservoirs is less than 1 mD. Techniques such as hydraulic fracturing or acidising are needed to extract gas from a tight formation at economically viable flow rates.

Tight gas reserves in Europe are mainly found in Germany, in particular in Lower Saxony.

2 Outline of conventional extraction and comparison

2.1 Conventional gas extraction

Conventional extraction refers to the traditional methods for accessing oil and gas from relatively easily accessible sources. Conventional oil and gas are extracted by drilling directly into the reservoir. Where oil and gas are present together the gas is termed ‘associated gas’; where it is a gas only reservoir it is termed ‘non-associated gas’.

During conventional drilling there will be associated drilling muds and fluids, which will be the same as for the initial drilling stages in hydraulic fracturing for non-conventional sources. It is on completion of the drilling and the local pre-production processing that the important differences between the two drilling and extraction approaches are seen.

During completion of a conventional well, the gas will rise to the wellhead and emerge as a wet gas. This is taken directly into the local production equipment to initially separate the gas from the free liquid water and natural gas condensates. The collected gas is then subject to heating, chemical treatment and dehydration prior to compression and export via ‘gathering lines’, to downstream gas processing. This downstream processing plant will be the same as that used for unconventional gas; indeed a gas processing plant can take raw natural gas from any source.

At the processing facility the raw natural gas will go through a number of stages (Figure 2.1) to remove:

- acid gases and specifically H_2S by amine treatment (Girdler process) or polymeric membrane – this stage can further treat the waste acid gases to commercially recover sulphur in a process termed ‘sweetening the natural gas’;
- residual water vapour – by processes such as glycol dehydration or pressure swing adsorption (PSA);
- mercury – by molecular sieve or activated carbon;
- nitrogen – by cryogenic distillation, absorption in a solvent or in lean oil, or adsorption on activated carbon.

Natural gas liquefiable products such as natural gasoline, butane and propane are recovered at the processing facility by absorption or a turbo-expander demethaniser for further fractionation into other products.

The end product of this process is the processed natural gas, ready for odorising and distribution. These processes will be the same irrespective of the natural raw gas source. However, the potential introduction of shale gas extraction opens the possibility of new infrastructure being constructed in areas where natural gas processing had not previously been carried out.

Each stage in the natural gas production process has the potential for fugitive emissions.

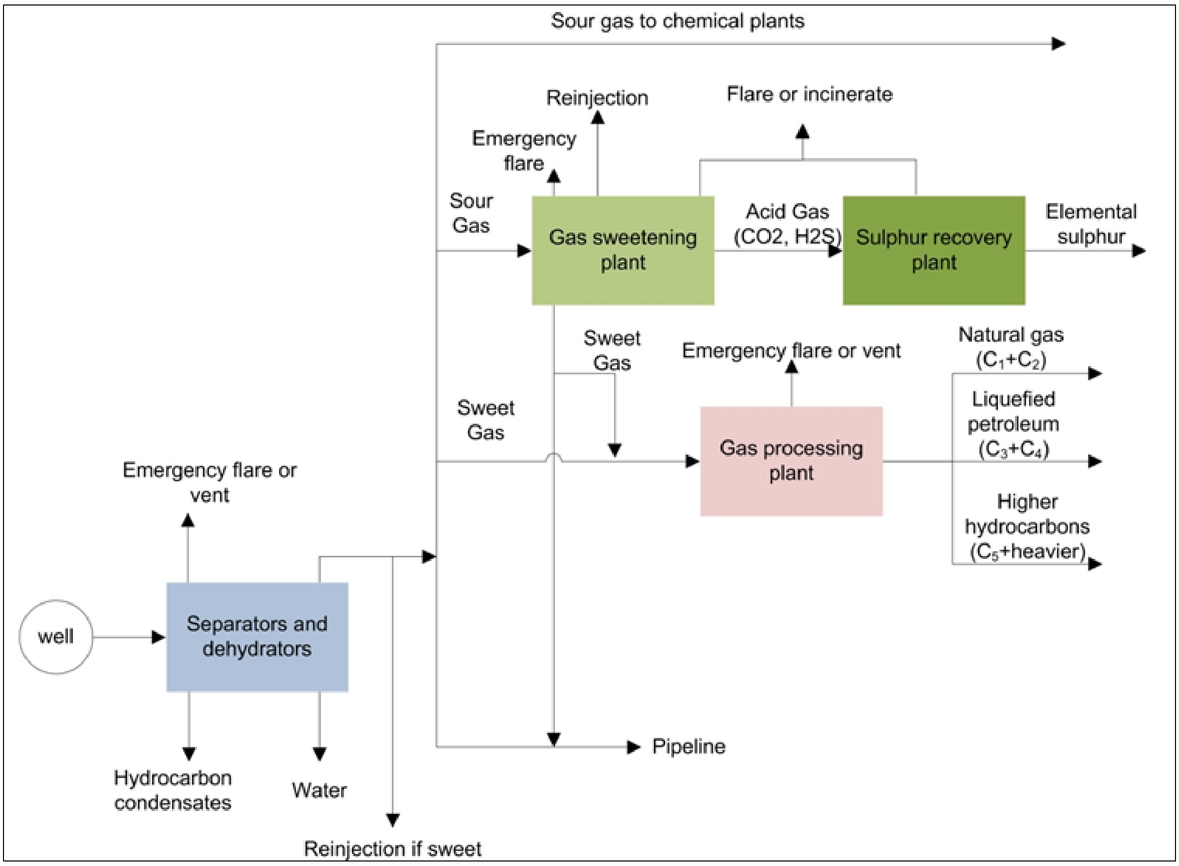
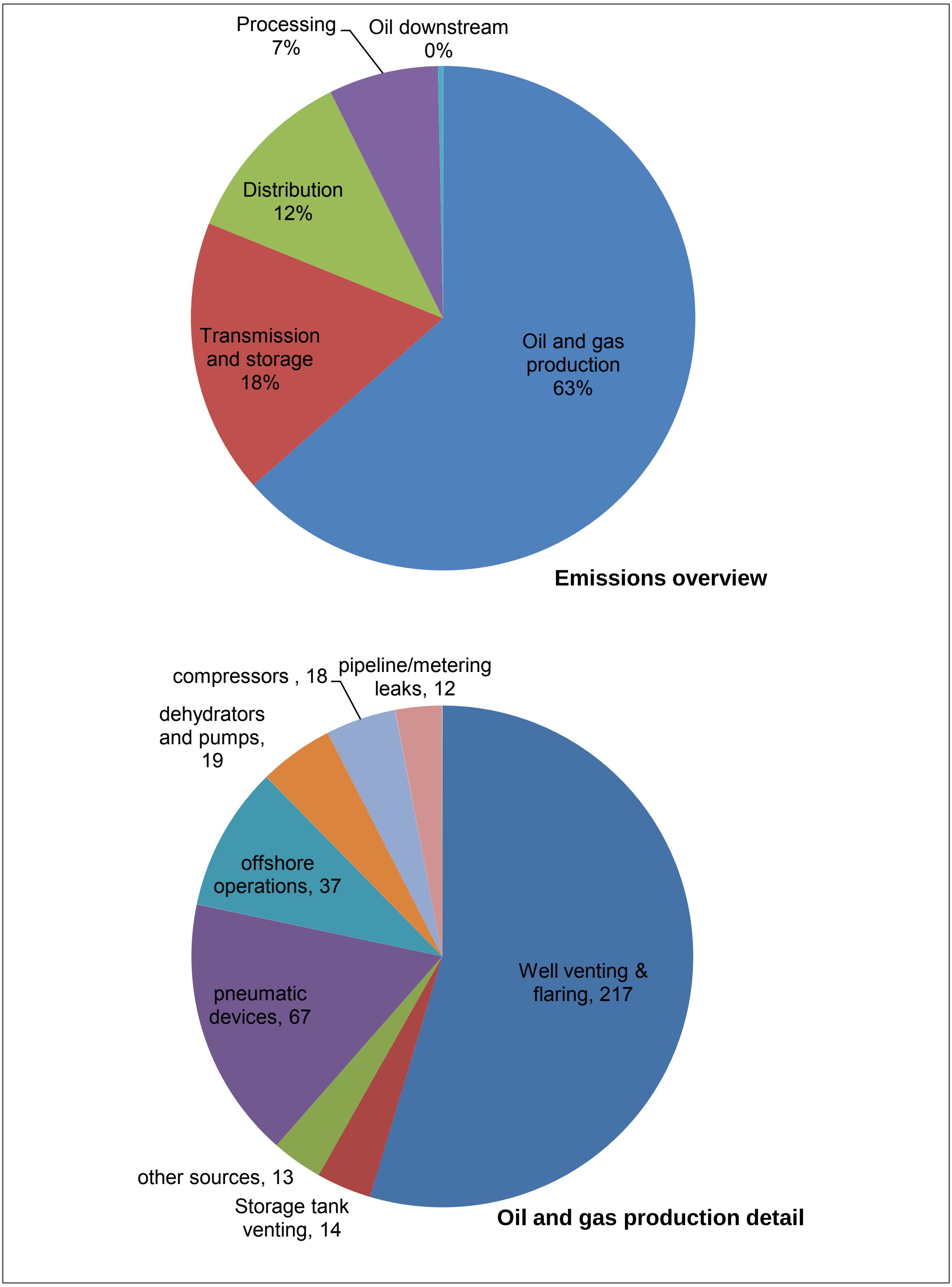


Figure 2.1 Generalised process flows and connectivities common to conventional and non-conventional gas extraction for the natural gas industry

Understanding all the different sources of emissions is important for a complete view of potential impacts and underpinning of the best regulation. Figure 2.2 summarises emissions inventory data compiled by the US EPA for the oil and gas sector. Emissions of methane from the oil and gas production account for 63 per cent of the total sector emissions, with the production emissions dominated by venting and flaring.



Source: US EPA (2001)

Figure 2.2 Breakdown of US fugitive emissions of methane (total emissions: 18 bcm per year)

2.2 Onshore conventional oil and gas extraction in the UK

There has been limited experience of onshore oil and gas extraction in the UK (Figure 2.3). Onshore extraction has been dominated by the Wytch Farm oil and gas fields in Dorset. Further extraction has taken place in the east Midlands, north-east England and Kent (BGS 2011). Onshore extraction is a small proportion of total UK oil and gas production: onshore oil production represents 2 per cent of total UK production. Similarly, onshore gas production is 0.4 per cent of the UK total.

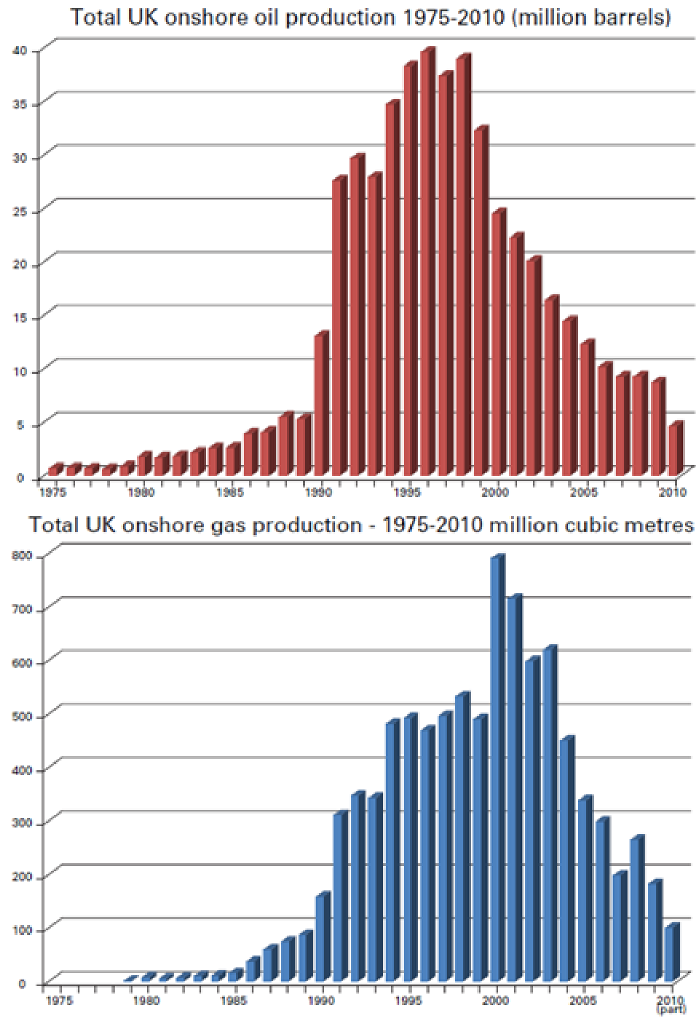


Figure 2.3 Onshore oil and gas extraction in the UK (BGS 2011)

2.3 Comparison of conventional and unconventional gas production

2.3.1 Overview

The basic configuration for the pre-production wet gas clean-up is shown in Figure 2.4 for conventional and unconventional gas. The figure shows three process diagrams: the first is for the conventional well completion, the second is for unconventional and the third is for unconventional with additional temporary handling equipment for control of methane (known as ‘green completion’ or ‘reduced emissions completion’). Reduced emissions completion is discussed further in Section 4.4.

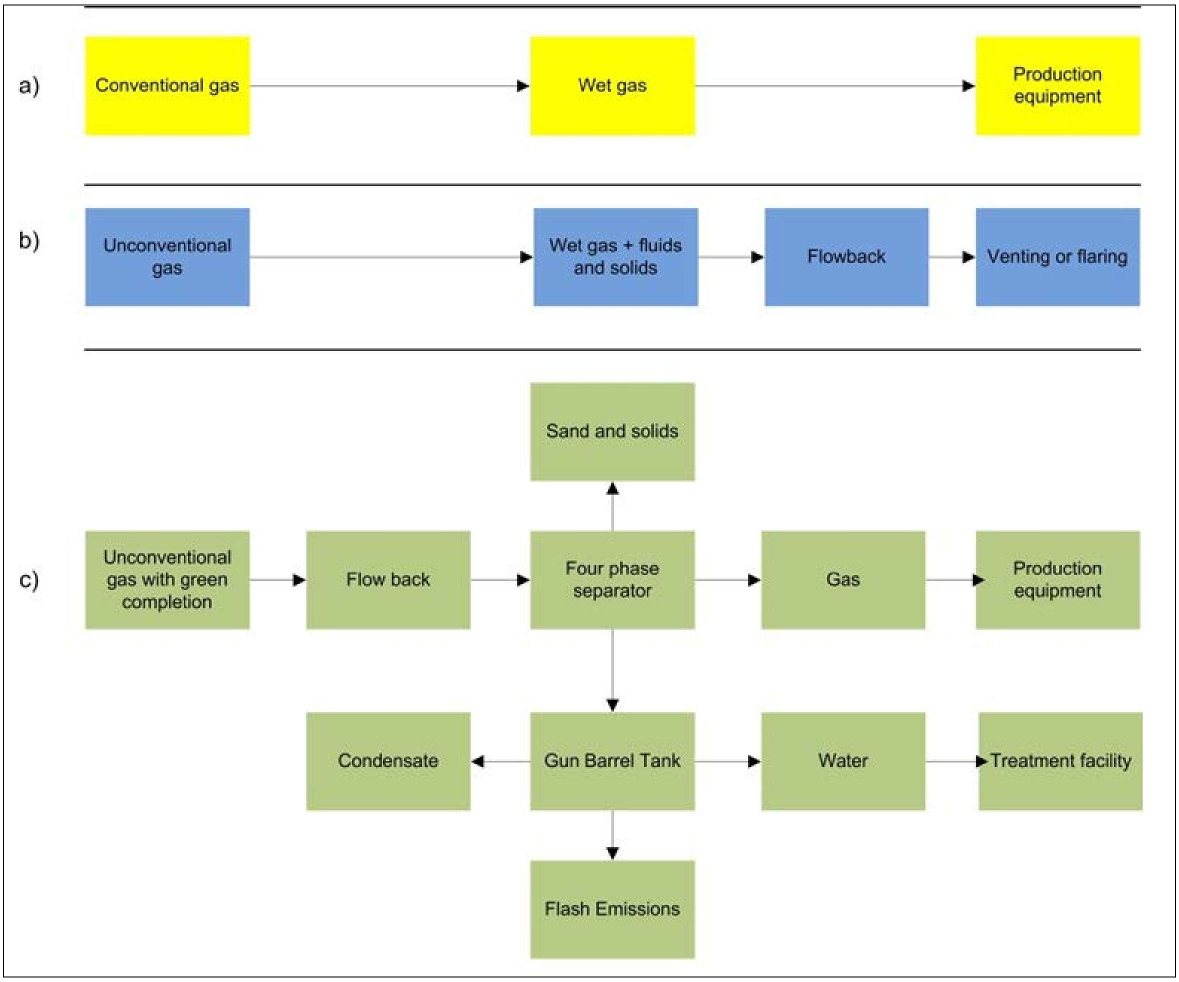


Figure 2.4 Overview of well completion strategies (personal communication from Professor Robert Field, University of Wyoming, 2012)

2.3.2 Schedule of differences between conventional and unconventional gas production

Table 2.1 sets out the stages of a high volume hydraulic fracturing activity, and summarises the differences between this and conventional hydrocarbon production. The aspects of direct relevance to this project are highlighted in bold text.

Table 2.1 Stages of high volume hydraulic fracturing and differences from conventional hydrocarbon production

Development and production stage	Step	Decision factors	Differences from conventional hydrocarbon production
Site selection and preparation	Site identification	Production yield versus development cost	None
	Site selection	Proximity to buildings / other infrastructure Geologic considerations Proximity to natural gas pipelines Feasibility of installing new pipelines	None None None None
		Site area (around three hectares/well needed during fracturing)	More space required during hydraulic fracturing for tanks / pits for water / other materials required for fracking process
		Access roads / requirement improvements	More lorry movements during hydraulic fracturing than conventional production sites due to need to transport additional water, fracking material (including sand/ceramic beads) and wastes
		Availability and cost of water supply and wastewater disposal	Obtaining/disposing of large volumes of water (10,000–20,000 m^3 per well)
		Availability of space to store make up water and wastewater	For example may require 20,000 m^3 of make-up water onsite before fracturing Will require sufficient trucks / tanks onsite to manage flowback (e.g. 40–50 trucks at 90 m^3 per tank)
	Site preparation	Number of wellheads per pad and per hectare Well pad design to control run off and spills and contain leaks Amount of water / proppant needed for production activities	Installation of additional tanks / pits More wells/pad Fewer wells/hectare
Well design	Deep well (directional) Shallow vertical	Separation of aquifer from hydrocarbon bearing formation by impermeable layers Existence of fault / fracture zones	Both conventional and unconventional wells are drilled through water-bearing strata and require same well design

Development and production stage	Step	Decision factors	Differences from conventional hydrocarbon production
		Maximising access to hydrocarbon in strata	standards
Well construction and development	Drilling	Depth to target formation (vertical or horizontal)	Horizontal drilling produces longer well bore (vertical depth plus horizontal leg) requires more mud and produces more cuttings/well Horizontal drilling requires special equipment, larger diesel engine for the drill rig, burns more fuel produces more emissions. Equipment is on site for a longer time. However, fewer horizontal wells would be needed to extract a similar quantity of gas
	Casing	Casing required or open hole construction (competent conditions only): casing would normally be required Conductor (for wellhead) Surface (to isolate near-surface aquifer from production) Intermediate (to provide further isolation) Production (in target formation) Centred casing to enable cementing	Casing material must be compatible with fracking chemicals (e.g. acids) Casing material must also withstand the higher pressure from fracturing multiple stages
	Annular packers Inflatable downhole tools installed on the outside diameter of a casing can provide a back-up to cement in hydraulically fractured wells	Need to prevent annular gas migration or separate horizontal wells into segments.	Could be used on both conventional and unconventional wells
	Cementing	Correct cement for conditions in well (e.g. geology	Hydraulic fracturing has the potential to

Development and production stage	Step	Decision factors	Differences from conventional hydrocarbon production
		and groundwater) and fracturing pressure	damage cement. This could theoretically give rise to fugitive methane emissions over the longer term
Well completion	Hydraulic fracturing: water sourcing	Quantity of water required for hydraulic fracturing Quality of water required for hydraulic fracturing Source and availability of water Impact on water resources and surface water flows Intensity of activity in watersheds / geologic basins	Requirement to abstract and transport water to wellhead for storage prior to hydraulic fracturing operations
	Hydraulic fracturing: chemical selection	Tailoring of fracturing fluid to properties of the formation / project needs Tailoring chemicals to make up water quality (e.g. highly saline flowback, acid mine drainage)	Chemical, physical and toxicological properties of chemical additives not used routinely in conventional hydrocarbon production
	Chemical transportation		Transport of large volumes of chemicals and proppant to well pad
	Chemical storage	Size, type, and material of tanks or other containers	More chemical storage required for high volume hydraulic fracturing
	Chemical mixing	Quality control on site to ensure correct mixture.	Mixing of water with chemicals and propping agent (proppant)
	Hydraulic fracturing: perforating casing (where present)	Use and type of explosive	Conventional wells are also hydraulically fractured. The amount and extent of perforations may be greater for high volume hydraulic fracturing
	Hydraulic fracturing: well injection of hydraulic fracturing fluid	Number of stages required Need to inject small amount of fluid before fracturing occurs to determine reservoir properties and enable better fracture design Pressure required to initiate fracturing with fracturing fluid without proppant dependent on depth and mechanical properties of formation Monitoring requirements (see next column)	Monitoring requirements and interaction of fracturing fluid with formation also occur in conventional wells but more extensive in high volume fracturing due to longer well length in contact with formation (up to 2,000 metres for high volume hydraulic fracturing, compared to up to a few hundred metres for conventional well

Development and production stage	Step	Decision factors	Differences from conventional hydrocarbon production
		Number, size, timing and concentration of delivery slugs of fracturing fluid and proppant	depending on formation thickness) More equipment required: Series of pump trucks, frack tanks, much greater intensity of activity.
	Hydraulic fracturing: pressure reduction in well / to reverse fluid flow recovering flowback and produced water	Chemical additions to break fracking gels (if used) Planning for storage and management of flowback recovered before the well starts gassing (varies from 0%-75% but strongly formation dependent). Planning for storage and management of smaller volumes of wastewater generated during production (decreasing flow rates and increasing salt concentrations)	'Flowback' of fracturing fluid and produced water containing naturally occurring materials (mostly salt) and hydrocarbons
	Connection of well pipe to production pipeline		None
	Reduced emission completion	Capture gas produced during completion and route to production pipeline or flare it if pipeline is not available	Larger volume of flowback and sand to manage than conventional wells
	Well pad removal	Amount of wastewater storage equipment to keep on site Remove unneeded equipment and storage ponds. Re-grade and re-vegetate well pad.	Larger well pad (with more wells/pad) with more ponds and infrastructure to be removed
Well production	Construction of pipeline	May need to construct a pipeline to link new wells to gas network.	Exploitation of unconventional resources may result in a requirement for gas pipelines in areas where this infrastructure was not previously needed
	Production	May need to re-fracture the well to increase recovery (e.g. after five years of service). Wastewater management (e.g. discharge to surface water bodies, reuse or disposal via	Produced water will contain fracturing fluid as well as hydrocarbon Conventional wells are often in wet formations that require dewatering to

Development and production stage	Step	Decision factors	Differences from conventional hydrocarbon production
		underground injection including transport to disposal site)	maintain production. In these wells, produced water flow rates increase with time. In shale and other unconventional formations, produced water flow rates tend to decrease with time.
Well site closure	Remove pumps and downhole equipment Plugging to seal well	Need to install surface plug to stop surface water seepage into wellbore and migrating into groundwater resources Need to install cement plug at base of lowermost underground source of drinking water Need to install cement plugs to isolate hydrocarbon, injection/disposal intervals	Likely to be similar to conventional well
Post-closure	Long-term monitoring to ensure well integrity	Methane can continue to be produced after well closure, at rates which are not commercially viable but which could result in methane seepage in the long term if seals or liners break down.	None

In summary, the key differences between on-shore hydraulic fracturing for unconventional gas extraction and conventional gas extraction practices with regard to potential environmental impacts are as follows:

- More space required for surface installations – 3.0 hectares per pad for high volume hydraulic fracturing compared to 1.9 hectares per pad for conventional drilling (NYSDEC 2011, Table 5.1).
- More equipment on site during well installation and fracturing (NYSDEC 2011, section 5.2.1).
- More heavy vehicle movements during well installation and fracturing (see, for example, NYSDEC 2011 section 5.5). For high volume hydraulic fracturing, this may amount to 7,000–10,000 heavy vehicle movements per 10 well pads (Broderick et al. 2011).
- Higher water requirement (NYSDEC 2011, section 3.2.2.1).
- Horizontal wells require more fuel and produce more drilling waste and wastewater than vertical wells (NYSDEC 2011, section 5.2.4), with the potential for higher emissions of methane.
- Increased risks associated with waste disposal, including the potential for higher emissions of methane.
- Casing material must be able to withstand higher pressures and chemical additives (US EPA 2011j, section 3.2.2).
- More intensive use of a different range of chemicals during fracturing (NYSDEC 2011, section 5.4.3; US EPA 2011j, Table E.1).
- Fracturing has potential to damage cement seals (Broderick et al. 2011, pp. 81–83).
- May be a higher risk of generating seismic events (de Pater and Baisch 2011, pp. iv–v).
- More infrastructure to be removed following completion (NYSDEC 2011, section 5.16.1).
- Higher risk of ecosystem effects due to habitat loss, introduction of invasive species and disturbance (for example, NYSDEC 2011, section 6.4.2).
- Shale gas plays typically cover wider areas than conventional reserves (consultation feedback).
- Other factors being equal, horizontal wells provide a more efficient means to access gas reserves than vertical wells (US EPA 2011j, section 3.2.1). Consequently, horizontal drilling from a limited number of wellheads would in principle be preferable to vertical drilling from a larger number of wellheads. In practice, however, horizontal drilling techniques open up reserves that would not otherwise be viable with vertical drilling techniques, and so this comparison is not directly relevant.

From the perspective of fugitive methane control, the key issues are therefore:

- control of methane contained in flowback water and produced water;
- control of gas leakage from site infrastructure related to hydraulic fracturing activities, as well as conventional infrastructure such as compressors.

Consideration may also need to be given to minimising the risk of methane reaching the surface via pathways from the well infrastructure (for example, in the event of failures of the well liner system) or via the overlying rocks following fracturing of the shale matrix. For deeper shale gas measures, release via the overlying rocks is less likely to pose a significant risk, although recent research has highlighted the importance of fully understanding the geological conditions in the design of unconventional gas extraction processes (Davies et al. 2012; Warner et al. 2012). Control of these risks will be built into the design of an unconventional gas extraction project. An appropriate pre-operational monitoring survey will be an important component of the project to ensure that if any emissions do occur via these pathways, they can be identified and addressed.

2.3.3 Control of fugitive methane

In conventional systems, the natural gas from the well can be connected rapidly to the production equipment. The gas quality could potentially range from natural gas, which is almost at production quality, to sour gas requiring more treatment. Conventional gas completion will already use some of the components of ‘green completion’ systems to avoid the need to cold vent or excessively flare the natural gas.

In basic unconventional systems, the flowback would be run off into a pit or tank prior to connecting to the production equipment. There would not normally be any collection of fugitive methane under these circumstances. This represents a potential source of fugitive methane emissions that does not occur for emissions from conventional gas extraction in Europe where hydraulic fracturing is much less common.

In green completion, the flowback is handled using a set of mobile plant to separate the solid, liquid and gas phases and to provide gas suitable for injection into the downstream gathering lines. The flowback phase may continue over a period of 3–10 days for an unconventional completion. The comparable completion time for a conventional well is much shorter as the produced gas can be introduced directly into the localised production equipment sooner.

With green completion, the number of additional physical linkages and additional equipment may increase the chances of fugitive releases. In the green completion process, the gun barrel tank – a further two-phase separator for condensate and water – does have a fugitive release issue, termed flash emissions.

In both conventional and unconventional systems, emissions from compressor plant may potentially be significant and require careful attention from operators and regulators.

2.3.4 Comparison of methane emissions from conventional and unconventional gas

US EPA recently re-evaluated emissions of methane to air from conventional and unconventional gas, following increasing evidence that emissions had previously been under-estimated (US EPA 2011g). The revised emissions factors set out in Table 2.2 indicate that methane emissions to air from completion and workovers of unconventional wells are much greater than those from conventional wells.

Table 2.2 Comparison of methane emissions factors (tonnes per event)

Emission source		Previous EPA emission factors	Revised emission factors
Gas well venting during completion	Conventional	0.02	0.71
	Unconventional	0.02	177
Gas well venting during well workovers	Conventional	0.05	0.05
	Unconventional	0.05	177

Source: US EPA (2011g)

A recent study by Howarth et al. (2011) compared the fugitive methane emissions of the different stages of natural gas production. The study's findings are summarised in Table 2.3.

Table 2.3 Fugitive methane emissions associated with development of natural gas (as a percentage of methane produced over the life cycle of a well)

Stage	Fugitive methane emissions as a percentage of well lifetime emissions	
	Conventional gas	Unconventional gas
Well completion	0.01	1.9
Routine venting and equipment leaks at site	0.3–1.9	0.3–1.9
Liquid unloading	0–0.26	0–0.26
Gas processing	0–0.19	0–0.19
Transport, storage and distribution	1.4–3.6	1.4–3.6
Total	1.7–6	3.6–7.9

Source: Howarth et al. (2011)

While this work remains controversial and subject to disagreement within the scientific community, it is consistent with the US EPA's view of much higher emissions from well completion for unconventional gas than from conventional gas. A later study by Pétron et al. (2012) provides support for higher emissions from a tight gas field compared to a conventional field. This study suggested that, applying the established methodology indicated, that approximately 2 per cent of methane production was lost to the atmosphere, whereas atmospheric measurements combined with the use of dispersion modelling tools indicated that approximately 4 per cent of methane was lost to the atmosphere during tight gas production.

There are differences between tight gas extraction and shale gas extraction, for example:

- tight gas reservoirs tend to be of higher porosity (up to 1 mD) than shale gas reservoirs (up to 0.001 mD);
- shale gas plays tend to cover a more extensive area than tight gas reserves (see Section 1.2.3), resulting in different approaches to exploring for tight gas and shale gases.

However, both types of gas reserve typically require horizontal drilling and hydraulic fracturing to enable gas to be extracted, and downstream gas handling and processing systems are similar. Hence, the information obtained by Pétron et al. (2012) for tight gas can be viewed as a reasonable model for shale gas.

3 Methane monitoring techniques

3.1 Introduction

The measurement of methane emissions is guided by a number of factors. The two principal ones are:

- **Safety.** In this case, the near field concentration is the most relevant. Methane can be explosive if present at concentrations within a defined range. Methane could potentially also act as an asphyxiant if present at elevated levels within a confined space. There is an additional commercial pay-off with near field assessment in that a loss of methane potentially reduces the overall profitability of the operation. This means that there is also an economic benefit to the operator to monitor and minimise fugitive methane emissions.
- **Environmental.** The quantity and flux in the near to medium field is of the most relevance. Methane has a global warming potential (GWP) 25 times greater than carbon dioxide over a 100-year timescale. This factor increases to 72 times that of carbon dioxide over a 20-year timescale (IPCC 2001). Emissions of methane may also contribute to regional air quality issues due to the photochemical formation of ozone. There may potentially be impacts resulting from odours and emissions of hazardous air pollutants, although a detailed air quality measurement study at Fort Worth Texas found that levels of hazardous substances complied with the applicable air quality standards (see Section 5.5).

A number of methods can be used to measure methane. The methods used need to be applied to the sources encountered during unconventional gas exploration and production. There are controlled and uncontrolled releases of methane during these processes. As described above, there are strong safety, environmental and economic pressures for operators to control and reduce natural gas losses.

The approach to measuring methane concentration can differ depending on the specific requirement. At the wellhead and local production equipment, identification of leaks and ensuring that the level of explosive mixtures in enclosed spaces are well below the lower explosive limit (LEL) are the priority.

Safety is a high priority. Methane present in air between the range of 5–15 per cent and oxygen levels above 13 per cent carries a risk of explosion. The risk is greatest at concentrations of 9.5 per cent at normal conditions (20°C and 1 atmosphere); at these conditions the maximum amount of energy would be realised in any explosion.

Hence, for leak detection, it is vital to assess if the released levels are in an explosive range, as well as the location and rate of leak. A total explosive capacity is measured using LEL measurement systems. This is not specific to methane, but includes other gaseous hydrocarbons that can form an explosive mixture. An LEL meter provides the concentration of the explosive gases on a scale of 0–100 per cent of the LEL of 5 per cent methane volume/volume (v/v).

For specific production equipment, understanding the rate of leak will form part of the regular measurement regime and part of any equipment performance acceptance test.

Further away from the local production equipment, it is important to know that methane is not significantly above the background level at or beyond the plant boundary. This is often tested using fenceline monitoring.

At the fenceline and in the medium field, measurements can be used for the assessment of methane flux, that is, the mass release rate over a period of time from a particular installation. At larger scales, the overall impact of multiple wells and associated infrastructure on methane concentrations and fluxes can be assessed on a regional basis.

The measurement of the absolute level of methane emitted from the well and production equipment, and from other potential fugitive sources, may have some importance. It could be important for assessment of wide area fugitive releases from sources such as shallower coal bed methane plays via local irregularities and weaknesses in the subsurface structure.

A number of approaches are available for estimating methane fluxes:

- **Emission factors.** Using published emission factors and knowledge of the type and number of components in the production process, a budget of methane releases can be estimated. Such an approach can be augmented using knowledge from site specific leak detection and repair (LDAR) surveys.
- **Flux emission measurement**. This involves using either point source, transect or open path or optical remote technology (or a combination) coupled with quality meteorological data with statistical assessment and modelling:
    - Radial plume mapping, for example, according to US EPA Other Method 10 (US EPA OTM 10)[2] using open path technology, with statistical and computational modelling in conjunction with meteorological monitoring. These techniques can be used to provide flux measurement and horizontal methane mapping to identify hotspots.
    - Discrete sampling campaigns, using multiple monitoring points with high mast sampling and vehicle mounted analyser transects (automobile and/or aircraft).
- These measurements can be used with tracer gas correlation and inverse-dispersion modelling (such as the backwards Lagrangian Stochastic inverse-dispersion modelling technique or the Community Multiscale Air Quality (CMAQ) 'adjoint' model) to locate and characterise possible source terms.
- These methods have the disadvantage of coping with possible complex source terms. The methodology is covered in the US EPA *Handbook: Optical Remote Sensing for Measurement and Monitoring of Emission Flux* (US EPA 2011h).
- **Emissions monitoring.** This measures the emissions of methane from controlled vents (stationery sources); it does not tackle the fugitive releases. Leaks can also be assessed using an enhanced approach to leak detection and repair, that is, using better sensitivity detectors when determining the leak rate and hence provide a quality feedback loop into the management of emission factors.

[2] http://www.epa.gov/ttn/emc/prelim.html

The UK has increasing experience of regional-scale models such as the Community Multiscale Air Quality (CMAQ) model, which can run inverse models to locate potential source terms. The CMAQ infrastructure in the UK is linked to advanced independent meteorological forecasting and is the basis of current UK pollution prediction forecasting.

Monitoring requirements will change over time, requiring different approaches.

- Prior to any drilling, it would be very useful to characterise the background methane levels.
- During drilling and production:
  - an emphasis on fugitive releases, primarily driven by safety and operational maintenance (LDAR regimes);
  - fenceline measurement;
  - receptor measurement in the wider community, including incident response.
  - methane flux assessment.
- After the well closure, a maintenance check on the status of the capped well.

The measurement methods set out below can be tailored to all these needs.

3.2 Leak detection and repair regimes

There is a need to minimise leaks. The first stage is to identify the leaks. The oil and gas processing industry has a systematic approach based on risk and cost–benefit to controlled and fugitive natural gas emissions.

For natural gas leaks, a common approach is to first identify the major processes at the site including compressors, separators, storage tanks, all pipe connections, valves, flanges, vents and open ended pipes. The risks of emissions and leaks are calculated and each connection is assessed so that a complete inventory can be made and issues dealt with directly. This process is known as leak detection and repair (LDAR).

Historically, this process was completed using calibrated hand-held devices, such as intrinsically safe flame ionisation detectors or catalytic combustion detectors, using a small probe to scan along all the identified weak points. Specific detection protocols were developed but generally followed the principle that a concentration at the component has to be above a leak definition criterion, typically 10–100 per cent of the LEL. To add a level of complexity, the local background level of methane also needs to be considered.

On detection of a leak, the regime for repair when above the ‘definition’ level can vary between 48 hours to 15 weeks, depending on local regulations. This repair schedule can be longer in the case of significant plant shutdown to enable the repairs to be carried out safety, so in these cases, it may be judged practicable to postpone the repair until the next planned shutdown.

This does not mean that leaks causing local methane concentrations below the definition criterion will not be addressed. In addition to the concentration, knowledge of the rate of leak is important – be it calculated from equipment emission factors or measured directly. For low level leaks, if the rate of methane release results in a monetised loss of methane greater than the cost of repair, then the repair would be done.

The LDAR process has been improved with the use of new technology, specifically the use of infrared (IR) thermal imaging. The standard IR technology is adjusted so that the detector is tuned to a specific wavelength at which a methane leak will show up and a visible gas. This advance has improved the speed of the LDAR process and, depending on the system, whole process areas can be scanned.

Within the local production equipment, an immediate difference between conventional and unconventional well treatment is the additional equipment introduced by the low emission or green completion – the more linkages within a system, the more leaks are likely.

3.3 Leak rate determination

Determination of the leak rate is necessary to generate evidence for the need to repair minor leaks and to compile greenhouse gas (GHG) emissions estimates.

From the concentration, tables such as stratified screening value tables are used to estimate the leak from the concentration and component type. These data come from emissions inventories and so the leak rate determination can carry large uncertainties. Furthermore, the emission factors are largely historic and seldom updated. The factors have been taken from:

- Canadian Gas Association emission inventory (CGA) 1990
- Gas Research Institute/US EPA natural gas industry study (GRI and US EPA 1996);
- Environment Canada methane emission measurements (Environment Canada 1996).

This is the basis used by companies to estimate their global methane emissions for LDAR results coupled with number of components. The data are based on a three tier system:

- Tier I is based on pipeline length. It is a very approximate method that does not take account of the presence of specific plant and equipment.
- Tier II is based on the number of major process/stations.
- Tier III is based on individual component counts/events

Direct measurement is also used, typically in relation to the high risk components such as compressors. Direct assessment is achieved using a flow flux principle. The source of leak or whole component is sealed in an enclosure (‘bagged’ up). A known flow of inert gas is introduced to the gas and the flow of total gas (inert plus leak) is measured at an outlet; knowing the concentration of methane, the mass emission rate of methane can be calculated. This emission rate and the recorded leak concentration at the component can be used to derive an emission factor.

An alternative to bagging is to use a system developed by the Gas Research Institute that samples the leak at a high rate, creating a fast-moving field of air moving at a known flow rate around the immediate source of the leak. The sample flow rate and methane concentration are measured and the mass emission rate of methane can then calculated. This has the major advantage of being portable and much easier to use than the bagging method.

3.4 Wellhead and associated production plant sources

All the component parts at a wellhead will have been catalogued and brought into a LDAR regime. The focus for leak detection and repair is on leak control. However, there are other controlled releases of methane such as those from vents, safety release valves and equipment blowdowns.

The simplified schematic of a possible well production in Figure 3.1 shows the natural gas flow from the wellhead through the 'Christmas tree' pipework at the wellhead, followed by gas/sand/ condensate separation and onto the compressor and any local treatment (such as dehydration) before the dried raw natural gas is fed into the gathering lines that take the raw natural gas to centralised natural gas processing facilities.

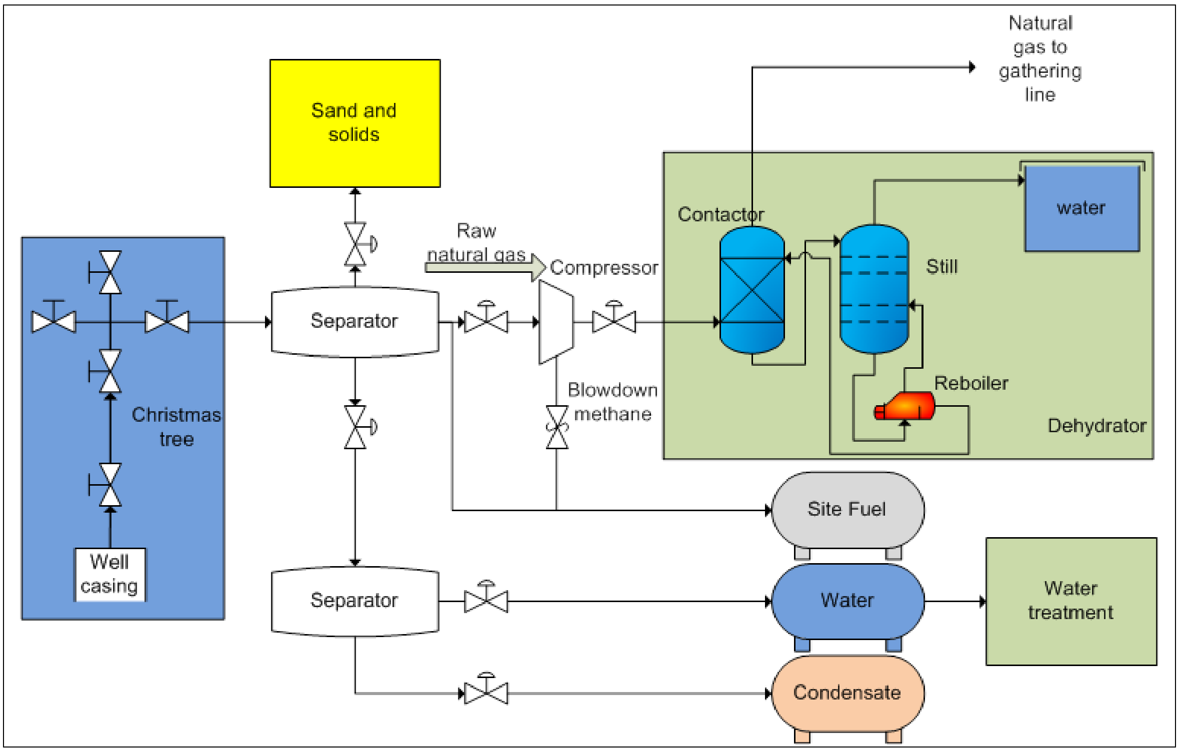


Figure 3.1 Natural gas well pad production equipment

If reduced emission (green) completion is not used, there is the potential for significant emissions of methane during unconventional well treatments. All processes and linkages can give rise to controlled and uncontrolled releases of methane. Major sources during production will be from vented tanks, separators and compressors. Smart design of the gas handling process and elimination or substitution of component parts can all help. These are discussed in more depth in Chapter 4 on control methods.

The first piece of equipment above ground is the wellhead and the valve manifold, known as the 'Christmas tree.' This will be under the same pressure as the well and will have multiple valves and flanges. It not only allows gas to be drawn out of the well but also allows other connections. After the Christmas tree, the gas, produced water and sands are taken through a series of separators to remove liquid water, sand and soils and condensate from the raw gas stream. This is then compressed and treated before entering the gathering lines to the centralised natural gas treatment facility.

Following the closure of the site, the well is capped, though this can be just the isolation of the Christmas tree if the closure is temporary. Leaks can develop over time, so a closed well requires periodic monitoring.

Compressors are reciprocating engines that drive a piston to compress the natural gas for production and transportation requirements. In normal operation, there are known leak issues from vents and from the piston rods. When not in operation, it was usual practice to depressurise the isolated system (blowdown), resulting in a large loss of natural gas. Additionally, the isolation valves from the pressurised gas pipeline can leak into the compressor and out through the blowdown vent to provide a constant emission. These emissions can be mitigated by measures ranging from simply avoiding blowdown and locking off the piston rod to recovering the gas from the blowdown vent (such as feeding into a lower pressure site gas fuel supply). Compressor blowdown and rod packing technology are important control features which are discussed in more detail in Chapter 4.

3.5 Instruments for LDAR/emission rate screening

Instruments for LDAR/emission rate screening include LEL meters, flame ionisation detectors, hand-held infrared and non-dispersive infrared instruments.

The basic protocol is based on US EPA Method 21 – Determination of volatile organic compound leaks.[3] Aside from these screening measurement systems and the much more expensive fugitive and ambient air instruments, Method 21 recommends a simple approach to identifying gas leakage. Soapy water is sprayed onto any pipe connection, flange or valve that is at ambient surface temperature. This enables any leaks to show up as the methane bubbles through the soapy water film.

There is a common misconception that a photoionisation detector (PID) can be used for methane detection. A PID uses an ultraviolent (UV) light source to ionise and detect any volatile organic compounds (VOCs). A properly configured and calibrated PID analyser can be used to measure a wide range of hydrocarbons and other compounds as long as the ionisation potential is below the ionisation energy output of the lamp. Depending on application, different UV lamps are available. The highest energy lamp available is 11.7 eV, which is below that needed to detect methane and ethane. PIDs are therefore specialised solvent detectors, but not detectors for methane.

These instruments are typically quite portable and it is common for the data to be recorded on a data-logger (built in or bolt on). It is normally useful to include GPS data: this capability can be included as optional extras for some equipment. The ability to log concentration and position data can be a powerful tool for the LDAR process and for overall site mapping.

The instruments described in this section can be used for LDAR without additional configuration. The purpose is to measure the concentration of methane and not the emission rate. Further information such as the flow rate of gases from a source, the increase of gas concentration over time in a bagged valve or flange and/or meteorological data can be used to derive an emission rate from the concentration data.

[3] http://www.epa.gov/ttn/emc/methods/method21.html

3.5.1 Hot bead and catalytic combustion analysers (LEL meters)

Portable combustible gas meters can be calibrated for methane, but are specifically designed to determine the concentration of an explosive gas mixture (not just methane) as a percentage of the lower explosive limit of 5 per cent (50,000 parts per million, ppm).

An 'LEL' meter is, however, possibly one of the most important single pieces of equipment for staff locating methane leaks when working around a well or natural gas processing facility – not to pin-point leaks but to alert staff to potentially high levels of methane.

The instrument works by comparing the resistance in a circuit known as a Whetstone Bridge; one of the arms has a catalytic substrate, the other a reference substrate. Combustible gas will ignite on the catalytic substrate, changing the resistance characteristics of the circuit. The change is proportional to the concentration of flammable gasses present

Method performance

- Price ranges from less than £1,000 to £3.000.
- Measures methane via thermal conductivity or heat of combustion in the range 1–10,000 ppm.
- Sensitive to low oxygen atmospheres or very high methane (greater than 12 per cent). The bead filament system can become 'poisoned' with use.
- Intrinsically safe, rugged and portable.
- Screening (LDAR) and personal protection use.

3.5.2 Hand-portable remote infrared – forward looking infrared (FLIR) and infrared absorption spectroscopy (IAS)

The basic forward looking infrared (FLIR) systems have become popular for leak detection within the gas industry, replacing the vapour analysers which were used to systematically as part of LDAR to check individual compression fittings, valves and flanges. In practice, FLIR will still be used with other measurement technology to generate required concentration data.

The main benefit of modern FLIR is that a captured, real-time image in the visible and IR range can be displayed on a screen, allowing the operator to see the actual leaks and methane plumes. This improves the speed of leak detection.

There will be a place for FLIR in assessing fugitive emissions as it will allow the screening of the production area for further assessment and can also be used for longer term surveillance. This equipment can be used in the same way as a handheld video camera; it can highlight gas leaks where other methods, such as complex machinery, cannot.

A hand-held infrared absorption spectroscopy (IAS) instrument uses a semiconductor laser for methane measurements. The detector measures a fraction of the diffusely reflected beam from its target point. The application has the advantage of working through water and glass, enabling its use during poor weather conditions such as fog and rain. It must be directed at a leak to take the measurement and therefore leaks cannot be found as quickly and easily as with the FLIR technique, though it can be used in conjunction with a FLIR system.

Method performance

- Price ranges from £1,500 to £50,000.
- An important screening tool – qualitative but provides visualisation of the extent of a leak.
- Portable and can be used at a distance.
- Typically, not intrinsically safe.
- Required ideal weather conditions for FLIR, although IAS is claimed to work in poor visibility.

3.5.3 Flame ionisation detection (FID)

The most popular methane monitoring method is flame ionisation detection. Within the sample chamber, a flame fuelled by hydrocarbon-free air and hydrogen ionises the methane and other VOCs into ionised carbon, changing the current across the chamber to an extent proportional to the VOC concentration.

The hydrogen fuel source is carried in a pressurised gas cylinder, while the hydrocarbon-free air is supplied by either a gas cylinder or a compressor. The FID will require adjustment against a zero gas (nitrogen) and a calibration gas (methane) at an appropriate concentration.

All FIDs have a relative response to other hydrocarbons, although it is possible to determine 'methane only' in higher end methane/non-methane systems. Each manufacturer publishes these response factors with the instrument.

This is a standard approach for both methane and non-methane VOC analysis in stack emissions and some comparable landfill gas applications. However, as good as this method is, it comes with inherent dangers in the gas industry. AEA has used this method at high risk sites where a high accuracy FID is set up for use in a safe zone, and bag or canister samples are collected at the measurement point and taken to the instrument for analysis. However, portable intrinsically safe FIDs are available.

Method performance

- Price range: the high end instruments will retail from £9,000 to £16,000. A hand-held system portable system will retail from £1,600 to around £6,000.
- Measures methane via flame ionisation, typically in the range 1–10,000 ppm.
- Assuming proper calibration, FIDs are sensitive and accurate. Typical hand-held instruments are capable of an accuracy for methane (after calibration with zero air and 500 ppm methane gas) within ± 0.5 ppm or ± 10 per cent of actual methane concentration (0.5–2,000 ppm range).
- The inherent disadvantage of a hand-held FID is the internal incandescent flame, though this has been addressed, and it is possible to purchase FID systems that are safe to use in controlled areas. Ambient FIDs need to use

100 per cent hydrogen, which presents a significant hazard for the operator.

- Specific training and care in operation required.
- Oxygen synergy for 100 per cent hydrogen FIDs can be a source of interference.
- With age, a FID can become ‘temperamental’ and so the user needs to be experienced with the full operation of the system.
- Used for screening (LDAR) and ambient assessment. Can be easily configured with internal data logging and GPS capability.

3.5.4 Non-dispersive infrared detection (NDIR)

Non dispersive infrared absorption (NDIR) spectroscopy uses the principle of infrared absorption of a target gas. The NDIR analyser will be set up such that the wavelength emitted by the IR source will be the same wavelength absorbed by methane. The attenuated IR at the end of the sample cell is detected by a sensitive photo-receptor. The signal is compared to the IR source in an inert gas such as nitrogen. The attenuation of the IR signal is used to calculate the concentration of methane in the test cell.

Different compounds have unique absorption spectra. However, this measurement principle does suffer from cross interference with water vapour and carbon dioxide, and so the gas does need to be conditioned before entry to the test cell.

Advanced versions of near IR spectroscopy such as cavity enhanced absorption spectroscopy could also be used, but these are more expensive. These more sensitive systems are more commonly associated with ambient measurements and used in vehicular transects, as discussed in the next section.

Method performance

- Price range: in the region of £6,000 to £10,000 (estimated).
- Measures methane via infrared light absorption spectroscopy but may have a limited range.
- Assuming proper calibration, NDIR sensitive and accurate.
- Interference from moisture and carbon dioxide.
- Used for screening (LDAR) and ambient assessment.
- Less common than FID and catalytic combustion.

3.6 Discrete ambient measurement

This section discusses devices for taking and analysing samples that are localised in space and time (often referred to as ‘grab’ samples). Samples taken in this way can be analysed to enable determination of the detailed hydrocarbon speciation, as well as measurement of methane concentration.

This section includes the use of high sensitivity FID instruments. The techniques referred to elsewhere in this chapter for ambient measurements can also be used in this context.

3.6.1 Sampling method

US EPA Compendium Method TO-14A and US EPA Compendium Method TO-15[4] are the primary methods for air sampling to determine total VOCs and VOC speciation. This method is deployed in current US EPA sponsored studies into fugitive releases from shale gas completion and production. The fundamental of this method is to take a gas sample into a stainless steel sampling canister (Summa canister). The sample is kept stable in the steel vessel. When ready, the gas captured in the canister can be analysed using gas chromatography (GC) to separate the constituted components for quantification using mass spectrometry (MS).

Advanced spectrographic pattern recognition software can be used with this assessment (as developed by AEA and currently being used by the University of Wyoming in ongoing ambient measurements in locations affected by unconventional gas extraction).

This method does not provide real-time concentration profiles or provide information relating to where a leak is, but can be used to gather many samples from a large area for fugitive assessment.

This principle of collecting samples for later assessment can allow speciation of hydrocarbons. This approach was used in conjunction with other methods by Pétron et al. (2012) in carrying out a pilot study to characterise methane emissions from the Colorado Front Range, an area of some 20,000 wells north-east of Denver, Colorado.

Canister sampling (or sampling into Tedlar bags) produces short-time resolved samples. The location, time, duration and local meteorological conditions (if possible) need to be recorded as part of the study. The number of samples and their location depend on the study objectives taking into account aspects such as:

- study area;
- number and complexity of potential sources;
- objective in terms of measurement of methane and/or other VOCs;
- extent to which source apportionment is required, or whether the objective is to estimate an overall emission flux;
- extent of meteorological measurements;
- whether the measurement survey is supplemented by dispersion modelling analysis;
- level of quality required in the measurement and analysis.

Historically, the aim may have been to analyse accurately the concentration of methane, but this role is performed by very accurate cavity enhanced absorption spectrographic technology. The aim in modern studies is to speciate the VOCs to look for ratio fingerprints to facilitate source apportionment. The metrics of interest for studies of this nature are ratios of the concentration of the alkanes to the concentration of the alkanes in a representative background, the data being expressed as the median mixing ratio. These measurements, coupled with quality meteorological data, can show in which direction the strongest maxing ratio emanates. Larger scale studies could be used to triangulate such information, with the aim of identifying individual sources.

[4] http://www.epa.gov/ttnamti1/airtox.html

Other techniques such as radial plume and range resolution mapping using open path optical techniques can be used to achieve the same outcome for methane flux assessment.

Method performance

- This method has a sample collection and sample analysis phase. This can take advantage of existing laboratory facilities with GC-MS systems and so the specific purchase of the analytical equipment is not necessary.
- This method can be modified (such as by using Tedlar bags) or using a field portable analyser (such as a high accuracy FID) closer to the sampling location.
- Price range: Summa canisters and Tedlar bags are both low cost. Laboratory analysis costs start from around £70.
- Measures a range of components, not just methane.
- Used ambient assessment.
- Useful in first line emergency call-out to collect samples for detailed, high accuracy analysis alongside screening methods.

3.6.2 Cavity enhanced adsorption spectroscopy (CEAS)

Absorption of electromagnetic energy by gases forms the basis of operation of IR absorption analysers using a light source – typically near infrared and a photo detector. In very general terms, the attenuation of the signal of the IR source by absorption by a specific gas is used to determine the concentration of that gas. With traditional IR systems, the concentration is determined from knowledge of the original IR source strength compared with the attenuated signal due to the presence of target gas along the IR beam path.

The technique can be specific as almost all molecules in the gas phase have a unique absorption spectrum in the near infrared; hence a specific gas can be measured by selecting a specific wavelength for the infrared source.

This approach is well-developed for:

- those gases that can be measured over short path lengths (that is, carbon monoxide and carbon dioxide);
- other advances such as Fourier transform infrared devices (FTIR) that can cover multiple gases;
- open path sensors that can integrate a sample over a large distance provide important tools.

The challenge has always been sensitivity and measurement uncertainty, caused by changes in source strength and component tolerance of the system introducing baseline and high gain drift in the detection.

The CEAS method is a derivative of tunable diode laser absorption spectroscopy (TDLAS). There are two main commercial forms of this technique:

- ‘time’ based cavity ringdown spectroscopy (CRDS);

- ‘intensity’ based integrated cavity output spectroscopy (ICOS) (so-called fourth generation CEAS technology).

A tuneable diode laser is used to introduce a near infrared beam into an absorption cell in which the laser pulse is reflected between two or more highly reflective mirrors, which creates the ‘cavity’. The path length of the light in the cavity is not the distance between the mirrors alone, but this length multiplied by the number of times the light is reflected creating virtual path lengths of tens of kilometres.

The laser system at the heart of modern CEAS systems is based on a room temperature operating quantum cascade laser (QCL). A drawback of the early CEAS systems was the size, complexity and power consumption of the lasers; early work-arounds were to use small communications style laser systems (that is, compact disc technology) to produce early cavity ringdown systems.

In CRDS, the light from the laser is blocked by design in pulsed laser systems or some form of shuttering mechanism operates in continuous wave laser systems such as an acousto-optic modulator (AOM) or a chopper. When the source of near infrared energy is interrupted, the IR already in the cavity will bounce off the mirrors but will lose energy exponentially over time, as no mirror can be fully 100 per cent reflective. The time that it takes the initial IR pulse to decay to zero because of these losses is the ‘ringdown’. The IR frequency is tuned to match specific absorption bands of the target gas, so when the IR beam in the cavity passes through the target gas, the decay in the IR intensity is accelerated. The difference in time for complete extinction of the IR beam in the cavity between mirror losses alone and combined mirror and target gas absorption losses is directly proportional to the concentration of the target gas.

The differences in the models come down to a choice of narrow or broadband laser, shutter mechanism, modulation systems and number of mirrors (from simple two-mirror to multiple mirror cavities).

In ICOS, determination is by intensity of the laser pulse (like normal TDLAS) and is not time based as in CRDS. The basic laser and cavity cell approach are similar. The near infrared laser can also be introduced at an angle, termed off-axis ICOS. These so-called third (and fourth) generation CEAS systems can be more sensitive but are very new to the market.

Development of CEAS systems over the last three decades has reduced measurement errors, improved stability and reduced power consumption, so that these systems are becoming much more common as field instruments. However, they involved greater capital outlay compared with cheaper alternatives, with prices around £30,000 for a single analyser. The real advantage comes in the post-procurement maintenance and operation costs, which are much lower. Over the long term, with most other instrument types having upwards of 70 per cent of total lifetime costs as post-purchase operating costs, the long-term use of a CEAS system does become attractive.

Method performance

Typical performance characteristics of modern CEAS systems are as follows (this example is off-axis ICOS):

- Price range: around £35,000 for current field portable instruments is a conservative estimate; a lab bench basic unit costs in the region of £27,000.
- Multiple operating ranges.
- Precision – 1 part per billion (ppb) or better.

- Uncertainty: <1 per cent without calibration; <0.03 per cent with calibration
- Low power consumption from 300 W down to 60 W.
- Low drift 0.8 ppb in 24 hours.
- High accuracy system for ambient assessment and not an alternative for LDAR methane leak detection screening.

3.7 Instruments for path integrated optical remote sensing for concentration and flux measurements

These techniques can be used to assess fugitive emissions from associated open sources or whole site fenceline assessment (such as in refineries). The following four main technologies are used:

- open path Fourier transform infrared (OP-FTIR) (>100 m pathlength);
- ultraviolet differential optical absorption spectroscopy (UV-DOAS) (>250 m pathlength);
- tunable diode laser absorption spectroscopy (TDLAS) (>250 m pathlength);
- path integrated differential absorption light (PI-DIAL) detection and ranging (1,000 m pathlength).

These technologies measure a path integrated concentration and can be used for either hot spot identification or flux measurements.

The common principal is to measure the spectra absorption by target gases. With the IR and UV systems, these require a transmitter and receiver along the path of the beam. These can either be discrete (that is, a fixed transmitter sending a beam to a receiver) or a combined unit in which the beam is reflected from a mirror. The IR and UV systems can also be used in a passive mode; this is more common for FTIR-based systems in which the Sun is used as a broadband source in a process called solar occultation.

These systems are complex and expensive compared with the other techniques discussed. Some data provided by the US EPA Environmental Technology Verification Program and other sources is given in Table 3.1. The application of advanced plume mapping methodology may enable large areas (such as a region with many wells or associated processes) to be assessed in order to derive an estimation of the overall emission rate to reconcile any bottom–up GHG inventory.

Measurement of methane concentration and meteorological factors can enable a methane flux to be determined. Such measurements can also be used with statistical analysis and computational modelling to find ‘hot spots’ in the flux field and hence aid the identification of significant sources over a large area. The modelling can include ‘inverse dispersion modelling’ to determine localised emission rates.

There can be short-term monitoring (such as the open path methods and discrete sampling) that provide data in intensive surveys for short-term flux and concentration profiles. These systems can also be used for long-term measurement, although this is often achieved by the use of continuous discrete sampling systems such as FID or a CEAS-based system.

Table 3.1 Summary of open path systems

Item	UV-DOAS	OP-TDLAS	OP-FTIR	LIDAR/DIAL
Price	£39,000–250,000	~£50,000	£50,000–80,000	Bespoke systems in the region of £500,000+
MDL	Benzene: 0.4–1.5 ppb	0.29–0.56 ppm Can drop to 2 ppm at distances	Ethylene: 0.32 ppm	76 ppb at 1,000 m
Linearity	Slope: 0.95 R2 = 99%	Slope: 0.95 R2 = 99%	Slope: 0.99 R2 = 99%	
Accuracy	2.1–14%	5.2–11%	1.6–7%	
Precision (RSD)	0.57% at 100 ppb	1.24% at 500 ppm and 220 m	0.53% at 50 ppm and 200 m	
interference	None seen (tested for O_2 and O_3)	None seen (tested for CO_2 and H_2O)	None seen (tested for CO_2 and H_2O)	
Field use	Range up to 500 m	Compact, quick response, high resolution	Rugged Range: 400–500 m Needs to intercept a large proportion of the plume	Portable (lorry) Range up to 3,000 m Capable of spatial resolution
Target gas	Not-specific – methane is an added extra to the standard suite	Single wavelength – target gas specific, needs good weather	Not-specific – relies on spectral library	Not-specific (multiple wavelengths) Not real-time Weather dependent

Notes: UV-DOAS = ultraviolet differential optical absorption spectroscopy

OP-TDLAS = tunable diode laser absorption spectroscopy

OP-FTIR = open path Fourier transform infrared

LIDAR/DIAL = light detection and ranging using differential absorption

3.7.1 Radial plume mapping (RPM)

Radial plume mapping (RPM) is defined in US EPA OTM10 and is an area source tool. It is used to determine emission fluxes over a large area with the aim of identifying any significant sources ('hot spots'). It is development from the classical line of site open path measurement. What defines the method is not the technology used (OP-FTIR, OP-TDLAS, UV-DOAS and DIAL can all be used) but how it is used.

In simple operation, an open path system provides the concentration along the line of sight of the system. This gives information along the single plane at a single distance. The purpose here is to take a series of measurements at different lengths at different vertical and horizontal paths. The measurements taken are then processed to provide a multi-path concentration, mapping a volume of air.

These methods also rely on quality meteorological measurements. This would ideally require a good quality weather station tower. The components of the weather to be measured are not just wind speed and direction but also:

- horizontal wind speed and direction;
- vertical wind speed and lateral turbulence;
- relative humidity and dew point;
- solar radiation;
- atmospheric pressure.

Application of this method is complex and would normally be applied as a standalone specialist scientific study rather than as a routine regulatory or management tool.

The equipment would normally be set up downwind of the source. Using OP-FTIR as an example the transmitter/receiver would be set up with several mirrors to measure:

- **Emission hot spots.** Using the horizontal component, several mirrors, which become the path-determining component, can be arranged as a radial pattern at different distances. The transmitter/receiver is targeted at each mirror in turn. The data are used to calculate a path-integrated concentration along all these paths and can be combined to provide a two-dimensional concentration contour map of the area assessed. This will show up any hot spots.
- **Methane fluxes.** Using the vertical component, a configuration of three mirrors or five or more mirrors is used. The three-mirror configuration used is mounted on a tower and the path-integrated concentration is determined for each mirror. The beam path would be perpendicular to the mean wind direction of the source under investigation. Hence combined with meteorological data, a two-dimensional cross-section of any plume can be measured and the methane flux calculated. A more complex mapping of the cross-section concentration can be achieved using additional ground beam mirrors at different distances to calculate a one-dimensional ground level flux.

The one-dimensional component of this can be used as a standalone fencline assessment technique to provide a fenceline concentration profile

The limitations will be those of the instrument type used; typically, inclement weather can have a significant effect on the method performance (high winds, poor visibility), although very low winds may also hinder the measurement. Complex terrain in the area and distance from the source can also influence the outcome.

This method relies on very accurate systems control to move the sensor to each of the receptor points in turn. This significantly increases the price to purchase and operate such systems.

The strengths of this method are:

- high spatial and temporal resolution;
- direct determination of emission rates;
- wide scale characterisation;
- scope for real-time data.

3.7.2 LIDAR based plume mapping using path integrated differential absorption (DIAL)

This is one of two major variations of the standard radial plume mapping approach, which are often considered completely separate techniques. A major limitation is the use of multiple mirrors or path-determining components and the level of calculations required to turn these measurements into two-dimensional concentration profiles. Using a system that does not need to rely on the use of mirrors would have significant advantages. This variation of RPM is often termed a ‘range resolved measurement’.

Based on the principle of elastic backscatter light detection and ranging (LIDAR), a beam consisting of two wavelengths is pulsed by the emitter; a photon is absorbed by an atom in the atmosphere, which immediately emits another photon at the same wavelength. One wavelength will be in the absorption spectrum of methane but the other wavelength will not, so there will be a measureable attenuation between the two. The difference between the returning signals will be proportional to the concentration of methane.

The important difference here is that the system will also determine the distance, allowing a two-dimensional profile to be determined by scanning at different heights. This, coupled with the range of the laser-based system of 1–3 km, will enable large cross-sectional areas to be assessed.

These data, coupled with meteorological data across the measurement plain, are used to derive the methane flux.

The strength of the method is the high resolution concentration profile that can be complied in a relatively short time period. The method does not rely on additional reflectors or sensors, and it can be configured to measure a limited number of other gases, giving the ability to be used in conjunction with a tracer gas surrogate, for localised validation and use in tracer gas correlation.

The major limitation of this method is the global scarcity of operational DIAL systems.

3.7.3 Solar occultation flux measurement

This is a further variation of the basic RPM method. In this case, a broadband IR or UV spectrum from the Sun is used as the source, measured by a ground-based spectrometer such as a passive FTIR. The system requires a means to track the Sun, maintain the optimal orientation for the sensor and record the position of the sensor on the ground (GPS).

As with the other remote flux assessment techniques, this method will also need local quality meteorological measurements.

The method has the advantage of being vehicle-based, so that measurement can be taken while mobile. Combining these data it is possible to assess a very large area. However, the advantage gained from using the Sun can also be a major disadvantage in poor visibility or unstable winds.

This method simplifies the instrumentation but does have a number of drawbacks in that the broadband IR or UV source will be the whole sky, with assessment along the entire length of the air column, resulting in a loss of spatial resolution compared with the other techniques. It is sensitive to cloud cover and wind speed.

3.8 Tracer gas correlation

This technique can be used in conjunction with discrete measurements, mobile measurements and with open-path techniques and technologies. The concentration of methane is measured together with the concentration of a tracer gas that is being released at a known constant rate. This aids in the determination of the emission flux of methane as an alternative to dispersion modelling where complex meteorological conditions may exist.

The tracer gas needs to be chemically stable with no other significant local sources so that the emission is stable; with methane, the tracer gas is typically acetylene. A tracer gas is released to mix with the plume being assessed and is detected by spectroscopic methods. Typically the technique has used fixed point or mobile measurement. This can take advantage of long-term fixed measurements such as the National Oceanic and Atmospheric Administration (NOAA) mast stations in the US and mobile units in vehicles (Pétron et al. 2012).

Single or multiple point measurement would be used with quality meteorological measurements (three-dimensional wind assessment) to determine the methane flux and detailed field notes and release logs. Any mobile units would need high resolution GPS systems. Data processing is critical.

This approach does provide more accurate emission flux estimation but has significant logistical considerations.

3.8.1 Mobile CEAS based systems used with tracer gas correlation

These systems are used in laboratories and in the field for accurate ambient concentration measurement. Field applications are for wide area fugitive methane releases. Examples have been used recently in the development of a fugitive methane emissions protocol for landfill and so could be applied to gas pipeline leak assessment or fugitive release in coal bed methane play development.

Depending on the system, they can be linked to meteorological measurements and GPS systems. Demonstration projects have been completed using vehicle-mounted cavity ringdown spectroscopy (CRDS) systems to develop large-scale methane release mapping and the applicability of these protocols to unconventional gas production is currently being explored.

Figure 3.2 shows a typical modern CRDS instrument output from a vehicle-mounted unit. The data are exported in a format directly compatible with Google Earth. The speed of response of CEAS based systems is a critical factor so that the transect data can be collected rapidly. The figure shows the transect concentration profile for the target gas (methane) and the tracer gas (acetylene).

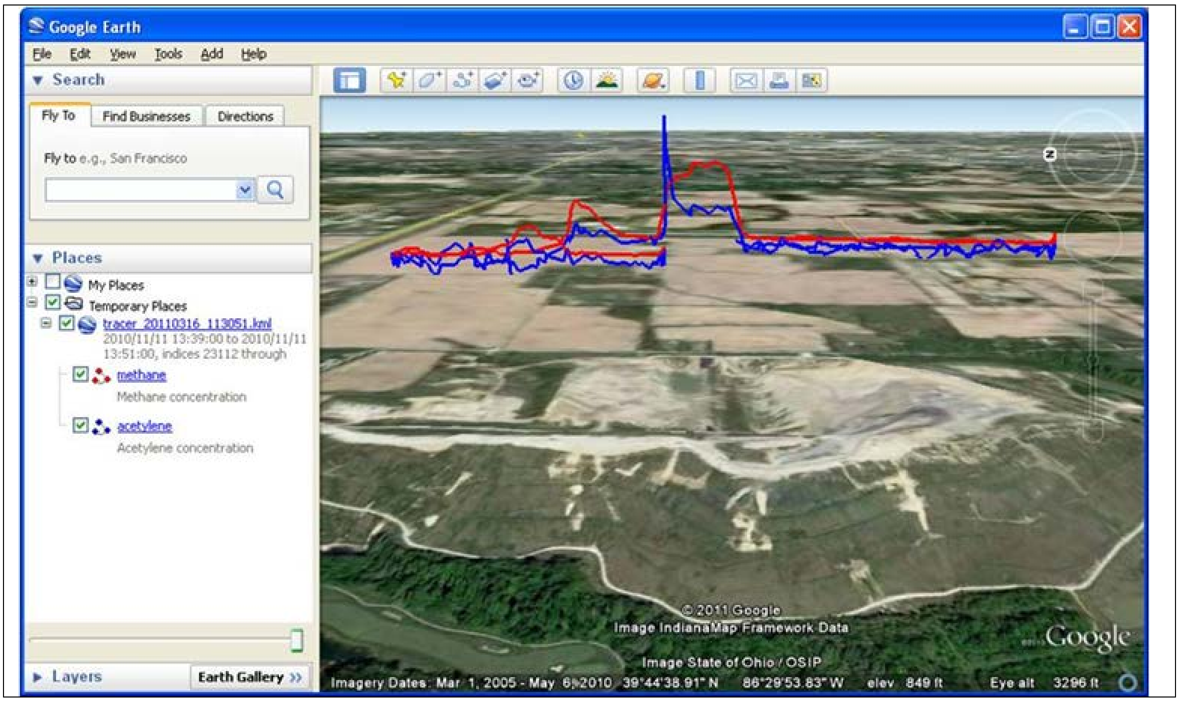


Figure 3.2 Methane transect from vehicle-mounted CRDS with GPS – data exported as a keyhole markup language (KML) file

3.9 Reverse dispersion modelling

This method can use a single downwind ambient measurement point to measure methane and meteorological conditions. An atmospheric dispersion model can then be used to calculate the emission rate indirectly. Measurement can be a point source instrument (such as a CEAS technology) or an open path method.

One method is called backward Lagrangian stochastic inverse-dispersion modelling and has been fully validated using tracer gas and multiple path measurements (Flesch et al. 2004). A suspected source emits an assumed emission rate; the unknown factor is the rate Q (kg/m^2/s). A time-resolved concentration *C* is measured at a defined location M (in the downwind plume); the background concentration (that is, upwind) also needs to be measured (C_b). The backward Lagrangian stochastic model will calculate the ratio of concentration to the emission rate (C/Q)sim and the emission rate is estimated from:

$$Q = \frac{C - C_b}{\left(\frac{C}{Q}\right)_{sim}}$$

This requires a single measurement point downwind of the source. The important factor is the calculation of the concentration to emission rate ratio. The model predicts the path of a fluid from a defined location backwards in time, thus predicting the source. The strength of the model is that it uses multiple possible paths which the methane ‘particle’ may have taken (Lagrangian) and will emulate the turbulent, random motion of each ‘particle’ (stochastic).

The inputs to the model for area sources are the wind data from the meteorological measurements, the surface roughness (Z0) and the Monin–Obukov stability of the atmosphere near to the ground (L). The ‘particle’ trajectories are calculated to ‘touchdown’ points and vertical velocities, where the ‘particles’ will have impacted the ground. Thousands of upwind trajectories will be calculated and those that have impacted within the boundary of the source are used to calculate the concentration to emission rate ratio.

A similar approach could be taken with the US EPA CMAQ adjoint (CMAQ_ADJ) model but would need further use in this version of the CMAQ toolkit to test its applicability.

3.10 Source attribution: chemical and isotopic techniques

When carrying out a monitoring survey, it may be important to differentiate between different sources of methane.

3.10.1 Chemical speciation

A specific profile based on the ratios of methane to the heavier hydrocarbons from the well can act as a signature. Knowledge of these ratios for a number of wells can aid in source apportionment. This analysis relies on a reliable understanding of the trace hydrocarbons present in emissions from unconventional gas processes. This information can be gained from source measurements and/or from an analysis of environmental measurements (R. Field, personal communication, 2011).

If the profile of methane and other alkanes is known (C_2–C_5), subsequent discrete air measurements with alkane speciation can be used to compare the emissions profile to the ambient measurement. The measurement can be extended to other trace species in the emission. Emissions of raw natural gas from venting have a different profile to flash emissions, with the flash emissions having a higher C_{2+} component. This alkane ratio approach has been used to corroborate emissions inventories, but involves very detailed measurement work which uses ratio profiling alongside additional measurements (Pétron et al. 2012).

The Denver hydrocarbon emission characterisation reported by Pétron et al. (2012) used a mixture of fixed and mobile measurements. The fixed measurements were carried out using the existing NOAA tall tower network of atmospheric dynamics measurement systems, which included measurements of:

- continuous carbon dioxide (CO_2) and carbon monoxide (CO) instruments measuring sample taken at 22 m, 100 m and 300 m above ground level;
- continuous ozone analysers – one at ground level and one at 300 m above ground level;
- discrete sample collection using the daily midday sample at 300 m. The samples are taken into a glass flask and the air is analysed for methane, carbon dioxide, propane (C_3H_8), *n*-butane (*n*-C_4H_{10}), isopentane (i-C_5 H_{12}), *n*-pentane (n-C_5 H_{12}), acetylene (C_2H_2), benzene (C_6H_6), chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs) and hydrofluorocarbons (HFCs). Wind speed and direction are also recorded.

The mobile measurements made by Pétron et al. (2012) were two-phase. First, a series of collection flasks was used to collected discrete samples at pre-determined locations. Secondly, a further vehicle-mounted wavelength scanned CRDS was used to measure carbon dioxide and methane; an infrared gas filter correlation analyser was used for carbon monoxide; a UV absorption analyser was used for ozone; and a global positioning system was used to undertake six-hour transects. During transects where high methane levels were detected, additional discrete flask measurements were made.

The additional data collected enabled the team to analyse the relative median mixing ratios of the different components from known air mass sources (tall tower sampling) and from discrete sources using the mobile approach. The measurement exercise was dependent on prior knowledge of emission profiles, not just from the wells but from other sources of methane and alkanes. The study showed the value of using pre-existing measurement networks with multiple species being measured and enhancing this with localised mobile measurement systems.

3.10.2 Carbon isotope speciation

The methane contained in coalbed seams and in shale is predominantly derived from thermogenic sources. Ancient organic matter (carbon, hydrogen and oxygen) in deposited sediments degenerates over time under high temperature and pressure conditions into hydrocarbons. Coal and oil can thermally decompose into natural gas.

The gas will rise through any permeable substrate until blocked by an impermeable layer, forming a reservoir. However, microbial methane can also be found alongside thermogenic methane in coalbed plays. Microbial methane comes from the reduction of carbon dioxide in water or the fermentation of acetate in freshwater.

A measurement of methane by itself will not differentiate between recent methane and fossil methane. A commonly applied test is to determine the amount of radioactive carbon-14 (^{14}C). When organic material is part of a living organism, it incorporates the available carbon in the atmosphere in the form of carbon dioxide. Carbon is mostly present as the stable isotope carbon-12, but also includes the radioactive carbon-14, formed in the upper atmosphere at a near constant rate from the neutron activation of nitrogen from the impact of high energy cosmic radiation on the Earth's atmosphere. In this process the nitrogen loses a proton and gains a neutron to result in a heavy isotope of carbon.

Ancient thermogenic methane is also originally derived from living matter. This process can take millions of years and the methane can remain trapped in a subterranean reservoir for tens to hundreds of million years. A large proportion of the available carbon-14 locked into this fossil methane will have decayed according to the radioactive half-life of carbon-14 of 5,730 years. The carbon-14 will undergo radioactive beta decay, where a neutron in the unstable carbon isotope will decay into a proton and an electron and electron anti-neutrino, resulting in a stable nitrogen-14 isotope.

This is the basis for radio-carbon dating. The techniques developed for this determination can be used to speciate the carbon isotopes in the fugitive methane to differentiate methane from recent or ancient sources.

4 Survey of control methods

4.1 Overview

Methane is emitted from unconventional gas extraction during several steps of the process including pre-production processes such as hydraulic fracturing and production processes such as gas dehydration and compression. Methane and other pollutants are emitted from the following activities and emission sources:

- drilling (primarily combustion emissions, with no significant methane);
- hydraulic fracturing (primarily combustion emissions, with no significant methane);
- flowback and well completion;
- liquids unloading;
- storage tanks;
- dehydration;
- pneumatic devices;
- compressors.

These sources and the methods available to minimise or control associated emissions are discussed below, focusing on those sources with potential for significant methane emissions. Emissions from drilling and hydraulic fracturing are discussed in Sections 4.8 and 4.9 respectively.

4.2 Flowback and well completion

On completion of the fracturing step, the fracturing fluid mixture, which now contains a combination of water, sand, hydrocarbon liquids and natural gas, is brought back to the surface. As this mixture is returned to the surface, it will contain an increasing quantity of natural gas from the formation.

Equipment used at an existing gas well under production conditions (including the piping, separator and storage tanks) is not designed to handle the initial mixture of wet and abrasive fluid that comes to the surface. Standard practice has been to vent or flare the natural gas during this step and to direct the sand, water and other liquids into ponds or tanks. After some time, the mixture coming to the surface will be largely free of the water and sand, and then the well will be connected to the permanent gas collecting equipment (Armendariz 2009).

The flowback step is the primary methane emission source present in unconventional gas extraction that is not present in conventional gas extraction. Emissions from the flowback process are short-term, typically occurring over a period of several days (US EPA 2011b).

Methane emissions from the flowback/well completion step may be controlled through the use of reduced emission completions (RECs) or green completions, as shown in Figure 4.1 (US EPA 2011b).

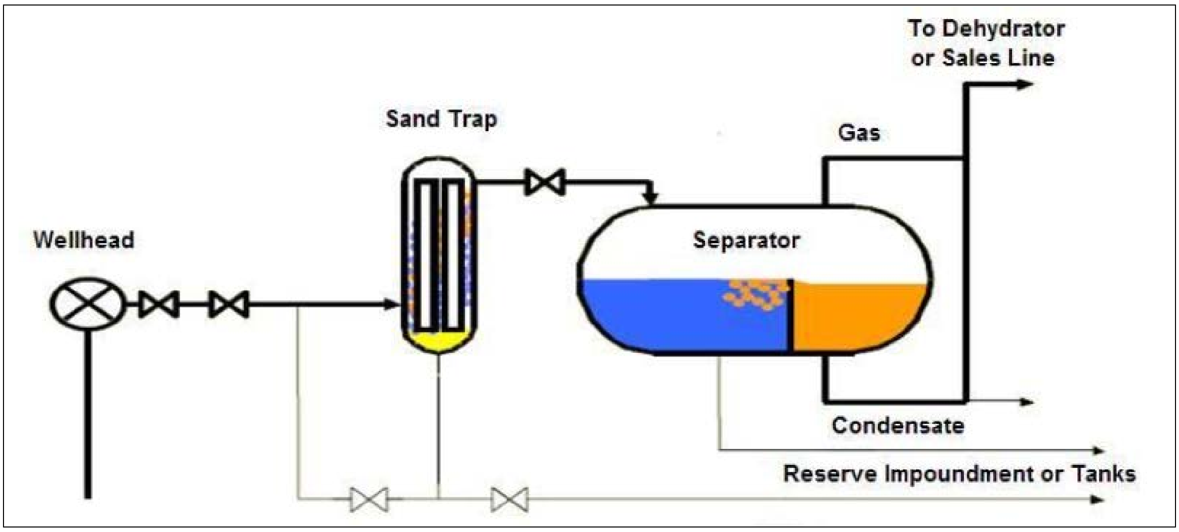


Figure 4.1 Reduced emissions completion equipment

A reduced emission completion involves the installation of portable equipment specially designed to handle the high initial flow of water, sand and gas. A sand trap is used to remove the solids and is followed by a three-phase separator which separates the water from the condensate (liquid hydrocarbons) and gas. The gas is then sent to a sales pipeline (or a dehydrator if needed). Where the pipeline infrastructure is not yet in place to receive saleable gas, the gas stream may be routed to a temporary flare.

While some companies have their own REC units, rental of third party equipment may be a more financially attractive option. For example, when BP implemented a REC programme in south-west Wyoming it commissioned the acquisition of six sets of REC equipment at a capital cost of approximately $1.4 million. Subsequently, in 2008 it moved to the rental of third-party equipment for its REC needs (Smith 2011).

The costs associated with the purchase or rental of REC equipment can be offset by the additional revenue from the sale of gas and condensate captured during the completion that would have otherwise been vented or flared. US EPA has estimated that up to 10,800 million cubic feet (Mcf) of natural gas per completion may be saved through the use of an REC at an implementation cost of approximately $33,000 per completion (using a third-party contractor to implement the REC) (US EPA 2011b). This would require a natural gas price of approximately $3 per Mcf ($0.11 per m^3) to justify use of a REC from a financial perspective. US EPA (2010d) evaluated economic payback based on natural gas prices of $3, $5 and $7 per Mcf, considering $5 per Mcf to be a conservative price (that is, prices would typically be higher than this). The typical price of 30 $ per MWh shown in Figure 4.2 is approximately equivalent to $8 per Mcf, supporting US EPA's view.

Although RECs are not currently required in the US at federal level, they have been used by some companies to reduce methane emissions in Texas Barnett Shale since 2004 (Devon Energy, undated). In addition, the states of Colorado and Wyoming and the city of Fort Worth require the use of RECs on hydraulically fractured wells. The US EPA has recently proposed regulations that would require the use of RECs on all new hydraulically fractured gas wells as well as on re-fractured gas wells (US EPA 2011d). These regulations are scheduled to be finalised in 2012.

4.3 Liquids unloading

In a producing natural gas well, liquids can collect in the well over time, slowing or stopping the flow of gas to the wellhead. These liquids may include 'produced water', a saline water contained in the gas formation itself, or condensate (liquid hydrocarbons). To re-establish the well gas flow, the well owner or operator may close the well to build up gas pressure until the pressure is sufficient to expel or ‘blowdown’ the accumulated liquid when the well is re-opened. Methane is emitted from this process as the well is opened back up and the built up gas and liquids are vented to the atmosphere. These emissions may be reduced or eliminated completely through the use of plunger lift systems, which drop a plunger to the bottom of the well. Eventually, the gas pressure under the plunger builds up and pushes the plunger to the surface, where liquids are separated and the gas is sent to the sales line (US GAO 2010).

US EPA has estimated that the implementation costs for installing a plunger lift system are $2,500–10,300 per well (US EPA 2006a). The benefits included up to 18,250 Mcf per year (500,000 m^3 per year) of gas production, with potential savings realised from preventing blowdown emissions from release to the atmosphere, as well as increased productivity from the well as downhole pressure due to the liquids accumulation is minimised.

4.4 Storage tanks

Storage tanks are used at natural gas wells to handled produced water and condensate. Emissions from storage tanks occur from:

- working losses – as the gas vapours in the head space of the tank are expelled as additional liquid enters the tank;
- breathing losses – due to changes in volatilisation of hydrocarbons in the liquid due to diurnal temperature changes;
- flashing losses – occur when a liquid with dissolved gases is transferred from a vessel with higher pressure to a vessel with lower pressure, allowing the gases to vaporise or ‘flash’ out of the liquid.

These emissions may be controlled through the use of vapour recovery units (VRUs) and flares. Control of emissions from storage tanks is included in the recently proposed US New Source Performance Standards (NSPS) (US EPA 2011a).

As with other recovery control methods, vapour recovery on storage tank batteries has the potential to not only result in an environmental benefit but also a financial benefit. A financial analysis of installing a VRU project as reported under the US EPA Natural Gas STAR Program found installation and capital costs ranging from $35,000 for a 25 Mcf per day (700 m^3 per day) system to over $100,000 for a 500 Mcf per day (14,000 m^3 per day) system. The estimated payback period varies based on natural gas price, but even at a relatively low price of $3 per Mcf ($0.11 per m^3), it is estimated that installing a VRU system to accommodate 100 Mcf per day (2,800 m^3 per day) would have a payback period of 16 months (US EPA 2006b).

4.5 Dehydration

Glycol dehydrators are commonly used at natural gas well pads, compressor stations and processing facilities to remove water from the gas stream prior to entering the sales line. Methane emissions may occur from glycol circulation pumps, gas strippers and the gas still column. In addition to methane, dehydrators are also a source of BTEX (benzene, toluene, ethylbenzene and xylene). Dehydrator emissions are regulated in the US under the National Emissions Standards for Hazardous Air Pollutants (NESHAP) programme, which requires 95 per cent control of emissions at larger sources through the use of vapour recovery units or flares (US EPA 2011e).

There are a variety of means of reducing emissions from dehydration systems including use of vapour recovery units, desiccant dehydrators, system optimisation, and installing flash tank separators. US EPA has estimated that 790 Mcf per year (22,000 m^3 per year) of natural gas savings could be realised by piping the vapours off the dehydrator system to an existing VRU at an estimated implementation cost of $2,000 (US EPA 2011b).

4.6 Pneumatic devices

Pneumatic devices powered by pressurised natural gas are used widely in the natural gas industry as liquid level controllers, pressure regulators and valve controllers. US EPA has estimated that approximately 400,000 of these devices are used in the production sector to control and monitor gas and liquid flows and levels in separators, storage tanks and dehydrators. By design, these devices emit small quantities of natural gas on a continual basis (continuous bleed) or in short bursts (intermittent bleed).

The following techniques can be used to minimise methane emissions from pneumatic devices (US EPA 2006c, 2006d, 2006e):

- replacement of high-bleed devices – those releasing over 6 cubic feet (0.17 m^3) of natural gas per hour – with low-bleed devices having similar performance capabilities;
- installation of low-bleed retrofit kits on operating devices;
- enhanced maintenance – cleaning and tuning, repairing/replacing leaking gaskets, tubing fittings and seals.

US EPA has estimated that converting a high-bleed device to a low-bleed device could save between 50 and 200 Mcf per year (1,400–5,700 m^3 per year) of natural gas, with a payback period of 2–27 months (US EPA 2006b), depending on the natural gas price. As natural gas prices are currently depressed with respect to historical levels, the current payback period would be at the upper end of this range.

4.7 Compressors

As discussed in Chapter 3, compressors are a major potential source of fugitive methane emissions due to the presence of natural gas in mechanical systems at high pressure.

Natural gas compressors are used to assist in natural gas extraction from the well and to increase pipeline pressure from an individual well to a compressor station or gas processing plant. These compressors are typically powered by natural gas-fired engines or turbines, which emit combustion by-products such as nitrogen oxides (NO_X), CO, CO_2 and hydrocarbons. In some urban oil and gas fields in the US, natural gas compressors may be powered from the local electrical grid, eliminating localised, combustion-related emissions.

In addition to combustion-related emissions, natural gas and methane may be emitted from wet seals in centrifugal compressors and from the packing seals of reciprocating-rod compressors. The proposed NSPS regulations scheduled for finalisation in the US in 2012 require the use of dry seals on centrifugal compressors and periodic replacement of the rod packing systems on reciprocating compressors (US EPA 2011c).

Dry seals are found on 90 per cent of new centrifugal compressors, and while replacing an existing wet seal system with a dry seal system requires capital expenditure

estimated at over $300,000, natural gas savings may be significant – over 45,000 Mcf per year (1 million m^3 per year). Regularly scheduled replacement of the rings and rods in a rod packing system has been estimated to cost less than $600 annually, with realised natural gas savings of 865 Mcf per year (24,000 m^3 per year) (US EPA 2006c).

4.8 Drilling

During the drilling phase, a temporary drilling rig is brought to the well pad and erected on-site. Energy for the drilling operation (and all ancillary support activities such as well pad lighting and crew housing) is provided by large, diesel-fired internal combustion engines. Typically, 2–3 engines (1,000–2,000 horsepower each, equivalent to 0.7–1.5 MW each) are used continuously from several weeks to a month or more. As mentioned previously, this step of the process is the same for conventional and unconventional gas wells, with the exception of the horizontal drilling leg in unconventional gas wells.

Drilling is not a significant source of methane emissions, but the drilling rig engines are a source of combustion-related pollutants such as NO_X), CO, CO_2 and unburned hydrocarbons.

Three-way catalytic oxidisers may be used on drilling rig engines to reduce emissions. In some instances, the drilling rig may be powered off the local electric grid instead of diesel engines.

4.9 Hydraulic fracturing

During this phase of the well development process, the wellbore is fractured as discussed in Section 1.2. As with the drilling phase, energy for the hydraulic fracturing operation is typically provided by large, diesel-fired internal combustion engines. However, the fracturing phase requires significantly more energy to fracture the formation than required to drill the well bore, and between 10 and 20 flatbed mounted engines of up to 2,500 hp (2 MW) each will be used. Depending on the number of fracturing phases involved in stimulating the formation, this step may last from several days to several weeks. Emissions during the fracturing phase are primarily a result of fuel combustion and may be controlled as described above for drilling rig engines (three-way catalytic oxidisers).

5 Case studies

Five case studies have been developed to illustrate good practice in the control and monitoring of fugitive methane emissions from unconventional gas operations. These case studies do not provide data to enable emissions of methane to be estimated from unconventional gas operations: the available information is summarised in Chapter 6.

5.1 Case study 1: Regulation in British Columbia, Canada

British Columbia is a gas producing province. Production is mainly shale gas, but reserves also include some tight gas in silt and sand. Shale gas is attractive to the industry because of the large areas and thickness of the reserves, which results in a low commercial risk in gas exploration. Shale gas is no longer 'unconventional' in British Columbia. Currently, 60 per cent of production in British Columbia is 'unconventional' but, as 90 per cent of new wells are for shale gas, this proportion will rise. The province currently produces 3.5 billion cubic feet (Bcf) of gas per day (approximately 100 million m^3 per day), with a capacity of approximately 4.0 Bcf per day (approximately 110 million m^3 per day).

The British Columbia Oil and Gas Activities Act was implemented in October 2010 in response to anticipated increased production of natural gas from shale, tight sands and coalbeds. This act consolidated existing regulations, but also increased the protection of surface and groundwater quality, and fish and wildlife habitat. The act enables the British Columbia Oil and Gas Commission (BCOGC) to manage the groundwater and surface water withdrawals used for hydraulic fracturing fluid make-up. The Commission ensures that the water drawdown does not affect shoreline or aquatic habitats.

With regard to control of fugitive methane, the British Columbia Energy Plan[5] sets a goal to:

'eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce routine flaring by half (50 per cent) by 2011'.

In February 2008, the Commission released the *Flaring and Venting Reduction Guideline* for British Columbia (known as the 'Flaring Guideline'). The guide, which was updated most recently in October 2011, ensures that expectations are clear and consistent, and creates a level playing field for operators (BCOGC 2011a). The goals of the Flaring Guideline are to:

- reduce emissions to air of natural gas, and thereby use and conserve natural gas resources;
- ensure flaring and incinerating are conducted in a safe and responsible manner;
- permit venting only where conservation or combustion of natural gas is not feasible.

The key components of the guideline are as set out in Box 5.1.

[5] http://www.energyplan.gov.bc.ca

Box 5.1 Flaring and Venting Reduction Guideline for British Columbia

8 Venting and Fugitive Emissions Management Requirements

Venting is not an acceptable alternative to conservation or flaring. Venting is the least preferred option and gas should be flared under all except the most exceptional circumstances.

8.1 General Requirements

- All continuous and temporary venting must be evaluated using the decision tree in the appropriate sections of this guideline.
- Permit holders must burn all non-conserved volumes of gas if volumes and flow rates are sufficient to support stable combustion.
- Vented gas must not constitute a safety hazard.
- Venting must not result in offsite odours.

8.2 Limitations of Venting Gas Containing H2S or Other Odorous Compounds

The Commission recommends that permit holders eliminate the venting of gas containing hydrogen sulphide. Wells drilled and facilities constructed after September 1, 2010 must not use gas containing hydrogen sulphide for instrumentation or to provide motive force for pumps unless exempted by the Commission.

The Commission recommends any pressure safety valves (PSVs) or blowdown systems be connected to a flare system where such systems are installed.

8.3 Limitations of Venting Gas Containing Benzene

In order to reduce and manage benzene emissions from glycol dehydrators in British Columbia, permit holders must comply with the following requirements, effective June 30, 2007:

1) When evaluating dehydration requirements in order to achieve the lowest possible benzene emission levels, permit holders must use the decision tree process in Appendix A of the Best Management Practices for Control of Benzene Emissions from Glycol Dehydrators, June 2006 (Benzene Control BMP), and retain appropriate analysis documentation for review by the Commission.

2) The permit holder must follow the public consultation process outlined in the Benzene Control BMP.

3) Permit holders must ensure that all dehydrators meet the following benzene emissions limits:

a. If more than one dehydrator is located at a facility or lease site, the cumulative benzene emissions for all dehydrators must not exceed the limit of the oldest dehydrator on site. Modifications may be required to existing units to meet the site limit.

b. Any new or relocated dehydrators added to an existing site with dehydrators must operate at a maximum benzene emission limit of 1 tonne/year or less. The cumulative benzene emissions must not exceed the limit of the oldest dehydrator on site.

c. For dehydrators that are only in operation for a portion of the year, the benzene emission rate must be prorated.

4) Permit holders must complete a DEOS (Dehydrator Engineering and Operations

Sheet), located in Appendix B of the Benzene Control BMP, to determine the benzene emissions from each dehydrator. The sheet must be posted at the dehydrator for use by operations staff and inspected by the Commission. The DEOS must be revised once each calendar year or upon change in operation status of a dehydrator.

5) Permit holders must complete and submit an annual Dehydrator Benzene Inventory List by email in accordance with Section 12 of the Benzene Control BMP.

8.4 Venting of Non-combustible Gas Mixtures

Release of inert gases such as nitrogen and carbon dioxide (CO_2) from upstream petroleum industry equipment or produced from wells may not have sufficient heating value to support combustion. These gases can be vented to atmosphere subject to the following requirement:

Non-combustible gas mixtures containing odorous compounds including H2S must not be vented to the atmosphere if off-lease odours may result. Alternatives to venting such gas include flaring or incinerating with sufficient fuel gas to ensure destruction of odorous compounds or underground disposal.

8.5 Surface Casing Vents

Refer to the Well Completion Maintenance and Abandonment Guideline.

8.6 Fugitive Emissions Management

Permit holders must develop and implement a program to detect and repair leaks.

These programs must meet or exceed the CAPP Best Management Practice for Fugitive Emissions Management.

Permit holders must use pressurized tank trucks or trucks with suitable and functional emission controls when transporting sour fluids from upstream petroleum industry facilities.

Source: BCOGC (2011a, pp. 54-56)

Additionally, operators are required to remove sand from flowback water and, as soon as the volumes of gas are sufficient to support combustion, to collect methane for flaring. If the well is located less than 1.5 km from the pipeline, the operator is required to connect to the pipeline. The US EPA is currently considering a similar rule for application in the US.

Permit holders of production facilities within 3 km of each other or other appropriate oil and gas facilities (including pipelines) are required to co-operate with the aim of providing economically viable methods for extraction and utilisation or flaring of dissolved gases.

The application of the Flaring and Venting Reduction Guideline has contributed to delivering the following improvements in natural gas management:

- 23 per cent reduction in annual flared volumes from 2006 to 2009;
- 30 per cent reduction in total flared volumes between 2008 and 2009;
- 56 per cent reduction in solution gas flaring between 2006 and 2009;
- 28 per cent reduction in well clean-up and well test flaring from 2008 to 2009.

Over this period, natural gas production in British Columbia increased by approximately 4 per cent per year.

A wide range of guidance for operators is provided via the British Columbia Oil and Gas Commission website (http://www.bcogc.ca) including a detailed facility application and operations manual.

The Commission maintains a team of inspectors, and provides a 24/7 emergency reporting line to log and follow up every incident or complaint reported. In the event of an emergency, the Commission will oversee the company response and advise or take action as necessary.

To lessen the potential consequences of incidents, the Commission requires oil and gas operators in British Columbia to establish emergency response pre-plans for facilities, pipelines and wells. The Commission ensures companies are prepared to respond appropriately to emergency incidents by:

- reviewing submitted Emergency Response Plans (ERPs) for accuracy and compliance with its requirements.
- ensuring ERPs for producing wells, pipelines and facilities are updated at least once a year or more if changes in information are key to implementing the plan;
- assessing a company's emergency preparedness by attending on-site preparation meetings;
- evaluating the application and scope of ERP exercises.

5.2 Case study 2: Reduced emissions completion, Wyoming, USA

BP has drilled and fractured almost 1,400 wells in tight sands in the Wamsutter and Jonah fields, south-west Wyoming. The Wamsutter field is a single producing horizon, and the majority of the 970 wells drilled in this field are 1–2 stage wells. In contrast, the Jonah field is a vertically lensed formation. BP has drilled 421 wells with up to 13 stages per well.

Flowback fluid is released from the well following hydraulic fracturing. This takes place in the first few hours following hydraulic fracturing and up to 1–2 days following fracturing. Flowback fluid initially consists mainly of the fracturing fluid and proppant without significant levels of methane. This is normally transferred to open top tanks. The methane level above these tanks is measured using an LEL detector. After the first 1–2 days, formation water begins to be produced and the methane level above the water begins to rise. This water has significant quantities of gas dissolved in the water. Under REC arrangements, produced water is pumped to large flowback separators. The separators are designed to separate the produced water into three separate streams – sand and other solids, liquid effluent and gases.

Initially, the gas produced from the well and separator is not clean enough or at sufficient pressure to be passed to the collection pipeline for sale. If carbon dioxide or nitrogen have been pumped into the well to support the flow of produced waters, these inert gases may be mixed in with the methane. Consequently, the methane may not meet the collection system operator's criteria for inert gases. Typically, collection system operators would specify an inert gas upper limit of 4 per cent. Gas of insufficient quality for sale is normally flared at the site. When the gas pressure is sufficient and gas is of suitable quality, the supply can be connected to the collection pipeline for sale, resulting in increased revenue for the operator.

The application of REC to well flowback water results in an increased back-pressure on the well and reduced flow velocity. This can result in the well completion and clean-up process taking longer than would otherwise be the case. In some cases, the back-pressure can restrict the flow of water which may block gas production from the shale formation. This requires operators to halt the REC operation and re-pressurise the well to restart the flow of produced water. Individual wells have their own characteristics which must be managed on a case-by-case basis.

BP has been carrying out RECs since 2001. The use of this technology is now widespread in the industry. However, REC is not appropriate to every well. For example, it is difficult to apply at low-pressure wells because of the need for additional compression. This results in an additional energy and financial cost. Furthermore, compressors are not well suited to operate on gas flows with variable pressures and/or volumes. BP considers that the industry will use REC techniques where it is appropriate to do so because of the commercial advantage of obtaining additional revenue from the gas recovered in this way. Shale gas wells are typically well suited for REC. Figure 5.1 shows an REC unit at the BP site in Wyoming.

Figure 5.1 Reduced emissions completion unit, Wyoming (BP 2011)

5.3 Case study 3: Regulatory agency and developer co-ordination in Utah, USA

The Greater Natural Buttes Project Area (GNBPA) encompasses approximately 66,000 hectares in an existing gas-producing area located in Uintah County in the State of Utah, which is located in the western US. The GNBPA lands are owned by the federal government, the State of Utah, the Ute Tribe and other private land owners. Figure 5.2 shows GNBPA's location.

Kerr-McGee Oil & Gas Onshore LP (KMG), a wholly owned subsidiary of Anadarko Petroleum Corporation, is developing the oil and gas resources within GNBPA. It currently includes 1,562 oil and gas wells and associated infrastructure (including 23 compressor stations, access roads, water management facilities, pipelines and power lines).

The gas field is a conventional gas resource (that is, shale gas has not yet been developed in this area), in which the majority of the wells are hydraulically fractured to facilitate production. It has been included as a relevant case study because it illustrates the kind of control and monitoring measures which can be designed to reduce emissions of methane (among other substances). In GNBPA, methane emissions are significant for regional photochemical smogs/ozone (with the potential to affect human health) as well as being an issue for global warming/radiative forcing (which affects climate).

In 2006, KMG proposed a significant increase in well drilling and development activity in GNBPA beyond what is currently permitted. Under the proposed expansion, up to 3,675 new gas wells would be drilled and approximately 760 miles of new roads, 820 miles of buried pipelines, 587 miles of surface pipelines, seven miles of electrical power lines, two camps for the project's workforce, two compressor stations and water disposal facilities would be constructed to support this proposed development. The proposed expansion of development of GNBPA could potentially produce an additional 170 billion cubic metres (bcm) of natural gas.

As much of GNBPA is located on federal land under the jurisdiction of the Bureau of Land Management (BLM), pursuant to the National Environmental Policy Act (NEPA), a Draft Environmental Impact Statement (EIS) was prepared in July 2010 to address potential environmental and socio-economic impacts from implementation of the project. The purpose of the Draft EIS is to:

- inform the public and regulatory agencies of the environmental impacts associated with implementing KMG's development proposal;
- evaluate alternatives to the proposal;
- solicit comments from other agencies and the public.

Finalisation of the EIS is the first step in allowing the proposed expansion of the oil and gas field development. Construction may not begin until after the issuance of the Final EIS and Record of Decision (ROD), approval of individual Applications for Permits to Drill, and approved Right-of-Way grants. Construction would require approximately 10 years with the productive life of the project estimated at 30–50 years.

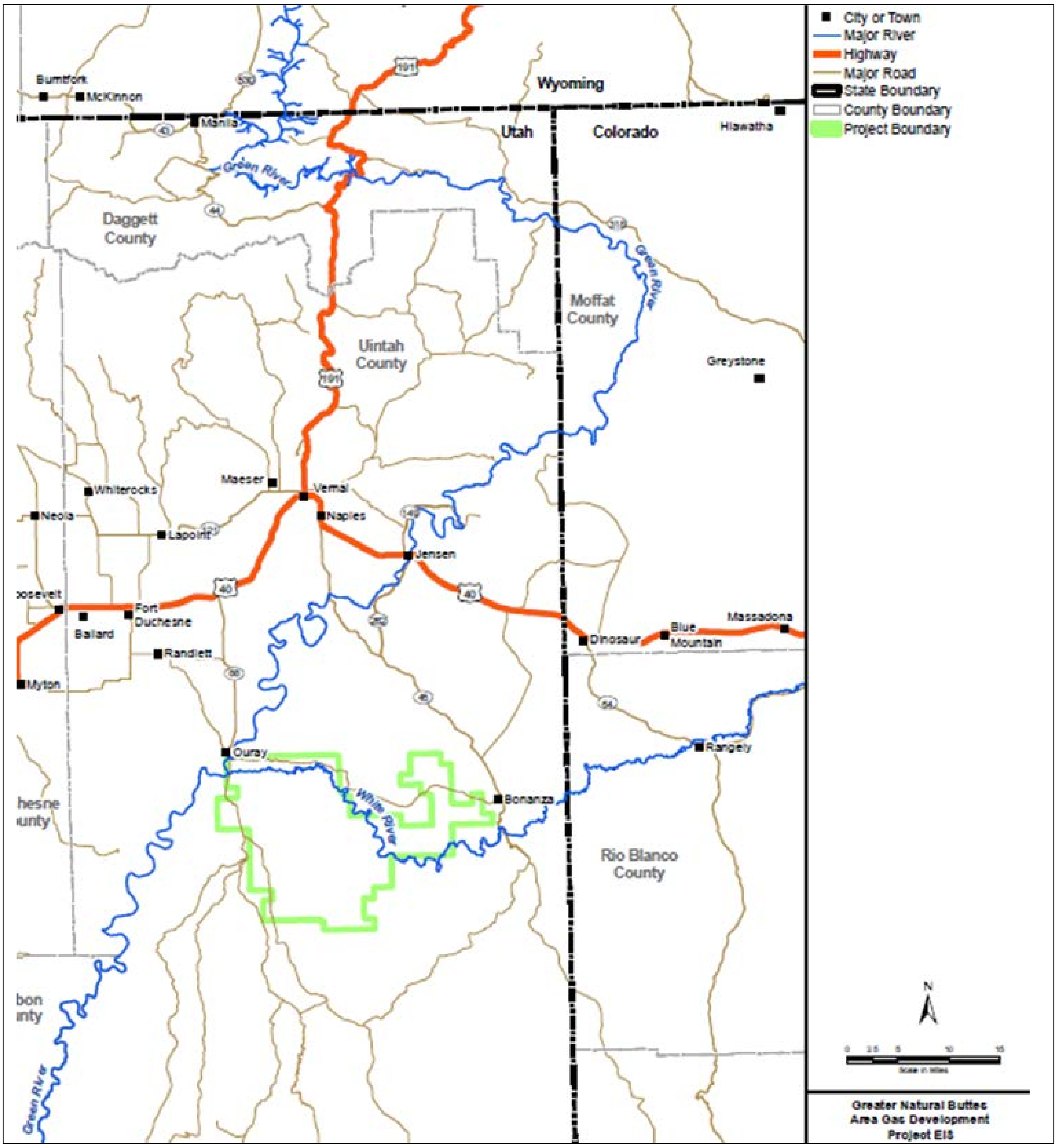


Figure 5.2 Location of Greater Natural Buttes Project Area (US Bureau of Land Management, 2010)

A supplement to the Draft EIS was prepared in July 2011 to address concerns about exceedances of the National Ambient Air Quality Standard (NAAQS) for ozone in the Uintah Basin in the winter of 2010–2011. Winter time ozone exceedances have also been observed in other oil and gas fields in the western US, including the Upper Green River Basin and the Jonah-Pinedale Anticline in Wyoming. To address these concerns, KMG, working with the US EPA and BLM, made changes to the Draft EIS to reflect additional environmental protection measures.

These measures, referred to as the 'Ozone Action Plan', are aimed at reducing emissions of the criteria pollutants (NO_X and VOCs), which are primarily associated with ozone formation. However, the same measures will also be effective at reducing emissions of the greenhouse gases methane and carbon dioxide, other criteria pollutants such as carbon monoxide and sulphur dioxide, and toxic air pollutants such as benzene.

The proposed measures included a pilot project to evaluate the feasibility of using low-emission natural gas fuelled drilling rigs to mitigate impacts associated with the project. As this natural gas play is currently active, natural gas from nearby wells would be available to power the drilling rigs, despite the remote location of the proposed wells. In the US, diesel fuel has historically been the fossil fuel used to power drilling rig engines.

Table 5.1, which reflects the mitigation measures in the proposed Ozone Action Plan, shows the estimated emissions associated with KMG's proposed expansion of the GNBPA development.

Table 5.1 Forecast air emission increases due to GNBPA development

Substance	Projected emissions increase (tons per year)
Carbon dioxide equivalent	1,760,000
Oxides of nitrogen	2,210
Carbon monoxide	1,300
Sulphur dioxide	25
PM10	1,010
VOCs	6,620
Benzene	67
Toluene	172
Ethylbenzene	13
Xylenes	186
Formaldehyde	71
n-Hexane	195

The following specific control and monitoring measures are included in the Ozone Action Plan:

- Low emission glycol dehydrators at all existing and new compressor stations and production wells.
- Electric compression, where feasible (approximately 50 per cent of the compression power to be electrically driven).
- Emission controls having a control efficiency of 95 per cent on existing condensate tanks with a potential to emit more than 20 tons per year and on new condensate tanks with a potential to emit 5 tons per year VOCs.
- Low-bleed pneumatic devices would be installed at all new compressor stations and production facilities. Within six months of the issue of the ROD, all existing high-bleed pneumatic devices would be replaced with low bleed pneumatic devices. High-bleed devices may be allowed to remain in service for critical safety and/or process reasons.
- Green completions for all well completion activities.
- Tier II drill rig engines by 2012, with phase-in of Tier IV engines or equivalent emission reduction technology as soon as possible thereafter, but no later than 2018.
- A natural gas or liquid natural gas drilling rig engine pilot project would be implemented as soon as operationally feasible, but no later than one year after the issue of the ROD. This pilot project would ascertain emission reduction benefits and operating experience and, if successful, may result in more natural gas or liquid natural gas engine use in the Uintah Basin.

- Lean burn natural gas-fired stationary compressor engines or equipment with equivalent emission rates.
- Catalysts on all natural gas-fired compressor engines to reduce the emissions of CO and VOCs.
- Dry seals on new centrifugal compressors.
- An annual inspection and maintenance program to reduce VOC emissions, including:
  - performing inspections of thief hatch seals and Enardo pressure relief valves to ensure proper operations;
  - reviewing gathering system pressures to evaluate any areas where gathering pressure may be reduced, resulting in lower flash losses from the condensate storage tanks.

Additional control and monitoring would be triggered under certain circumstances, including a re-designation of the area as 'nonattainment' for ozone by the US EPA. The additional control and monitoring requirements would include:

- seasonally reducing or ceasing drilling during specified periods;
- using only lower-emitting drill and completion rig engines during specified time periods;
- using natural gas-fired drill and completion rig engines;
- replacing internal combustion engines with gas turbines for natural gas compression;
- using electric drill rig or compression engines;
- centralising gathering facilities;
- limiting blowdowns or restricting them during specified periods;
- installing plunger lift systems with smart automation;
- employing a monthly forward looking infrared (FLIR) programme to reduce VOCs;
- enhancing a direct inspection and maintenance programme;
- employing tank load-out vapor recovery;
- employing enhanced VOC emission controls with 95 per cent control efficiency on additional production equipment having a potential to emit of greater than five tons per year.

Many of these control and monitoring measures are reflected in the proposed updates and revisions to the US EPA's national air quality regulations for oil and gas exploration and production.

5.4 Case study 4: Bacton natural gas terminal, Norfolk, UK

Bacton is one of the largest gas terminal complexes in the UK (Figure 5.3). Gas lands onshore at the three producer terminals from fields in the southern North Sea and from the Shearwater Elgin Area Line (SEAL) and is then distributed to UK customers via the

National Grid terminal, or to Belgium via the interconnector system. When in reverse flow mode, the Interconnector IBT Terminal is used to import gas into the UK.[6]

Although some gas clean-up and refining is carried out at the site, it is not a natural gas extraction site. However, it provides a useful case study of approaches adopted to the control of methane emissions from an operational gas processing facility in the UK, focusing on issues which arise once the gas has been extracted to pipeline.

Figure 5.3 The Bacton gas terminal, Norfolk (EDP24, 2010)

Gas produced at the site is used to operate the pumps used to transfer gas from the North Sea gas fields to the site and onwards into the transmission network. North Sea condensate hydrocarbons extracted from the gas are despatched for processing at the Harwich refinery.

The operator reported emissions of 405 tonnes of methane to air in 2010. This is a small proportion of the estimated throughput at the site of approximately 10 million tonnes per year (derived from media reports of typical daily throughput of 15 m^3 per day) and indicates that the key issue for methane control is the extraction process.

A rolling maintenance programme is carried out by a team of qualified pressure system specialists over a 5–10 year cycle. Pipework is cleaned internally using spherical pigs to clear condensed material.

The pressure within the system is monitored continually and normal tolerances are well known. If a flange leakage were to occur, this would be detected via a pressure drop. Under these circumstances, gas can be pumped back to low pressure areas of the plant to enable a repair to be carried out. The site is also inspected visually and aurally by the operational staff, and a pressurised leak can normally be heard as a hiss. There is no programme of leak testing using techniques such as the application of a fluid to a flange with the aim of observing whether a bubble is formed.

[6] http://www.interconnector.com/PhysicalOps/Bacton.htm

Laser scanning techniques for leak detection have been investigated at the operator's Canvey Island plant. The techniques were not implemented at Bacton because the plant was considered too complex for them to provide useful results. However, a gas extraction wellhead site is typically a simpler facility than a gas processing plant and laser scanning techniques may be applicable to a well pad, as described in Chapter 4.

Best Available Techniques (BAT) for the control of fugitive methane for older established plant is retro-engineering to divert methane to low pressure zones. This approach would need to be built in to newer plant.

In the event of an emergency, the operator would vent methane using a variety of process vents. There are no flares at Bacton. This was a local decision, taken on the basis that flares would be too intrusive for this location.

Fugitive methane emissions from Bacton are estimated using well-established/generic guidelines developed by the industry – the American Petroleum Institute (API) guidelines (API 2009). The estimates are obtained by counting the number/type of joints/outlets in the pipework (flanges, pressure release valves and so on) and estimating the fugitive emissions from this information and from associated gas pressures, temperatures and flow rates. This approach would normally be considered satisfactory for a small-scale facility, but may potentially need to be reviewed in the event of extensive development over a wider area.

The operator provided further information, as follows:

'To estimate fugitive emissions for this study the component count method detailed in the API compendium (API 2001) and the emission factors in the API publication: Emission Factors for Oil and Gas Production Operations (API 1995) were used. Population counts of components using P&IDs were undertaken for the various sections of plant.

The estimation of fugitive emissions using the component count method assumes that all components are operating and emitting VOCs at a standard rate. During the component count it is likely that large numbers of components which are non-emitting or low emitting connections may have been counted.'

At crude oil refineries, the leak detection and repair (LDAR) programme is carried out in accordance with the relevant API guidelines. Some refineries have recently moved to the use of hand-held IR cameras for leak detection. These can be efficiently used to cover a whole refinery in a few days. The emphasis of these surveys is on detecting leaks so that they can be rapidly repaired. IR cameras are an effective tool in prevention of leakage, but one disadvantage is that they do not enable emissions to be quantified. Consequently, other refineries, having made significant investment in the traditional LDAR programmes, are reluctant to invest in a camera.

5.5 Case study 5: Fort Worth natural gas air quality study, Texas, USA

5.5.1 Background

The city of Fort Worth is home to extensive natural gas production and exploration as it lies on top of the Barnett Shale, a highly productive natural gas shale formation in north-central Texas. Over the past several years, natural gas production in the Barnett Shale has increased dramatically. This increase in activity has been brought about by advancements in drilling technologies, most notably hydraulic fracturing (fracking) and horizontal drilling.

As the Barnett Shale formation is located beneath a highly populated urban environment, extraction of natural gas from it has involved exploration and production operations in residential areas, near public roads and schools, and close to where the citizens of Fort Worth live and work. Due to the highly visible nature of natural gas drilling, fracturing, compression and collection activities, many citizens and community groups in the Fort Worth area were concerned that these activities could have an adverse effect on their quality of life.

In response to these concerns, the Fort Worth City Council appointed an independent committee to review air quality issues associated with natural gas exploration and production. This committee was composed of private citizens, members of local community groups, members of environmental advocacy groups and representatives from industry. The committee was charged with making recommendations to the City Council on defining a study for a comprehensive air quality assessment to evaluate the impacts of natural gas exploration and production, to evaluate proposals submitted in response to a solicitation for conducting this study, and to ultimately choose a qualified organisation to conduct the study.

5.5.2 Overview

The Fort Worth Natural Gas Air Quality Study was a year-long study comprised of four main activities:

- ambient air monitoring to measure air pollution levels near active well pads, natural gas compressor stations and natural gas well hydraulic fracturing activities;
- point source testing to measure the amount of air pollution emitted from natural gas drilling, fracturing, production and processing sites;
- air dispersion modelling to estimate downwind impacts from these activities;
- a public health evaluation of the study's findings.

This study provides a useful example of a strategic community-wide monitoring programme using a variety of techniques. Although not limited to methane, the study is indicative of reconnaissance work that could be carried out in a systematic way to identify and quantify emissions sources, and to enable environmental and health risks to be investigated. It demonstrates the use of offsite measurements to provide additional validation of, and support to, regulatory efforts.

5.5.3 Ambient air monitoring

Ambient air monitoring was conducted at eight different locations around the city of Fort Worth over a two-month period in September and October 2010. The ambient air monitoring programme measured levels of nearly 140 pollutants – including over 40 Hazardous Air Pollutants (HAPs) – and resulted in the generation of over 15,000 data points. Figure 5.4 shows the ambient air monitoring results for benzene, which was a pollutant of particular interest as defined by the independent committee.

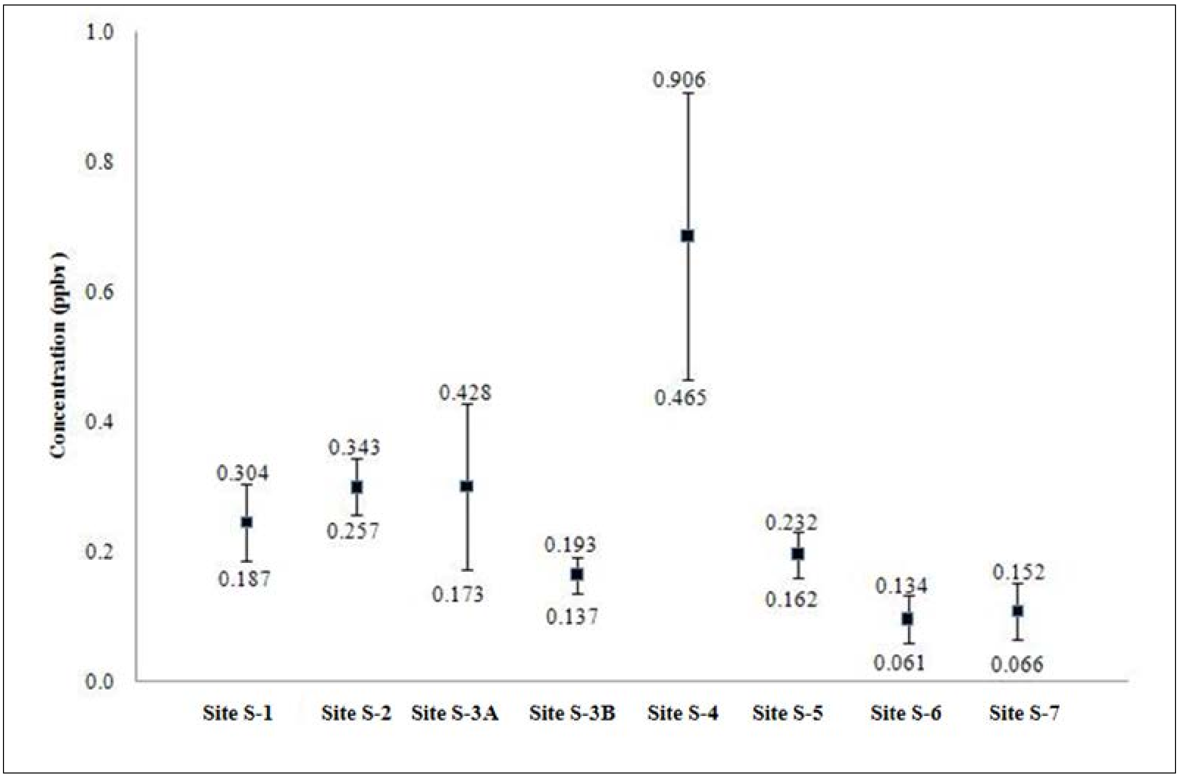


Figure 5.4 Ambient air monitoring results for benzene

5.5.4 Point source testing

Point source testing was conducted in two phases, with Phase I of the field work commencing in August 2010 and lasting through to October 2010, and Phase II occurring in January and February 2011. Under the point source testing programme, a total of 388 sites were tested including well pads, compressor stations, processing facilities, a salt water treatment facility, drilling operations, fracking operations and completion operations. At each site, emissions from storage tank thief hatches and pressure relief vents, pneumatic valve controllers, separators, valves, flanges, compressor engines, glycol dehydrators and natural gas piping were evaluated. FLIR™ infrared (IR) cameras, toxic vapour analysers, Bacharach™ Hi Flow samplers and Summa passivated stainless steel canisters were used to locate and quantify air emissions. Emission estimates of over 90 pollutants were obtained from the point source testing task including methane, benzene, carbon disulphide, formaldehyde, toluene and xylene.

The first step in the point source testing task was to identify potential emission sources through the use of FLIR™ (IR) cameras (Figure 5.5). Upon identification of a leaking component, a toxic vapour analyser was used to obtain concentration measurements (Figure 5.6). A Bacharach™ Hi Flow sampler was then used to quantify the leak rate of the leaking component (Figure 5.7). Finally, a Summa canister was used to collect a sample of gas for analysis at the laboratory (Figure 5.8).

Figure 5.5 Leak identification using a FLIR™ (IR) camera

Figure 5.6 Concentration data obtained through the use of a toxic vapour analyser

Figure 5.7 Leak rate quantification using a Bacharach™ Hi Flow sampler

Figure 5.8 Summa canister sample collection

5.5.5 Air dispersion modelling

The next stage was air dispersion modelling analysis to quantify downwind impacts from natural gas activities at facility property lines and beyond using the AMS/EPA Regulatory MODel (AERMOD) air dispersion model. Modelling was conducted for four different scenarios, including both average and maximum emission rates from well pads and compressor stations. Figure 5.9 shows the results of the worst-case modelling scenario for acrolein emitted from a co-located well pad and compressor station.

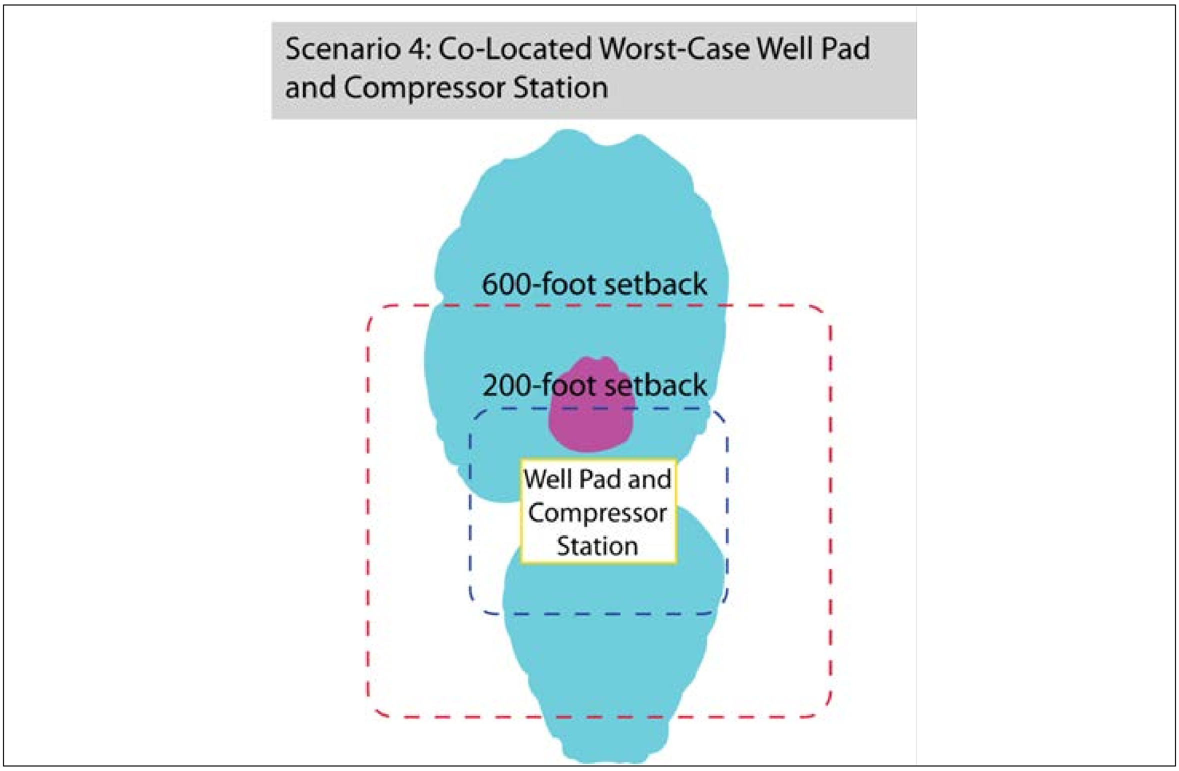


Figure 5.9 Worst-case dispersion modelling results for acrolein

5.5.6 Public health evaluation

Finally, a public health evaluation was conducted using the ambient air monitoring data along with the dispersion modelling results. This evaluation compared measured and modelled air pollution levels with Texas Commission on Environmental Quality (TCEQ) health-based screening levels.

The ambient air monitoring programme data did not reveal any evidence of pollutants associated with natural gas exploration and production activity reaching concentrations above applicable screening levels: The highest 24-hour average concentrations of all site-related pollutants were lower than TCEQ's health-based short-term screening levels and the programme-average concentrations of all site-related pollutants were lower than TCEQ's health-based long-term screening levels. However, the dispersion modelling analysis indicated that benzene emissions from storage tanks could lead to air pollution levels slightly higher than TCEQ's short-term Effects Screening Level (ESL), although this occurred infrequently and only in very close proximity to the highest emitting tanks. The modelling also indicated that sites containing multiple, large line engines can emit acrolein and formaldehyde at levels that would cause offsite ambient air concentrations to exceed TCEQ's short-term and long-term screening levels over various distances.

6 Related issues for methane emissions reporting

6.1 Introduction

The aim of this chapter is to identify and summarise related issues expected to arise during the regulation and reporting of fugitive methane emissions from unconventional gas extraction operations.

The chapter covers the following aspects:

- collation of emission estimates;
- provision of metadata;
- conversion of concentrations and emission estimates to standard conditions;
- evaluation of claimed performance of emissions control methods;
- cost–benefit issues to assist the Environment Agency in applying the principles of Best Available Techniques equitably;
- summary of key findings and identification of evidence gaps and areas where new methods need to be developed.

6.2 Methodology

To identify information of use to support the development of a regulatory approach to the estimation and reporting of fugitive methane emissions from unconventional (shale) gas extraction activities, the study team researched:

- UK information/guidance/reporting for the offshore oil and gas sector;
- UK information/guidance/reporting for the onshore oil sector;
- EU Member State regulatory information for the onshore gas sector (conventional and unconventional);
- information specific to unconventional shale gas exploration from the US and Canada, where the activity has been regulated for many years.

The study team reviewed available information, summarised the different approaches and information available from different countries, and sought to collate the information most closely aligned with the expected challenges of regulating an evolving onshore unconventional gas exploration and production industry. Where the team identified resources that go beyond the scope of the immediate project, it has collated reference sources for the Environment Agency to review.

6.3 UK review and consultation

6.3.1 Environment Agency regulation and guidance

The Environment Agency was contacted to obtain input from site inspectors responsible for the regulation of onshore oil fields and gas terminals. A response from one consultee stated that:

‘The initial phases of well exploration and completion are not regulated under IPPC/IED/EPR. My understanding is that that DTI used to control/permit/licence such work. I don't know which government department does this now: DECC themselves or BIS possibly. As, I guess, we are not involved with anything other than groundwater issues at the exploration stage, I would not expect the [Environment] Agency to have information on emissions during this phase of work’.

No further information on the UK onshore oil fields has become available, but we note that there are several sites that could potentially provide information useful to this study:

- Star Energy
  - WP3531LU Welton Gathering Station
  - BP3839XA Horndean B well site
  - VP3231LI Scampton North Oilfield
- PR Singleton
  - PP3437LK Singleton well site
- BP Exploration
  - FP3039MR and CP3039MV Wytch Farm well site (and gathering station).

Existing Environment Agency guidance for operators of petroleum activities (Environment Agency 2010) outlines the available release estimation techniques for fugitive and point source emissions, which could be applied to unconventional gas exploration and production activities. Review of this guidance indicates that further research would be needed to identify emission factors for activities specific to shale gas exploration and production.

Although no specific mention of methane is made, the sources identified as potentially significant sources of VOCs are:

- storage and handling facilities;
- gas separation units;
- oil/water separation systems;
- fugitive emissions (valves, flanges, compressors and so on);
- vents;
- flare systems.

All these are either applicable directly to unconventional gas exploration and production activities or analogous to the type of sources that would be required for these activities (for example, wastewater treatment for flowback water containing methane in bubbles and in solution may be handled in similar units as the separation systems for other sectors).

The methods for estimating fugitive VOCs given in Environment Agency (2010) cover some of the sources that are applicable to fugitive methane emissions from shale gas exploration and production. These include:

- a method derived from the US EPA protocol for equipment leak estimates, which uses a tiered approach to estimating emissions, compiling a site inventory of the number and service type of fugitive sources, grouping that inventory into process streams, noting the operational hours and then applying source activity-specific emission factors (typically quoted in terms of kg per hour per source);

- a leak/no leak method which uses leak measurements from fugitive sources and estimates the emission rate using calculations of the emission rate for equipment type, number of sources for that emission source as monitored above a screening test of a set concentration (10,000 ppmv used for VOCs) and operational hours;

The appendices to the guidance provide methods to normalise emission concentrations (which should not be required for fugitive releases) and conversion factors for ppm to mg/m^3.

The use of such methods has been the focus of discussion following the publication of emissions estimates based on the use of ambient monitoring techniques (Pétron et al. 2012). This work suggests that use of an established leak estimate methodology potentially underestimated emissions of methane from a tight gas extraction field by a factor of approximately two. The established methodology based on emission factors and activity estimates indicated that approximately 2 per cent of methane production was lost to the atmosphere, whereas the measurement study combined with the use of dispersion modelling tools indicated that approximately 4 per cent of methane was lost to the atmosphere.

6.3.2 DECC regulatory functions and data collection

The DECC energy statistics team collates annual flaring and venting data for onshore oil sites, as part of the department's regulatory functions for the upstream oil and gas industry. In view of DECC's role in licensing onshore oil and gas exploration, it is likely that operators of unconventional gas exploration and production sites would also be required to report venting and flaring volumes to DECC, together with production statistics (monthly, quarterly, annual).

Under the Petroleum Act 1998 and the Petroleum (Production) (Landward Areas) Regulations 1995, DECC regulates the licensing for all exploration, development, production and abandonment of all hydrocarbon fields. In a note on onshore oil and gas exploration and development integration between regulatory agencies,[7] DECC states that:

'The process of obtaining consent to drill a well within Great Britain is essentially the same whether the well is targeted at conventional or unconventional gas. Most companies seek a new Petroleum Act Licence from DECC which grants exclusivity, but

[7] Downloadable from http://og.decc.gov.uk/en/olgs/cms/explorationpro/onshore/onshore.aspx [Accessed 30 July 2012]

they could also purchase an interest in another company's existing licence. However, DECC's licence does not remove the need to comply with health and safety or environmental regulation, or to respect landowners' rights. Therefore, when an operator is ready to drill a well, it will have to address several factors including:

- access to the land (including the drill site and any location under which deviated wells are to be drilled), which usually means negotiating access with landowners;
- the need for planning permission;
- well consent pursuant to the Licence by DECC;
- environmental regulation implemented in England and Wales by the Environment Agency (EA) and in Scotland by the Scottish Environmental Protection Agency (SEPA);
- health and safety legislation implemented by the Health & Safety Executive (HSE);
- and permission from the Coal Authority if the drilling entails encroachment on coal seams.'

A list produced by DECC of all relevant UK legislation is given in Appendix 1.

6.3.3 DECC offshore inspectorate: EEMS guidance

The Environmental Emissions Monitoring System (EEMS) guidance for offshore operators provides some useful documentation for the Environment Agency to use in drafting guidance and setting up reporting protocols for the industry – as does the Environment Agency's own guidance note on petroleum processes (Environment Agency 2010).

Although the EEMS operator guidance (DECC and Oil & Gas UK 2008) provides estimation methods for direct emissions including gas venting and fugitive emissions, the methods and factors within the guidance note are intended for application to offshore conventional oil and gas exploration and production emission sources. Where gas composition data can be obtained for the unconventional gas exploration and production sites, many of the protocols within EEMS guidance would be applicable to shale gas activities. However, their applicability is limited to sources that are replicated in the offshore sector such as point source vents and plant component leaks (connections, valves, pumps, open ended pipes and others). Separate estimates using alternative methods will be needed for estimation of fugitive emissions from well exploration to completion and from flowback water.

Section 5 of the EEMS guidance provides the equations and factors needed to convert data to standard reporting conditions. These are summarised in Appendix 4.

6.3.4 List of UK consultees

Table 6.1 lists those consulted by the study team in the UK.

Table 6.1 List of UK consultees

Organisation	Consultee(s)
DECC (Oil and Gas Statistics)	Clive Evans
DECC (Energy Development)	John Arnott
DECC (Offshore Inspectorate)	Derek Saward, David Foskitt

6.4 Summary of findings from EU Member State review and consultation

6.4.1 European Environment Agency (EEA)

Consultation with lead experts on Pollutant Release and Transfer Register (PRTR) regulation have indicated that emissions from exploration for onshore gas (and the related fugitive emissions) are not included explicitly within the scope of the PRTR reporting requirements. In some cases, however, it is evident that Member States include estimates of fugitive emissions within submissions for co-located combustion activities (for example, there is evidence of this in the offshore oil and gas sector) and hence there is some degree of variable interpretation of the scope of PRTR reporting across Member States. It is possible that some countries may consider unconventional gas extraction to fall within 'Mining and underground activities' within PRTR national reporting (B. Boyce, personal communication, 2012).

6.4.2 Netherlands

National emission estimates for the oil and gas sector are compiled by the PBL Netherlands Environmental Assessment Agency (PBL).

There is a Dutch industry-wide protocol that is used by all operators in the sector, including onshore gas operators, but the protocol does not provide details of emission factors for specific sources. One consultee stated that:

'The ten Dutch oil and gas operators all use the electronic annual environmental report (e-MJV) to provide their emission- and production data. They … use a special Oil and Gas module. The e-MJV data of all operators are controlled and approved by the Ministry of Economic Affairs, Agriculture and Innovation (Directorate Energy market), their competent authority ... the operators do use detailed data of their installations to calculate their emissions but unfortunately the emissions and production data are only available in aggregated form'.

Operator reporting guidance is available on the PBL website.[8] The documents do not provide detailed emission factors by source and further enquiries to determine whether the data held by the Ministry of Economic Affairs, Agriculture and Innovation would provide source-specific detail were not productive as the data are regarded as commercially confidential.

However, the operator reporting guidance and periodic industry publications do provide an insight into the level of data granularity at which emission calculations are performed by Dutch oil and gas companies. While the study team did not find specific estimation methods/protocols and factors for fugitive methane sources for onshore gas exploration and production, evidence from energy conservation plans drawn up by Dutch oil and gas companies indicates that such methods and protocols exist and distinguish between hardware down to the level of a specific piece of equipment such as a dehydration installation, its glycol system and its flare or furnace.

[8] http://www.nogepa.nl/language/en-GB/Home/DownloadCenter.aspx

6.4.3 Germany

The study team consulted national GHG inventory experts and PRTR regulatory contacts. There are no sites in Germany reporting under PRTR and the data available from operators are aggregated by site with no detail on source-specific emissions.

Official statistics in Germany do not currently differentiate between drilling for oil or gas, but an ongoing study to determine country-specific emission factors for oil and for gas exploration and production activities is due to report later in 2012 (UBA, personal communication, 2012). The German Oil & Gas Production Association (WEG) in Hannover is the lead organisation for the development of guidance.

The practice of hydraulic fracturing has been used in Germany since the 1960s with over 300 fracs nationally, indicating the relatively low uptake of this extraction technology to date.

6.4.4 Poland

Emission estimates used in the national GHG inventory are derived from a country study, but the details of the emission factors used at the source level are not readily available. The study team is waiting for a further response from contacts at the Ministry of Environment, but it is unclear whether the State Mining Authority as the regulatory authority holds any relevant information developed for use in Poland.

6.4.5 Norway

No response has so far been received from the Norwegian Pollution Control Authority.

6.4.5 List of EU consultees

Table 6.2 lists those consulted by the study team in the EU.

Table 6.2 List of EU consultees

Country	Organisation	Consultee(s)
Norway	Norwegian Pollution Control Authority (oil & gas sector expert)	Eilev Gjerald
Germany	Umweltbundesamt (UBA) (Federal Environment Agency)	Kristina Juhrich, Christian Boettcher
Netherlands	PBL (GHG inventory compilers)	Kees Peek, Johanna Montfoort
Poland	Head of HC Division, Department of Geology and Geological Concessions in the Ministry of Environment	Marta Wagrodzka
Poland	Kobize, National Centre for Emissions Management Institute of Environmental Protection - National Research Institute	Anna Olecka
EU	European Environment Agency (PRTR lead)	Bob Boyce

6.5 Summary of findings from USA and Canada review and consultation

6.5.1 Information from Canada

Environment Canada

Environment Canada is the national GHG inventory (GHGI) agency. The study team contacted the lead authors of the chapter in the Canadian national inventory report on fugitive emissions from the energy supply sector and also reviewed the chapter text. The Canada GHGI method does not provide any detailed factors specific to shale gas extraction and is based on a detailed study in 2000, scaled across the time series using specific indicators for sub-sectors of the upstream oil & gas (UOG) sector. Environment Canada recently commissioned a new UOG study due to report in 2013, which will include consideration of shale gas fugitive emissions. The study team did consult the lead expert conducting this study but there is no information specific to unconventional gas exploration and production currently available.

State regulators: British Columbia and Alberta

Much useful information on regulation, reporting and mitigation options is available from:

- British Columbia – which has the most shale gas exploration and production activity in Canada;
- Alberta – where shale gas exploration and production activities are under development, but there is no commercial production yet.

British Columbia

Regulator reports from the British Columbia Oil & Gas Commission can be viewed on its website.[9] These reports give a useful insight into the type of data that operators in Canada are required to report, which includes both conventional and unconventional natural gas extraction.

For example, the *Flaring, Incinerating and Venting Reduction Report for 2010* (BCGOC 2011b) indicates that operators must report annual data on:

- total flared gas volume (which in the UK the study team believes would be required to be reported to DECC as is the case for onshore oil fields);
- solution gas flaring volume (which is primarily aimed at gas produced at oil producing wells, but could be considered applicable to unconventional gas well flowback waters);
- natural gas production;
- well clean-up and well testing flaring (which could also be applied to well workouts in unconventional production);
- total gas vented volume (also expected to be reported to DECC, as above for flaring).

[9] http://www.bcogc.ca/publications/reports.aspx

In addition, the report states that:

'Venting is an intentional, controlled release of un-combusted gas into the atmosphere without flaring or incinerating. The practice is restricted primarily to gas streams that do not support stable combustion'.

The reports also provide an insight into the approach to regulation through, for example, the provision of operator guidance on technical procedures such as the Clean Air Strategic Alliance (CASA) 'Solution Gas Flaring/Venting Decision Tree', which the Commission requires all operators to apply to all solution gas flares and vents of greater than 900 m^3/day (BCOGC 2011b). The 'Flaring Guideline' (see Section 5.1) supports the regulatory requirements for flaring and venting and 'ensures that expectations are clear, consistent and create a level playing field' (BCOGC 2011b, p. 9).

The Field Inspection Annual Report summarises site audit activity by the regulator, thus providing further insight into the regulatory management approach to checking compliance as well as seeking to ensure 'optimal recovery of oil and gas resources over time' (BCOGC 2010). The report covers data gathered through operator reporting and site visits including:

- number of wells drilled;
- pipeline km built;
- geophysical exploration programmes;
- site inspections performed;
- public complaints;
- incident types and causes (for example blowouts due to fracking, unplanned gas releases, fires and so on).

The report outlines a risk-based approach to ranking sites to prioritise those for site visits, considering factors such as:

- history of compliance;
- site sensitivity/proximity to residents and sensitive environments;
- assessment of probability and consequences of any incidents on site.

These approaches may be of use in any future development of a regulatory regime in the UK for onshore unconventional gas production.

Alberta

In Alberta in 2011, the Energy Resources Conservation Board (ERCB) published *Unconventional Gas Regulatory Framework – Jurisdictional Review*, which aimed specifically to review existing regulations that had been designed for conventional oil and gas extraction activities, and assess their applicability and need for revision to address the specific challenges of unconventional gas extraction (ERCB 2011). It reviewed the legislative issues facing the regulators across North America through a survey, and summarised the main challenges and how the regulators were addressing them.

The review identified and discussed the common regulatory challenges covering:

- well spacing requirements;
- hydraulic fracturing;

- water management;
- landowner / public concerns;
- environmental issues;
- regulatory process;
- information collection and dissemination.

6.5.2 US EPA: Natural Gas STAR, GHG Reporting Protocol

There are a large number of sources of information on shale gas exploration and production environmental issues from the US, including data on fugitive methane emissions from the early phases of exploration to well completion and management of methane in flowback fluids.

There are a wide range of emission factors and emission estimates quoted in the available literature, and seemingly a high degree of uncertainty in the available data. During 2011, US EPA finalised a collated set of emission estimation methods and factors for the oil and gas sector to use under the (new) GHG Reporting Protocol. Generation of this guidance included a substantial review/consultation with input from leading authorities across industry and government, including the API. See Section 6.7 for further discussion of the emission factors derived in the US EPA GHG Reporting Protocol.

There are also a number of voluntary industry reporting mechanisms, including the Natural Gas STAR system, for oil and gas companies to share mitigation activity information. The data presented in the Gas STAR outputs (hosted by US EPA) are **not** independently validated but nevertheless give a useful insight into the typical achievable methane emission reductions for different mitigation options. Chapter 4 and Section 6.8 provide further details on mitigation options, which include options specific to addressing fugitive methane from unconventional gas exploration and production sources.

6.5.3 List of North American consultees

Table 6.3 lists those consulted by the study team in North America.

Table 6.3 List of consultees in North America

Country	Organisation	Consultee(s)
Canada	Environment Canada (National Inventory Report authors)	Warren Baker, Steve Smyth, Chia Ha
Canada	Clearstone Engineering (lead author of 2006 IPCC GLs and lead on new UOG study for Environment Canada)	Dave Picard
USA	ERG in its role as Natural Gas STAR lead contractor to US EPA	Allison Berkowitz, Clint Burklin

6.6 Recommendations for operator reporting of metadata to support methane emission estimates

From its experience of Environment Agency regulatory reporting and the review of information from EU and North American resources, the study team recommends that a wide range of metadata be requested as part of the permit requirements for shale gas operators. These are listed below.

6.6.1 Metadata to support estimated fugitive methane releases from unconventional gas operations

- Number of wells drilled; depth and description of vertical depth and directional/horizontal extent
- Number of fracking activities conducted (number of fracturing stages per well; volume of fluid used for each stage)
- Number of well completions
- Number of well workovers
- Annual gas production from each well and across the installation
- Volume of wastewater treated (onsite or offsite)
- Fracking flowback fluid volumes
- Annual inventory of use of fracking fluids
- Description of any reduced emissions completion methods used
- Gas venting volume (reported to DECC)
- Gas flaring volume (reported to DECC)
- Any other information used by the operator to estimate methane emissions
- Annual report on LDAR programmes and progress on plant improvement and emission mitigation activities, including changes to plant design operation and abatement systems
- Description of instrumentation techniques used for methane measurements
- Full details of the emission estimation methodology including:
    - emission factors used (including reference sources for factors used);
    - assumptions made;
    - standard methods;
    - relevant operator and laboratory accreditations/certification for measurements and analytical techniques.

6.6.2 Generic reporting requirements

- Data identifier

- Lineage: that is, background information, sources of data used. This can also include data quality statements (for example, whether the data were obtained using established techniques, research methods, indirect measurements or estimates), measurement and analytical data, description of estimation method
- Units
- Operator estimate of uncertainty in reported emissions data, by source
- Description of any ambient methane monitoring programme, together with results and interpretation
- Geographic, temporal and technical applicability of data
- Spatial resolution (grid reference of each wellhead, emission source)
- Statement regarding any limitations on public access to data
- Keywords
- Responsible party/ies and roles
- Contact details for operator key contacts (such as environmental manager, plant manager)
- Frequency of update/maintenance (if appropriate)

6.7 Quantitative estimation of methane emissions from gas extraction and production operations

6.7.1 Emissions from completion

US EPA default emission factor

The latest US EPA guidance for the oil and gas industry reporting to the GHG Reporting Protocol, a new mandatory reporting system in the USA, outlines the range of information from industry sources across the USA (US EPA 2011g). Under the new mandatory reporting rule, operators in the oil and gas sector must start to report their GHG emission estimates to the US EPA from the year 2010 onwards. Appendix B of the guidance outlines the process of deriving the recommended US EPA default emission factor for emissions of gas per unconventional gas well completion states:

'The emission factor for unconventional well completions was derived using several experiences presented at Natural Gas STAR technology transfer workshops'

The recommended emission factor for emissions of gas per unconventional gas well completion is identified as 9,175 Mcf (260,000 m^3) per completion.

The US EPA analysis of industry presentations and documents regarding RECs for unconventional gas wells suggests a figure of around 90 per cent mitigation of methane emissions through use of this technology and a factor for emissions from unconventional gas well completions including reduced emissions technology is cited as 700 Mcf (20,000 m^3) per completion.

Review of US EPA default emission factor

On further inspection of the underlying data and the approach to deriving these emission factors, the study team concluded that the US EPA approach to deriving the 'average factor' is flawed. It is not surprising, therefore, that there is a high degree of uncertainty and variability associated with these data which are subject to ongoing challenges by industry and the scientific community.

The US EPA quoted factor of 9,175 Mcf per completion is derived as an average of four well completion factors, each based on data from Natural Gas STAR presentations with estimated well completion estimates of 6,000, 10,000, 700 and 20,000 Mcf per completion (US EPA 2011g). However, this average of four data points from different studies mis-represents the underlying datasets, as the four data points cover different numbers of well completions.

The first factor of 6,000 Mcf per completion is based on 2002 data from just under 13,000 well completions, and back-calculating activity data using the API Basic Petroleum Handbook, together with an assumption that 60 per cent of wells were high-pressure tight formations and 40 per cent were low pressure wells. The second factor of 10,000 Mcf per completion is based on data from 2004 from a study of just 30 completions. The third factor of 700 Mcf per completion is taken from a presentation in 2004 by vendors of REC equipment and appears to be based on just three completions. The fourth factor of 20,000 Mcf per completion is based on data from 2002–2006 covering just over 1,000 completions; before rounding the factor is 24,449 Mcf per completion, which is then rounded down to give 20,000 Mcf per completion.

Hence, the data points used to derive the US EPA factor are based mainly on data from the early 2000s. The data indicate the wide range of industry estimates for gas emissions per unconventional completion. Even disregarding the factor from the three RECs, the range of averaged values for unmitigated completions of 6,000–24,500 Mcf per completion indicates the high variability in emissions from different wells with different underlying features (depth, pressure, permeability and so on).

A more reliable weighted emission factor using these four underlying datasets gives an 'average' emission factor of 7,400 Mcf per completion (210,000 m^3/completion) (unmitigated).

Several source documents indicate that reduced well completions typically achieve mitigation of fugitive/vented methane from flowback of around 90 per cent and therefore an estimate for reduced emission completions is 740 Mcf (21,000 m^3) per reduced emission completion.

Converting these weighted-average factors to a mass basis, assuming a gas density of 0.68 kg/m^3 and methane content of the vented gas to be 78.8 per cent mole fraction, gives factors of 112 tonnes methane per unmitigated completion and 11 tonnes methane per reduced emission completion.

These factors derived for the unconventional well completions should only be regarded as indicative and 'typical' for unconventional well completions. The underlying dataset from industry studies indicates that the fugitive gas emissions per completion are highly variable and uncertain, and are dependent on many factors including well depth, pressures, shale gas composition, and the duration of gas venting during well completion (which can range from three to 30 days).

A number of industry representatives in the USA are challenging the US EPA factors. One example, a submission by the American Exploration and Production Council (AXPC) and America's Natural Gas Alliance (ANGA) in a letter to US EPA in January 2012 challenges a number of the underlying assumptions in the derivation of the suggested factor of 9,175 Mcf per completion (AXPC and ANGA 2012). The letter outlines data from completions during 2011 at just under 1,500 wells from various basins across the US, with 93 per cent using reduced emission completions. Of the remaining 7 per cent of unmitigated completions, over half were flared rather than vented. The data from these wells show a range of unconventional gas well completion emissions, with basin-specific completion averages ranging from 340 to 1,160 Mcf (9,600–33,000 m^3) per completion (5–18 tonnes methane per completion) and company averages ranging from 443 to 1,455 Mcf (12,500–41,000 m^3) per completion (7–22 tonnes methane/completion). Although these data are based on a more limited dataset than the US EPA data, they suggest that the US EPA factor may over-estimate emissions from unconventional well completions by roughly a factor of 10.

6.7.2 Operational emissions

Significant work on the comparison of basic unconventional completion and 'green completion' within the US petroleum and natural gas industry has been reported by the US EPA (2010c). This work included a review and revision of the methane emission factors for venting in conventional and unconventional well completions and well maintenance (workovers). Emissions from unconventional gas well completions can be mitigated by the use of reduced emission (or 'green') completion systems to recover gas during the flowback period.

The difference between the factors for conventional and unconventional gas production is attributable to the additional time that gas is vented as a consequence of the drill out and flowback of the hydraulic fracturing fluids during the completion process. US EPA estimates that the gas venting during unconventional gas well completions may range from three to 30 days, and provides an estimation methodology that enables the duration of well completion venting to be taken into account. Industry data from just under 1,500 unconventional gas well completions in 2011 (AXPC and ANGA 2012) indicate that unmitigated completions averaged 3.5 days per completion, whereas reduced emission completions averaged 7.7 days per completion.

The US EPA has published emissions factors for methane for conventional and unconventional sources (US EPA 2011g). This work found that methane emissions from well completion and workovers had previously been underestimated. Further work reported in *Climatic Change Letters* by Howarth et al. (2011) compared the fugitive methane emissions for the stages of natural gas production, although this work remains controversial and subject to disagreement within the scientific community. The findings of these studies are summarised in Tables 6.2 and 6.3.

6.7.3 Implications for the Pollution Inventory

Based on these estimates, and considering that the reporting threshold for Pollution Inventory annual reporting by operators is 10 tonnes, while the PRTR reporting threshold for methane is 100 tonnes, the study team concluded that every onshore gas extraction site that may come under future Environment Agency regulatory control is likely to be required to report annual estimates to the Pollution Inventory.

Furthermore, given that the well completion phase with fracking fluid backflow typically lasts for a period of 10–30 days, with venting of fugitive gases to atmosphere, these activities could potentially result in significant emissions of methane and other trace components. Regulatory controls will need to address these short-term activities.

Emissions of methane are likely to be associated with a variable range of other hydrocarbons. It is possible that these trace constituents of fugitive emissions from unconventional operations could make a contribution to the global warming potential of emissions from shale gas activities. The chemicals likely to be emitted alongside methane emissions from unconventional gas extraction in the UK, and the quantities of these substances, are not known at present. UK measurements will be needed to establish the norms for unconventional gas in the UK.

Currently the onshore oil sector has 15 sites which reported over 10 tonnes of methane to the Pollution Inventory in 2010 (see Appendix 2). Only one of these was over 100 tonnes (although several others were close to 100 tonnes) and hence featured in PRTR reporting.

6.8 Mitigation options and cost–benefit information

The study team has not identified a wide range of data sources regarding mitigation options to address the potential sources of fugitive methane that are specific to shale gas extraction. There is a large amount of material from industry sources in the US; a limited review of some of these data sources is presented here, though the study team acknowledges that this is a subject area that requires significantly more time to develop a more complete and independent analysis of mitigation options and their cost–benefits.

The primary source in the US for fugitive methane mitigation measures for the oil and gas industry is the US EPA sponsored voluntary industry programme, the Natural Gas STAR Program.

The materials on the Natural Gas STAR website[10] provide a range of mitigation options aimed at sources that are generic across the oil and gas industry, including:

- **Compressors/engines**: seven options with an estimated payback of less than one year and a further five options with an estimated payback of 1–3 years.
- **Dehydrators**: seven options with an estimated payback of less than one year and a further four options with an estimated payback of 1–3 years.
- **Directed inspection and maintenance**: four options with an estimated payback of less than one year and one further option with an estimated payback of 1–3 years.
- **Pipelines**: seven options with an estimated payback of less than one year and a further three options with an estimated payback of 1–3 years.
- **Pneumatics/controls**: one option with an estimated payback of less than one year and a further four options with an estimated payback of 1–3 years.
- **Tanks**: three options with an estimated payback of less than one year and a further three options with an estimated payback of 1–3 years.
- **Valves**: four options with an estimated payback of less than one year and one further option with an estimated payback of 1–3 years.
- **Wells**: five options with an estimated payback of less than one year and a further three options with an estimated payback of 1–3 years.
- **Other**: five options with an estimated payback of less than one year and a further three options with an estimated payback of 1–3 years.

Within these options, there are a number that are more likely to be directly applicable to fugitive methane emissions from unconventional gas exploration and production:

[10] http://www.epa.gov/gasstar/tools/recommended.html

- **Install flares**: $10,000–50,000 (US EPA 2011i). Note that the applicability of installing flares to unconventional gas exploration and production systems is limited, however, due to the variable pressure of the initial well venting/flowback phase, which is the period in which the largest fugitive emissions are produced.
- **Reduced emission completions for hydraulically fractured natural gas wells**: >$50,000 (US EPA 2011b). The technology involves installation of sand trap and fluid separator systems to capture flowback fluid and entrained methane (and other) gas, and separate the water, condensate and recover the gas which may be recoverable via a dehydrator to the sales line. Overall, the installation costs are estimated at around $620,000, and payback is estimated at 3–6 months using various scenarios for gas price. US EPA (2011b) gives a detailed summary of this option.

6.9 Key reference documents

6.9.1 Fugitive emission estimation protocols and emission factors

- *National GHG Inventory Report 1990–2009* (US EPA 2011f)
- Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry: Background Technical Support Document (US EPA 2011g)
- Environmental Emissions Monitoring System: Atmospheric Emissions Calculations (DECC and Oil & Gas UK 2008)
- Compendium of GHG Emissions Methodologies for the Oil and Natural Gas Industry (API 2009)
- *Revised attachment 3: Gas well completion emissions data*, AXPC and ANGA letter to US EPA, 19 January 2012

6.9.2 Other regulatory information sources

- 'Onshore oil & gas exploration and development' – DECC website (http://og.decc.gov.uk/en/olgs/cms/explorationpro/onshore/onshore.aspx)
- The following resources have a wider scope than this study, so have not been fully reviewed:
  - 'Shale gas regulation' – Energy Institute, University of Texas in Austin, 29 February 2012 (http://energy.utexas.edu/index.php?option=com_content&view=article)
  - Unconventional Gas Regulatory Framework – Jurisdictional Review (ERCB 2011).

6.10 Conclusions

The information obtained in the study has been evaluated to identify areas where data gaps exist, considering the following issues:

- aspects of unconventional gas extraction that could give rise to methane emissions but which have not been assessed in terms of their potential significance;
- aspects of unconventional gas extraction that have been identified as potentially significant but where data are currently inadequate for the development of quantitative emissions estimates;
- aspects where fugitive methane emissions are highly variable, depending on factors such as geological conditions; management and control techniques used, storage and distribution arrangements.

No emission factors or detailed industry datasets applicable to onshore unconventional gas exploration and production have been found from UK or EU sources. The findings indicate that operator emission estimates (in EU Member States where hydraulic fracturing occurs) are typically aggregated at the installation level, with no transparency of emissions of methane from specific fugitive or vented sources, or from specific activities on the site.

There are examples from existing Environment Agency Pollution Inventory reporting guidance (for onshore petroleum activities) and UK offshore oil and gas sector operator emissions monitoring guidance that provide many of the component parts of the regulatory reporting requirements that would be applicable to the onshore shale gas exploration and extraction sector in the UK.

The Environment Agency is the Government's executive body for protection against adverse releases to environment in England and Wales, and is likely to take responsibility for evaluating and regulating methane emissions from unconventional gas extraction. The exact arrangements with regards to shale gas have not yet been specified. Any regulatory process would need to develop an understanding of the source term for methane emissions. This information would normally be published for access by the public. The processes and requirements are likely to be comparable to those applied to other industrial processes and typically involve the reporting of release rates of substances from point sources and fugitive sources that are above specified thresholds. On a case-by-case basis, the regulator may also require operators to report ambient levels of substances such as methane (for example, to assist in understanding the source terms, and to evaluate changes and trends in levels of released substances).

Typically, an emission factor approach is used to derive emission estimates for regulatory reporting and/or emission inventory purposes. This involves the development of a factor relating the quantity of methane emitted to a measure of activity, such as the mass or volume of gas extracted. Emission factors are typically more uncertain for fugitive sources than for contained process sources or combustion sources (including flaring). See Section 6.7 for a discussion of the variability and uncertainty of the factors for unconventional gas well completions based on US research.

The use of emission factors from other industries for use in shale gas exploration and production emission estimation methods increases uncertainty in the derived emission estimates. For many sources that are not unique to shale gas (flaring emissions, fugitive emissions from component leakages and so on), the estimation methods used in other industries are likely to be applicable to shale gas exploration and production. However, new emission factors specific to each local shale gas basin will need to be developed to estimate emissions from shale gas exploration and production sources. Shale gas compositional data will need to be collected to derive emission factors that are representative of shale gas, which typically differs in its hydrocarbon content compared with conventional gas and varies according to the local geological conditions.

There are industry-specific, source-specific emission estimation protocols and factors developed by the US oil and gas industry and the US EPA, within their GHG reporting protocols. But despite shale gas exploration and production activity having been established for many years in the US, there remains a lack of clear, detailed data to provide the evidence base for determining emission factors for specific sources. This is reflected in ongoing challenges to published data, protocols and emission factors, and has been highlighted by Pétron et al. (2012), who used dispersion modelling analysis to estimate overall methane loss to the atmosphere around a US shale gas field and estimated emissions at a level double that estimated using a ‘bottom–up’ inventory technique. Howarth et al. (2011) also suggested that emissions to air of methane may be higher than previously thought.

There is a high degree of uncertainty in the existing dataset for estimating fugitive methane emissions from shale gas exploration and production sources, which presents challenges to all regulatory agencies. Investment is needed in regulatory development, measurement and reporting protocols, and guidance that promotes a high degree of transparency and accuracy to emission estimates, together with a robust programme of data checking, benchmarking and verification by regulators. Environment Canada recently commissioned a new study to improve national estimates from its oil and gas industry, including consideration of shale gas exploration and production, which is scheduled to report in 2013.

The research for this study has not identified many relevant sources to provide insight into the effectiveness of mitigation options or the cost–benefits of different options. The available data are primarily provided directly by the gas industry in the US. It is recommended that further time should be allocated to seek out validated data and impartial, independent cost–benefit analysis.

The study team has identified a small number of references from the US that mention the range of shale gas composition evident from different basins in the US, and the ‘typical’ compositional differences between gas from shales and gas from conventional reservoirs. Gas derived from shale tends to exhibit a more variable content of hydrocarbons and carbon dioxide, inferring a greater need for local gas sampling and compositional analysis to derive accurate emission factors for fugitive, process and combustion sources.

7 Conclusions and recommendations

This chapter sets out the main conclusions, together with early views on ways forward for future work for the Environment Agency, bearing in mind the objective of this study to provide recommendations for a cost-effective strategic programme of monitoring and emission estimation.

It is recommended that the Environment Agency uses the information in this report as a starting point for its regulatory programme in relation to the monitoring and control of fugitive methane from unconventional gas operations. The Environment Agency should continue to monitor developments in the US closely, for example in relation to the recently confirmed US EPA requirement for green completions and ongoing developments in the estimation of whole-field methane emissions.

7.1 Control measures

A range of potentially effective control measures were identified. The US EPA has published illustrative information on payback periods for these measures. At face value, there appears to be a wide range of highly cost-effective control measures. If they are verified as being applicable in the UK and if similar payback periods are identified using the Environment Agency's cost–benefit tools, there would be a presumption in favour of applying these control measures. There may be site-specific constraints on the implementation of these measures, which would need to be addressed on a case-by-case basis by operators and regulators.

It is recommended that the Environment Agency and the unconventional gas industry should consider carrying out further research into mitigation options, different technologies and their effectiveness, scope of application, and cost–benefit analysis.

7.2 Estimation of methane emissions

The use of generic emissions factors to estimate methane emissions from other industries is of questionable value for unconventional gas. Recent research published by the US EPA indicates that methane emissions from unconventional gas well completion may be higher than previously thought.

There is information from North American sources regarding fugitive methane emissions from shale gas extraction, but there is also a notable level of discord in the messages from industry, regulators, academics and public sources. The study team's recommendations for the prioritisation of future research effort in relation to emissions estimates reflect this deficiency in the core evidence base surrounding this industry.

Emission factors derived by the American Petroleum Industry are widely used to estimate methane emissions in the oil and gas industry. These may not be applicable to the plant and equipment used for unconventional gas extraction, and may also reflect outdated practices in the unconventional gas industry. It is recommended that the Environment Agency should avoid relying solely on these factors and should request that operators develop emissions estimates from multiple data sources wherever possible. This may require additional measurement surveys to be carried out on representative plant if relevant data are not otherwise available.

It was found that conventional oil and gas operator emission estimates in the EU are typically aggregated at the installation level, with no transparency of emissions of methane from specific fugitive or vented sources, or from specific activities on the site. In the design of data reporting systems for onshore gas operators (at least at the IPPC/EPR permit application stage and ideally also in the requirements for operators to submit annual emission estimates to the Pollution Inventory), it is recommended that source-specific emission estimates and full details of the emission estimation methodology be reported by site operators, rather than annual, installation-wide estimates. This is especially important to provide transparency and comparability to operator estimates, and to ensure that a suitable evidence base is developed for the emission sources that are unique to unconventional gas exploration and production, and new to the UK regulatory system. The study team suggests that, as a minimum, operators be requested to provide emission estimates and all underlying measurement data and subsequent calculations for the fugitive and vented methane emissions from well completions, well workovers and flowback fluid management systems.

It is recommended that the Environment Agency should require operators of unconventional gas extraction facilities to carry out surveys to measure ambient methane levels:

- before operations commence;
- during drilling, hydraulic fracturing and completion;
- during production.

It is also recommended that a monitoring survey designed to verify methane emissions estimates from unconventional gas extraction during drilling, hydraulic fracturing, completion and production would provide useful information to support industry emissions reporting, regulation of unconventional gas extraction facilities and inclusion of emissions estimates in the national inventories. This monitoring survey may be supplemented by the use of inverse dispersion modelling techniques in order to infer emission rates from ambient concentrations.

7.3 International co-ordination

It is recommended that the Environment Agency initiates and continues consultation with peers in regulatory agencies across the EU (in particular in Poland, Germany and the Netherlands), the European Environment Agency and the European Commission. It is also recommended that links between Environment Agency and US EPA experts could usefully be developed. In the UK context, it is recommended that the Environment Agency convenes a UK regulatory steering group made up of:

- Environment Agency regulatory leads and site inspectors from onshore oil and gas sites;
- DECC geologists;
- upstream oil and gas specialists.

Further work to research measurement campaigns and to seek out other examples of modelling from ambient measurements to back-calculate emissions from shale gas fields is needed to further refine emission estimates, especially of fugitive/vented methane from unconventional gas well completions. It is recommended that the Environment Agency maintains a watching brief on the use of chemical speciation to assist in methane emissions source apportionment.

It is recommended that the Environment Agency should maintain a watching brief on Canadian studies due to be published during 2012 and 2013, as well as a German inventory study due to report later in 2012 and which will be used in the next edition of the German GHG inventory.

7.4 Environmental and health studies

This study has focused on releases from process infrastructure. It is recommended that the Environment Agency supports and, if appropriate, commissions wider ranging environmental and health impact studies to encompass local and regional air quality and health impacts of fugitive releases of VOCs, together with other environmental issues of potential concern.

Consideration may also need to be given to minimising the risk of methane reaching the surface via pathways from the well infrastructure (for example, in the event of failures of the well liner system) or via the overlying rocks following fracturing of the shale matrix. In this case, concerns are likely to focus on groundwater contamination risks. For deeper shale gas measures, release via the overlying rocks is less likely to pose a significant risk. Control of these risks will be built into the design of an unconventional gas extraction project. An appropriate pre-operational monitoring survey will be an important component of the project to ensure that, if any emissions do occur via these pathways, they can be identified and addressed.

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Glossary and abbreviations

The glossary adapted in part from NYSDEC (2011). The majority of terms are referred to in the report. Some additional terms are included to assist in wider discussion of unconventional gas operations.

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
AERMOD	American Meteorological Society (AMS)/EPA Regulatory MODel
ANGA	America's Natural Gas Alliance
Annular space or annulus	Space between casing and the well bore, or between the tubing and casing or well bore, or between two strings of casing.
Anticline	A fold with strata sloping downward on both sides from a common crest.
AOM	acousto-optic modulator
API	American Petroleum Institute.
Aquifer	A zone of permeable, water-saturated rock material below the surface of the earth capable of producing significant quantities of water.
AXPC	American Exploration and Production Council
Bactericides	Also known as a 'biocide.' An additive that kills bacteria.
Barrel	A volumetric unit of measurement equivalent to 42 US gallons or 0.159 m^3
BAT	Best Available Techniques
bbl/year	barrels per year
bbl	barrel
Bcf	Billion cubic feet. A unit of measurement for large volumes of gas. 1 Bcf is equivalent to 28.3 million m^3
bcm	billion cubic metres
BCOGC	British Columbia Oil and Gas Commission
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
Biocides	See 'Bactericides'.
BLM	Bureau of Land Management [US federal]

Blowout	An uncontrolled flow of gas, oil or water from a well, during drilling when high formation pressure is encountered.
BMP	Best Management Practice (see above for definition)
Breaker	A chemical used to reduce the viscosity of a fluid (break it down) after the thickened fluid has finished the job it was designed for.
BTEX	Collective term for benzene, toluene, ethylbenzene and xylene. These are all aromatic hydrocarbons.
Buffer	A weak acid or base used to maintain the pH of a solution at or close to a chosen value.
CAS Number	Number assigned by the Chemical Abstracts Service.
Casing	Steel pipe placed in a well.
CBM	coalbed methane (see below for definition)
CEAS	cavity enhanced adsorption spectroscopy
CFR	Code of Federal Regulations.
CGA	Canadian Gas Association
CH_4	Chemical formula of methane
Chemical additive	A product composed of one or more chemical constituents that is added to a primary carrier fluid to modify its properties in order to form hydraulic fracturing fluid.
Chemical constituent	A discrete chemical with its own specific name or identity, such as a CAS number, which is contained within an additive product.
CFC	chlorofluorocarbon
CMAQ	Community Multiscale Air Quality [model]
CO	Chemical formula of carbon monoxide
CO_2	Chemical formula of carbon dioxide
CO_{2e}	Carbon dioxide equivalent, a measure used to compare the emissions from various greenhouse gases based upon their global warming potential. For example, the global warming potential for methane over 100 years is 21. This means that emissions of one million tonnes of methane is equivalent to emissions of 21 million tonnes of carbon dioxide.
Coalbed methane	A form of natural gas extracted from coal beds. The term refers to methane adsorbed onto the solid matrix of the coal.
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.
Compressor station	A facility that increases the pressure of natural gas to move it in pipelines or into storage.
Condensate	Liquid hydrocarbons that were originally in the reservoir gas and are recovered by surface separation.
Conventional reserve	A high permeability formation (greater than 1 millidarcy) containing oil and/or gas, which can be more readily extracted than hydrocarbons from unconventional reserves. The term 'conventional gas' is not always used in accordance with this technical definition, particularly in the US where a different definition is commonly used, and care must be exercised in the use and interpretation of this term.
Corrosion inhibitor	A chemical substance that minimises or prevents corrosion in metal equipment.
CRDS	cavity ringdown spectroscopy
Crosslinker	A compound, typically a metallic salt, mixed with a base-gel fluid, such as a guar gel system, to create a viscous gel used in some stimulation or pipeline cleaning treatments. The crosslinker reacts with the multiple strand polymer to couple the molecules, creating a fluid of high viscosity.
Darcy	A unit of permeability. A medium with a permeability of 1 darcy permits a flow of 1 cm^3 per second of a fluid with viscosity 1 cP (1 mPa·s) under a pressure gradient of 1 atmosphere per cm acting across an area of 1 cm^2.
DECC	Department of Energy and Climate Change [UK]
Dehydrator	A device used to remove water and water vapours from gas.
DIAL	differential absorption light detection and ranging
Directional drilling	Deviation of the borehole from vertical so that the borehole penetrates a productive formation in a manner parallel to the formation, although not necessarily horizontally.
Disposal well	A well into which waste fluids can be injected deep underground for safe disposal.
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.
EEA	European Environment Agency
E&P	exploration and production
Economically recoverable	Technically recoverable petroleum for which the costs of discovery, development, production, and transport,

reserves	including a return to capital, can be recovered at a given market price.
Ecosystem	The system composed of interacting organisms and their environments.
EEMS	Environmental Emissions Monitoring System
EIS	Environmental Impact Statement.
ERCB	Energy Resources Conservation Board [Alberta, Canada]
ERP	Emergency Response Plan
ESL	Effects Screening Level
Fault	A fracture or fracture zone along which there has been displacement of the sides relative to each other.
FID	flame ionisation detection
Field	The general area underlain by one or more pools.
Flare	The burning of unwanted gas through a pipe.
Flash tank separator	As well as absorbing water from the wet gas stream, a glycol solution occasionally carries with it small amounts of methane and other compounds found in the wet gas. In order to recover this methane, a flash tank separator–condenser can be used to remove these compounds before the glycol solution reaches the boiler. The pressure of the glycol solution stream is reduced, allowing the methane and other hydrocarbons to vaporise ''flash') and be captured.
FLIR	forward-looking infrared
Flowback fluids	Liquids produced following drilling and initial completion and clean-up of the well.
Fold	A bend in rock strata.
Footwall	The mass of rock beneath a fault plane.
Formation water	See production water
Formation	A rock body distinguishable from other rock bodies and useful for mapping or description. Formations may be combined into groups or subdivided into members.
Fossil methane / fossil fuel	A natural fuel such as coal or gas, formed in the geological past from the remains of living organisms.
Fracking or fracing (pronounced 'fracking')	Informal abbreviation for 'hydraulic fracturing'.
Friction reducer/friction reducing agent	A chemical additive which alters the hydraulic fracturing fluid allowing it to be pumped into the target formation at a higher rate and reduced pressure.
FTIR	Fourier transform infrared

Gas meter	An instrument for measuring and indicating, or recording, the volume of natural gas that has passed through it.
Gas–water separator	A device used to separate undesirable water from gas produced from a well.
GC-MS	gas chromatography–mass spectrometry
GEIS	Generic Environmental Impact Statement
Gelling agents	Polymers used to thicken fluid so that it can carry a significant amount of proppants into the formation.
Geothermal well	A well drilled to explore for or produce heat from the subsurface.
GHG	greenhouse gas.
GHGI	greenhouse gas inventory
GHGRP	greenhouse gas reporting protocol
Girdler process	A widely used method for removal of hydrogen sulphide from natural gas by reacting the H_2S with amine compounds.
Glycol dehydration	A process in which a liquid desiccant dehydrator is used to absorb water vapour from the gas stream. A glycol solution, usually either diethylene glycol or triethylene glycol, is brought into contact with the wet gas stream. The glycol/water solution is put through a specialised boiler to vaporise the water, and enable glycol to be recovered for re-use
GNBPA	Greater Natural Buttes Project Area
gpd	gallons per day.
gpm	gallons per minute
GPS	global positioning system
Green completion	See reduced emissions completion
Groundwater	Water in the subsurface below the water table. Groundwater is held in the pores of rocks and can be connate (that is, trapped in the rocks at the time of formation) from meteorological sources or associated with igneous intrusions.
GWP	global warming potential A measure of how much a given mass of greenhouse gas is estimated to contribute to global warming.
H_2O	Chemical formula for water
H_2S	Chemical formula for hydrogen sulphide
HAPs	Hazardous Air Pollutants [as defined under the US Clean Air Act] See list at http://www.epa.gov/ttn/atw/188polls.html
HCFC	hydrochlorofluorocarbon

HGC	hydrofluorocarbon
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 NYSDEC (2011) as fracturing using 300,000 gallons (1,350 m^3) 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 formational layering.
Hydraulic fracturing fluid	Fluid used to perform hydraulic fracturing. Includes the primary carrier fluid, proppant material and all applicable additives.
Hydraulic fracturing	The act of pumping hydraulic fracturing fluid into a formation to increase its permeability.
Hydrocyclone	A device to classify, separate or sort particles in a liquid suspension based on the densities of the particles. A hydrocyclone may be used to separate solids from liquids or to separate liquids from different density.
Hydrogen sulphide	A malodorous, toxic gas with the characteristic odour of rotten eggs.
IAS	infrared absorption spectroscopy
ICOS	integrated cavity output spectroscopy
Igneous rock	Rock formed by solidification from a molten or partially molten state (magma).
IR	infrared
Iron inhibitors	Chemicals used to bind the metal ions and prevent a number of different types of problems that iron can cause (for example, scaling problems in pipe).
KMG	Kerr-McGee Oil & Gas Onshore LP
KML file	Computer file used in the Google Earth system.
LDAR	leak detection and repair
LEL	Lower Explosive Limit
LIDAR	light detection and ranging
Limestone	A sedimentary rock consisting chiefly of calcium carbonate ($CaCO_3$).
Make-up water	Water in which proppant and chemical additives are mixed to make fracturing fluids for use in hydraulic fracturing.

Manifold	An arrangement of piping or valves designed to control, distribute and often monitor fluid flow.
Mcf	Thousand cubic feet (equivalent to 28.3 m^3).
mD	millidarcy
MDL	Minimum Detection Limit
Methane	Methane (CH_4) is a greenhouse gas that remains in the atmosphere for approximately 9–15 years. Methane is also a primary constituent of natural gas and an important energy source.
millidarcy	A unit of permeability, equivalent to one thousandth of a darcy
MMcf	million cubic feet (equivalent to 28,300 m^3)
NAAQS	National Ambient Air Quality Standard [US]
NDIR	non-dispersive infrared
NEPA	National Environmental Policy Act [US]
NESHAPs	National Emission Standards for Hazardous Air Pollutants [US]
NH_3	Chemical formula for ammonia.
NOAA	National Oceanic and Atmospheric Administration [US]
NORM	naturally occurring radioactive material Low-level radioactivity that can exist naturally in native materials, like some shales and may be present in drill cuttings and other wastes from a well.
NO_X	Abbreviation for 'oxides of nitrogen' made up primarily of nitrogen dioxide (NO_2) and nitric oxide (NO).
NSPS Regulations	New Source Performance Standard Regulations [US]
NYSDEC	New York State Department of Environmental Conservation
O_2	Chemical formula for oxygen
O_3	Chemical formula for ozone
Operator	Any person or organisation in charge of the development of a lease or drilling and operation of a producing well.
OP-FTIR	open path Fourier transform infrared
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 well bore.
Permeability	A measure of a material's ability to allow passage of gas or liquid through pores, fractures, or other openings. The unit of measurement is the darcy or millidarcy.

Petroleum	In the broadest sense. the term embraces the full spectrum of hydrocarbons (gaseous, liquid, and solid).
PID	photoionisation detector
PI-DIAL	path integrated differential absorption light detection and ranging
PM_{10}	Particulate matter with a diameter less than 10 microns (in Europe, defined strictly as 'particulate matter which passes through a size-selective inlet with a 50 per cent efficiency cut-off at 10 μm aerodynamic diameter'.
Pneumatic	Run by or using compressed air.
Polymer	Chemical compound of unusually high molecular weight composed of numerous repeated, linked molecular units.
Pool	An underground reservoir containing a common accumulation of oil and/or gas. Each zone of a structure which is completely separated from any other zone in the same structure is a pool.
Porosity	Volume of pore space expressed as a percentage of the total bulk volume of the rock.
ppb	part per billion
ppm	part per million
ppmv	part per million by volume
Primary carrier fluid	The base fluid, such as water, into which additives are mixed to form the hydraulic fracturing fluid which transports proppant.
Primary production	Production of a reservoir by natural energy in the reservoir.
Product	A hydraulic fracturing fluid additive that is manufactured using precise amounts of specific chemical constituents and is assigned a commercial name under which the substance is sold or utilised.
Production casing	Casing set above or through the producing zone through which the well produces.
Production water	Liquids co-produced during oil and gas wells production.
Proppant or propping agent	A granular substance (sand grains, aluminium pellets, or other material) that is carried in suspension by the fracturing fluid and that serves to keep the cracks open when fracturing fluid is withdrawn after a fracture treatment.
Proved reserves	The quantity of energy sources estimated with reasonable certainty, from the analysis of geologic and engineering data, to be recoverable from well-established or known reservoirs with the existing equipment and under the existing operating conditions
PRTR	Pollutant Release and Transfer Register

QCL	quantum cascade laser
REC	reduced emissions completion (see definition below)
Reduced emissions completion (also known as 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 can be delivered into the sales pipeline. RECs help to reduce methane, VOC and HAP emissions during well clean-up and can eliminate or significantly reduce the need for flaring.
Reservoir (oil or gas)	A subsurface, porous, permeable or naturally fractured rock body in which 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.
Reservoir rock	A rock that may contain oil or gas in appreciable quantity and through which petroleum may migrate.
ROD	Record of Decision
RPM	radial plume mapping
RSD	relative standard deviation
Sandstone	A variously coloured sedimentary rock composed chiefly of sand-like quartz grains cemented by lime, silica or other materials.
Scale inhibitor	A chemical substance which prevents the accumulation of a mineral deposit (for example, calcium carbonate) that precipitates out of water and adheres to the inside of pipes, heaters, and other equipment.
SEAB	Secretary of Energy Advisory Board [US]
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.
SEIS	Supplemental Environmental Impact Statement
Seismic	Related to earth vibrations produced naturally or artificially.
Separator	Tank used to physically separate the oil, gas and water produced simultaneously from a well.
SGEIS	Supplemental Generic Environmental Impact Statement.
Shale oil	Oil shale, also known as kerogen shale, is an organic-rich fine-grained sedimentary rock containing kerogen (a solid mixture of organic chemical compounds) from which liquid hydrocarbons called shale oil can be produced. Crude oil which occurs naturally in shales is

	referred to as 'tight oil'.
Shale	A sedimentary rock consisting of thinly laminated claystone, siltstone or mud stone. Shale is formed from deposits of mud, silt, clay, and organic matter
Show	Small quantity of oil or gas, not enough for commercial production.
Siltstone	Rock in which the constituent particles are predominantly silt size.
Slickwater fracturing (or slick-water)	A type of hydraulic fracturing which utilises water-based fracturing fluid mixed with a friction reducing agent and other chemical additives.
SO_2	Chemical formula for sulphur dioxide.
Spudding	The breaking of the Earth's surface in the initial stage of drilling a well.
Squeeze	Technique where cement is forced under pressure into the annular space between casing and the wellbore, between two strings of pipe, or into the casing-hole annulus.
Stage plug	A device used to mechanically isolate a specific interval of the wellbore and the formation for the purpose of maintaining sufficient fracturing pressure.
Stage	Isolation of a specific interval of the wellbore and the associated interval of the formation for the purpose of maintaining sufficient fracturing pressure.
Stimulation	The act of increasing a well's productivity by artificial means such as hydraulic fracturing or acidising.
Stratum (plural strata)	Sedimentary rock layer, typically referred to as a formation, member or bed.
Surface casing	Casing extending from the surface through the potable fresh water zone.
Surfactants	Chemical additives that reduce surface tension; or a surface active substance. Detergent added to hydraulic fracturing fluid is a surfactant.
Target formation	The reservoir that the driller is trying to reach when drilling the well.
TCEQ	Texas Commission on Environmental Quality
Tcf	trillion cubic feet, equivalent to 28.3 billion m^3
TDLAS	tunable diode laser absorption spectroscopy
Technically recoverable reserves	The proportion of assessed in-place petroleum that may be recoverable using current recovery technology, without regard to cost.
Tight formation	Formation with very low (less than 1 millidarcy) permeability.

Tight gas	Natural gas obtained from a tight formation
tpy	tonnes per year
UMB	Umweltbundesamt [German Federal Environment Agency]
UIC	underground injection control
Unconventional gas	Gas contained in rocks (which may or may not contain natural fractures) which exhibit in-situ gas permeability of less than 1 millidarcy. The term 'unconventional gas' is not always used in accordance with this technical definition, particularly in the US where a different definition is commonly used, and care must be exercised in the use and interpretation of this term.
UOG	upstream oil & gas
USDW	underground source of drinking water An aquifer or portion of an aquifer that supplies any public water system or that contains a sufficient quantity of groundwater to supply a public water system, and currently supplies drinking water for human consumption, or that contains fewer than 10,000 mg/L total dissolved solids and is not an exempted aquifer.
US EPA	US Environmental Protection Agency
US EPA OTM10	US Environmental Protection Agency Other Test Method 10
USGS	US Geological Survey
UV	ultraviolet
UV-DOAS	ultraviolet differential optical absorption spectroscopy
Vapour recovery unit	A system to which gases from gas collection and processing operations are charged to separate the mixed gases for further processing. The vapours are sucked through a scrubber, where the liquid trapped is returned to the liquid pipeline system or to the tanks, and the vapour recovered is pumped into gas lines.
Viscosity	A measure of the degree to which a fluid resists flow under an applied force.
VOC	volatile organic compound
VRU	vapour recovery unit (see definition above)
Water well	Any residential well used to supply potable water.
Watershed	The region drained by, or contributing water to, a stream, lake or other body of water.
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. The area directly disturbed during drilling and operation

	of a gas well.
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.
Well bore	A borehole; the hole drilled by the bit. A well bore 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 well bore. A wellhead includes such equipment as the casing head and tubing head.
Wildcat well	A 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.

Appendix 1: Environmental legislation applicable to the onshore hydrocarbon industry (England, Scotland and Wales)

The tables in this appendix were produced by DECC and are available from http://og.decc.gov.uk/en/olgs/cms/environment/leg_guidance/onshore/onshore.aspx. In this appendix, 'licence' is a term used for either a licence, authorisation, registration or permit issued under the various statutory instruments.

Table A1.1 Key EC and UK environmental legislation

EC legislation	Associated UK legislation	Main requirements	Regulator, applies in
EC Directive (85/337/EEC): Assessment of the effects of certain public and private projects on the environment	1. Town & Country Planning (Environmental Impact Assessment) (England and Wales) Regulations 1999, 2. Environmental Impact Assessment (Scotland) Regulations 1999	Requires certain developments to prepare an Environmental Statement as part of the planning approval process.	Local Authorities, England and Wales Local Authorities, Scotland
EC Directive (92/43/EEC); Conservation of natural habitats and of wild fauna and flora; and	Conservation (Natural Habitats) Regulations 1994	Requires developments to take account of Special Areas of Conservation in their environmental impact assessment. Approvals granted via the above Regulations.	EA or English Nature, England and Wales SEPA or Scottish Natural Heritage, Scotland
EC Directive (96/82/EC): Control of major accident hazards	1. Control of Major Accident Hazards (COMAH) Regulations 1999 2. Planning (Control of Major Accident Hazards) Regulations 1999 [2000 in Scotland]	Authorisation is required for storage of listed hazardous substances. Requires operators to implement certain management practices and report to the competent authorities.	1. EA & Local Authorities, England and Wales 2. SEPA & Local Authorities, Scotland
EC Directive (80/68/EEC) old Groundwater Directive (in force till Dec 2013); and (2006/118/EC) Groundwater	The Environmental Permitting Regulations in England & Wales The Water Environment (Controlled Activities) (Scotland) Regulations 2011	Systems of permits and registrations to control inputs of pollutants to the water environment	1. EA, England and Wales 2. SEPA, Scotland

EC legislation	Associated UK legislation	Main requirements	Regulator, applies in
Daughter Directive and; EC Directives 2006/118/EC and 2008/105/EC			
Water Framework Directive	The Environmental Permitting Regulations The Water Environment (Controlled Activities) (Scotland) Regulations 2011	Prevent deterioration and achieve good status for all water bodies, reduce pollution from priority substances in surface waters , reverse significant and sustained upward trends in concentrations of pollutants in groundwater, prevent or limit inputs of pollutants to groundwater.	1. EA, England and Wales 2. SEPA, Scotland
Directive 2004/35/EC on environmental liability with regard to the prevention and remedying of environmental damage	The Environmental Liability (Scotland) Regulations 2009 The Environmental Damage (Prevention and Remediation) Regulations 2009	To introduce a system of reporting and management of significant releases of pollutants to land and the water environment.	SEPA, England and Wales
EC Regulation (259/93): Supervision and control of shipments of waste within, into and out of the European Community	Transfrontier Shipment of Waste Regulations 1994	A licence is required to control the transport and disposal of movement and disposal of hazardous waste	Environment Agency, England SEPA, Scotland
EC Regulation (3093/94): Substances that deplete the ozone layer	Environmental Protection (Controls on Substances that Deplete the Ozone Layer) Regulations 1996 Ozone Depleting Substances (Qualifications) Regulations 2006 SI 1510 Fluorinated Greenhouse Gases Regulations 2008 (S.I No 41)	A licence is required for the production, supply, use, trading and emission of certain 'controlled substances' that deplete the ozone layer.	DEFRA, England, Wales & Scotland
EC Directive 96/61/EC concerning integrated pollution prevention and	The Environmental Permitting Regulations The Pollution Prevention and Control (Scotland) Regulations 2000 (as	Control of emissions from industrial premises through requirement to apply Best Available	1. EA, England and Wales 2. SEPA, Scotland

EC legislation	Associated UK legislation	Main requirements	Regulator, applies in
control	amended)	Technology and Permitting	
Industrial Emissions Directive	To be transposed into Scottish Legislation by 2012.	Brings together previous Directives on IPPC, WID, LCP, SED and TiO2 into single text.	
CCS Directive		Sets out requirements for carbon capture and storage	

Table A1.2 Key UK domestic environmental legislation

UK legislation	Main requirements	Regulator, applies in
Town and Country Planning Act 1990 (England and Wales) as amended by the Planning Act 2008 Town and Country Planning (Scotland) Act 1997 as amended by the Planning etc (Scotland) Act 2006 Planning and Compensation Act 1991 (as amended) ;and Environment Act 995 (as amended).	Planning permission is required for all hydrocarbon developments.	Local authorities / county councils, England, Wales & Scotland
Petroleum Act 1998; and The Petroleum (Production) (Landward Areas) Regulations 1995	A licence is required for exploration, development, production and abandonment of all hydrocarbon fields	DECC, England, Wales & Scotland
Pipelines Act 1962; and Pipe-line Works (Environmental Impact Assessment) Regulations 2000	Requires pipelines over 16 km in length to prepare an Environmental Statement as part of the approval process.	DECC, England, Wales & Scotland
Gas Act, 1986; and Public Gas Transporter Pipe-line Works (Environmental Impact Assessment) Regulations 1999	Requires certain pipeline developments to prepare an Environmental Statement as part of the approval process.	DECC, England, Wales & Scotland
Environmental Protection Act 1990, Part II;	Most wastes may only be disposed of at a facility operated by the holder of a suitable permit.	Environment Agency / SEPA
Environmental Protection Act 1990, Part III	Statutory nuisance (i.e. non-regulated activities), noise, odour, antisocial behaviour, etc	Local authorities
Energy Act 1976; and The Petroleum Act 1998	Consent is required for flaring or venting of hydrocarbon gas. Requires licensees of an onshore field to ensure that petroleum is contained both above and below ground.	DECC, England, Wales & Scotland

UK legislation	Main requirements	Regulator, applies in
Air Quality Regulations 2000; The Air Quality Standards (Scotland) Regulations 2007. Scottish Statutory Instrument No. 182; The air Quality Standards (Scotland) Regulations 2010. Air Quality (Scotland) Regulations 2000. Scottish Statutory Instrument No. 97 The Air Quality (Scotland) Amendment Regulations 2002	Set emission limits for certain substances and requires authorities to take action where quality parameters are exceeded. Provides SEPA with reserve powers to improve AQ by LAs where not being achieved.	Local authorities/SEPA
Control of Pollution Act 1974, Part III; Environmental Protection Act 1990, Part III; and Environment Act 1995, Part V.	Requires local authorities to take action where noise limits are exceeded.	Local authorities, England, Wales and Scotland
Environmental Protection Act 1990, Part I; Environmental Protection (Prescribed Processes and Substances) Regulations 1991	Requirement to license certain potentially polluting processes. Industries must demonstrate environmental management through Best Available Technology Not Entailing Excessive Cost (BATNEEC) for IPC	Environment Agency & Local Authorities, England and Wales SEPA & Local Authorities

Application of this legislation in relation to the currently operating onshore fields is summarised in Table A1.3.

Table A1.3 Application of environmental legislation

Legislation	Application
Town and Country Planning Act 1990 [1997 in Scotland], Planning and Compensation Act 1991, Environment Act 1995	Applies to all hydrocarbon developments.
Town & Country Planning (Environmental Impact Assessment) (England and Wales) Regulations 1999, Environmental Impact Assessment (Scotland) Regulations 1999	New onshore fields, unless on the production scale of Wytch Farm, would only require an Environmental Statement if determined by the Local Authority as having potentially significant environmental effect.
Pipelines Act 1962; and Pipe-line Works (Environmental Impact Assessment) Regulations 2000	Construction of pipelines over 16 km in length would require an Environmental Statement.
Gas Act, 1986; and Public Gas Transporter Pipe-line Works (Environmental Impact Assessment) Regulations 1999	Construction of pipelines over 40 km in length or 800mm diameter would require an Environmental Statement.
EC Directive (96/82/EC): Control of major accident hazards; and a) Planning (Control of Major Accident Hazards) Regulations 1999 (2000 in Scotland) b) Control of Major Accident Hazards (COMAH) Regulations 1999	Conventional onshore fields are unlikely to store hydrocarbon products in sufficiently large volumes so as to warrant control under these Regulations.
EC Directive (80/68/EEC): Protection of	Activities (including re-injection of produced

Legislation	Application
groundwater against pollution EC Directive (99/31/EC) on the landfill of waste Directive 2000/60/EC The Water Framework Directive Directive 2006/118/EC Protection of groundwater against pollution The Water Environment and Water Services (Scotland) Act 2003 Transposes Directive 2000/60/EC Directive 2008/105/EC Environmental Standards The Water Environment (Controlled Activities) (Scotland) Regulations 2011 Provides regulatory framework for activities likely to cause adverse effects to the water environment The Water Environment (Groundwater and Priority Substances) (Scotland) 2009 Regulations Introduce the regulatory requirements of Directives 2006/118/EC and 2008/105/EC Directive 2004/35/EC Environmental Liability Directive The Environmental Liability (Scotland) Regulations 2009 transpose the requirements of Directive 2004/35/EC	water) at the following onshore fields are permitted under the Environmental Protection Regulations. These Regulations also cover the requirements for protecting groundwater. Wytch Farm Whisby Welton Singleton Palmers Wood Humbly Grove Horndean Periodic reviews of permits for these activities are required to check whether permit conditions continue to reflect appropriate standards and remain adequate in light of experience and new knowledge.
EC Regulation (259/93): Supervision and control of shipments of waste within, into and out of the European Community; and Transfrontier Shipment of Waste Regulations 1994	It is unlikely that any onshore field would require to ship waste outside the UK.
Environmental Protection Act 1990, Part I; Environmental Protection (Prescribed Processes and Substances) Regulations 1991; and Pollution Prevention and Control Act 1999 and Pollution Prevention and Control Regulations 2000 The Pollution Prevention and Control (Scotland) Regulations 2000 (as amended)	Onshore fields will require an IPPC licence under the new legislation, depending upon the activities undertaken at the site. In Scotland would require a PPC licence under Scottish regulations
Emissions Trading System Directive 2009/29/EC (Phase III) The Greenhouse Gas Emissions Trading Scheme Regulations 2005 (S.I. 2005/925) (as amended)	DECC/SEPA/EA
Petroleum Act 1998; Energy Act 1976; and The Petroleum (Production) (Landward Areas) Regulations 1995	All onshore hydrocarbon fields will require a licence for development, production, venting and flaring of gas, and abandonment.

Appendix 2: Emissions from onshore oil exploration and production, 2010

Table A2.1 Emissions from onshore oil exploration and production reported to Environment Agency Pollution Inventory, 2010

SUBSTANCENAME	AUTHORISATIONID	AUTHORIS	OPERATORNAME	SITEADDRESS	SITEPOSTCODE	YEAR	Emission
Methane	VP3931LC	IPPC	STAR ENERGY (EAST MIDLANDS) LTD	Cold Hanworth Oil Well The Moors,Wetmore Lane Cold Hanworth Lincoln Lincolnshire	LN2 3RH	2010	8800
Methane	BP3839XA	IPPC	Star Energy Weald Basin Ltd	Horndean B Well SIte Sheepwash Road Horndean Hampshire	PO8 0DS	2010	90039
Methane	CP3039MV	IPPC	BP Exploration Operating Co Ltd	Wytch Farm Wytch Corfe Castle WAREHAM Dorset	BH20 5JR	2010	384940
Methane	FP3039MR	IPPC	BP Exploration Operating Company Limited	BP WYTCH FARM KIMMERIDGE WELLSITE KIMMERIDGE WAREHAM Dorset	BH20 5PF	2010	286400
Methane	VP3231LJ	IPPC	Star Energy (East Midlands) ltd	Scampton North Oilfield Welton Cliff Welton Lincolnshire	LN2 3PU	2010	84420
Methane	PP3437LK	IPPC	P R Singleton Ltd	Singleton Well Site Singleton Forest Off A286 between Cock'g and Singleton Near Chichester West Sussex	PO18 0HL	2010	39570
Methane	WP3931LZ	IPPC	Star Energy (East Midlands) ltd	Stainton Oil Well Stainton-by-Langworth Stainton Lincoln Lincolnshire	LN3 5BE	2010	14310
Methane	WP3531LU	IPPC	Star Energy (East Midlands) ltd	Welton Gathering Centre Barfield Lane,Off Wragby Road Sudbrook Lincoln Lincolnshire	LN2 2QU	2010	1317000

Appendix 3: US EPA GHG reporting protocol technical guidance for unconventional gas

The information below is a transcript of the relevant section of the US EPA's latest guidance to oil and gas operators, providing emission estimation methods and emission factors, including for unconventional gas exploration and production.

Source: Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry: Background Technical Support Document (US EPA 2011h, pp. 81-82).

►Estimate the Emission Factor for Unconventional Well Completions

The emission factor for unconventional well completions was derived using several experiences presented at Natural Gas STAR technology transfer workshops.

One presentation reported that the emissions from all unconventional well completions were approximately 45 bcf using 2002 data. The emission rate per completion can be back-calculated using 2002 activity data. API Basic Petroleum Handbook[14] lists that there were 25,520 wells completed in 2002. Assuming Illinois, Indiana, Kansas, Kentucky, Michigan, Missouri, Nebraska, New York, Ohio, Pennsylvania, Virginia, and West Virginia produced from low-pressure wells that year, 17,769 of those wells can be attributed to onshore, non-low-pressure formations. The Handbook also estimated that 73% (or 12,971 of the 17,769 drilled wells) were gas wells, but are still from regions that are not entirely low-pressure formations. The analysis assumed that 60% of those wells are high pressure, tight formations (and 40% were low-pressure wells). Therefore, by applying the inventory emission factor for low-pressure well cleanups (49,570 scf/well-year[11]) approximately 5,188 low-pressure wells emitted 0.3 bcf.

40% × 12,971 wells × 49,570 scf/well × (1 Bcf / 10^9 scf) ≈ 0.3 bcf

The remaining high pressure, tight-formation wells emitted 45 bcf less the low-pressure 0.3 bcf, which equals 44.7 bcf. Since there is great variability in the natural gas sector and the resulting emission rates have high uncertainty; the emission rate per unconventional (high-pressure tight formation) wells were rounded to the nearest thousand Mcf.

(44.7 Bcf / 60% × 12,971 wells) × (106 Mcf / 1 bcf) ≈ 6,000 Mcf/completion

The same Natural Gas STAR presentation12 provides a Partner experience which shares its recovered volume of methane per well. This analysis assumes that the Partner recovers 90% of the flowback. Again, because of the high variability and uncertainty associated with different completion flowbacks in the gas industry, this was estimated only to the nearest thousand Mcf – 10,000 Mcf/completion.

A vendor/service provider of 'reduced emission completions' shared its experience later in that same presentation12 for the total recovered volume of gas for 3 completions. Assuming that 90% of the gas was recovered, the total otherwise-emitted gas was back-calculated. Again, because of the high variability and uncertainty associated with different completion flowbacks in the gas industry, this was rounded to the nearest hundred Mcf – 700 Mcf/completion.

The final Natural Gas STAR presentation15 with adequate data to determine an average emission rate also presented the total flowback and total completions and re-completions. Because of the high variability and uncertainty associated with different completion flowbacks in the gas industry, this was rounded to the nearest 10,000 Mcf – 20,000 Mcf/completion.

This analysis takes the simple average of these completion flowbacks for the unconventional well completion emission factor: 9,175 Mcf/completion.

►Estimate the Emission Factor for Unconventional Well Workovers (‘re-completions’)

The emission factor for unconventional well workovers involving hydraulic re-fracture (‘re-completions’) was assumed to be the same as unconventional well completions; calculated in the previous section.’

Appendix 4: DECC technical guidance for offshore operators, EEMS (2008)

The information below is an extract of the relevant section of DECC's 2008 guidance to **offshore** oil and gas operators, providing conversion factors and equations to deliver mass emissions data at standard conditions.

Source: EEMS-Atmospheric Emissions Calculations (DECC and Oil & Gas UK 2008, pp. 16-19)

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5 STANDARD CONDITIONS

Mass is the preferred physical quantity for reporting gas emissions because of its independence of temperature and pressure. All gas amounts reported to EEMS are masses, usually in tonnes (t). However, most gas measurements made in the field are volumes at non-standard temperatures and pressures.

Commonly used in the oil and gas industry are the API standard conditions, which differ from the European definition of 'standard'.

The following guidelines should be used when converting nonstandard volumes to reported masses.

5.1 Definition

Standard conditions are defined in SI units of measure (uom) as

$P_{std} = 101.325 \times 10^3$ Pa 5.1

$T_{std} = 273.15 + 15 = 288.15$ K 5.2

Alternatively, in non-SI uom:

P_{std} = 1 Atmosphere (atmos) 5.1a

T_{std} = 15 degrees Celsius (C) 5.2a

If volumes are measured under non-standard conditions they are converted to standard conditions using Boyle's Gas Law based on the Ideal Gas Law

$V_{std} = (P_{obs} \times V_{obs} / T_{obs}) \times T_{std} / P_{std}$

$= (P_{obs} \times V_{obs} / T_{obs}) \text{ x } 288.15/101.325 \times 10^3$ 5.3

Where

P_{obs} is the observed pressure (Pa)

V_{obs} is the observed volume (m^3)

T_{obs} is the observed temperature (K)

P_{std} is the standard pressure (Pa)

V_{std} is the standard volume (sm^3 (15C))

T_{std} is the standard temperature (K)

If only the temperature is non-standard, i.e. the volume is measured at standard or atmospheric pressure.

$V_{std} = V_{obs} / T_{obs} \times 288.15$ 5.3a

5.2 API Standard Conditions

Standard conditions used in the oil and gas industry are the API standards, widely used in commerce in the U.S - 14.7 psia and 60°F. This is equivalent to 379.3 standard cubic feet (scf)/lb-mole or 23,685 cm^3/g-mole. Equation 5.3 a becomes:

$V_{std} = V_{obs} / T_{obs} \times 288.71$ 5.3b

In the oil and gas industry, standard m^3 or sm^3 may refer to conditions at 60 deg F (15.555 deg C) but 15 deg C may also be used, particularly in Europe. Hence there is a need to precisely define conditions.

5.3 Standard Molar Volume

Using the Ideal Gas Law (Equation 4.1), 1 mole of molecules of an ideal gas at standard conditions has a standard molar volume

$V_{mol} = V_{std} / n$ 5.4

$= R \times T_{std} / P_{std}$

$= 8.314\,510 \times 288.15 / 101.325 \times 10^3$

$= 23.644\,96 \times 10^{-3} \pm 0.000\,000\,20\ m^3\ mol^{-1}$

5.4 Standard Densities

The molecular weight of a molecule is equivalent to the mass in grammes (g) of 1 mole (mol). Using the standard molar volume of an ideal gas (Equation 5.4) and the molecular weight (Appendix C) standard densities can be calculated

$\rho_{std} = MWT / V_{mol}\ g\ m^{-3}$ 5.5

$= MWT / 23.644\,96\ kg\ m^{-3}$

This approach can also be used to calculate the standard density of a gaseous mix using the average molecular weight.

$\rho_{std} = MWT_{ave} / V_{mol}\ g\ m^{-3}$ 5.5a

$= MWT_{ave} / 23.644\,96\ kg\ m^{-3}$

5.5 Converting Non-Standard Volume to Mass

To convert a non-standard volume of an ideal gas to a mass

$m = \rho_{std} \times V_{std}$ 5.6

Where

m is the gas mass (kg)

ρ_{std} is the ideal gas density at standard conditions – see Appendix D ($kg\ m^{-3}$)

Substituting from Equation 5.3

$= \rho_{std} \times (P_{obs} \times V_{obs} / T_{obs}) \times T_{std} / P_{std}$ 5.7

$= \rho_{std} \times (P_{obs} \times V_{obs} / T_{obs}) \times 288.15/101.325 \times 10^3$

If $P_{obs} = P_{std}$ then

$= \rho_{std} \times V_{obs} / T_{obs} \times 288.15$ 5.8

For example:

50 m^3 of H_2S at 20 C = 293.15 K and 1.1 bar = 111.457 5 $\times$ 10^3 Pa has a mass of 77.925 kg.

This approach can also be used to convert the non-standard volume of a gas mix to a mass using the standard density of the mix (Equation 5.5a) which in turn uses the average molecular weight of the mix (see Section 6). If volumes are in units of measure other than m^3 the appropriate conversion constant must be used (Appendix A).

5.6 Normal Conditions

A common alternative to standard conditions is normal conditions:

$P_{nor} = 101.325 \times 10^3$ Pa 5.9

$T_{nor} = 273.15$ K 5.10

Alternatively, in non-SI uom:

P_{nor} = 1 Atmosphere (bar) 5.9a

T_{nor} = 0 degrees Celsius (C) 5.10a

Using the same approach for standard conditions outlined above.

Normal molar volume:

$V_{mol} = 22.414\ 97 \times 10^{-3} \pm 0.000\ 000\ 20\ m^3\ mol^{-1}$ 5.11

Normal density:

$\rho_{nor} = MWT / 22.414\ 97\ kg\ m^{-3}$ 5.12

Normal volumes (m^3) can be converted to masses (kg) using the normal density. If volumes are in units of measure other than m^3 the appropriate conversion constant must be used (Appendix A).

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