Project Acronym and Title:

M4ShaleGas - Measuring, monitoring, mitigating and managing the environmental impact of shale gas

REVIEW OF GAS EMISSIONS TO AIR RELATED TO SHALE GAS OPERATIONS

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Public introduction

M4ShaleGas stands for *Measuring, monitoring, mitigating and managing the environmental impact of shale gas* and is funded by the *European Union's Horizon 2020 Research and Innovation Programme*. The main goal of the M4ShaleGas project is to study and evaluate potential risks and impacts of shale gas exploration and exploitation. The focus lies on four main areas of potential impact: the subsurface, the surface, the atmosphere, and social impacts.

The European Commission's Energy Roadmap 2050 identifies gas as a critical fuel for the transformation of the energy system in the direction of lower CO_2 emissions and more renewable energy. Shale gas may contribute to this transformation.

Shale gas is – by definition – a natural gas found trapped in shale, a fine grained sedimentary rock composed of mud. There are several concerns related to shale gas exploration and production, many of them being associated with hydraulic fracturing operations that are performed to stimulate gas flow in the shales. Potential risks and concerns include for example the fate of chemical compounds in the used hydraulic fracturing and drilling fluids and their potential impact on shallow ground water. The fracturing process may also induce small magnitude earthquakes. There is also an ongoing debate on greenhouse gas emissions of shale gas (CO_2 and methane) and its energy efficiency compared to other energy sources

There is a strong need for a better European knowledge base on shale gas operations and their environmental impacts particularly, if shale gas shall play a role in Europe's energy mix in the coming decennia. M4ShaleGas' main goal is to build such a knowledge base, including an inventory of best practices that minimise risks and impacts of shale gas exploration and production in Europe, as well as best practices for public engagement.

The M4ShaleGas project is carried out by 18 European research institutions and is coordinated by TNO-Netherlands Organization for Applied Scientific Research.

Executive Report Summary

Environmental impact associated with large scale shale gas development is of major concern to the public, policy makers and other stakeholders. The major knowledge on the effects and consequences of shale gas exploration and exploitation comes, mostly, from shale gas practices in the United States. It is important to address differences in geological settings and societal environment between European countries and the US and the impact of these differences for the potential future development of shale gas in Europe. It is also important to evaluate whether or not the existing EU Directives and regulations appropriately apply to unconventional hydrocarbon extraction. This report aims at assessing the impact of gas emissions related to shale gas exploration and exploitation in North America and Europe and comparing emissions from shale gas with those of conventional fuel exploitation. The different sources and types of emissions (e.g., CH_4, NMVOC, NO_x, SO_x, PM, benzene, HPA, O_3) associated with the various phases of shale gas production were identified and reviewed. Other air pollutants were also assessed, but the information available was much lesser. The main concern, present in the many studies consulted is the GHG emissions. However we consider that, more attention should be given to the other types of emissions. The evaluation of the different pollutants balance of shale gas takes into account all air emissions related to the (1) pre-production, (2) production, transportation, distribution and end-use of shale gas, (4) end of exploration and well closure. The most significant sources of emissions of GHG and other air pollutants during the pre-production phase are well completion and gas treatment but also emissions from combustion sources (particulate matter, nitrogen oxides and hazardous air pollutants, and CO_2). The main emissions during production phase derive from the use of conventional equipment (e.g. dehydration equipment, pumps and compressors) and leakage from gas distribution pipes. Regarding the end of exploration and closure phases, the main risk is leakage to the surface of hydrocarbon and other fluids from the well, or their migration between different formations. Some potential emission reduction techniques are also discussed and knowledge gaps are identified e.g. well and borehole integrity.

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1 INTRODUCTION

1.1 Context of M4ShaleGas

Shale gas source rocks are widely distributed around the world and many countries have now started to investigate their shale gas potential. Some argue that shale gas has already proved to be a game changer in the U.S. energy market (EIA 2015[1]). The European Commission's Energy Roadmap 2050 identifies gas as a critical energy source for the transformation of the energy system to a system with lower CO_2 emissions that combines gas with increasing contributions of renewable energy and increasing energy efficiency. It may be argued that in Europe, natural gas replacing coal and oil will contribute to emissions reduction on the short and medium terms.

There are, however, several concerns related to shale gas exploration and production, many of them being associated with the process of hydraulic fracturing. There is also a debate on the greenhouse gas emissions of shale gas (CO_2 and methane) and its energy return on investment compared to other energy sources. Questions are raised about the specific environmental footprint of shale gas in Europe as a whole as well as in individual Member States. Shale gas basins are unevenly distributed among the European Member States and are not restricted within national borders, which makes close cooperation between the involved Member States essential. There is relatively little knowledge on the footprint in regions with a variety of geological and geopolitical settings as are present in Europe. Concerns and risks are clustered in the following four areas: subsurface, surface, atmosphere and society. As the European continent is densely populated, it is most certainly of vital importance to understand public perceptions of shale gas and for European publics to be fully engaged in the debate about its potential development.

Accordingly, Europe has a strong need for a comprehensive knowledge base on potential environmental, societal and economic consequences of shale gas exploration and exploitation. Knowledge needs to be science-based, needs to be developed by research institutes with a strong track record in shale gas studies, and needs to cover the different attitudes and approaches to shale gas exploration and exploitation in Europe. The M4ShaleGas project is seeking to provide such a scientific knowledge base, integrating the scientific outcome of 18 research institutes across Europe. It addresses the issues raised in the Horizon 2020 call LCE 16 – 2014 on *Understanding, preventing and mitigating the potential environmental risks and impacts of shale gas exploration and exploitation.*

[1] EIA (2015). Annual Energy Outlook 2015 with projections to 2040. U.S. Energy Information Administration (*www.eia.gov*).

1.2 Study objectives for this report

In this report, different sources and types of emissions (e.g., methane, non-methane volatile organic compounds, nitrogen oxides, particulate matter, benzene) were identified and reviewed. The pre-production and production emissions were assessed. Pre-production related emissions to air include: emissions from roads and well-pad construction and from diesel engines and compressors used during drilling. The evaluation of the greenhouse gas (GHG) balance of shale gas take into account all GHG air emissions related to the production, transportation and end-use of shale gas. Based on the on-going work in USA and Canada, possible emission reduction techniques are discussed.

1.3 Aims of this report

This report aims at assessing the impact of gas emissions related to shale gas exploration and exploitation in Europe. It presents a review of the different sources and types of emissions associated with the different phases of shale gas production.

The overall objective of this report is to give an overview on the current technical-scientific knowledge base of the possible contribution of shale gas production to gaseous emissions. Furthermore, shale gas related emissions are compared with those of other energy sources.

1.4 Structure of the report

This report is divided in eight chapters. The first one is an introductory chapter where the objectives of the M4ShaleGas and of this report are presented. The comparison of shale gas with conventional fuels is addressed in Chapter 2. Chapter 3 reports the emission types and their different sources. Chapter 4 describes the existing legislation for controlling GHG emissions from shale gas operations. The best available techniques for reducing GHG emissions are summarised in Chapter 5. The experience of other countries, especially USA, Canada, UK and Poland is discussed in Chapter 6, with the presentation of the best practices available in these countries. The knowledge gaps on shale gas existing technologies, the needs for further studies and the main conclusions are summarised in Chapter 7, References are listed in Chapter 8.

2 COMPARISON WITH CONVENTIONAL FUELS

2.1 Introduction

All of the oil and gas we use today began as microscopic plants and animals living in the ocean millions of years ago. As these microscopic plants and animals lived, they absorbed energy from the sun, which was stored as carbon molecules in their bodies. When they died, they sank to the bottom and over millions of years, layer after layer of sediment and other plants and bacteria formed layers of an organic polymer called kerogen. This material is by far the most abundant organic material in the Earth's crust. Sand, clay and other minerals were buried with the kerogen during geological time and eventually were turned into sedimentary rocks. Rocks which have abundant kerogen are called oil shales or black shales.

With ever deeper burial, heat and pressure began to rise. The amount of pressure and the degree of heat, along with the type of kerogen, determined if the material became oil or natural gas. More heat produced lighter oil. Even higher heat or kerogens made predominantly from plants, produced natural gas.

After oil and natural gas were formed, they tended to migrate through pores in the surrounding rock. The rocks also moved and folded over millions of years, as tectonic plates shifted. Some oil and natural gas migrated all the way to the surface and escaped. Other oil and natural gas deposits migrated until they were caught under or against a layer of rock that it couldn't move through. It was trapped and sealed against this impermeable rock, and slowly, very slowly, the oil and gas built up. As it did, reservoirs were formed. These trapped deposits are where we find oil and natural gas today. Most oil and gas fields are found in sedimentary rocks such as sandstone and limestone because they have the rock porosity and rock permeability for oil and gas to move through and accumulate. The porosity determines the capacity of the reservoir and the permeability determines the productivity of the reservoir.

Shale oil and gas, unlike conventional hydrocarbons, are produced directly from the source shale rock. This shale rock acts as the hydrocarbon source rock, reservoir and seal

It is typically found at greater depths than conventional oil and gas. As the shale is much less permeable, it requires more effort to extract the hydrocarbons from the rock.

Natural oil and gas is extracted from different geological resource plays:

- Those trapped in structures in the rock that are caused by folding and/or faulting of sedimentary layers, as explained above. These hydrocarbons can be relatively easily recovered and have been extracted for more than 100 years. North Sea gas is an example. These resource plays are often termed conventional hydrocarbons.

- Those trapped in impermeable rock that cannot migrate to a trap and form a conventional deposit. These types of resource plays are often termed unconventional hydrocarbons, for example shale oil, shale gas and coal bed methane.

By contrast, unconventional resources are trapped in reservoirs with low permeability, meaning little to no ability for the oil or natural gas to flow through the rock and into a wellbore. In order to produce from unconventional reservoirs, industry uses a stimulation technique like hydraulic fracturing to create cracks in the underground rock that allow the oil or natural gas to flow. Of course this is more time-consuming and costly than producing from a reservoir that requires no stimulation beyond a pumpjack or wellhead compressor. The key outward difference is flow rate. Drilling into a conventional accumulation would normally result in at least some flow of oil and gas immediately. An unconventional accumulation has to be stimulated in some way before it will even begin to flow. For example, shale has very low permeability so must be stimulated before oil or gas can flow from it.

Hydraulic fracturing is simply a method used to stimulate the oil or gas either to begin or continue flowing. A conventional well can also be hydraulically fractured to help extraction by improving flow rates. This does not mean it has become an unconventional well as the nature of the hydrocarbon accumulation has not changed.

2.2 Conventional Gas versus Unconventional Gas

Conventional gas and oil flow naturally through rocks, which is easy to collect. Conventional gas is "… gas that is trapped in structures in the rock...caused by folding and/or faulting of sedimentary layers." Conventional gas comes from an organic rock that has compressed marine or terrestrial organic debris. This debris is heated by the pressure put on it, which creates hydrocarbons. The hydrocarbons move to the pores in permeable rocks seeking lower levels of pressure, and thereby become available for extraction. The gas moving toward the well is referred to as a "natural flow". Conventional gas is considered a "natural gas" because of how easy it is to be pumped to the surface.

Unlike conventional gas, unconventional gas is not as easy to extract. Unconventional gas is the gas that is trapped inside the impermeable rock that does not migrate out. This gas is impossible to obtain using normal methods due to the low permeability of the rock where there are poorly connected pores. To retrieve the gas, one must drill horizontally into the well, stimulating the pores to connect and allowing the gas to flow into a well bore - a hole to aid the recovery of natural resources. Unconventional gas comes in three forms: shale gas, tight gas, and coal seam gas. The most common is shale gas, which is gas that is trapped in a source rock such as a fine-grained rock or an organic-rich rock. Tight gas is found in sandstones and limestone. Coal seam gas is methane gas found in coal seams that are being held by water pressure. Coal seam gas is usually closer to the surface than the other two unconventional gasses. In order to extract coal seam gas, you must first remove the water applying pressure to the gas.

2.3 Shale gas GHG balance and comparison with other fossil sources

A study taken by AEA Technology for the European Commission concluded that the lifecycle CO_2 emissions for shale gas could be 2-10% lower than emissions from electricity generated from conventional pipeline gas located outside of Europe and 7-10% lower than that of electricity generated from Liquefied Natural Gas (LNG) imported into Europe. A highly regulated UK onshore industry can ensure that shale gas extraction has the potential to have lower emissions than imported natural gas located outside of Europe. The Committee on Climate Change concluded in April 2013 that shale gas "could have lower emissions than imported LNG if regulatory arrangements are in place to manage methane released during its production."

MacKay & Stone (2013) analysed local GHG emissions due to shale gas exploration and production and compared these emissions with those obtained by conventional gas, Liquefied Natural Gas (LNG), and coal utilisation. This study focused on carbon dioxide (CO_2) and methane (CH_4) emissions, because CH_4 contribution to green house emissions is around 25 times greater than that of CO_2.

Shale gas extraction and use usually lead to a carbon footprint of around 200 – 253 g CO_2e per kWh of chemical energy. CO_2e means carbon dioxide equivalent and include CO_2, CH_4 and N_2O, weighted according to their global warming potentials. This range of emissions is only slightly higher than carbon footprint due to gas extraction by conventional sources, which is likely to be in the range 199 – 207 g CO_2e/kWh(th), MacKay & Stone (2013). However, shale gas carbon footprint is lower that the values associated with Liquefied Natural Gas, which are normally between 233 and 270g CO_2e/kWh(th). Carbon footprint of shale gas use for electricity generation is estimated to be between 423 and 535 g CO_2e/kWh(e). This value is lower than the carbon footprint due to coal utilisation, which is expected to be in the range 837 – 1130 g CO_2e/kWh(e).

MacKay & Stone (2013) stated that GHG emissions from shale gas exploration and production are only a small percentage of the total carbon footprint of shale gas, as the main emissions are due to shale gas combustion, as it happens to other fossil fuels utilisation, due to the formation of CO_2 by oxidation reactions.

According to MacKay & Stone (2013) local GHG emissions from shale gas exploration and production would have to fall within the non trade sector of the UK's carbon budgets. Thus, if shale gas operation increases GHG emissions, emissions from other sources would have to be reduced accordingly. Thus, it is fundamental to define global climate policies about emissions to prevent the risk of climate change. Otherwise, the exploitation of new fossil fuel like shale gas, may lead to an increase in cumulative carbon emissions.

3 TYPES OF EMISSIONS AND DIFFERENT SOURCES

The GHG and other gaseous emissions from shale gas production has been the subject of a number of studies since 2010 ((Howarth et al. (2011), Skone et al. (2011), Jiang et al.(2011), Burnham et al. (2012), Zammerilli A.(2014), Bunch A. G. (2014), (Robinson A. (2014)). These studies have yielded a large variation in the estimated environment impacts of shale gas, due to differences in methodology and data assumptions. Shale gas production activities can produce significant amounts of air pollution that could have impact on local air quality.

In addition to methane CH_4, carbon dioxide (CO_2) and nitrogen oxides (NO_x) (considered GHG emissions), fugitive emissions from shale gas production can release volatile organic compounds (VOCs) and hazardous air pollutants (HAPs). Also, the GHG are produce by internal combustion engines used for drilling, hydraulic fracturing, and compression.

In the literature, apart from CH_4 and CO_2, the emissions of six air pollutants are often discussed, whose regional ambient air levels are regulated by the Environmental Protection Agency (EPA), which are: ozone, particulate matter (PM), carbon monoxide (CO), nitric oxides (NO_x), sulphur oxides (SO_x), and lead. The emissions of volatile VOCs and hazardous air pollutants (HAPs) are also debated. The VOCs include aromatic hydrocarbons, halogenated compounds, aldehydes, alcohols, and glycols. The HAPs is a term used by US EPA to cover toxic air pollutants that “cause or may cause cancer or other serious health effects, or adverse environmental and ecological effects” (ICF International, 2014). The list of these compounds include: acetaldehyde, acrolein, benzene, ethylbenzene, formaldehyde, n-hexane, hydrogen sulphide, methanol, toluene and xylene. The principal compounds of this list, that are considered relevant in shale gas emissions, are discussed in the literature to be benzene, toluene, ethylbenzene, and xylenes.

The emissions of these air pollutants and of GHG and their sources are discussed below:

- CO_2, SO_x and NO_x are the main emissions during fossil fuel combustion to provide energy to equipment, such as diesel engines used for drilling, hydraulic fracturing and natural gas compression and during flaring operations. SO_x may be form when fossil fuels containing sulphur are burned. They can be emitted from gasoline or diesel powered equipment used at a shale gas production site. However, emissions of SO_x are usually very small for shale gas operation compared to coal or oil. Incomplete combustion can, also, result in other emissions such as carbon dioxide (CO), methane, volatile organic compounds and particulate matter (PM). Moreover, natural gas fired engines can be a significant source of formaldehyde, which is considered a secondary pollutant (U.S. Department of Energy (2009)).

- Ozone (O_3) itself is not released directly, but can be formed by the reaction of nitrogen oxides (NO_x) and VOCs in the presence of sunlight. So, O_3 can be associated with exploration and production operations (Robinson (2014)).
- Besides from combustion particulate matter, may, also appear from dust or soil entering the air during pad construction, due to earth movement, and traffic on access roads (U.S. Department of Energy (2009)).
- CH_4 is the principal component of natural gas, so it is the main worry of vented (for example release of gases during flow back) and fugitive emissions. Even though the processing of natural gas is essentially restricted from the well to consumption, CH_4 may be released as a fugitive emission from gas processing equipment (such as pneumatic controls, valves, well heads and others) or it may escape into ground water due to fracking activities.
- Besides being formed during the incomplete combustion, VOCs can also be emitted during the dehydration step of natural gas U.S. Department of Energy (2009)). It is also associated with fugitive emissions and flaring from shale gas extraction, but in small concentrations (Zammerilli (2014), Bunch (2014)).
- Hazardous air pollutants (HAPs) The principal compounds of the list of HAPs, relevant in shale gas emissions, are proposed in the literature to be benzene, toluene, ethylbenzene and xylenes. These are associated with fugitive emissions, but, as they were not detected in significant amounts in the gas stream, their presence in general emissions is considered to be small. Their presence can also occur in the dehydratation of the gas before entering the distribution line (AEA (2012)). The H_2S is associated with the flow back of fracturing fluids and produced water during well completion. It is also one of the components of the shale gas, but in small amounts. The gas treatments applied to the gas can reduce the presence of this pollutant (AEA (2012)).

The majority of studies (Jiang et al. (2011), Stephenson et al. (2011), Cathles et al. (2012), AEA (2012), Jenner (2013), Zammerilli (2014), Bunch (2014)) suggest that emissions from shale gas are lower than coal, but higher than conventional gas. However, some studies, which have received a lot of media attention, have concluded that the lifecycle of GHG emissions from shale gas may be larger than those from conventional natural gas, oil, or coal when used to generate heat and viewed over the time scale of 20 years (Howarth et al. (2011). This study was highly disputed by Cathles et al. (2012) who present a substantially lower value for the estimation of methane emissions. The emission values presented require an extensive study to understand the energy and carbon emission of different sources required for production including sub-surface manipulation, product clean-up and separation and other activities requiring a careful analysis, which will themselves, depend on the specific extraction and processing systems devised.

The potential climate impact of shale gas, and how it can be compared to other conventional fuels, can only be understood by analysing all the emissions data associated with the life cycle of shale gas (i.e. from exploration to end-use). However, this data are not always accessible and the existing one has a highly degree of uncertainty. Also, the main studies assess only the GHG emissions.

In this chapter is analysed the emissions to air of the different stages of shale gas production. It is divided into three stages: (1) Emissions from Pre-production Stage, (2) Emissions from Production Stage, transport, distribution and storage, (3) Emissions in the end of production and closure.

3.1 Pre-production Stage

The assessment of the emissions from pre-production stage aims to conduct a research to try to answer a number of uncertainties regarding the level of emissions associated, especially with the well completion stage. The preproduction stage includes exploration, site clearing, and road construction to drilling, hydraulic fracturing, well completion and waste treatment. The GHG emissions from pre-production stage include: emissions from roads and well-pad construction; from diesel engines and compressors used during drilling. However these emissions are mainly due to combustion operations. Other pollutants are also present; especially the ones associated with flow back and combustion sources, but were not so studied in extensively like GHG.

In a report presented by Forster and Perks (2012) is stated that the most significant source of GHG emissions, in this stage are the well completion and gas treatment, which account for 39% and 27% of pre-combustion emissions respectively. However, these authors indicate that if flaring of flow back gases or green completion take place, the importance of the well completion stage decreases significantly, only accounting for between 7% and 14% of pre-combustion emissions. Regarding the emission of other air pollutants, (PM, CO, SO_x, VOCs, HAPs) their presence is associated mainly to combustion sources and fugitive emissions.

3.1.1 Site preparation

This stage of operations includes the identification of a suitable site for locating a well pad as well as steps taken to prepare a site for drilling. This step comprises the vegetation removal, building of access roads and the well pad, drilling rig mobilization and demobilization.

The site preparation involves cleaning, levelling, and digging at a well site to install the well pad, freshwater pits, and associated access roads. The emissions from these sources can be from:

- Combustion sources, which include: general construction equipment (bull dozers, graders, loaders, dump trucks, and clearing equipment) powered by diesel engines;
- Mobile road sources, which include: trucks used to deliver equipment to the site;
- Non-combustion sources like fugitive dust/particulate emissions from earth moving and road traffic.

The potential air impacts associated with construction site preparation should include:

- Emissions from combustion sources - contain particulate matter, sulphur oxides and hazardous air pollutants;
- Emissions from earth moving and suspension - particulate emissions;
- Greenhouse gas emissions -carbon dioxide and nitrous oxide emissions.

These emissions were found to be negligible in the literature. For instance, Jiang et al. (2011) and Santoro et al. (2011) presented values for the emissions from site preparation, concluding that these emissions are negligible.

However, the emissions from combustion sources (from diesel engines) are major sources of fine particulate matter and also contain ozone-forming nitrogen oxides and toxic air pollutants, such as NO_x and NMVOCs. Also, particulate emissions are generated when disturbing soil and handling aggregates used in well pad or road construction. Little information is available regarding overall exposures and environmental or human health effects of combustion or dust emissions specifically from well pad site preparation. The probability of combustion emissions are considered high since they will occur routinely from site preparation activities. However, the relatively limited scope and duration of site preparation activities reduces overall human health and environmental consequences to minor levels. For a single well, preproduction is usually completed within a few weeks; but these operations may be carried out for a much higher number of wells on a pad and at multiple sites in the field, normally lasting for months. Also, several pollutants with environmental and human health impacts have been related to this stage.

Truck traffic also generates particulate matter, emitted from tire wear, brake wear, and suspended road dust. However, a study from Litovitz et al.(2013) performed in Pennsylvania, states that the emissions from transportation related to oil and gas operation, were small compared to other emissions from natural gas activities, contributing only to 0.5 to 1.2% of VOCs, about 3.5% of NO_x, and 2.1 to 3.5% of fine particulate matter emitted from natural gas activities.

The emission estimation is very difficult because it depends on the characteristics and dimension of the site. There are many uncertainties related to the representativeness of results from one site to another and also to calculation methodologies uncertainties. For instance the site specific characteristics have an important influence on the overall results. The studies found in the literature present very different values for this kind of emissions. For example the values determined by Jiang et al. (2011) were almost the double of those calculated by Santoro et al. (2011). This difference can be justified by different calculation methodology. The main GHG emissions from this sub-stage are carbon dioxide from energy use, with a small amount of methane and nitrous oxide emissions from combustion.

3.1.2 Drilling and casing

The emissions on this stage come from the energy used in the drilling of the well bore, and in the pumping of water and other material during hydraulic fracturing.

The extraction of shale gas requires both vertical drilling and horizontal drilling. The vertical drilling process is very similar to drilling for conventional fossil fuels. However the shale reserves are often at depths of approximately 2 km, which is deeper than conventional reserves (MacKay and Stone (2013)). Drilling is performed in stages with a narrower section which has a bigger diameter to allow the additional casing to protect the groundwater. After the well has been lined, accurately positioned holes are made in the horizontal section to allow hydraulic fracturing. Typically compressed air or freshwater mud is used as the drilling fluid. The depth of drilling will depend on the geology. Once the well is drilled it is cased to seal it from the surrounding rock. Energy for the drilling operation and all ancillary support activities is normally provided by, diesel-fired internal combustion engines. Sometimes the drilling rig can be powered by the local electric grid instead of diesel engines. The drilling rig engines can be a source of pollutants, including CO_2 (AEA (2012)). The quantity of fuel consumed, and the associated emissions, depend on the specific characteristics of the site (e.g. depth and lateral length of the well and number of wells).

Obviously the emissions from energy use in drilling are directly connected to these issues. The geological characteristics have also, to be taken into account, once the drilling effort required is dependent, for instance, from the strength of the shale formation. This step of the process is similar to the conventional and unconventional gas wells, except for horizontal drilling, which is specific for shale gas wells.

There are a few studies that present estimated values for these emissions, but they are very similar (Santoro et al. (2011), Jiang et al. (2011)). The only exception is the study presented by Broderick et al. (2011) when the values obtained are lower than the other estimations, particularly for drilling, but these authors only included horizontal drilling and not vertical. So, the differences can be, in part, justified by methodological differences.

3.1.3 Hydraulic fracturing

The fracturing phase requires significantly more energy to fracture than required to drill the wellbore. Hydraulic fracturing is essential for shale gas production. It involves the high pressure injection of the fracturing fluid into the well. The fluid, approximately 90% water with 1-2% chemical additives (hydrochloric acid for pH control, guar gum as a gelling agent, glutaraldehyde as a bactericide and petroleum based surfactants) and a proppant agent, usually sand, is pumped down the well at high pressure (MacKay and Stone (2013)). The process is typically powered by large, diesel-fired internal combustion engines. These fractures allow the gas present in the formation to flow from the well.

3.1.4 Well completion

Well completion is one of the final steps before production and it involves the recovery of residual liquids and sand, or flow back, from the hydraulic fracturing process. The flow back takes place after the injection phase is completed. During this stage, a proportion (dependent on the geology) of the injected fracturing fluid flows back to the surface, accompanied by large volumes of gas. The flow back can contain dissolved gases such as methane and other components of natural gas. The amount of this gas and how it is handled have been highly discussed. Moreover, for the quantification of the possible emissions produced during this stage, it is necessary to know the duration of the flow back stage, and the rate of gas production during that period (Francis and Paltsev (2012)). For instance, EPA assumes that the flow back period lasts from 3 to 10 days (EPA (2011)), but, in some cases, the flow may continue during the life of the well. After the flow back period, primarily hydrocarbons are produced from the well (MacKay and Stone (2013)).

This gas can have different destinations, can be directly emitted to the atmosphere (vented), flared, or it can be captured to reduce the emissions. Some studies assume that the combustion emissions would be mainly CO_2 (MacKay and Stone (2013)). However, incomplete combustion could result in other emissions. The flow back gas flaring can emit pollutants, such as VOC and hazardous air pollutants. The quantity of SO_2 and hazardous air pollutants increases with heavier hydrocarbon content (Goetz et al. (2015)). Also, the conditions during the flow back are variable, so it may not be a continuous supply of gas enough to self-sustain the flaring. Moreover the exposed flame may pose a fire hazard or other impacts like noise, heat and smoke.

A recent work, presented by Allen (2013), which presents the methane emissions directly measured at 190 natural gas production sites in United States, reported that emissions from well completions have a wide range of values (from 0.01 to 17 Mg), suggesting that the quantity emitted is probably controlled by variable factors such as the completion procedures.

It has been defended by Howarth et al. (2011), that large amounts of gas are directly vented to the atmosphere during flow back, and so, the GHG emissions of shale gas production were much higher than those of conventional gas (Howarth et al.(2011)). However, Cathles et al. (2012) defends that gas venting during flow back is low, once large flows of gas are not possible while fracturing fluids fill the well and that that this situation continues until the well starts to produce. Howard et al. (2012) claims that flow back is, initially, only liquid, but then becomes a two-phase flow of liquid and gas as backpressure inside the fractures declines. This gas cannot be put into production and commercialization until flow back rates are enough (Howard et al. (2012)).

The good practices guidelines for shale gas operations include the minimisation of fugitive emissions, and suggest that operators should plan and implement control mechanisms in order to minimise all emissions, eliminating all unnecessary flaring and venting of gas (MacKay and Stone (2013)). These guidelines were established, in UK, by the department of energy climate change (DECC), industry regulators, and the Onshore Operators Group (MacKay and Stone (2013)).

Also the presence of H_2S is associated with the flow back of fracturing fluids and produced water during well completion, but it can be reduced with a gas treatment process.

3.2 Production, storage, distribution and use

In the production phase, there are two main sources of emissions, conventional equipment (e.g. dehydration equipment, pumps and compressors) and leakage from gas distribution pipes. Though, most of the emissions came from the compressors, there are also significant methane emissions from the dehydration operations (NYSDEC (2011)). Since most of the emissions in this stage arise from equipment also used for conventional gas production, there are not significant differences from shale gas and conventional gas production. Howarth et al. (2011) presented values between 0.3 to 1.9% of the methane produced for the GHG emissions from a well, for both conventional gas and shale gas. These emissions were from venting and leaks during the production stage.

The first emissions can be reduced with the improvement of the technologies applied to the conventional equipment. The reduction of emissions due to leakage from gas distribution pipes will involve improvements in the gas supply infrastructure off-site.

3.2.1 Production

The chemical composition of the shale gas is, typically, methane, heavier hydrocarbons, carbon dioxide and water. However, this composition depends on the geology of the shales. The gas is dehydrated, to remove the water content, usually using glycol dehydrators. The heavier hydrocarbons and the carbon dioxide are removed from the gas and the methane is compressed to be distributed. This process is equal to the production of conventional gas. The emissions associated to this stage are, mainly from the compressors and fugitive emissions. During the dehydration of the gas, other than GHG, it can also, be released VOCs and HPAs.

Large quantities of methane may be released into the atmosphere during the flow back phase of a shale gas well: when the fracturing fluid is returning to the surface, it brings along natural gas that is released from the freshly-fractured shale.

It was common practice in shale gas developments to release the gas produced during flow back into the atmosphere or to flare it. Flaring the gas results in the conversion of methane to carbon dioxide which is also a GHG. Available technologies, so-called Reduced Emission Completions (REC), can capture the emerging gas at the wellhead. RECs are increasingly being applied by shale gas operators for various reasons, one of mainly due the income from selling the captured natural gas.

3.2.2 Transport, distribution and storage

After processing, the gas is frequently transported over large distances, mostly through a pipeline system. This system includes the pipeline, compression stations, import / export stations and metering. The gas is compressed to high pressures (approximately 70 bar) before being transported. It is necessary the presence of intermediate compressor stations along the pipeline to compensate the pressure loss due to the friction between the gas and pipeline wall. Besides the energy consumed in the transport itself, the energy required for maintenance and check-up activities, should also be taken into account.

The distribution and storage stage involves three main activities (Lukey (2014)):

- Transmission;
- Storage;
- Distribution.

Transmission

The transmission refers to the transference of the gas from a processing plant to the delivery points (Branosky et al. (2012)). This operation occurs at pipelines with a large diameter and higher pressure (Branosky et al. (2012)). During this process the main sources of GHG emissions are fugitive emissions resulting from leaks and vented GHG emissions from pipeline or combustion GHG emissions from conventional equipment (engines of compressors). However when the gas has enter the distribution pipelines, there are no differences in the leakage rates, and consequently in the emissions, whether the gas has been provided from conventional or shale gas reserves. Some studies present estimations of these emissions for both sources. Howarth et al. (2011) estimate that the fugitive emissions of methane are between 1.4% and 3.6% of the methane produced over the lifecycle of a well. Another study, estimate that loss would be lower, suggesting that 0.066% of gas is lost to fugitive emissions over 1440 km (which was taken as a typical distance for transmission to a power station in the U.S.) (Stephenson et al, 2011). EPA (2011) proposes that approximately 0.52% of total gas production is lost during this stage. Stephenson et al. (2011) also estimated that about 1.4% of gas would be consumed by compressor stations along the pipeline (assuming a distance of 1440 km). However, further research is required to better understand the GHG emissions associated with this process (Bradbury et al. (2013)).

Storage

The storage of natural gas is short or long term storage in high pressure pipes and tanks, or underground (usually in depleted gas reservoirs or salt domes) (Branosky et al. (2012)). The GHG emissions during this stage result from injection compressors and from leaks in the storage infrastructure.

Distribution

Some authors include in their studies two phases of natural gas transport: transmission and distribution (Howarth et al. (2011), Cathles et al. (2011)). The distribution refers to the transport of natural gas to an end user (commercial or residential) through a local pipeline system. These pipelines are smaller in diameter in comparison to transmission pipelines (Branosky et al. (2012)). Like in transmission phase, the emissions on this stage are due to fugitive emissions resulting from leaks and vented GHG emissions from pipeline or combustion GHG emissions from conventional equipment.

3.2.3 Use

In the use stage are, normally, stated three main processes, combustion and conversion to transport fuel. The most cited one is the combustion for energy production (Skone at al. (2011), Fulton et al. (2011), Jiang et al. (2011)). A study from Burnham et al. (2012) also refers to combustion of natural gas as a transport fuel. Like in the three previous stages, there are no differences between the emissions from shale gas or conventional gas use.

3.3 End of production and closure

The closure of unconventional wells is similar to closure of conventional wells. It consists of sealing the well, subsequently removal of the surface material and restore the production site to its previous condition. These operations are called plugging and abandonment of the well. These activities occur at the end of the productive life of a well or when the exploration has been unsuccessful. The tubing and other downhole equipment may need to be removed from the zones of the well where the plug will be installed to avoid potential leak paths and hence failure. The abandonment will remove the surface and upper part of the well to avoid subsequent disturbance.

The objective of this stage is to assure that the well is sealed and to prevent leakage to the surface of hydrocarbon and other fluids from the well, or their migration between different formations. The appropriate plugging is critical to avoid potential leaks. To seal the surface, aquifer and hydrocarbon production zones of the well cement, is normally used, but other materials can be employed (expanding cement, resins, silicone rubber, clay gels and soft metal alloy). Uncemented casing in critical areas need to be either pulled or perforated, and cement must be placed across or squeezed to these intervals to allow free movement of cement for the seal and ensure effective seals. Multiple plugs may be needed to provide isolation from the surface and avoid the movement of gas, hydrocarbons and / or water between different levels of the well bore. The intervals between plugs have, also, to be filled with a heavy mud or fluid. In addition, for gas wells, a minimum of 15 m of cement must be placed in the top of the wellbore to prevent any release or escape of hydrocarbons or waste water (Broderick et al. (2011)).

In the U.S. the abandonment procedures for onshore gas wells are defined in Federal and State regulations. The state regulations define the abandonment procedures for redundant wells, and include the technical requirements and observation of the plugging procedure by local inspectors (Forster and Perks (2012)).

Measures to plug and abandon wells have to be frequently undertaken, mainly to make the operating site safe for further use and to prevent pollution release to water and land.

3.4 Comparison between GHG emissions from conventional and shale gas production

Natural gas is considered the cleanest burning fossil fuel. The climate impact advantage of conventional natural gas regarding shale gas has been questioned. Results from recent studies indicate that the impact on climate of shale gas is only slightly higher in comparison with conventional natural gas and significantly lower than coal, when currently available best technologies are used. For instance, according to Broderick et al. (2011) the emissions from an exploration and vertical drilling for shale gas is similar to natural gas, but complementary horizontal drilling and hydraulic fracturing is needed.

Regarding natural gas emissions during combustion, some authors claim that if natural gas is burned using common technological means is cleaner than other fossil fuels, emitting lesser pollutants, such as carbon dioxide, into the atmosphere. They also claim that this natural gas resource (conventional or unconventional) could replace other fossil fuels, particularly coal, consequently reducing pollution. However, others authors (Howarth (2014)), suggest that emissions are worse if the entire life cycle (i.e., well to burner) emissions are taken into account, especially due to methane emissions.However, most studies explicitly state large uncertainty in some, or many, of their assumptions, and more research is needed on this topic.

The emissions results of the US and UK studies ((Allen et al. (2013, EPA (2013), Hirst et al. (2013)) as well as the “low” and “base” cases of Stephenson (2011) and the German studies (SRU (2013)) indicate a wide range of life-cycle emissions for electricity from shale gas. The EU studies (Forster and Perks (2012), AEA (2012)) give a more optimistic view, but their low and base cases are comparable to respective findings from Stephenson (2011). The “high” cases given in all studies can be compared only with extreme caution, as they represent very different assumptions on diffuse CH_4 releases. Following Howarth et al. (2011), there are two major issues to be considered when assessing shale gas:

-The “per unit” comparison of GHG emissions from electricity generation based on shale gas and coal reflect the life-cycles, but not the overall balance of the real-world energy system. With increasing use of shale gas for electricity generation in the US, the domestic role of coal was reduced in the last years, leading to reduced domestic CO_2 emissions. Yet, exports of US coal to Europe increased due to favorable energy prices, leading to increased GHG emissions from coal-fired power plants in Europe (Broderick et al. (2011), Allen et al. (2013)). This “leakage” must be considered when evaluating the absolute GHG impacts of shale gas development (SRU (2013)).

- GHG emissions are important when discussing the environmental impacts from shale gas development, but other aspects such as risks of groundwater contamination and induced seismicity as well as local air pollution and noise (mainly due to truck transports) need to be reflected as well.

4 LEGISLATION

4.1 EU issues

It is important to evaluate whether or not the existing EU Directives /regulations apply to unconventional hydrocarbon extraction. In the United States there are ongoing debates on the issue and “shale gas governance remains a patchwork of rules” (Konschnik (2014)) with regulators facing a changing industry operating tens of thousands of wells across 30 states and EPA requiring GHG emissions reporting from oil and gas wells and green completions of natural gas wells to cut NMVOC and methane.

Public concern is growing regarding the environmental impact of the operations of shale gas and relatively to GHG emissions the focus is on the well completion stage given the relative importance.

There are a number of directives designed to prevent or to reduce emissions into the air, water and land and to prevent the generation of waste. These directives are applied in European member states through transposition into national law, the extent of which depends on each Member State.

The overview analysis of the EU legal acts identified as relevant to shale gas has shown that there are very few requirements applicable specifically to GHG emissions from shale gas projects.

4.1.1 EIA (Environmental Impact Assessment) Directives

The EIA Directive (*85/337/EEC on the assessment of the effects of certain public and private projects on the environment codified by 2011/92/EU and amended by the Directive 2014/52/EU)*,the most relevant, sets requirements as to the consideration of climate change effects and air emissions. It requires Member States to ensure that developers supply information, such as a description of estimated air emissions and significant environmental impacts resulting from the project. Furthermore, the Directive provides for competent authorities to give an opinion on the information supplied which, as a minimum, should include a description of the measures envisaged in order to avoid, reduce and if possible, remedy significant adverse side effects.

Despite these requirements, uncertainties remain as to whether Member States would require an EIA for shale gas operations and if so how Member States should implement the EIA, e.g. implementation of the methodology to be used to quantify GHG emission baseline scenarios.

The EIA Directive requires that public and private projects likely to have significant effects on the environment should be subject to an EIA. The main requirement of an EIA is to identify, describe and assess the direct and indirect effects of the project on different factors of the environment. This includes air and climate, and its interactions (Article 3).

The Directive distinguishes between those projects subject to a mandatory EIA and those projects which are determined by Member States as requiring an EIA (Article 4). A mandatory EIA is required for all projects which are considered as having significant effects on the environment (Annex I). Unconventional / shale gas projects are included - extraction of natural gas where the amount of gas extracted exceeds 500,000 m^3 per day – (Annex I.14).

The European Commission has confirmed that the EIA Directive would apply to those unconventional / shale gas activities falling within Annex I.14 and that, where such projects fall below the threshold in Annex I.14, a screening would be required in accordance with Articles 2(1), 4(2)-(4) and Annex III of the Directive. Projects related to exploration or unconventional / shale gas would be subject to the requirements of the Directive, noting that Annex II.2 refers to "deep drillings" and provided the view that the list of activities associated with deep drillings, which does not include shale gas extraction, is non-exhaustive. The European Commission stresses the need for the precautionary principle to be applied in deciding that an EIA is needed, if the project could not be excluded due to expected significant environmental effects. In case of doubts as to the absence of knowledge on significant effects, an EIA must be carried out according to the precautionary principle.

Operations on shale gas are in its beginning in Europe and the scenario at the level of legislation can be rather complex among Member States application of the rules. As an example Poland is extending its fracking program but in June 2014 the European Commission began legal proceedings against the country for amending its national laws to allow shale drills at depths of up to 5,000 m without assessing potential environmental impacts, thereby infringing the EIA Directive.

4.1.2 Industrial Emissions Directive

With regard to the Directive on Industrial Emissions (2010/75/EU) it is not clear in which circumstances it would apply to shale gas exploration and exploitation activities and whether its measures on air emissions would cover methane contained within flow back. Annex I to this Directive does not explicitly refer to unconventional hydrocarbon exploration and exploitation activities as it does not refer to mining activities in general.
Overall the application of Directive 2010/75/EU to shale gas exploration and exploitation activities is subject to interpretation and requires a case by case approach. Furthermore it is not clear whether the emission limit value measures required under this Directive would apply to methane contained within flow back from these activities.
Therefore it would be possible that hazardous waste is generated during shale gas exploration and exploitation activities and that provided the threshold is fulfilled (disposal capacity exceeding 10 tons per day, capacity exceeding 50 tons for temporary storage and 50 tons for underground storage) their waste water disposal installations could thus fall under Annex I to the Industrial Emissions Directive. However shale gas

activities would not fall under Sections 5.1, 5.5, 5.6 of Annex I if the storage of hazardous waste is temporary prior to being transferred to a waste treatment facility.

Substances listed in Annex II do not include methane. Methane could however be considered as a polluting substance which is likely to be emitted from the installation concerned in significant quantities that would require specific emission limit measures. The Directive lays down rules on integrated prevention and control of pollution arising from industrial activities.

Furthermore it can also be interpreted that the Industrial Emissions Directive could apply to shale gas exploration and exploitation activities if a combustion plant of at least 50 MW or another activity (e.g. gas refinery) listed in Annex I of the Industrial Emissions Directive:

(i) would be directly associated to shale gas exploration and exploitation;
(ii) would have a technical connection with shale gas exploration and exploitation;
(iii) would be operated *in situ*. However, it is not clear if the directive would always apply to methane emissions from shale gas installations and there is no BAT reference document specific to shale gas extraction technologies.

4.1.3 Directive on Emission Trading System

The Directive on Emission Trading System (EU ETS Directive - 2003/87/EC) could provide precedents for the regulation of shale gas emissions, through its treatment of venting and flaring, and emissions related to carbon capture and storage processes.

The Directive establishes a system for GHG emissions trading, which began in 2005 with subsequent revisions, covering stationary installations that carry out any activity listed in Annex I.

This annex does not contain any activities that would directly relate to the extraction of natural gas but shale gas sites could be included in the system through the inclusion of the combustion of fuels in installations with a total rated thermal input exceeding 20MW, including engines and flares. Notably there is no mention in the Directive of including installations due to the GHG emissions arising from the venting of natural gas.

The EU ETS contains provisions for the inclusion of combustion installations including flaring, but not for venting of GHG emissions at those installations. With regards to a potential model for the regulation of fugitive emissions from hydraulic fracturing, examples can be taken from the Directive’s treatment of capture and geological storage of carbon dioxide. The Directive includes geological storage of GHG in a storage site permitted under Directive 2009/31/EC.

4.1.4 National Emission Ceilings Directive

The NEC Directive (2001/81/EC) set upper limits for each Member State for the total emissions in 2010 of the four pollutants responsible for acidification, eutrophication and ground-level ozone pollution (sulphur dioxide, nitrogen oxides, volatile organic compounds and ammonia). The Directive requires Member States to draw up programmes in order to reduce these emissions, to ensure that the limits are complied with and that emission ceilings for these pollutants are not exceeded in any year after 2010. The Directive leaves it largely to the Member States to decide which measures (on top of Community legislation for specific source categories) to take in order to comply with these limits.

4.1.5 Hydrocarbons Directive

The Hydrocarbons Directive (94/22/EC) sets common rules among Member States to ensure non-discriminatory procedures for granting authorisations for access to the activities of prospection, exploration and production of hydrocarbons, which include shale gas activities.

4.1.6 Proposed content of the Hydrocarbons BREF

The Commission organised (in its Communications on European energy security and on the exploration and production of Hydrocarbons (such as shale gas) using high volume hydraulic fracturing in the EU) an exchange of information to draw up a Best Available Techniques (BAT) reference document on Hydrocarbons exploration and extraction (BREF). The Hydrocarbons BREF is not directly linked to the implementation of a particular Directive. Conclusions drawn from the information exchange will have no legally binding effect on Member States.

The Hydrocarbons BREF will address the extractive oil and gas industry. It will focus on the installations linked to actual wells i.e. the development and operation of the offshore facility or onshore well pad (including directly related activities such as onsite storage prior to distribution), but excluding delivery infrastructure such as pipelines. In this context, the BREF will focus on BAT to manage impacts of releases of pollutants and best risk management techniques to manage risks of releases of substances as a result of incidents for the purpose of protecting human health and the environment.

4.2 Specific regulatory regimes - the UK

In the UK, shale gas activities are covered by the general provisions for conventional oil and gas exploration and development and there are no general control regimes which deal specifically with GHG emissions and methane flow back. A number of regulatory regimes in the UK have the indirect effect of restricting or controlling methane emissions from oil and gas activities including shale gas. These include the regimes relating to petroleum licensing, environmental permitting and health and safety. Licenses for shale gas exploration and exploitation are issued by the relevant authority who must be satisfied with the technical competence and environmental awareness of its proposed operator, but GHG emissions are not specifically taken into account.

In light of the early stage of development of shale gas activities in the UK, the authorities confirmed that the regulatory position for some aspects of on-shore unconventional gas is currently under review. In Northern Ireland consideration is currently being given by Department of Energy (DOE) to the existing regulatory regimes which could be used, either in their current form or amended, to control emissions to air from shale gas production and to establish whether these need to be supplemented. DOE is working with its counterparts in the rest of the UK in a similar review, although neither has yet progressed sufficiently to have reached any conclusions. In anticipation of any future application for hydraulic fracturing, NIEA have drafted an environmental regulatory framework that would apply. However, they indicated that the specific suite of regulations that will apply will be on a case by case basis specific to each individual operations proposed working practices and location.

4.3 Non-European regimes

The US Environmental Protection Agency (USEPA) issued new Clean Air Act regulations relevant to shale activities including: (i) a new source performance standard for VOC and SO_2 emissions with expanded applicability to natural gas operations; (ii) an air toxics standard for oil and natural gas production; and (iii) an air toxics standard for natural gas transmission and storage.

State regulations, which cover abandonment procedures for redundant wells, can include financial provision for abandonment as well as technical requirements and observation of the plugging procedure by local inspectors. The requirements in these regulations have evolved to replace a range of historic drilling and plugging techniques and to avoid future environmental issues arising from wells which had been abandoned.

4.4 EU legislation not directly relevant to regulate air emissions

The EU legislation that could apply to unconventional / shale gas projects, but that are not directly relevant to regulate GHG emissions as they do not include any provision specific to GHGs, are summarised below:

Habitats Directive: Council Directive 92/43/EEC on the conservation of natural habitats and of wild fauna and flora Shale gas projects would be prohibited in special areas of conservation unless it is demonstrated that here are imperative reasons of overriding public interest.

Fracking operations which operate hours a day can have a significant impact on protected species, particularly those affected by noise and light pollution such as bats and some migratory birds. The requirements of the Habitats Directive therefore need to be considered when deciding on a site.

Shale gas exploration and exploitation requires a significant number of wells linked end-to-end to achieve horizontal drilling. Depending on the extent of the shale area, the associated impact on communities and habitats is therefore greatly influenced by the length of the horizontal part of the well. Increasing the length reduces the surface area required and, therefore, the impact on the countryside.

The Directive 92/91/EEC sets requirements to protect workers from harmful and explosive atmospheres. These requirements can indirectly and potentially control the air emissions of methane at the project site even though it is not the aim of this Directive and did not contain any provisions specifically relating to GHG emissions. It does, however, set requirements to protect workers from harmful and / or explosive substances. This would primarily apply to methane present in such concentration that it could represent a risk in terms of flammability for workers.

While the Directive does not contain any provisions specifically relating to GHG emissions it requires employers to take the necessary measures to ensure, *inter alia*, that workplaces are designed, constructed, equipped, commissioned, operated and maintained so that workers can perform their work without endangering their health and safety and those of others.

5 EMISSION REDUCTION TECHNIQUES

As the most significant difference in GHG emissions from shale gas production compared to conventional gas production arises in the pre-production phase the analysis is focused on this process.

5.1 By process phase

5.1.1 Site preparation

Appropriate site selection and preparation may reduce GHG emissions, and in particular CO_2, from combustion emissions by reducing fuel consumption. Preparation of the well pad requires resources, for example to level the site, prepare well cellars and install impermeable membranes. Use of existing roads, water resources and other infrastructure can minimise such work and the associated emissions from their construction. Provision of on-site storage of water and hydraulic fracturing fluids is often achieved through use of mobile tanks but some sites install reservoirs or lagoons for water and drilling / hydraulic fracturing fluids, but these have to be removed and land restored on completion. Use of transportable tanks will generally require less site preparation but this will depend on the site and availability of water, quantity of generated materials and treatment facilities. Consideration of drilling and well completion requirements during site selection will avoid or minimise situations where combustion or recovery of flow back gas (or accidental releases) might be constrained by proximity to buildings or other amenity space.

The following measures could be included to reduce these emissions: drilling as many wells as possible using one rig move; optimising the well spacing for efficient recovery of natural gas; planning for efficient rig and fracturing equipment moves from one pad to another; ensuring that personnel and equipment can be sourced locally; identifying sources or materials locally (including water and sand used in the hydraulic fracturing process); identifying local facilities to recycle, and dispose of waste products; planning to reduce the number of vehicle journeys and using efficient transport engines.

5.1.2 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. This step of the process is the same for conventional and 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 nitrogen oxides, carbon monoxide, carbon dioxide and unburned hydrocarbons. Three-way catalytic oxidizers may be used on drilling rig engines to reduce non-CO_2 emissions. Use of gas engines or engines powered from the local electricity grid may also be possible if supplies are available at the site.

Appropriate well design and supervision, including choice and depth of casings, seals and monitoring are essential to assure safety, avoid gas / fluid migration and maintain well integrity during the drilling phase.

5.1.3 Hydraulic Fracturing

During this phase of the well development process, the wellbore is fractured. Carbon dioxide emissions during the fracturing phase are primarily a result of fuel combustion. Typically a well pad will include several wells and, after completion of the first well, gas is likely to be available at the site and use of gas engines may be possible if gas quality is suitable. Similarly, if a well has to be re-fractured at a later stage, then use of gas engines could be an alternative to diesel-fired engines.

5.1.4 Well completion and flow back

Upon completion of the fracturing step the fracturing fluid mixture that returns to the well head will contain a combination of water (including produced water and waste water), sand, hydrocarbon liquids and natural gas (flow back fluid). If it is not captured or used, the methane within the natural gas will be released into the atmosphere. Methane emissions from the flow back / well completion step may be controlled through the use of reduced emission completions, or green completions (AEA (2012)).

A reduced emission completion involves the temporary installation of equipment 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 to other processing facilities where needed). Where the pipeline infrastructure is not yet in place to receive saleable gas, the gas stream may be routed to suitable storage before treatment and transfer offsite or a temporary flare.

Limitations include availability of pipelines to transport the gas for sale or of equipment for other forms of natural gas utilisation (e.g. small scale power production); during the exploratory phase the sales pipelines may not have been constructed and pressure of the produced gas.

If pressure is too low then it may be difficult to displace the hydraulic fracturing fluid - compressed natural gas or inert gas may need to be pumped down the well to help displace the hydraulic fracturing fluid. Low pressure may limit effectiveness of any treatment stages (it may not be possible to produce sales or pipeline quality gas) and will limit the amount of gas that can be recovered into a storage vessel (without additional compression).

5.1.5 Completion combustions (Flares)

If the concentration of inert gases, such as CO_2 or N_2, is too high then it may not be possible to economically recover the natural gas and as above it may be necessary to flare the gas until the composition of the gas is acceptable. Completion combustion devices are used to control VOC in many industrial applications. They can be as simple as a pipe with a basic ignition source. Gas contained within flow back may or may not be combustible depending on the composition of inert gases and may therefore require the use of a continuous ignition source. These devices (pit flares) are not controlled and are not capable of being tested or monitored for efficiency (O'Sullivan and Paltsev (2012)).

Due to the variable conditions during flow back there may not be a continuous supply of gas and so self-sustained flaring may not be possible. Furthermore the exposed flame may pose a fire hazard or other impacts in some situations, for example dry windy conditions and proximity to nearby occupied buildings. However such issues may be mitigated by appropriate management techniques including location of the well pad and design and location of the flare.

5.2 Management techniques

Technology provides part of a best available techniques approach to management of methane emissions from unconventional gas exploration and production. However, best available techniques in other areas of industrial activity include management techniques. In natural gas refining, best available techniques include a range of measures which can help an operator avoid and mitigate emissions. These include (AEA (2012)):

- Environmental Management System: this can provide a focus for monitoring performance, benchmarking, continuous improvement plans, energy management, emissions assessment and reporting to stakeholders. An externally-accredited system provides credibility and assurance that the processes and plans are being applied;
- Application of good practice for maintenance and cleaning;
- Development of environmental awareness;
- Implementation of monitoring systems, including Leak Detection and Repair.

Other management areas relevant to GHG emissions from unconventional gas include:

- Consider transport distances, access roadway provision and compression / processing emission options for sitting of well pads;
- Availability of gas for drilling technology;
- Avoiding constraints on deploying on flare or capture technology for well-completion;
- Transport of recovered gas from completion activities to processing facilities.

6 CASE STUDIES

6.1 USA

6.1.1 Introduction

Until recently, unconventional natural gas production was almost exclusively a USA phenomenon. Tight gas production has the longest history, having been expanding steadily for several decades.

Commercial production of coalbed methane began in the 1980’s, but only took off in the 1990s, it has levelled off in recent years. Shale gas has also been in production for several decades, but started to expand only in the mid-2000s, growing at more than 45% per year between 2005 and 2010.

Unconventional gas production was nearly 60% of total gas production in the United States in 2010. While tight gas and shale gas account for the overwhelming bulk of this, shale gas is expected to remain the main source of growth in overall gas supply in the United States in the coming decades. The United States and Canada still account for virtually all the shale gas produced commercially in the world, though many countries are now trying to replicate this experience.

There are large resources of all three types of unconventional gas across the United States. Of the 74 trillion cubic metres (tcm) of remaining recoverable resources of natural gas atend-2011, half are unconventional, in total, gas resources represent around 110 years of production at 2011 rates (Source: World Energy Outlook Special Report on Unconventional Gas, 2012).

Major unconventional gas deposits in the United States are distributed across much of the country. Coalbed methane resources are found principally in the Rocky Mountain state of Wyoming, Utah, New Mexico, Colorado and Montana.

Tight gas and shale gas are located in a number of different basins stretching across large parts of the United States, some of which are shared with Canada and Mexico. Two of the largest shale plays that have been identified, the Marcellus and Haynesville formations, taken as single reservoirs are among the largest known gas fields of any type in the world.

In the United States, IHS Global Insight estimates that the lower gas prices attributable to shale gas production will save households $926 per year between 2012 and 2015 (IHS (2011)). Cheaper gas also stimulates industries – chemicals and fertilisers, in particular – that rely on gas as a key feedstock or source of energy. Several chemical companies have announced expansion plans in the United States. In the Low Unconventional Case, gas consumption in the United States grows until 2020 and then declines thereafter, ending almost 15% lower by 2035 than in the Golden Rules Case (IEA (2012)).

The boom in shale gas thus far has already transformed prospects for gas trade. The future of this unconventional "revolution" will determine whether the United States becomes an influential gas exporter over the coming decades or, alternatively, sees its imports rise from current levels. As recently as 2008, the United States was projected to require increasing imports of liquefied natural gas (LNG) to meet incremental gas demand (US DOE/EIA, 2008). In the Low Unconventional Case, this again becomes a prospect as domestic production declines.

Successfully meeting public concerns by putting in place the regulatory conditions that deal convincingly with environmental risks could be expected to have a significant impact on the pace of development of unconventional gas resources in other parts of the world.

The United States has been the testing ground for unconventional gas technology and the place where this technology has been most widely and most productively applied. Just as experience from the United States has prompted both global interest in developing unconventional resources and reservations about their environmental impact, so too will other countries look to the United States for evidence that social and environmental risks can be managed successfully, in part with appropriate regulation.

6.1.2 USA Production

Natural gas from shales has the potential to significantly increase America's security of energy supply, reduce greenhouse gas emissions, and lower prices for consumers. Although shale gas has been produced in the United State for many decades, it was not considered to be a significant resource until the last decade when new horizontal drilling and hydraulic fracturing technology facilitated economic production.

Shale gas currently contributes about 16 percent of U.S. natural gas production, an amount that is expected to grow significantly as this huge resource is developed (US DOE/EIA (2013).

Natural gas can replace high-emissions fuels like oil and coal and facilitate variable renewable energy sources such as wind and solar. However, concerns about the safety, risk, and environmental impacts associated with shale gas development must be addressed before production can significantly increase.

6.1.3 Main Basins

Many of the shale gas formations of North America have been proven to contain natural gas and are already being exploited. Large-scale shale gas production started in the U.S. in the Barnett shale, Texas, in the late 1990s (OECD/IEA (2012). The U.S. Energy Information Administration (EIA) estimates in the Annual Energy Outlook 2015 that about 11.34 trillion cubic feet of dry natural gas was produced directly from shale and tight oil resources in the United States in 2013. This was about 47% of total U.S. dry natural gas production in 2013 (EIA (2015).

6.1.4 Positive economic impact

Several reports have concluded that the shale gas industry in the U.S. has created a large number of jobs and has had a profound, positive economic impact, such as reducing consumer costs of natural gas and electricity, stimulating economic growth and increasing federal, state and local tax revenue.

Globally, 32 % of the total estimated natural gas resources are in shale formations (EIA, (2013)). Due to its proven quick production in large volumes at a relatively low cost, extraction of shale gas resources has revolutionized the U.S. natural gas industry, providing 40 % of total U.S. natural gas production in 2012 (EIA(2013)).

"*The Economic and Employment Contributions of Shale Gas in the United States*", published in December, 2011, by IHS concluded that in 2010 shale gas production contributed $18.6 billion in federal, state and local government tax and federal royalty revenues. Also, the study reports the shale gas contribution to GDP to have been more than $76 billion in 2010. An update of the report was published in June, 2012 ("T*he Economic and Employment Contributions of Unconventional Gas Development in State Economies*") that includes tight gas and coal bed methane as well as shale gas. It is assumed that the unconventional gas industry contributes more than $49 billion annually to government revenues, and will contribute $197 billion to U.S. gross domestic product by 2015. Furthermore, unconventional gas activity supported 1 million jobs in 2010 and this will grow to nearly 1.5 million jobs in 2015.

The study "*Ohio's Natural Gas and Crude Oil Exploration and Production Industry and the Emerging Utica Gas Formation - Economic Impact Study*" (Kleinzhenz & Associates (2011)), highlighted the economic contribution and benefits of the natural gas and crude oil industry to the State of Ohio. It included an estimate of the economic impact of planned industry spending on the development of the Utica shale gas formation. One of the findings was that "more than 204,000 jobs will be created or supported by 2015 due to exploration, leasing, drilling and connector pipeline construction for the Utica Shale reserve." A more recent study "*America's New Energy Future: The Unconventional Oil and Gas Revolution and the US Economy. Volume 2 – State Economic Contributions*" published in December, 2012 by IHS[2], reports that the industry paid over $910 million in state and local taxes in Ohio in 2011. Moreover, the IHS study shows Ohio currently has a total of 38,380 jobs related to unconventional gas and oil activity, a number expected to increase to 143,595 in 2020 and to 266,624 by 2035.

6.1.5 Shale Gas and emissions in USA

The recent experience in the USA shows how shale gas can help European countries like the UK meet their carbon demands:

[2] *Information Handling Services (IHS Inc.) serves international clients in five major areas: energy, product lifecycle, environment, security and electronics and media.*

- Between 2005 and 2010, carbon emissions in the USA fell by 403 million tonnes, at a time when electricity production from natural gas rose by 62%,
- This coincided with a reduction in the USA's reliance on coal for its energy needs, with electricity net generation from coal falling by 25% between 2007 and 2012.

This helped the USA to reduce its carbon emissions to a 20 year low in the first quarter of 2012, achieving approximately 70% of the CO_2 emission reductions targeted under the Kyoto Agreement. Natural gas is increasingly used as a transport fuel, helping to reduce carbon emissions and improve air quality still further.

Natural gas now powers 19% of public transport buses, and the fuelling infrastructure necessary to allow natural gas to be used in long distance trucks is also being developed. The Chief Executive of FedEx has predicted that up to 30% of US long-distance trucking will be fuelled by compressed or LNG over the next 10 years.

6.2 CANADA

6.2.1 Production

Canada is endowed with large unconventional gas resources of all three types and is one of the few countries outside the United States where commercial production is underway.

Production of tight gas was around 50 bcm in 2010 and production of coalbed methane (concentrated in the province of Alberta) close to 8 bcm. Shale gas is believed to have the greatest production potential in the longer term, although commercial production is only 3 bcm. The main Canadian shale gas plays currently being explored and appraised are the Horn River Basin and Montney shales in northeast British Columbia, the Colorado Group in Alberta and Saskatchewan, the Utica Shale in Quebec and the Horton Bluff Shale in New Brunswick and Nova Scotia. Remaining recoverable unconventional resources in Canada at end-2011 are estimated to be 18 tcm (11 tcm shale gas, 5 tcm coalbed methane and 2 tcm tight gas), representing around 6% of world unconventional resources. 80% of Canada's total remaining recoverable gas resources are unconventional.

Canada has 174 billion barrels of oil reserves, of which 169 billion barrels are oil sands reserves. Extra-heavy oil and oil sands are categorized as unconventional oil, along with light tight oil, also known as shale oil. Concerning the conventional versus unconventional natural gas, the natural gas resource triangle shown here illustrates the amount of natural gas reserves in Canada by type.

According to the Canadian Association of Petroleum Producers the conventional resources are by far the smallest in volume, compared to the unconventional resources.

Canada's unconventional natural gas resources include tight gas sands, coal bed methane (also known as natural gas from coal), shale gas and gas hydrates. Of these, only shale gas, is discussed because it offers high volumes of natural gas, accessible by today's technologies.

Gas hydrates are trapped in ice and while Canada's gas hydrate reserves are enormous, but at the present, there are no commercially viable technology to access them.

Most importantly, whether conventional or unconventional, shale gas, tight gas, coal bed methane or gas hydrates, we are still talking about natural gas. No matter what form it comes in, natural gas is abundant, reliable, versatile and clean-burning. (In: NOV 2013, PSAC's public outreach program Canada**).**

Unconventional gas in Canada is expected to play an increasingly important role in offsetting a projected decline in conventional gas production and meeting rising domestic demand. In the Golden Rules Case, unconventional gas production rises from 62 bcm in 2010 to about 120 bcm in 2035, its share of total gas output increasing from just under 40% to two-thirds. Shale gas and, to a slightly lesser extent, coalbed methane drive this growth. Total gas production increases from 160 bcm to nearly 180 bcm between 2010 and 2035 (Rivard et al. (2014)).

Canadian gas demand grows even faster, so net exports drop sharply - from around 65 bcm in 2010 to 25 bcm in 2035.

In the Low Unconventional Case, shale gas production remains relatively robust, even with the assumed limitations on access to resources. It is about the only unconventional gas resource type with room to grow to offset otherwise rising North American demand for imports.

However, overall gas production peaks before 2025 and falls back below current levels by the end of the projection period. The higher prices that result from slower development constrain demand, which reaches around 130 bcm in 2035, 15% lower than in the Golden Rules Case.

Although production is lower in the Low Unconventional Case, it is noteworthy that the required upstream investment is at a level similar to that in the Golden Rules Case; this is because of the relative resilience of shale gas production in the Low Unconventional Case and to the assumption (built into the model) that production tends to become more costly as a given resource starts to become more difficult to access. Since access to shale gas resources is limited in this case, the cost of production rises in a way that balances the effect of lower output on the overall investment requirement.

Production of hydrocarbons from Canadian shales started slowly in 2005 and has significantly increased since.

Natural gas is mainly being produced from Devonian shales in the Horn River Basin and from the Triassic Montney shales and siltstones, both located in north-eastern British Columbia and, to a lesser extent, in the Devonian Duvernay Formation in

Alberta (western Canada). Other shales with natural gas potential are currently being evaluated, including the Upper Ordovician Utica Shale in southern Quebec and the Mississippian Frederick Brook Shale in New Brunswick (eastern Canada).

There are abundant supplies of natural gas in Canada. Unconventional resources have doubled Canada's natural gas resource base and, as exploration continues, this number could still increase. Presently, large-scale production is occurring only in north-eastern British Columbia, where the population is sparse. Four plays are in production, of which the Horn River Basin and the Montney Play Trend are the most productive. Modest exploitation of dry gas occurs in the Duvernay Formation (Alberta), where liquids are also being produced at increasing rates.

6.2.2 Shale Gas and Carbon emissions in Canada

The main concerns about emissions associated with shale gas in Canada are with the fugitive Emissions, so the Canadian Association of Petroleum Producers has developed a Best Management Practice for Fugitive Emissions Management (CAPP (2007)), which some provinces have adopted to guide industry in developing programs to detect and repair leaks (Alberta Energy Regulator (2014)), (BC Oil and Gas Commission (2015)). This document identifies the typical key sources of fugitive emissions at upstream oil and gas facilities, presents strategies for achieving cost-effective reductions in these emissions (e.g., through improved designs, Directed Inspection and Maintenance (DI&M) practices, improved operating practices, and the application of new and retrofit technologies).

There is, also, one Canadian study, prepared for Natural Resources Canada, in 2011, that uses a model (GHGenius model) which was updated to address shale gas production. The weighted average GHG emissions obtained were 7.2 g/CO_2e/MJ, which were considerably lower than the best estimation obtained in US studies (13.5 to 14.7 g/CO_2e/MJ) (Natural Resources Canada (2011)).

However, several reasons for these lower values were presented (ICF Consulting Canada (2012)). In particular, the main sources of methane accounted in the U.S. studies are the well completion emissions for shale gas and well liquids unloading for conventional gas production. In the Canadian study the emissions from these operations are not included because, according to this study, the well completion emissions are flared in Canadian shale gas operations and the venting for liquids unloading is not used in conventional gas production operations.

In the Natural Resources Canada study the upstream GHG emissions presented for shale gas production are higher than for conventional production mainly due to higher CO_2 content in the gas from the particular region studied (Horn River) and, in a minor extent, due to an increase in energy for drilling and fracturing. The gas from regions with lower CO_2 content would present lower life-cycle emissions from shale gas. Even including combustion emissions, the total life-cycle emissions from shale gas are less than 4%, though higher than those from conventional gas and they are lower than almost all of the U.S. studies (ICF Consulting Canada (2012)).

6.3 EUROPE

6.3.1 Introduction

Whether the large shale deposits in Europe are promising for large-scale, shale gas production is in most cases yet unknown. A few prospective wells have been drilled, and scientific investigations are now being carried out to find and compile data on where the shales are located and also how they were formed (US EIA (2013), IEA (2012)).

A prominent effort in this respect is the project "Gas Shales in Europe" (GASH). It is the first European interdisciplinary shale gas research initiative. Coordinated by GFZ German Research Centre for Geosciences, GASH is developing a GIS-based European black shale database, and is conducting 12 research projects with a multinational expert task force drawn from research institutions, geological surveys, universities and consultants.

Regarding greenhouse gas emissions, the EASAC (2014) report states that in principle, natural gas offers the potential to significantly reduce carbon dioxide emissions from electricity generation when it replaces coal. However, the relative merits in terms of specific greenhouse gas emissions of using shale gas instead of coal are highly sensitive to the levels of methane leakage during shale gas extraction, transportation and distribution, as well as to any future leakage from abandoned shale gas wells.

Best practices for ensuring 'well bore integrity' and thereby minimising methane emissions during construction and production are well known. Similarly, best practices for 'green completion' to capture and manage methane and other gases emitted from flow back water during the extraction process, and for long-term sealing of abandoned wells, are also available. The implementation and monitoring of such best practices should be made obligatory when licensing and regulating shale gas extraction activities.

The EU has legally binding GHG reduction policies to address the threat of global warming. Shale gas is often cited in the public debate as offering the potential to reduce EU GHG emissions more efficiently (on the assumption that less coal or other high carbon- energy sources would be used) and potentially providing economic leeway for more ambitious GHG reduction targets in the short to medium term. However, the volume of methane emissions from gas leakage at the wellhead and in the distribution system is a critical factor in view of methane's global warming potential10 (GWP) being much higher than that of CO2. In this context, the critical importance of timescale to methane's contribution to global warming may not be fully appreciated by policymakers. The commonly quoted GWP for methane is from the assessment of IPCC (2007), where the GWP is given as 25 (effect over 100 years). However, the assessment of IPCC (2013) increases methane's GWP to 34 (100 years), and calculates the GWP for the first 10 years after emission is 108, and 86 for the first 20 years after emission. There are re-evaluations of methane's GWP in course not related to any particular source of methane.

Some authors (e.g. Allen et al. (2013)) conclude that hydraulic fracturing is not a substantial emissions source relative to current national totals but there are differences between field measurements and emissions inventories. This issue should be better understood to allow efforts to reduce methane emissions to be properly prioritised.

It is claimed that the potential climate 'benefit' of natural gas relative to coal is highly sensitive to methane emissions but there is large controversy on the subject with the US EPA assuming a 1.5% leakage rate in natural gas extraction and production, and recent studies (e.g. Brandt et al. (2014); Caulton et al. (2014)) suggesting that fugitive emissions in the USA may be considerably higher.

The German upstream industry is reporting approximately 0.02% of methane emissions from natural gas production (Ziemkiewicz et al. (2014)), indicating that significant methane emissions can be avoided with appropriate regulations.

A recent meta-analysis (Heath et al. 2014) of the scientific publications on this issue came to two conclusions:

(1) emissions from shale gas extraction are similar to those from conventional gas extraction;

(2) both when used in power generation would probably emit less than half the CO_2 emissions of coal. Nevertheless, the analysis also noted that higher assumptions on fugitive emissions '*may lead to emissions approaching best-performing coal units, with implications for climate change strategies'*.

Regarding potential sources of emissions from shale gas extraction, flaring and venting in conventional exploitation in Europe ceased during the 1990s (with the exception of initial flow tests in successful exploratory drilling); industry therefore possesses the necessary expertise to avoid this problem. 'Green' completion technologies are also widely used to capture and then sell (rather than vent or flare) methane and other gases emitted from flow-back water (they can be recovered at low cost by taking out the gas within a confined separator). This will be mandatory for hydraulic fracturing of all gas wells in the USA from 2015 onwards. Ensuring 'green completion' is fully applied in Europe is thus an essential prerequisite for maximizing benefits from shale gas to climate change policies.

To eliminating methane emissions it is critical during well construction and production to ensure 'wellbore integrity' one of the identified gaps. These stresses the need for appropriate regulations and standards to be applied and well integrity secured by proper well design and drilling/completion procedures, including down-hole logging to detect whether cementing of the casing is effective. Monitoring arrangements should be applied to detect any well failure as early as possible and continue after closure. Europe should ensure a high degree of elimination and minimization of emissions in its shale gas policies and regulations.

6.3.2 UK

Shale gas clearly has potential in Britain but it will require geological and engineering expertise, investment and protection of the environment. It will also need organisations like the British Geological Survey (BGS) to play their part in providing up-to-date and accurate information on resources and the environment to the public, industry and government. The shale gas estimates presented in this sub-chapter is a resource figure (gas-in-place) and so represents the gas that BGS thinks is present, but not the gas that might be possible to extract. The proportion of gas that it may be possible to extract is unknown as it depends on the economic, geological and social factors that will prevail at each operation. The estimate is in the form of a range to reflect geological uncertainty. The lower limit of the range is 822 tcf (trillion cubic feet) and the upper limit is 2281 tcf, but the central estimate for the resource is 1329 tcf.

6.3.2.1 Permits and regulations in UK

Regarding permitting and regulation of shale gas operations, UK involves several stages:

a) First of all, exploration and production of shale gas from onshore UK requires the operator to obtain licences from the UK Department of Energy and Climate Change (DECC).

b) Environmental regulators

The operator must also meet a number of strict regulatory requirements set by the Environment Agency (EA) or the Scottish Environment Protection Agency (SEPA) in Scotland.

- Environment Agency's role[3]
- SEPA's role[4]

c) Safety regulator

The Health and Safety Executive (HSE) monitors shale gas operations from a well integrity and site safety perspective.

- Health and Safety Executive's role[5]

d) Planning approval

The operator must also obtain planning permission from the relevant local authority to permit the surface operations required to explore and extract shale gas.

e) Coal Authority licence

Any activity, such as drilling boreholes for shale gas that intersects, disturbs or enters any of the Authority's coal interests requires a Coal Authority licence[6].

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[3] https://www.gov.uk/government/organisations/environment-agency
[4] http://www.sepa.org.uk/
[5] http://www.hse.gov.uk/offshore/unconventional-gas.htm
[6] https://www.gov.uk/guidance/get-a-licence-for-coal-mining

6.3.2.2 **Shale gas research in UK**

According with British Geological Survey (BGS) online[7], the BGS is taking a central role in shale gas research in the UK and also across Europe as follows:

a) undertaking a baseline groundwater survey of methane concentrations and other relevant chemical indicators in groundwaters across Great Britain;
b) evaluating the spatial relationship between different potential shale gas source rocks and the principal aquifers in England and Wales;
c) researching the induced seismicity that may be related to fracking; studies of the organic content and the organic make-up of the shales to improve the understanding of how much shale gas they might produce and how the gas is stored within the rocks;
d) understanding the distribution and correlation of shale and how the shale layers behave in response to depositional and tectonic controls;
e) advice and guidance for Government in trying to understand the amount of gas that may be both in place and possibly recoverable within the shales in the UK.

Shale gas prospectivity is controlled by the amount and type of organic matter held in the shale, thermal maturity, burial history, micro-porosity and fracture spacing and orientation.

In a report Moore et al. (2014) refer areas currently under license and potential areas to be opened up for exploration in the 14th onshore oil and gas licensing round in Great Britain.

Factors influencing these properties are related to the depositional and post-depositional history of shale deposits. BGS is using wide range of skills and expertise is needed to address these topics:

- basin analysis
- seismic interpretation
- sequence stratigraphy
- organic and stable isotope geochemistry
- mineralogy and petrology and palynology

Regarding UK energy needs, estimates of the amount of recoverable gas and the gas resources are variable. It is possible that the shale gas resources in UK are very large. However, despite the size of the resource, the proportion that can be recovered is the critical factor. A better understanding of the shale gas resource, and the amount of gas that is potentially recoverable, will come from further geological research, such as that carried out by the BGS. If the amount of recoverable shale gas does prove to be larger this will be a significant indigenous source of gas for the UK and may reduce the reliance on imported gas[7].

[7]BGS (http://www.bgs.ac.uk), sub-page Shale Gas (http://www.bgs.ac.uk/shalegas), visited on 4th August 2015

6.3.2.3 Main basins: BGS research update

Carboniferous organic-rich basinal marine shales are present across a large part of central Britain and the study area extends from Merseyside to Humberside and Loughborough to Pickering. The shales are either buried at depth or occur at outcrop. These organic-rich shales are recognised to be excellent source rocks, in which oil and gas matured before some of it migrated into conventional oil and gas fields (e.g. UK Midlands area, East Irish Sea) (BGS (2013)). So far, BGS in association with the Department of Energy and Climate Change (DECC) has completed shale resource estimates for several areas in the UK, namely Midland Valley of Scotland, Wales and Jurassic shale of the Weald Basin.

The main UK basins are listed below:

- **Midland Valley of Scotland** (Carboniferous shales) (excerpt from brief summary of 30th June 2014)
- **Wales** (report from 26th June 2014)
- **Jurassic shale of the Weald Basin** (brief summary from 23rd May 2014)
- **Bowland Shale** (excerpts from report published at 27th July 2013)

6.3.2.4 Shale gas and carbon emissions in UK

The report Independent Expert Scientific Panel – Report on Unconventional Oil and Gas (2014) gives insides on how the potential development of unconventional oil and gas resources in Scotland would sit with the Scottish Government's commitment to reduce greenhouse gas emissions.

Several factors supported the development of unconventional oil and gas production in the US, namely:

- A consistent reduction in US energy-related CO_2 emissions over the last few years, which has been predominantly due to the increased use of shale gas instead of coal in power generation. According to US EIA statistics, the US achieved a reduced level of CO_2 emissions in 2012 (5.29 billion tonnes), similar to that in 1995 (5.32 billion tonnes), which represented a 3.8% reduction on the 2011 figures and 12% less than the 2007 peak.
- There have been positive impacts in the US – stimulating the economy, reducing CO_2 emissions, reducing consumer bills – the knock-on effects are felt globally.
- UK shale gas will not be exploited unless it is cheaper than imported gas. It is unlikely to be exploited until the use of cheap imported coal is curtailed through enforcement of existing requirements that coal-fired power plants have their emissions abated in future by means of carbon capture and storage.
- It is reported that virtually zero emissions of methane are technically achievable using best practice well construction and gas monitoring methods. There is no

evidence to suggest that leakage of fracking fluids has led to increased levels of chemicals, salts, metals or radioactivity in near-well groundwaters (Warner et al. 2012).

Air emissions and air quality changes, as a result of unconventional hydrocarbon extraction, may be direct (site emissions) or indirect as a result of a changing fuel mix. In the UK (Scotland), such emissions currently occur from some landfill sites, peat lands and oil and gas processing and handling infrastructure.

Direct air emissions arising from unintentional leaks, venting and flaring are termed ‘fugitive emissions’. With unconventional hydrocarbon extraction, fugitive emissions are predominantly released from flow back and produced water and leaking infrastructure.

In the United States, the level of fugitive emissions from shale gas operations has been estimated to range from 0.42 - 7.9 % of total gas production (EPA (2013), Allen et al. (2013)).

In the UK, except in emergencies, venting would not be permitted and high emissions associated with venting are therefore unlikely. Also it is assumed that the contrasts in geology in Scotland are such that fugitive emission profiles from the US cannot be assumed to represent the Scottish situation.

In relation to indirect changes to air quality, the increased use of gas as a fuel could result in lower emissions of sulphur dioxide, oxides of nitrogen and particulate matter both from point sources (e.g. power stations) and locally (e.g. transport). Also a reduction in atmospheric loading of air pollutants through the use of unconventional hydrocarbons could represent an environmental benefit.

In Scotland unconventional hydrocarbon extraction will maintain and continue Scottish emissions above an alternative scenario of importing more gas – because ownership of all this group of emissions during extraction lies locally with the state where the extraction occurs. Importing methane gas brings less liability than home-produced gas.

6.3.3 Poland

6.3.3.1 Introduction

With an established onshore conventional oil and gas production industry as well as recent experience with coalbed methane exploration, Poland offers Europe’s best prospects for developing a viable shale gas/oil industry. Poland has four main basins where Paleozoic shales are prospective and exploration activity is taking place.

Is estimated, by the EIA, that Europe have 470 tcf of technically recoverable resources, with Poland (148 tcf) and France (137 tcf) having much the largest shares. Poland has large coal reserves and relies on coal for 90% of its power, while nearly 70% of Poland’s gas is imported, mainly from Russia. There was an active drilling programme for shale gas, with major international companies such as Chevron, ConocoPhilips, and Marathon involved. Shale gas production in Poland was most likely to substitute for Russian gas imports, which would be broadly carbon neutral, or to replace coal for power generation, which could be positive. However, nowadays, prospects for major fracking activities in Poland look far-off happening, as Poland's shale gas industry appears to be collapsing[7]. Just sixty six wells have been drilled to date, twelve involving horizontal fracking. Permits for a further twenty seven drills were put on hold in the southeastern Tomaszów Lubelski region, waiting for the outcome of a long inquiry[8]. Poland is, also facing a huge popular mobilization against shale gas.

6.3.3.2 Main basins

The mainshale basins in Poland include the Baltic Basin and Warsaw Trough in northern Poland, the Podlasie Depression and the Lublin Basin, in east Poland, and the Fore-Sudetic Monocline in the southwest. A fifth region, the Carpathian Foreland belt of south-eastern Poland, could be prospective for oil-prone Jurassic shales, but this area is structurally complex and has not yet been targeted for shale leasing. The Paleozoic sedimentary sequence in Poland contains several marine-deposited shale deposits which in places are thick, organic-rich and buried at prospective depths of 1000 to 5000 m. Most areas are in the gas-prone thermal maturity window, with smaller liquids-rich areas occurring in the north and east. Abundant geologic data exists on these Paleozoic shales. They have been subjected to extensive study as they are considered the main source rocks for Poland's conventional oil and gas fields. However, exploration drilling and seismic surveys are still needed to define potential sweet spots.

The main stratigraphic targets for shale gas/oil exploration in Poland are the Lower Silurian and Ordovician marine-deposited shales. The thinner but thermally more mature Cambrian shale is emerging as a secondary objective, while non-marine Carboniferous shales also have potential. The Lower Cambrian is dominated by quartz sandstones interbedded with shales, while the relatively thin Mid-Cambrian Alum Shale is a transgressive, sediment-starved sequence containing high TOC. The Upper Cambrian to Tremadocian shale, present only in the northern part of the Baltic Basin, contains high average TOC of 3-12% but is quite thin (several to 50 m).

In addition to these four main stratigraphic targets that were assessed, additional organic-rich shale candidates exist in Poland but were excluded from this study. These apparently less prospective shales include:

- Upper Permian Kupferschiefer Shale
- Mesozoic and Tertiary Shales

[7] http://www.theguardian.com/environment/2015/jan/12/polands-shale-gas-revolution-evaporates-in-face-of-environmental-protests
[8] http://www.theguardian.com/environment/2015/oct/09/polish-shale-industry-collapsing-as-number-of-licenses-nearly-halves

6.3.3.3 Estimated Resources in Poland

Poland’s risked, technically recoverable shale resources are estimated to be around 146 tcf of shale gas and 1.8 billion barrels of shale oil in four assessed basins. Poland’s shale industry is still at an early exploratory, pre-commercial phase. About 30 vertical exploration wells and a half-dozen vertical and two horizontal production test wells have been drilled to date. However, early results have not met industry’s high initial expectations with ExxonMobil abandoning the fault-prone Lublin and Podlasie basins after drilling two vertical test wells. ConocoPhillips and Chevron are moving cautiously towards drilling their initial test wells in the Baltic and Lublin basins, respectively. Even in the geologically favourable Baltic Basin, Marathon and Talisman recently exited after expressing disappointment with reservoir quality and being not particularly encouraged with the results obtained. Meanwhile, the government has debated rolling back some favourable shale investment terms, by introducing higher taxes and mandating government back-in rights.

Initial estimations by the US Department of Energy, in 2011, pegged out Polish shale reserves as the largest in Europe. The authors of the report calculated that the country had reserves of about 22.45 trillion cubic meters of shale gas, of which 5.30 trillion cubic meters was recoverable. More recent estimates by the Polish Geological Institute put recoverable reserves at around 350–750 billion cubic meters, and a 2012 assessment by the U.S. Geological Survey estimated 38.09 billion cubic meters of recoverable gas. The reduced estimates, slow rate of exploration, legal and regulatory wrangling, and challenging geology lead to the exit of most major companies, including ExxonMobil, Marathon Oil, Eni and Talisman Energy, of the country. Chevron and ConocoPhillips are the only two major international companies left. Nevertheless, Poland has more shale-gas exploration, drilling, and extraction in progress than any other European country.

Poland is highly dependent on coal for electrical generation. Unlike in most of Western Europe, Polish coal mines are still active. Methane in the mine workings poses safety problems. Most methane is currently treated as waste, but studies show that coalbed methane can be profitably used as a gas resource. As of 2010, Poland imports two-thirds of its natural gas from Russia. Tapping shale gas resources would greatly boost Poland's proven reserves, and lessen the importance of gas imports from Russia.

6.3.3.4 Shale Gas and Carbon emissions in Poland

It was not possible to find, in the literature, specific information about studies of shale gas emissions in Poland. But the environment minister of Poland believes that one of the possibilities of reducing the greenhouse emissions in the country is investing in shale gases activities. The minister stated that Poland is highly depend of coal, so the reduce of carbon emissions could be achieved by replacing outdated power plants with coal-fired units based on new technology and by exploring shale gas resources. In his opinion shale gases could incentive economic growth and also help to reduce greenhouse gas emissions[9].

[9]http://www.reuters.com/article/2013/11/08/us-poland-emissions-minister-idUSBRE9A70KS20131108#QTDr8rmTkC7jSqaE.97

7 KNOWLEDGE GAPS

This report presents a review of the different sources and types of emissions associated with all phases of shale gas production. The GHG and other gaseous emissions related to shale gas production has been the subject of a number of studies, as shale gas is a major concern of the public, policy makers and other stakeholders.

It has been referred that well and its integrity remains the weak spot in the system being the primary concern in environmental protection issues. On this topic the number of scientific publications has increased exponentially since 2005 but there is a question need to be addressed on how to estimate the degree of uptake of best available techniques by industry. Innovations in the exploitation phase, such as cryogenic fracturing, are being considered to eliminate some negative impacts on the environment from hydraulic fracturing but there are other aspects, e.g. solid waste management, well abandonment and the reuse of produced flow back waters needing more research (Aldous and Briere de L'Isle (2014)).

Other issues were also identified as gaps (AEA, 2012):

- wells in Europe and sufficient gas pressure to allow application of green completion;
- Processing infrastructure for captured gas on well completion;
- Availability and experience in equipment / technology to capture the gas released on well completion and re-fracturing activity;
- Methane emissions which have not been assessed in terms of their potential significance (Broomfield and Donovan(2012));
- Variability in fugitive methane emissions;
- Lack of transparency of emissions of methane from specific fugitive or vented sources, or from specific activities on the site;
- Environmental and health studies.

8 ABBREVIATIONS AND UNITS

Abbreviations

BAT - Best Available Techniques
BGS – British Geological Survey GHG – Greenhouse gas
BREF - Best Available Techniques Reference Document
CH_4 - Methane
CO_2 – Carbon Dioxide
EIA - Environmental Impact Assessment
ETS - Emission Trading System
EPA - Environmental Protection Agency
HAP - Hazardous air pollutants
HC – Hydrocarbons
IHS - Information Handling Services
LNG - Liquefied Natural Gas
N_2 – Nitrogen
NO_x- Nitrogen oxides
PM - Particulate matter
REC - Reduced Emission Completions
SO_x – Sulphur oxides
VOC - Volatile organic compounds

Units

bcf - billion cubic feet
bcm - billion cubic metres
e - equivalent
mcm- million cubic metres
mcf - million cubic feet
tcf - trillion cubic feet
tcm - trillion cubic metres

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