Support to the identification of potential risks for the environment and human health arising from hydrocarbons operations involving hydraulic fracturing in Europe

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Contact:

Dr Mark Broomfield
AEA Technology plc
Gemini Building, Harwell, Didcot, OX11 0QR
t: 0870 190 6389
e: mark.broomfield@aeat.co.uk

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Author:

Dr Mark Broomfield

Approved By:

Andrew Lelland

Date:

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Signed:

Executive summary

Introduction

Exploration and production of natural gas and oil within Europe has in the past been mainly focused on conventional resources that are readily available and relatively easy to develop. This type of fuel is typically found in sandstone, siltstone and limestone reservoirs. Conventional extraction enables oil or gas to flow readily into boreholes.

As opportunities for this type of domestic extraction are becoming increasingly limited to meet demand, EU countries are now turning to exploring unconventional natural gas resources, such as coalbed methane, tight gas and in particular shale gas. These are termed 'unconventional' resources because the porosity, permeability, fluid trapping mechanism, or other characteristics of the reservoir or rock formation from which the gas is extracted differ greatly from conventional sandstone and carbonate reservoirs.

In order to extract these unconventional gases, the characteristics of the reservoir need to be altered using techniques such as hydraulic fracturing. In particular high volume hydraulic fracturing has not been used to any great extent within Europe for hydrocarbon extraction. Its use has been limited to lower volume fracturing of some tight gas and conventional reservoirs in the southern part of the North Sea and in onshore Germany, the Netherlands, Denmark and the UK.

Preliminary indications are that extensive shale gas resources are present in Europe (although this would need to be confirmed by exploratory drilling). To date, it appears that only Poland and the UK have performed high-volume hydraulic fracturing for shale gas extraction (at one well in the UK and six wells in Poland); however, a considerable number of Member States have expressed interest in developing shale gas resources. Those already active in this area include Poland, Germany, the Netherlands, the UK, Spain, Romania, Lithuania, Denmark, Sweden and Hungary.

The North American context

Technological advancements and the integration of horizontal wells with hydraulic fracturing practices have enabled the rapid development of shale gas resources in the United States – at present the only country globally with significant commercial shale gas extraction. There, rapid developments have also given rise to widespread public concern about improper operational practices and health and environmental risks related to deployed practices. A 2011 report from the US Secretary of Energy Advisory Board (SEAB) put forward a set of recommendations aiming at "reducing the environmental impact "and "helping to ensure the safety of shale gas production."

Almost half of all states have recently enacted, or have pending legislation that regulates hydraulic fracturing. In 2012, the US Environmental Protection Agency (EPA) has issued Final Oil and Natural Gas Air Pollution Standards including for natural gas wells that are hydraulically fractured as well as Draft Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels. The EPA is also developing standards for waste water discharges and is updating chloride water quality criteria, with a draft document expected in 2012. In addition, it is implementing an Energy Extraction Enforcement Initiative, and is involved in voluntary partnerships, such as the Natural Gas STAR program. The US Department of the Interior proposed in April 2012 a rule to require companies to publicly disclose the chemicals used in hydraulic fracturing operations, to make sure that wells used in fracturing operations meet appropriate construction standards, and to ensure that operators put in place appropriate plans for managing flowback waters from fracturing operations).

The general European context

In February 2011, the European Council concluded that Europe should assess its potential for sustainable extraction and use of both conventional and unconventional fossil fuel resources.[1] A 2011 report commissioned by the European Parliament drew attention to the potential health and environmental risks associated with shale gas extraction.

At present, close to half of all EU Member States are interested in developing shale gas resources, if possible. Member States active in this area include Poland, Germany, Netherlands, UK, Spain, Romania, Lithuania and Denmark. Sweden, Hungary and other EU Member States may also be interested in developing activity in this area. However, in response to concerns raised by the general public and stakeholders, several European Member States have prohibited, or are considering the possibility to prohibit the use of hydraulic fracturing. Concurrently, several EU Member States are about to initiate discussions on the appropriateness of their national legislation, and contemplate the possibility to introduce specific national requirements for hydraulic fracturing.

The recent evolution of the European context suggests a growing need for a clear, predictable and coherent approach to unconventional fossil fuels and in particular shale gas developments to allow optimal decisions to be made in an area where economics, finances, environment and in particular public trust are essential.

Against this background, the Commission is investigating the impact of unconventional gas, primarily shale gas, on EU energy markets and has requested this initial, specific assessment of the environmental and health risks and impacts associated with the use of hydraulic fracturing, in particular for shale gas.

Study focus and scope

This report sets out the key environmental and health risk issues associated with the potential development and growth of high volume hydraulic fracturing in Europe. The study focused on the net incremental impacts and risks that could result from the possible growth in use of these techniques. This addresses the impacts and risks over and above those already addressed in regulation of conventional gas exploration and extraction. The study distinguishes shale gas associated practices and activities from conventional ones that already take place in Europe, and identifies the potential environmental issues which have not previously been encountered, or which could be expected to present more significant challenges.

The study reviewed available information on a range of potential risks and impacts of high volume hydraulic fracturing. The study concentrated on the direct impacts of hydraulic fracturing and associated activities such as transportation and wastewater management. The study did not address secondary or indirect impacts such as those associated with materials extraction (stone, gravel etc.) and energy use related to road, infrastructure and well pad construction.

The study has drawn mainly on experience from North America, where hydraulic fracturing has been increasingly widely practised since early in the 2000s. The views of regulators, geological surveys and academics in Europe and North America were sought. Where possible, the results have been set in the European regulatory and technical context.

The study includes a review of the efficiency and effectiveness of current EU legislation relating to shale gas exploration and production and the degree to which the current EU framework adequately covers the impacts and risks identified. It also includes a review of risk management measures.

[1] European Council, Conclusions on Energy, 4 February 2011 (http://www.consilium.europa.eu/uedocs/cms_Data/docs/pressdata/en/ec/119141.pdf)

Preliminary risk assessment

The main risks were assessed at each stage of a project (well-pad) development, and also covered the cumulative environmental effects of multiple installations. The stages are:

1. Well pad site identification and preparation
2. Well design, drilling, casing and cementing
3. Technical hydraulic fracturing stage
4. Well completion
5. Well production
6. Well abandonment.

The study adopted a risk prioritisation approach to enable objective evaluation. The magnitude of potential hazards and the expected frequency or probability of the hazards were categorised on the basis of expert judgement and from analysis of hydraulic fracturing in the field where this evidence was available to allow risks to be evaluated. Where the uncertainty associated with the lack of information about environmental risks was significant, this has been duly acknowledged. This approach enabled a prioritisation of overall risks.

The study authors duly acknowledge the limits of this risk screening exercise, considering notably the absence of systematic baseline monitoring in the US (from where most of the literature sources come), the lack of comprehensive and centralised data on well failure and incident rates, and the need for further research on a number of possible effects including long term ones. Because of the inherent uncertainty associated with environmental risk assessment studies, expert judgement was used to characterise these effects.

The study identified a number of issues as presenting a high risk for people and the environment. These issues and their significance are summarised in the following table.

Table ES1: Summary of preliminary risk assessment

Environmental aspect	Project phase						
	Site identification and preparation	Well design drilling, casing, cementing	Fracturing	Well completion	Production	Well abandonment and post-abandonment	Overall rating across all phases
Individual site							
Groundwater contamination	Not applicable	Low	Moderate-**High**	**High**	Moderate-**High**	Not classifiable	**High**
Surface water contamination	Low	Moderate	Moderate-**High**	**High**	Low	Not applicable	**High**
Water resources	Not applicable	Not applicable	Moderate	Not applicable	Moderate	Not applicable	Moderate
Release to air	Low	Moderate	Moderate	Moderate	Moderate	Low	Moderate
Land take	Moderate	Not applicable	Not applicable	Not applicable	Moderate	Not classifiable	Moderate
Risk to biodiversity	Not classifiable	Low	Low	Low	Moderate	Not classifiable	Moderate
Noise impacts	Low	Moderate	Moderate	Not classifiable	Low	Not applicable	Moderate – **High**
Visual impact	Low	Low	Low	Not applicable	Low	Low-moderate	Low - Moderate
Seismicity	Not applicable	Not applicable	Low	Low	Not applicable	Not applicable	Low
Traffic	Low	Low	Moderate	Low	Low	Not applicable	Moderate
Cumulative							
Groundwater contamination	Not applicable	Low	Moderate-**High**	**High**	**High**	Not classifiable	**High**
Surface water contamination	Moderate	Moderate	Moderate-**High**	**High**	Moderate	Not applicable	**High**
Water resources	Not applicable	Not applicable	**High**	Not applicable	**High**	Not applicable	**High**
Release to air	Low	**High**	**High**	**High**	**High**	Low	**High**
Land take	**Very high**	Not applicable	Not applicable	Not applicable	**High**	Not classifiable	**High**
Risk to biodiversity	Not classifiable	Low	Moderate	Moderate	**High**	Not classifiable	**High**
Noise impacts	Low	**High**	Moderate	Not classifiable	Low	Not applicable	**High**
Visual impact	Moderate	Moderate	Moderate	Not applicable	Low	Low-moderate	Moderate
Seismicity	Not applicable	Not applicable	Low	Low	Not applicable	Not applicable	Low
Traffic	**High**	**High**	**High**	Moderate	Low	Not applicable	**High**

Not applicable: Impact not relevant to this stage of development
Not classifiable: Insufficient information available for the significance of this impact to be assessed

General risk causes

In general, the main causes of risks and impacts from high-volume hydraulic fracturing identified in the course of this study are as follows:

- The use of more significant volumes of water and chemicals compared to conventional gas extraction
- The lower yield of unconventional gas wells compared to conventional gas wells means that the impacts of HVHF processes can be greater than the impacts of conventional gas exploration and production processes per unit of gas extracted.
- The challenge of ensuring the integrity of wells and other equipment throughout the development, operational and post-abandonment lifetime of the plant (well pad) so as to avoid the risk of surface and/or groundwater contamination
- The challenge of ensuring that spillages of chemicals and waste waters with potential environmental consequences are avoided during the development and operational lifetime of the plant (well pad)
- The challenge of ensuring a correct identification and selection of geological sites, based on a risk assessment of specific geological features and of potential uncertainties associated with the long-term presence of hydraulic fracturing fluid in the underground
- The potential toxicity of chemical additives and the challenge to develop greener alternatives
- The unavoidable requirement for transportation of equipment, materials and wastes to and from the site, resulting in traffic impacts that can be mitigated but not entirely avoided.
- The potential for development over a wider area than is typical of conventional gas fields
- The unavoidable requirement for use of plant and equipment during well construction and hydraulic fracturing, leading to emissions to air and noise impacts.

Environmental pressures

Land-take

The American experience shows there is a significant risk of impacts due to the amount of land used in shale gas extraction. The land use requirement is greatest during the actual hydraulic fracturing stage (i.e. stage 3), and lower during the production stage (stage 5). Surface installations require an area of approximately 3.6 hectares per pad for high volume hydraulic fracturing during the fracturing and completion phases, compared to 1.9 hectares per pad for conventional drilling. Land-take by shale gas developments would be higher if the comparison is made per unit of energy extracted. Although this cannot be quantified, it is estimated that approximately 50 shale gas wells might be needed to give a similar gas yield as one North Sea gas well. Additional land is also required during re-fracturing operations (each well can typically be re-fractured up to four times during a 40 years well lifetime). Consequently, approximately 1.4% of the land above a productive shale gas well may need to be used to exploit the reservoir fully. This compares to 4% of land in Europe currently occupied by uses such as housing, industry and transportation. This is considered to be of potentially major significance for shale gas development over a wide area and/or in the case of densely populated European regions.

The evidence suggests that it may not be possible fully to restore sites in sensitive areas following well completion or abandonment, particularly in areas of high agricultural, natural or cultural value. Over a wider area, with multiple installations, this could result in a significant loss or fragmentation of amenities or recreational facilities, valuable farmland or natural habitats.

Releases to air

Emissions from numerous well developments in a local area or wider region could have a potentially significant effect on air quality. Emissions from wide scale development of a shale gas reservoir could have a significant effect on ozone levels. Exposure to ozone could have an adverse effect on respiratory health and this is considered to be a risk of potentially high significance.

The technical hydraulic fracturing stage also raises concerns about potential air quality effects. These typically include diesel fumes from fracturing liquid pumps and emissions of hazardous pollutants, ozone precursors and odours due to gas leakage during completion (e.g. from pumps, valves, pressure relief valves, flanges, agitators, and compressors).

There is also concern about the risk posed by emissions of hazardous pollutants from gases and hydraulic fracturing fluids dissolved in waste water during well completion or recompletion. Fugitive emissions of methane (which is linked to the formation of photochemical ozone as well as climate impacts) and potentially hazardous trace gases may take place during routeing gas via small diameter pipelines to the main pipeline or gas treatment plant.

On-going fugitive losses of methane and other trace hydrocarbons are also likely to occur during the production phase. These may contribute to local and regional air pollution with the potential for adverse impacts on health. With multiple installations the risk could potentially be high, especially if re-fracturing operations are carried out.

Well or site abandonment may also have some impacts on air quality if the well is inadequately sealed, therefore allowing fugitive emissions of pollutants. This could be the case in older wells, but the risk is considered low in those appropriately designed and constructed. Little evidence exists of the risks posed by movements of airborne pollutants to the surface in the long-term, but experience in dealing with these can be drawn from the management of conventional wells.

Noise pollution

Noise from excavation, earth moving, plant and vehicle transport during site preparation has a potential impact on both residents and local wildlife, particularly in sensitive areas. The site preparation phase would typically last up to four weeks but is not considered to differ greatly in nature from other comparable large-scale construction activity.

Noise levels vary during the different stages in the preparation and production cycle. Well drilling and the hydraulic fracturing process itself are the most significant sources of noise. Flaring of gas can also be noisy. For an individual well the time span of the drilling phase will be quite short (around four weeks in duration) but will be continuous 24 hours a day. The effect of noise on local residents and wildlife will be significantly higher where multiple wells are drilled in a single pad, which typically lasts over a five-month period. Noise during hydraulic fracturing also has the potential to temporarily disrupt and disturb local residents and wildlife. Effective noise abatement measures will reduce the impact in most cases, although the risk is considered moderate in locations where proximity to residential areas or wildlife habitats is a consideration.

It is estimated that each well-pad (assuming 10 wells per pad) would require 800 to 2,500 days of noisy activity during pre-production, covering ground works and road construction as well as the hydraulic fracturing process. These noise levels would need to be carefully controlled to avoid risks to health for members of the public.

Surface and groundwater contamination

The study found that there is a high risk of surface and groundwater contamination at various stages of the well-pad construction, hydraulic fracturing and gas production processes, and during well abandonment. Cumulative developments could further increase this risk.

Runoff and erosion during early site construction, particularly from storm water, may lead to silt accumulation in surface waters and contaminants entering water bodies, streams and groundwater. This is a problem common to all large-scale mining and extraction activities. However, unconventional gas extraction carries a higher risk because it requires high-volume processes per installation and the risks increase with multiple installations. Shale gas installations are likely to generate greater storm water runoff, which could affect natural habitats through stream erosion, sediment build-up, water degradation and flooding. Mitigation measures, such as managed drainage and controls on certain contaminants, are well understood. Therefore the hazard is considered minor for individual installations with a low risk ranking and moderate hazard for cumulative effects with a moderate risk ranking. Road accidents involving vehicles carrying hazardous materials could also result in impacts on surface water.

The study considered the water contamination risks of sequential as well as simultaneous (i) well-drilling and (ii) hydraulic fracturing.

i. Poor well design or construction can lead to subsurface groundwater contamination arising from aquifer penetration by the well, the flow of fluids into, or from rock formations, or the migration of combustible natural gas to water supplies. In a properly constructed well, where there is a large distance between drinking water sources and the gas producing zone and geological conditions are adequate, the risks are considered low for both single and multiple installations. Natural gas well drilling operations use compressed air or muds as the drilling fluid. During the drilling stage, contamination can arise as a result of a failure to maintain storm water controls, ineffective site management, inadequate surface and subsurface containment, poor casing construction, well blowout or component failure. If engineering controls are insufficient, the risk of accidental release increases with multiple shale gas wells. Cuttings produced from wells also need to be properly handled to avoid for instance the risk of radioactive contamination. Exposure to these could pose a small risk to health, but the study concluded that this would only happen in the event of a major failure of established control systems. No evidence was found that spillage of drilling muds could have a significant effect on surface waters. However, in view of the potential significance of spillages on sensitive water resources, the risks for surface waters were considered to be of moderate significance.
ii. The risks of surface water and groundwater contamination during the technical hydraulic fracturing stage are considered moderate to high. The likelihood of properly injected fracturing liquid reaching underground sources of drinking water through fractures is remote where there is more than 600 metres separation between the drinking water sources and the producing zone. However, the potential of natural and manmade geological features to increase hydraulic connectivity between deep strata and more shallow formations and to constitute a risk of migration or seepage needs to be duly considered. Where there is no such large depth separation, the risks are greater. If wastewater is used to make up fracturing fluid, this would reduce the water requirement, but increase the risk of introducing naturally occurring chemical contaminants and radioactive materials into aquifers in the event of well failure or of fractures extending out of the production zone. The potential wearing effects of repeated fracturing on well construction components such as casings and cement are not sufficiently understood and more research is needed.

In the production phase, there are a number of potential effects on groundwater associated however with the inadequate design or failure of well casing, leading to potential aquifer contamination. Substances of potential concern include naturally occurring heavy metals, natural gas, naturally occurring radioactive material and technologically enhanced radioactive material from drilling operations. The risks to groundwater are considered to be moderate-high for individual sites, and high for development of multiple sites.

Inadequate sealing of a well after abandonment could potentially lead to both groundwater and surface water contamination, although there is currently insufficient information available on the risks posed by the movement of hydraulic fracturing fluid to the surface over the long term to allow these risks to be characterised. The presence of high-salinity fluids in shale gas formations indicates that there is usually no pathway for release of fluids to other formations under the geological conditions typically prevailing in these formations, although recently published research indicates that pathways may potentially exist in certain geological areas such as those encountered in parts of Pennsylvania, emphasising the need for a high standard of characterisation of these conditions.

Water resources

The hydraulic fracturing process is water-intensive and therefore the risk of significant effects due to water abstraction could be high where there are multiple installations. A proportion of the water used is not recovered. If water usage is excessive, this can result in a decrease in the availability of public water supply; adverse effects on aquatic habitats and ecosystems from water degradation, reduced water quantity and quality; changes to water temperature; and erosion. Areas already experiencing water scarcity may be affected especially if the longer term climate change impacts of water supply and demand are taken into account. Reduced water levels may also lead to chemical changes in the water aquifer resulting in bacterial growth causing taste and odour problems with drinking water. The underlying geology may also become destabilised due to upwelling of lower quality water or other substances. Water withdrawal licences for hydraulic fracturing have recently been suspended in some areas of the United States.

Biodiversity impacts

Unconventional gas extraction can affect biodiversity in a number of ways. It may result in the degradation or complete removal of a natural habitat through excessive water abstraction, or the splitting up of a habitat as a result of road construction or fencing being erected, or for the construction of the well-pad itself. New, invasive species such as plants, animals or micro-organisms may be introduced during the development and operation of the well, affecting both land and water ecosystems. This is an area of plausible concern but there is as yet no clear evidence base to enable the significance to be assessed.

Well drilling could potentially affect biodiversity through noise, vehicle movements and site operations. The treatment and disposal of well drilling fluids also need to be adequately handled to avoid damaging natural habitats. However, these risks are lower than during other stages of shale drilling.

During hydraulic fracturing, the impacts on ecosystems and wildlife will depend on the location of the well-pad and its proximity to endangered or threatened species. Sediment runoff into streams, reductions in stream flow, contamination through accidental spills and inadequate treatment of recovered waste-waters are all seen as realistic threats as is water depletion. However, the study found that the occurrence of such effects was rare and cumulatively the risks could be classified as moderate.

Effects on natural ecosystems during the gas production phase may arise due to human activity, traffic, land-take, habitat degradation and fragmentation, and the introduction of invasive species. Pipeline construction could affect sensitive ecosystems and re-fracturing would also cause continuing impacts on biodiversity. The possibility of land not being suitable for return to its former use after well abandonment is another factor potentially affecting local ecosystems. Biodiversity risks during the production phase were considered to be potentially high for multiple installations.

Traffic

Total truck movements during the construction and development phases of a well are estimated at between 7,000 and 11,000 for a single ten-well pad. These movements are temporary in duration but would adversely affect both local and national roads and may have a significant effect in densely populated areas. These movements can be reduced by the use of temporary pipelines for transportation of water.

During the most intensive phases of development, it is estimated that there could be around 250 truck trips per day onto an individual site – noticeable by local residents but sustained at these levels for a few days. The effects may include increased traffic on public roadways (affecting traffic flows and causing congestion), road safety issues, damage to roads, bridges and other infrastructure, and increased risk of spillages and accidents involving hazardous materials. The risk is considered to be moderate for an individual installation, and high for multiple installations.

Visual impact

The risk of significant visual effects during well-pad site identification and preparation are considered to be low given that the new landscape features introduced during the well pad construction stage are temporary and common to many other construction projects. The use of large well drilling rigs could potentially be unsightly during the four-week construction period, especially in sensitive high-value agricultural or residential areas. Local people are not likely to be familiar with the size and scale of these drills, and the risk of significant effects was considered to be moderate in situations where multiple pads are developed in a given area.

The risk of visual effects associated with hydraulic fracturing itself is less significant, with the main changes to the landscape consisting of less visually intrusive features. For multiple installations, the risk is considered to be moderate from the site preparation to the fracturing phases. During the post-abandonment phase, it may not be possible to remove all wellhead equipment from the site; however, this is considered to pose a low risk of significant visual intrusion, in view of the small scale of equipment remaining on site.

Seismicity

There are two types of induced seismic events associated with hydraulic fracturing. The hydraulic fracturing process itself can under some circumstances give rise to minor earth tremors up to a magnitude of 3 on the Richter Scale, which would not be detectable by the public. An effective monitoring programme can be used to manage the potential for these events and identify any damage to the wellbore itself. The risk of significant induced seismic activity was considered to be low.

The second type of event results from the injection of waste water reaching existing geological faults. This could lead to more significant underground movements, which can potentially be felt by humans at ground level. This would not take place at the shale gas extraction site.

European Legislation

The objectives of the review of the current EU environmental framework were threefold:

- To identify potential uncertainties regarding the extent to which shale gas exploration and production risks are covered under current EU legislation
- To identify those risks not covered by EU legislation
- To draw conclusions relating to the risk to the environment and human health of such operations in the EU.

An analysis of all EU 27 Member States' legislation and standards was outside the scope of this study, as was the consistency of Member States' implementation of the EU legislation reviewed.

In all, 19 pieces of legislation relevant to all or some of the stages of shale gas resource development were identified and reviewed.

A number of gaps or possible inadequacies in EU legislation were identified. These were classified as follows:

- *Inadequacies in EU legislation* that could lead to risks to the environment or human health not being sufficiently addressed.
- *Potential inadequacies –uncertainties in the applicability of EU legislation*: the potential for risks to be insufficiently addressed by EU legislation, where uncertainty arises because a lack of information regarding the characteristics of high volume hydraulic fracturing (HVHF) projects.
- *Potential inadequacies –uncertainties in the existence of appropriate requirements at national level*: aspects relying on a high degree of Member State decision-making for which it is not possible to conclude under this study whether or not at EU level the risks are adequately addressed.

The legislative review identified the following gaps or potential gaps in European legislation (please see the discussion of limitations of the analysis in Section 3.1):

Table ES2: Summary of gaps and potential gaps in European legislation

Gap or potential gap	Impact	Risk associated with gap/potential gap
	Gaps in legislation	
Environmental Impact Assessment Directive (2011/92/EU) Annex I threshold for gas production is above HVHF project production levels. Result: no compulsory EIA.	All, especially relevant to key impacts from landtake during preparation, noise during drilling, release to air during fracturing, traffic during fracturing and groundwater contamination	A decision on the exploration and production may not be based on an impact assessment. Public participation may not be guaranteed, permits may not be tailor-made to the situation Impacts may not be known and assessed. Measures to mitigate possible impacts may not be applied through consent process or permitting regime.
Environmental Impact Assessment Directive (2011/92/EU) Annex II no definition of deep drilling; exploration phase would not be covered under Annex II classification "Surface industrial installations for the extraction of coal, petroleum, natural gas and ores, as well as bituminous shale". Result: no compulsory EIA	All, especially relevant to key impacts from landtake during preparation, noise during drilling, release to air during fracturing, traffic during fracturing and groundwater contamination	A decision on the exploration and production may not be based on an impact assessment. Public participation may not be guaranteed, permits may not be tailor-made to the situation HVHF project involving shallow drillings not covered by EIA. For these projects, impacts may not be known and assessed. Measures to mitigate possible impacts may not be applied through consent process or permitting regime. Preventative measures may not be undertaken. Aquifers in surroundings not known, leading to unanticipated pollution.
Environmental Impact Assessment Directive (2011/92/EU) No explicit coverage of geomorphological and hydrogeological aspects, no obligation to assess geological features as part of the impact assessment	Especially relevant for groundwater contamination, seismicity, land impacts, release to air	No assessment of geological and hydrogeological conditions (e.g. natural and manmade faults, fissures, hydraulic connectivity, distance to aquifers, etc) in the frame of the impact assessment or screening, resulting in sub-optimal site selection and risks of subsequent pollution Monitoring of groundwater quality of aquifers in surrounding of the site may not be done and preventative measures not undertaken. Aquifers in surroundings not known, leading to unanticipated pollution.
Water Framework Directive (2000/60/EC) WFD programmes of measures are not required to be enforced until	Abstraction of water and impacts due to water contamination	Inadequate monitoring and measures to prevent these impacts

Gap or potential gap	Impact	Risk associated with gap/potential gap
22.12.2012		
Water Framework Directive (2000/60/EC) For substances which are not pollutants, the WFD does not prevent direct fracturing into groundwater that may ultimately impact aquifers	Pollution of groundwater	"Pollutants" are defined as "any substance liable to cause pollution, in particular those listed in Annex VIII." Permit conditions may not require monitoring or measures to prevent hydraulic fracturing leading to impacts on aquifers
Mining Waste Directive (2006/21/EC) No reference document on Best Available Techniques (BREFs)	Waste management as covered by MWD – treatment of hydraulic fracturing fluids during and after fracturing	No shared opinion on Best Available Techniques nor enforcement of those techniques Higher levels of pollution arising from the management of mining waste
Directives on Emissions from Non-Road Mobile Machinery (Directive 97/68/EC as amended) Lack of emission limits for off-road combustion plant above 560 kW	Air pollution especially during drilling and fracturing	Measures may not be taken to prevent high emissions to air, leading to localised increased air pollution, although purpose of legislation is to regulate machine standards not emissions during use.
IPPC Directive (2008/1/EC) and IED (2010/75/EC) No BREF for drilling equipment	Air pollution especially during drilling and fracturing	Measures may not be taken to prevent high emissions to air, leading to localised increased air pollution. This potential gap arises because of uncertainty over the hazardous character of fracturing fluids which would determine the applicability of the IPPC Directive (2008/1/EC) to hydraulic fracturing installations
The Outdoor Machinery Noise Directive2000/14/EC Gaps in limits to prevent noise for specific equipment	Noise during drilling	Drilling equipment used in HVHF processes however is not included in the equipment cited in this directive. Compressors used for drilling have a power capacity over 350 kW, which is the limit for this directive
Air Quality Directive (2008/50/EC) Not specific about remedial measures or prohibition of polluting activities	Air pollution during drilling and fracturing and traffic impacts	No measures to reduce emissions to air. Levels of air pollution may be above impact levels or air quality standards.
Environmental Liability Directive (2004/35/EC) Damage caused by non Annex III activities not covered unless it is damage to protected species and natural habitats resulting from a fault or negligence on part of operator. Impacts caused by diffuse pollution are not covered, unless a causal link can be established	Landtake, air impacts during drilling and fracturing and traffic	Some environmental impacts may not be covered.
Uncertainties in application		
IPPC Directive (2008/1/EC) and IED (2010/75/EC) Activity not mentioned or may not be covered under hazardous waste or combustion capacity	Emissions to air, water and soil	No permit obligation under IPPC and no BREF under IPPC or IED .This potential gap arises because of uncertainty over the hazardous character of fracturing fluids which would determine the applicability of the IPPC Directive (2008/1/EC) to hydraulic fracturing installations

Gap or potential gap	Impact	Risk associated with gap/potential gap
		The monitoring requirements as mentioned in IPPC directive may not be applied. Integrated measures designed to prevent or to reduce emissions in the air, water and land, including measures concerning waste, in order to achieve a high level of protection of the environment may not be taken. Monitoring of emissions to air might not take place.
Mining Waste Directive (2006/21/EC) Uncertainty over classification of Category A waste facility	Major accidents, groundwater and surface water pollution, air impacts	The classification may be inadequately performed Major accidents might occur without proper prevention and emergency plans.
Seveso II Directive (96/82/EC) Uncertainty over whether the Directive covers high volume hydraulic fracturing (HVHF), subject to storage of natural gas or of specific chemical additives on-site.	Major accidents involving dangerous substances (e.g. water pollution events)	Major accidents might occur without proper prevention and emergency plans.
Issues currently at the discretion of Member States		
The Strategic Environmental Assessment Directive (2001/42/EC) Remains up to Member States to decide whether or not a plan or programme might have significant effects	All	No SEA would be made Information on possible environmental effects would not be available and therefore would not be used in an authorisation/consent process or permits
Environmental Impact Assessment Directive (2011/92/EU) Member States must decide whether an EIA is required (Article 4(2)) for activities covered by Annex II.	All	No EIA would be made. The environmental impacts would not be assessed and properly described. The measures that can prevent or mitigate the impacts will not be presented
Hydrocarbons Authorization Directive (94/22/EC) No compulsory account of environmental aspects	All	Member States may not take account of environmental impacts during the authorisation process
Mining Waste Directive (2006/21/EC) Member States decide on the permit and the control measures	Waste management as covered by MWD – treatment of hydraulic fracturing fluids during and after fracturing	There may be inadequate measures for the monitoring and control of impacts related to management of mining waste
IPPC Directive (2008/1/EC) Member State decisions on monitoring and inspection	Emissions to air, especially during drilling and fracturing, and releases to water during fracturing	There may be inadequate measures for the monitoring and control of impacts related to air and water emissions
Air Quality Directive(2008/50/EC) Member States responsible for making	Emissions to air, especially during drilling, fracturing and traffic, and releases to	No specific measures for emission abatement may be required. Air pollution may not be prevented or mitigated

Gap or potential gap	Impact	Risk associated with gap/potential gap
plans to meet the AQ standards	water during fracturing	
Water Framework Directive (2000/60/EC) Member State determination of control measures related to abstraction	Water use during fracturing	There may be unmitigated or poorly controlled impacts arising from water use during abstraction
Noise Directive (2002/49/EC) Up to Member States to set noise levels and to make plans to meet these levels	Noise during drilling and fracturing and traffic during fracturing	No specific measures for noise abatement may be required. Noise may not be prevented or mitigated

Study recommendations

As highlighted above, the risks posed by high volume hydraulic fracturing for unconventional hydrocarbon extraction are greater than those of conventional extraction. A number of recent reports have looked at opportunities and challenges of unconventional fossil fuels and shale gas developments, and found that developing unconventional fossil fuel resources generally poses greater environmental challenges than conventional developments. Robust regulatory regimes would be required to mitigate risks and to improve general public confidence (e.g. the "Golden Rules for a Golden Age of Gas" special report from the International Energy Agency, or an independent German study on shale gas entitled "Empfehlungen des Neutralen Expertenkreis" ("Recommendations of the neutral expert group").

Measures for mitigation of these risks were identified from existing and proposed legislation in the US and Canada where shale gas extraction is currently carried out. Measures set out in industry guidance and other publications were also reviewed and included where appropriate.

A number of the recommendations made by the US Department of Energy (SEAB 2011a NPR) are relevant for regulatory authorities in Europe. In particular, it is recommended that the European Commission should take a *strategic* overview of potential risks. This will require consideration of aspects such as:

- Undertaking science-based characterisation of important landscapes, habitats and corridors to inform planning, prevention, mitigation and reclamation of surface effects.
- Establishing effective field monitoring and enforcement to inform on-going assessment of cumulative community and land use effects
- Restricting or preventing development in areas of high value or sensitivity with regard to biodiversity, water resources, community effects etc.

As set out in Section 3.17 and in the table above, it is recommended that the European Commission considers the gaps, possible inadequacies and uncertainties identified in the current EU legislative framework. It is also recommended that Member States' interpretation of EU legislation in respect of hydraulic fracturing should be evaluated.

This study has identified and made recommendations on specific risk management measures for a number of aspects of hydrocarbon developments involving HVHF, and in particular:

- The appropriate siting of developments, to reduce above and below-ground risks for specified projects

- Measures and approaches to reduce land disturbance and land-take
- Measures to address releases to air and to effectively reduce noise during drilling, fracturing and completion
- Measures to address water resource depletion
- Measures to reduce the negative effects caused by increased traffic movements
- Measures to improve well integrity and to reduce the risk of ground and surface water contamination
- Measures to reduce the pressure on biodiversity

A number of recommendations for further consideration and research are made with regard to current areas of uncertainty. These include:

- Consideration and further research over relevant provisions of the Carbon Capture and Storage Directive (2009/31/EC) covering aspects such as: site characterisation and risk assessment, permitting arrangements, monitoring provisions, transboundary co-operation, and liability.
- The use of micro-seismic monitoring in relation to hydraulic fracturing
- Determination of chemical interactions between fracturing fluids and different shale rocks, and displacement of formation fluids
- Induced seismicity triggered by hydraulic fracturing
- Development of less environmentally hazardous drilling and fracturing fluids
- Methods to improve well integrity through development of better casing and cementing methods and practices
- Development of a searchable European database of hydraulic fracturing fluid composition
- Research into the risks and causes of methane migration to groundwater from shale gas extraction
- The development of a system of voluntary ecological initiatives within sensitive habitats to generate mitigation credits which could be used for offsetting future development.

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Appendices

1 Overview of hydraulic fracturing in Europe

1.1 Introduction

This report for the European Commission sets out the key environmental and health risk issues associated with the potential development and growth of high volume hydraulic fracturing in Europe. The study focuses on the net incremental risks which could result from the possible growth in use of high volume hydraulic fracturing in Europe, over and above those risks which are already addressed in regulation of conventional gas practices.

In order to do this, the study identifies activities involving high volume hydraulic fracturing and their potential environmental issues which have not previously been encountered in Europe, or which could be expected to present more significant environmental challenges.

This chapter includes the following components:

- Section 1.2: a description of the study objectives
- Section 1.3: a description of the EU context for shale gas extraction and hydraulic fracturing
- Section 1.4: a discussion of unconventional gas extraction techniques

In chapter 2, the key environmental risks and potential impacts are described. Drawing on the risks identified in chapter 2, chapter 3 describes the identification and appropriateness of applicable EU legislation, providing insights into likely and potential gaps, inadequacies and further uncertainties.

Chapter 4 presents an overview of risk management measures summarised mainly on the basis of the North-American experience. Key risk management measures are discussed in chapter 5 in relation to regulatory gaps, inadequacies and uncertainties identified in chapter 2. A glossary of some relevant terms is provided in Appendix 1.

In this report, peer reviewed references are denoted " PR " and non-peer reviewed references are denoted " NPR ".

1.2 Objective of the study

At present, a considerable number of EU Member States are interested in developing shale gas resources, if possible. Member States active in this area include Poland, Germany, Netherlands, UK, Spain, Romania, Lithuania and Denmark. Sweden, Hungary and other EU Member States may also be interested in developing activity in this area. However, in response to concerns raised by the general public and stakeholders, several European Member States have prohibited, or are considering the possibility to prohibit the use of hydraulic fracturing. Concurrently, several EU Member States are about to initiate discussions on the appropriateness of their national legislation, and are considering the possibility of introducing specific national requirements for hydraulic fracturing.

In its meeting of 4 February 2011, the European Council concluded that Europe should assess its potential for sustainable extraction and use of conventional and unconventional fossil fuel resources.[2] A 2011 report commissioned by the European Parliament drew

[2] European Council, Conclusions on Energy, 4 February 2011 (http://www.consilium.europa.eu/uedocs/cms_Data/docs/pressdata/en/ec/119141.pdf)

attention to environmental risks associated with shale gas extraction (Lechtenböhmer et al. 2011, NPR). More recently, a number of reports that looked at opportunities and challenges of unconventional fossil fuels and shale gas developments have found that producing unconventional fossil fuel resources generally imposes a larger environmental footprint than conventional developments. These studies indicate that robust regulatory regimes would be required to mitigate risks and to improve general public confidence (e.g. International Energy Agency 2012 NPR ; Exxon Mobil 2012a NPR).

Against this background, the Commission requested a specific assessment of the environmental and health risks associated with the use of hydraulic fracturing for hydrocarbon extraction, and in particular, shale gas extraction.

Throughout this report, the term “risk” refers to an adverse outcome which may possibly occur as a result of the use of hydraulic fracturing for hydrocarbon extraction in Europe. Risks may be mitigated by taking steps to reduce the likelihood and/or significance of the adverse outcome. The term “impact” refers to all adverse outcomes – that is, those which will definitely occur to a greater or lesser extent, as well as those which may possibly occur. For example, the use of high volume hydraulic fracturing will definitely result in traffic movements, and this can be described as an “impact.” High volume hydraulic fracturing may result in spillage of chemicals, and this can be described as a “risk”.

This study focuses on environmental and health risks. The potential climate impacts of shale gas exploration and production are not addressed in this study, but will be addressed in a separate study commissioned by DG CLIMA.

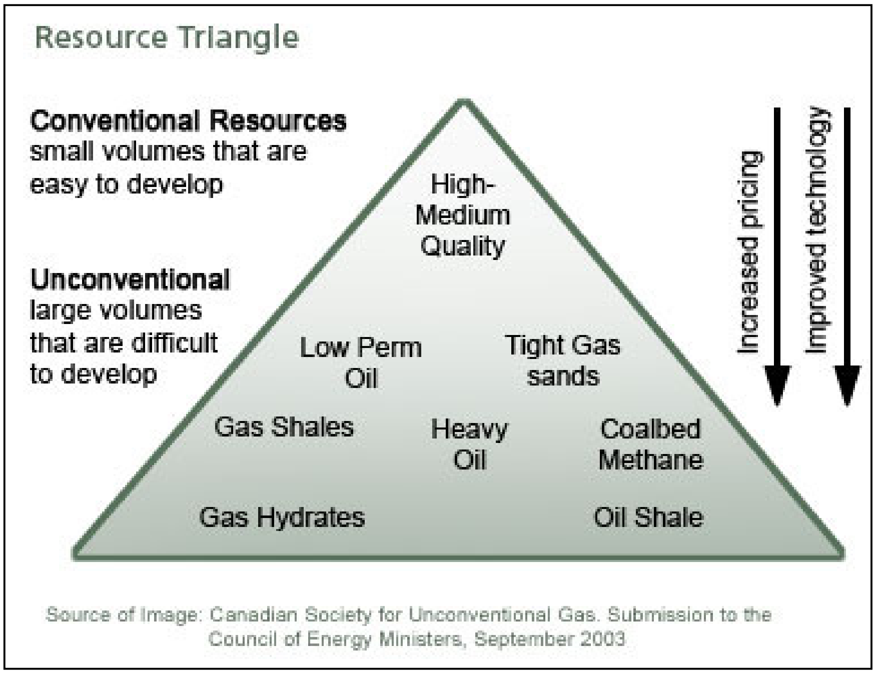
1.3 EU Context

1.3.1 Conventional and unconventional fossil fuels

Conventional and unconventional hydrocarbons can be considered on the basis of the resource triangle provided below (see Figure 1). Conventional resources (illustrated at the apex of the triangle) represent a small proportion of the total hydrocarbons but are less expensive to develop and produce. In contrast, unconventional hydrocarbons depicted by the lower part of the triangle tend to occur in substantially higher volumes but require more costly technologies to develop and produce.

Exploration and production in Europe has in the past mainly been focused on the apex of the triangle. However, opportunities at the top of the triangle are becoming increasingly inadequate to meet demand. As well as importing natural gas from outside Europe, the industry is thus pursuing opportunities lower in the triangle as long as market conditions are such that the opportunities are considered to be economically viable, and can attract investment.

Figure 1: The hydrocarbon resource triangle



"Conventional" gas is trapped in reservoirs in which buoyant forces keep hydrocarbons in place below a sealing caprock. The combination of good permeability and high gas content typically permits natural gas (and oil) to flow readily into wellbores through conventional methods that do not require artificial stimulation. Conventional reservoirs are typically sandstone, siltstone and carbonate (limestone) reservoirs (British Geological Survey, 2011 NPR). In contrast, releasing natural gas from unconventional formations and bearing rocks requires typically a system of natural and/or artificial fractures.

Shale gas, along with tight gas and coalbed methane, is an example of unconventional natural gas (see Figure 1). The term "*unconventional*" does not refer to the characteristics or composition of the gas itself, which are the same as "conventional" natural gas, but to the porosity, permeability, fluid trapping mechanism, or other characteristics of the reservoir or bearing rock formation from which the gas is extracted, which differ from conventional sandstone and carbonate reservoirs. These characteristics result in the need to alter the geological features of the reservoir or bearing rock formation using artificial stimulation techniques such as hydraulic fracturing in order to extract the gas.

Oil could potentially also be extracted from unconventional reservoirs such as oil shales using hydraulic fracturing techniques. However, there is at present no indication of a significant increase in shale oil production in Europe or the US. This study therefore focuses on unconventional gas extraction.

Shale gas

Gas shales are geologic formations of organic-rich shale, a sedimentary rock formed from deposits of mud, silt, clay, and organic matter, in which substantial quantities of natural gas could be present. As described above, the shales are continuous deposits typically extending over areas of thousands of square kilometres, (US EIA 2011 NPR Sections V, VI and VII), have very low permeabilities and low natural production capacities. The extremely low permeability of the rock means that shales must be artificially stimulated (fractured) to enable the extraction of natural gas.

Gas generation in a shale formation occurs by two main processes. Both require the presence of organic rich material in the shale:

1. Biogenic production related to the action of anaerobic micro-organisms at low temperatures and,
2. Thermogenic production associated with higher temperatures and pressures and, greater burial depths

Biogenic processes tend to produce less gas per unit volume of sediment than thermogenic processes (New Mexico Bureau of Geology and Mineral Resources, undated NPR). Consequently, wells used for extraction of biogenic shale gas tend to be low volume and at shallower depths (<600 m), although this is not necessarily the case (Clayton, 2009 NPR).

The main differences between conventional reservoirs and unconventional shale gas reservoirs are:

- In conventional reservoirs the hydrocarbons have migrated (upward) from a source rock (e.g. coal or shale). In contrast, in a shale gas reservoir, the natural gas is held within the source rock. Because of the large areas of clay deposition in tidal flats and deep water, shale gas reserves can cover wider areas extending to tens of thousands of square km(US EIA 2011 NPR Sections V, VI and VII) and typically have low gas content per rock volume;
- In conventional reservoirs a stratigraphic trap or cap rock is always present (e.g. salt or shale). With unconventional reservoirs in Europe, a cap rock is not always present. When used in conventional reservoirs, fracturing fluids are thus always contained by the stratigraphic trap. In unconventional reservoirs such as shale gas, this is not always the case.
- The permeability in unconventional reservoirs is significantly lower than the permeability in unconventional (shale gas) reservoirs. Unconventional reservoirs have a very low permeability, which ranges typically from 10^{-4} to 10^{-1}millidarcy (md)[3] in the case of tight gas, or 10^{-5} to $5.0x10^{-4}$ md in the case of shale gas. By contrast, the permeability of a conventional reservoir ranges from 10^{-1} to 10^{4} md (Holditch 2006 PR Figure 1; Reinicke 2011 NPR p4). The higher permeability of conventional reservoirs means that hydrocarbons are able to flow freely to the bored well casing. USEIA (2012 NPR) defines conventional gas production as "*natural gas that is produced by a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the oil and natural gas to readily flow to the wellbore*").
- In Europe, the majority of conventional oil and gas extraction has taken place offshore. In contrast, the majority of shale gas exploration and potential is onshore. This results in a different range of risks, potential environmental and human exposure, and consequences to those which need to be addressed for offshore extraction.

Considerable potential for expansion in shale gas exploration and production has been identified in industry forecasts (PGNiG (2011 NPR) quoting Douglas-Westwood, 2011 NPR). The United States Department of Energy (2011 NPR) estimated technically recoverable shale gas reserves to amount to approximately 13 trillion cubic metres, approximately equivalent to 35 years of natural gas consumption in Europe. However, questions remain regarding the long-term viability of the industry in the light of ongoing availability of conventional resources, questions about the lifetime of unconventional wells and preliminary results from exploratory drilling in Poland (e.g. New York Times, June 2011 NPR ; Exxon Mobil 2012b NPR). Only exploratory drilling can confirm the economic potential of unconventional gas in Europe.

The low permeability of shale gas plays means that horizontal wells paired with hydraulic fracturing are required in order for natural gas recovery to be viable. The typically extensive

[3] Darcy (or darcy unit) and Millidarcy (md, or one thousandth of a darcy), are units of fluid permeability used by geologists to characterise geological formations, in particular oil and gas reservoirs.

area of shale gas formations opens the possibility of extensive development of large gas fields. This is in contrast to conventional gas extraction, which has been localised in nature within the European gas fields (see USGS, 1997 NPR).

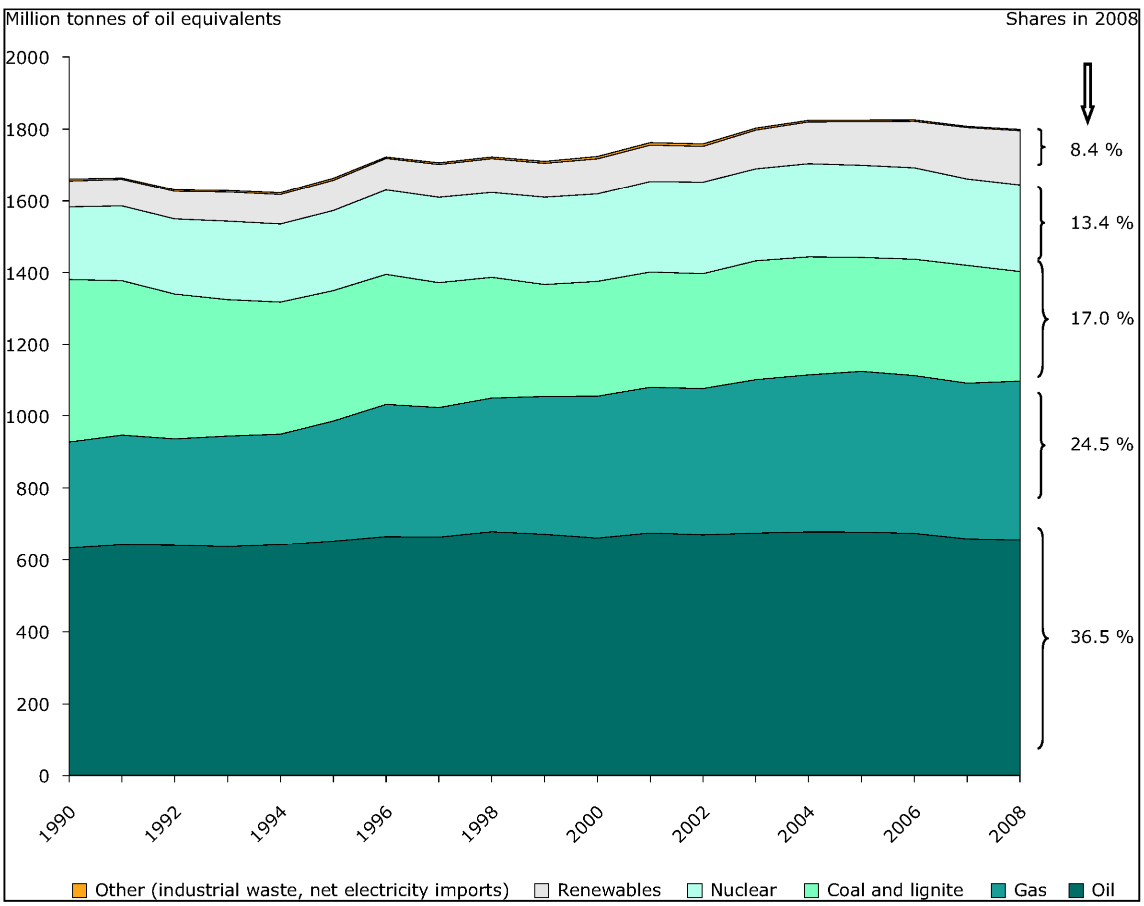
The majority of prospective shale gas formations in Europe can be expected to be deep – for example, shale gas formation plays in Poland and the Baltic states are at a depth of below 2km. However, the situation is more complex in relation to the Alum Shale in the Baltic area, and the extremely complex geology in Romania and Bulgaria. In particular, Alum Shale reaches the near surface (<10m) in the Baltic area. In complex, folded and fractured geology where the target formation might be close to the surface, the likelihood of any near surface formation retaining sufficient gas to be exploitable is much lower. This is because of the need for the formation to have been previously buried deep enough to reach the temperatures required for gas generation, and the need for the formation to retain impermeable rock of high integrity. Consequently, near-surface shale gas deposits are possible in Europe, although they are not likely to be widespread. Recent industry reports indicate that shale gas has been confirmed at shallow depths of 75 – 85 metres in the Ekeby area, onshore Sweden (Natural Gas Europe, 2012 NPR).

Appendix 4 provides further information on conventional and unconventional hydrocarbon extraction and resources in Europe.

1.3.2 Energy sources in Europe

Primary energy consumption in Europe between 1990 and 2008 is summarised in Figure 2.

Figure 2: Sources of primary energy consumption in Europe



Source: European Environment Agency, 2012 NPR
(http://www.eea.europa.eu/data-and-maps/figures/primary-energy-consumption-by-fuel-1)

Natural gas accounted for approximately 25% of primary energy consumption in Europe in 2008. The vast majority of this gas production was from conventional reservoirs. No specific figures are available for unconventional gas or oil production in Europe, most likely because the contribution of unconventional sources is an extremely small proportion of total gas production.

1.3.3 Definition of high volume hydraulic fracturing

From a technical viewpoint, hydraulic fracturing is the process by which a liquid under pressure causes a geological formation to crack open. The main use of interest for the purpose of this project is the use of hydraulic fracturing for extraction of hydrocarbons (natural gas or oil). The process is also known as “HF”, “fracking,” “fraccing” or “fracing,” but is referred to as “hydraulic fracturing” or “fracturing” in this report.

Within the scope of this study, hydraulic fracturing is to be understood as the cycle of operations from the upstream acquisition of water, to chemical mixing of the fracturing fluid, injection of the fluid into the formation, the production and management of flowback and produced water, and the ultimate treatment and disposal of hydraulic fracturing wastewater.

Hydraulic fracturing is used for vertical wells in conventional oil and gas formations to a limited extent in Europe and to a considerable extent in the US. Hydraulic fracturing is used in vertical and directional wells in unconventional formations.

Use of horizontal wells

It had long been recognized that substantial supplies of natural gas were embedded in shale rock. Horizontal drilling techniques were developed at the Wytch Farm shale oil and gas site in the UK during the 1980s. In 2002/2003, hydraulic fracturing and horizontal drilling enabled commercial shale gas extraction to commence in the US (SEAB, 2011a NPR ; New York State 2011 PR Section 1). Directional/horizontal drilling techniques and hydraulic fracturing techniques developed in the US allow the well to penetrate along the hydrocarbon bearing rock seam. This maximises the rock area that, once fractured, is in contact with the well bore and so maximises well production in terms of the flow and volume of gas that may be collected from the well.

To drill and fracture a shale gas well, operators first drill down vertically until they reach the shale formation. Within the target shale formation, the operators then drill horizontally or at an angle to the vertical to create a lateral or angled well through the shale rock. The US EPA (2012a NPR) indicates that horizontal well length may be up to 2000 metres. New York State DEC (2011 PR p5-22) suggests that well lengths are normally greater than 1200 metres. In the Marcellus Shale formation in Pennsylvania, a typical horizontal well may extend from 600 to 2,000 metres and sometimes approaches 3,000 metres (Arthur et al., 2008 NPR). The USEPA (2011a PR) reports that horizontal wells used for unconventional gas extraction can extend more than 1.5 km below the ground surface (Chesapeake Energy, 2010 NPR), while the “toe” of the horizontal leg can be up to 3 km from the vertical leg (Zoback et al., 2010 NPR). This suggests that a typical horizontal section can be expected to be 1200 to 3000 metres in length

Directional drilling is also used in coalbed methane recovery. In this case, the drilling follows the coal seam, and is not necessarily horizontal. The term “horizontal” drilling is normally used in respect of shale gas, and is used to represent both horizontal and directional drilling in this report.

Definition of high volume horizontal fracturing

Because of the longer well lengths, higher pressures and higher volumes of water are required for horizontal hydraulic fracturing compared to conventional fracturing. The quantities of water used depend on well characteristics (depth, horizontal distance) and the number of fracturing stages within the well. Vertical shale gas wells typically use approximately 2,000 cubic metres water (US Department of Energy 2009 NPR pp 74-77). In contrast, horizontal shale gas wells typically use 10,000 to 25,000 m^3 water per well, based on the following assessments:

- New York State DEC (2011 PR p3-6) indicates that a single multi-stage well would typically use 10,800 to 35,000 m^3 fluid per well.
- DOE (2009 NPR p64) reports that shale gas wells typically use 10,000 – 17,000 m^3 water per well, with typically 4-5 stages per well. This information is referenced by US EPA (2011a PR p22)
- BRGM suggests that horizontal wells typically use 10,000 to 20,000 m^3 fluid per well (BRGM 2011 NPR , p59).
- The SEAB (2011a NPR) suggests that a shale gas well requires 4,500 to 22,500 m^3 fluid per well.

The use of higher volumes of water in this way is known as high volume horizontal (or directional) fracturing. This differentiates the use of hydraulic fracturing for unconventional gas extraction from current hydraulic fracturing activities in Europe. High volume hydraulic fracturing requires significantly more water than current hydrocarbon extraction techniques, and could potentially enable the development of extensive shale gas plays in Europe which would not otherwise be commercially or technically viable. Consequently, attention has been focused in this study on high volume hydraulic fracturing.

In this context, the term "high volume" has been interpreted following the definition in the New York SGEIS (State of New York, 2011 PR Glossary and section 3.2.2.1): "*The stimulation of a well using 300,000 gallons or more of water as the base fluid in fracturing fluid.*" This figure corresponds to 1,350 m^3 cumulatively in the hydraulic fracturing phase.

An appropriate definition for the European context was identified by comparing the fluid volumes used in recent test drillings against the volumes used in past hydraulic fracturing activities. This enabled a definition to be identified which differentiates the use of hydraulic fracturing for unconventional gas extraction from the past use of hydraulic fracturing in conventional oil and gas wells. In the European context, it appears that a definition of 1,000 m^3 per stage would be a more appropriate working definition, based on the following observations:

- For the test drillings carried out by Cuadrilla in Boxtel, the Netherlands, a hydraulic fracturing volume of 1000m^3/hour is estimated for 1 to 2 hours, per stage. No specific information on the number of stages or actual fluid volumes are available as exploration is currently on hold in the Netherlands, but it is expected that the total amount of water used will be about the same as in the UK (9000 - 29000 m^3/well) (Broderick et al 2011 NPR).
- For the hydraulic fracturing carried out by Halliburton at Lubocino-1 well in Poland, 1600 m^3fluid was used in a single stage.
- The Danish Energy Agency (2012 NPR) provided information on two examples of hydraulic fracturing processes using some 7,000 m^3 fluid to fracture 11 zones in the first example, and 8,000 m^3 fluid to fracture 11 zones in the second example. The fracturing was carried out for tight gas extraction and involved somewhat lower pressures, of 580 bar.

The volumes of fluid used for coal-bed methane fracturing are typically 200 m^3 to 1500 m^3 per well (USEPA 2011a PR p22). As coal-bed methane fracturing typically takes place across multiple stages in a directional well, this amounts to less than 1,000 m^3 per stage (USEPA 2011a PR p22). The volumes of fluid used for fracturing of tight gas reservoirs are also typically less than 1,000 m^3 per stage (Chambers et al, 1995 NPR ; Danish Energy Agency 2012 NPR). Consequently, these activities lie outside the scope of this project.

1.3.4 Hydraulic fracturing practices

The US EPA describes hydraulic fracturing as:

> "*a well stimulation process used to maximize the extraction of underground resources, including oil, natural gas, geothermal energy, and even water. The oil and gas industry uses hydraulic fracturing to enhance subsurface fracture systems to allow oil or natural gas to move more freely from the rock pores to production wells that bring the oil or gas to the surface.*
>
> *The process of hydraulic fracturing begins with building the necessary site infrastructure including well construction. Production wells may be drilled in the vertical direction only or paired with horizontal or directional sections. Vertical well sections may be drilled hundreds to thousands of feet below the land surface and lateral sections may extend 1000 to 6000 feet* [300 to 2000 metres] *away from the well.*
>
> *Fluids, commonly made up of water and chemical additives, are pumped into a geologic formation at high pressure during hydraulic fracturing. When the pressure exceeds the rock strength, the fluids open or enlarge fractures that can extend several hundred feet away from the well.*
>
> *After the fractures are created, a propping agent is pumped into the fractures to keep them from closing when the pumping pressure is released. After fracturing is completed, the internal pressure of the geologic formation cause the injected fracturing fluids to rise to the surface where it may be stored in tanks or pits prior to disposal or recycling. Recovered fracturing fluids are referred to as flowback. Disposal options for flowback include discharge into surface water or underground injection.*"

(Taken from "*Hydraulic fracturing background information,*" http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_hydrowhat.cfm)

Typical and maximum fracture lengths are discussed in Section 1.4.2.

Hydraulic fracturing has been used in the United States for over 60 years. By the end of the 1970s, hydraulic fracturing of tight gas wells had become a proven technique for developing commercial wells in low-permeability or tight gas formations. Hydraulic fracturing is also widely used for conventional gas extraction in North America (CAPP, 2011 NPR) The combination of multi-stage hydraulic fracturing and horizontal drilling for hydrocarbon extraction has been in use for commercial extraction of shale gas in North America since 2002/2003 (SEAB, 2011a NPR p8). In Europe, the use of hydraulic fracturing for recovery of conventional gas (that is, reservoirs with an average permeability of more than 1 milliDarcy (mD)) is not common. This is principally because it has not in the past been economic or necessary for field development.

The gas extraction sector has developed a number of different oil- and water-based fluids for use in hydraulic fracturing and related treatments (US EPA 2004 NPR page 4-2). For ideal performance, fracturing fluids should possess the following four qualities:

- Be viscous enough to create a fracture of adequate width.
- Maximize fluid travel distance to extend fracture length.
- Be able to transport large amounts of proppant into the fracture.
- Require minimal gelling agent to allow for easier degradation or "breaking" and reduced cost.

Due to the high costs involved, horizontal drilling and hydraulic fracturing have in the past not routinely been used for conventional hydrocarbon extraction in Europe. The use of hydraulic fracturing for hydrocarbon extraction in Europe has been limited to lower volume fracturing of some tight gas and conventional reservoirs in the southern part of the North Sea and in onshore Germany, Netherlands, Denmark and the UK. These activities did not in general constitute High Volume hydraulic fracturing as defined in Section 1.3.3 above.

1.4 Shale gas extraction

This section provides a description of the shale gas extraction process, based directly or indirectly on experience from North America.

1.4.1 Stages in shale gas field development

Philippe and Partners (2011 NPR p7-8) describe five stages of development of a shale gas project covering exploration (stages 1 to 4) and commercial production (stage 5):

1. Identification of the gas reservoir. During this stage the interested company performs initial geophysical and geochemical surveys in a number of regions. Seismic and drilling location permits are secured.
2. Early evaluation drilling. At this stage, the extent of gas bearing formation(s) is/are measured via seismic surveys. Geological features such as faults or discontinuities which may impact the potential reservoir are investigated. Initial vertical drilling starts to evaluate shale gas reservoir properties. Core samples are often collected.
3. Pilot project drilling. Initial horizontal well(s) are drilled to determine reservoir properties and completion techniques. This includes some multi-stage hydraulic fracturing, which may comprise high volume hydraulic fracturing. The drilling of vertical wells continues in additional regions of shale gas potential. The interested company executes initial production tests.
4. Pilot production testing. Multiple horizontal wells from a single pad are drilled, as part of a full size pilot project. Well completion techniques are optimised, including drilling and multistage hydraulic fracturing and micro seismic surveys. Pilot production testing starts. The company initiates the planning and acquisition of rights of way for pipeline developments.
5. Commercial development. Provided the results of pilot drilling and testing are favourable, the company takes the commercial decision to proceed with the development of the field. The developer carries out design of well pads, wells, pipelines, roads, storage facilities and other infrastructure. The well pads and infrastructure are developed and constructed, leading to the production of natural gas over a period of years or decades. As gas wells reach the point where they are no longer commercially viable, they are sealed and abandoned. During this process, well pad sites are restored and returned to other uses.

1.4.2 Stages in well development

This section sets out the process of well development for an individual unconventional gas well during the pilot drilling, pilot production testing and commercial development phases, based on the following six stages (adapted from New York State DEC 2011 PR p5-91 to 5-137):

Figure 3: Stages in well development

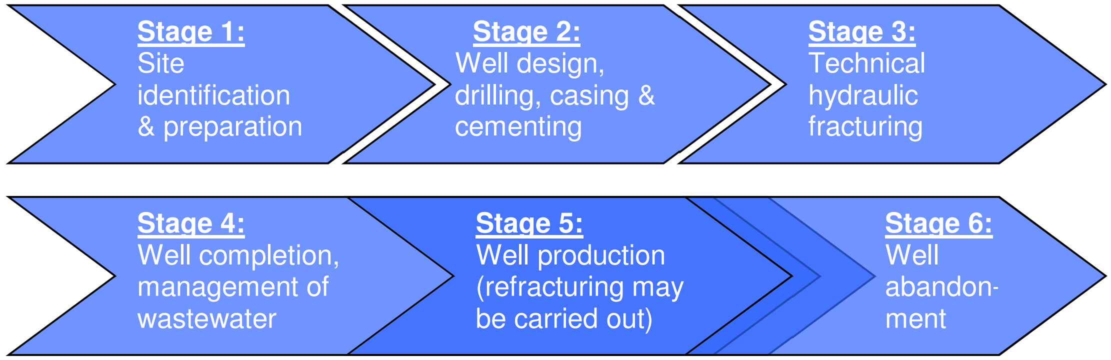
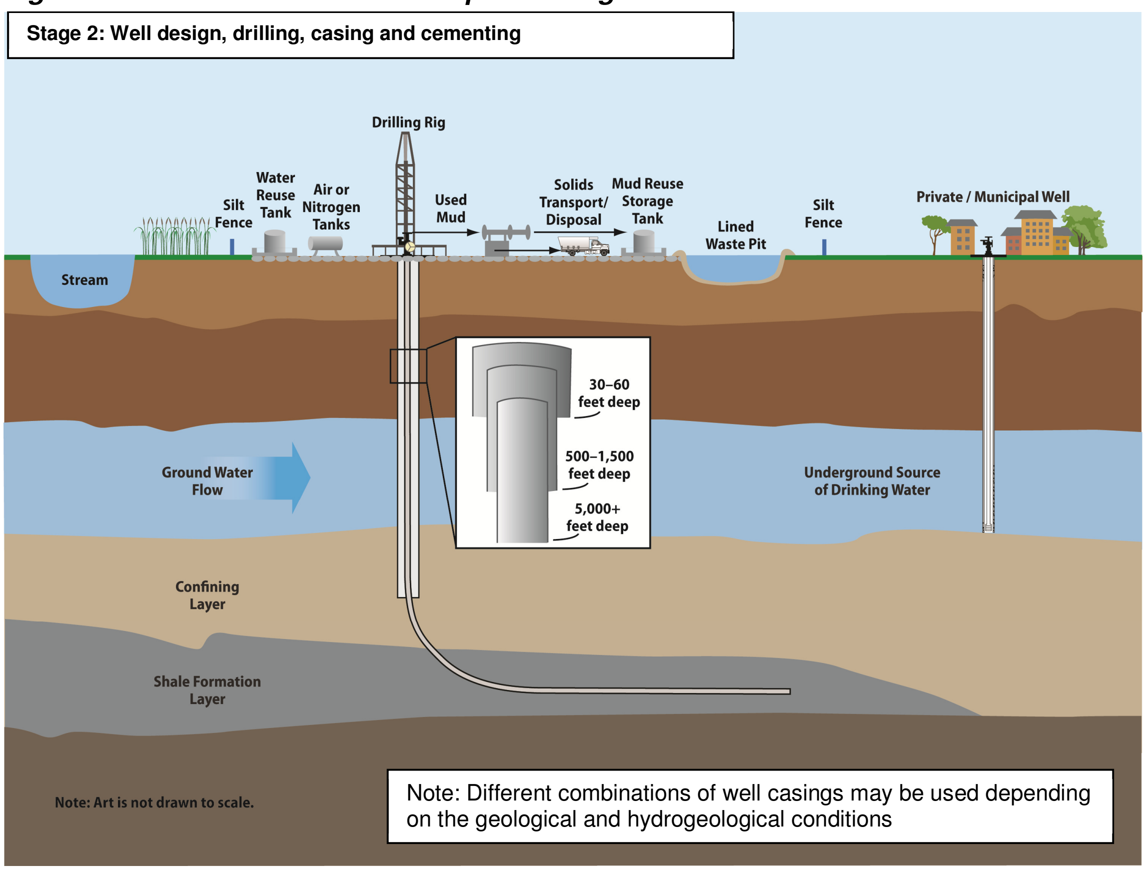
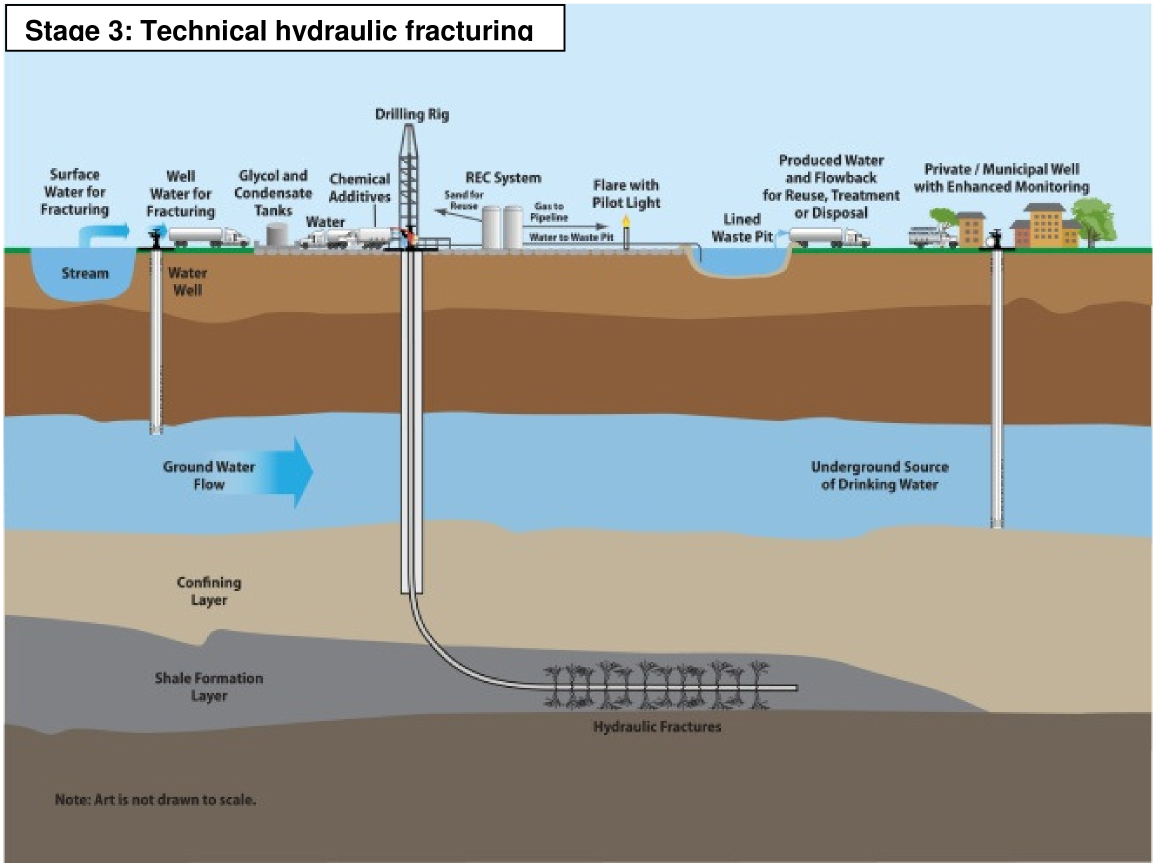


Figure 4 provides an illustration of the two key stages in the hydraulic fracturing process.

Figure 4: Illustration of Well Development Stage 2





Source: ERG. These drawings are illustrative only, and based on US practices

These stages are described in more detail below.

Stage 1: Site identification and preparation

Site identification

The operator identifies sites to be used as well pads. An individual well pad may typically have 6 to 10 well heads, each of which extends in a different direction from the site, covering underground an area of up to 250 hectares (New York State 2011 PR p 5-17). Further land would be needed at the surface for supporting infrastructure such as roads, pipelines and storage facilities. SEAB (2011a NPR p33) reports that up to 20 wells have been constructed on a single pad, and King (2012 PR) reports that a single 2.4 hectare well pad is used to collect shale gas from a 2,400 hectare area, although the construction of well pads with only 1 to 2 wells is still a widespread practice at present in some states in the USA. The planned shale gas development in the UK is intended to operate with 10 well heads per pad (Broderick et al 2011 NPR p19). The site selection stage can have an important influence on the potential environmental and health impacts, as discussed in Chapter 2. During the first four stages of gas field development set out in Section1.4.1, a small number of sites will be identified. During the commercial production stage, a much greater number of sites may be identified (potentially up to 2,400 well pad sites within a single concession with a typical separation of approximately 1.5 km, as discussed in Chapter 2).

Site preparation

Site preparation activities consist primarily of clearing and levelling an area of adequate size and preparing the surface to support movement of heavy equipment (New York State DEC 2011 PR p5-10). Site access routes need to be designed and constructed. The well pad site area is typically up to 3.0 hectares (New York State DEC 2011 PR p5-6), with further land requirements needed for site access routes, pipelines and other infrastructure. Ground surface preparation typically involves staking, grading, stripping and stockpiling of topsoil reserves, then placing a layer of crushed stone, gravel, or cobbles over geotextile fabric. Site preparation also includes establishing erosion and sediment control structures around the site, and constructing pits as needed for retention of drilling fluid and, possibly, freshwater.

Stage 2: Well design; drilling; casing; cementing; perforation

Well design; drilling; casing; cementing

Except for the use of specialized downhole tools, horizontal drilling is performed using similar equipment and technology as vertical drilling (New York State DEC 2011 PR p5-25 to 5-17). Wells for shale gas development using high-volume hydraulic fracturing will be drilled with rotary rigs. Operators may use one rig to drill an entire wellbore from the surface to toe of the horizontal bore, or may use two or three different rigs in sequence. At a multi-well site, two rigs may be present on the pad at once, but more than two are unlikely because of logistical and space considerations. New York State DEC (2011 PR p6-191 to 6-192) estimates that a maximum of four wells could be drilled at a single pad in any 12 month period.

The first drilling stage is to drill, case, and cement the conductor hole at the ground surface. This process takes approximately 1 day, with the depth and size of the hole depending on the ground conditions.

A vertical pipe is set into the hole and grouted into place. The second drilling stage is to drill the remainder of the vertical hole. This can take up to 2 weeks or longer if drilling is slow or problems occur. A surface casing is constructed which extends below the lowest aquifer and is sealed to the surface. Additional casing should be provided for the surface layers (USEPA 2011 NPR p14; New York State DEC 2011 PR p5-91 to 5-92). A further intermediate casing extends to the top of the hydrocarbon-bearing formation. Cement is pumped between the intermediate casing and the intervening formations to isolate the well bore from the surrounding rock, act as a barrier to upward migration through this space, and provide support to the intermediate casing. The third drilling stage is to drill the horizontal bore. Again, this stage would take up to 2 weeks or longer if delays occur. This gives a total duration of the drilling stage of up to 4 weeks (Broderick et al 2011 NPR p29). The production casing extends into the shale gas formation itself and along the horizontal bore.

In other cases, "open hole" completions are carried out, in which the production casing penetrates the top of the producing zone only. No casing is provided for the horizontal section of the wellbore within the production zone. This approach can be adopted in formations capable of withstanding production conditions. The environmental risks of open hole completions are not significantly different to those posed by standard well designs, because the only differences are within the producing measure.

Perforation

Once the cement hardens, shaped charges are pushed down the pipe to perforate the pipework and cement layer at the required locations. In some cases, pre-perforated liners are used (University of North Dakota EERC, accessed 2012 NPR ; Surjaatmadja et al., 2007 PR). Surjaatmadja et al. indicate that there are limitations for using pre-perforated liners with hydraulic fracturing, and pre-perforated liners are not widely used in the US on-shore. Anecdotal evidence suggests that in-place perforation provides more accuracy for placing the perforations. Perforation is not required for open hole completions.

Installation of wellhead

The last steps prior to fracturing are the installation of a wellhead which is designed and pressure-rated for the fracturing operation. The system is then pressure tested (New York State DEC 2011 PR p5-92).

Stage 3: Technical hydraulic fracturing

Hydraulic fracturing fluid

Fracturing fluid is produced by mixing proppant and other additives into the substrate. Water is the most widely used substrate. Propane gel based fluids are also available, but these are not widely used at present (Inside Climate News 2011 NPR). This requires the transportation of water, additives and proppant to the site. Transportation is normally by truck, although transportation of water by pipeline is becoming increasingly common in the USA (New York State DEC 2011 PR p5-84; Auman 2012 NPR). Appropriate transportation is needed for all materials, and in particular, potentially hazardous additives.

The sources of water used during hydraulic fracturing activities include surface water and ground water, which can be supplemented by recycled water from previous hydraulic fracturing. Water, proppant and additives must be stored securely at the site, and then mixed in the appropriate proportions, while avoiding spillage of any materials (US EPA 2011a PR p28). The additives are designed primarily to modify the fluid characteristics to improve the performance of the fracturing fluid. King (2012 PR) indicates that a slick water fracturing fluid typically includes:

i. Water – About 98% to 99% of total volume

ii. Proppant – about 1% to 1.9% of total volume, usually sand or ceramic particles

iii. Friction reducer – about 0.025% of total volume, often polyacrylamide

iv. Disinfectant (biocide) – about 0.005% to 0.05% of total volume. Common biocides include glutaraldehyde, quaternary amine or tetrakis hydroxymethyl phosphonium sulphate (THPS) These chemicals are giving way to the use of UV light, ozone and chlorine dioxide.

v. Surfactants used to modify surface or interfacial tension, break or prevent emulsions – about 0.05% - 0.2% of total volume

vi. Gelation chemicals (thickeners) such as guar gum and cellulose polymers are not commonly used, but may be used in hybrid fractures which use both ungelled and gelled water

vii. Scale inhibitors – typically phosphate esters or phosphonates

viii. Hydrochloric acid may be used in some cases to reduce fracture initiation pressure

ix. Corrosion inhibitor, used at 0.2% to 0.5% of acid volumes, and only used if acid is used.

New York State DEC (2011 PR) confirms that fracturing fluids typically consist of about 98% to 99% water and proppant, together with 0.5% to 2% additives (New York State, 2011 PR p5-40 and Table 5.6), as set out in Table 1.

Table 1: Fracture fluid additives (taken from New York State, 2011 PR , table 5.6)

Additive Type	Description of Purpose	Examples of chemicals
Proppant	“Props” open fractures and allows gas / fluids to flow more freely to the well bore.	Sand [Sintered bauxite; zirconium oxide; ceramic beads]
Acid	Removes cement and drilling mud from casing perforations prior to fracturing fluid injection, and provides accessible path to formation.	Hydrochloric acid (HCl, 3% to 28%) or muriatic acid

Additive Type	Description of Purpose	Examples of chemicals
Breaker	Reduces the viscosity of the fluid in order to release proppant into fractures and enhance the recovery of the fracturing fluid.	Peroxydisulphates
Bactericide / Biocide / Antibacterial Agent	Inhibits growth of organisms that could produce gases (particularly hydrogen sulphide) that could contaminate methane gas. Also prevents the growth of bacteria which can reduce the ability of the fluid to carry proppant into the fractures.	Glutaraldehyde; 2,2-dibromo-3-nitrilopropionamide
Buffer / pH Adjusting Agent	Adjusts and controls the pH of the fluid in order to maximize the effectiveness of other additives such as crosslinkers.	Sodium or potassium carbonate; acetic acid
Clay Stabilizer / Control / KCl	Prevents swelling and migration of formation clays which could block pore spaces thereby reducing permeability.	Salts (e.g., tetramethyl ammonium chloride), Potassium chloride (KCl)
Corrosion Inhibitor (including Oxygen Scavengers)	Reduces rust formation on steel tubing, well casings, tools, and tanks (used only in fracturing fluids that contain acid).	Methanol; ammonium bisulphate for Oxygen Scavengers
Crosslinker	Increases fluid viscosity using phosphate esters combined with metals. The metals are referred to as crosslinking agents. The increased fracturing fluid viscosity allows the fluid to carry more proppant into the fractures.	Potassium hydroxide; borate salts
Friction Reducer	Allows fracture fluids to be injected at optimum rates and pressures by minimizing friction.	Sodium acrylate-acrylamide copolymer; polyacrylamide (PAM); petroleum distillates
Gelling Agent	Increases fracturing fluid viscosity, allowing the fluid to carry more proppant into the fractures.	Guar gum; petroleum distillates
Iron Control	Prevents the precipitation of metal oxides which could plug off the formation.	Citric acid
Scale Inhibitor	Prevents the precipitation of carbonates and sulphates (calcium carbonate, calcium sulphate, barium sulphate) which could plug off the formation.	Ammonium chloride; ethylene glycol
Solvent	Additive which is soluble in oil, water & acid-based treatment fluids which is used to control the wettability of contact surfaces or to prevent or break emulsions.	Various aromatic hydrocarbons
Surfactant	Reduces fracturing fluid surface tension thereby aiding fluid recovery.	Methanol; isopropanol; ethoxylated alcohol

The US House of Representatives (2011 NPR page 7) found that the following chemicals were most frequently encountered in fracturing fluids used between 2005 and 2009. A full list of 750 chemicals is provided in Appendix A to the US House of Representatives report. This list of chemicals does not distinguish in terms of the quantities of chemicals or their potential hazards:

- Methanol (Methyl alcohol) (as surfactant)
- Isopropanol (Isopropyl alcohol, Propan-2-ol) (as surfactant)
- Crystalline silica - quartz (SiO_2) (as proppant)
- Ethylene glycol monobutyl ether (2-butoxyethanol) (as surfactant)
- Ethylene glycol (1,2-ethanediol) (as scale inhibitor)

- Hydrotreated light petroleum distillates (as friction reducer)
- Sodium hydroxide (Caustic soda) (as pH adjusting agent)

The chemicals reported as being used by Cuadrilla Resources at its Preese Hall-1 well in the UK are provided in Appendix 3.

Based on discussions held at the Society of Petroleum Engineers (SPE) Workshop "*Reducing Environmental Impact of Unconventional Resource Development*", April 2012 (NPR), operators are developing methods of reducing the number and quantity of chemicals in hydraulic fracturing fluids, and improving the environmental performance of fluid additives. Hydraulic fracturing service providers and chemical suppliers are developing schemes to evaluate the potential human health and environmental impacts of hydraulic fracturing chemicals. These schemes follow the UN Globally Harmonized System of Chemical Classification and Labelling. These systems allow operators to select chemicals based on their hazard as well as cost and effectiveness. The risks posed by flowback waters from shale gas wells are linked to the constituents of fracturing fluids, but are also driven by the presence of naturally occurring substances in flowback water.

Injection of fracturing fluid

When perforations are present at the appropriate point, fracturing fluid is pumped into the well at high pressure.

The proppant is forced into the fractures by the pressured water, and holds the fractures open once the water pressure is released. For conventional fracturing, the fracture pressure gradient is typically 0.4-1.2 psi/foot (0.09 – 0.27 bar/metre) (derived from project team experience). For instance, for a typical conventional well, this would correspond to approximately500 bar, and pressures would generally be below 650 bar. The range of fluid pressures used in high volume hydraulic fracturing is typically 10,000 to 15,000 psi (700 – 1000 bar),and exceptionally up to 20,000 psi (1400 bar). This compares to a pressure of up to 10,000 psi (700 bar) for a conventional well. In the tight gas example from the Danish authorities, pressures of up to 8,400 psi (580 bar) were applied.

Fracture lengths can be expected to vary depending on the geological properties of the rock matrix and the fracture treatment. Operators have a commercial incentive to restrict the extent of fractures to the gas-bearing formation (NETL, 2012a NPR). Davies et al. (2012 PR) reported a maximum fracture length from several thousand shale gas fracturing operations in the US of 588 metres. The majority of fractures were less than 100 m in length. It is not known how many of these operations were high volume hydraulic fracturing operations, or whether these findings would be applicable in the European setting. Similar data are reported by Fisher and Warpinski (2012 PR Figure 2), indicating a maximum vertical fracture extent of approximately 600 metres. The analysis carried out by Fisher and Warpinski indicated that fracturing carried out close to the surface tended towards the formation of horizontal fracturing, which would reduce (although not eliminate) the risk of fractures interacting with water resources in shallower shale gas formations.

The fractures allow natural gas and oil to flow from the rock into the well.

Stage 4: Well completion and management of wastewater

Well completion and flowback handling

Following the release of pressure, injected fracturing fluids are returned to the surface as flowback. Hydraulic fracturing fluid is typically returned to the surface over a period of several days (Broderick et al. (2011) NPR p26) to two weeks or more (USEPA 2011a PR page 23; SEAB 2001a NPR). Recovered fracturing fluid and produced waters from wet shale formations are collected and sent for treatment and disposal or re-use where possible. The latter can contain substances that are found in the formation, and may include dissolved solids, gases (e.g. methane, ethane), trace metals, naturally occurring radioactive elements (e.g. radium, uranium), and organic compounds.

Wastewater – a term used to designate collectively fracturing fluids returned to the surface as flowback and produced water – continues in many cases to flow to the surface from shale gas wells during the well completion phase and during the production phase of the well. After the initial recovery of hydraulic fracturing fluid, waste water usually consists of fluids displaced from within the shale play (referred to as "produced water") with decreasing quantities of hydraulic fracturing fluid. Experience in the US is that between 0% and 75% of the injected fracturing fluid is recovered as flowback (DOE 2009 NPR p66; EPA 2011 p42 NPR ; Webb 2012 PR ; a similar range was suggested by consultees).

As shale formations were originally laid down in marine environments, produced water tends to be of high salinity. API (2010 NPR) reports that "*water salinity can range from brackish (5,000 parts per million (ppm) to 35,000 ppm TDS), to saline (35,000 ppm to 50,000 ppm TDS), to supersaturated brine (50,000 ppm to >200,000 ppm TDS.*" Hydraulic fracturing wastewaters in Europe are expected to generally have a high salinity due to their predominant marine origin, which may result in issues for disposal and re-use. Preliminary data from test drilling in the north-west of England suggests total sodium chloride levels in the range 23,000 ppm to 103,000 ppm (Broderick et al. 2011 NPR Table A.2). This covers a wide range of salt contents, but at the upper level is of high salinity.

Hydraulic fracturing wastewater may be stored in tanks or pits prior to disposal or recycling. In the US, hydraulic fracturing wastewater is frequently disposed to well injection facilities, or following treatment to surface waters. A proportion of these waters can be re-used in some cases, with operators citing goals of up to 100% recycling (New York State DEC 2011 PR p.1-2). Techniques for recycling hydraulic fracturing wastewater are subject to rapid development. DOE (2009 NPR p70) reported that, "*With further development, such specialized treatment systems may prove beneficial, particularly in more mature plays such as the Barnett; however, their practicality may be limited in emerging shale gas plays. Current levels of interest in recycling and reuse are high, but new approaches and more efficient technologies are needed to make treatment and re-use a wide-spread reality.*" However, because recovery of fracturing fluid is incomplete (typically below 75%), fresh water was reported as comprising 80-90% of the water used at each well for high-volume hydraulic fracturing (New York State DEC 2011 PR p.1-2 and p5-122). The limiting factors on re-use are the salinity and presence of other contaminants (North American regulator consultation response 2012 NPR), the volume of flowback water recovered, and the timing of upcoming fracture treatments (New York State DEC 2011 PR p5-122).

Friction reducers are now available which can be used in highly saline waters. A combination of technical developments and commercial factors has resulted in increased wastewater recycling. Yoxtheimer (2012 PR) reported that 67% of wastewater generated from the Pennsylvania Marcellus Shale was recycled in the first half of 2011, increasing to 77% in the second half of 2011, although there is uncertainty over the typical rate of recycling in the US, which may be significantly lower.

Typical levels of contaminants found in flowback water from shale gas extraction are set out in Table 2 (Alley et al. 2011 PR).

Table 2: Levels of contaminants in flowback water from shale gas extraction

Parameter	Minimum(mg/L)	Maximum(mg/L)
pH	1.21	8.36
Alkalinity	160	188
Nitrate	nd	2670
Phosphate	nd	5.3
Sulphate	nd	3663
Radium 226 (pCi/g)	0.65pCi/g	1.031pCi/g

Parameter	Minimum(mg/L)	Maximum(mg/L)
Hydrogen carbonate	nd	4000
Aluminium	nd	5290
Boron	0.12	24
Barium	nd	4370
Bromine	nd	10600
Calcium	0.65	83950
Chloride	48.9	212700
Copper	nd	15
Fluoride	nd	33
Iron	nd	2838
Potassium	0.21	5490
Lithium	nd	611
Magnesium	1.08	25340
Manganese	nd	96.5
Sodium	10.04	204302
Strontium	0.03	1310
Zinc	nd	20

As well as these contaminants, flowback waters may also contain sand, heavy metals, oils, grease fracturing fluid additives, and naturally occurring radioactive materials (DOE 2011 NPR p21, New York State (2011 PR) p5-101, US EPA 2011a PR p43).

During the production phase, the well is connected to the gas network. During the exploratory phases, the gas is collected and flared, although the preference is for flaring to be minimised by connecting the well to the gas main as soon as this can be done.

The pre-production stages may last 500 to 1500 days at an individual well pad (Tyndall Centre 2011 NPR p28).

Stage 5: Production

Before gas production can commence, pipeline infrastructure must be developed to collect natural gas for transfer to the existing natural gas pipeline infrastructure.

Once the well is connected to the gas main, gas can be dehydrated, and then passed to the collection system. Ongoing maintenance and monitoring is required to confirm that the gas production process is proceeding satisfactorily without adverse environmental or health effects.

The flow to the well can be expected to decrease rapidly following the initial phase. New York State DEC (2011 PR p5-139) quotes operator estimates suggesting the following gas production rates from a new well in the Marcellus shale:

- Year 1: initial rate of 92,000 to 250,000 m^3/day declining to 32,000 to 100,000 m^3/day
- Years 2 to 4: 32,000 to 100,000 m^3/day declining to 14,000 to 35,000 m^3/day
- Years 5 to 10: 14,000 to 35,000 m^3/day declining to 8,000 to 16,000 m^3/day
- Years 11 and after: 8,000 to 16,000 m^3/day declining at 5% per annum.

An operator may choose to re-fracture a well in order to increase the rate of gas production, if this is considered worthwhile from a commercial perspective (ICF, 2009 NPR p20). Experience in the US suggests that wells are likely to be re-fractured infrequently – either once every 5 to 10 years, or not at all. The situation in the US regarding re-fracturing is not clear at present (New York State DEC 2011 PR p5-98), and it is not clear whether this experience is transferrable to the European context. For the present study, it has been assumed that re-fracturing may be carried out once over a 10 year period, while recognising that this is an area of uncertainty. Well lifetime may be between 10 years and 30 years (New York State DEC 2011 PR p6-276) or 40 years (US National Parks Service 2009 NPR). This is also subject to considerable uncertainty at present, with indications that well lifetime may be shorter than anticipated. A lifetime of up to 40 years suggests that wells may be refractured between zero and four times during their operational lifetime.

Stage 6: Abandonment

When the well is no longer economic to operate, it is taken out of service temporarily or permanently. Abandonment takes place in accordance with established procedures in the oil and gas production industry. Abandonment procedures for use in the conventional oil and gas industry in Europe have been specified by national regulators (e.g. Norsok Standard D-010 is applied in Norway; see also Oil and Gas UK 2012 NPR). Abandonment procedures include the installation of a surface plug to stop surface water seepage into wellbore. A cement plug is installed at the base of the lowest underground source of drinking water to isolate water resources from potential contamination by hydrocarbons or other substances migrating via the well bore. A cement plug is also installed at the top of the shale gas formation.

1.4.3 Comparison of high volume hydraulic fracturing and conventional hydrocarbon extraction practices

Table 3 below sets out the stages of a high volume hydraulic fracturing activity, and summarises the differences between this and conventional hydrocarbon production (adapted from USEPA 2011a PR and New York State DEC 2011 PR).

Early evaluation drilling referred to in Section 1.4.1 would not require hydraulic fracturing. Drilling carried out at the pilot testing stage would require hydraulic fracturing. As of 2012 in Europe, pilot testing only has been carried out for shale gas. As discussed previously, the majority of drilling and hydraulic fracturing activity would be carried out during the production stage.

Table 3: High Volume Hydraulic Fracturing: Stages, Steps, and Differences from Conventional Hydrocarbon practices

Development & Production Stage	Step	Decision factors	Differences from Conventional Hydrocarbon practices
Site Selection and Preparation	Site identification	Production yield versus development cost	None
	Site selection	Number of wells required	Many more shale gas wells are required for recovery of a given volume of gas than for recovery of the same volume of gas from conventional reservoirs. Of the order of 50 shale gas wells might be needed to recover the same volume of gas as a typical North Sea well (see Section 2.1.2).
		Proximity to buildings / other infrastructure Geologic considerations Proximity to natural gas pipelines Feasibility of installing new pipelines	None None None None
		Site area (around 3 hectares/well needed during fracturing)	More space required during hydraulic fracturing for tanks / pits for water / other materials required for fracturing process (New York State 2011 PR

Development & Production Stage	Step	Decision factors	Differences from Conventional Hydrocarbon practices
			p5-6)
		Access roads / requirement improvements	More lorry movements during hydraulic fracturing than conventional production sites due to need to transport additional water, fracturing material (including sand/ceramic beads) and wastes
		Availability and cost of water supply and wastewater disposal	Obtaining large volumes of water (10,000 to 25,000 m^3 per well) (see1.3.3) Disposing of large volumes of contaminated water (up to19,000 m^3flowback water per well assuming up to 75% recovery, together with produced water) (Derived from Broderick et al 2011 NPR)
		Availability of space to store make up water and wastewater	Storage of large volumes of water (10,000 to 25,000 m^3 per well) (see 1.3.3) Will require sufficient trucks / tanks onsite to manage flowback (e.g. 250 – 625 trucks at 40 m^3 per truck) (derived from New York State DEC 2011 PR p6-302)
	Site preparation	Number of wellheads per pad and per hectare Well pad design to control run off and spills and contain leaks Amount of water / proppant needed for production activities	Installation of additional tanks / pits sufficient to accommodate up to 25,000 m^3 of make-up water 6-10 wells/pad (New York State 2011 PR p3-3) whereas 1 well/pad has been more common for conventional production Fewer wellpads/hectare: 1 multi-well horizontal well pad can access c. 250 hectares, compared to c.15 hectares for a vertical well pad (New York State 2011 PR p5-17)
Well Design, drilling, casing and cementing	Selection of horizontal vs vertical well Well drilling	Separation of aquifer from hydrocarbon bearing formation by impermeable layers Existence of fault / fracture zones Maximising access to hydrocarbon in strata	Both conventional and unconventional wells may be drilled through water bearing strata and need to achieve the same performance standards. The hydraulic fracturing process places additional stresses on the well casing, which may require changes to the well design and/or additional monitoring
		Depth to target formation (vertical or horizontal)	Horizontal drilling produces longer well bore (vertical depth plus horizontal leg) requires more mud and produces more cuttings/well. Typically 40% more mud and cuttings for horizontal well compared to a vertical well, depending on depth and lateral extent (New York State 2011 PR p5-34). However, horizontal wells allow access to a greater extent of shale gas formation, and are more effective for exploitation of a given shale gas formation. Horizontal drilling requires specialist equipment: larger diesel engine for the drill rig uses more fuel and produces more emissions. Equipment is on site for a longer time (typically 25days for horizontal well compared to 13days for vertical well; New York State DEC 2011 PR p6-192). However, horizontal wells have a smaller land surface footprint than conventional vertical wells(USEPA 2011a PR 3.2.1). Consequently, horizontal drilling from a limited number of well heads would in principle be preferable to vertical drilling from a larger number of well heads. In practice, horizontal drilling techniques are normally used to open up reservoirs which would not otherwise be viable with vertical drilling techniques, and so this comparison is not directly relevant.

Development & Production Stage	Step	Decision factors	Differences from Conventional Hydrocarbon practices
	Casing	Casing required or open hole construction (competent conditions only):casing would normally be required Conductor (for wellhead) Surface (to isolate near-surface aquifer from production) Intermediate (to provide further isolation) Production (in target formation) Centred casing to enable cementing	Casing material must be compatible with fracturing chemicals (e.g., acids) Casing material must also withstand the higher pressure from fracturing multiple stages
	Cementing	Correct cement for conditions in well (e.g. geology and groundwater) and fracturing pressure	Hydraulic fracturing has the potential to damage cement: may pose a higher risk during re-fracturing, although unclear at present (EPA 2011 NPR p82)
Well Completion	Hydraulic Fracturing: Water sourcing	Quantity of water required for hydraulic fracturing Quality of water required for hydraulic fracturing Source and availability of water Impact on water resources and surface water flows Intensity of activity in watersheds / geologic basins	Requirement to abstract and transport water to wellhead for storage prior to hydraulic fracturing operations
	Hydraulic Fracturing: Chemical Selection	Tailoring of fracturing fluid to properties of the formation / project needs Tailoring chemicals to make up water quality (e.g., highly saline flowback, acid mine drainage)	Current information indicates that the composition of chemicals used in high volume fracturing is similar to that used in conventional fracturing (New York State DEC 2011 PR p5-54). Less harmful additives are being developed and used at lower concentrations in both conventional and unconventional applications (King 2011 PR p39). Record-keeping and disclosure of chemicals is also improving (e.g. see www.fracfocus.org).
	Chemical Transportation		Transport of large volumes of water, chemicals and proppant to well pad (up to 25,000 m^3 water per well, together with a further 8-15% proppant and 0.5-2% chemical additives; New York State DEC 2011 PR p5-51)
	Chemical storage	Size, type, and material of tanks or other containers	More chemical storage required for high volume hydraulic fracturing (as for transportation above)
	Chemical Mixing	Quality control on site to ensure correct mixture and avoidance of potentially harmful spills	Mixing of water with chemicals and propping agent (proppant)
	Hydraulic Fracturing: Perforating casing	Use and type of explosive (not required if open-hole drilling is carried out)	Conventional wells are hydraulically fractured in North America, although this is uncommon in Europe. The amount and extent of perforations may be greater for high volume HF
	Hydraulic Fracturing: Well injection of hydraulic fracturing fluid	Number of stages required Need to inject small amount of fluid before fracturing occurs to determine reservoir properties and enable better fracture design Pressure required to initiate fracturing with fracturing fluid without proppant dependent on depth and mechanical properties of formation Monitoring and control of hydraulic fracturing process. Number, size, timing and concentration of delivery slugs of fracturing fluid and proppant	Monitoring requirements and interaction of fracturing fluid with formation also occur in conventional wells but more extensive in high volume fracturing due to longer well length in contact with formation (up to 2,000 metres for HVHF compared to up to a few hundred metres for conventional well depending on formation thickness) More equipment required: series of pump trucks, fracturing fluid tanks, much greater intensity of activity.
	Hydraulic Fracturing: Pressure reduction in well / to reverse fluid flow recovering flowback and	Chemical additions to break fracturing gels (if used) Planning for storage and management of flowback	"Flowback" of fracturing fluid and produced water containing residual fracturing chemicals, together with materials of natural origin: brine (e.g., sodium chloride), gases (e.g., methane, ethane, carbon dioxide, hydrogen sulphide, nitrogen, helium),

Development & Production Stage	Step	Decision factors	Differences from Conventional Hydrocarbon practices
	produced water	recovered before the well starts gassing (varies from 0%-75% but strongly formation dependent). Planning for storage and management of smaller volumes of wastewater generated during production (decreasing flow rates and increasing salt concentrations)	trace elements (e.g. mercury, lead, arsenic), naturally occurring radioactive material (e.g. radium, thorium, uranium), and organic material (e.g. acids, polycyclic aromatic hydrocarbons, volatile and semi-volatile organic compounds) (USEPA 2011a PR Table 5)
Well completion (continued)	Connection of well pipe to production pipeline	During exploration phase, natural gas is likely to be flared Wells should be connected to production pipeline immediately in production phase.	In principle, no difference to conventional wells. However, potential for impacts in areas which would not otherwise be commercially viable
	Reduced Emission Completion	Capture gas produced during completion and route to production pipeline or flare it if pipeline is not available	Larger volume of flowback and sand to manage than conventional wells (10,000 to 25,000 m^3 per well) (Derived from Broderick et al 2011 NPR)
	Well pad removal	Amount of wastewater storage equipment to keep on site Remove unneeded equipment and storage ponds Regrade and re-vegetate well pad	Larger well pad (with more wells/pad) with more ponds and infrastructure to be removed, as described above
Well Production	Construction of pipeline	May need to construct a pipeline to link new wells to gas network	Exploitation of unconventional resources may result in a requirement for gas pipelines in areas where this infrastructure was not previously needed
	Production	May need to refracture the well to increase recovery. This could take place up to four times over a 40 years well lifetime. Wastewater management (e.g. discharge to surface water bodies, reuse or disposal via underground injection including transport to disposal site)	Produced water will contain decreasing levels of fracturing fluid as well as hydrocarbons Conventional wells are often in wet formations that require dewatering to maintain production. In these wells, produced water flow rates increase with time. In shale and other unconventional formations, produced water flow rates tend to decrease with time.
Well Site Abandonment	Remove pumps and downhole equipment Plugging to seal well	Need to install surface plug to stop surface water seepage into wellbore and migrating into ground water resources Need to install cement plug at base of lowermost underground source of drinking water Need to install cement plugs to isolate hydrocarbon, injection/disposal intervals	Abandonment of unconventional wells is similar to abandonment of conventional wells.
Post-abandonment	Potential for methane seepage to occur in the long-term if seals or liners break down	Proper design and construction of well plugs and liners. Long-term monitoring programme of abandoned wells	Abandonment of unconventional wells is similar to abandonment of conventional wells.

1.5 Short chronological summary of use of hydraulic fracturing and horizontal drilling

Shale gas was first extracted in the 1920s in the US. Horizontal well drilling was first carried out in 1929. The first use of hydraulic fracturing for hydrocarbon extraction was in 1947 in a short vertical well. The process rapidly developed to commercial use in the US during the 1950s and 1960s. High volume hydraulic fracturing was first used in the Barnett Shale in Texas, U.S. in 1986. The first economical horizontal well in the Marcellus Shale, Pennsylvania was drilled in 2003 (Harper 2008 PR ; Montgomery 2010 PR ; Givens 2005 NPR).

Hydraulic fracturing appears to have been introduced in Europe in the early 1980s. Multi-stage hydraulic fracturing in tight gas reservoirs has been carried out in horizontal wells in the Soehlingen field in Germany, and in the South Arne field in Denmark (Rodrigues and Neumann, 2007 NPR ; Danish Energy Ministry 2012 NPR). Hydraulic fracturing has been carried out elsewhere in Germany (Reinicke 2011 NPR p11), as well as the Netherlands (NOGEPA, 2012 NPR) and the United Kingdom (UK Department of Energy and Climate Change, 2012 NPR). These fracturing operations did not use sufficient fluid to be classified as HVHF.

Exploratory drilling for shale gas with hydraulic fracturing in Germany, Poland and the UK commenced in 2010. Appendix 5 provides further information on shale gas development in Europe.

2 Impacts and risks potentially associated with shale gas development

2.1 Introduction

2.1.1 Background

The US Department of Energy identified four major areas of concern for potential human and ecosystem impacts with regard to the use of hydraulic fracturing for shale gas production (SEAB, 2011a NPR):

- Possible pollution of drinking water from methane and chemicals used in fracturing fluids;
- Air pollution;
- Community disruption during shale gas production; and
- Cumulative adverse impacts

The potential significance of local effects, together with cumulative and regional effects of multiple drilling, hydraulic fracturing, production and delivery activities on the environment was also highlighted by the International Energy Agency (2012 NPR p14), which noted in particular the potential cumulative effects on water use and quality, land use, air quality, traffic and noise as well as the issue of waste water management

New York State DEC (2011 PR p11-2 to 11-9) identified impacts associated with the following resources:

- Potential effects on people (e.g. via noise, radioactive materials, air emissions)
- Water resources
- Sensitive ecosystems and species
- Air quality
- Visual quality of the landscape
- Transportation

The USEPA (2011a PR p viii) focused specifically on the relationship between hydraulic fracturing and drinking water resources.

The range of potential hazards identified in these key references were considered systematically at each stage of the HVHF process, to enable the risks associated with each aspect of HVHF to be characterised in a preliminary manner, considering the limits of the exercise, as indicated below.

When considering environmental risks and impacts, it is important to consider the probability and severity of a possible event. King (2012 PR) suggests categorising events according to the significance of impacts on people and the environment, and according to experience of the frequency of their occurrence, consistent with more general guidance on environmental risk assessment (e.g. UK Department for Environment, Transport and the Regions, 2000 NPR). The activities identified by King (2012 PR) as potentially significant are:

- transport of fracturing materials to the well
- the specific act of fracturing
- recovery of hydraulic fracturing wastewater from the well ; and
- the transport of wastewater from the well

A wider range of impacts was considered in the present study, in accordance with the project specification.

2.1.2 Study approach and limitations

The study uses a preliminary risk screening approach to identify the most significant risks which require consideration in the study. This is described in Section 2.2. This review considered all potential issues identified during the literature review, discussion with consultees, and from the knowledge of the project team. The review focused in particular on the issues which differ for HVHF compared to conventional oil and gas extraction.

The preliminary risk screening approach was applied by developing criteria for evaluating the potential significance and likelihood of impacts occurring. Each potential issue was considered against these criteria to the extent permitted by the available information. The study authors duly acknowledge the limits of this risk screening exercise, considering notably the absence of systematic baseline monitoring in the US (from which most of the examined literature sources come from), the lack of comprehensive and centralised data on well failure and incident rates, and the need for further research on a number of possible effects including long term ones. Greater weight was given to information available in peer reviewed publications, the number of which is limited. In carrying out this analysis, it was assumed that controls normally applied in the oil and gas extraction industry in Europe would be applied to shale gas extraction.

Ideally, a comparison of risks and impacts with conventional gas extraction would be made on the basis of the impacts per unit of energy extracted. Within the constraints of this project, it was not possible to develop this analysis, and furthermore the data on the scale of impacts and their frequency are not available or sufficiently robust to enable this analysis to be carried out for the majority of potential impacts under consideration. In particular, there is no clear indication of the volume of gas likely to be recoverable from shale gas wells in Europe (the “Estimated Ultimate Recovery” or EUR”). New York State DEC (2011, p5-139) quotes a range of 60 to 280 million m^3 EUR per well for the US. Lechtenböhmer et al. (2011 NPR) and US EIA (2010 NPR) indicate that the figure of 60 million m^3 is more likely to represent an upper limit for EUR from the Marcellus shale, and lower recoveries would be applicable from other US formations. These gas volumes may not be economically recoverable in practice. It is not possible to state whether this wide range would be representative of EURs in Europe. For comparison with conventional gas extraction, a conventional North Sea gas well might result in recovery of up to 2,800 million m^3 of natural gas based on unconfirmed information – that is, it is likely that many more wells would be needed to extract unconventional gas compared to conventional gas.

2.1.3 Cumulative impacts

The development of shale gas plays opens the possibility of development of gas extraction infrastructure over a wide area. Consequently, cumulative risks need to be taken into account in the risk assessment. This was carried out by separately evaluating the risks posed by development of individual installations, and the risks posed by development of an entire shale gas play. Shale gas infrastructure may cover an area of several tens of thousands of square kilometres. For example, in Poland, concessions may extend up to 1,200 km^2, and there is no limit to the number of concessions that an individual company may hold (Baginski, 2010 NPR p150). Chevron reports the acquisition of a 6,100 km^2 concession in Romania (Chevron, 2012a NPR).

The current trend towards the use of multi-well pads, in which up to 10 wells may be placed on a single pad mitigates these impacts to some extent. New York State (2011 PR p5-17) indicates that one well pad may allow approximately 250 hectares of shale formation to be accessed (a similar value of 259 hectares was derived from DOE, 2009 NPR). This would correspond to a typical separation between well pads of approximately 1.5 km. Over an area of 6,000 km^2, this would correspond to up to 2,400 multi-well installations, occupying approximately 1.4% of the land area. The potential for cumulative effects was assessed on the basis of development of this scale. The rate of well pad development is likely to be limited by the availability of plant and equipment. For the purposes of this assessment, it was assumed that development of an individual shale gas concession could proceed at up to 5% of the rate of well development in the US as a whole (PGNiG 2011 NPR quoting Douglas-Westwood 2011 NPR) – that is, approximately 850 wells per year with development of up to 85 well pads per year.

This is comparable to the highest number of wells forecast to be drilled in any EU state for the period up to 2020 (1090 wells for Poland) (PGNiG 2011 NPR quoting Douglas-Westwood 2011 NPR). This is also comparable to the total of approximately 710 shale gas wells drilled in Pennsylvania during 2009 (Cuadrilla Resources Ltd 2011 NPR p12). The area of Marcellus Shale formation in Pennsylvania is approximately 250,000 square kilometres, of which only a fraction has been developed (Cuadrilla Resources Ltd 2011 NPR p40). This suggests that the assumed rate of intensive development of a shale gas play in Europe is likely to be an over-estimate of the rate of development that would arise in practice.

This assessment allowed risks to be preliminary screened to identify those of greater significance. Potentially significant risks were then considered in the context of the legislative analysis described in Chapter 3.

2.1.4 Study scope and boundaries

Following the description of the hydraulic fracturing process in Chapter 1, the following aspects fall under the scope of the assessment:

- water withdrawal
- transport of fracturing materials to the well
- mixing of chemicals and use in the specific act of fracturing
- recovery, treatment and disposal of wastewater
- well abandonment and post-abandonment,
- cumulative effects associated with development over a wide area

The study considers the direct environmental and health issues associated with these aspects of shale gas extraction. The study is not a "life-cycle" assessment, and consequently the risks associated with secondary processes are outside the scope of the study (e.g. the specific risks/impacts, resources and energy consumed in order to manufacture sand and other proppants, gravel, stone and chemical additives for well pad construction; or to construct and maintain road and pipeline infrastructure; or to produce fracturing fluids).

The potential impacts associated with traffic have been highlighted as a distinct issue from the impacts associated with the gas extraction process itself and associated infrastructure. Some of the impacts associated with traffic (such as emissions of air pollution, noise impacts and land take) can be expected to be similar in nature to those of the gas extraction process, whereas others (such as impacts on community severance or accident risks) differ in nature. The nature of the sources and the relevant control measures are sufficiently different for it to be useful to consider traffic-related impacts as a distinct but related issue.

The study inevitably draws on experience from the US, but where possible the findings from the US have been set in the European regulatory and technical context.

This study is not designed to draw conclusions on the potential significance of hazards posed by specific installations in Europe or the US. The approach taken is to draw on published information in relation to environmental and health risks, and make a preliminary judgment in terms of the potential significance of the hazards under consideration for the use of HVHF in Europe. The basis for reaching each preliminary judgment is set out in the text following each classification in the sections below.

2.1.5 Summary of impacts

Tables A5.1, A5.2 and A5.3 in Appendix 6 summarise the potential environmental impacts of hydrocarbons operations involving high-volume hydraulic fracturing (adapted from USEPA 2011a PR and other references).

These tables classify potential impacts as follows:

- Impacts which are unique to hydraulic fracturing, but which are likely to be more significant for high-volume hydraulic fracturing than for other hydraulic fracturing activities;
- Impacts which are common to hydraulic fracturing and conventional exploration / extraction practices in Europe, but which are more significant with hydraulic fracturing;
- Impacts which are common to both hydraulic fracturing and to conventional practices in Europe.

2.2 Risk prioritisation

2.2.1 Risk prioritisation framework

A preliminary risk prioritisation approach has been adopted to enable potential impacts to be evaluated.

King (2012 PR) sets out a useful basis for risk prioritisation in the context of shale gas development. This follows established principles of screening and prioritisation for environmental risk and impact assessment and management (e.g. UK Department for Environment, Transport and the Regions, 2000 NPR).

The risk prioritisation was carried out by classifying environmental hazards and hazards for people on the following basis:

- **Slight:** Slight environmental effect– e.g. a planned or unplanned discharge which does not result in exceedances of an environmental quality standard
- **Minor:** Minor environmental effect – e.g. a planned or unplanned discharge which could result in exceedances of an environmental quality guideline in the immediate vicinity of the release point, but which would not be expected to have significant environmental or health effects
- **Moderate:** Localised environmental effect – e.g. a discharge or incident resulting in potential effects on natural ecosystems in the vicinity of the release point or incident; ongoing effects on people in the vicinity of a site due to impacts such as noise, odour or traffic
- **Major:** Major environmental effect – e.g. an ongoing discharge resulting in persistent exceedances of European environmental quality standard; permanent degradation of a protected habitat

- **Catastrophic:** Massive environmental effect – e.g. a pollution incident resulting in harm to the health of members of the public over a wide area due to contamination of drinking water supplies; accident resulting in death or serious injury to workers and/or members of the public.
- **No data:** Insufficient data to allow a preliminary judgment to be reached

The frequencies or probabilities of hazards occurring were classified on the following basis (adapted from King, 2012 PR):

- **Rare:** Encountered rarely or never in the history of the industry; not forecast to be encountered under foreseeable future circumstances in view of current knowledge and existing controls on oil and gas extraction.
- **Occasional:** Encountered several times in this industry; could potentially occur under foreseeable future circumstances if management or regulatory controls fall below best practice standards
- **Periodic:** Occurs several times a year in this industry; a short-term impact would be expected to occur with the use of hydraulic fracturing for hydrocarbon operations
- **Frequent/definite:** Occurs several times a year at a specific site; a long-term impact would be expected to occur with the use of hydraulic fracturing for hydrocarbon operations
- **No data:** Insufficient data to allow a preliminary judgment to be reached

In environmental risk assessment studies of hazard significance and probability, it is often necessary to use some judgment because of uncertainty associated with the evidence base. This was the case for the present study. The frequency or probability of hazards occurring was estimated from reported analysis of hydraulic fracturing activities in the field where this was available. As indicated above, independent and comprehensive information for instance on well failures and incident rates is limited, which makes this risk prioritisation exercise a preliminary one, pending additional data. Indeed the absence of evidence of hazards does not necessarily mean evidence of the absence of hazards. Where expert judgment needed to be used, this was noted in the text.

Considering the hazard significance and associated probability enables risks to be prioritised and screened, as set out in Table 4 (adapted from King 2012 PR , after DeMong et al., 2010 PR).

Table 4: Risk ranking table

Probability classification	Hazard classification					
	Slight	**Minor**	**Moderate**	**Major**	**Catastrophic**	**No data**
Rare	Low	Low	Moderate	Moderate	High	Not classifiable
Occasional	Low	Moderate	Moderate	High	Very high	
Periodic/short term definite	Low	Moderate	High	Very high	Very high	
Frequent/long-term definite	Moderate	High	Very high	Very high	Very high	
No data	Not classifiable					

Where more than one scenario is envisaged, the combination giving rise to the highest ranking is presented. Risks can then be screened and prioritised as follows:

- Green: Low risk
- Yellow: Moderate risk

- Orange: High risk
- Red: Very high risk

This approach is useful for evaluating individual risks, and has been applied in the following sections to characterise the potential risks which could occur if specific mitigation in relation to the risks posed by shale gas extraction is not carried out.

2.2.2 Well lifetime and re-fracturing

Conventional and unconventional gas well production rates tend to drop after a period of time. An operator may choose to re-fracture the well, in order to increase the gas flow rate. As discussed in Chapter 1, this may take place approximately once every 10 years, or between 0 and 4 times over a well lifetime of up to 40 years while recognising that this is an area of uncertainty.

In practice, the evaluation in this chapter is not sensitive to the assumed frequency of re-fracturing, because the study is designed to be applicable to a wide range of circumstances involving the potential for development of multiple well pads in a local area such as a municipality, and across a wider area of thousands of square kilometres.

2.3 Stages in shale gas development

A shale gas development project is carried out in five main stages (Philippe and Partners, 2011 NPR p7-8; see Section 1.4) covering exploration (stages 1-4) and production (stage 5):

1. Identification of the gas resource.
2. Early evaluation drilling.
3. Pilot project drilling.
4. Pilot production testing.
5. Commercial development.

The exploration phase initially consists of drilling and fracturing a small number of vertical wells (typically only two or three wells) to determine if shale gas is present and can be extracted. A ‘plug and perforate completion’ technique tends to be used in the exploration phase. The well is lined and then perforated at certain points. Sections with the perforations are isolated with cement plugs before being fractured. The plugs are drilled through to allow the gas to flow to the surface where the potential for further development can be appraised.

If the initial indications are favourable, more wells (typically 10 to 15 wells) are drilled and fractured to characterise the shale, examine how fractures will tend to propagate and establish if the play could produce gas economically. Further wells (typically up to 30 wells) may be drilled to ascertain the long-term economic viability of the play (Royal Society and Royal Academy of Engineering (UK) 2012 PR).

The exploration phase is important in relation to the impacts of these pilot drilling and fracturing activities themselves, as well as in influencing the areas where full-scale shale gas extraction will take place.

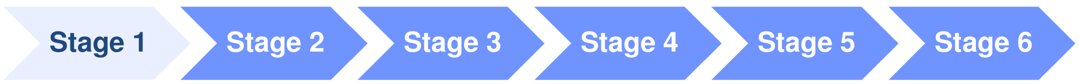
For an individual unconventional gas well, the process of well development is as follows (again as described in Chapter 1.4.2):

1. Well pad site identification and preparation
2. Well Design, Drilling, Casing and Cementing
3. Technical Hydraulic Fracturing Stage
4. Well Completion (flowback)

5. Well Production
6. Well Abandonment

The remaining part of this chapter focus on the above six stages of well development and the key risks associated with each individual stage and for the total project.

2.4 Stage 1: Well pad site identification and preparation



2.4.1 Surface water contamination risks

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*rare*	*low*
Cumulative effects of multiple installations	*moderate*	*rare*	*moderate*

Peer reviewed research

Runoff and erosion during early site construction may lead to silt accumulation in surface waters (This has a greater potential risk in HVHF because of larger well pads and storage impoundment construction). New York State DEC 2011 PR (page 6-14) highlights the particular risk of stormwater runoff leading to contaminants such as nutrient phosphorus and nitrogen, hydraulic oil, fuel and lubricating fluids entering water bodies, streams and groundwater. Common to industrial activity and construction sites generally, this impact relates to the extent of groundworks and the nature of surface construction (roads, concrete areas etc). The larger footprint of high volume multi-well pad installations (up to 3.0 hectares/pad; New York State 2011 PR p5-6) compared with those for conventional gas (c.1.9 hectares/pad) as well as larger storage impoundments make this an elevated risk of the former when assessed on a “per site” basis.

For similar reasons, shale gas installations have greater scope for habitat impacts directly associated with stormwater runoff, through the impact this has on the erosion of streams, sediment build-up, water quality degradation and potentially flooding. These stormwater impacts can be mitigated to an extent through managed drainage and controls on potential groundwater contaminants.

Other research

Other research was not used in this evaluation.

Preliminary judgment

As the risks to habitat sites are well understood for similar installations resulting in minimal impacts, the potential significance was considered to be “low”.

The potential cumulative effects on water quality due to development of multiple sites over an area of hundreds or thousands of square kilometres are a potential concern. As potential impacts could be additive, the potential significance of cumulative effects was considered to be “moderate”.

2.4.2 Release to air

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*slight*	*short-term definite*	*low*

Cumulative effects of multiple installations	*slight*	*short-term definite*	*low*

Peer reviewed research

Heavy machinery/installations used for site preparation and construction give rise to exhaust emissions. At the site construction stage, these are not significantly different to emissions from any other similar construction activity, although the larger well pad site area in the case of HVHF means that emissions would be greater for HVHF than for conventional gas extraction. Adopting the findings of New York State (2011 PR p5-6) that the well pad may be approximately 60% larger for HVHF than for conventional gas, releases to air may be also expected to be approximately 60% higher. Attention is normally focused on diesel engine emissions during the drilling and fracturing stages (Howarth and Ingraffea, 2011 NPR) rather than the site preparation phase, and are of less concern during site preparation. In this context, diesel engine emissions do not pose a significant environmental or health risk, and were assessed as a hazard of “slight” significance.

Similarly, there is a risk of fugitive emissions to air in the event of an equipment fuel or oil spillage, but this risk would be common to any similar activity and controlled via normal procedures for the oil and gas industry.

The well pad construction phase may be expected to last up to 4 weeks per well pad (New York State 2011 PR p5-135).

Other research

Lechtenböhmer et al. (2011 NPR) concur that diesel engine emissions during the drilling and fracturing stages are an area of concern, and hence are not of significance at the site preparation stage.

Broderick et al (2011 NPR , p28) concur that the well pad construction phase may be expected to last up to 4 weeks per well pad.

Preliminary judgment

A consistent view was identified that emissions to air during site preparation are of less concern than emissions during later stages in the project. In this context, diesel engine emissions would not pose a significant environmental or health risk, and were assessed as a hazard of “slight” significance.

Although no specific information was available with regard to the risks posed by fugitive emissions to air following a fuel or oil spillage, because these risks would be common to any similar activity, it was judged that this potential impact would be of “slight” significance.

Although no specific information was available in relation to cumulative impacts, in view of the limited significance of emissions to air during well pad site preparation, and with a typical well pad separation of approximately 1.5 km, it is judged unlikely that the cumulative effect of emissions to air during this phase could pose a significant risk to air quality in the context of wider sources of emissions to air such as road traffic. This was therefore assessed as a hazard of “slight” significance.

2.4.3 Land take

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*short-term definite*	*moderate*
Cumulative effects of multiple installations	*major*	*short-term definite*	*very high*

Peer-reviewed research

According to New York State DEC (2011 PR p5-6) land disturbance directly associated with high-volume hydraulic fracturing will consist primarily of constructed gravel access roads, well pads and utility corridors. It explains how well numbers and pattern layouts contribute to the overall pad size. Well pad equipment includes pits, impoundments, tanks, hydraulic fracturing equipment, reduced emission completion equipment, dehydrators and production equipment such as separators, brine tanks. Additionally, construction of pipelines would require land-take during the construction and operational phases. Pipelines may be buried which could enable this land to be returned to the previous use, or other beneficial use such as agriculture or road verges.

In the present study, the potential risks and impacts associated with the production of materials needed for road construction, such as minerals (gravel, stone, etc) and energy inputs associated with the production of these materials, are not assessed (see Section2.2.1).

Surface installations require an area of approximately 3.0 hectares per pad for high volume hydraulic fracturing during the fracturing and completion phases, compared to 1.9 hectares per pad for conventional drilling (New York State DEC 2011 PR Table 5.1) The additional area for HVHF well pads is needed to accommodate the equipment and storage tanks/pits required for up to 30,000 m^3 of make-up water, together with chemical additives and waste water.

Multi-well pads are now in widespread use for shale gas extraction. This enables a single pad to accommodate 6-10 wells (New York State 2011 PR p3-3), resulting in a lower land take impact compared to 1 well/pad for conventional production. This enables a single multi-stage horizontal well pad to access approximately 250 hectares of shale gas play, compared to approximately 15 hectares for a vertical well pad (adapted from New York State 2011 PR p 5-17). Assuming 3.6 hectares per multi-well pad (see below), this suggests that approximately 1.4% of the land above a productive shale gas reservoir may need to be used to fully exploit the reservoir, or more if other indirect land-uses (e.g. central storage facilities and pipelines) are taken into account.

It may not be possible to fully restore a site in a sensitive area following well completion or well abandonment. For example, sites in areas of high agricultural, natural or cultural value could potentially not be fully restorable following use.

As well as the well pads themselves, the associated infrastructure (access roads and pipelines) also results in land take and habitat fragmentation. For example, Sutherland et al. (2011 PR) highlight that over 30% of the 8,900 km^2 forests of the State of Pennsylvania have been made available for natural gas extraction, although only around 1.4% of this area (or less than 0.5% of the total forest area) would be taken for use in well pad development.

The use of land for gas development could be viewed as incurring an “opportunity cost” due to its unavailability for other, potentially more beneficial, uses. These opportunity costs have not been taken into account in this study.

Other research

The New York State DEC estimate of well pad area is consistent with a study carried out by the Nature Conservancy (2011 NPR p18) who estimate that 3.6 hectares of forest land would be taken per well pad, including roads and other infrastructure.

US DOE (2009 NPR) confirms the land requirements for conventional installations and installations using HVHF.

Lechtenböhmer et al.(2011 NPR page 21)highlight the potential significance of land take and habitat fragmentation due to associated infrastructure (access roads and pipelines).

Preliminary judgment

Land-take associated with an individual site is within the normal range of commercial and infrastructure developments in Europe, and it was judged that this can be considered as a minor impact. The cumulative land-take impact of 1.4% for full development of a gas reservoir compares to 4% of land in Europe currently occupied by "artificial areas" such as housing, industry and transportation. This is judged to be of potentially major significance, and would be a short-term impact likely to be associated with the full development of any large shale gas concession and therefore classified as "short term definite" likelihood.

2.4.4 Biodiversity impacts

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*not classifiable*	*not classifiable*
Cumulative effects of multiple installations	*not classifiable*	*not classifiable*	*not classifiable*

Peer-reviewed research

The term "biodiversity" refers to the variability among living organisms from all sources; … this includes diversity within species, between species and of ecosystems (adapted from the Convention on Biological Diversity). For the purposes of this project, "biodiversity" refers to the range of species supported by the ecosystem(s) surrounding a shale gas development or area of shale gas development, and the evaluation considers the risks to these species and ecosystems which could potentially result in a loss of biodiversity.

Gas extraction can affect biodiversity via a number of routes (New York State DEC 2011 Section 6.4; Entrekin et al. PR 2011). These include:

- removal of habitat (addressed in Section 2.4.3 above) or degradation of habitat (e.g. as a result of excessive water abstraction); or fragmentation (e.g. as a result of fencing, road construction)
- introduction of invasive species;
- noise and other disturbance
- water and land pollution

An invasive species is a species that is not native to the ecosystem under consideration and whose introduction causes or is likely to cause economic or environmental harm or harm to human health. Invasive species can be plants, animals, and other organisms such as micro-organisms, and can impact both terrestrial and aquatic ecosystems (New York State DEC 2011 PR p 6.4.2). New York State DEC highlights the potential effects on biodiversity due to invasive species as a potential concern.

The main impacts at the site preparation stage would be associated with habitat loss or fragmentation, following land take as described in Section 2.4.3. At this stage, the risks posed by sediment runoff into streams and potential contamination of streams from accidental spills should be considered, in order to minimise the risk of impacts at a later stage in the process (Entrekin et al., 2011 PR p8). Entrekin et al. conclude that there are preliminary indications of detectable effects of sedimentation of watercourses due to shale gas development, and consider that scientific data are needed to ensure protection of water resources.

Other research

Lechtenböhmer et al.(2011 NPR page 19) found that there were no documented effects of shale gas extraction on biodiversity. The EPA (2012 NPR p9) highlighted a local issue linked to the introduction of algae into local water courses, resulting in major fish kills. Locallygathered evidence indicates that gas extraction can affect biodiversity via the introduction of invasive species and via habitat loss (e.g. Heatley, 2011 NPR) but this evidence has not been published for external verification.

The Nature Conservancy (2011 NPR page 18) confirmed that development of well pads in forest areas in Pennsylvania affects a wider area than the site area itself. It was estimated that the area indirectly affected would be approximately an additional 2.4 hectares for every hectare of well pad area, or an additional 9 hectares per well pad.

Preliminary judgment

The risks to biodiversity arise due to accidental releases and habitat loss (up to 1.4% of habitat may be lost, with a further 3.4% of habitat indirectly affected). In view of the absence of published peer-reviewed research in this area, the risks to biodiversity posed by these impacts remains an area of plausible concern, but without a clear evidence base.

It was judged that the impacts on biodiversity associated with individual sites are likely to be limited to the vicinity of the site, supported by the conclusions of Entrekin et al. (2011 PR p8)and Nature Conservancy (2011 NPR). It was judged that cumulative effects of development of multiple sites could be more widespread, but it was not possible to classify the potential significance of these impacts.

It was judged that impacts associated with disturbance and potential for introduction of invasive species would be less than at other stages in the process. No information on the likelihood of impacts occurring during this stage of shale gas development was identified.

2.4.5 Noise

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*slight*	*periodic*	*low*
Cumulative effects of multiple installations	*minor*	*rare*	*low*

Peer-reviewed research

Noise from excavation, earth moving, other plant and vehicle transport could affect residential amenity and wildlife, particularly in sensitive areas during the period of site preparation – typically up to four weeks (see Section 2.4.2).

The levels of noise during site preparation were estimated by New York State DEC (2011 PR p6-289 to 6-300).

Other research

None referenced

Preliminary judgment

The levels of noise identified by New York State DEC (2011 PR) could be controlled to avoid risks to health for members of the public. Site operatives and visitors may need additional controls to ensure that no adverse effects on health occur due to noise during this stage.

The issues associated with site preparation would be typical of the scale of impacts associated with any comparable construction activity and are therefore judged to be of “slight” significance for individual development. The separation of approximately 1.5 km between multi-well pads would result in significant attenuation for receptors potentially affected by multiple developments, and there is judged to be a low risk of cumulative impacts due to noise during site development.

2.4.6 Visual impact

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*slight*	*periodic*	*low*
Cumulative effects of multiple installations	*minor*	*occasional*	*moderate*

Peer-reviewed research

Visual impacts are described by New York State DEC (2011 PR p6-263) as impacts that "*would typically result from the introduction of new landscape features into the existing settings surrounding well pad locations that are inconsistent with (i.e., different from) existing landscape features in material, form, and function.*" New York State DEC reviewed a number of field studies of visual impacts of shale gas production facilities, and concluded that, in the context of development in New York state, "*the visibility of new landscape features associated with well sites tends to be minimal from distances beyond 1 mile*" (p6-283). New York State DEC went on to summarise the range of features which may result in a visual impact over the lifetime of a shale gas development.

Other research

None referenced

Preliminary judgment

The use of heavy plant, stockpiles, fencing, site buildings etc could potentially result in adverse visual intrusion during site preparation, particularly in sensitive areas of high landscape value, or in close proximity to residential areas.

The new features introduced as a result of well pad construction would be temporary in nature, and in general familiar to local populations, even if they may represent a new feature in a particular landscape, and are therefore judged to represent a "slight" impact. These features are likely to proceed sequentially as a shale gas play is developed. The sequential development of well pads would reduce the potential for cumulative effects which could result from simultaneous development of a number of pads in a given area, but would equally tend to make the impacts a longer-term feature in the landscape. Cumulative effects are therefore judged to represent a "minor" hazard.

2.4.7 Traffic

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*slight*	*short term definite*	*low*
Cumulative effects of multiple installations	*moderate*	*long term definite*	*high*

Peer-reviewed research

New York State DEC (2011 PR) summarises the potential effects of road traffic as follows: "*The introduction of high-volume hydraulic fracturing has the potential to generate significant truck traffic during the construction and development phases of the well. These impacts would be temporary, but the cumulative impact of this truck traffic has the potential to result in significant adverse impacts on local roads and, to a lesser extent, state roads where truck traffic from this activity is concentrated.*"

The New York State DEC (2011 PR Table 6.60) indicates that the total number of truck movements during drill pad construction is likely to be approximately 135 one-way trips per well, or about 7% of the total truck movements. This suggests approximately 500 – 800 truck movements for the development of a 10 well pad. This number of movements over a pad construction period of approximately 4 weeks (see Section 2.4.2) would not be environmentally significant in itself, although it would be noticeable in a rural or residential area (New York State DEC 2011 PR p6-308).

Other research

Broderick et al (2011 NPR) state that the data for New York combined with data in relation to exploratory drilling in the UK "*…suggests a total number of truck visits of 7,000-11,000 for the construction of a single ten well pad ... Local traffic impacts for construction of multiple pads in a locality are, clearly, likely to be significant, particularly in a densely populated nation…*"

Preliminary judgment

The maximum permitted vehicle weight in the US is 80,000 pounds (67 CFR 658.17), equivalent to 36 tonnes, although heavier longer combination vehicles are also permitted. In the EU, the maximum permitted vehicle weight is 44 tonnes gross (Directive 96/53/EC). Hence, the number of heavy vehicle movements in an EU context may be approximately 83% of those set out in New York State DEC (2011 PR), equivalent to 20 to 30 movements per day.

It is judged that this number of vehicle movements associated with site preparation would be a small proportion of the numbers of vehicles likely to give rise to significant environmental or health impacts. On this basis, it is judged to represent a "slight" impact. The impacts include air emissions, noise and visual impact, as well as transport system effects such as infrastructure damage, congestion and effects on road safety during the period of site preparation.

If a number of well pads are developed in a given area, the potential for adverse effects would be more significant, as there would potentially be a sustained increase in numbers of goods vehicle movements in a local area. The cumulative impacts may be considered on the basis of the estimated site separation of approximately 1.5 km. The most sensitive situation is likely to be a route located through a town centre leading to a shale gas development area. A single route could plausibly be needed for the development of the order of 100 well pads, covering an area of 15 km × 15 km. This could result in a combination of increased vehicle numbers, or an extension of the period of site development by a factor of up to 100, equivalent to approximately 8 years. This is considered to be a "minor" potential impact in view of the longer development period. Any impact is likely to be more severe on unsuitable roads and for longer haulage distances.

2.5 Stage 2: Well Design, drilling, casing and cementing

Stage 1 Stage 2 Stage 3 Stage 4 Stage 5 Stage 6

In this section, the options of sequential well drilling and simultaneous well drilling have been considered. Each well is likely to take up to two weeks to drill, and one or two wells may be drilled at a time at an individual well pad (Broderick et al 2011 NPR p28). If wells are drilled sequentially, it may take three to five months to complete drilling at a single well pad with six to ten well bores. If two wells are drilled simultaneously, the drilling process would take six to ten weeks to complete, but activity would be more intense during this period.

2.5.1 Groundwater contamination and other risks

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*rare*	*low*
Cumulative effects of multiple installations	*minor*	*rare*	*low*

Peer-reviewed research

During the well construction and development phase there is a risk of subsurface groundwater contamination due to drilling muds, additives and naturally-occurring chemicals in well cuttings. New York State DEC (2011 PR p6-40) identifies these risks as:

- Turbidity (suspension of solids within the water supply) arising from aquifer penetration, which it notes is short term in nature. The report (p2-24) highlights an incident in which an operator caused turbidity in drinking water supplies during well construction as a result of a "non-routine incident" in which a drill bit became stuck in a partially drilled well;
- Flow of fluids into or from rock formations – discussed below for hydraulic fracturing
- Natural gas migration. New York State DEC 2011 PR cites the preceding GEIS (New York State 1992 PR) which observes that natural gas migration to water supplies poses a hazard because it is combustible and an asphyxiant. It notes that whilst the impact may manifest itself during the production phase, the root cause lies in well construction integrity. Good construction practices can help to mitigate this risk.

Other research

The EPA (2012 NPR p8) noted a potentially higher risk of methane migration with air drilling compared to drilling using liquid muds, and recommended further research in this area.

SEAB (2011a NPR page 19) noted that where there is a large depth separation between drinking water sources and the producing zone the chances of contamination reaching drinking water is remote in a properly constructed well.

A surfactant additive used in well drilling was found to be emerging from a spring and contaminating a watercourse in Pennsylvania in 2010 (PFBC 2011). The source was identified as a shale gas well site situated above the spring discharge, at a distance of approximately 600 metres The surfactant was pumped into the well during the drilling process and was then flushed laterally through the underground rock strata by heavy rain runoff.

Preliminary judgment

Poor well construction can have important environmental consequences due to the effect that inadequate design or execution can have on the risks associated with hydraulic fracturing. These risks are described in more detail in section 2.6.1. The risk rating here is provided for risks occurring during the well construction and development phase.

The causes of groundwater contamination associated with the well design, drilling, casing and cementing stage generally relate to the quality of the well structure. The risk of contamination would increase in situations where casings are of inadequate depth. As discussed in section 2.6.1, wellbore casings provide the primary line of defence against contamination of groundwater, and any loss of integrity from catastrophic failure of well casing to poor cement seals can lead to a contamination event. Poor casing quality can thus lead to pollution of groundwater during subsequent well development stages, such as hydraulic fracturing, flowback or gas production activities. Furthermore, the risks due to surface spills, discussed in section 2.5.2would also apply for drilling wastes.

The risks from these activities would increase linearly with the number of wells and the time period over which the risk exposure arises. Any significant increase in groundwater pollution during this phase could potentially affect health in the event that members of the public were exposed to pollution in drinking water.

The risks to groundwater posed by well construction for HVHF during the well construction stage are similar to those posed by well construction for conventional natural gas extraction.

In view of the limited extent of potential effects and the established issues under consideration, impacts are considered to be of "minor" potential significance. In view of the limited number of incidents associated with the drilling and casing stage of the process in the peer reviewed and other literature, the frequency was considered to be "rare" for both individual facilities and cumulative impacts. It is also important to achieve a high standard of well integrity to ensure impacts are properly controlled during subsequent stages in the process, as discussed in Sections 2.6, 2.7 and 2.8 below.

2.5.2 Surface water contamination risks

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*moderate*	*rare*	*moderate*
Cumulative effects of multiple installations	*moderate*	*rare*	*moderate*

Peer-reviewed research

Natural gas well drilling operations use compressed air or muds during the drilling process as the drilling fluid. Compressed air may be used for vertical wells, and horizontal wells are normally drilled with muds (New York State DEC 2011 PR p5-32). The quantities of muds involved are likely to be greater for a horizontal shale gas well than for a conventional vertical well of similar depth, although the quantities would not be unusual in the context of wells encountered in the oil and gas extraction industry. A well with a 1,200 metre horizontal section would give rise to approximately 47 m^3 of mud and cuttings from the horizontal section (adapted from New York State 2011 PR p5-34). A multi-well pad would give rise to this quantity of material from each well.

Wells also produce cuttings which need to be properly handled. For example, a vertical well with surface, intermediate and production casing drilled to a total depth of 2,100 metres produces approximately 120 cubic metres of cuttings, while a horizontally drilled well with the same casing program to the same target depth with an example 1,200 metre lateral section produces a total volume of approximately 170 cubic metres of cuttings (i.e., about 40% more). A multi-well site would produce approximately that volume of cuttings from each well (adapted from New York DEC 2011 PR p5-34).

During the drilling stage, contamination can arise as a result of failure to maintain stormwater controls (potentially leading to site-contaminated runoff), ineffective site management, inadequate surface and subsurface containment, poor casing construction or more generally well blowout or component failure events (New York State 2011 PR page 6-15). The greater intensity and duration of well pad activities for multiple shale gas wells increases the potential for accidental release if engineering controls are not sufficient. As well as management and engineering practices, these risks can be reduced by avoiding locating drilling fluids in primary or principal aquifer areas.

Measurement of radioactivity of cuttings from the Marcellus Shale and Barnett Shale found that levels were not significantly elevated above background (New York State 2011 PR p5-34).

Other research

USEPA (2011a PR) states that "*drilling muds are known to contain a wide variety of chemicals that might impact drinking water resources. This concern is not unique to hydraulic fracturing and may be important for oil and gas drilling in general.*"

The US EPA (2012a NPR p4) highlights that horizontal wells would overall result in a lower volume of cuttings than vertical wells for development of a given area.

The Paleontological Research Institute (2011 NPR p5) also found that levels of radioactivity in cuttings were not significantly elevated above background, although the US EPA (2012a

NPR p4 and p5) reports other data sets from the Marcellus Shale with higher levels of Naturally-Occurring Radioactive Material (NORM).

Preliminary judgment

Exposure to materials with elevated radiological activity could potentially be of concern with regards to health, but this would only take place in the event of failure of established control systems. There is insufficient information on the potential for radiological impacts in gas-bearing shales in Europe to enable a judgment to be made on the potential significance of this issue in Europe, although established procedures are in place to address radiological risks.

It is important to ensure proper storage and disposal of cuttings. Established procedures are in place for management of waste from hydrocarbon extraction activity, for example, under the Mining Waste Directive (see Chapter 3). The introduction of wide scale shale gas extraction would result in a significant increase in the quantities of potentially contaminated material requiring storage, handling, treatment and disposal. Depending on the nature of shales in Europe, this material may have elevated levels of radioactivity.

There is no centralised database of information on spillages of muds during shale gas drilling activities, although it may be expected that any potentially significant incidents would be reported. No evidence was found that a spillage of muds has caused a significant impact on surface waters – for example, this was described by Lechtenböhmer et al.(2011 NPR p27) as a "possible" source of water contamination. Bearing in mind that absence of evidence of impacts is not the same as evidence of absence of impacts, the frequency was classified as "rare" albeit subject to some uncertainty. In view of the potential significance of impacts of spillages on sensitive water resources, the risks were considered to be of "moderate" significance.

2.5.3 Release to air

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*occasional*	*moderate*
Cumulative effects of multiple installations	*major*	*occasional*	*high*

Peer-reviewed research

As described in New York State DEC 2011 PR (page 6-114), drilling operations can lead to air emission from 1) combustion from diesel-powered plant on site; and 2) truck activities near the well pad. The overall impact of these is affected by the period over which the activities take place.

New York State DEC 2011 PR (page 6-105) identifies the primary pollutants as particulate matter (PM), NO_x, CO, VOCs and SO_2, and estimates, based on industry data, emissions for drilling, completion and production under flaring and venting scenarios. While there is a complex picture of diverse impacts and stages, the overall assessment of hazardous air pollutants shows greatest impacts associated with flaring of wet gas, production of wet gas and drilling in all scenarios. Wet gases from some fields have relatively high levels of higher molecular weight VOCs (Academic sector consultation response 2012 NPR). In dry gas scenarios, drilling is the largest single emitting activity when pollutants are aggregated. These figures are indicative and New York State DEC 2011 PR should be examined for further details and also regarding the extensive modelling performed to calculate expected air quality impacts from potential developments.

The main issue of potential concern with regard to emissions to air during well drilling is the risk of emissions of diesel exhaust fumes from well drilling equipment (Howarth and Ingraffea, 2011 NPR ; Academic sector consultation response 2012 NPR).

Other research

The period of well drilling is typically four weeks per well(Broderick et al 2011 NPR). Lechtenböhmer et al. (2011 NPR)concur that the main issue of potential concern with regard to emissions to air during well drilling is the risk of emissions of diesel exhaust fumes from well drilling equipment.

Emissions from numerous well developments in a local area or wider region could potentially have a significant effect on air quality. For example, diesel emissions are considered likely to be a contributory factor to winter ozone episodes in rural Wyoming and Ohio (Argetsinger, 2011 NPR ; University of Wyoming, 2012 NPR ; Academic sector consultation response 2012 NPR).

Preliminary judgment

The potential effects of emissions from diesel-powered plant would in principle be greater for HVHF than for conventional gas extraction because of the larger well volumes, as described in Section2.5.2. Emissions from diesel-engined plant are well understood and emissions from plant up to 560 kW are controlled in Europe. In view of this, the emissions from individual installations are judged to be of “minor” significance. No significant adverse effects on health would be expected to arise from a properly designed and operated individual installation.

In view of the evidence from non-peer reviewed but independent sources of the cumulative effects of emissions to air from hydrocarbon facilities on environmental levels of ozone, the potential significance of these impacts was described as “major.” The atmospheric chemistry environment in Europe differs from that in continental North America, in that ozone is typically associated with summertime photochemical activity rather than calm winter conditions (Derwent et al. 2003 PR). Nevertheless, it is considered in principle possible for emissions to air to have a comparable indirect effect on summer ozone levels in Europe, although it is not possible to quantify the scale of this potential effect on air quality and hence on health. Exposure to elevated levels of ozone can have an adverse effect on respiratory health, and this impact was also considered to be potentially “major”.

Additionally, there is a risk of fugitive emissions to air in the event of an equipment fuel or oil spillage, but this risk would be common to any similar activity. There is no centralised database of information on such spillages during shale gas drilling activities. No evidence was found that fuel spillages pose a significant risk to air quality. It was judged that the potential effects of any intermittent spillage would not be significant in the overall context of gas extraction processes.

2.5.4 Biodiversity impacts

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*rare*	*low*
Cumulative effects of multiple installations	*minor*	*rare*	*low*

Peer-reviewed research

Gas well drilling could potentially affect biodiversity primarily via noise and disturbance caused by the drilling process itself, together with associated vehicle movements and site operations. However, the evidence in relation to biodiversity impacts is that any impacts are associated with other stages of the well development process – e.g. via land-take at well pad construction stage (New York State 2011 PR p6-67). Consequently, the impacts at this stage are considered to be of “minor” significance.

Adequate handling, treatment and disposal of well drilling fluids as described in Section 2.5.2 is needed to avoid potentially significant impacts on biodiversity, and more data is needed to fully understand these effects (Entrekin et al., 2011 PR).

Other research

As discussed above, drilling at a multi-well pad could take place for up to 5 months (Broderick et al 2011 NPR p28) assuming wells are drilled sequentially.

Preliminary judgment

As noted in Section 2.4.4, there is no evidence in the peer-reviewed literature for effects of shale gas extraction on biodiversity, although informal publications and presentations provide plausible indications that adverse effects on biodiversity could occur due to activities other than well drilling. Well drilling could potentially cause local disturbance as described in Section 2.5.5 below, but would not give rise to concerns related to wider scale effects associated with other aspects of shale gas extraction. On this basis, it is judged that there is a minor potential for cumulative impacts on biodiversity associated with well drilling at multiple well pad installations.

2.5.5 Noise

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*occasional*	*moderate*
Cumulative effects of multiple installations	*moderate*	*occasional*	*high*

Peer reviewed research

New York State DEC (2011 PR p6-289 to 6-297) indicates that well drilling is one of the more significant sources of noise, other than during the fracturing process itself. This would also need to be seen in the context of ongoing noise from sources including well pad construction, hydraulic fracturing and road traffic.

Other research

The process lasts up to 4 weeks per well (Broderick et al 2011 NPR table 2.5), but drilling is continuous for 24 hours per day over this time. Broderick et al consider that drilling is the stage of greatest continuous noise pollution. Furthermore, if a number of wells are developed on a single pad, this would extend the period that this impact takes place to up to five months.

Preliminary judgment

If two wells are drilled simultaneously at a well pad, this could result in a doubling of the noise source, with a resultant increase in noise level experienced in the local area by up to 3 dB(A). Because of the sensitivity of the human ear to sound, an increase of 3 dB(A) would be detectable, but would not be perceived as a doubling of sound level. With this increase, the noise levels would continue to be less significant although longer lived than those associated with the hydraulic fracturing process. Effective noise abatement controls are well established in the oil and gas industry (New York State DEC 2011 PR p6-289 to 6-297). It is expected that established noise controls would be applied during drilling, and consequently this impact was judged to be of “minor” significance.

Noise from well drilling could potentially affect residential amenity and wildlife, particularly in sensitive areas. Noise impacts over the shale gas pre-production stages are discussed in section 2.6.7 and highlight that whilst construction and drilling noise levels can be significant, they are lower than for the hydraulic fracturing stage itself.

The levels of noise during drilling forecast by New York State DEC (2011 PR p6-289 to 6-300) could be controlled to avoid risks to health for members of the public. Site operatives and visitors may need additional controls to ensure that no adverse effects on health occur due to noise during this stage.

If a number of well pads are developed in a given area close to sensitive residential areas or habitats, the potential for adverse effects would be more significant, as there would potentially be a sustained increase in noise levels for an extended period. A typical separation of 1.5 km between well pads would provide significant attenuation of cumulative noise impacts. These cumulative impacts were judged to be of potentially “moderate” significance.

2.5.6 Visual impact

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*slight*	*periodic*	*low*
Cumulative effects of multiple installations	*minor*	*occasional*	*moderate*

Peer-reviewed research

The use of well drilling rigs could potentially result in adverse visual intrusion over the approximately 4 week period of well drilling, particularly in sensitive areas of high landscape value, or in close proximity to residential areas (New York State DEC (2011) PR section 6.9.2.2).

Other research

An example drilling rig is shown as the highest vertical feature in Figure 5.

Figure 5: Drilling rig used in well excavation, Eagle Ford Shale, Texas

Preliminary judgment

The new features introduced as a result of well pad construction would be temporary in nature, but would typically be unfamiliar to local populations, and would represent a new industrial feature in a particular landscape. Individual wellpads would be separated by approximately 1.5 km. Furthermore, the development of a number of wells on a single pad would extend the period that this impact takes place. In view of the limited duration associated with drilling at individual well pads, this impact is judged to be of "slight" significance.

These features are likely to proceed sequentially as a shale gas play is developed. The sequential development of well pads would reduce the potential for cumulative effects which could result from simultaneous development of a number of pads in a given area, but would equally tend to make the impacts a longer-term feature in the landscape. Consequently, development of a shale gas play could affect a landscape over a longer period. Cumulative impacts were therefore judged to be potentially of "minor" significance.

2.5.7 Traffic

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*slight*	*short term definite*	*low*
Cumulative effects of multiple installations	*moderate*	*long term definite*	*high*

Peer-reviewed research

New York State DEC (2011 PR Table 6.60) indicates that the total number of truck movements during well drilling is likely to be approximately 515 one-way trips per well, or about 26% of the total truck movements. This suggests approximately 5,000 truck movements for the development of a 10 well pad. This number of movements over a pad construction period of approximately three to five months would not be environmentally significant in itself, although it would be noticeable in a rural or residential area (New York State DEC 2011 PR p6-308).

Other research

Broderick et al (2011 NPR) state that the data for New York combined with data in relation to exploratory drilling in the UK "*…suggests a total number of truck visits of 7,000-11,000 for the construction of a single ten well pad ... Local traffic impacts for construction of multiple pads in a locality are, clearly, likely to be significant, particularly in a densely populated nation…*"

Preliminary judgment

The number of heavy vehicle movements in an EU context may be approximately 83% of those set out in New York State DEC (2011 PR), equivalent to approximately 50 movements per day.

It is judged that this number of vehicle movements associated with site preparation would be a small proportion of the numbers of vehicles likely to give rise to significant environmental or health impacts. On this basis, it is judged to represent a "slight" impact. The impacts include air emissions, noise and visual impact, as well as transport system effects such as infrastructure damage, congestion and effects on road safety during the period of site preparation.

If a number of well pads are developed in a given area, the potential for adverse effects would be more significant, as there would potentially be a sustained increase in numbers of goods vehicle movements in a local area. Following the approach adopted in Section 2.4.7, it is judged that the cumulative traffic impacts may be considered a "minor" potential impact.

2.6 Stage 3: Technical Hydraulic Fracturing

Stage 1 Stage 2 Stage 3 Stage 4 Stage 5 Stage 6

Constituents of fracturing fluid

Peer reviewed research

Many chemicals have been used across the hydraulic fracturing industry. However, only a small number of chemicals are used in an individual fracturing operation – typically 6 – 12 chemicals, depending on the nature of the fluid used (King, 2012 PR).

Other research

The constituents of hydraulic fracturing fluids are examined in USEPA (2011a PR page 30), although it states this list to be incomplete given the lack of information regarding the frequency, quantity and concentration of chemicals used. It identifies a research activity to gather additional data on hydraulic fracturing fluid composition, although acknowledges that this information may be seen as commercially confidential by the companies using the fluids. USEPA (2011a PR page 31) sets out a programme to examine the chemical, physical and toxicological properties of these chemicals, citing the US House of Representatives Committee on Energy and Commerce (2011 NPR) which identified 2,500 hydraulic fracturing products containing 750 chemicals in use between 2005 and 2009 in the US. These included 29 chemicals that were known human carcinogens, regulated under safe drinking water legislation or listed as hazardous air pollutants under clean air legislation.

SEAB (2011a NPR page 23) examines the issue of composition of fracturing liquids and notes that some US States have adopted disclosure regulations for chemicals added to fracturing liquids, as well as there being (as of August 2011) Federal interest in this issue.

2.6.1 Risks of groundwater contamination

Leakage via wellbore or induced fractures

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installations (more than 600 m separation between fracturing zone and groundwater)	*moderate*	*rare*	*moderate*
Individual installation (less than 600 m separation between fracturing zone and groundwater)	*moderate*	*occasional*	*high*
Cumulative effects of multiple installations	*major*	*rare*	*moderate*

Peer-reviewed research

Considerable measures are taken during hydraulic fracturing to prevent leakage of the fracturing liquid into the groundwater due to inadequacies in the well casing or due to the extension of induced fractures into zones which could potentially result in movement of contaminants to groundwater. Hydraulic fracturing can also affect the mobility of naturally occurring substances in the subsurface, particularly in the hydrocarbon-containing formation (EPA 2011a PR). The substances of potential concern include the chemical additives in hydraulic fracturing fluid, produced water, gases, trace-elements, naturally occurring radioactive material and organic material. Some of these substances may be liberated from the formation via complex biogeochemical reactions with chemical additives found in fracturing fluid (Falk et al., 2006 PR ; Long and Angino, 1982 PR quoted in EPA 2011a PR). If fractures extend beyond the target formation and reach aquifers, or if the casing around a wellbore is inadequate in extent or fails under the pressure exerted during hydraulic fracturing, contaminants could potentially migrate into drinking water supplies.

Recent evidence indicates that a separation of the order of 600 m would result in a remote risk of properly injected fluid resulting in contamination of potable groundwater (Davies et al., 2012 PR). Similar data are reported by Fisher and Warpinski (2012 PR Figure 2), indicating a maximum vertical fracture extent of approximately 600 metres. Another recent study finds evidence however that in particular locations methane and fugitive gases from deep geological layers can migrate upwards into shallow strata through natural pathways (Warner et al. (2012) PR). This indicates a need for systematic processes to characterise the geology to enable any such migration risks to be understood and taken into account in the site selection and design process. This study followed on from a study of methane contamination in aquifers overlying the Marcellus and Utica shale formations of north-eastern Pennsylvania and upstate New York (Osborn et al. 2011 PR) which is discussed in Section 2.8.1. No evidence for contamination of drinking-water samples with deep saline brines or fracturing fluids was found by Osborn et al.

The analysis carried out by Fisher and Warpinski indicated that fracturing carried out close to the surface tended towards the formation of horizontal fracturing, which would reduce (although not eliminate) the risk of fractures interacting with water resources in shallower shale gas formations.

The lack of baseline monitoring carried out in the US prior to shale gas development may partly explain why the evidence of contamination associated with shale gas extraction is complex and uncertain.

Other research

SEAB (2011a NPR page 28) states, in the context of the potential effects of methane contamination, *“leakage to water reservoirs is widely believed to be due to poor well completion, especially poor casing and cementing….. there need to be multiple engineered barriers to prevent communication between hydrocarbons and potable aquifers. In addition, the casing program needs to be designed to optimize the potential success of cementing operations. Poorly cemented cased wells offer pathways for leakage; properly cemented and cased wells do not."* In this context, the term “reservoirs” refers to underground aquifers.

SEAB (2011a NPR , p19) highlights that regulators and geophysical experts agree that the likelihood of properly injected fracturing liquid or naturally occurring contaminants reaching underground sources of drinking water through fractures is remote where there is a large depth separation between drinking water sources and the producing zone. According to SEAB, this view is confirmed by the existence of few, if any, documented examples of such migration. The SEAB does not specify what a “large depth” would constitute.

Preliminary indications are that most but not all shale gas reservoirs in Europe exhibit a separation of more than 600 metres between the depth of shale gas formations and aquifer resources (US Department of Energy EIA, 2011 NPR).

In contrast, where there is no such large depth separation, nor cap rock between the aquifer and the gas play, the risks are greater. At one such site setting (Pavillion, Wyoming), hydraulic fracturing occurred in gas production wells at a depth as shallow as 372 metres below ground surface (EPA, 2011c NPR (draft)). Overlying the gas field, there is an aquifer in a formation where water wells are excavated to depths of 15m to 230m or more. These wells are the principal source of domestic, municipal and agricultural water in the area of Pavillion. Groundwater contamination has been found in this area. The US EPA (2011c NPR) draft report concluded that the data indicate likely impact to ground water which can be explained by hydraulic fracturing. The USEPA’s draft report concluded that the observed contamination was linked to inadequate vertical well casing lengths and a lack of well integrity (USEPA 2011c NPR p37, p38). However, the initial sampling will need to be completed in a next phase of testing. (Wyoming State Governor; the Northern Arapaho and Eastern Shoshone Tribes, and US EPA Administrator, 3 March 2012 NPR).

The geological setting at Pavillion is unique in the US, and fracturing was carried out directly from vertical wells, whereas fracturing which is the focus of this study is carried out from the horizontal section of wells.

Broderick et al (2011 NPR page 81) notes that once installed, wellbore casings provide the primary line of defence against contamination of groundwater, and states that any loss of integrity from catastrophic failure of well casing to poor cement seals can lead to a contamination event. It notes, however, that loss of casing integrity events would require physical failure of both steel casing and cement. In this respect Broderick et al (2011 NPR pages 81 and 82) emphasise the role of high quality cementing as protection against contamination.

The US EPA (2011a PR p35) highlights the potential impacts on well integrity of multiple-stage fracturing processes and of repeated fracturing of a well over its lifetime. As discussed in Section 2.2, it is assumed that hydraulic fracturing may be repeated up to four times during the operational lifetime of a well to maintain the flow of hydrocarbons to the well. The EPA indicates that the potential effects of repeated hydraulic fracturing treatments on well construction components (e.g., casing and cement) are not well understood. This is an area where additional information is needed to draw firm conclusions with regard to potential impacts, and is highlighted as an issue of high potential significance.

Preliminary judgment

The issue of groundwater contamination as a result of the technical hydraulic fracturing stage will be highly site specific and can be to a degree mitigated through site selection processes as mentioned above. Measures may include limiting extraction to shale gas formations at significant depth and ensuring the presence of low permeable geological strata between the producing zone and aquifers in use as a source of drinking water. Furthermore, there is little information on the potential impacts on well integrity of repeated fracturing of a well over its lifetime.

In view of the currently available evidence that there have been few past incidents of contamination which were associated with practices which would not be carried out under HVHF and the controls which are now well established in the industry, it is judged that the frequency of incidents of groundwater contamination during hydraulic fracturing due to wellbore leakage is rare. The frequency would increase when considering drilling across an entire shale gas concession with approximately 24,000 wells.

It is judged that the magnitude of a contamination event is no more than “moderate,” defined as “a localised environmental effect." Because of the low likelihood of contamination events taking place on adjacent wells, it is judged that the magnitude of cumulative impacts would be unchanged compared to the magnitude for individual events with more than 600 m separation between the fracturing zone and groundwater. For individual sites with less than 600 m separation between the fracturing zone and groundwater, the risk was judged "high".

<u>Migration through faults and pre-existing manmade structures</u>

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installations (more than 600 m separation between fracturing zone and groundwater)	*moderate*	*rare*	*moderate*
Individual installation (less than 600 m separation between fracturing zone and groundwater)	*moderate*	*occasional*	*high*
Cumulative effects of multiple installations	*major*	*rare*	*moderate*

Peer-reviewed research

As discussed above, the potential exists in principle for the fugitive gases, chemical additives in the fracturing liquid or the liberated, naturally occurring substances to reach underground sources of drinking water raises concerns over the risks to human health. This could potentially occur, for example, if extended fractures are linked to aquifers via faults or pre-existing manmade structures.

Recent evidence discussed above indicates that in most cases a separation of the order of 600 m would result in a remote risk of properly injected fluid resulting in contamination of potable groundwater, though site-specific geological circumstances would need to be considered. Besides leakage through artificial pathways, Warner et al (2012 PR) show that there is also a possibility of leakage of fluids or gases through natural geological structures, cracks, fissures or interconnected pore spaces.

Other research

Research indicated that predicted and actual fracture lengths often differ (Daneshy, 2003 NPR ; Warpinski et al. 1998 NPR , quoted in EPA 2011a PR ; Damjanac et al, 2010 NPR). Due to this uncertainty in fracture location, fracturing may lead to fractures intersecting local geologic or man-made features, potentially creating subsurface pathways that allow fluids or gases to contaminate drinking water resources.

Broderick et al (2011 NPR page 81) identified common subsurface pathways as the outside of the wellbore itself, incomplete or plugged wellbores from abandoned wells, fractures and other natural cracks, fissures and interconnected pore spaces. As described above, Broderick et al (2011 NPR pages 81 and 82) emphasise the role of high quality cementing as protection against contamination.

Preliminary judgment

Control measures may include preliminary surveys to ensure the absence of natural pathways in the geological strata). The potential also exists for pre-existing manmade structures (e.g. abandoned oil and gas wells) in the vicinity of injection zones or wells to serve as conduits increasing the reach of contaminated groundwater. The existence of abandoned wells is a significant issue in the US, where oil and gas extraction has proceeded for decades. The existence and location of many of these wells is not recorded. Abandoned gas wells also exist in Europe, although indications are that there are fewer such wells in Europe than in the US. It is considered likely that unrecorded abandoned wells may be a more significant issue in Eastern Europe than in Western Europe, but no evidence to substantiate this view could be identified.

Based on the examined literature, there appears to be no identified records of incidents of contamination due to hydraulic fracturing linked to faults and pre-existing manmade structures. It is judged that the frequency of incidents of groundwater contamination during hydraulic fracturing via this pathway would be rare when there is more than 600 metres of separation between the fracturing zone and groundwater, and could be reduced further by the specification of appropriate minimum separation distances (see Chapter 4).

The evidence from other stages in the process and via other pathways is that contamination is likely to be limited to the immediate vicinity of the relevant wells. In view of this, it is judged that the magnitude of a contamination event is no more than “moderate,” defined as “a localised environmental effect.” Because of the low likelihood of contamination events taking place on adjacent wells, it is judged that the magnitude of cumulative impacts would be unchanged compared to the magnitude for individual events. For individual installations with less than 600 m separation between the fracturing zone and groundwater, the risk was judged to be "high".

Accidental surface spills

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*moderate*	*not classifiable*	*not classifiable*
Cumulative effects of multiple installations	*major*	*not classifiable*	*not classifiable*

A further aspect of groundwater contamination during hydraulic fracturing is that related to accidental spills and leakages. Section 2.6.2 sets out the potential sources of spillages during hydraulic fracturing.

Peer-reviewed research

New York State DEC (2011 PR p6-15) highlights the risks to subsurface soils and aquifers via this pathway.

Other research

Broderick et al (2011 NPR page 81) highlight the key factors affecting the potential severity of groundwater contamination, citing the significance of the aquifer for abstraction; the extent and nature of contamination; the concentration of hazardous substances; and connection between groundwater and surface waters. US EPA (2011a PR p28) highlights the risk of contamination of soil and near-surface aquifer via this pathway, and has focused further research in this area. The Department of Energy SEAB (2011a NPR p19-20) also highlights the risks to subsurface soils and aquifers via this pathway.

Preliminary judgment

The potential significance of impacts posed by a single well pad is considered likely to be localised in nature but with potential for transport away from the site. Taking the issues outlined above into consideration, this impact is judged to be potentially of “moderate” significance.

Multiple development would pose risks of more widespread contamination if not properly managed, which is considered to be potentially of “major” significance.

No information was identified on the frequency of liquid spillage, and it was therefore not possible to classify the frequency of risks to groundwater posed by spillages.

2.6.2 Risks of surface water contamination

The relevant issues are:

- Accidental spillage of fracturing fluid and other fluids at the surface;
- Wellbore leakage; and

Accidental surface spills and vehicle accidents (see Section 2.6.10)

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*moderate*	*occasional*	*high*
Cumulative effects of multiple installations	*major*	*rare*	*moderate*

Peer-reviewed research

New York State DEC 2011 PR (page 6-15) identifies that the amount of fracturing liquid used is considerably greater for horizontal drilling compared with more conventional vertical drilling. As discussed in Chapter 1, typically 10,000 to 20,000 m^3 fracturing fluid may be used per well (New York State 2011 PR p3-6), compared with 1,350 to 2,700 m^3 for a vertical well (New York State 2011 PR p3-6). New York State 2011 PR p6-15 quotes an analysis carried out by the state which indicates that the proposed additives for high volume horizontal drilling are similar to those used for vertical drilling. It therefore concludes that the risks (from spillage) are proportionally higher for horizontal drilling, although notes previous work (New York State 1992 GEIS PR) that there are no qualitatively different exposure situations for horizontal drilling.

New York State DEC 2011 PR (page 6-15) highlights that other spillage events could arise from tank ruptures, piping failures, equipment or surface impoundment failures, overfills, vandalism, accidents, fires, drilling and production equipment defects or improper operations. It expands on the causes and management practices related to these:

- The causes and modes of release events are similar for hydraulic fracturing additives as for drilling fluids. Contamination can arise as a result of failure to maintain stormwater controls, ineffective site management, inadequate surface and subsurface containment, poor casing construction or more generally well blowout or component failure events. Risks can be reduced by siting hydraulic fracturing fluids away from primary or principal aquifer areas. The risk is increased under high-volume hydraulic fracturing because of the larger fluid volumes.
- Leaks and spills of flowback water could also pose environmental or human health risks. The potential causes of releases are similar to those for the primary injection fluid, with the added risks associated with flowback water containment and processing equipment, including hoses or pipes to convey flowback water to tanks and trucks or leakage from those vessels. Flowback water will include fracking liquid additives as well as constituents from the local environment and well equipment. Produced water from wet shales could include dissolved solids, metals, biocides, lubricants, organics and naturally occurring radioactive materials and degradation products.

New York State DEC (2011 PR) also refers to the risks posed by truck accidents, although these risks are not quantified.

Other research

DOE (2009 NPR p64) and BRGM (2011 NPR p59) confirm that typically 10,000 to 20,000 m^3 fracturing fluid may be used per well.

The frequency of spillage events is not well known. USEPA (2011a PR page 29) cites numerous media reports of spills but also points to a lack of robust data on the frequency or causes of such events. A key concern for accidental fluid release is the potential impact on surface waters as well as public water supplies. The risks of drinking water contamination from spills are affected by the processes for managing contaminated water and the actions taken to mitigate the effects of any spills or leakages. SEAB (2011a NPR page 20) states that additional measures are being taken by some operators and regulators to manage this risk, including the use of mats, catchments and groundwater monitors associated with the hydraulic fracturing installation, together with buffers around surface water resources. Whilst the specific measures may be considered site specific the principles and approaches to managing these risks may be treated as generic best practice.

Preliminary judgment

A spillage at a single well pad or a vehicle accident could potentially affect surface water at some distance away from the site. Taking the issues outlined above into consideration, this impact is judged to be potentially of “moderate” significance.

Multiple development of wellpads at approximately 1.5 km separation would pose more significant risks due to the number of activities being undertaken, which is considered to be potentially of “major” significance.

The existence of reported spillages indicates that the frequency of occurrence should be considered “occasional” although improved data would be useful in this regard. The likelihood of cumulative impacts is judged to be “rare” because it is less likely that multiple events would affect one surface water body: reported incidents refer to single events only.

Wellbore leakage

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*moderate*	*rare*	*moderate*
Cumulative effects of multiple installations	*major*	*rare*	*moderate*

Peer-reviewed research

A common concern with hydraulic fracturing is leakage of the fracturing liquid through fractures into the groundwater (as discussed in Section 2.6.1 above) and ultimately into drinking water. The key control measures for this are set out in Section 2.6.1.

Other research

None reviewed

Preliminary judgment

Wellbore leakage at a single well pad could potentially affect surface water at some distance away from the site. This impact is judged to be potentially of “moderate” significance.

Multiple development of wellpads at approximately 1.5 km separation could pose a more significant and widespread risk to surface waters, which is considered to be potentially of “major” significance.

The absence of reports of surface water contamination due to wellbore leakage during technical hydraulic fracturing indicates that the frequency of occurrence should be considered “rare” although improved data would be useful in this regard. The likelihood of cumulative impacts is also judged to be “rare” because it is unlikely that multiple events would affect one surface water body.

2.6.3 Water resource depletion

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*occasional*	*moderate*
Cumulative effects of multiple installations	*moderate*	*occasional*	*high*

Peer-reviewed research

The hydraulic fracturing process is water intensive and abstraction impacts can be significant. In the broader context, however, New York State DEC 2011 PR (page 6-9) notes that water abstraction from conventional oil and gas drilling is a very small percentage of overall water withdrawal, and the contribution of gas extraction with hydraulic fracturing would be expected to be low (less than 0.25% of the total water resource use in New York State based on the peak forecast usage rate for the oil and gas industry in the state; New York State DEC 2011 PR p6-12). In view of the wide range of other water uses, a similar pattern would expect to prevail in Europe. However, New York State DEC also points out that there is potential for adverse effects when water withdrawals occur on low flow or drought conditions or in unsustainable locations New York State DEC 2011 PR (page 6-10). A proportion (25% to 100%) of the water used in hydraulic fracturing is not recovered, and consequently this water is lost permanently to re-use, which differs from some other water uses in which water can be recovered and processed for re-use. The potential impacts described cover:

- Reduced stream flow affecting the availability of resources for downstream use, such as for public water supply.
- Adverse impacts on aquatic habitats and ecosystems from affects such as degradation of water quality, reduced water quantity, changes to water temperature, oxygenation and flow characteristics, including the effects of sediment and erosion under altered responses to stormwater runoff.
- An interplay with downstream dischargers, affecting their ability to discharge where limits are related to stream flow rate, or the overall concentration of pollutants where discharge rates remain unaffected.
- Impacts on water quality, affecting the use which can be made of surface waters

New York State DEC 2011 PR (page 6-9) considers the potential volume of abstraction in New York and states this to be unknown due to uncertainty in the number of wells that could be operated. This highlights that the overall cumulative impact from hydraulic fracturing is as much determined by the local density of well sites as the characteristics of the fracking process itself. As an example of the figures involved, New York State DEC 2011 PR (page 6-10) reports that between July 2008 and February 2011, average water usage for high-volume hydraulic fracturing within the Susquehanna River Basin in Pennsylvania was 19,000 m^3per well based on data for 553 wells.

The quantity of water withdrawn is influenced by the re-use of flowback water from previous fracturing operations, which New York State DEC 2011 PR (page 6-10) estimated to typically account for 10%-20% of the injected fracturing fluids. Recent estimates indicate recycling of approximately 77% of wastewater in the second half of 2011 in Pennsylvania, compared to 10% two years previously (Yoxtheimer, 2012 PR), although there is uncertainty over the typical rate of recycling in the US, which may be significantly lower.

Yoxtheimer (2012 PR) described how many of the challenges associated with processing the flowback for re-use have been overcome, in particular by the introduction of friction reducers which permit the re-use of high salinity water.

Other research

The evaluation of potential impacts is supported by Broderick et al (2011 NPR page 90). This study highlighted that local effects could be much more significant and areas already under the strain of water scarcity may be affected especially as longer term climate change impacts of water supply and demand are taken into account.

USEPA (2011a PR pages 25 and 27) cites similar impacts. In highlighting the potential of diversion of drinking water supplies, it references stakeholder concerns regarding high volume withdrawals from small streams in the headwaters of watersheds supplying drinking water in the Marcellus Shale area. This impact on the drinking water system can lead to the need for engineering solutions for reduced aquifer levels – for example lowering of pumps or deepening of wells as required in the area of the Haynesville Shale. Further consequences of reduced water levels mentioned include:

- The potential for chemical changes to aquifer water, including altered salinity, as a result of the exposure of naturally occurring minerals to an oxygen rich environment.
- stimulated bacterial growth, causing taste and odour problems in drinking water.
- upwelling of lower quality water or other substances (e.g. methane – shallow deposits) from deeper and subsidence or destabilization of geology

Following recent low rainfall, water withdrawal permits for shale gas well development in the Susquehanna River Basin in Pennsylvania have been temporarily suspended (SRBC, 2012b NPR). This substantiates the concerns expressed by New York State DEC (2011 PR).

The water abstraction volumes identified by New York State DEC (2011 PR) are consistent with the range of 4,500 to 22,500 m^3per well cited in SEAB (2011a NPR p19). USEPA (2011a PR pages 22 and 25) cites similar figures.

USEPA (2011a PR page 23) estimates that 25-75% of the original fluid injected in the first two weeks after a fracture is recovered. North American regulator consultation response, (2012 NPR) confirmed that processing and re-use of flowback has improved substantially in recent years. Because of the incomplete fluid recovery, re-used fluid is typically blended with a similar volume of fresh water.

Preliminary judgment

In view of the above discussion, the potential impact of a single site on water resources is judged to be “minor.” The potential exists for development of multiple sites within a single water catchment. This would require careful management to ensure that development takes place at an appropriate pace. If this management is not in place, development of multiple sites could pose a “moderate” risk to water resources in some areas. The frequency of these potential effects are judged to be “occasional,” defined as “could potentially occur … if management or regulatory controls fall below best practice standards.”

2.6.4 Release to air

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*occasional*	*moderate*
Cumulative effects of multiple installations	*moderate*	*occasional*	*high*

Peer-reviewed research

As discussed in section2.5.3, New York State DEC 2011 PR (page 6-114) identifies the main sources of air emissions from drilling, completion and production activities and examines their relative significance. Sources of emissions include diesel fumes and truck activities near the well pad. Emitted substances include PM, NO_x, CO, VOCs and SO_2. Emissions of diesel fumes from fracturing fluid pumps were highlighted by Howarth and Ingraffea (2011 NPR).

Other research

The issues of potential concern with regard to emissions to air during hydraulic fracturing comprise the following:

- Emissions of diesel fumes from fracturing fluid pumps (Lechtenböhmer et al. 2011 NPR)
- On-site handling (by conveyor and blender) of proppant (sand) which can emit significant quantities of dust. Kellam (2012 NPR) reported that 0.25% (by weight) of proppant sand was emitted to the air as fine dust during fracturing fluid make up operations.

Preliminary judgment

As discussed in Section 2.5.3, impacts during hydraulic fracturing from individual sites are considered to be of “minor” significance, but the cumulative impact from multiple sites could potentially be of greater significance. The major contributor to regional air quality issues is likely to be the completion and production stages, and the cumulative impact from the technical hydraulic fracturing stage was judged to be “moderate”.

Additionally, there is a risk of fugitive emissions to air in the event of an equipment fuel or oil spillage, but this risk would be common to any similar activity and not significant in the overall context of gas extraction processes. There is no centralised database of information on such spillages during shale gas drilling activities. No evidence was found that fuel spillages pose a significant risk to air quality in the context of other sources of emissions to air. On this basis, the risks of fugitive emissions following a spillage were judged to be of minor significance.

2.6.5 Land take

Land is required for storage of hydraulic fracturing fluids and waste water, together with vehicle access, pipelines and associated plant and equipment. This is addressed in Section 2.4.3.

2.6.6 Biodiversity impacts

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*rare*	*low*
Cumulative effects of multiple installations	*moderate*	*rare*	*moderate*

On-site storage and transportation of water can affect biodiversity due to land take, disturbance and/or by the introduction of non-native invasive species. This is discussed in Section 2.4.4.

Peer-reviewed research

New York State DEC (2011 PR p6-3) cites the effect of shale gas exploitation activities on ecosystems and wildlife. The impacts will be strongly location dependent but general effects can be defined. These include fragmentation of habitat, potential transfer of invasive species and impacts on endangered or threatened species. Entrekin et al (2011 PR p8) describe the risks to wildlife posed by sediment runoff into streams, reductions in streamflow, contamination of streams from accidental spills, and inadequate treatment practices for recovered wastewaters as “realistic threats”.

Other research

The EPA (2012 NPR p9) highlighted a local issue linked to the introduction of algae into local water courses, resulting in major fish kills.

Three examples of uncontrolled release of fluids with actual or potential effects on biodiversity and agriculture are quoted by Michaels et al. (2011 NPR).

Preliminary judgment

The impact will be related to the footprint of the development sites, including the effects of access roads and utility services. These are discussed in section 2.4.3. In addition, contamination of local water sources and the effects of water depletion can all harm local ecosystems. The potential causes of these effects are described in sections 2.6.1 and 2.6.3.

In view of the existence of limited evidence of effects of hydraulic fracturing on biodiversity, the frequency is considered to be “rare.” The biodiversity impacts of potential concern (e.g. Michaels et al. 2011 NPR ; New York State DEC 2011 PR p6-3) are associated with cumulative development over a wider area, and are judged to be of “moderate” significance.

2.6.7 Noise

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*short-term definite*	*moderate*
Cumulative effects of multiple installations	*minor*	*short-term definite*	*moderate*

Peer-reviewed research

Noise emissions associated with operation of well and associated equipment could affect residential amenity and wildlife, particularly in sensitive areas. New York State DEC 2011 PR (pages 6-289 to 6-300) describes the noise impacts from hydraulic fracturing. The noise level differs with the stages in the preparation and production cycle. At 75 metres, for example, the maximum calculated composite noise level for construction equipment is 70dBA. For horizontal drilling the corresponding maximum noise level is 64dBA. The hydraulic fracturing process, however, can produce noise levels of 90dBA at that distance. This is calculated on the basis that up to 20 diesel pumper trucks are required to operate simultaneously to inject the required water volume to achieve the necessary pressure. The operation takes place over a period of several days for each well and would be repeated at a site for multiple wells and pads. This noise has the potential to temporarily disrupt and disturb local residents and wildlife.

Other research

Broderick et al (2011 NPR , p92) examined noise pollution, with a focus on the extent of activities rather than their noise levels, focusing on Cuadrilla Resources' Preese Hall exploratory site in the UK. It states that each well pad (assuming 10 wells per pad) would require 800 to 2,500 days of noisy activity during pre-production. This covers ground works and road construction as well as the hydraulic fracturing process. Drilling, which it states as the stage of greatest continuous noise pollution, is required for 24 hours per day for four to five weeks at each well.

Preliminary judgment

The levels of noise during fracturing forecast by New York State DEC (2011 PR p6-289 to 6-300) would need to be carefully controlled to avoid risks to health for members of the public. Site operatives and visitors may need additional controls to ensure that no adverse effects on health occur due to noise during this stage. Because controls on noise are widely used in the oil and gas industry, it is judged that the potential significance of noise issues with these controls in place is "minor".

2.6.8 Seismicity

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*slight*	*rare*	*low*
Cumulative effects of multiple installations	*minor*	*rare*	*low*

Peer-reviewed research

New York State DEC 2011 PR (page 6-319) describes two types of induced seismic events associated with hydraulic fracturing. One is micro-seismic events resulting from the physical fracturing process. These are sufficiently small to require very sensitive monitoring equipment to be detected. This is an inherent part of the fracturing process and data on these events is used to guide the fracturing process. Indeed SEAB (2011a NPR page 21) recommends micro seismic surveys as a means to understand fracture growth and limit methane leakage (as opposed to the management of seismic risks). For hydraulic fracturing, New York State DEC 2011 PR (page 6-321) notes that seismic activity is only detectable at the surface by very sensitive equipment, and that the magnitude can be minimised by avoiding pre-existing faults. It also describes the potential for sheer slip, in which slippage occurs on bedding planes, which it states to be several orders of magnitude less than that which would be felt by humans. It reviews operating experience and reports on consultations with experts to conclude that the possibility of fluids injected during hydraulic fracturing the Marcellus or Utica Shales reaching a nearby fault and triggering a seismic event is remote. A recent peer reviewed European report nevertheless provides recommendations on the need to introduce traffic light monitoring systems to mitigate induced seismicity (Royal Society and Royal Academy of Engineering PR 2012, p.6).

The second type of event results from injection fluids reaching existing geological faults, leading to more significant ground accelerations, potentially felt by humans at the ground surface. These types of events can arise in any process involving the injection of pressurised liquids underground. For example, New York State DEC 2011 PR (page 6-321) notes that carbon sequestration can cause such events, with magnitudes typically less than 3, and the events connected to circumstances that could be avoided through site selection and injection design.

Well integrity could potentially be affected by seismic activity – either activity induced by the hydraulic fracturing process, or other seismic events. This is managed by the normal processes for monitoring and maintaining well integrity. Induced seismicity from hydraulic fracturing is of very small magnitude and would not be expected to adversely affect wellbore integrity.

Other research

Broderick et al (2011 NPR page 93) reviewed the discussion in the previous draft New York State DEC study (2009 PR) but went on to describe experiences at the Cuadrilla Resources' Preese Hall exploratory site in the UK. At that location hydraulic fracturing was halted in May 2011 following instrumental detection of seismic events of magnitude 1.5 and 2.3 in the vicinity. Subsequent studies suggested a link between the fracturing activities and the seismic events (de Pater and Baisch 2011 NPR). As reported by Broderick et al (2011 NPR), one study indicated a maximum induced magnitude of around 3, for that location, which was considered insufficient to cause surface structural damage but to potentially damage the wellbore itself. The UK Government has published research which sets out a proposed monitoring and control approach (DECC 2012 NPR) and anticipates lifting the temporary embargo on hydraulic fracturing operations in the UK with this system in place. Seismic activity was also recorded in Oklahoma in January 2011 (Holland 2011 NPR). It was concluded that the recorded earth tremors could possibly be linked to hydraulic fracturing activity in a nearby water disposal well. The study reported two previous events in Oklahoma, in which a link to hydraulic fracturing had been suggested over the period 1977 to 2011.

Preliminary judgment

In view of these evaluations and the low frequency of reported incidents, it is judged that the frequency of significant seismic events is "rare" and the potential significance of this impact is "slight." Multiple development could increase the risk of seismic events due to one operation affecting the well integrity of a separate operation, although in view of the low frequency of the reported events and the established measures for monitoring well integrity, the risks are judged to remain low.

2.6.9 Visual impact

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*slight*	*short-term definite*	*low*
Cumulative effects of multiple installations	*slight*	*long-term definite*	*moderate*

Peer-reviewed research

New York State DEC 2011 PR (page 6-275) reviewed visual impacts associated with hydraulic fracturing activities at well sites. It identifies landscape features as access roads, pipelines, water impoundment areas, storage vessels and other hydraulic fracturing equipment, vehicles and buildings. It notes that these impacts would be short-term, but could repeat periodically over the life of a multi-well location. The visual impact is of more consequence in developments at more rural locations. A more comprehensive summary of visual impacts is presented in New York State DEC 2011 PR (page 6-285) for Horizontal Drilling and Hydraulic Fracturing in the Marcellus and Utica Shale Area of New York, although many of the impacts have more general applicability.

Other research

Broderick et al (2011 NPR page 92) also identifies visual impacts, citing the UK Cuadrilla development at Blackpool as involving a footprint of 1ha per well pad for up to 80 pads. Broderick et al. concur that the visual impact is of more consequence in rural locations.

Preliminary judgment

In view of the perception-based nature of these impacts, and lower visual impact compared with the drilling stage, they are judged to be “slight”. Impacts can be expected to occur with an individual site over a short period, and for multiple development over an extended period. On this basis, the likelihood of impacts was judged to be “short-term definite” for individual sites and “long-term definite” for multiple sites.

2.6.10 Traffic

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*occasional*	*moderate*
Cumulative effects of multiple installations	*moderate*	*occasional*	*high*

Peer-reviewed research

The traffic impacts of shale gas pre-production are examined in New York State DEC 2011 PR (pages 6-300 to 6-316). It estimates the number of loaded truck trips per horizontal well during construction. Two scenarios are considered, one in which all water (fracking fluid and backflow) are transported by truck, and one in which pipelines are used in part of that activity. In the former, a total of heavy 1,148 truck trips are envisaged, with the largest single activities associated with hydraulic fracturing (175 for the transportation of equipment and 500 for transport of water to site). This figure reduces to 625 where pipelines are assumed to be available for water and waste transport. Furthermore, the temporal distribution of these activities is uneven, so the total number of trips during the heaviest period could be as high as 250 per day (including lighter trucks). The maximum permitted weight of articulated vehicles is slightly greater in Europe than in the US, and so the number of vehicle movements may be slightly less. .

New York State DEC 2011 PR goes on to examine some of the potential impacts of this level of transport. These include:

- Increased traffic on public roadways. This could affect traffic flows and congestion.
- Road safety impacts.
- Damage to roads, bridges and other infrastructure. This could lead to decreased road quality and increased costs associated with maintenance for roads not designed to sustain the level of traffic experienced.
- Risks of spillages and accidents involving hazardous materials.

In addition to the above, the road vehicles would cause air emissions with the potential for localised air quality impacts, as well as increasing the potential for community severance (reduction in community interaction due to roads with high traffic volumes) and potentially affecting residents’ quality of life. The noise impacts are described above.

Other research

For more widespread development, EPA (2012 NPR p14) suggests that there may be a sustained impact at this level.

Road traffic accident statistics in Europe focus on fatalities rather than on the number of vehicle accidents (see http://epp.eurostat.ec.europa.eu/portal/page/portal/statistics). These statistics indicate an ongoing decline in the rate of fatal accidents associated with truck transportation in Europe.

Preliminary judgment

Even at the levels described above, the impact in traffic terms associated with an individual site would be no more than "minor" in view of the short duration, although it would potentially be noticeable by local residents.

An increase in road transportation of potentially hazardous chemicals and waste materials would result in an increased risk of environmental pollution due to accidents, although these risks cannot be quantified at present. The established controls on transportation of dangerous goods such as Directive 2008/68/EC on the inland transport of dangerous goods would reduce the risks posed by vehicle accidents.

Following the views of the EPA (2012 NPR p14), the impact of traffic associated with more widespread development, including the risks posed by traffic accidents, could be considered of "moderate" significance.

2.7 Stage 4: Well Completion

2.7.1 Groundwater contamination and other risks

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*moderate*	*occasional*	*high*
Cumulative effects of multiple installations	*major*	*occasional*	*high*

During the well completion phase, operators need to handle flowback and produced water to ensure that accidents, runoff and surface spillages do not occur, which would pose risks of groundwater contamination. If flowback water is used to make up fracturing fluid, this would increase the risk of introducing naturally occurring chemical contaminants and radioactive materials to groundwater. Relevant naturally occurring substances could include:

- Salt
- Trace elements (mercury, lead, arsenic)
- NORM (radium, thorium and uranium)
- Organic material (organic acids, polycyclic aromatic hydrocarbons)

Peer-reviewed research

New York State DEC (2011 PR Table 6.1) lists a large number of chemicals recorded in flowback water, or present in fracturing fluid which may be present in flowback waters, and concludes that "… *high-volume hydraulic fracturing operations, although temporary in nature, may pose risks to Primary and Principal Aquifers…*"

Other research

As noted in Section 2.6.6, three examples of uncontrolled release of fluids with actual or potential effects on biodiversity and agriculture are quoted by Michaels et al. (2011 NPR).

Preliminary judgment

These risks are similar to those discussed during the hydraulic fracturing phase in Section 2.6.1.

In view of the risks posed by metals and NORM in flowback fluid and the findings of New York State DEC quoted above, the potential impacts are judged to be of "moderate" significance for individual installations, and "major" significance in relation to cumulative impacts. On the basis of reported instances of uncontrolled releases in non-peer reviewed research, it is judged that the likelihood of impacts from individual sites and for cumulative impacts should be considered as "occasional" – defined as "could potentially occur … if management or regulatory controls fall below best practice standards."

2.7.2 Surface water contamination risks

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*moderate*	*occasional*	*high*
Cumulative effects of multiple installations	*moderate*	*occasional*	*high*

Peer-reviewed research

Treatment in municipal sewage treatment plant can affect the plant due to the salt content of the water. If not properly handled, this can reduce the overall effectiveness of the sewage works. New York State (2011 PR p6-62) highlights the scale of water treatment resources that would be needed to maintain adequate treatment capacity. Also, some parameters which are likely to be present in flowback water may not be properly treated in a standard sewage treatment facility. New York State DEC highlights the potential for accumulation of NORM in sewage sludges.

Howarth and Ingraffea (2011 NPR) cite examples of water contamination of tributaries of the Ohio River with barium, strontium and bromides from municipal wastewater treatment plants receiving wastewater from hydraulic fracturing processes.

Other research

As described in Chapter 1, flowback waters are collected and recycled in the hydraulic fracturing process, or sent for treatment and disposal. The options for recycling are limited to some extent because of a build-up of salts and contaminants in flowback fluid which ultimately makes the fluid unsuitable for use without dilution (North American regulator consultation response, 2012 NPR). Arthur (2008 NPR p19-20) highlights the development of research and pilot-scale projects for flowback water recycling. This work has accelerated in recent years, with 77% of wastewater estimated to have been recycled in Pennsylvania in the second half of 2011 (Yoxtheimer, 2012 NPR). However, there is uncertainty over the typical rate of recycling in the US, which may be significantly lower.

A number of options are available for disposal of flowback water:

- Direct discharge to surface rivers and streams can affect water quality, particularly in the light of the high salt content. This practice is banned in the U.S. and would not be permitted in Europe under the terms of the Mining Waste Directive.
- Waste water may be injected into disposal wells if such facilities are available and if it is not prohibited by law (see discussion in Chapter 3)

- Waste water may be treated in on-site facilities or in separate sewage works including commercial facilities designed for treatment of produced water from wet shale formations. Extensive desalination treatment, such as evaporation/distillation, allows discharge of the treated water to surface waters. Less extensive chemical precipitation treatment is used to remove suspended solids and divalent cations (magnesium, calcium, strontium, barium and radium) to facilitate wastewater reuse (Yoxtheimer, 2012 NPR).

Arthur (2008 NPR p19) refers to the need for development of new waste water treatment technologies.

Lechtenböhmer et al. (2011 NPR section 5.4.2) refers to the treatment of waste water as an issue that "may also complicate projects" and cites an example in which the rate of disposal of gas drilling wastewaters had to be reduced by 95% as a result of non-compliance with water quality standards. Lechtenböhmer et al. highlighted in particular the risks potentially posed by metals and NORM in waste waters.

Examples of spillages and accidental discharges are cited by Michaels et al. (2011 NPR) – for example, 109 spillages were reported in Colorado during a three year period.

Preliminary judgment

In view of the risks posed by metals and NORM in waste waters, the potential impacts are judged to be of "moderate" significance.

In view of the reported incidents of discharges to water in peer reviewed and non-peer reviewed research, it is judged that the likelihood of impacts from individual sites and for cumulative impacts should be considered as "occasional" – defined as "could potentially occur … if management or regulatory controls fall below best practice standards."

2.7.3 Release to air

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*occasional*	*moderate*
Cumulative effects of multiple installations	*major*	*occasional*	*high*

Individual installation:

Hazard classification: minor   Probability classification: occasional Risk ranking: moderate

Cumulative effects of multiple installations:

Hazard classification: major   Probability classification: occasional Risk ranking: high

Peer-reviewed research

As discussed in section 2.5.3, New York State DEC 2011 PR (page 6-114) identifies the main sources of air emissions from drilling, completion and production activities and examines their relative significance. Sources of emissions include combustion from engines and flares; venting; and truck activities near the well pad. Emitted substances include PM, NO_x, CO, VOCs and SO_2. Flowback gas would normally be dry although wet gas, requiring removal of condensable hydrocarbons, could be encountered.

Other research

The issues of potential concern with regard to emissions to air during hydraulic fracturing comprise the following:

- Emissions of hazardous air pollutants, ozone precursors and/or odours due to gas leakage during completion (Lechtenböhmer et al., 2011 section 2.3.1; Michaels et al.

2011 NPR p19). Leakage may take place from pumps, valves, pressure relief valves, flanges, agitators, and compressors (EPA 2011b NPR Sections 4.2 and 8.1).

- Emissions of hazardous air pollutants, ozone precursors and/or odours from gases dissolved in flowback water during well completion or recompletion (EPA 2011b NPR Section 4). The short-term storage of flowback water on site can lead to considerable emissions of VOCs (Academic sector consultation response 2012 NPR). The amount of VOCs and methane released varies over the flow back period. Reduced Emissions Completions can use open tank storage, which may result in flashing and evaporative emissions.
- Fugitive emissions of methane and other trace gases may take place from routeing gas generated during completion via small diameter pipeline to the main pipeline or gas treatment plant. This is likely to be more severe from wells developed during the pilot stages than from production stage wells, by which stage robust pipeline infrastructure should be in place (EPA 2011b NPR Section 4.4.2.1). Emissions to air could also occur from flaring of methane during exploratory phases prior to the construction of gas collection infrastructure (British Columbia OGC 2011 NPR).

Preliminary judgment

Relevant naturally occurring substances could include:

- Gases (natural gas (methane, ethane), carbon dioxide, hydrogen sulphide, nitrogen and helium)
- Organic material (volatile and semi-volatile organic compounds)
- Naturally-occurring radioactive material (NORM)

The potential effects of emissions during well completion can be expected to be greater for HVHF than for conventional gas extraction because of the wider range of potential sources of process and fugitive emissions. Emissions to air from a properly designed and operated individual facility would not be expected to have a significant adverse effect on health, although a residual risk does remain.

As discussed in Section 2.5.3, impacts from individual sites are therefore considered to be of “minor” significance, but based on non-peer reviewed evidence from the US, the cumulative impact from multiple sites could potentially be of “major” significance. Exposure to elevated levels of ozone can have an adverse effect on respiratory health, and this potential cumulative impact on health was also considered to be potentially “major”.

2.7.4 Land take

Following completion, some of the land used for a well pad and associated infrastructure can be returned to the prior use, or to other uses. However, well established natural habitats cannot necessarily be fully restored following use of the land for shale gas extraction. Consequently, it may not be possible to fully restore a site, or to return the land to its previous status resulting in habitat loss (New York State DEC (2011) p6-68), resulting in a long-term impact as described in previous sections and in Section 2.8.5.

2.7.5 Biodiversity impacts

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*rare*	*low*
Cumulative effects of multiple installations	*moderate*	*rare*	*moderate*

Contamination of local water sources due to spillages or inadequate treatment of waste waters can potentially harm local ecosystems, similarly to the impacts described in 2.6.6. The potential causes of these effects are described in sections 2.6.1, 2.6.2 and 2.7.2.

2.7.6 Noise

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*not classifiable*	*short-term definite*	*not classifiable*
Cumulative effects of multiple installations	*not classifiable*	*short-term definite*	*not classifiable*

Peer-reviewed research

Noise from the well completion process could arise from on-site plant and machinery, but is likely to be lower than at other stages in the gas extraction process, and of limited duration (New York State DEC 2011 PR p 6-289 to 6-300).

Preliminary judgment

No peer-reviewed evidence was found in relation to noise from gas flaring. Noise from flares can be minimised using appropriate flare design. Residual noise from flares could not be controlled using engineering measures in the same way that plant and equipment noise can be controlled because of the nature of the source.

No adverse effects on public health would be expected to arise due to noise from plant and equipment provided established controls used in the oil and gas industry are applied. However, because of the uncertainty associated with flaring noise, it is judged that noise impacts are not classifiable.

2.7.7 Seismicity

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*rare*	*low*
Cumulative effects of multiple installations	*minor*	*rare*	*low*

Peer-reviewed research

None reviewed

Other research

Recent evidence indicates that injection of waste water into disposal wells may have been associated with minor earth tremors of magnitude 2.7 to 4.0 on the Richter scale (Ohio Department of Natural Resources, 2012 NPR ; Arkansas Sun Times, 2011 NPR).

Preliminary judgment

Injection of waste water into aquifers is not permitted in Europe, although disposal into geological formations with no connection to aquifers may be permitted as discussed in Chapter 3.

If injection of waste water from hydraulic fracturing into disposal wells were permitted, earth tremors of the magnitude recorded in Ohio would not normally have significant consequences at the surface, and are judged to be of minor significance. On the basis of some reported occurrences of minor earth tremors, the frequency of seismic impacts is judged to be rare.

2.7.8 Traffic

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*slight*	*short-term definite*	*low*
Cumulative effects of multiple installations	*minor*	*short-term definite*	*moderate*

Peer-reviewed research

The traffic impacts of shale gas pre-production are examined in New York State DEC 2011 PR (pages 6-300 to 6-316). It estimates the number of loaded truck trips per horizontal well during completion. 100 truck movements per well are estimated to be needed for waste water disposal. This figure reduces to 17 movements where pipelines are assumed to be available for water and waste transport. This represents a small proportion of overall truck movements, but would contribute to the net impacts of traffic associated with a well development.

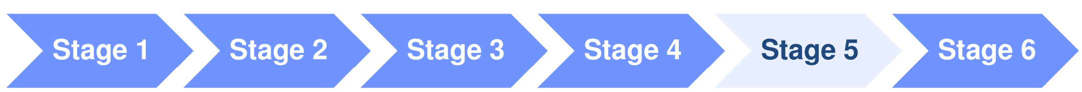
Other research

None reviewed

Preliminary judgment

In view of the low number of traffic movements associated with well completion phase, the impacts associated with an individual well pad are judged to be slight, and those associated with wider area development are judged to be minor.

2.8 Stage 5: Well Production



2.8.1 Groundwater contamination and other risks

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installations (more than 600 m separation between fracturing zone and groundwater)	*moderate*	*rare*	*moderate*
Individual installation (less than 600 m separation between fracturing zone and groundwater)	*moderate*	*occasional*	*high*
Cumulative effects of multiple installations	*moderate*	*occasional*	*high*

Risks to groundwater are principally those posed by failure or inadequate design of well casing leading to potential aquifer contamination. The substances of potential concern comprise naturally occurring substances such as heavy metals, together with natural gas, naturally occurring radioactive material (NORM), and technologically enhanced NORM (TENORM) from drilling operations.

Peer-reviewed research

Osborn et al (2011 PR) investigated methane in shallow groundwater used as a drinking water resource in aquifers overlaying the Marcellus and Utica shales of NE Pennsylvania. Samples taken close to active gas extraction sites were compared with samples distant from any active gas extraction. Higher levels of methane were identified in samples taken near active wells than at more distant sites. The isotopic signature of the methane samples taken near active wells was found to be characteristic of deeper deposits. Whilst this suggests a link between the elevated methane levels and the gas extraction process, there was no evidence of mixing of aquifer water with either fracturing fluids or shale formation waters and thus it was concluded that the water chemistry was consistent with historical baseline data.

Osborn et al. considered the possible mechanisms for elevated concentrations of thermogenic gas to be found in the aquifers. The three mechanisms they propose are: first, physical movement of gas rich fluids from the shale, but this would have to be rapid, and they therefore rule this out based on their negative results from chemical analysis to identify evidence of mixing of aquifer water with deep formation water. Second, the fracturing process could create new fracture pathways from the shale to the aquifer and methane gas being released to solution due to pressure reduction during extraction. This could then allow gas phase methane to migrate through the fissure network. Indeed there is evidence that rapid vertical gas migration is possible, particularly where there are old unused gas wells that are uncased and abandoned in the neighbourhood, and where the overlying formations are naturally highly fractured, and faulted. Third, the authors conclude that a more likely explanation would be that the methane may have leaked from leaky gas casings at depths of up to hundreds of metres below ground, followed by migration of the methane both laterally and vertically towards the water wells. This finding has been challenged by Molofsky et al. (2011 PR), who found that the isotopic signatures of thermogenic methane identified by Osborn et al. (2011 PR) were more consistent with shallow deposits overlying the Marcellus shale. Molofsky et al interpreted these results to mean that the methane detected in the Duke study could have originated entirely from shallower sources above the Marcellus which are entirely unrelated to hydraulic fracturing. Osborn et al. reported methane present at lower levels at locations distant from active gas extraction wells, and concluded that this was likely to have resulted from natural release of methane from source rocks in view of its more biogenic signature. The Duke University team is continuing its research, sampling approximately 150 water wells in Northeast Pennsylvania (see Warner et al. (2012 PR) discussed in Section 2.6.1).

Considine et al. (2012 PR) reviewed all the Notices issued by the Pennsylvania Department for Environmental Protection between 2008 and 2011 in relation to incidents at shale gas extraction sites. The 2,988 notices issued related to 845 environmental events, of which 25 were considered to be major events. Six events were not fully mitigated, of which two related to contamination of groundwater. The causes of these events were linked to inadequate well casing.

Other research

A number of studies have highlighted potential links between shale gas extraction and groundwater contamination. However, reliable examples of contamination are limited, partly because of the difficulty of distinguishing between naturally or previously occurring contamination, and contamination associated with shale gas extraction operations. The US EPA (2011c NPR , in draft) found that hydraulic fracturing of tight and conventional gas fields may have resulted in contamination of a drinking water aquifer at Pavillion in Wyoming. This incident was linked in the EPA draft report to inadequate vertical well casing lengths and a lack of well integrity (USEPA 2011c NPR p37, p38). However, the findings of this study are preliminary and will be followed by further ongoing research (see Section 2.6.1).

It is well established that methane can be present in shallow aquifers independent of shale gas extraction activity (e.g. Breen et al., 2007). SEAB (2011a NPR) found that the research carried out by Osborn et al. (2011 PR) provided credible evidence of elevated levels of methane originating in shale gas deposits in wells surrounding a shale production site and recommended further investigation of this issue.

Re-fracturing may be needed during the production phase. It is estimated that re-fracturing may take place up to four times from an individual well, as described in Section 2.2. The

USEPA (2011a PR p82) highlights concerns that the potential effects of repeated pressure treatments on well construction components (e.g., casing and cement) are not well understood.

Preliminary judgment

It is anticipated that any potential failure of the well would be monitored during the re-fracturing process, and remedial measures implemented to address any issues identified using established industry processes (e.g. API 2009 NPR is used as a reference standard for shale gas production operations in the US). Nevertheless, in view of the possible evidence for methane migration into potable groundwater (Osborn et al. 2011) and uncertainty around the risks associated with re-fracturing, the potential for increased risk due to re-fracturing remains an area of uncertainty, and hence has been assigned a risk ranking of "high" for installations with less than 600 m distance between fracturing zone and groundwater and "moderate" for installations with more than 600 m distance. In other respects, the risks and impacts associated with re-fracturing would be similar to those described in Section 2.6.

Because potential emissions to groundwater would only occur in the event of a failure of control systems, it is judged highly unlikely that multiple incidents would affect the same location. On this basis, cumulative impacts are not judged likely to be significantly different to the impacts associated with individual installations.

2.8.2 Surface water contamination risks

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*rare*	*low*
Cumulative effects of multiple installations	*minor*	*occasional*	*moderate*

Peer-reviewed research

Production water is the fluid returning from the borehole during the production phase (US EPA 2011a PR page 1; New York State DEC 2011 PR p6-17). This brine requires interim storage, transport, processing and disposal or re-use. Accidental releases can arise as a result of tank ruptures, equipment or surface impoundment failures, overfills, vandalism, fires and improper operations. The production brine can have elevated levels of naturally occurring radioactive materials (higher than for flowback liquid) such as radium, thorium and uranium.

Well blowout has been reported as giving rise to four major environmental incidents in Pennsylvania between 2008 and 2012. When blowout or uncontrolled venting occurs, fluids and gases may be released from the wells(Considine et al. 2012 PR). The quantities of fluid cannot be quantified, but discharges identified by Considine et al were sufficient to result in significant pollution of surface waters, requiring remedial action.

Re-fracturing may be needed during the production phase on up to four occasions, as described in Section2.2. This could potentially pose additional risks to surface waters in the event that repeated pressure treatment affects the integrity of the well(US EPA 2011a PR). In this case, the integrity and capacity of the well would need to be assessed, to enable a site-specific assessment of risks and impacts to be carried out (King 2012 PR , p2).

Other research

None reviewed

Preliminary judgment

The risks posed by the handling and treatment of production water are similar to those described in Section 2.7.2 above.

Because of the risks potentially associated with re-fracturing, it is judged that there would remain a higher risk of impacts compared to the risks described in Section 2.6.2.

2.8.3 Water resource depletion

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*occasional*	*moderate*
Cumulative effects of multiple installations	*moderate*	*occasional*	*high*

Re-fracturing may be needed during the production phase on up to four occasions, as described in Section2.2. In this case, the impacts would be similar to those described in Section 2.6.

2.8.4 Release to air

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*periodic*	*moderate*
Cumulative effects of multiple installations	*major*	*occasional*	*high*

Peer-reviewed research

Flaring has been carried out during the first 24 hours of flowback operations while a well produces a high ratio of flowback water to gas (New York State DEC 2011 PR p5-134). Flaring may result in emission to air of combustion gases, and of some unburnt hydrocarbons, depending on the efficiency of the flaring process.

Well blowout has been reported as giving rise to four major environmental incidents in Pennsylvania between 2008 and 2012 resulting in the release of fluids and gases (Considine et al. 2012 PR). The quantities of fluid cannot be quantified, but discharges identified by Considine et al were sufficient to result in significant pollution of surface waters, requiring remedial action.

Other research

Flaring or venting of gas may also be required during the pilot testing phases, before a gathering line is in place (British Columbia OGC 2011 NPR).

Ongoing fugitive losses of methane and other trace hydrocarbons are likely to occur during production phase via leakages from valves, flanges, compressors etc (US EPA 2011b NPR ; Lechtenböhmer et al. 2011 NPR). These fugitive losses may contribute to local and regional air pollution, with potential for adverse effects on health, as described in the above sections.

Emissions from numerous well developments in a local area or wider region could potentially have a significant effect on air quality. For example, emissions from regional shale gas development are considered likely to be a contributory factor to ozone episodes in Texas, Wyoming and Ohio (Michaels et al. 2011 NPR ; Argetsinger, 2011 NPR ; University of Wyoming, 2011 NPR).

Preliminary judgment

As discussed in Section 2.5.3, impacts from individual sites are considered to be of “minor” significance, but the cumulative impact from multiple sites could potentially be of “major” significance. The potential effect of elevated levels of ozone on respiratory health was also considered to be potentially “major”.

Emissions to air during blow-outs would contribute to fugitive emissions from shale gas extraction more widely. The risk of direct environmental or health effects due to emissions under blowout conditions cannot be ruled out, although there are no specific reports associated with these incidents.

Re-fracturing may be needed during the production phase on up to four occasions, as described in Section2.2. In this case, the impacts would be similar to those described in Section 2.6. The potential climate impacts of fugitive methane emissions are not addressed in this study, but will be addressed in a separate study commissioned by DG CLIMA.

2.8.5 Land take

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*slight*	*long-term definite*	*moderate*
Cumulative effects of multiple installations	*minor*	*long-term definite*	*high*

Peer-reviewed research

Following completion, some of the land used for a well pad and associated infrastructure can be returned to the prior use, or to other uses. However, well established natural habitats cannot necessarily be fully restored following use of the land for shale gas extraction. Consequently, it may not be possible to fully restore a site, or to return the land to its previous status resulting in habitat loss (New York State DEC (2011) p6-68), resulting in a long-term impact as described in previous sections.

Other research

None reviewed

Preliminary judgment

It is judged that land take during the production phase would be ongoing, but at a lower level than during earlier phases. This is judged to be of potentially minor significance, and would be a long-term impact likely to be associated with the full development of any large shale gas formation.

Re-fracturing may be needed during the production phase on up to four occasions, as described in Section2.2. In this case, the impacts would be similar to those described in Section 2.6.

2.8.6 Biodiversity impacts

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*occasional*	*moderate*
Cumulative effects of multiple installations	*moderate*	*occasional*	*high*

Peer-reviewed research

There would be a slight potential for disturbance to natural ecosystems during production phase due to human activity, traffic, land-take, habitat degradation and fragmentation, and introduction of invasive species (New York State 2011 PR Section 6.4).

Pipelines constructed for use during the production phase would constitute new linear features, which could adversely affect biodiversity, particularly in sensitive ecosystems.

Other research

None reviewed

Preliminary judgment

The discussion in New York State 2011 PR Section 6.4 was used to assess the risks to biodiversity during the production stage.

Re-fracturing may be needed during the production phase on up to four occasions, as described in Section2.2. In this case, the impacts would be similar to those described in Section 2.6.

2.8.7 Noise

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*slight*	*occasional*	*low*
Cumulative effects of multiple installations	*slight*	*occasional*	*low*

Peer-reviewed research

Once completed, there is expected to be minimal ongoing noise from wellhead installations (New York State 2011 PR p6-300) although no specific information is available on noise levels.

Other research

Noise may be associated with new gas compressor stations and treatment facilities which may be needed to handle gas extracted from new well infrastructure (Lechtenböhmer et al. 2011 NPR).

Preliminary judgment

Noise from pipeline construction could affect residential amenity and wildlife, particularly in sensitive areas. However, this is likely to be lower intensity than other phases in shale gas development, and not to be correlated with other sources of noise associated with shale gas extraction.

Re-fracturing may be needed during the production phase on up to four occasions, as described in Section2.2. In this case, the impacts would be similar to those described in Section 2.6.

2.8.8 Seismicity

Re-fracturing may be needed during the production phase, as described in Chapter 1. In this case, the impacts would be similar to those described in Section 2.6, although improved knowledge gained during the initial fracturing may enable these risks to be reduced.

2.8.9 Visual impact

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*rare*	*low*
Cumulative effects of multiple installations	*minor*	*rare*	*low*

Peer-reviewed research

None reviewed

Other research

None reviewed

Preliminary judgment

Well head plant and equipment could have a visual impact, particularly in residential areas or high landscape value areas, but this would be minimal compared to the impacts during the drilling and fracturing stages.

Pipelines could have a significant visual impact, particularly in residential areas or high landscape value areas

Re-fracturing may be needed during the production phase on up to four occasions, as described in Section2.2. In this case, the impacts would be similar to those described in Section 2.6

2.8.10 Traffic

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*slight*	*periodic*	*low*
Cumulative effects of multiple installations	*slight*	*periodic*	*low*

Peer-reviewed research

None reviewed

Other research

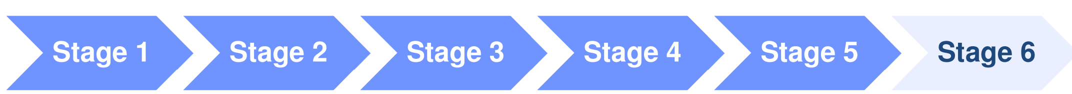
None reviewed

Preliminary judgment

Transportation of materials and equipment for maintenance could have minor adverse effects due to noise, community severance etc during the operational phase. These impacts are judged to be minimal compared to impacts during the drilling, fracturing and completion stages.

Re-fracturing may be needed during the production phase on up to four occasions, as described in Section2.2. In this case, the impacts would be similar to those described in Section 2.6.

2.9 Stage 6: Well / Site Abandonment



The assessment of post-abandonment impacts considers potential impacts over short-medium timescales and long timescales. Over short-medium timescales of decades, it is assumed that management and maintenance regimes will be in place. Over long timescales of hundreds of years, potentially management and maintenance regimes will no longer be in place.

There is generally little difference between conventional and unconventional wells in the post-abandonment phase, with the exception of the presence of unrecovered hydraulic fracturing fluids in the shale formations in the case of hydraulically fractured wells. The presence of high salinity fluids in shale gas formations indicates that there is normally no pathway for release of fluids to other formations (New York State 2011 PR p11). Hence, the issue of potential concern would be the risk of movement of fracturing fluids to aquifers or surface waters via the well and/or via fractures introduced during the operational phase.

2.9.1 Groundwater contamination and other risks

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*not classifiable*	*not classifiable*	*not classifiable*
Cumulative effects of multiple installations	*not classifiable*	*not classifiable*	*not classifiable*

At present, there is little information to enable a judgment to be made regarding the risks posed by movement of hydraulic fracturing fluid to the surface in the long term. The presence of high salinity fluids in shale gas formations indicates that there is normally no pathway for release of fluids to other formations (New York State 2011 PR p11). Furthermore, some of the chemicals used in fracturing fluids will be adsorbed to the rocks (e.g. surfactants and friction reducers) and some will be biodegraded in situ (e.g. guar gums used for gels). For shale gas measures at significant depths, the volume of the rock between the producing formation and the groundwater is substantially greater than the volume of fracturing fluid used

Other research

None reviewed

Preliminary judgment

Inadequate sealing of a well could potentially result in subsurface pathways for contaminant migration leading to groundwater pollution, and potentially surface water pollution. Experience in the US to date is that the risks posed by poorly controlled and logged historical wells far outweigh the risks posed by wells designed and constructed to current standards. However, this experience does not yet extend into the long term (considered to represent periods of hundreds of years following abandonment).

It is considered likely that unrecorded abandoned wells may be a more significant issue in Eastern Europe than in Western Europe, but no evidence to substantiate this view could be identified.

The chemical constituents of hydraulic fracturing fluids remain an area of uncertainty pending the development of a more extensive database of behaviour of fluids in shale formations over time.

2.9.2 Release to air

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*rare*	*low*
Cumulative effects of multiple installations	*moderate*	*rare*	*low*

Peer-reviewed research

None reviewed

Other research

None reviewed

Preliminary judgment

Inadequate sealing of wells could result in fugitive emissions to air. Experience in the US to date is that the risks posed by poorly controlled and logged historical wells far outweigh the risks posed by wells designed and constructed to current standards. However, this experience does not yet extend into the long term (considered to represent periods of hundreds of years following abandonment). It is considered likely that unrecorded abandoned wells may be a more significant issue in Eastern Europe than in Western Europe, but no evidence to substantiate this view could be identified.

At present, there is little information to enable a judgment to be made regarding the risks posed by movement of airborne pollutants to the surface in the long term. It is judged that any risks are likely to be similar to those posed by conventional wells..

2.9.3 Land take

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*not classifiable*	*not classifiable*
Cumulative effects of multiple installations	*moderate*	*not classifiable*	*not classifiable*

Peer-reviewed research

It may not be possible to return the entire site to beneficial use following abandonment e.g. due to concerns regarding public safety (New York State DEC 2011, PR Section 6.4).

Other research

None reviewed

Preliminary judgment

It is judged that the consequences for land take at an individual site in the post-abandonment phase would be comparable with many other industrial and commercial land-uses, and are of no more than minor significance. It may not be possible to return the entire site to beneficial use following abandonment, e.g. due to concerns regarding public safety. Over a wider area, this could result in a significant loss of land, and/or fragmentation of land area such as an amenity or recreational facility, valuable farmland, or valuable natural habitat. There is no evidence available to enable the likelihood of permanent effects on land-use to be evaluated.

2.9.4 Biodiversity impacts

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*minor*	*not classifiable*	*not classifiable*
Cumulative effects of multiple installations	*moderate*	*not classifiable*	*not classifiable*

Peer-reviewed research

It may not be possible to return the entire site to its previous state following abandonment, which could be particularly significant for sites located in sensitive areas. Over a wider area, this could potentially result in a significant loss or fragmentation of a sensitive natural habitat (New York State DEC 2011 PR Section 6.4).

Other research

None reviewed

Preliminary judgment

It is judged that the consequences for biodiversity at an individual site in the post-abandonment phase would be comparable with many other industrial and commercial land-uses, and are of no more than minor significance. Over a wider area, this could potentially result in a significant loss of natural habitat. There is no evidence available to enable the likelihood of effects on biodiversity during the post-abandonment phase to be evaluated.

2.9.5 Visual impact

Risk Characterisation	Hazard classification	Probability classification	Risk ranking
Individual installation	*slight*	*not classifiable*	*moderate or low*
Cumulative effects of multiple installations	*slight*	*not classifiable*	*moderate or low*

Peer-reviewed research

None reviewed

Other research

None reviewed

Preliminary judgment

It may not be possible to remove all wellhead equipment from site. This is not considered likely to pose a significant impact in view of the small scale of equipment potentially remaining on site.

2.10 Summary of key issues

The preliminary risk assessment is summarised in Table 5. This table also sets out an overall risk rating across all project phases. This is identified as the highest rating of any individual phase as a minimum. A higher risk rating was considered in any cases where the ongoing nature of shale gas development could potentially warrant a higher risk rating than was applied to individual phases.

Table 5: Summary of preliminary risk assessment

Environmental aspect	Project phase						
	Site identification and preparation	Well design drilling, casing, cementing	Fracturing	Well completion	Production	Well abandonment and post-abandonment	Overall rating across all phases
Individual site							
Groundwater contamination	Not applicable	Low	Moderate-**High**	**High**	Moderate-**High**	Not classifiable	**High**
Surface water contamination	Low	Moderate	Moderate-**High**	**High**	Low	Not applicable	**High**
Water resources	Not applicable	Not applicable	Moderate	Not applicable	Moderate	Not applicable	Moderate
Release to air	Low	Moderate	Moderate	Moderate	Moderate	Low	Moderate
Land take	Moderate	Not applicable	Not applicable	Not applicable	Moderate	Not classifiable	Moderate
Risk to biodiversity	Not classifiable	Low	Low	Low	Moderate	Not classifiable	Moderate
Noise impacts	Low	Moderate	Moderate	Not classifiable	Low	Not applicable	Moderate – **High**
Visual impact	Low	Low	Low	Not applicable	Low	Low-moderate	Low - Moderate
Seismicity	Not applicable	Not applicable	Low	Low	Not applicable	Not applicable	Low
Traffic	Low	Low	Moderate	Low	Low	Not applicable	Moderate
Cumulative							
Groundwater contamination	Not applicable	Low	Moderate-**High**	**High**	**High**	Not classifiable	**High**
Surface water contamination	Moderate	Moderate	Moderate-**High**	**High**	Moderate	Not applicable	**High**
Water resources	Not applicable	Not applicable	**High**	Not applicable	**High**	Not applicable	**High**
Release to air	Low	**High**	**High**	**High**	**High**	Low	**High**
Land take	**Very high**	Not applicable	Not applicable	Not applicable	**High**	Not classifiable	**High**
Risk to biodiversity	Not classifiable	Low	Moderate	Moderate	**High**	Not classifiable	**High**
Noise impacts	Low	**High**	Moderate	Not classifiable	Low	Not applicable	**High**
Visual impact	Moderate	Moderate	Moderate	Not applicable	Low	Low-moderate	Moderate
Seismicity	Not applicable	Not applicable	Low	Low	Not applicable	Not applicable	Low
Traffic	**High**	**High**	**High**	Moderate	Low	Not applicable	**High**

Not applicable: Impact not relevant to this stage of development
Not classifiable: Insufficient information available for the significance of this impact to be assessed

Table 5 highlights the issues potentially associated with road traffic and emissions to air throughout the project lifetime. These issues are addressed in the following sections of the report.

Visual impacts would also be ongoing throughout the lifetime of a project to a varying degree. Based on the findings of New York State DEC (2011 PR p6-283) that visual impacts of individual facilities are minimal over a distance of 1.5 km, it is judged that the overall risk of visual impact of cumulative shale gas development can be considered as "moderate." The risks posed by noise would continue throughout the initial stages of an unconventional gas project. In view of this, and reliance on effective abatement to manage the potential impacts on noise, the overall risk of noise associated with an individual well-pad was considered to be "moderate to high."

Table 5 also highlights the uncertainties associated with the post-abandonment phase. Further research in this area is recommended in Chapter 5.

One issue was identified as "very high" in the European context using this approach:

- Land-take during site preparation (cumulative)

This analysis has identified the following "high" significance issues:

- Traffic during site preparation (cumulative)
- Releases to air during drilling (cumulative)
- Noise during drilling (cumulative and due to overall impact across all phases)
- Surface water contamination during fracturing (individual installation)
- Water resource depletion during fracturing (cumulative)
- Traffic during fracturing (cumulative)
- Groundwater contamination during completion (individual installation and cumulative)
- Surface water contamination during completion (individual installation and cumulative)
- Releases to air during completion (cumulative)
- Groundwater contamination during production (individual installation)
- Releases to air during production (cumulative)
- Land take during production (cumulative)
- Biodiversity impacts during production (cumulative)

The following issues were identified as being "not classifiable" due to a lack of relevant data:

- Potential impacts on biodiversity due to cumulative development in the European context
- Frequency of surface spillages during hydraulic fracturing
- Potential frequency and significance of road accidents involving trucks carrying hazardous substances in support of HVHF operations
- Noise impacts due to flaring, and associated controls
- Risks of groundwater contamination following abandonment
- Land take following abandonment
- Risks to biodiversity following abandonment

The issues identified during the preparation, drilling, fracturing and completion phases are more significant for high volume hydraulic fracturing than for conventional installations, or are unique to HVHF. A further set of "moderate" significance issues was identified:

- Surface water contamination risks during site identification and preparation (cumulative)
- Land take during site identification and preparation (individual installation)
- Visual impact during site identification and preparation (cumulative)
- Traffic during site identification and preparation (cumulative)
- Surface water contamination risks during well design, drilling, casing and cementing(individual installation and cumulative)
- Release to air during well design, drilling, casing and cementing(individual installation)
- Noise during well design, drilling, casing and cementing (individual installation)
- Visual impact during well design, drilling, casing and cementing (cumulative)
- Risks of groundwater contamination during hydraulic fracturing preparation (individual installation and cumulative)
- Risks of surface water contamination during hydraulic fracturing (individual installation and cumulative)
- Water resource depletion during hydraulic fracturing (individual installation)
- Release to air during hydraulic fracturing (individual installation)
- Biodiversity impacts during hydraulic fracturing (cumulative)
- Noise during hydraulic fracturing (individual installation and cumulative)
- Visual impact during hydraulic fracturing (cumulative)
- Traffic during hydraulic fracturing (individual installation)
- Release to air during well completion (individual installation)
- Biodiversity impacts during well completion (cumulative)
- Traffic during well completion (cumulative)
- Groundwater contamination and other risks during production (individual installation)
- Surface water contamination risks during production (cumulative)
- Water resource depletion during production (individual installation)
- Release to air during production (individual installation)
- Biodiversity impacts during production (individual installation)
- Visual impact following well abandonment (cumulative)

Particular attention was paid to the "very high" and "high" significance issues in the subsequent phases of this project. Consideration was also given to the "moderate" significance issues at the conclusion of the analysis of high/very high significance issues.

The main causes of impacts and risks were as follows:

- The use of more significant volumes of water and chemicals compared to conventional gas extraction

- The challenge of ensuring the integrity of wells and other equipment throughout the development, operational and post-abandonment lifetime of the plant (well pad) so as to avoid the risk of surface and/or groundwater contamination
- The challenge of ensuring that spillages of chemicals and waste waters with potential environmental consequences are avoided during the development and operational lifetime of the plant (well pad)
- The challenge of ensuring a correct identification and selection of geological sites, based on a risk assessment of specific geological features and of potential uncertainties associated with the long-term presence of hydraulic fracturing fluid in the underground
- The potential toxicity of chemical additives and the challenge to develop greener alternatives
- The unavoidable requirement for transportation of equipment, materials and wastes to and from the site, resulting in traffic impacts that can be mitigated but not entirely avoided.
- The potential for development over a wider area than is typical of conventional gas fields
- The unavoidable requirements for use of plant and equipment during well construction and hydraulic fracturing. This equipment necessarily requires space to be sited and operated, and results in unavoidable emissions to air and noise impacts.

3 The efficiency and effectiveness of current EU legislation

3.1 Introduction to the legal review

Chapter 2 provides an overview of the environmental and health risks of hydrocarbons operations involving hydraulic fracturing, in particular HVHF in each project phase. In Chapter 3, the appropriateness of the EU legal environmental framework is analysed and conclusions are drawn regarding the degree to which the current EU framework adequately covers these risks. Developing an understanding of EU legislation applying to in particular high-volume hydraulic fracturing is the key basis for understanding the need for control against any eventual gaps in the EU regulatory framework in relation to possible net incremental risks of these techniques identified in Chapter 2, and summarised in section 2.10.

Potentially relevant regulatory risk management measures considered, proposed or adopted for hydrocarbons operations using hydraulic fracturing techniques are set out in Appendix 7 and summarised in Chapter 4.

3.2 Objectives and approach

The objectives of the review of relevant legislation within this study are:

- Identifying potential *uncertainties* with regard to the degree to which shale gas exploration and production specific risks and impacts are covered under current EU legislation applicable to such operations in the EU
- Identifying risks and impacts which are *not covered* by existing EU legislation
- Drawing conclusions with regard to the key risks to the environment and human health of such operations in the EU

The study was designed to provide an appreciation of the appropriateness of the legislation in place for ensuring an adequate level of protection to the environment and to humans. The study identifies whether this legislation is appropriate to address risks of operations involving hydraulic fracturing and in particular high-volume hydraulic fracturing. It identifies which European laws apply; whether the provisions are adequate; what (if anything) is missing; and whether there are relevant areas where no EU provisions exist. The study uses definitions from the legislative documents where appropriate. In some instances, these differ from one legislative instrument to another.

Pieces of EU legislation described below are essentially Directives (with the exception of the REACH Regulation), which naturally do not result in a full harmonisation of rules and practices among Member States as they allow for a degree of Member State autonomy in their implementation. This clearly leads to the possibility of different approaches being adopted, with potential differential treatment of environmental or human health impacts.

Limitations of the analysis

Given the breadth of the scope as well as time and resource limitations, this report does not elaborate on international conventions, standards and industry guidelines. This study does not aim to assess the extent to which existent jurisprudence by the European Court of Justice would provide sufficient clarity on relevant issues identified by this study (concerning for example the Environmental Impact Assessment Directive (2011/92/EU), EU waste and water legislation, etc.) This could potentially have a bearing on the study findings regarding the EIA Directive and possibly other pieces of EU legislation. Relevant International Standards Organisation (ISO) standards for the hydrocarbon extraction industry are listed in Appendix 8.

Likewise, we do not consider the extent to which health and safety legislation could influence or reduce risks to the environment from HVHF. The most applicable legislation in respect of health and safety is the Directive concerning minimum requirements for improving health and safety of workers in the mineral-extracting industries through drilling (Directive 92/91/EEC).

It is also beyond the scope of this study to examine the consistency of Member States' transposition and implementation of EU legislation, but this is a factor in the ultimate level of environmental protection or remediation required for developments involving hydraulic fracturing, in particular HVHF. Within the present project we therefore highlight below instances where, in line with applicable rules, the extent of environmental protection is governed by Member State decision-making. In these cases it cannot be concluded that the associated risks are sufficiently or adequately addressed at EU level. It is beyond the scope of this study to assess the sufficiency or adequacy of Member State measures.

Summary

Summarising the above, including the acknowledged limitations of this study, this section draws three categories of conclusion with regard to the potential for inadequacy in the way risks are dealt with in the EU legislation;

- Inadequacies in EU legislation that could lead to risks to the environment or human health not being sufficiently addressed.
- Potential inadequacies - uncertainties in the applicability of EU legislation: the potential for risks to be insufficiently addressed by EU legislation, where uncertainty arises because of lack of information regarding the characteristics of HVHF projects.
- Potential inadequacies - uncertainties in the existence of appropriate requirements at national level: for aspects relying on a high degree of Member State decision-making it is not possible to conclude whether or not at EU level the risks are adequately addressed.

3.3 Study Overview

The assessment starts by analysing the EU environmental acquis, using the Commission's legal assessment of the applicable framework (EC, 2011) as the starting point. Given more in-depth information about the type and nature of risks related to hydraulic fracturing and in particular HVHF, a number of conclusions in this report may go further than the Commission's interpretation providing better insights with regard to particular legal aspects. For instance, this appears to be the case with regard to the Environmental Impact Assessment (EIA) Directive 2011/92/EU, under which an EIA is not (always) mandatory with regard to shale gas extraction activities due to the fact that:

- activities are expected not to fall within the scope of Annex I of the Environmental Impact Assessment Directive (2011/92/EU).
- it is questionable whether shallow drillings are covered when looking at Annex II of the same Directive.
- approaches between Member States could differ regarding the way in which risk and impacts are weighted and whether or not an EIA is required. In that sense the Environmental Impact Assessment Directive (2011/92/EU) *in itself* does not prescribe that an EIA, addressing the risks and impacts identified in Chapter 2, is mandatory.

This analysis and other regulatory aspects are identified and discussed below. In Table 6, the pieces of legislation falling within the scope of the analysis are listed to provide an enhanced overview.

Table 6: Overview of relevant EU legislation

Number	Legislative measure
1.	Strategic Environmental Impact Assessment Directive (2001/42/EC) (relating to plans and programmes only)
2.	Environmental Impact Assessment Directive (2011/92/EU)
3.	Integrated Pollution and Prevention Control - Directive (2008/1/EC), if applicable
4.	Industrial Emissions Directive (2010/75/EC), if applicable
5.	Mining Waste Directive(2006/21/EC)
6.	Environmental Liability Directive (2004/35/EC)
7.	Waste Framework Directive (2008/98/EC)
8.	Water Framework Directive (2000/60/EC)
9.	Groundwater Directive (2006/118/EC)
10.	Noise Directive (2002/49/EC)
11.	Air Quality Directive (2008/50/EC)
12.	Habitats Directive (1992/43/EEC)
13.	Birds Directive(2009/147/EC)
14.	REACH (Regulation 1907/2006/ EC)
15.	Biocidal Products Directive (98/8/EC)
16.	Authorization (for the prospection, exploration and production) of hydrocarbons Directive (94/22/EC)
17.	SEVESO II Directive (1996/82/EC)
18.	1992/29/Euratom Directive
19.	Urban wastewater Directive (97/271/EEC)

Some pieces of legislation are relevant for all of the project phases and some only come into play at certain stages (e.g. when actual shale gas extraction activities take place). However, the impacts tackled by the different pieces of legislation might differ. In the following sections, the impacts identified per well development stage are considered, and the legislation relevant for tackling these impacts is discussed.

In section 3.4, an analysis is provided of directives which are not specific to individual risks or stages of the shale gas production process.

In sections 3.5 to 3.15, the impacts identified in section 2.10 as potentially being of "very high" or "high" significance are discussed in the context of legislation which is relevant for these impacts. Where appropriate, reference is made to the general provisions described in section 3.4. These more severe impacts are treated as bounding cases and it can be expected that less severe impacts would be either covered by the legislation in a similar manner or be considered insufficiently significant to be addressed by the legislation.

This analysis covers the impacts of most significant potential concern with regard to the use of high volume hydraulic fracturing techniques in Europe. The provisions and analysis set out in section 3.4 to 3.15 also addresses the majority of potential impacts of lower (moderate) priority identified in Chapter 2. In section 3.16, a brief discussion is provided of "moderate" priority issues. The overall conclusions of the regulatory analysis are provided in section 3.17.

3.4 General provisions

There are several steps that a competent authority should take prior to granting development consent - see Strategic Environmental Assessment Directive (2001/42/EC) and Environmental Impact Assessment Directive (2011/92/EC). These steps give the competent authorities the legal framework for impact assessments, permits and other decisions.

Among these steps are:

- Deciding which area is to be permitted for exploration;
- Identifying where environmental assessments have to be undertaken; and
- Identifying which permits can or should be granted.

In this section we cover these more general directives and the extent to which they are relevant to the use of High Volume Hydraulic Fracturing (HVHF) for hydrocarbons operations. The final subsection of section 3.4 presents a consolidated review of the monitoring and inspection requirements specified by the IPPC Directive (2008/1/EC), the Mining Waste Directive (2006/21/EC) and the Water Framework Directive (2000/60/EC).

The section starts with the level of planning and decision making. In this case it is the decision of a national competent authority to dedicate a certain area for prospecting, exploration or production of hydrocarbons. Subsequently it is decided whether or not to grant permits to entities who apply for the authorisation of prospecting, exploring or producing. An important distinction to make, therefore, is that some Directives relate to plans/programmes and others to developments/projects. This is explained in the discussion of each Directive below.

At the start of the actual prospecting, any necessary environmental assessments have to be carried out, and any required environmental permits have to be applied for.

3.4.1 Strategic Environmental Assessment Directive (2001/42/EC)

The Strategic Environmental Assessment Directive (2001/42/EC) obliges Member States to provide strategic environmental assessments (SEA) of all governmental programmes and plans that might have significant environmental impacts. The SEA is aimed at providing the necessary information for the authorities to decide on their plan taking into account the environmental risks and impacts associated with, in this case, high volume hydraulic fracturing processes.

Article 2 of Strategic Environmental Assessment Directive (2001/42/EC) defines 'plans and programmes' as plans and programmes, including those co-financed by the European Community, as well as any modifications to them:

— which are subject to preparation and/or adoption by an authority at national, regional or local level or which are prepared by an authority for adoption, through a legislative procedure by Parliament or Government, and

— which are required by legislative, regulatory or administrative provisions.

Article 3(2) of the Strategic Environmental Assessment Directive (2001/42/EC) sets out that an environmental assessment (EA) shall be carried out for all plans and programmes which are prepared for, inter alia, energy, industry, waste management, water management and country planning or land use which set the framework for future development consent of projects listed in Annexes I and II of the Environmental Impact Assessment Directive (2011/92/EU). Additionally, an environmental assessment is mandatory for plans and programmes which require an assessment related to the Habitats Directive (1992/43/EEC).

With regard to the Strategic Environmental Assessment Directive (2001/42/EC), and its relation to the impact of shale gas activities, a key consideration is whether there exist or could exist relevant overlying programmes/plans subject to an SEA obligation. Country planning programmes fall within this category. Annex II of the Environmental Impact Assessment Directive (2011/92/EU) mentions, in the section Extractive Industry, d) deep drillings and e) Surface industrial installations for the extraction of coal, petroleum, natural gas and ores, as well as bituminous shale. Because shale gas is natural gas, an SEA is required for plans and programmes concerning the country planning of shale gas activities. Decisions on granting and using authorisations for prospection, exploration and production of hydrocarbons concern the use of areas of land and are therefore considered country planning. Only in the case of the use of small areas at local level a SEA is not mandatory according to article 3(3) of the Strategic Environmental Assessment Directive (2001/42/EC). Member States can require a SEA in those cases if they determine that there are likely significant environmental effects.

The first step that a competent authority has to undertake, when considering opening the possibility of granting permits or authorisations for prospecting, exploring or producing hydrocarbons is to carry out a strategic environmental assessment.

Annex I provides guidance related to the information that should be reported in the strategic environmental assessment. Impacts that should be covered are stated in Annex I (f): the likely significant effects (1) on the environment, including on issues such as biodiversity, population, human health, fauna, flora, soil, water, air, climatic factors, material assets, cultural heritage including architectural and archaeological heritage, landscape and the interrelationship between the above factors.

When looking at other hydraulic fracturing impacts, there is no explicit reference to resource (e.g. water) use, impacts on the underground environment and noise (human health) and nuisance factors (such as from traffic). However, Annex I(f) states that *"the likely significant effects on the environment should be taken into account.*" We therefore consider these to be covered.

Conclusions on applicability of the Strategic Environmental Assessment Directive (2001/42/EC)

- The Strategic Environmental Assessment Directive (2001/42/EC) is applicable since shale gas extraction activities fall within the scope defined in Article 3(2). This means that a strategic environmental assessment is obligatory in as far as Member States develop public plans and programmes related to shale gas extraction activities.
- The Strategic Environmental Assessment Directive (2001/42/EC) is aimed at targeting all the relevant significant environmental aspects (Annex I). We therefore consider these to also be covered, perhaps with the exception of certain specific aspects, including geological aspects, for which there is no explicit reference.

3.4.2 Environmental Impact Assessment Directive (2011/92/EU)

As indicated in the Commission's legal interpretation of the environmental acquis (EC, 2011a), the Environmental Impact Assessment Directive (2011/92/EU) is relevant to HVHF activities.

Article 2(1) of the Environmental Impact Assessment Directive (2011/92/EU) requires that "*Member States shall adopt all measures necessary to ensure that, before consent is given, projects likely to have significant effects on the environment by virtue, inter alia, of their nature, size or location are made subject to a requirement for development consent and an* *assessment with regard to their effects.*" The projects to which these provisions are applicable are defined in Article 4 of the Environmental Impact Assessment Directive (2011/92/EU). The aspects covered by the Environmental Impact Assessment therefore play an important role in the development consent of the project and through this route the competent authority has the powers to impose measures to protect and preserve the environment potentially impacted by the development. However, it is uncertain if an EIA will automatically be mandatory for shale gas extraction activities. The reason for this is discussed in the paragraphs below.

Obligation to carry out an EIA for projects concerning high volume hydraulic fracturing processes

According to Article 4(1) of the Environmental Impact Assessment Directive (2011/92/EU), an assessment is obligatory for certain projects mentioned in Annex I. This annex lists: "Extraction of petroleum and natural gas for commercial purposes where the amount extracted exceeds 500 tonnes/day in the case of petroleum and 500,000 cubic metres/day in the case of gas." Operator information quoted by New York State DEC (2011 PR p5-139) indicates that the maximum foreseeable production rate in the initial phases of a well in the Marcellus Shale would be 250,000 m^3 per day, rapidly declining to less than 100,000 m^3 per day (see section 1.4.2). Preliminary indications from exploratory drilling in Europe suggest that production rates are likely if anything to be lower than in the US (Bloomberg, 2012 NPR). Consequently, it is unlikely that the threshold of 500,000 cubic metres/day will be met in case of shale gas production at a single well. However, for multiple well sites, the total production rate could exceed the 500,000 cubic metres/day threshold. The Environmental Impact Assessment Directive (2011/92/EU) is clear that cumulative impacts need to be taken into account (as discussed below) when Member States apply discretion in the requirement for an EIA, but it is not explicit in stating whether or not the production rates from multiple projects need to be taken into account in determining the need for an EIA under Annex I.

The obligation for conducting an EIA is derived from the general notion that environmental impacts that might be significant must be known before a decision on project is made. The assessment must have a role in the decision making process. One of the reasons for this lies in the precautionary principle. Given this principle, and the fact that the impacts related to HVHF processes are higher than those of conventional gas production and the chance of occurrence of the impacts is greater (as discussed in Chapter 2), it would make sense to have a lower threshold. This threshold is applicable for the expected maximum production capacity within the project and should be used at the outset of the approval process for the project.

However, Article 4(2) provides discretionary powers for Member States to require an environmental impact assessment (EIA) for projects listed in Annex II of the Environmental Impact Assessment Directive (2011/92/EU). These include projects in the extractive industries, with specific reference to underground mining, deep drillings and surface industrial installations for the extraction of natural gas (among others) and surface storage of natural gas.

Under Article 4(2) Member States themselves shall determine whether the project shall be made subject to an EIA through either a case-by-case examination or setting thresholds or criteria (or both). In doing so they are obliged to take into account the relevant selection criteria given in Annex III of the Environmental Impact Assessment Directive (2011/92/EU). These criteria involve:

- Characteristics of projects, in particular: size, cumulation with other projects, use of natural resources, production of waste, pollution, nuisances and risks of accidents;
- Location of projects, in the sense that the environmental sensitivity of geographical areas likely to be affected by projects must be considered;

- Characteristics of the potential impact, including: the extent of the impact, the transfrontier nature of the impact, the magnitude and complexity of the impact, the probability of the impact and the duration, frequency and reversibility of the impact.

Furthermore, according to the EC's "*guidance note on the application of Directive 85/337/EEC to projects related to the exploration and exploitation of unconventional hydrocarbon*" (EC, 2011 NPR), the overall objective (to apply to projects with significant effects on the environment) should be taken into account. That guidance also makes clear that the examples under the Annex IId reference to deep drillings should be treated as indicative and to be taken as including unconventional hydrocarbon projects that use deep drillings.

However, uncertainty may remain in relation to a shallow well by virtue of lack of precision over the definition of "deep drilling", which would not cover shallow drilling activities (not defined). Based on Annex II (2) (e) though "Surface industrial installations for the extraction of coal, petroleum, natural gas and ores, as well as bituminous shale," Member States are obliged to determine whether or not a project shall be made subject to an EIA for installations related to the extraction of natural gas.

Scope of EIA

The Environmental Impact Assessment Directive (2011/92/EU) requires an assessment of projects likely to have significant effects on the environment. It is not specific as to what those measures are but arguably can be considered adequate in that there are no limitations regarding impacts that could be excluded (i.e. true goal-based approach). If hydraulic fracturing were to result in unforeseen impacts then they may not be addressed through EIA, but this would be a weakness in the understanding of the technology, and not the construction of the EIA legislation which is a horizontal instrument by nature. In relation to this aspect, the EC guidance regarding application of Environmental Impact Assessment Directive (2011/92/EU) to unconventional hydrocarbon projects (EC, 2011 NPR) stated that unconventional hydrocarbon projects would be subject to an EIA if it cannot be excluded, on the basis of objective information, that the project will have significant environmental effects. The precautionary and prevention principles also imply that in case of doubts as to the absence of significant effects, an EIA must be carried out.

The EIA Directive (2011/92/EC) has no explicit coverage of geomorphological and hydrogeological aspects, and there is a lack of clarity as to whether there is an obligation to assess impacts related to geological features as part of the impact assessment. This might lead to a knowledge gap and could potentially result in significant impacts to groundwater.

Also of significance is the list of specific selection criteria contained in Annex III of the Environmental Impact Assessment Directive (2011/92/EU), which guides Member States in the decision on whether an EIA is required under Article4(3). If significant impacts from hydraulic fracturing were not covered by Annex III then this would be an inadequacy of the legislation. In the table below we list the Annex III criteria alongside the relevant aspects of hydraulic fracturing.

Table 7: Relevance of criteria in Environmental Impact Assessment Directive (2011/92/EU) Annex III to hydrocarbons activities involving the use of HVHF

Annex III aspect	Relevance to hydrocarbons activities involving the use of high volume hydraulic fracturing
CHARACTERISTICS OF PR OJECTS	
The characteristics of projects must be considered having regard, in particular, to:	
• the size of the project	This recognises the potential scale of the project including its expansion
• the cumulation with other projects	Covers cumulative effects including those with other technologies/activities

Annex III aspect	Relevance to hydrocarbons activities involving the use of high volume hydraulic fracturing
• the use of natural resources	Particularly relevant to water abstraction
• the production of waste	Covers mining waste and waste hydraulic fracturing fluids including constituents
• pollution and nuisances	Recognises noise, traffic and visual impacts as well as surface water and groundwater contamination and gaseous emissions
• the risk of accidents, having regard in particular to substances or technologies used	Recognises risks, especially relevant to those posed by accidental release of hydraulic fracturing fluids, fluid additives, waste waters, or gaseous emissions
LOCATION OF PR OJECTS	
The environmental sensitivity of geographical areas likely to be affected by projects must be considered, having regard, in particular, to:	
• the existing land use	Acknowledges land take and usage
• the relative abundance, quality and regenerative capacity of natural resources in the area	Recognises local context to land use
• the absorption capacity of the natural environment, paying particular attention to the following areas	
o wetlands	Considers impacts on water bodies from additives, fracturing liquids, treated and untreated waste water
o coastal zones	Considers impacts on water bodies from additives, fracturing liquids, treated and untreated waste water
o mountain and forest areas	Covers deforestation from land clearance and for road construction
o nature reserves and parks	Recognises impacts on reserves and local amenities from all impacts
o [protected areas listed under point 2(v) of Annex III]	Covers potential impacts on protected ecosystems
o areas in which the environmental quality standards laid down in Union legislation have already been exceeded	Covers cumulative and additional effects for all pollution types
o densely populated areas	Recognises elevated risks to higher density local populations, covering effects of groundwater and drinking water contamination, air pollution, noise, visual impact
o landscapes of historical, cultural or archaeological significance	Addresses the significance of land take and land usage in the context of local landscape importance
CHARACTERISTICS OF THE POTENTIAL IMPACT	
The potential significant effects of projects must be considered in relation to criteria set out in points 1 and 2, and having regard in particular to:	
• the extent of the impact (geographical area and size of the affected population)	Covers the scale of hydraulic fracturing zones. It is unclear whether this point is intended to cover the underground environment
• the transboundary nature of the impact	Covers impacts crossing boundaries and with potentially great extent
• the magnitude and complexity of the impact	Covers the size of the impact and recognising complexities such as those related to risks of contamination of water bodies with highly toxic

Annex III aspect	Relevance to hydrocarbons activities involving the use of high volume hydraulic fracturing
	hydraulic fracturing substances, at low and high concentrations
• the probability of the impact	Will require consideration of the likelihood of accidental releases of hydraulic fracturing fluids, additives, waste waters, air pollutants, invasive species etc
• the duration, frequency and reversibility of the impact	Acknowledges temporal extent of impacts, the reversibility and residual environmental impact

An environmental impact assessment must address the whole project, since impacts that might occur in any one of the project stages might be significant enough to deny the approval for the project as a whole.

With regard to the assessment of impacts in Chapter 2, the following are clearly covered by the above list (the Environmental Impact Assessment Directive (2011/92/EU) covers the whole life of the project and therefore the covered impacts are not identified against project stage):

- Surface water contamination risks
- Release to air
- Land take
- Noise
- Visual impact
- Traffic
- Groundwater contamination
- Water resource depletion

Nevertheless, under the EIA Directive there is less clarity on the treatment of impacts from underground activities. This is implicitly covered by the inclusion of pollution (which can be underground) under project characteristics, but underground environments are not explicitly mentioned. There is no reference to seismicity within the Annex, although again implicitly environmental impacts related to induced seismic activity would be covered.

Impacts on biodiversity are not explicitly listed but would be accounted for insofar as important species reside within protected areas listed under point 2(v) of Annex III, or in relation to impacts on biodiversity caused by releases of pollution, noise or other impacts which are covered. Impacts on flora and fauna at other areas of nature conservation value are to be assessed in an EIA. It is up to Member States to indicate the nature conservation value of the area(s) concerned in the vicinity of the proposed production site(s).

The EIA must, according to Article 5 and Annex IV, provide information on the project itself, the location, size, time of operation, etc. It must also provide information on the possible impacts of the project and the measures foreseen to prevent or mitigate the impacts. This information should cover the direct effects and any indirect, secondary, cumulative, short, medium and long-term, permanent and temporary, positive and negative effects of the project. For the projects concerning hydrocarbons operations involving hydraulic fracturing this means that at least the impacts addressed in chapter 2 of this report will be taken into account in an EIA. The estimated or calculated impacts will be decisive for the competent authorities for their decision on for instance granting a permit for exploration or extraction. This also includes providing information on the use of chemicals and its properties.

Disclosure of the information on these chemicals is also regulated through the REACH regulation (1907/2006/EC), Articles 117 and 118.

The EIA must take into account other projects that cumulatively might result in larger impacts on the environment. This means that an EIA on a shale gas project must also describe other projects in the same area and the effects of multiple wells. This is done in order to prevent the slicing of projects into smaller parts just to reduce the environmental impacts.

Projects concerning hydrocarbons operations involving hydraulic fracturing usually start with a few wells to be expanded with more wells in due time. This expansion is to be foreseen in the EIA and is to be taken into account. A thorough assessment of the impacts of also future wells must be part of the EIA. A multiple well site should be assessed with the same methods as a single or double well site. The location of the (future) wells must be known in order to address and assess the impacts. In addition, this means that the output of a multiple well site must be taken into account when determining whether the Annex I threshold of 500,000 cubic metres/day is exceeded.

The size of a project that could be the subject of an EIA is not limited by law, nor in practice, by the feasibility of assessing the impacts. All activities in the project at all locations must be described and assessed.

An EIA can be conducted in a very large area and for projects that have several phases in process. In general one should start with a survey of the main impacts that can occur and at least should be addressed in the EIA. This is a scoping phase in the assessment project. In this scoping phase the area of study for the assessment is also part of this first step. With the use of the SEA, the most important impacts and areas of concern may already be known, provided there are national public plans or programmes encompassing shale gas activities. This would make it possible to conduct a meaningful EIA even if there is a large number of well sites. Each of these sites has its own characteristics, but they also have many common features.

The public shall be informed, whether by public notices or by other appropriate means such as electronic media where available, of the matters set out in Article 6 early in the environmental decision-making procedures. The information collected under Article 5 on the project itself, its impacts and the foreseen measures to prevent or to mitigate the impacts shall also be made available to the public. The public concerned shall be given early and effective opportunities to participate in the environmental decision- making procedures referred to in Article 2(2) and shall, for that purpose, be entitled to express comments and opinions.

In this way the public has the opportunity to participate in the decision making process by giving comments and opinions. According to Article 8 the results of consultations and the information gathered pursuant to Articles 5, 6 and 7 shall be taken into consideration in the development consent procedure.

Article 11 of the EIA directive (2011/92/EC) regulates the public's right to have access to a review procedure before a court of law or another independent and impartial body established by law to challenge the substantive or procedural legality of decisions, acts or omissions subject to the public participation provisions of this Directive.

Conclusions on applicability of Environmental Impact Assessment Directive (2011/92/EU)

- According to Article 4(1) of the Environmental Impact Assessment Directive (2011/92/EU), an assessment is mandatory for certain projects mentioned in Annex I. Shale gas extraction activities are expected not to fall under the activities listed in Annex I due to the fact that they will not likely reach the 500,000m^3/day gas extraction threshold stated in that Annex.

- The impacts of HVHF processes can be greater than the impacts of conventional gas exploration and production processes per unit of gas extracted. The use of a single volume threshold for all gas extraction activities in Annex I could lead to more severe impacts from HVHF not being assessed in an impact assessment under this Directive. This is an inadequacy in the EU legislation that could lead to risks not being sufficiently addressed. It is beyond the scope of this work to examine alternative thresholds or approaches for HVHF.
- Member States must decide whether an EIA is required (Article 4(2)) for activities covered by Annex II. Guidance on making this decision is given in the Directive but approaches between Member States could differ regarding the way in which risk and impacts are weighed and whether or not an EIA is required. It is not possible to conclude that risks are adequately addressed at EU level and it is beyond the scope of this project to assess the adequacy of Member State decision-making for activities in Annex II. We consider it appropriate though that the requirement for EIA for HVHF projects falling outside of Annex I be assessed on the basis of project specific characteristics, as is the approach taken in the Directive.
- Based on the characteristics of shale gas extraction activities they fall within the scope of Annex II of the Environmental Impact Assessment Directive (2011/92/EU) with regards Annex II (2) (e) for "Surface industrial installations for the <u>extraction</u> of coal, petroleum, natural gas and ores, as well as bituminous shale" (which however would not cover exploration activities) and, insofar as they constitute "deep drillings" as specified in Annex II (2)(d) (which would cover both exploration and extraction activities).
- However, uncertainty may remain in relation to a shallow well by virtue of lack of precision over the definition of "deep drilling", which would not cover shallow drilling activities (not defined). This is an inadequacy of legislation at EU level. In addition, geological/underground aspects are not explicitly mentioned.
- If an EIA is deemed appropriate by a national authority, cumulative impacts are covered by the Environmental Impact Assessment Directive (2011/92/EU). This is specified in Article 5(1) and Annex IV of the Directive.

3.4.3 Hydrocarbons Authorization Directive (94/22/EC)

The Hydrocarbons Authorization Directive (94/22/EC) sets a common framework aimed at guaranteeing non-discriminatory access to the activities of prospection, exploration and production of hydrocarbons. It stipulates that the limits of the geographical areas covered by an authorisation and the duration of that authorisation must be determined in proportion to what is justified in terms of the best possible exercise of the activities from an economic and technical point of view.

The Hydrocarbons Authorization Directive (94/22/EC) prescribes that Member States shall take the necessary measures to ensure that authorizations are granted on the basis of certain criteria, concerning in all cases the way in which applicants propose to prospect, explore and/or bring into production the geographical area in question (Article 5(1b)). It is not specifically aimed at addressing the risks and impacts identified in Chapter 2, as it focuses on ensuring fair competition in the internal market. At most, this directive allows Member States to provide in authorization conditions imposed on concession holders if this is justified from, e.g., the perspective of environmental protection and protection of biological resources (amongst others Article 6(2)). This provision makes it possible for Member States to draft authorization conditions aimed at preventing or mitigating environmental impacts it deems necessary. In this respect there is arguably a potential overlap with the Mining Waste Directive (2006/21/EC), which puts in place specific conditions associated with managing the environmental aspects of mining waste management. However, as such measures are not a requirement under the Hydrocarbons Authorization Directive (94/22/EC), Member States themselves determine if and how to implement the option in practice. This is not a gap in the

EU legislation per se and it is beyond the scope of this study to go into the degree to which Member States make use of the option under the Hydrocarbons Directive to draft authorization conditions aimed at preventing or mitigating environmental impacts.

In accordance with the Convention on Access to Information, Public Participation in Decision-making and Access to Justice in Environmental Matters (Aarhus Convention) public participation is required in respect of permitting decisions for activities listed in Annex I to the convention (Article 6). These include, inter alia, installations for the treatment and disposal of waste and hazardous waste (point 5), extraction of natural gas exceeding 500,000 m^3/day (point 12) and other activities for which national environmental impact assessment legislation requires public participation (point 20). These provisions potentially therefore require public participation in the procedure for authorisations granted under the Hydrocarbons Authorization Directive (94/22/EC).

3.4.4 Integrated Pollution Prevention and Control Directive (2008/1/EC)

The IPPC Directive (2008/1/EC) has the objective of achieving integrated prevention and control of pollution arising from the activities that cause significant pollution. It lays down measures designed to prevent or, where that is not practicable, to reduce emissions in the air, water and land from these activities, including measures concerning waste, in order to achieve a high level of protection of the environment taken as a whole.

In order to achieve this objective, the directive consists of a system of permitting, setting emission standards, monitoring and documents for best available technology.

Activities covered by the Directive

Annex I of the IPPC Directive (2008/1/EC) states the activities that fall under the jurisdiction of the directive. This covers energy industries, production and processing of metals, mineral industry, chemical industry and waste management.

Annex I includes combustion emissions from combustion installations in energy industries which have a rated thermal input of over 50MW. New York DEC 2011 PR (p6-100) identifies drilling rig power of 5400Hp, implying at a thermal input at 50% efficiency (illustrative) a thermal input of 8MW; well below the IPPC threshold. This means that combustion emissions from single drilling rigs are not covered by the IPPC Directive (2008/1/EC). However, Annex I also states that if there are multiple installations on the site, the total thermal input of all installations should be used as the value to meet the threshold, leading to the potential for large multiple well operations to be covered.

A further area of potential relevance to shale gas lies in the hazardous waste treatment installations, principally for hazardous waste. The used hydraulic fracturing fluids that return from the well or stay underground and will not be reused are considered waste.

Annex I section 5.1 includes:

Installations for the disposal or recovery of hazardous waste as defined in:

- the list referred to in Article 1(4) of Directive 91/689/EEC (Council Directive on hazardous waste, amended by Directive 2008/98/EC)
- Annexes II A and II B to Directive 2006/12/EC (Council Directive on hazardous waste)
- Council Directive 75/439/EEC on the disposal of waste oils (2),

with a capacity exceeding 10 tonnes per day.

In this case hazardous waste' means hazardous waste as defined in point 2 of Article 3 of the Waste Framework Directive (2008/98/EC). "'hazardous waste' means waste which displays one or more of the hazardous properties listed in Annex III;" That directive cites the following (with descriptions):

- 'Explosive'

- 'Oxidizing'
- 'Highly flammable'
- 'Flammable'
- 'Irritant'
- 'Harmful'
- 'Toxic'
- 'Carcinogenic'
- 'Corrosive'
- 'Infectious'
- 'Toxic for reproduction'
- 'Mutagenic'
- Waste which releases toxic or very toxic gases in contact with water, air or an acid. 'Sensitizing'
- 'Ecotoxic'
- Waste capable by any means, after disposal, of yielding another substance, e.g. a leachate, which possesses any of the characteristics listed above.

To clarify these points the Waste Framework Directive (2008/98/EC) notes:

1. Attribution of the hazardous properties 'toxic' (and 'very toxic'), 'harmful', 'corrosive', 'irritant', 'carcinogenic', 'toxic to reproduction', 'mutagenic' and 'eco-toxic' is made on the basis of the criteria laid down by Annex VI, to Council Directive 67/548/EEC of 27 June 1967 on the approximation of laws, regulations and administrative provisions relating to the classification, packaging and labelling of dangerous substances.

2. Where relevant the limit values listed in Annex II and III to Directive 1999/45/EC of the European Parliament and of the Council of 31 May 1999 concerning the approximation of the laws, regulations and administrative provisions of the Member States relating to the classification, packaging and labelling of dangerous preparations shall apply.

The US House of Representatives Committee on Energy and Commerce inquiry into the practice of hydraulic fracturing in the US examined the constituents of hydraulic fracturing fluids (US House of Representatives, 2011 NPR). It noted (page 1) that additive products included 29 chemicals that are: (1) known or possible human carcinogens; (2) regulated under the Safe Drinking Water Act for their risks to human health; or (3) listed as hazardous air pollutants under the Clean Air Act. This would suggest that the disposal of hydraulic fracturing fluids would be covered by the IPPC Directive (2008/1/EC) due to the potentially hazardous constituent compounds. New York State DEC (2011 PR p5-54 onwards), examines the potential constituents of hydraulic fracturing fluids and concludes that "*Chemicals in products proposed for use in high-volume hydraulic fracturing include some that, based mainly on occupational studies or high-level exposures in laboratory animals, have been shown to cause effects such as carcinogenicity, mutagenicity, reproductive toxicity, neurotoxicity or organ damage."* However the effect that these could have on human health depend on exposure routes.

This suggests that hydraulic fracturing fluids could constitute hazardous waste: however further detailed examination of hydraulic fracturing additives would be required to confirm their classification as hazardous under the Waste Framework Directive (2008/98/EC). Thresholds for the constituents of liquids to determine classification as hazardous wastes require specific values to be calculated, under the terms of the Classification, Packaging and Labelling Directive (1999/45/EC). Furthermore, In order to harmonise the approach of declaring waste as hazardous, the European Commission issued a decision 2000/532/EC which gives thresholds on substances in waste. Wastes with characteristics above these thresholds are classified as hazardous. The assessment of whether hydraulic fracturing fluids could be hazardous would need to be carried out on a case by case basis, in view of the variability in constituents of fracturing fluids.

Annex I of the IPPC Directive (2008/1/EC) also identified non-hazardous waste disposal as requiring an IPPC permit under certain circumstances. It includes (point 5.3): "*Installations for the disposal of non-hazardous waste as defined in Annex II A to Directive 2006/12/EC under headings D8 and D9, with a capacity exceeding 50 tonnes per day,"* where headings D8 and D9 specify biological and physico-chemical treatment respectively. Whilst hydraulic fracturing injection rates could exceed this threshold, the fluids would not necessarily be seen to be treated in this way for the purposes of disposal.

Pollution covered by the Directive

It is important to consider the extent to which the IPPC Directive (2008/1/EC) covers the impacts from activities such as drilling and hydraulic fracturing. One could consider the interpretation of Art 1 to cover Annex I activities irrespective of whether or not they are the main activities of the site.

The rationale for this is that the approach of IPPC is to regulate activities, and not sites, or main activities. An installation is defined by Art 2 as a technical unit where annex I activities take place, including directly associated activities with a technical connection to the activities. This is reflected in the boundary of the installation from a permit perspective, Arts 6 and 9, which require that permits and their conditions apply to installations, and hence the activities taking place there.

In summary, there is no definition of an installation separate from the activities in Annex I, so one can conclude that IPPC would apply to all Annex I activities irrespective of the main purpose of a site or the boundaries drawn for that site for other purposes (EIA-Directive, Mining Waste Directive etc). This means that the IPPC Directive (2008/1/EC) could apply to hydraulic fracturing installations that meet Annex I criteria for waste management, even though the primary purpose of the installations is not the management of waste.

A further consideration is whether the permit covers only the polluting substances resulting from Annex I activities, or more widely all pollution from the installation. For example, consider a hydraulic fracturing site involved the disposal of hazardous waste with a capacity of >10 tonnes per day (Annex I 5.1) and at the same time its combustion capacity is below 50MW, therefore it does not meet any Annex I requirements in relation to air emissions from that drilling equipment. According to Art 2(3) the "installation" means: "a stationary technical unit where one or more activities listed in Annex I are carried out, and any other directly associated activities which have a technical connection with the activities carried out on that site and which could have an effect on emissions and pollution;". Therefore one needs to determine if air emissions would be covered by an IPPC permit for the installation in the above example. Two considerations apply:

- Whether the drilling equipment has a technical connection with the activity of waste disposal (the hydraulic fracturing process).If it is a general and broad definition of connection, then it could be interpreted that the Directive covers any activity associated with shale gas exploitation at the site and drilling pollution would be covered. A narrow definition, however, would be that the technical connection means the connected activities would need to influence the pollution of the Annex I activity. In other words, in the example above drilling would only be connected if it influenced the pollution due to waste disposal. However, technical connection is not defined in the directive, and Art 2(3) does not limit this connection as being associated with Annex I activities. Therefore the broad interpretation appears reasonable.

- The drilling equipment could have an effect on emissions and pollution. Critical to this interpretation, though, is that Art 2(3) does not limit the directly associated activities to those which have an effect on the pollution associated with the Annex I activity; it refers to emissions and pollution in a more general sense. In other words, there is no need to demonstrate that the operation of the drilling equipment (and for example the technology used) has an effect on the pollution associated with waste disposal. It is enough that it has some impact on pollution (where pollution is defined in Art 2(2)).

Taken together, the above analysis suggests that the undertaking of any Annex I activity at a shale gas exploitation site would include under IPPC any pollution from any equipment directly connected with the shale gas exploration work. This is the approach taken in the report. If this broad definition is not supported then the coverage of IPPC would be limited to a subset of activities or pollution at the site.

Relationship to Industrial Emissions Directive (2010/75/EC).

The IPPC directive will be replaced by the Industrial Emissions Directive (2010/75/EC). Under that directive the potential permit requirements for HVHF processes would be similar. Operators of industrial activities listed in Annex I to the Directive must obtain an integrated permit from relevant national authorities prior operation. As with IPPC, Annex I to this Directive does not explicitly refer to unconventional hydrocarbon exploration and exploitation activities, but covers activities related to combustion capacity (thermal input over 50MW) and waste (for which the thresholds relating to hazardous and non-hazardous waste are the same as IPPC, albeit the definitions within the annex differ). Also , the exemption of research, development and testing activities in annex I of IPPC is not included in the corresponding annex of IED.

Under the permit, operators will be subject to the compliance with certain conditions which include measures on emission limit values for polluting substances listed in Annex II to the Directive and for other polluting substances that are likely to be emitted from the installation concerned in significant quantities.

One of the extra requirements is a baseline report which contains at least the following information:

- Information on the present use and, where available, on past uses of the site;
- Where available, existing information on soil and groundwater measurements that reflect the state at the time the report is drawn up or, alternatively, new soil and groundwater measurements having regard to the possibility of soil and groundwater contamination by those hazardous substances to be used, produced or released by the installation concerned.

These baseline reports are of importance to establish a good reference of environmental quality of the site at the start and in case of site closure.

The inspection regime is also strengthened under the Industrial Emissions Directive (2010/75/EC) compared to the IPPC directive (2008/1/EC).

The Industrial Emissions Directive (2010/75/EC) will be effective for new installations as of January 7, 2013 and as of July 7, 2015 for existing installations.

Conclusions on applicability of IPPC Directive (2008/1/EC) and IED Directive (2010/75/EC)

Based on the analysis in this section we conclude that it is uncertain whether or not a permit according to the IPPC Directive (2008/1/EC) and respectively the IED Directive (2010/75/EC) is required. Under the IPPC Directive and IED Directive, the permit would be required if (part of) the installation is defined as an installation for the disposal or recovery of hazardous waste, where ‘hazardous waste’ is defined in the Waste Framework Directive (2008/98/EC). The chemical composition of the hydraulic fracturing fluids used is commercially sensitive and can differ between production sites, therefore whilst they could be defined as hazardous (Reins, 2011 PR), it is not possible to form a conclusive and generalised view at this stage. This is not necessarily an inadequacy of EU legislation, but because of the uncertainty over HVHF technology characteristics it is not possible to confirm that related environmental risks would be adequately addressed.

If an IPPC (or IED) permit were required, then the permit conditions would include measures that are related with the best available techniques (BAT). However, documents to confirm BAT for this sector are not yet available (Lechtenböhmer et al., 2011 NPR).

Article 6 of the IPPC directive (article 12 IED) states the information required for application for a permit. This information can be derived from a performed EIA, but will also be more specific on the techniques and management measures that will be taken.

The permit shall include emission limit values for polluting substances likely to be emitted from the installation concerned in significant quantities, having regard to their nature and their potential to transfer pollution from one medium to another (water, air and land). If necessary, the permit shall include appropriate requirements ensuring protection of the soil and ground water and measures concerning the management of waste generated by the installation.

The permit must also include the suitable release monitoring requirements, specifying measurement methodology and frequency, evaluation procedure and an obligation to supply the competent authority with data required for checking compliance with the permit.

If the IPPC Directive (2008/1/EC) or IED (2010/75/EC) does not apply, this means that (extra) safeguards regarding possible pollutant activities laid down in these Directives and highlighted above do not apply to hydraulic fracturing.

Since there is no obligation for a permit that covers the complete process on the site and its impacts, this might be considered as a gap.

3.4.5 Mining Waste Directive (2006/21/EC)

The Mining Waste Directive (2006/21/EC) places specific obligations on operators of facilities that pose a potential risk to public health or the environment. The wastewater that is the result of the activities during the HVHF process falls within the scope of the Mining Waste Directive. This is because the Mining Waste Directive (2006/21/EC), Article 3 (1), refers to the definition of waste as given in the Waste Directive (Directive 75/442/EEC, subsequently repealed by Directive 2008/98/EC). In the Waste Directive (2008/98/EC) waste is defined as "any substance or object which the holder discards or intends or is required to discard" (Article 3(1)). Commission Decision 2000/532/EC gives a further definition of the waste. The annex of this decision identifies "01 05 Drilling muds and other drilling wastes" as a category. The water resulting from HVHF processes is to be considered a drilling waste. This enables us to conclude that wastewater constitutes waste under the Mining Waste Directive (2006/21/EC).

The scope of such operations is defined in Article 2 as the management of waste resulting from the prospecting, extraction, treatment and storage of mineral resources and the working of quarries. However, it makes exclusions for waste which is generated by prospecting, extraction and treatment of mineral resources not directly resulting from those operations and waste from offshore prospecting extraction and treatment of mineral resources. Recognising these definitions it can be concluded that the directive applies to shale gas extraction.

Due to the fact that, after the hydraulic fracturing, wastewater not only comes out of the well, but also partly remains underground, the well must be considered as an underground storage facility for wastewater.

HVHF processes also need a permit under the Mining Waste Directive (2006/21/EC) as stated in Article 7(1):

"No waste facility shall be allowed to operate without a permit granted by the competent authority".

The permit must contain the waste management plan and adequate arrangements by way of a financial guarantee or equivalent (Article 7(2)). In fact the combination of the permit and the waste management plan ensure the necessary measures to prevent accidents and environmental impacts due to the waste facility. The permit does not cover the activities on the site that are not related to the waste management. On the other hand the permit under 2006/21/EC can be combined with a permit that might be required under the Water Framework Directive (2000/60/EC) since discharge of wastewater to surface water must be regulated with a permit.

The waste management plan must also include measures that the operator takes in the after abandonment phase, such as monitoring and control. This is most relevant for the waste water remaining in the wells. It also means that measures must be taken in order to ensure the construction of the borehole and the well is safe enough to prevent leakage of wastewater outside the well.

Part of the waste management plan is the characterisation of the waste facility. The operator must give the information to classify the waste facility as either Category A or non-Category A according to the criteria laid down in Annex III of the Mining Waste Directive (2006/21/EC).

Category A classification is carried out on the basis of the following criteria (Commission Decision 2009/337/EC also gives more detailed criteria for this categorisation):

- a failure or incorrect operation, e.g. if the collapse of a heap or the bursting of a dam, could give rise to a major accident, on the basis of a risk assessment taking into account factors such as the present or future size, the location and the environmental impact of the waste facility; or
- it contains waste classified as hazardous under Directive 91/689/EEC above a certain threshold; or
- it contains substances or preparations classified as dangerous under Directives 67/548/EEC or 1999/45/EC above a certain threshold.

As for these criteria and their application to the hydraulic fracturing process:

- the amounts of stored waste water are estimated to stay below 30,000 m^3 (see Table 3). Any collapse of a storage facility would not cause a major accident as referred to in the first criteria; or
- the concentrations of hazardous waste or dangerous substances above certain thresholds could occur, but there is a knowledge gap in relation to these concentrations, and this would need to be assessed on a case-by-case basis. This uncertainty over whether HVHF liquids would constitute hazardous waste is discussed in section 3.4.4.

If the concentrations mentioned are exceeded, the waste facility must be characterised as a Category A Facility and is subject to a stringent regime including major accident prevention measures and external emergency plan. If a facility is not characterised as a Category A facility the operator still has to draw up a waste management plan. However, in that case the operator does not have to have a major accident prevention policy and external emergency plan.

A major accident as defined in the Mining Waste Directive (2006/21/EC) means: an occurrence on site in the course of an operation involving the management of extractive waste in any establishment covered by this Directive, leading to a serious danger to human health and/or the environment, whether immediately or over time, on-site or off-site. Migration of fracturing fluids and/or displaced formation fluids into an aquifer is one of the potential risks of HVHF processes, but is not considered a major accident under the Mining Waste Directive (2006/21/EC).

Waste classification

One of the questions that has to be answered, in order to determine the application of the IPPC directive for HVHF sites and whether to classify the waste treatment installation as a Category A installation under the Mining Waste Directive (2006/21/EC), is whether or not the waste coming from the well or remaining in the underground is hazardous. This issue is described in section 3.4.4.

It is concluded that, in order to classify hydraulic fracturing wastewaters as hazardous or non-hazardous, the chemical composition of the waste must be known. Waste chemical composition will vary from site to site, depending on the nature of the hydraulic fracturing fluids used, and the levels of naturally occurring potentially hazardous substances present in wastewater.

This makes it impossible at this stage to classify the waste coming from the well, or the waste remaining in the well, other than to indicate the possibility that waste waters may potentially be classified as hazardous. Nevertheless, as noted above, any waste facility shall require a permit granted by the competent authority and which will contain the waste management plan (Articles 5 and 7(1) Mining Waste Directive (2006/21/EC)).

Conclusions on applicability of the Mining Waste Directive (2006/21/EC)

The (contaminated) wastewaters related to activities during the HVHF process are considered to fall under the definition of waste from extractive industries. This conclusion is in line with the Commission’s legal interpretation on this issue (EC, 2011). Based on the provisions in the Mining Waste Directive (2006/21/EC) it is not clear whether or not the waste facility is classified as a Category A waste facility, for which additional safeguards are mandatory (major accident prevention policy and external emergency plan). This uncertainty is brought about by the fact that it is unclear whether or not the waste coming from the well or remaining in the underground is considered ‘hazardous’. The chemical composition of the hydraulic fracturing fluids used is commercially sensitive and can differ between production sites. This is not necessarily an inadequacy of EU legislation, but because of the uncertainty over HVHF technology characteristics it is not possible to confirm that environmental risks in relation to accidents would be adequately addressed.

If a facility is not characterised as a Category A facility the operator still has to draw up a waste management plan addressing how he will deal with waste issues and the risks of chemicals remaining in the underground (which should also be assessed in any environmental impact assessment before the start of the project). However, in that case the operator is not required to have a major accident prevention policy and external emergency plan.

In each case the provisions of the Mining Waste Directive (2006/21/EC) should provide guidance to Member States in addressing the risks arising from HVHF. The Directive requires Member States to ensure the operator takes all measures necessary to prevent as far as possible any adverse effects on the environment or human health, including following its abandonment (Article (4(2)), implemented through the permit and management plan (Article 7). However, at present there is no Best Available Technology Reference Document (BREF) at EU level for shale gas waste management. Whilst reliance on Member State permitting regimes and associated decision-making is not a gap in the EU legislation per se, it is beyond the scope of this project to determine whether the Member States’ implementation for this aspect adequately addresses all environmental risks.

3.4.6 Seveso II Directive (96/82/EC)

The Seveso II Directive (96/82/EC) aims to prevent major accidents involving dangerous substances, limit their consequences and ensure high levels of protection in a consistent and effective manner.

Article 4 states the exclusions of the Directive, especially 4(e) [the exploitation (exploration, extraction and processing) of minerals in mines, quarries, or by means of boreholes, with the exception of chemical and thermal processing operations and storage related to those operations which involve dangerous substances, as defined in Annex I] and '(g) [waste land-fill sites, with the exception of operational tailings disposal facilities, including tailing ponds or dams, containing dangerous substances as defined in Annex I, in particular when used in connection with the chemical and thermal processing of minerals].

In both (e) and (g) there must be chemical and thermal processing operations and storage which involves dangerous substances, although the terms "chemical and thermal processing" are not defined in the directive. Chemical and thermal processing operations are common in the ore mining industry. HVHF processes do not use chemical and thermal processing operations, but do involve mechanical processes, i.e. the mixing of substances. The Seveso II Directive (96/82/EC) is not applicable to waste storage of HVHF processes. The risks involving the management of waste are covered by the Mining Waste Directive (2006/21/EC).

There may be another reason for applicability of Seveso II Directive (96/82/EC), which is the presence of natural gas in the ground or on land. Under Article 2 it applies to dangerous substances that are present in quantities equal to or in excess of the quantities listed in Annex I, Part 1, or substances with the characteristics mentioned in Annex I Part 2.

The storage of natural gas above 50 tonnes is one of the thresholds (Annex I, part 1) related to HVHF processes. In general the gas produced at a HVHF site is, after dehydrating, delivered to the main gas infrastructure. The presence of gas in the underground is not considered to be storage as meant in the Seveso II Directive (96/82/EC). The gas is well preserved underground and has no possibility of causing risks as addressed by the directive. Storage of gas on site is not a common procedure, since storage in fact takes place in the well itself. As discussed above, the constituents of hydraulic fracturing fluids, and therefore the chemicals held or mixed on site, are complex, often subject to commercial sensitivity and may vary between sites. It is therefore not possible to conclude whether the requirements of the Seveso II Directive (96/82/EC) apply. Given the amounts that must be on site to meet the characteristics of Annex I, part 2, it is however very unlikely that they will be exceeded, even if the addition rule of Annex I, part 2, Notes (4) was applied. The addition rule uses the sum of the amount of the substances relative to the thresholds set out in the Annex. If the sum is larger than 1, then the threshold is met due to the combined presence of the substances. This would be the case if toxic substances exceed the amount of 50 tonnes, very toxic substances 5 tonnes or substances dangerous to the environment 200 or 500 tonnes (depending on their impact).

Should the substances involved fall under the Directive then Member States shall ensure that the operator is obliged to take all measures necessary to prevent major accidents and to limit their consequences and to notify the competent authority of these measures (Article 5). The Operator must also draw up major accident prevention policies (Article 7). A safety report must be carried out and made public under Article 13 and a regime of competent authority inspections must be applied (Article 18) to assess whether the operator has implemented the measures and to confirm the accuracy of the safety report. Regarding information disclosure, certain information must be exchanged between member States and the European Commission with regard major accidents and their prevention (Article 19) and make the information publicly available, although subject to commercial or industrial sensitivity restrictions specified in Article 20.

Conclusions on applicability of the Seveso II Directive (96/82/EC).

Whilst the authors judge it unlikely that the Seveso II Directive is applicable to HVHF process sites, it is not possible to say definitively that this is the case.

The risks of major accidents are related to the mining waste and for Category A installations they are addressed in the Mining Waste Directive (2006/21/EC).

3.4.7 The Environmental Liability Directive (2004/35/EC)

As described in the document with legal interpretation of the environmental acquis drafted by the Commission (EC, 2011) the Environmental Liability Directive (2004/35/EC) provides the framework for Member States to require:

- preventive measures in case of an imminent threat of environmental damage; or
- necessary restorative measures where environmental damage has occurred.

The Directive applies to (Article 3):

- environmental damage caused by any of the occupational activities listed in Annex III, and to any imminent threat of such damage occurring by reason of any of those activities; or
- damage or threat of damage to protected species and natural habitats caused by any occupational activities other than those listed in Annex III, whenever the operator has been at fault or negligent.

Environmental damage (Article 2(1)) means damage to protected species and natural habitats, water or land with significant adverse effects.

The activities listed in Annex III include those subject to a permit concerning IPPC Directive (2008/1/EC), Water Framework Directive (2000/60/EC) and waste management in relation to hazardous wastes or handling of dangerous substances, which would be required to hold a permit under the Mining Waste Directive (2006/21/EC). In addition to this, Article 15 of the Mining Waste Directive (2006/21/EC) amends the Environmental Liability Directive (2004/35/EC) adding the following to Annex III:

- The management of extractive waste pursuant to Directive 2006/21/EC of the European Parliament and of the Council of 15 March 2006 on the management of waste from extractive industries.

It is also important to note that Article 4(5) of the Environmental Liability Directive (2004/35/EC) which states the directive to only apply to environmental damage or to an imminent threat of such damage caused by pollution of a diffuse character, where it is possible to establish a causal link between the damage and the activities of individual operators. This will limit the applicability of the directive to diffuse impacts such as from air pollution.

In conclusion, all damage from activities covered by directives referred to in Annex III of the Environmental Liability Directive (2004/35/EC) would be covered under the strict liability scope of Directive 2004/35/EC. However, activities not covered by the Annex III directives would not be included in this way. For example, emissions to air during fracturing are not covered by the Mining Waste Directive (2006/21/EC), therefore it follows that these impacts are not automatically covered by the Environmental Liability Directive (2004/35/EC) by virtue of the inclusion of the Mining Waste Directive (2006/21/EC) in Annex III. Nevertheless, these impacts could be covered by the Environmental Liability Directive where the IPPC Directive is applicable to these projects.

In order for other impacts to fall within the scope of the Directive they have to involve damages to protected species and natural habitats with significant adverse effects for which the operator has been at fault or negligent.

3.4.8 Monitoring and Inspection

The legal interpretation of the Commission (EC, 2011) briefly describes relevant monitoring and inspection provisions following form the EU regulatory framework. This section presents a consolidated review of the monitoring and inspection requirements specified by the IPPC Directive (2008/1/EC), the Mining Waste Directive (2006/21/EC) and the Water Framework Directive (2000/60/EC) as directly relevant to hydraulic fracturing. The Directives related to environmental quality (air, noise and water) all have their own monitoring schemes that allow the Member States to follow and report on changes in the environmental quality. Since these are general monitoring schemes and not directly related to specific sites, they are not discussed further in this report.

For Hydraulic fracturing processes, monitoring would need to be related to the chemical and physical characteristics of the wastewater, as well as to emissions to water, groundwater and air. Monitoring of induced seismicity could be of relevance to reduce public concerns.

Under the Mining Waste Directive (2006/21/EC) Article 11.2 (c) the operator must have suitable plans and arrangements for regular monitoring and inspection of the waste facility by competent persons and for taking action in the event of results indicating instability or water or soil contamination. Article 11.3 obliges the operator to, without undue delay and in any event not later than 48 hours thereafter, notify the competent authority of any events likely to affect the stability of the waste facility and any significant adverse environmental effects revealed by the control and monitoring procedures of the waste facility. The operator shall implement the internal emergency plan, where applicable, and follow any other instruction from the competent authority as to the corrective measures to be taken. Also, the operator remains responsible for the maintenance, monitoring and corrective measures in the after-abandonment phase as long as it is required by the competent authority (Article 12.4; Directive 2006/21/EC).

Article 17 of the Mining Waste Directive (2006/21/EC) deals with inspections by the competent authority in the following manner:

1. Prior to the commencement of deposit operations and at regular intervals thereafter, including the after-abandonment phase, to be decided by the Member State concerned, the competent authority shall inspect any waste facility covered by Article 7 in order to ensure that it complies with the relevant conditions of the permit. An affirmative finding shall in no way reduce the responsibility of the operator under the conditions of the permit.
2. Member States shall require the operator to keep up-to-date records of all waste management operations and make them available for inspection by the competent authority and to ensure that, in the event of a change of operator during the management of a waste facility, there is an appropriate transfer of relevant up-to-date information and records relating to the waste facility

Both monitoring and inspection of the waste are regulated through the Mining Waste Directive (2006/21/EC).

Emissions to surface water have their monitoring requirements in the Water Framework Directive (2000/60/EC). Article 11 (g) for point source discharges liable to cause pollution, a requirement for prior regulation, such as a prohibition on the entry of pollutants into water, or for prior authorisation, or registration based on general binding rules, laying down emission controls for the pollutants concerned, including controls in accordance with Articles10 and 16. These controls shall be periodically reviewed and, where necessary, updated. The monitoring requirements are to be part of the permit under the Water Framework Directive (2000/60/EC).In fact the regulation of emissions to surface water is done by permit which can be combined with the permit under the Mining Waste Directive (2006/21/EC).

The monitoring of underground stored wastewater is also part of the monitoring requirements in the permit under the Mining Waste Directive (2006/21/EC). Article 5 of the waste management plan is the legal basis for these requirements. This means that the groundwater in the direct vicinity of the well must be monitored in order to detect possible leakage from the well.

Within river basins districts, the monitoring of the quality of groundwater in general is dealt with in the Water Framework Directive (2000/60/EC) Annex V, 2.4, which gives the directions on the monitoring of groundwater. Annex V, 2.4.3 of the Water Framework Directive gives the requirements for operational monitoring to be carried out by Member States, at least once a year *for all those groundwater bodies […] which on the basis of both the impact assessment carried out [by Member States] in accordance with Annex II and surveillance monitoring are identified as being at risk of failing to meet the objectives under Article 4.* This "identification process" is drawing on the initial characterisation performed by Member States at the latest 13 years after the date of entry into force of this Directive and every six years thereafter. Therefore, no operational monitoring is required for groundwater bodies that, in a time frame of six years, were not identified as being at risk of failing to meet the objectives under Article 4 of the Water Framework Directive (2000/60/EC). As monitoring of aquifers in the surrounding of HVHF process activities should always be required, this indicates a possible gap in legislation.

There are no requirements on the frequency of the monitoring of both discharge to surface waters and the quality of groundwater in the vicinity of the site. It is up to the competent authority to establish these requirements and regulate them through the permit under the Mining Waste Directive (2006/21/EC).

Monitoring of emissions to air is only required under EU legislation if the installation needs a permit under the IPPC Directive (2008/1/EC). Article 9 (5) states the monitoring aspects that should be in the permit. Article 14 (3) deals with the inspection by the competent authority in order to verify the compliance with the permit. There are no requirements on the frequency of monitoring and inspections. This is not necessarily an inadequacy of EU legislation, but because of the uncertainty over HVHF technology characteristics (i.e. where it would fall under the IPPC Directive (2008/1/EC) it is not possible to confirm that related environmental risks would be adequately addressed.

Under the IPPC Directive (2008/1/EC) it is up to the competent authorities to decide on the frequency of monitoring and inspections. In the case the permit under IPPC is not required, the complete monitoring and inspection is the jurisdiction of the competent authority.

If the IED (2010/75/EC is applicable, the monitoring and inspection requirements in Articles 14 and 16 of that directive apply. Article 14 sets out the provisions that must be included in permits for regulated installations, including provisions relating to emissions monitoring. Article 16 lays down the principles for monitoring regimes, with specific provisions for soil and groundwater monitoring.

3.4.9 Conclusions regarding general provisions

The Strategic Environmental Assessment Directive (2001/42/EC) applies to programmes and plans and gives the competent authorities the obligation to conduct an environmental assessment before starting the concession processes. This assessment provides the information on the possible environmental impacts in the area where the concessions are to be granted.

The Environmental Impact Assessment Directive (2011/92/EC) is the basis for environmental impact assessments to be included as part of the development consent process and is applicable for hydraulic fracturing projects. These assessments however are not always mandatory since the Environmental Impact Assessment Directive (2011/92/EC) gives the Member States the possibility for defining the kind of projects that need an assessment.

Inadequacies in the EU legislation have been identified with regards the use of a single threshold in Annex I for all gas extraction technologies requiring mandatory EIA, and the absence of a clear definition of deep drilling in Annex II. It is beyond the scope of this project to assess the adequacy of Member State application of optional EIA for activities in Annex II.

Permits are required under the Mining Waste Directive (2006/21/EC) and the Water Framework Directive (2000/60/EC). It is beyond the scope of this project to determine whether the Member States' implementation for this aspect adequately addresses all associated environmental risks. Permits might be required under the IPPC Directive (2008/1/EC) or IED (2010/75/EC) depending on whether the installation in question is deemed to be handling hazardous waste or has combustion capacity over the threshold in those directives. This is not necessarily an inadequacy of EU legislation, but because of the uncertainty over HVHF technology characteristics it is not possible to confirm that related environmental risks would be adequately addressed.

The Hydrocarbons Authorization Directive (94/22/EC) prescribes that Member States shall take the necessary measures to ensure that authorizations are granted on the basis of certain criteria. This directive allows Member States to provide in authorization conditions imposed on concession holders if this is justified, however, such measures are not a mandatory requirement.

Whilst the authors judge it unlikely that the Seveso II Directive (96/82/EC) is applicable to HVHF process sites, it is not possible to say definitively that this is the case. However, to the extent that a HVHF process site constitutes a Category A installation under the Mining Waste Directive (subject to whether fracturing fluids are deemed to be hazardous or not), the risks of major accidents related to the mining waste are addressed in the Mining Waste Directive (2006/21/EC).

All damage from activities covered by the Mining Waste Directive (2006/21/EC) would be covered under the strict liability scope of the Environmental Liability Directive (2004/35/EC). In order for other impacts to fall within the scope of the Environmental Liability Directive (2004/35/EC) they have to involve damages to protected species and natural habitats with significant adverse effects for which the operator has been at fault or negligent.

3.5 Land-take during site preparation and production (cumulative, project stage 1)

3.5.1 Impacts and applicable legislation

The key issue with regard to land take impacts deals with the fact that surface installations for high-volume hydraulic fracturing, without mitigating measures, could take up approximately 60% more space per well pad than conventional drilling (see Chapter 2). This additional area is needed to accommodate the plant and storage tanks/pits required for up to 30,000 m^3 of make-up water, together with chemical additives and waste water. Additionally, shale gas formations cover areas of tens of thousands of square kilometres, with concessions being granted for areas of up to 6,000 km^2. The analysis in Chapter 2 (section 2.4.3) indicates that approximately 1.4% of the land above a productive shale gas reservoir may need to be used to fully exploit the gas reservoir, or more if other indirect land-uses are taken into account.

As already indicated in Chapter 2 multi-well pads are in increasing use for shale gas extraction in the US. This enables a single pad to accommodate 6-10 wells instead of just 1 in the case of conventional gas extraction activities or earlier shale gas developments, resulting in a lower land-take impact per well. This partly compensates up for the extra space needed for surface installations if no mitigating measures are in place. Therefore, land-take associated with an individual site is expected to be within the normal range of commercial and infrastructure developments in Europe, and can be considered as a minor impact.

However, the cumulative land-take impact of multiple installations is considered to be of potentially major significance. It may not be possible to fully restore a site in a sensitive area following well completion or well abandonment. For example, sites in areas of high agricultural, natural or cultural value could potentially not be fully restorable following use. Also, the associated infrastructure (access roads and pipelines) result in land-take and habitat fragmentation.

The following legislation is applicable:

- The Environmental Impact Assessment Directive (2011/92/EU)
- The Strategic Environmental Assessment Directive (2001/42/EC)
- The Environmental Liability Directive (2004/35/EC)
- The Habitats Directive (1992/43/EEC)
- The Birds Directive (2009/147/EC)
- The Hydrocarbons Authorization Directive (94/22/EC)

The relevance of these Directives with regard to sufficient coverage of (cumulative) land-take impacts in the site preparation phase of the project is discussed below.

3.5.2 Applicability of the legislation

EIA obligation in relation to land take impacts

In sections 3.4.1 and 3.4.2 the question whether shale gas extraction activities are always subject to an EIA obligation was discussed. It was concluded that shale gas extraction activities fall within the scope of Annex II of the Environmental Impact Assessment Directive (2011/92/EU). With regard to these activities it is up to the Member States to decide whether an EIA is appropriate (Article 4(2) of the Environmental Impact Assessment Directive (2011/92/EU)). Therefore, as already mentioned, the Environmental Impact Assessment Directive (2011/92/EC) *in itself* does not prescribe that an EIA, addressing the (cumulative) land-take impacts during site preparation, is mandatory. It is beyond the scope of this study to determine the adequacy of implementation of the Environmental Impact Assessment Directive (2011/92/EC) at Member State level.

In the remainder of this section, it is assumed that an EIA obligation is deemed appropriate by the Member State. The next question is whether land-take impacts are expected to be sufficiently covered in this EIA.

Article 3 of the Environmental Impact Assessment Directive (2011/92/EU) sets out what should be assessed in an EIA. In particular it states: *“The environmental impact assessment shall identify, describe and assess in an appropriate manner, …. the direct and indirect effects of a project on the following factors:*

(a) human beings, fauna and flora;

(b) soil, water, air, climate and the landscape;

(c) material assets and the cultural heritage;

(d) the interaction between the factors referred to in points (a), (b) and (c).”

The expected land take impacts are covered by the obligation to pay attention to the effects of a project on the fauna and flora and the landscape (Article 3(a) and 3(b) Environmental Impact Assessment Directive (2011/92/EU)). Also, the Member State has to ensure that the developer provides the authority responsible for approving the project with the information listed in Annex IV insofar as the Member State deems it to be relevant for the case concerned (Article 5(1) of the Environmental Impact Assessment Directive (2011/92/EU)). This information should consist of a description of the expected environmental impacts related to land-take and information with regard to the land-use requirements during the construction and operational phases of the whole project (Point 1a of Annex IV of the Environmental Impact Assessment Directive (2011/92/EU). One approach that could be adopted would be to split the EIA according to the phases in the exploration and exploitation process. The impacts that occur during the exploration phase (Stages 1 and 2 in Figure 3) are likely to be smaller than those of the exploitation phase where larger areas of land are involved; there would be less opportunity for collection and utilisation of fugitive gases during the exploration phase. The systematic approach of the EIA however requires an integrated impact analysis over the whole period of the project.

For the projects concerning hydrocarbons operations involving hydraulic fracturing this means that the land-take impacts described in Chapter 2 of this report will have to be dealt with in an EIA. This also holds for cumulative land-take effects of shale gas extraction activities (footnote 1 in Annex IV of the Environmental Impact Assessment Directive (2011/92/EU), which states that information must cover, inter alia, cumulative effects of the project), in order to prevent the slicing of projects into smaller parts to reduce the reported environmental impacts. Projects usually start with a limited amount of wells to be expanded with more wells in due time. This expansion, increasing land-take impacts, is to be foreseen in the EIA and is to be taken into account. The full (future) size of the project plant, and associated land-take impacts, is brought under the scope of the EIA carried out, as was already clarified in section 3.4.2 .

3.5.3 The Environmental Liability Directive (2004/35/EC)

As described in section 3.4.7, the Environmental Liability Directive (2004/35/EC) covers environmental damage from activities regulated by directives cited in Annex III. The presence and use of waste facilities on site are part of the activities cited in Annex III. Environmental damage caused by these activities fall under the Environmental Liability Directive (2004/35/EC).Next to that, damages to protected species and natural habitats with significant adverse effects under the 1992/43/EEC Habitats Directive and the 2009/147/EC Birds Directive would also be included if caused by non-Annex III occupational activities, provided that the operator has been at fault or negligent. Impacts from land take not caused by waste facilities would therefore only be covered by the directive insofar as they cause damage to these protected species and habitats. This is an inadequacy of the legislation.

3.5.4 Conclusions

In cases where shale gas extraction activities as such are subject to an EIA obligation, a Member State is obliged to indicate in its EIA what the estimated land-take impacts are, now and in the future, and how these are dealt with (Article 3 and 5 of the Environmental Impact Assessment Directive (2011/92/EU)). However, the Environmental Impact Assessment Directive (2011/92/EU) leaves at the discretion of competent authorities the way in which land-take impacts are analysed, assessed and weighted. Whilst this is not a gap in the EU legislation per se considering the horizontal nature of the EIA Directive (2011/92/EU), further examination beyond the scope of this project is needed to determine whether the Member States' implementation for this aspect adequately addresses land take risks.

The 2004/35/EC Environmental Liability Directive only covers land-take impacts which qualify as 'environmental damage', for which the operator is at fault or negligent. The usual land-take impacts are economic issues which are dealt with using economic instruments such as payment.

3.6 Release to air during drilling (project stage 2)

3.6.1 Impact and applicable legislation

The release to air of polluting substances during drilling is described in section 2.5.3. The main issue of potential concern with regard to emissions to air during well drilling is the risk of emissions of diesel exhaust fumes from well drilling equipment. While less-polluting processes do exist, this section builds on findings from section 2.5.3, which looks at shale gas developments known in the USA.

The directive that in principle covers the emissions to air from equipment at drilling sites, such as diesel engine equipment, is the IPPC Directive (2008/1/EC) or the IED (2020/75/EC). As indicated in section 3.4.4 the question whether or not the IPPC Directive (2008/1/EC) or IED (2010/75/EC) is applicable is uncertain, due to uncertainties over the likely combustion capacity and classification of waste at the site.

With regards combustion capacity the IPPC Directive (2008/1/EC) and IED (2010/75/EC) Annex I includes combustion emissions from combustion installations in energy industries which have a rated thermal input of over 50MW. New York DEC 2011 PR (p6-100) identifies drilling rig power of 5400Hp, implying at a thermal input at 50% efficiency (illustrative) a thermal input of 8MW; well below the IPPC threshold. At this level single drilling rigs are not covered by the IPPC Directive (2008/1/EC) or IED (2010/75/EC). However, Annex I also states that if there are multiple installations on the site, the total thermal input of all installations should be used as the value to meet the threshold, leading to the potential for large multiple well operations to be covered.

The Air Quality Directive (2008/50/EC) sets limit values of air polluting substances in ambient air, however it does not regulate specific site emissions and monitoring under that directive will not necessarily be local to sources of hydraulic fracturing air emissions.

If the project is subject to an environmental impact assessment obligation (see section 3.4.2) the developer/operator has to provide information on emissions to air and their impacts (Article 3b, Article 5(1) and Annex IV point 1(c) of the Environmental Impact Assessment Directive (2011/92/EU).

Emission limits for off-road combustion plant are specified via the Directives on Emissions from Non-Road Mobile Machinery (Directive 97/68/EC as amended by 2010/26/EC). These directives specify limits on emissions of carbon monoxide, oxides of nitrogen, hydrocarbons and particulate matter from engines up to 560 kW and are aligned with the equivalent US emissions standards. It's important to note, however, that this legislation applies only to type-approval and new off-road machines; it does not limit their emissions during the use. Therefore the effect on emissions is indirect and therefore possibly of marginal effectiveness in mitigating these emissions. Emissions limits applicable to engines rated above 560 kW were proposed in the review of amending Directive 2004/26/EC, either by extending the limits for engines below 560 kW, or by creating an additional class of engines above 560 kW (Joint Research Centre, 2008 PR p78). Plant used for drilling in advance of HVHF operations is likely to be rated above 560 kW (e.g. see New York DEC 2011 PR p6-100). Hence, the existing European emissions limits may not apply to larger drilling plant if the scope of the directive is not extended to plant rated above 560 kW. This is an inadequacy of legislation at EU level.

3.6.2 Applicability of the legislation

The preceding section mentions that air emission would be covered by any assessment under the Environmental Impact Assessment Directive (2011/92/EU) and subject to a permit regime under the IPPC Directive (2008/1/EC), if that directive applies. In the absence of these directives applying then air emissions would not be regulated. The inadequacies concerning the EIA directive and the role of Member State decision-making are discussed in section 3.4.2.

The remainder of this section examines the legislative requirements for installations where emissions from drilling and hydraulic fracturing equipment for a shale gas development were to be covered by the IPPC Directive (2008/1/EC). The IPPC permit application should describe the nature and quantities of foreseeable emissions from the installation into each medium as well as identification of significant effects of the emissions on the environment. It should also describe the proposed technology and other techniques for preventing or, where this not possible, reducing emissions from the installation (Article 6 IPPC). These techniques should meet the general criteria of the IPPC Directive or IED on best available technology. However, there are no Best Available Technology Reference documents (BREF, IPPC or IED) for drilling and hydraulic fracturing equipment. This potential gap arises because of uncertainty over the applicability of the IPPC Directive (2008/1/EC) or IED (2010/75/EC) to hydraulic fracturing installations.

In the case of emissions to air from diesel engines used during the drilling process, the possible technology includes: particle filters, selective catalytic reduction filters, low sulphur fuels, adequate stack height and others. However, Article 10 of IPPC specifies that where an environmental quality standard requires stricter conditions than those achievable by the use of the best available techniques, additional measures shall in particular be required in the permit, without prejudice to other measures which might be taken to comply with environmental quality standards.

Emissions from numerous well developments in a local area or wider region could potentially have a significant effect on air quality. The IPPC directive article 9(4) covers such situations in stating that emission limit values, based on Best Available Techniques, should take account of geographical location and local environmental conditions. In the case of many emission sources in the vicinity of a drilling site, the combination of Article 6 (1)e and Article 10 of the IPPC directive mean that the cumulative impact of these sources on air quality must be taken into account in the permit application.

The Air Quality Directive(2008/50/EC) Article 13 and Annex XI, provides the limit values and alert thresholds for the protection of human health, in general referred to as air quality standards. These standards are to be met for all ambient air in the troposphere, with the exemption of workplaces. Article 10 of the IPPC Directive (2008/1/EC) gives a direct link to the environmental quality directives such as the Air Quality Directive 2008/50/EC. Where an environmental quality standard requires stricter conditions than those achievable by the use of the best available techniques, additional measures shall in particular be required in the permit, without prejudice to other measures which might be taken to comply with environmental quality standards.

With the monitored data the competent authorities are able to judge whether the emissions to air are within the emission limits set in the permit or not. If the air quality limit values are exceeded, extra emission abatement techniques must be used in order to meet the required levels. The permit should also contain measures planned to monitor emissions into the environment. This should be part of the permit application as mentioned in Article 6 of the IPPC Directive (2008/1/EC).

3.6.3 Conclusions

The legislative framework that consists of the IPPC Directive (2008/1/EC) – if applicable – and Air Quality Directives could provide the appropriate structure to manage the impacts from emissions to air during drilling. As discussed in section 3.4.4, it is uncertain whether the IPPC Directive (2008/1/EC) would apply to shale gas projects. Hydraulic fracturing activities would be covered by the directive if hydraulic fracturing fluids were classified as a hazardous waste. They would also be covered if the combustion capacity were over 50MW. However, if the combustion equipment at the hydraulic fracturing site were to be below the 50MW capacity threshold for energy industries, then this would suggest that the air emission impacts are at a threshold below which would be regulated under the IPPC Directive (2008/1/EC). The absence of a BREF under IPPC on diesel-engined drilling processes is a potential gap at EU level, arising from the uncertainty over the applicability of the IPPC Directive (2008/1/EC). Knowledge of emissions abatement techniques by both competent authorities and operators is well established in Europe, but it is not possible to say whether standards are applied in a consistent way. It is beyond the scope of this project to determine whether the Member States' implementation for this aspect adequately addresses all environmental risks.

Compliance with the emissions standards for off road mobile machinery (Directive 97/68/EC, as amended) would influence emissions of potential concern from on-site plant through design limits, but would not by itself control emissions during use of these devices or deliver compliance with standards and guidelines for air quality. This would need to be implemented via national provisions specified by Member States under the Air Quality Framework Directive. The member states have a resultant obligation on this subject. This is not a gap in the EU legislation per se, but it is beyond the scope of this project to determine whether the Member States' implementation for this aspect adequately addresses all environmental risks.

3.7 Noise during drilling (cumulative, project stage 2)

With regard to the impact of 'noise' in particular, the Environmental Impact Assessment Directive (2011/92/EU), the Strategic Environmental Impact Assessment Directive (2001/42/EC), the Noise Directive (2002/49/EC)the Outdoor machinery noise directive (2000/14/EC) and the IPPC Directive (2008/1/EC) are relevant.

In sections 3.4.1 and 3.4.2 the requirements for an EIA for hydraulic fracturing were discussed. It was concluded that shale gas extraction activities fall within the scope of Annex II of the Environmental Impact Assessment Directive (2011/92/EU). With regard to these activities it is up to the Member States to decide whether an EIA is appropriate (Article 4(2) of the Environmental Impact Assessment Directive (2011/92/EU)). Therefore, as already mentioned, the Environmental Impact Assessment Directive (2011/92/EC) *in itself* does not prescribe that an EIA, addressing impacts associated with noise during drilling, is mandatory. It is beyond the scope of this study to determine the adequacy of implementation of the Environmental Impact Assessment Directive (2011/92/EC) at Member State level.

Under the Environmental Impact Assessment Directive (2011/92/EU) the Member State has to ensure that the developer provides the authority responsible for approving the project with the information listed in Annex IV insofar as the Member State deems it to be relevant for the case concerned (Article 5(1)). This information should consist of a description of the expected environmental impacts, including noise impacts (point 1c of Annex IV of the Environmental Impact Assessment Directive (2011/92/EU)), resulting from the operation of the proposed project. For the projects concerning hydrocarbons operations involving hydraulic fracturing, this means that noise during drilling will have to be dealt with in an EIA and taken into account before the competent authority grants development consent.

If the IPPC Directive is applicable, noise is a part of the permit under the IPPC, similar to air pollution discussed in section 3.6. The discussion and conclusion for noise would be similar and is therefore not further elaborated.

3.7.1 The 2002/49/EC Noise Directive

The Noise Directive 2002/49/EC sets a general framework with regard to environmental noise to which humans are exposed, particularly in built-up areas, public parks or other quiet areas. It does not set noise limits for specific kind of activities. Under the Noise Directive, Member States are required to develop strategic noise maps for noise sensitive locations and implement measures to tackle problem areas where maximum noise levels are violated.

Strategic noise mapping is obligatory for all agglomerations with more than 250,000 inhabitants and for all major roads which have more than six million vehicle movements, and major railways with more than 60,000 train movements per year and major airports within their territory. Action plans must include measures to manage noise levels, however the measures within the plans are at the discretion of the competent authorities and do not automatically prohibit noise creating activities.

3.7.2 The Outdoor Machinery Noise Directive 2000/14/EC

The Outdoor Machinery Noise Directive(2000/14/EC) and its amendments have been reviewed for applicability. This directive covers much of the equipment that is likely to be used on the hydraulic fracturing site. For that equipment maximum produced noise levels are defined in the directive. These levels must be met when the equipment is put on the market or taken into use.

Drilling equipment used in HVHF processes however is not included in the equipment cited in this directive. Compressors used for drilling have a power capacity over 350 kW, which is the limit for this directive (Article 12).

3.7.3 Conclusions

In cases where shale gas extraction activities are subject to an EIA obligation, a Member State is obliged to indicate in its EIA what the estimated noise impacts are and how these are dealt with (point 1c of Annex IV of the Environmental Impact Assessment Directive (2011/92/EU)). However, the Environmental Impact Assessment Directive (2011/92/EU) leaves at the discretion of competent authorities *the way in which* noise impacts are analysed, assessed and weighted. Whilst this is not a gap in the EU legislation per se, further examination, beyond the scope of this project, is needed to determine whether the Member States' implementation for this aspect adequately addresses the noise related risks.

The Noise Directive does not provide noise limits for specific kind of activities, such as drilling activities for shale gas production purposes and does not mandate specific actions to reduce noise or prohibit noise creating activities. We do not consider this to be an inadequacy, because the Outdoor Machinery Noise Directive(2000/14/EC) does specify such limits. However we have identified that drilling and compressors with a capacity over 350 kW would not be covered by this Directive, which is an inadequacy of legislation at EU level.

3.8 Water resource depletion during fracturing (project stage 3)

3.8.1 Impact and applicable legislation

The Water Framework Directive (2000/60/EC) is applicable to the water resource depletion. This directive sets a framework on all water related impacts. The Framework should promote sustainable water use based on a long-term protection of available water resources as stated in Article 1 of the directive.

3.8.2 Applicability of the legislation

The degradation of resources due to emissions of pollutants is dealt with in sections 3.11, 3.12 and 3.13. The current section examines the measures to control the abstraction of water and to manage the effects of abstraction.

Article 11 of the Water Framework Directive (2000/60/EC) requires Member States to establish a programme of measures that ensures the achieving of the objectives of the Water Framework Directive (2000/60/EC). The basic measures that must be in the programmes of measures are stated in that article.

According to Article 11(3)(e) the programme of measures should inter alia contain controls over the abstraction of fresh surface water and groundwater, and impoundment of fresh surface water, including a register or registers of water abstractions and a requirement of prior authorisation for abstraction and impoundment. In other words, the abstraction of water from surface waters or groundwater sources should need prior authorisation. The only potential exemption is that Member States can exclude abstractions that have no significant impact on water status.

This authorisation would be required to ensure that the objectives of Article 4 of 2000/60/EC are met and take account of the assessment in Article 5 of the directive

- Article 4 sets out objectives to protect, enhance and restore surface waters, groundwater and projected areas.
- Article 5 specifies that analysis be undertaken for the river basin that takes into account its characteristics, the impact of human activity on the status of water bodies and the economics of water use.

The competent authority must take into account the impacts that arise from the intake and use of water. If the impacts do not interfere with the achieving of the objectives for the river basin area involved, the authorisation can be granted. If they do interfere, mitigating measures must be taken, and if these measures are not sufficient, the intake must be prohibited. This is not a gap in the EU legislation per se, but it is beyond the scope of this project to determine whether the Member States' implementation for this aspect adequately addresses all environmental risks.

The programmes of measures are due to be in operation at the latest 12 years after the directive's entry into force. The directive came into force on 22.12.2000 which means there is a gap in legislation for Member States that have not yet made the measures operational, although this should not exist beyond 22.12.2012.

Environmental damage under the Environmental Liability Directive (2004/35/EC) would be covered insofar as it relates to activities regulated under the Water Framework Directive (2000/60/EC).

3.8.3 Conclusions

The Water Framework Directive (2000/60/EC) gives the instruments to address the risk of water resource depletion. There is a requirement for authorisation of water intake and adequate measures for reducing the water intake need or for mitigation. This means that environmental damage should be limited. Further examination, beyond the scope of this project, is necessary to determine whether the Member States' implementation for this aspect adequately addresses water resource depletion risks.

There is a gap due to the timeframe of a full implementation of the Water Framework Directive (2000/60/EC). This should not exist after 22.12.2012.

3.9 Release to air during fracturing (project stage 3)

3.9.1 Impact and applicable legislation

The release to air of polluting substances during fracturing is described in 2.6.4.

The IPPC Directive (2008/1/EC) is relevant with regard to the emissions to air at the fracturing site. The Air Quality Directive 2008/50/EC concerns the limit values of air polluting substances in ambient air. The applicability of IPPC is discussed in section 3.4.4 and in relation to gaseous emissions in section3.6.

Information on emissions to air and its impacts on the environment would be considered as part of the development consent granted in accordance with the Environmental Impact Assessment Directive (2011/92/EU).

3.9.2 Applicability of the legislation

In instances where a hydraulic fracturing development is covered by IPPC or IED, the permit application should describe the nature and quantities of foreseeable emissions from the installation into each medium as well as identification of significant effects of the emissions on the environment. It should also describe the proposed technology and other techniques for preventing or, where this not possible, reducing emissions from the installation (Article 6 IPPC). These techniques should meet the general criteria of the IPPC on best available technology.

In the case of emissions to air from diesel engines used during the process, the possible technology includes: particle filters, selective catalytic reduction filters, low sulphur fuels, adequate stack height and others. The emission due to leakage from pumps, valves etc is not different than in other industrial settings. General abatement techniques and good maintenance procedures prevent or minimise these emissions. The permit for the site should contain provisions for this.

Emissions from numerous well developments in a local area or wider region could potentially have a significant effect on air quality. The IPPC directive (2008/1/EC) article 9(4) or IED (2010/75/EC) article covers such situations in stating that emission limit values should take account of geographical location and local environmental conditions. Where an environmental quality standard requires stricter conditions than those achievable by the use of the best available techniques, additional measures shall in particular be required in the permit, without prejudice to other measures which might be taken to comply with environmental quality standards.

The Air Quality Directive, (2008/50/EC), article 13 and Annex XI, provides the limit values and alert thresholds for the protection of human health, in general referred to as air quality standards. The member states have a resultant obligation on this subject.

In the case of many emission sources in the vicinity of a HVHF process site, the cumulative impact of these sources to the air quality must be taken into account in the permit application. If the air quality standards are exceeded, extra emission abatement techniques must be used in order to meet the air quality standards.

The IPPC permit should also contain measures planned to monitor emissions into the environment, Article 6 2008/1/EC. With the monitored data, the competent authorities are able to judge whether the emissions to air are within the emission limits set in the permit or not. In the case of exceeding the limit values, extra abatement techniques are required.

The Environmental Impact Assessment Directive (2011/92/EU) requires an assessment of projects likely to have significant effects on the environment and includes the effects of air emissions (point 1c of Annex IV of the Environmental Impact Assessment Directive (2011/92/EU)). The requirement for an EIA to be carried out is discussed in section 3.4.2. Aspects covered by the Environmental Impact Assessment affect the development consent of the project and through this route the competent authority has the powers to impose measures to protect and preserve the environment potentially impacted by the development. Should releases to air have a significant effect on the environment, these would be covered by an EIA.

3.9.3 Conclusions

The legislative framework that consists of the IPPC Directive (2008/1/EC) (or IED 2010/75/EC) – if applicable – and Air Quality Directive (2008/50/EC) could provide the appropriate structure to manage the impacts from emissions to air during drilling. As discussed in section 3.4.4, it is uncertain whether IPPC or IED would apply to shale gas projects. Hydraulic fracturing activities would be covered by IPPC if hydraulic fracturing fluids were classified as a hazardous waste. They would also be covered if the combustion capacity were over 50MW. However, if the combustion equipment at the hydraulic fracturing site were to be below the 50MW capacity threshold for energy industries, then this would suggest that the air emission impacts are at a threshold below which would be regulated under IPPC. This is not necessarily an inadequacy of EU legislation, but because of the uncertainty over HVHF technology characteristics it is not possible to confirm that related environmental risks would be adequately addressed.

Significant air impacts would be covered by any assessment carried out under the Environmental Impact Assessment Directive (2011/92/EU) and taken into account when the local authority grants development consent. The inadequacies concerning the EIA directive and the role of Member State decision-making are discussed in section 3.4.2.

3.10 Traffic during fracturing (cumulative, project stage 3)

Traffic impacts during the fracturing phase of the project are described in section 2.5.9. Traffic impacts during fracturing involve air pollution due to emissions from exhaust fumes (localised air quality impacts), noise impacts and land take, but also impacts on community severance and accident risks. The severity of traffic impacts will depend on whether liquids (hydraulic fracturing fluid and wastewater) are transported by truck or by pipelines instead.

When looking at relevant legislation applicable to traffic impacts the Environmental Impact Assessment Directive (2011/92/EU), the Strategic Environmental Impact Assessment Directive (2001/42/EC), the Noise Directive (2002/49/EC) and the Air Quality Directive (2008/50/EC) are relevant.

Regulation (EC) No 595/2009 on type-approval of motor vehicles and engines with respect to emissions from heavy duty vehicles places obligations on manufacturers of such vehicles to obtain type approval (Article 4) to ensure compliance with emission limit values set out in Annex I. This will have an indirect effect on emissions associated with traffic during fracturing, but is not intended to directly regulate emissions during use.

3.10.1 The Environmental Impact Assessment Directive (2011/92/EU) and the Strategic Environmental Impact Assessment Directive (2001/42/EC)

Noise impacts and land-take impacts, including those related to traffic, are discussed elsewhere in the report. The way in which these impacts are covered in the fracturing stage of gas shale extraction activities is the same. According to the Environmental Impact Assessment Directive (2011/92/EU estimated noise impacts and land-take impacts over the whole of the project have to be addressed, including measures how to prevent and mitigate these impacts (Article 3 and 5 of the Environmental Impact Assessment Directive (2011/92/EU)). However, as already mentioned in sections 3.4.1 and 3.4.2, Member States decide whether or not an EIA is appropriate (Article 4(2) of the Environmental Impact Assessment Directive (2011/92/EU)). Guidance on making this decision is given in the Directive but approaches between Member States may differ. Also, if an EIA obligation is applied, the way in which noise and land-take impacts are weighed when deciding whether or not to grant a permit is the competence of national authorities. Therefore, as already mentioned, the Environmental Impact Assessment Directive (2011/92/EC) *in itself* does not prescribe that an EIA, addressing (cumulative) impacts related to traffic during fracturing, is mandatory. Further examination, beyond the scope of this study, is needed to determine the adequacy of implementation of the Environmental Impact Assessment Directive (2011/92/EC) at Member State level.

3.10.2 The 2002/49/EC Noise Directive

As already mentioned in section 3.7.2,the Noise Directive (2002/49/EC) itself does not set noise limits for specific kind of activities. Under the Noise Directive (2002/49/EC) Member States are required to develop strategic noise maps for noise sensitive locations and implement measures to tackle problem areas where maximum noise levels are violated. Furthermore action plans under the Noise Directive (2002/49/EC)must include measures to manage noise levels, however the measures within the plans are at the discretion of the competent authorities and do not automatically prohibit noise creating activities. Whilst this is not a gap in the EU legislation per se, further examination beyond the scope of this project is needed to determine whether the Member States' implementation for this aspect adequately addresses all environmental risks.

Noise emissions of four-wheel motor vehicles are addressed by Council Directive 70/157/EEC of 6 February 1970 on the approximation of the laws of the Member States relating to the permissible sound level and the exhaust system of motor vehicles , as modified by Directives 73/350/EEC, 77/212/EEC, 81/334/EEC, 84/372/EEC, 84/424/EEC, 87/354/EEC, 89/491/EEC, 92/97/EEC, 96/20/EC, 99/101/EC, 2006/96/EC, 2007/34/EC. The proposed[4] Regulation on the sound level of motor vehicles would repeal these Directives. The proposal aims at updating the requirements for the type-approval system as regards the sound level of motor vehicles and of their exhaust systems. In particular, if adopted it would introduce a new test method for noise emissions measurement, lower noise limit values and introduce additional sound emission provisions in the EU type-approval procedure. The proposed Regulation would have effect on new vehicles put on the market or taken into use. Eventually it would reduce the noise levels in the vicinity of roads. It would have no direct relation with HVHF processes and related traffic.

With regard to noise impacts associated with shale gas extraction activities, these are dealt with in the EIA, if these projects are subject to an EIA obligation. In those cases noise impacts are expected to be fully/sufficiently covered. This is due to the fact that a Member State is obliged to indicate in its EIA what the estimated noise impacts are and how these are dealt with (point 1c of Annex IV of the Environmental Impact Assessment Directive (2011/92/EU)). However, the Environmental Impact Assessment Directive (2011/92/EU) leaves at the discretion of competent authorities *the way in which* noise impacts are analysed, assessed and weighted. Therefore, as already mentioned, the Environmental Impact Assessment Directive (2011/92/EC) *in itself* does not prescribe that an EIA, addressing (cumulative) impacts related to traffic during fracturing, is mandatory. Further examination, beyond the scope of this study, is needed to determine the adequacy of implementation of the Environmental Impact Assessment Directive (2011/92/EC) at Member State level.

3.10.3 The Air Quality Directive (2008/50/EC)

Article 13 and Annex XI of the Air Quality Directive (2008/50/EC) provide the limit values and alert thresholds for the protection of human health, in general referred to as air quality standards which Member States have to respect. The Directive includes standards for sulphur dioxide, nitrogen dioxide, benzene, carbon monoxide, lead and PM_{10}. .The Member States have a resultant obligation on this subject. With regard to air quality impacts associated with shale gas extraction activities, including associated (cumulative) traffic impacts, are dealt with in the EIA covering the whole project, if these projects are subject to an EIA obligation. In those cases impacts are expected to be fully/sufficiently covered. This is due to the fact that a Member State is obliged to indicate in its EIA what the estimated air quality impacts are and how these are dealt with (point 1c of Annex IV of the Environmental Impact Assessment Directive (2011/92/EU)). However, the Environmental Impact

[4] COM(2011) 0856

Assessment Directive (2011/92/EU) leaves at the discretion of competent authorities *the way in which* the impacts are analysed, assessed and weighted.

Under Article 19 of Air Quality Directive (2008/50/EC), Member States are required to act in the event of thresholds (in Annex XII) being exceeded. However, these actions need only extend to communication with the public and the European Commission. The requirements for remedial actions are described in Chapter IV of the directive, which relates to the production of air quality plans, including short term plans. That chapter is not specific about what measures should be taken and there is no requirement for the prohibition of specific polluting activities in the event that limits are exceeded. Furthermore, it is the Member States that decide on the sources to be regulated and the actions to be taken to prevent limits being exceeded, which arguably could introduce the possibility of inconsistent approaches to the regulation of hydraulic fracturing emissions. Further examination, beyond the scope of this study, is needed to determine the adequacy of implementation of the Air Quality Directive (2008/50/EC) at Member State level. The Air Quality Directive (2008/50/EC) *in itself* does not prescribe how to deal with (cumulative) impacts related to traffic during fracturing.

3.10.4 Conclusion

There is no EU legislation that deals specifically with the impact of traffic during fracturing and this could represent an inadequacy where potential significant risks arise from cumulative project developments.

3.11 Groundwater contamination during fracturing and completion (project stages 3 and 4)

3.11.1 Impact and applicable legislation

Groundwater contamination during hydraulic fracturing and well completion can be caused through several routes as explained in sections 2.6.1 and 2.7.1. The relevant legislation on the impacts for groundwater contamination is: 2006/118/EC Groundwater Directive; 2000/60/EC Water Framework Directive, and; the REACH regulation, 1907/2006.

3.11.2 Applicability of the legislation

Water Framework Directive (2000/60/EC) and Groundwater Directive (2006/118/EC)

The Water Framework Directive (2000/60/EC) contains general provisions for the protection and conservation of groundwater and the Groundwater Directive (2006/118/EC) establishes specific measures to prevent and control groundwater pollution

The Groundwater Directive (2006/118/EC) in particular puts forward criteria for the assessment of groundwater quality (including monitoring schemes (Article 4)). Article 6 also contains provisions preventing or limiting inputs of pollutants into groundwater. The monitoring of the groundwater quality by competent authorities has the purpose of identifying the change in groundwater quality in an early stage and enabling action to be taken accordingly. The directive places obligations on Member States in relation to monitoring and measures to protect groundwater; it does not regulate directly potentially polluting installations. It is therefore only indirectly applicable to the impacts of hydraulic fracturing installations, although Article 6(3) excludes measures related to, inter alia, the consequences of accidents or exceptional circumstances of natural cause that could not reasonably have been foreseen, avoided or mitigated. Noting the exceptions, under Article 6 of the Groundwater directive, Member States must ensure that the programme of measures includes all measures necessary to prevent or limit inputs into groundwater of pollutants, and thus could in principle involve the prevention of hydraulic fracturing operations, should the latter involve the injection underground of pollutants. Overall, we do not consider there to be inadequacies in relation to the Groundwater Directive.

The Water Framework Directive (2000/60/EC) Annex V, 2.4 gives the directions on the monitoring of groundwater. Annex V, 2.4.3 of the Water Framework Directive gives the requirements for operational monitoring to be carried out by Member States, at least once a year *for all those groundwater bodies […] which on the basis of both the impact assessment carried out [by Member States] in accordance with Annex II and surveillance monitoring are identified as being at risk of failing to meet the objectives under Article 4*. This "identification process" is drawing on the initial characterisation performed by Member States at the latest 13 years after the date of entry into force of this Directive and every six years thereafter. Therefore, no operational monitoring is required for groundwater bodies that, in a time frame of six years, were not identified as being at risk of failing to meet the objectives under Article 4 of the Water Framework Directive (2000/60/EC). As monitoring of aquifers in the surrounding of HVHF process activities should always be required, which this indicates a possible gap in legislation.

Well bore leakage

The well bore is constructed by using steel piping combined with a cement casing. The risk of leakage is one of the aspects that could cause environmental impacts and therefore should be addressed in the EIA, the permit application under the IPPC Directive (2008/1/EC) if required, and the waste management plan required under the Mining Waste Directive (2006/21/EC) as applicable.

The coverage of well integrity issues under Directive 1992/91/EEC, concerning minimum requirements for improving the safety and health protection of workers in the mineral-extracting industries through drilling, is limited to well control (i.e. blowout prevention) rather than well integrity for the whole life cycle of the well (e.g. design, construction, operation, maintenance and abandonment). This directive's scope is also health and safety of workers, and not the environment.

The construction of the well is subject to a number of ISO standards for use in the oil and gas industry. Amongst these standards are ISO 10426-1 on well cementing; ISO 10405 Care/use of casing/tubing; ISO 11961 Drill pipe. These and other technical standards give the framework of the technical lay out and construction of the wells and the bore holes. Amongst these standards are testing and control standards. The content and effectiveness of the standards were not assessed in the framework of this study.

Migration of wastewater from the production zone into aquifers

In 2.6.1 and 2.7.1 the risk of migration of wastewater from the production zone to aquifers is considered remote in suitable geological settings and where there is at least a separating impermeable layer of 600 metres between them. In cases where the layer is smaller or where specific geological features may constitute natural or manmade migration pathways, the risk will be higher.

The measures aiming at preventing the risk of the possible migration of wastewater from the production zone to an aquifer are generally part of an EIA. It is nevertheless acknowledged that the EIA Directive (2011/92/EU) does not include explicitly geological aspects. The Environmental Impact Assessment Directive (2011/92/EU) leaves at the discretion of competent authorities the way in which generic and specific geologic risks are analysed, assessed and weighted. Whilst this is not a gap in the EU legislation per se, further examination beyond the scope of this project is needed to determine whether the Member States' implementation for this aspect adequately addresses all environmental risks.

Accidental surface spills

The risk of accidental surface spills has been identified in several stages of the HVHF process. Within the permit for the whole site and the waste management plan, preventive measures can be taken to avoid or diminish the impacts of these spills. The main issue of the impacts at this stage for groundwater, but also for surface waters, is the runoff of pollutants due to spillage or stormwater takings from the working area.

The runoff of pollutants is to be seen as a diffuse emission of contaminated water. Measures can be prescribed in permits to prevent the runoff of pollutants. The construction of tanks, containers or other means of storage of chemicals or other used substances should be properly designed for their use.

The measures aiming at preventing surface spills or avoiding impacts of surface spills are dealt with under the permit for the Mining Waste Directive (2006/21/EC). Further examination, beyond the scope of this project, is needed to determine whether the Member States' implementation for this aspect adequately addresses all environmental risks.

Reuse of wastewater

The reuse of wastewater (flowback and produced water) is one of the possibilities to reduce the amount of water that needs to be taken in from either groundwater or surface water sources (or alternative sources). There are however some constraints on the reuse of wastewater.

Under the Water Framework Directive (2000/60/EC) programmes of measures must be made including a number of basic measures, as listed in Article 11(3) of that directive.

Article 11 (3)(j) prohibits the direct discharge of pollutants into groundwater, subject to specific provisions (exclusions to this general prohibition).

The second one of these provisions is that Member States may authorise re-injection, specifying conditions for *"injection of water containing substances resulting from the operations for exploration and extraction of hydrocarbons or mining activities, and injection of water for technical reasons, into geological formations from which hydrocarbons or other substances have been extracted or into geological formations which for natural reasons are permanently unsuitable for other purposes. Such injections shall not contain substances other than those resulting from the above operations"*

The Commission considers that Article 11(3)(j) of the Water Framework Directive does not allow the injection of flowback water (containing hazardous chemicals) for disposal into geological formations. As such, the exception clause under Article 11(3)(j) first indent does not apply to shale gas activities. The Commission sees this approach as being consistent with the objective of the Water Framework Directive (i.e. ensuring a good status of water resources) and as being supported by the negotiation history of the Directive, since the exception clause in Article 11(3)(j) was devised for conventional hydrocarbon operations.

Article 2.2 of the Water Framework Directive (2006/60/EC) defines groundwater as:

> *"(…) all water which is below the surface of the ground in the saturation zone and in direct contact with the ground or subsoil"*

According to this definition, 'groundwater' encompasses all water, including 'aquifers' and 'bodies of groundwater'.

> Article 2.11: *'Aquifer' means a subsurface layer or layers of rock or other geological strata of sufficient porosity and permeability to allow either a significant flow of groundwater or the abstraction of significant quantities of groundwater.*
>
> Article 2.12: *'Body of groundwater' means a distinct volume of groundwater within an aquifer or aquifers.*

Article 11(3)(j) prohibits the discharge of pollutants into groundwater. Pollutants are defined in the Water Framework Directive (2006/60/EC), Annex VIII and Annex X as "any substance liable to cause pollution". According to the above, the chemicals that are used in hydraulic fracturing must therefore not be pollutants, otherwise their use is prohibited.

As mentioned above, Article 11 (3)(j) of the Water Framework Directive (2006/60/EC) provides as follows (emphasis added by authors):

> *"(j) a prohibition of direct discharges of pollutants into groundwater subject to the following provisions: (…)*
>
> (Member States) *may also authorise, specifying the conditions for:*
>
> *injection of water containing substances <u>resulting from</u> the operations for exploration and extraction of hydrocarbons or mining activities, and injection of water for technical reasons, into geological formations from which hydrocarbons or other substances have been extracted or into geological formations which for natural reasons are permanently unsuitable for other purposes. <u>Such injections shall not contain substances other than those resulting from the above operations</u>,"*

The fracturing fluid does not qualify as "water containing substances resulting from the operations" as

(i) employed fracturing fluids are designed to maximise the flow of hydrocarbons from the geological formation to the wellhead – they serve a purpose and are not a consequence of the operations, and

(ii) the flowback water contains the initial fracturing fluid that was 'prepared' for the fracturing process itself, plus substances liberated by the fracturing process itself and which were originally present in the geological formation.

In neither case does the flowback water only contain substances resulting from the extraction process itself – that is, only substances that were originally present in the geological formation and which have been removed from the formation by the respective practice. Accordingly, used fracturing fluid is to be considered as extractive waste and flowback water must be treated according to the requirements of Directive 2006/6621/EC. The classification of substances as hazardous does not play a role in this respect. A closed-loop use of flowback water however may avoid the classification as waste.

There are possible impacts in the case that the underground fracturing area is or may be in connection with aquifers. The EIA and permit application should make these possibilities clear and migration of polluting substances in the wastewaters must be prevented. Further examination, beyond the scope of this project, is needed to assess Member State implementation of the Directives

Waste water that has been (pre)treated up to a level that is not hazardous waste according to 2008/98/EC, can be used as a product in other industrial sites or at other hydraulic fracturing jobs provided it does not contain substances identified as pollutants under the Water Framework Directive.

3.11.3 Naturally occurring radioactive material

The wastewaters contain substances from the geological structure where the fracturing took place. These substances can also be radioactive substances. The Council Directive 96/29/EURATOM addresses the approach in Article 17 on operational protection of exposed workers be based in particular on the following principles, inter alia:

- Article 11 (a) prior evaluation to identify the nature and magnitude of the radiological risk to exposed workers and implementation of the optimization of radiation protection in all working conditions;
- Article 11 (d) implementation of control measures and monitoring relating to the different areas and working conditions, including, where necessary, individual monitoring;

In addition, the general provisions in Article 6 require Member States to ensure that the sum of doses for members of the public shall not exceed prescribed limits. This means that the operator has the responsibility to evaluate the possible risks from the wastewaters for the health of the workers and the general public.

The wastewater must be already monitored on its content according to the Mining Waste Directive (2006/21/EC) Article 11 (2). The combination of the above mentioned also means that naturally occurring radioactive materials (NORM) must be taken into account, since it is possible that these substances can occur in wastewater.

Article 5 of Council Directive 96/29/EURATOM gives the obligation for prior authorisation of activities concerning radioactive materials, like wastewaters containing NORM. This gives the competent authorities the means to require measures that prevent impacts due to radiation. The measures are not generally addressed in the Council Directive 96/29/EURATOM, but can be specified in a case by case approach.

3.11.4 Chemicals used and the management of their impacts

Drilling muds and hydraulic fracturing fluids contain a wide variety of chemicals. These chemicals fall under the REACH regulation, (1907/2006/EC). Within the REACH system manufacturers and importers of substances are obliged to register each substance manufactured or imported in quantities of 1 tonne or above per year.

The registration dossier' for a substance is the set of information submitted electronically (in IUCLID 5 format) by a registrant to the European Chemicals Agency. It consists of two main components:

(i) a technical dossier, always required for all substances subject to the registration obligations,

(ii) a chemical safety report, required if the registrant manufactures or imports a substance in quantities of 10 tonnes or more per year. Substances present in low concentrations in preparations (see Article 14(2)), and intermediates under strictly controlled conditions do not need a chemicals safety report.

The registration must contain information on the substances, which must be used to assess the risks arising from their use and to ensure that the risks which they may present are properly managed. This should be done through guidance on safe use for the substance or preparation. Annex VI of the REACH regulation cites the information required for a registration.

Downstream users of chemicals must make sure that the chemicals they use are properly registered for their intended use. They must consider the safety of their use of substances based primarily on information from the suppliers. They must take the risk management measures that are appropriate for their intended use Regulation (EC) on REACH (1907/2006),Article 37(5).This information must be available to the operator of the HVHF process.

Hence, the operator of a hydraulic fracturing installation must be aware of the risks and impacts of the use of chemical substances and act according to the risk management measures. The enforcement of this principle is by Member States. This means that a Member State can and must act if chemical substances are used outside their intended use or without registration.

There are two possibilities for the operator of a shale gas facility to acquire the relevant information to meet this obligation. They have the right to make their uses known to their suppliers or they can choose to keep the use confidential. In the first case the supplier can include the use in the chemical safety assessments. In the second case the user must perform a chemical safety assessment. This is also the case if the user wants to use a chemical outside the exposure scenarios communicated by the supplier.

This obligation does not apply if the operator uses less than 1 tonne of the substance per year. However, an operator always needs to consider the use(s) of the substance and identify, apply and recommend appropriate risk management measures, REACH (1907/2006) Article 37.

Provisions for the disclosure of information are contained in Article 118 of REACH (1907/2006), which states that disclosure of certain information shall normally be deemed to undermine the protection of commercial interests of the concerned person. This information includes details of the full composition of a preparation, its use and the quantities manufactured or placed on the market. Article 119 prescribes arrangements for public access to information, but also allows for certain information to be withheld for reasons of commercial sensitivity (Article 119 (2)).

Directive 98/8/EC on biocidal products also has a strict regime on authorisation. Under Article 3(1) Member States may not permit biocidal products to be placed on the market unless they are low risk products subject to authorisation (Article 3(2)(i)) or have been entered into Annex IB of the directive (Article 3(2)(ii)). This directive is also applicable for fracturing fluids insofar as they may contain biocides. Only biocides that are registered for this intended use via the above routes are allowed in hydraulic fracturing fluids. This directive will be replaced by Regulation 528/2012/EU which lays down rules for:

(a) the establishment at Union level of a list of active substances which may be used in biocidal products;

(b) the authorisation of biocidal products; EN 27.6.2012 Official Journal of the European Union L 167/7

(c) the mutual recognition of authorisations within the Union;

(d) the making available on the market and the use of biocidal products within one or more Member States or the Union;

(e) the placing on the market of treated articles.

The Regulation 528/2012 will be applicable as of 1 September 2013. It retains the authorisation regime of the Directive 98/8/EC on biocidal products. In practice there are no major changes related to HVHF processes.

The Biocidal Directive 98/8/EC prescribes the exchange of information between Member States and the European Commission regarding authorisation and registration of products (Article 18), including those for which authorisation or registration is refused. Under that directive, the information must include, inter alia, specific details of applicants, the biocidal product, quantities to be used and conditions imposed on use. Article 19(1) of 98/8/EC allows for Member States to take necessary steps to ensure the confidentiality of information which is industrially or commercially sensitive. Applicants may indicate information which they consider industrially or commercially sensitive, although it is for the Member State to decide which information must be treated as such. Sensitive information must be exchanged with other Member States and the European Commission as does non-sensitive information under Article 18, but sensitive information bust be treated as confidential by these receiving parties under Article 19.

These provisions allow for the exchange of hydraulic fracturing related biocidal information between Member States and the European Commission but also for this to be treated as commercially sensitive.

The Aarhus Convention (on access to information, public participation in decision-making and access to justice in environmental matters 25 June 1998) sets requirements that have relevance to disclosure of chemicals. The objective of the Convention is to contribute to the protection health and the environment by guaranteeing access to information and decision making in environmental matters and under Article 6 of the convention public participation in decision-making is required for activities falling under Annex I. In particular, Annex 1 (12) confirms the Convention to apply to Extraction of petroleum and natural gas for commercial purposes where the amount extracted exceeds 500 tons/day in the case of petroleum and 500 000 cubic metres/day in the case of gas. This aligns with the Annex I threshold in the Environmental Impact Assessment Directive (2011/92/EU). Also, Annex I (5) lists installations for the treatment of hazardous waste or disposal of non-hazardous waste exceeding 50 tons per day, which could in principle relate to the waste management activities under the Mining Waste Directive (2006/21/EC).

The Aarhus Convention also sets out requirements for access to environmental information, defined as follows:

> *"Environmental information" means any information in written, visual, aural, electronic or any other material form on:*
> *(a) The state of elements of the environment, such as air and atmosphere, water, soil, land, landscape and natural sites, biological diversity and its components, including genetically modified organisms, and the interaction among these elements;*
> *(b) Factors, such as substances, energy, noise and radiation, and activities or measures, including administrative measures, environmental agreements, policies, legislation, plans and programmes, affecting or likely to affect the elements of the environment within the scope of subparagraph (a) above, and cost-benefit and other economic analyses and assumptions used in environmental decision-making;*
> *(c) The state of human health and safety, conditions of human life, cultural sites and built structures, inasmuch as they are or may be affected by the state of the elements of the environment or, through these elements, by the factors, activities or measures referred to in subparagraph (b) above;*

Article 4(4) allows for requests for information to be refused on the grounds of, inter alia, confidentiality of commercial and industrial information, although information on emissions which is relevant for the protection of the environment must be disclosed. Article 5, describes how information provided must be collected and disseminated. These requirements align with those contained in the REACH Regulation(1907/2006/EC) and the Biocidal Products Directive (98/8/EC).

3.11.5 Conclusions

The risks from contamination of groundwater could be regulated through the permit under IPPC (if required) and Mining Waste Directive (2006/21/EC). The Water Framework Directive (2000/60/EC) prohibits the direct discharge of pollutants in groundwater, but gives way for reuse of wastewater if the latter does not contain pollutants. Activities under Water Framework Directive (2000/60/EC) that cause environmental damage under the Environmental Liability Directive (2004/35/EC) would then be covered.

Risks would be possible in the case that the underground fracturing area is or can be in connection with aquifers. The EIA and permit application must have made these possibilities clear and migration of polluting substances in the wastewaters must be prevented. However, the Environmental Impact Assessment Directive (2011/92/EU) does not address explicitly geological conditions and leaves at the discretion of competent authorities the way in which such risks and impacts are analysed, assessed and weighted. Whilst this is not a gap in the EU legislation per se (given the horizontal nature of the EIA Directive), further examination beyond the scope of this project is needed to determine whether the Member States' implementation for this aspect adequately addresses all environmental risks.

The use of chemicals is regulated through REACH (1907/2006) and the directive on biocidal products (98/8/EC). We conclude that this legislation adequately gives the controlling mechanism for the use of chemicals and biocides associated with HVHF, due to the authorisation and registration requirements they impose. The legislation does, however, allow for commercially sensitive information to be withheld from the public under certain conditions. The legal interpretation of the Commission (EC, 2011) does not provide additional guidance on this matter.

Council Directive 96/29/EURATOM provides adequate protection for naturally occurring radioactive materials to workers and the public.

3.12 Surface water contamination risks during fracturing and completion (project stages 3 and 4)

3.12.1 Impacts and applicable legislation

Wastewaters are collected and recycled in the hydraulic fracturing process, or sent for disposal. The wastewaters consist not only of the chemicals used in the hydraulic fracturing process but also salts, metals and other substances dissolved or migrated from the well. The wastewater is contaminated and needs special attention.

A number of options are available for management of wastewater:

- Wastewater may be injected into disposal wells if such facilities are available according to the contractor's interpretation
- Wastewater may be treated in on-site facilities or in separate sewage works
- Re-use

3.12.2 Applicability of the legislation

Discharging wastewater to surface water

The handling of impacts on surface water is addressed in the Water Framework Directive, 2000/60/EC (Water Framework Directive (2000/60/EC)). Under this directive (Article 4(1)(a) Member States shall implement the necessary measures to prevent deterioration of the status of all bodies of surface water; and protect, enhance and restore all bodies of surface water, with the aim of achieving good surface water status. For this purpose Member States shall implement the necessary measures to prevent deterioration of the status of all bodies of surface water.

This means that any deterioration of the status of surface waters that can be foreseen by the competent authorities must be prevented. There is no exemption for specific installations therefore the provisions will apply to hydraulic fracturing installations. Article 11 of 2000/60/EC, specifies, inter alia, basic measures to be undertaken by Member States to meet the objectives in Article 4. It contains (Article 11(3)(g)) a requirement for prior regulation, authorisation or registration of point sources liable to cause pollution. The Directive is not prescriptive regarding the regulatory regime implemented by Member States and it may be that that a combined permitting approach incorporating permits required under the IPPC Directive (2008/1/EC) – if applicable – or Mining Waste Directive (2006/21/EC) would be applied. In fact the permit under the Mining Waste Directive (2006/21/EC) can contain measures concerning the discharging of wastewater to surface water, provided the wastewater is generated from the mining process.

The Water Framework Directive (2000/60/EC) ensures that all discharges into surface waters are controlled according to the combined approach set out in Article 10 of that directive. Accordingly, Member States must establish/implement emission controls based on best available techniques, relevant emission limit values, or in the case of diffuse impacts the controls including, as appropriate, best environmental practices. These measures are to be enforced through the prior regulation, authorisation or registration arrangements required under Article 11.

Discharge of wastewater is to be seen as an emission of contaminated water. The water must be treated in order to satisfy the control measures applicable for discharges to surface water as referred to in Article 10 of the Water Framework Directive (2000/60/EC).

Priority substances in the field of water policy under the Environmental Quality Standards Directive (2008/105/EC) are specified in Annex II to that directive. A total of 33 specific substances of families of substances are listed. For comparison, House of Representatives (2011 NPR) Annex A identified all chemical components of hydraulic fracturing products used between 2005 and 2009. In the table below we provide an analysis of which Environmental Quality Standards Directive (2008/105/EC) appear within the House of Representatives (2011) report. There are some important caveats to this assessment:

- Chemical names may be represented differently between the two sources. The approach was to investigate any positive identifications between the two lists. No substances listed in the Environmental Quality Standards Directive (2008/105/EC) were categorically discounted from those listed in House of Representatives (2011).
- Even if substances in House of Representatives (2011) match those in Environmental Quality Standards Directive (2008/105/EC) this does not necessarily mean they would be used or be intended to be used in future HVHF operations in the EU.

For ease of reference positive matches are highlighted in bold.

Table 8: Review of chemicals listed in Environmental Quality Standards Directive

Environmental Quality Standards Directive (2008/105/EC) priority substances	Included in House of Representatives (2011) Annex A?	Environmental Quality Standards Directive (2008/105/EC) priority substances	Included in House of Representatives (2011) Annex A?
Alachlor	Not found	Mercury and its compounds	Not found
Anthracene	Not found	Naphthalene	**Included**
Atrazine	Not found	Nickel and its compounds	**Included**
Benzene	Included	Nonylphenol	As below
Brominated diphenylether	Not found	(4-nonylphenol)	(Nonyl phenol ethoxylate included)
Pentabromodiphenylether	Not found	Octylphenol	As below
Cadmium and its compounds	Not found	(4-(1,1′,3,3′-tetramethylbutyl)-phenol)	Not found
Chloroalkanes, C10-13	**Included**	Pentachlorobenzene	Not found
Chlorfenvinphos	Not found	Pentachlorophenol	Not found
Chlorpyrifos (Chlorpyrifos-ethyl)	Not found	Polyaromatic hydrocarbons	As below
1,2-dichloroethane	Not found	(Benzo(a)pyrene)	Not found
Dichloromethane	Not found	(Benzo(b)fluoranthene)	Not found
Di(2-ethylhexyl)phthalate (DEHP)	Not found	(Benzo(g,h,i)perylene)	Not found
Diuron	Not found	(Benzo(k)fluoranthene)	Not found
Endosulfan	Not found	(Indeno(1,2,3-cd)pyrene)	Not found
Fluoranthene	Not found	Simazine	Not found
Hexachlorobenzene	Not found	Tributyltin compounds	As below
Hexachlorobutadiene	Not found	(Tributyltin-cation)	Not found
Hexachlorocyclohexane	Not found	Trichlorobenzenes	Not found
Isoproturon	Not found	Trichloromethane (chloroform)	Not found
Lead and its compounds	**Included**	Trifluralin	Not found

On the basis of this limited assessment, it is concluded that it is possible that the constituents of hydraulic fracturing fluids would include substances identified as priority substances under the Environmental Quality Standards Directive (2008/105/EC).

Since wastewater could contain harmful substances the Environmental Quality Standards (EQS) as set in Directive 2008/105/EC are to be taken into account in the process of granting the prior regulation, authorisation or registration under the Water Framework Directive (2000/60/EC) Article 11(3)(g). If the EQS are exceeded this might require extra treatment of the wastewater or even result in prohibiting discharge to surface water.

The permit discharging water to surface waters under the Water Framework Directive (2000/60/EC) will also have specific monitoring requirements based on article 11(4) in order to control the emissions of water to surface waters..

Environmental damage under the Environmental Liability Directive (2004/35/EC) would be covered insofar as it relates to activities regulated under the Water Framework Directive (2000/60/EC).

Injection of wastewater into (disposal) wells

Another way of disposing flowback water and other wastewater is to re-inject it in (disposal) wells. This is however prohibited by Article 11(3)(j) of the Water Framework Directive (2000/60/EC). See also Section 3.11.

Flowback water disposal to a waste water treatment plant

The urban waste water directive, 97/271/EEC, Article 11, regulates the discharge of industrial waste water into the collecting systems and urban waste water treatment plants. Under this article and Annex I.C, discharge of waste water is only permitted if the waste water has been pre-treated in order to prevent malfunction of the urban waste water treatment facility, to protect the health of the workers at the plant, to ensure that discharges from treatment plants do not adversely affect the environment and to ensure the sludge of the treatment plant can be disposed of safely in an environmentally acceptable manner.

In the case of flowback water, which is contaminated with chemicals from hydraulic fracturing fluids, as well with salts and other residues that dissolved from the geological formations during the hydraulic fracturing process, pre-treatment would be required before discharging it to a municipal waste water treatment plant. These salts and residues should be examined, and pre-treated, before the water can be presented to the waste water treatment plant.

3.12.3 Chemicals used and the management of their impacts

The use of chemicals is discussed in section 3.12.3. The impacts of potential concern and regulatory mechanisms are similar in relation to groundwater and surface waters.

3.12.4 Conclusions

Discharges of waste water, mainly flowback waters are regulated through the permit under the Water Framework Directive (2000/60/EC) taking in to account the environmental quality standards for the substances in the water and through the obligations under the Mining Waste Directive (2006/21/EC). Activities under Water Framework Directive (2000/60/EC) that cause environmental damage under the Environmental Liability Directive (2004/35/EC) would then be covered. The potential applicability of IPPC to HVHF is discussed in section 3.4.4.

Waste water cannot be sent to waste water treatment plants without pre-treatment.

3.13 Groundwater contamination during production (project stage 5)

Risks to groundwater are principally those posed by failure or inadequate design of well casing, and possibly – in rare circumstances – by the migration of wastewater from the production zone into aquifers, leading to potential aquifer contamination.

These risks and legislation are discussed in Section 3.11.

3.14 Release to air during production (project stage 5)

3.14.1 Impact and applicable legislation

The impacts related to the release to air during production are addressed in sections 2.8.4and3.9.

3.14.2 Applicability of the legislation

There are no additional aspects over and above those mentioned in 3.9.2.

3.14.3 Conclusions

The legislative framework that could consist of the IPPC Directive (2008/1/EC; provided it applies) and the Air Quality Directives (2008/50/EC) could give the appropriate structure to manage the impacts from emissions to air during production. However, Member States themselves set requirements deemed necessary when implementing the Air Quality Directive (2008/50/EC). It is beyond the scope of this study to determine the adequacy of implementation of the Air Quality Directive (2008/50/EC) at Member State level. The Air Quality Directive (2008/50/EC) *in itself* does not prescribe how to deal with (cumulative) impacts related to traffic during fracturing.

3.15 Biodiversity impacts (all project stages)

3.15.1 Impacts and applicable legislation

Impacts on biodiversity may occur during all phases of the HVHF process. They are partly related to other impacts already covered in the previous sections (e.g. potential effects on water resources).

The most important legislation that addresses the impacts on biodiversity are: The Habitats Directive (1992/43/EEC) and the Birds Directive (2009/147/EC). Next to this the Commission's legal interpretation of the environmental acquis (EC, 2011) describes that due to the large number of wells needed to exploit a shale gas play, the appropriate assessment of cumulative impacts, as required by Article 6(3) of the Habitats Directive (1992/43/EEC) and the Environmental Impact Assessment Directive (2011/92/EU) is of importance.

The Habitats Directive (1992/43/EEC) aims to help maintain biodiversity in the Member States. Under the Habitats Directive the "Natura 2000" network has been established. This network consists of special areas of conservation designated by Member States. It also includes special protection areas classified pursuant to the Birds Directive (2009/147/EC).

The areas within the Natura 2000 network get special attention under this directive. If activities or projects are planned in those areas or their impacts might affect these areas, an EIA must be carried out. Any negative impact on these areas must be prevented and, if not possible, must be compensated (Article 6 (4)) and will be taken into account in the granting of a development consent in accordance with the Environmental Impact Assessment Directive (2011/92/EU).

3.15.2 Applicability of the legislation

When a Member State is considering the granting of authorisation of prospecting, exploring or production of hydrocarbons, the possible impacts on designated areas under the Habitats Directive (1992/43/EEC) and Birds Directive (2009/147/EC) must be taken into account.

During the decision process the competent authority has to carry out an assessment of a proposed project against the requirements of the Habitats Directive, with the aim of demonstrating that there would be no harm to the integrity of a Natura 2000 site. The results of this assessment must be taken into account in the decision. This also applies for the following decisions on granting a permit. In those cases where significant impacts on the Habitats are expected, mitigating measures must be taken. This is the case during all phases of the HVHF process.

The EIA Directive (2011/92/EC) Annex IV 3 and national legislation can be used to address impacts at sites which are not protected at an EU level. This approach is appropriate for sites which do not receive protection at an EU level.

3.15.3 Conclusions

Where the EIA Directive applies, the legal framework would cover the potential adverse impacts on biodiversity.

3.16 Lower priority impacts

This assessment has addressed directly the impacts identified as above moderate risk in Chapter 2. The application of legislation discussed for these more severe risks is directly relevant to those of lesser significance described in Chapter 2. This will be the case for issues related to different stages of the gas exploration and production process, and/or in relation to cumulative effects in some cases where the effects of individual installations are considered to be of moderate significance.

It is concluded that the discussion set out above addresses all the issues identified as being of “low” or “medium” significance, in addition to the “high” and “very high” significance issues.

3.17 Conclusions

In this chapter we have examined the applicability of EU legislation with regard to HVHF and determined the extent to which key environmental risks are adequately covered. In doing so we have drawn three types of conclusion:

- Inadequacies in EU legislation that could lead to risks to the environment or human health not being sufficiently addressed.
- Potential inadequacies - uncertainties in the applicability of EU legislation: the potential for risks to be insufficiently addressed by EU legislation, where uncertainty arises because a lack of information regarding the characteristics of HVHF projects.
- Potential inadequacies - uncertainties in the existence of appropriate requirements at national level: for aspects relying on a high degree of Member State decision-making for which it is not possible to conclude under this study whether or not at EU level the risks are adequately addressed.

Each of these types of conclusion are summarised below

3.17.1 Inadequacies in EU legislation

Impact Assessment Directive (2011/92/EU)

The impacts of HVHF processes can be greater than the impacts of conventional gas exploration and production processes per unit of gas extracted. The use of a single volume threshold for all gas extraction activities in Annex I could lead to more severe impacts from HVHF not being assessed in an impact assessment under this Directive. It is beyond the scope of this work to examine alternative thresholds or approaches for HVHF. This inadequacy affects all environmental impacts for which an EIA would involve a more detailed assessment than would otherwise occur. In our report we have identified it to be particularly relevant to the key risk stages of landtake during preparation, noise during drilling, release to air during fracturing, traffic during fracturing and groundwater contamination.

Based on the characteristics of shale gas extraction activities, the latter fall within the scope of Annex II of the Environmental Impact Assessment Directive (2011/92/EU),(2) (e) ["Surface industrial installations for the extraction of coal, petroleum, natural gas and ores, as well as bituminous shale"] and insofar as they constitute "deep drillings" as specified in Annex IId. However, uncertainty may remain in relation to a shallow well by virtue of lack of precision over the definition of "deep drilling", which would not cover shallow drilling activities (not defined)

The EIA Directive (2011/92/EC) has no explicit coverage of geomorphological and hydrogeological aspects, and there is a lack of clarity as to whether there is an obligation to assess impacts related to geological features as part of the impact assessment. This is considered a potential inadequacy in EU legislation.

Water Framework Directive (2000/60/EC)

The monitoring of the quality of groundwater in general is dealt with in the Water Framework Directive (2000/60/EC). Annex V, 2.4 gives the directions on the monitoring of groundwater. Annex V, 2.4.3 of the Water Framework Directive gives the requirements for operational monitoring to be carried out by Member States, at least once a year *for all those groundwater bodies […] which on the basis of both the impact assessment carried out [by Member States] in accordance with Annex II and surveillance monitoring are identified as being at risk of failing to meet the objectives under Article 4*. This "identification process" is drawing on the initial characterisation performed by Member States at the latest 13 years after the date of entry into force of this Directive and every six years thereafter. Therefore, no operational monitoring is required for groundwater bodies that, in a time frame of six years, were not identified as being at risk of failing to meet the objectives under Article 4 of the Water Framework Directive (2000/60/EC). Monitoring of aquifers in the surrounding of HVHF process activities should always be required, which indicates a possible gap in legislation. The monitoring of the groundwater can, and must, be regulated through the permit under the Mining Waste Directive (2006/21/EC).It affects impacts associated with groundwater contamination.

The programmes of measures are due to be in operation at the latest 12 years after the directive's entry into force. The directive came into force on 22.12.2000 which means there is a gap in the legislation for Member States that have not yet made the measures operational, although this should not exist beyond 22.12.2012. This could affect water abstraction and water contamination impacts prior to that date.

Mining Waste Directive (2006/21/EC)

At present there is no Best Available Technology Reference Document (BREF) at EU level for shale gas waste management. This could affect the adequacy of measures to manage impacts related to mining waste. The key mining waste from HVHF is the fracturing fluid and therefore this inadequacy most directly relates to groundwater and surface water contamination.

Directives on Emissions from Non-Road Mobile Machinery (Directive 97/68/EC as amended)

These directives specify limits on emissions of carbon monoxide, oxides of nitrogen, hydrocarbons and particulate matter from engines up to 560 kW and are aligned with the equivalent US emissions standards. Emissions limits applicable to engines rated above

560 kW were recommended in the review of amending Directive 2004/26/EC, either by extending the limits for engines below 560 kW, or by creating an additional class of engines above 560 kW. It's important to note, however, that this legislation applies only to type-approval and new off-road machines; it does not limit their emissions during the use. Therefore the effect on emissions is indirect. Plant used for drilling in advance of HVHF operations is likely to be rated above 560 kW (e.g. see New York DEC 2011 p6-100). Hence, the existing European emissions limits may not apply to larger drilling plant if the scope of the directive is not extended to plant rated above 560 kW. This inadequacy affects air emissions during drilling and fracturing.

IPPC Directive (2008/1/EC) and IED (2010/75/EC)

The IPPC or IED permit application should describe the proposed technology and other techniques for preventing or, where this not possible, reducing emissions from the installation (Article 6 IPPC, Article 12 IED)). These techniques should meet the general criteria of the IPPC on best available technology. However, there are no Best Available Technology Reference documents (BREF, IPPC or IED) for drilling equipment. This potential gap arises because of uncertainty over the applicability of the IPPC Directive (2008/1/EC) or IED 2010/75/EC) to hydraulic fracturing related installations, it is not a gap in the IPPC or IED legislation per se. A similar shortfall would be expected under the Industrial Emissions Directive (2010/75/EC) regime. It in practice affects air emissions during drilling and fracturing. It also affects discharges to water bodies since the Water Framework Directive (2000/60/EC) requires that emission prevention measures under IPPC are taken into account.

Noise Directive (2002/49/EC) and the Outdoor Machinery Noise Directive(2000/14/EC)

The Noise Directive does not provide noise limits for specific kind of activities, such as drilling activities for shale gas production purposes and does not mandate specific actions to reduce noise or prohibit noise creating activities. 2000/14/EC Outdoor Machinery Noise Directive(2000/14/EC) does specify noise limits, however we have identified that drilling and compressors with a capacity over 350 kW would not be covered by (2000/14/EC), which is an inadequacy of legislation at EU level.

Environmental Liability Directive (2004/35/EC)

In conclusion, all environmental damage from activities covered by directives referred to in Annex III of the Environmental Liability Directive (2004/35/EC) would be covered by 2004/35/EC. However, activities not covered by the Annex III directives would not be included in this way. In order for other impacts to fall within the scope of the Directive they have to involve damages to protected species and natural habitats with significant adverse effects for which the operator has been at fault or negligent. Also, damage caused by pollution of a diffuse character where it is not possible to establish a causal link between the damage and the activities of individual operators would be excluded. Impacts potentially not covered would therefore relate to land-take, release to air during drilling and fracturing (if not covered by IPPC Directive (2008/1/EC)) and traffic impacts.

3.17.2 Potential inadequacies – uncertainties in the applicability of EU legislation

There is the potential for risks to be insufficiently addressed by EU legislation, where uncertainty arises because a lack of information regarding the characteristics of HVHF projects. The conclusions regarding potential gaps are as follows:

IPPC Directive (2008/1/EC) and IED (2010/75/EC)

It is uncertain whether or not a permit according to the IPPC Directive (2008/1/EC) or IED (2010/75/EC) is required. This is due to uncertainties in whether fracturing fluids would be classified as hazardous, since chemical composition of the hydraulic fracturing fluids used is commercially sensitive and can differ between production sites, and whether combustion capacity thresholds in the directive would be met (considered unlikely). This is not necessarily an inadequacy of EU legislation, but because of the uncertainty over HVHF technology characteristics it is not possible to confirm that related environmental risks would be adequately addressed. This impacts releases to air during drilling and fracturing and releases to water during fracturing, since it is not clear if monitoring and control measures under that directive would apply.

Mining Waste Directive (2006/21/EC)

It is not clear whether or not a waste facility under this Directive would be classified as a Category A waste facility, for which additional safeguards are mandatory (major accident prevention policy and external emergency plan). This uncertainty is brought about by the fact that it is unclear whether or not the waste coming from the well or remaining in the underground is considered hazardous. As mentioned above the chemical composition of the hydraulic fracturing fluids used could be commercially sensitive and can differ between production sites. It is not possible to confirm that environmental risks in relation to major accidents would be adequately addressed.

Seveso II Directive (96/82/EC)

Whilst the authors judge it unlikely that the Seveso II Directive is applicable to HVHF process sites, it is not possible to say definitively that this is the case. This uncertainty affects the measures that would be required to prevent major accidents involving dangerous substances, limit their consequences and ensure high levels of protection.

3.17.3 Potential inadequacies - uncertainties in the existence of appropriate requirements at national level

The following aspects rely on a high degree of Member State decision-making for which it is not possible to conclude in the scope of this project whether or not at EU level the risks are adequately addressed. In particular, there is potential for differing interpretations of directives or the application of conditions within national authorisation and permitting regimes. It is beyond the scope of this project to examine Member State implementation of EU Directives or other Member State national legislation.

Strategic Environmental Assessment Directive (2001/42/EC)

This Directive is applicable since shale gas extraction activities fall within the scope defined in Article 3(2). This means that a strategic environmental assessment is obligatory for public plans and programmes related to shale gas projects which might have significant environmental impacts.

Environmental Impact Assessment Directive (2011/92/EU)

Member States must decide whether an EIA is required (Article 4(2)) for activities covered by Annex II. Guidance on making this decision is given in the Directive but approaches between Member States could differ regarding the way in which risk and impacts are weighted and whether or not an EIA is required. The Directive also leaves at the discretion of competent authorities *the way in which* land-take impacts are analysed, assessed and weighted. Any shortfalls could affect all significant environmental impacts since measures in relation to these would be part of the consenting process were they to be covered by this directive.

Hydrocarbons Authorization Directive (94/22/EC)

This Directive, which focused on ensuring non-discriminatory access to licences for the prospection, exploration and production of hydrocarbons, allows Member States to provide in authorization conditions imposed on concession holders if this is justified from, e.g., the perspective of environmental protection and protection of biological resources (amongst others Article 6(2)). This provision makes it possible for Member States to draft authorization conditions aimed at preventing or mitigating environmental impacts it deems necessary.

However, this is not a requirement and Member States themselves determine if and how to implement this in practice.

Mining Waste Directive (2006/21/EC)

The Directive requires Member States to ensure the operator takes all measures necessary to prevent as far as possible any adverse effects on the environment or human health, including following abandonment of the well (Article (4(2)), implemented through the permit and waste management plan (Article 7). Any shortfalls would affect the management of mining waste and in particular hydraulic fracturing fluids.

IPPC Directive (2008/1/EC) and IED (2010/75/EC)

If applicable, under this directive it is up to the competent authorities to decide on the frequency of monitoring and inspections. In the case the permit under IPPC or IED is not required, the complete monitoring and inspection is the jurisdiction of the competent authority as far as the permit required under the Mining Waste Directive (2006/21/EC) does not provide the necessary monitoring. Any shortfalls could affect the prevention and minimisation of emissions to air, especially during drilling and fracturing, and releases to water during fracturing.

Air Quality Directive (2008/50/EC) and Emissions Standards for Off Road Machinery Directive 97/68/EC

Compliance with the emissions standards for off road machinery Directive 97/68/EC as amended would influence emissions of potential concern from on-site plant through design limits, but would not of itself control emissions during use or deliver compliance with standards and guidelines for air quality This would need to be implemented via national provisions specified by Member States under the Air Quality Directive. This could affect regulation of emissions to air during drilling and hydraulic fracturing.

Under Article 19 of Air Quality Directive (2008/50/EC), Member States are required to act in the event of thresholds (in Annex XII) being exceeded. Furthermore, it is the Member States that decide on the sources to be regulated and the actions to be taken to prevent limits being exceeded, which introduces the possibility of inconsistent approaches to the regulation of hydraulic fracturing emissions. This could affect regulation of emissions to air during drilling and hydraulic fracturing and traffic emission during fracturing. Note however, that the Air Quality Directive (2008/50/EC) is concerned with ambient air quality rather than installation air emissions.

Water Framework Directive (2000/60/EC)

The competent authority must take into account the impacts that arise from the intake and use of water. If the impacts do not interfere with the achieving of the objectives for the river basin area involved, the authorisation can be granted. If they do interfere, mitigating measures must be taken, and if these measures are not sufficient, the intake must be prohibited. Any potential shortfalls here would affect the management of impacts from water usage during hydraulic fracturing.

Noise Directive (2002/49/EC)

Action plans under the Noise Directive (2002/49/EC) must include measures to manage noise levels, however the measures within the plans are at the discretion of the competent authorities and do not automatically prohibit noise creating activities. This would particularly affect management of noise during drilling, fracturing and traffic during fracturing.

3.17.4 Risk assessment

In this section we describe the main risks arising from the gaps identified in the legislation review. The purpose is to summarise the gaps and uncertainties in the legislation, highlight the potential consequences of these and indicate their significance. The findings from all three categories of conclusion in the preceding subsections are included. The limitations of this analysis are set out in Section 3.1.

Table 9: Summary of risks arising from gaps or potential gaps in European legislation

Gap or potential gap	Impact	Risk associated with gap/potential gap
	Gaps in legislation	
Environmental Impact Assessment Directive (2011/92/EU) Annex I threshold for gas production is above HVHF project production levels. Result: no compulsory EIA.	All, especially relevant to key impacts from landtake during preparation, noise during drilling, release to air during fracturing, traffic during fracturing and groundwater contamination	A decision on the exploration and production may not be based on an impact assessment. Public participation may not be guaranteed, permits may not be tailor-made to the situation Impacts may not be known and assessed. Measures to mitigate possible impacts may not be applied through consent process or permitting regime.
Environmental Impact Assessment Directive (2011/92/EU) Annex II no definition of deep drilling; exploration phase would not be covered under Annex II classification "Surface industrial installations for the extraction of coal, petroleum, natural gas and ores, as well as bituminous shale". Result: no compulsory EIA	All, especially relevant to key impacts from landtake during preparation, noise during drilling, release to air during fracturing, traffic during fracturing and groundwater contamination	A decision on the exploration and production may not be based on an impact assessment. Public participation may not be guaranteed, permits may not be tailor-made to the situation HVHF project involving shallow drillings not covered by EIA. For these projects, impacts may not be known and assessed. Measures to mitigate possible impacts may not be applied through consent process or permitting regime. Preventative measures may not be undertaken. Aquifers in surroundings not known, leading to unanticipated pollution.
Environmental Impact Assessment Directive (2011/92/EU) No explicit coverage of geomorphological and hydrogeological aspects, no obligation to assess geological features as part of the impact assessment	Especially relevant for groundwater contamination, seismicity, land impacts, release to air	No assessment of geological and hydrogeological conditions (e.g. natural and manmade faults, fissures, hydraulic connectivity, distance to aquifers, etc) in the frame of the impact assessment or screening, resulting in sub-optimal site selection and risks of subsequent pollution Monitoring of groundwater quality of aquifers in surrounding of the site may not be done and preventative measures not undertaken. Aquifers in surroundings not known, leading to unanticipated pollution.
Water Framework Directive (2000/60/EC) WFD programmes of measures are not required to be enforced until 22.12.2012	Abstraction of water and impacts due to water contamination	Inadequate monitoring and measures to prevent these impacts
Water Framework Directive (2000/60/EC) For substances which are not pollutants, the WFD does not prevent direct fracturing into groundwater that may ultimately impact aquifers	Pollution of groundwater	"Pollutants" are defined as "any substance liable to cause pollution, in particular those listed in Annex VIII." Permit conditions may not require monitoring or measures to prevent hydraulic fracturing leading to impacts on aquifers
Mining Waste Directive (2006/21/EC) No reference document on Best Available Techniques (BREFs)	Waste management as covered by MWD – treatment of hydraulic fracturing fluids during and after fracturing	No shared opinion on Best Available Techniques nor enforcement of those techniques Higher levels of pollution arising from the management of mining waste
Directives on Emissions from Non-Road Mobile Machinery (Directive 97/68/EC as amended)	Air pollution especially during drilling and fracturing	Measures may not be taken to prevent high emissions to air, leading to localised increased air pollution, although purpose of legislation is to regulate machine standards not emissions during use.

Gap or potential gap	Impact	Risk associated with gap/potential gap
Lack of emission limits for off-road combustion plant above 560 kW		
IPPC Directive (2008/1/EC) and IED (2010/75/EC) No BREF for drilling equipment	Air pollution especially during drilling and fracturing	Measures may not be taken to prevent high emissions to air, leading to localised increased air pollution. This potential gap arises because of uncertainty over the hazardous character of fracturing fluids which would determine the applicability of the IPPC Directive (2008/1/EC) to hydraulic fracturing installations
The Outdoor Machinery Noise Directive2000/14/EC Gaps in limits to prevent noise for specific equipment	Noise during drilling	Drilling equipment used in HVHF processes however is not included in the equipment cited in this directive. Compressors used for drilling have a power capacity over 350 kW, which is the limit for this directive
Air Quality Directive (2008/50/EC) Not specific about remedial measures or prohibition of polluting activities	Air pollution during drilling and fracturing and traffic impacts	No measures to reduce emissions to air. Levels of air pollution may be above impact levels or air quality standards.
Environmental Liability Directive (2004/35/EC) Damage caused by non Annex III activities not covered unless it is a damage to protected species and natural habitats resulting from a fault or negligence on part of operator. Impacts caused by diffuse pollution are not covered, unless a causal link can be established	Landtake, air impacts during drilling and fracturing and traffic	Some environmental impacts may not be covered.
Uncertainties in application		
IPPC Directive (2008/1/EC) and IED (2010/75/EC) Activity not mentioned or may not be covered under hazardous waste or combustion capacity	Emissions to air, water and soil	No permit obligation under IPPC and no BREF under IPPC or IED .This potential gap arises because of uncertainty over the hazardous character of fracturing fluids which would determine the applicability of the IPPC Directive (2008/1/EC) to hydraulic fracturing installations The monitoring requirements as mentioned in IPPC directive may not be applied. Integrated measures designed to prevent or to reduce emissions in the air, water and land, including measures concerning waste, in order to achieve a high level of protection of the environment may not be taken. Monitoring of emissions to air might not take place.
Mining Waste Directive (2006/21/EC) Uncertainty over classification of Category A waste facility	Major accidents, groundwater and surface water pollution, air impacts	The classification may be inadequately performed Major accidents might occur without proper prevention and emergency plans.
Seveso II Directive (96/82/EC) Uncertainty over whether the Directive covers high volume hydraulic fracturing (HVHF), subject to storage of natural gas or of specific chemical additives on-site.	Major accidents involving dangerous substances (e.g. water pollution events)	Major accidents might occur without proper prevention and emergency plans.

Gap or potential gap	Impact	Risk associated with gap/potential gap
Issues currently at the discretion of Member States		
The Strategic Environmental Assessment Directive (2001/42/EC) Remains up to Member States to decide whether or not a plan or programme might have significant effects	All	No SEA would be made Information on possible environmental effects would not be available and therefore would not be used in an authorisation/consent process or permits
Environmental Impact Assessment Directive (2011/92/EU) Member States must decide whether an EIA is required (Article 4(2)) for activities covered by Annex II.	All	No EIA would be made. The environmental impacts would not be assessed and properly described. The measures that can prevent or mitigate the impacts will not be presented
Hydrocarbons Authorization Directive (94/22/EC) No compulsory account of environmental aspects	All	Member States may not take account of environmental impacts during the authorisation process
Mining Waste Directive (2006/21/EC) Member States decide on the permit and the control measures	Waste management as covered by MWD – treatment of hydraulic fracturing fluids during and after fracturing	There may be inadequate measures for the monitoring and control of impacts related to management of mining waste
IPPC Directive (2008/1/EC) Member State decisions on monitoring and inspection	Emissions to air, especially during drilling and fracturing, and releases to water during fracturing	There may be inadequate measures for the monitoring and control of impacts related to air and water emissions
Air Quality Directive(2008/50/EC) Member States responsible for making plans to meet the AQ standards	Emissions to air, especially during drilling, fracturing and traffic, and releases to water during fracturing	No specific measures for emission abatement may be required. Air pollution may not be prevented or mitigated
Water Framework Directive (2000/60/EC) Member State determination of control measures related to abstraction	Water use during fracturing	There may be unmitigated or poorly controlled impacts arising from water use during abstraction
Noise Directive (2002/49/EC) Up to Member States to set noise levels and to make plans to meet these levels	Noise during drilling and fracturing and traffic during fracturing	No specific measures for noise abatement may be required. Noise may not be prevented or mitigated

4 Review of risk management measures

This chapter provides a review of the practices, legislation, and standards which can be used to manage hydraulic fracturing risks.

4.1 Methodology

Information was derived from the literature review, supplemented by additional information necessary to identify state-of-the-art technologies for control of environmental risks and impacts associated with high volume hydraulic fracturing, and the expected evolution of these controls. The following resources were consulted:

- Existing technology-based environmental regulations (e.g., the Industrial Emissions Directive (2010/75/EU); the Control of Major Accidents Hazards (COMAH) Directive (96/82/EC, also referred to as the Seveso II Directive); and the US EPA's Oil and Gas New Source Performance Standards published in April 2012);
- The collaborative initiative between industry and regulatory authorities in the US known as STRONGER (State Review of Oil and Natural Gas Environmental Regulations). The STRONGER website summarises US state regulations. Relevant information was also reviewed from US EPA, Delaware River Basin Commission, Susquehanna River Basin Commission, British Columbia, and US States where hydraulic fracturing is under way (Colorado, Delaware, Ohio, Oklahoma, Pennsylvania, Texas, Wyoming).
- Government-drafted "best management practices," for example, those issued by the state of Pennsylvania, proposals from the State of New York, and recommendations from the US Secretary of Energy Advisory Board (SEAB) Natural Gas Subcommittee.
- Industry guidance materials, principally the American Petroleum Institute series of Guidance Documents:
    - "*Hydraulic Fracturing Operations - Well Construction and Integrity Guidelines (HF1)*," October 2009 NPR ;
    - "*Water Management Associated with Hydraulic Fracturing (HF2)*," June 2010 NPR
    - "*Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing (HF3),*" January 2011 NPR
- Academic research
- Recommendations from local interest groups in relation to shale gas activities in their local area (referred to as "community group recommendations"
- Discussions with consultees
- Presentations at industry technical conferences; and
- Vendor literature, particularly case studies.

The focus of this evaluation was to address the potential impacts set out in Chapter 2. Where necessary, the review of best practice technologies and regulatory requirements from hydraulic fracturing used during oil and gas production was expanded to risk management measures and frameworks used for similar/comparable contexts.

The review of control measures from non-European territories focused on regulatory controls, permitting requirements, and financial assurance (bonding) requirements targeted to hydrocarbon extraction using high volume hydraulic fracturing – that is, HVHF used for shale gas extraction, as discussed in Chapter 1.

Where available, information characterising the potential cost and affordability of control measures was provided

This chapter sets out measures available to government and regulatory authorities, such as regulations, permitting and bonding requirements. Risk management measures for shale gas developments which have been recommended for use in Europe, and/or proposed or implemented by non-European governments are discussed.

The chapter also describes best management practices for environmental control used by the shale gas industry, largely based on US experience. These are defined by the US Environmental Protection Agency as: "*A practice used to reduce impacts from a particular land use,*" and this section provides a description of measures which are currently required by regulatory authorities, or recommended by regulators, industry, academics or other bodies. No single body, EPA or otherwise, has made an ultimate decision about what constitutes best practice, but there is a consensus between US industry and regulators that best management practices can be used to reduce impacts or risks of environmental pollution, based on experience in the US.

The wider oil and gas industry does not always have a positive reputation in terms of environmental responsibility. Incidents such as the Deepwater Horizon incident or environmental pollution in the Niger delta have had an adverse effect on the industry's reputation. However, HSE awareness is deeply integrated in the oil and gas industry and the large oil and gas companies are particularly concerned about their reputation in terms of environmental responsibility. The environmental risk and control measures which are in place in the oil and gas industry are relevant to hydraulic fracturing, particularly since the industries active in the exploration and production of unconventional resources in the US are already part of the established oil and gas industry or are an offshoot of the industry. A similar situation appears likely to develop in Europe, with established businesses taking a leading role in the emerging shale gas industry (e.g. see www.europeunconventionalgas.org; Chevron 2012b NPR). The businesses highlighted in Table A6.1 are established operators in the oil and gas industry, or are joint ventures with significant input from established operators.

Industry groups, such as the American Petroleum Institute (API) and government research organizations, such as the National Energy Technology Laboratory (NETL) have developed and compiled guidance for best management practices currently used in the oil and natural gas industry to address potential environmental impacts. This guidance was taken as representing the industry's view of robust operating practices, and was not separately reviewed or evaluated. Industry best management practices (BMPs) do not account for site-specific conditions. In implementing these best practices, operators must consider local, state, and federal regulations as well as the setting and geology of each oil and gas extraction project.

Industry BMPs can address potential impacts that are not feasible (or legal) for government regulators to address.

The remainder of this section presents information on regulatory and industry-led initiatives. Some sources identified similar or identical BMPs.

In the wider oil and gas industry, numerous documents, guidelines and standards address and define environmental control and risk management measures. These focus on the risks which are common to conventional gas extraction, and do not address the risks which are specific to HVHF. E&P Forum/UNEP (1997 NPR) is a document developed by the oil and gas industry jointly with the public sector. This report provides an overview of the environmental issues and the technical and management approaches to achieving high environmental performance in the activities necessary for oil and gas exploration and production. Management systems and practices, technologies and procedures that prevent and minimize impact are described.

The chapter text provides a summary of identified risk management measures. The detailed analysis of measures is provided in Appendix 7. Following discussion of overarching risk management measures, Appendix 7 is organised by the stages in shale gas facility development set out in Chapter 2.

4.2 Summary of risk management measures

Risk management measures and controls are summarised in Table 10, with details provided in Appendix 7. Some of these measures are already established in Europe, and other measures may already form part of controls applied under a permitting regime such as those laid down by the IPPC Directive, the Industrial Emissions Directive, or the Mining Waste Directive, but an analysis of national permitting requirements was out of the scope of this study.

Table 10: Summary of risk management measures and controls

Aspect	Description of measure	Status
Database	Creation of a national database of public sources of information	Expert panel recommendation to US Government
	Develop database of baseline water quality and quantity, and geologic information across a shale gas formation, prior to the commencement of HVHF	Recommended best practice from geological survey consultee
Peer review	Funding to enable peer review of regulatory activity	Expert panel recommendation to US Government
Zoning (general)	Identifying zones which are off-limits to hydraulic fracturing if required for environmental protection	Independent report recommendation to European Parliament; expert panel recommendation to US Government
	Prevent HVHF in reforestation areas, wildlife management areas and high quality aquifers	Proposed regulatory measure by New York State
	Prevent HVHF in areas specified for protection of groundwater	Recommendation from academic sector
Buffer zones	Minimum distance to private water well: 150 m	Recommendation to Pennsylvania state authorities Delaware River Basin Commission proposal
	Minimum distance to public water well or reservoir: 300 m	Recommendation to Pennsylvania state authorities Delaware River Basin Commission proposal
	Minimum distance from well to surface watercourse: 90 m	Recommendation to Pennsylvania state authorities Delaware River Basin

Aspect	Description of measure	Status
		Commission proposal
	Minimum distance from disturbance to surface watercourse: 90 m	Recommendation to Pennsylvania state authorities Delaware River Basin Commission proposal
	Minimum distance to watersheds used for drinking water supply: 1,200 m	Proposed regulatory measure by New York State
	Minimum distance to residential areas: 1,600 m (where possible)	Recommended industry best practice measure
	Distance within which detailed investigation of noise mitigation is needed: 305 m	Proposed regulatory measure by New York State
	Require site-specific separation from abandoned wells and other potential pathways for fluid migration	Regulatory measure adopted by State of Michigan. Proposed regulatory measure by New York State
	Require additional containment to prevent surface water impacts for sites within 800 m of surface water supply locations	Regulatory measure adopted by State of Colorado
Notification	Notification to local communities when drilling is planned	Recommendation to Pennsylvania state authorities. Public involvement in decision-making is an important part of existing permitting processes (e.g. Article 15(1) of the IPPC Directive 2008/1/EC)
	Notification to water suppliers in the event of spills or leaks	Recommended industry best practice measure
Mitigation credit system	Voluntary ecological initiatives within critical habitats that would generate mitigation credits which can be used to offset future development	Recommendation to Pennsylvania state authorities
Environmental management systems	Encourage or require accreditation for shale gas installation operators to secure ongoing environmental improvements	Measure used voluntarily in conventional oil and gas industry
Surface and water quality monitoring	Surveys of water quality and levels to be carried out before, during and after HVHF operations	Recommended best practice by geological surveys and academics Established measure in US shale gas industry
Air quality monitoring	Surveys of air quality to be carried out before and during HVHF operations	Established measure in US shale gas industry
Pit liners	Require pit liners to be installed	Established measure in US shale gas industry Regulatory measure, e.g. State of Louisiana
Secondary containment	Require secondary containment for storage of specified hazardous fluids	US Federal regulatory measure Recommended industry best practice measure

Aspect	Description of measure	Status
Spill control plans	Require spill control plans to be produced and maintained	US Federal regulatory measure
Well spacing	Minimum spacing of well pads of one per 2.6 square km, with all the horizontal wells in the unit drilled from a common well pad	Proposed regulatory measure by New York State
	Specify minimum well spacing	Expert panel recommendation to US Government
Minimise habitat fragmentation	Implement mitigation measures to minimise ecological impacts.	Proposed practice by New York State
Minimise impacts on sensitive habitats	Develop and implement a specific mitigation plan and monitor in sensitive wildlife areas	Proposed practice by New York State
Invasive species plan	Develop and implement an invasive species mitigation plan	Proposed practice by New York State
Noise mitigation	Locate sites away from occupied structures and places of assembly	Proposed practice by New York State
	Implement management measures to minimise noise	Proposed practice by New York State. Established practice in US shale gas industry
	Implement barrier methods to minimise noise	Proposed practice by New York State. Established practice in US shale gas industry
	Carry out noisy operations during the day	Proposed practice by New York State Established practice in US shale gas industry
Seismicity monitoring	Monitoring of seismic activity with intervention in the event of events occurring	Proposed practice by UK government European regulator and geological survey consultee recommended best practice
Visual impact mitigation	Standard measures to minimise visual impacts with regard to site location, lighting and paintwork	Proposed practice by New York State Established practice in conventional gas extraction
Minimise impacts of traffic	Road use agreement/transportation plan covering vehicle routeing and timing	Proposed practice by New York State Recommended industry best practice measure
	Use existing roads where possible	Recommended industry best practice measure
	Locate access roads away from residential areas	Recommended industry best

Aspect	Description of measure	Status
		practice measure
	Centralise gathering facilities to reduce truck traffic	Proposed practice by State of Wyoming
	Minimise impacts of new road construction via design and use of appropriate standards; build in mitigation at design stage	Recommended industry best practice measure
	Limit truck weights	Proposed practice by New York State
	Vehicles to conform with highest emissions standards	Established best practice for US shale gas industry. Vehicle emissions standards are already applied in Europe.
	Unnecessary idling to be prevented	Established best practice for US shale gas industry
	Carry out effective maintenance	Recommended industry best practice measure
	Repair road damage, or make payments to allow damage to be repaired	Proposed practice by New York State
	Use temporary pipeline for water transportation	Recommended industry best practice measure
Site selection	Comprehensive assessment to identify optimum site	Established measure in US shale gas industry
Management	Staff selection, training and supervision in environmental protection	Established measure in US shale gas industry
Land restoration	Maintain land used for gas extraction to a suitable standard to enable restoration so far as possible	Proposed practice by New York State
	Stockpile surface soils for use in restoration	Recommended industry best practice measure
	Loose soil should be covered with geotextiles or other materials	Recommended industry best practice measure
Pace of development	Limiting the pace of development could reduce some acute effects associated with shale gas development	Suggested measure by New York State Suggested measure by State of Wyoming
Site layout	Use cut areas for surface impoundment construction to avoid unnecessary increases in facility footprint	Recommended industry best practice measure Suggested community group measure
Minimise risks from liquid storage and handling	Avoid the use of surface impoundments and reserve pits where possible	Suggested community group measure
	Avoid the use of surface impoundments and reserve pits in flood zones or other sensitive areas	Suggested community group measure
	Silt fences, sediment traps or basins, hay bales, mulch, earth bunds, filter strips or grassed swales can be used to slow runoff and trap sediment from	Established best practice for US shale gas industry

Aspect	Description of measure	Status
	leaving the site.	
	Where possible, activities should be staged to reduce soil exposure and coincide with a season of low rainfall	Recommended industry best practice measure
	Contingency planning and training to address spillage risks	Established best practice for US shale gas industry
	Visual inspection of primary containment before hydraulic fracturing is carried out	Established best practice for US shale gas industry
	Use conductance monitors for rapid detection and assessment of spillages	Geological survey recommended measure
Minimise risks from temporary pipelines	Pipelines should not be located on steep hillsides or within watercourses	Recommended industry best practice measure
Extent of surface casing	Surface casing to extend to at least 30 m below aquifers	Regulatory measure, State of Michigan
	Surface casing to extend to at least 15 m below aquifers	Regulatory measure, States of Colorado, Illinois, Pennsylvania, Oklahoma and Ohio Established industry best practice
	Surface casing to extend below aquifers	Regulatory measure, State of Montana
	Surface casing to extend to at least 30 m below ground level	Established best practice for US shale gas industry
	Surface casings should be cemented before reaching a depth of 75 metres below underground sources of drinking water.	Established best practice for US shale gas industry
Extent of production casing	Production casing should be cemented up to at least 150 metres above the formation where hydraulic fracturing will be carried out	Established best practice for US shale gas industry
Well integrity	Pressure tests of the casing and state-of-the-art cement bond logs should be carried out	Expert panel recommendation to US Government
	Regulation and inspection regime needed to confirm effective repair of defective cementing	Expert panel recommendation to US Government
	Measure compressive strength with benchmarks between 2.1 and 8.3 MPa, based on setting times between 4 and 72 hours	Regulatory measure, States of Colorado, Illinois, Texas, Pennsylvania, Montana, Ohio Established industry best practice
	Include well integrity measures in permit specified under Mining Waste Directive	Independent recommendation to European Parliament
	Complete cementing and isolation of underground sources of drinking water must be carried out prior to further drilling	Established industry best practice
	Casing centralizers should be used to centre the	Established industry best

Aspect	Description of measure	Status
	casing in the hole	practice
	Testing of well integrity should take place at construction, and throughout the lifetime of the well	Established industry best practice
Minimum depth for hydraulic fracturing	Fracturing at depths of less than 600 m requires a specific permit	Regulatory measure, British Columbia
	Fracturing not permitted with a separation of less than 46 m between fracture zone and aquifer	Regulatory measure, State of Michigan
	Fracturing at depths of less than 600 m or with less than 300 m separation between fracture zone and aquifer requires a specific analysis and review	Proposed practice by New York State
	Fracturing with a separation of less than 600 m between horizontal section of well and aquifer should not be permitted	Academic sector recommendation
Multi-stage fracturing	Maintain hydraulic isolation between porous zones	Regulatory measure, British Columbia
Disclosure	Operators should disclose publicly the chemical constituents of hydraulic fracturing fluid, including product name and purpose/type; proposed composition of fracturing fluid by weight; and proposed volume of each additive	Regulatory measure in five US states Proposed measure by US federal authority, EPA and Bureau of Land Management Proposed measure by New York State and State of British Columbia Expert panel recommendation to US Government
	Operators should disclose publicly the results of well integrity tests	Proposed practice by US federal authority
Drilling engines	Emissions from diesel engines to conform with highest applicable standards	Established industry best practice
	Use natural gas powered engines and compressors where feasible	Emerging industry best practice Expert panel recommendation to US Government
	Use electrically driven engines and compressors where feasible	Emerging industry best practice Expert panel recommendation to US Government
	Use selective catalytic reduction to reduce emissions from drilling rig engines	Emerging industry best practice
Waste handling	Use established procedures and regulatory frameworks in Europe to manage waste	European regulator recommendation
Drilling fluids	Drillers should select fluids to minimise the environmental hazard posed by drilling wastes	Proposed practice by New York State
	Separation of drilling fluids and processing to facilitate re-use	Recommended industry best practice
	Use closed-loop systems to reduce drilling time, drilling fluid use and surface disturbance	Suggested community group measure

Aspect	Description of measure	Status
Composition of HVHF fluid	Develop guidance for use of diesel fuel in HVHF fluid	Proposed measure by US EPA
	Prohibit use of diesel fuel in HVHF fluid	Expert panel recommendation to US Government
	Prohibit use of specified volatile organic compounds in groundwater zone	Regulatory measure in State of Wyoming
	Use of specified volatile organic compounds in HVHF fluid requires prior authorisation	Regulatory measure in State of Wyoming
	Select appropriate additives to minimise environmental impacts	Established measure in US shale gas industry
	Minimise biocide use, e.g. via use of UV disinfection techniques in place of chemical biocides	Industry best practice measure under consideration
	Select proppants which minimise the HVHF treatment required	Industry best practice measure under consideration
Water resource management	Develop and use an integrated water management system	Expert panel recommendation to US Government Established practice in State of British Columbia Established practice by Susquehanna River Basin Commission Proposed practice by Delaware River Basin Commission
	Require use of alternative sources of water	Proposed practice by Delaware River Basin Commission Industry best practice measure under consideration
	Avoid sensitive areas for water withdrawals	Recommended industry best practice measure
Control of invasive species	Implement precautions to prevent invasive species from water storage by cleaning vehicles and appropriate disposal of surplus water	Proposed practice by New York State Recommended industry best practice measure
Control of HVHF process	Predictive modelling to optimise fracturing strategies	Established measure in US shale gas industry
	Share data from nearby fracturing operations	Established measure in US shale gas industry
	Ensure equipment compatible with composition of fracturing fluid	Established measure in US shale gas industry
	Use all available techniques to minimise risk of fracturing taking place outside the target reservoir	Established measure in US shale gas industry
	Thorough planning and testing of equipment prior to fracturing operations	Established measure in US shale gas industry
	Development of contingency plan prior to	Established measure in US

Aspect	Description of measure	Status
	fracturing operations	shale gas industry
	Detailed monitoring of process during fracturing operations	Established measure in US shale gas industry
Wastewater management	Develop pre-treatment standards for discharges of shale gas extraction wastewater to municipal wastewater treatment plants	Proposed regulatory measure by US EPA
	Establish treatment requirements/discharge limits for treatment and final discharge of wastewater	Regulatory measure adopted by the State of Pennsylvania. A framework for emission controls and emission limit values for discharges into surface waters in Europe is already set out in Article 10 of the Water Framework Directive (2000/60/EC), although the establishment and/or enforcement of such emission control and limit values is at the discretion of Member States
	Re-use waste water where possible	Recommended industry best practice measure Academic sector recommendation
	Store waste water in storage tanks, or in double lined lagoons constructed with regard to local topography	Recommended industry best practice measure
	Ensure receiving treatment works is capable of handling wastewaters	Established measure in US shale gas industry
	Install on-site wastewater treatment if appropriate	Industry best practice measure under consideration
	Measure the composition of the stored return water	Expert panel recommendation to US Government
	Use closed-loop systems manage and reprocess waste waters	Suggested community group measure
Emissions to air from well completion	Develop and adopt air emission standards for methane, air toxics, ozone-forming pollutants, and other airborne contaminants	Expert panel recommendation to US Government
	Require Reduced Emissions Completions to be carried out	Regulatory measure adopted by the US EPA Expert panel recommendation to US Government Recommended industry best practice measure, where applicable
	Prohibit venting of gases, and minimise use of flaring	Regulatory measure adopted by the State of British Columbia Recommended community group measure

Aspect	Description of measure	Status
	Control of VOC emissions by combustion for any tank emitting more than 6 tons VOCs per year	Regulatory measure adopted by the US EPA
	Prohibit use of open-top or blow down tanks	Regulatory measure adopted by the State of Wyoming
	Specify required reductions in uncontrolled VOC emissions	Regulatory measure adopted by the States of Colorado and Wyoming
	Use low-bleed or no-bleed pneumatic controllers	Regulatory measure adopted by the State of Colorado
	Replace glycol systems with alternatives	Industry measure under consideration
Leakage to air during operation	Survey well head equipment to identify and address leakage	Recommended industry best practice measure
	Use equipment with low potential for leakage	Recommended industry best practice measure
	Automatic fail-safe equipment on pipelines	Recommended industry best practice measure
	Reduce the number of storage tanks on site	Recommended industry best practice measure
Temporarily abandoned wells	Set requirements for plugging and inspection of shut-in wells	Regulatory measure adopted by the States of Colorado, Illinois, Oklahoma, Pennsylvania Texas and Wyoming
	Inspect and maintain wellheads every 90 days	Established industry best practice measure
Permanent well abandonment	Plug with 30 m of cement every 760 m and at least 30 m cement at the surface, with 30 m of cement in horizontal section	Regulatory measure adopted by the State of Wyoming
	Plug with 15 m of cement above every zone to be protected	Regulatory measure adopted by the State of Colorado
	Plug at least 15 m below the deepest perforation and 15 m above the shallowest perforation	Regulatory measure adopted by the State of Illinois
	Plug at least 15 m above and below the base of the deepest usable aquifer	Regulatory measure adopted by the State of Texas
	Plug at least 30 m above and 15 m below each fluid-bearing stratum	Regulatory measure adopted by the State of Pennsylvania
	Plug from 15 m below to 15 m above the base of the treatable water zone	Regulatory measure adopted by the State of Oklahoma
	Set requirements for inspection of abandoned wells	Regulatory measure adopted by the States of Colorado, Pennsylvania and Wyoming
	Ensure a micro-annulus is not formed at temporary plugs	Recommended industry best practice measure
	Carry out ongoing monitoring programme	Established industry best practice measure

Aspect	Description of measure	Status
	Maintain records of well location and depth indefinitely	Established industry best practice measure
	Transfer ownership and liability to competent authority on surrender of permit to ensure long-term management	Established practice in other industries e.g. mineral extraction
Well pad restoration	Remove surface impoundments as soon as possible when no longer needed	Recommended industry best practice measure
	Remediate well pads on an ongoing basis to facilitate return to original conditions	Recommended community group measure
	Well sites must be restored as soon as possible after the end of extraction operations	Regulatory measure adopted by the State of British Columbia
Bonding	All operators are required to have financial security for the wells through performance bonds on an individual well or a field of wells	Regulatory measure adopted by US states or other regulatory bodies
Wider area development	Operators should work cooperatively with regulatory agencies and other stakeholders to promote best practices, and improve communication with local communities.	Recommended industry best practice measure
	Neighbouring operators work together to ensure efficient provision of gas collection and water treatment infrastructure	Regulatory measure adopted by the State of British Columbia
Transboundary co-operation	Competent authorities should co-operate in jointly meeting regulatory requirements	Established practice in other industries e.g. minerals extraction industry

Tables A7.1, A7.2 and A7.3 in Appendix 7 summarise the potentially effective controls available to address the potential environmental impacts and risks of shale gas extraction using high-volume hydraulic fracturing compared to conventional practices currently in use.

5 Recommendations

5.1 Introduction

This section of the report provides recommendations on justified, feasible and effective risk management measures applicable in the EU for hydrocarbons operations which involve high volume hydraulic fracturing. The measures listed below include possible technical and regulatory measures and are presented as options for consideration by the Commission. Some measures are established within comparable industries in Europe and/or the USA. At this stage, it is not possible to be confident that the implementation of some or all of these measures will be effective in avoiding all risks of environmental and health impacts. In particular, some impacts such as those resulting from land-take can be minimised but not fully eliminated. Similarly, risks such as those posed by traffic accidents can be minimised with the implementation of measures such as those set out below, but cannot be completely eliminated.

The discussion focuses on the risks identified in Section 2.10 as being of “very high” or “high” significance for individual well pads or multiple developments in Sections 0 to 5.13. Consideration is given in overall terms to the risks identified as being of “moderate” significance in Section 5.14. Recommendations for further consideration and research are provided in Section 5.16. As in chapter 2, the term “impact” refers to all adverse outcomes – that is, those which will definitely occur to a greater or lesser extent, as well as those which may possibly occur. The term “risk” refers to an adverse outcome which may possibly occur as a result of shale gas operations.

The recommendations set out in this chapter draw on the findings of Chapters 2, 3 and 4. Potential control measures are drawn largely from experience of application of such measures to hydraulic fracturing operations in the US. Information on these measures is taken from New York State DEC (2011 PR), EPA (2011a PR), SEAB (2011a NPR) and IEA (2012). Information has also been taken from publications from within the gas production industry, in particular from the Natural Gas Star website hosted by the EPA, and from recent industry-focused conferences. As the study focuses mainly on issues linked specifically to HVHF, standards and guidance from the European natural gas extraction industry were not evaluated.

Where possible, information on costs was provided, and its relevance for the European context considered where appropriate. Measures which are widely implemented in the US were considered likely in principle to be practicable and cost-effective for application in Europe, unless there were specific indications to the contrary. In practice, the costs of HVHF in Europe, including the costs associated with risk management measures, are likely to be greater than those associated with similar activities in the US in the early years of establishment of a shale gas extraction industry.

5.2 General recommendations

A number of the recommendations made by the US Department of Energy (SEAB, 2011a NPR) are relevant for regulatory authorities in Europe. It is recommended that the European Commission should take a strategic overview of potential impacts and risks. This will require consideration of relevant issues for Europe, such as:

- Undertaking science-based characterisation of important landscapes, habitats and corridors to inform planning, prevention, mitigation and reclamation of surface impacts.

- Establishing effective field monitoring and enforcement to inform on-going assessment of cumulative community and land use impacts
- Restricting or preventing development in areas of high value or sensitivity with regard to biodiversity, water resources, community effects etc.

As set out in Section 3.17 and in the table above, it is recommended that the European Commission considers the gaps, possible inadequacies and uncertainties identified in the current EU legislative framework. It is also recommended that Member States' interpretation of EU legislation in respect of hydraulic fracturing should be evaluated.

5.3 Traffic during site preparation and fracturing

The traffic impacts of shale gas pre-production are principally associated with the need for road delivery of hydraulic fracturing fluid, together with a significant contribution from other project requirements such as movement of equipment and waste water.

5.3.1 Site selection and design

Taking traffic considerations into account at the site selection stage is likely to enable efficiencies to be built into the process and thereby deliver reduced traffic impacts.

Description of measure

The impact of transportation and other impacts can be minimised by selecting an appropriate location, which is close to the main highway network and minimises the use of inappropriate roads or the need to construct site roads (see also Section5.4.2. Locating sites close to sources of materials can also be effective in reducing overall vehicle mileage. Developers should also consider the impacts of potential access road locations at the planning stage, and preferably, locate access road away from homes and businesses. API (2011a NPR p17) recommends that existing roads that meet transportation needs should be utilized, where feasible. When it is necessary to build new roadways, they should be developed with potential impacts and purpose in mind. Mitigation options should be considered prior to construction and landowner recommendations should be part of the planning process.

Effectiveness

Appropriate site selection can be effective in reducing the impact of road traffic. However, site selection and design measures would not significantly affect the number of vehicle movements required, and further measures may still be necessary.

Feasibility

The feasibility of locating a site close to the existing highway network, and the benefits of other site design measures on traffic impacts, will vary from one site to another. Consideration of traffic-related impacts at the project design stage is established practice for development projects in Europe. An EIA must show the potential impacts and the possible mitigating measures used to manage these impacts. Site location choice is one of the aspects considered within an EIA. This instrument should be used in the assessment of shale gas developments.

Recommendation

This measure should be considered in view of the potential effectiveness of appropriate site selection and design in mitigating road traffic impacts. The exploration phase is likely to influence site selection for the production phase, and this measure is therefore relevant for both exploration and production phases.

5.3.2 Using alternatives to road transportation

Alternatives to road traffic can be effective in reducing vehicle movements associated with high volume hydraulic fracturing operations.

Description of measure

Operators can adopt alternatives for reducing truck traffic. These could include:

- Use of waterless (or reduced water) fracturing
- Use of temporary surface pipes to transport water to the well pad and to transport flowback and produced water to storage, treatment, or injection points.
- Use of well pads that act as a hub to serve multiple well pads through a temporary piping system
- Use of central facilities for storage of other materials and equipment to reduce vehicle mileage
- Onsite treatment and reuse of produced water

Implementation of measures such as these requires a strategic approach to the development of a site, or (more typically) development of multiple sites in a wider area. It may require investment in planning and development of additional infrastructure such as local storage facilities and temporary pipelines.

Reducing road transportation is likely to be attractive in principle to operators because of the opportunity to reduce costs associated with transport of materials and equipment.

Implementation of some options may have associated impacts – e.g. the use of temporary pipelines or local storage facilities may require short-term land take.

Effectiveness

Measures such as those set out above can be effective in reducing road transportation associated with high volume hydraulic fracturing schemes. However, further measures may still be necessary depending on local circumstances.

Feasibility

The feasibility of implementing alternatives to road transportation will vary from one site and local area to another. It would be important to consider and minimise the potential impacts of these alternatives. This would require consideration throughout the development of individual sites and wider scale projects. Implementing this requirement would be complex because of the balance between diverse impacts which are potentially covered by more than one regulatory framework. For example, road traffic and temporary pipework may be addressed by the EIA Directive; water treatment, re-use and disposal may be covered under the Water Framework Directive, Mining Waste Directive, IPPC Directive and/or Industrial Emissions Directive. More sustainable use of water would have positive consequences for other impacts.

Recommendation

This measure should be considered in view of the potential effectiveness of measures to reduce road transportation.

5.3.3 Development of transportation plans

Developing a transportation plan for development of an individual site, or at a strategic level for a number of sites in a wider area, can be effective in reducing the impact of unavoidable road traffic.

Description of measure

Developing a transportation plan can be an effective means to reduce truck traffic (e.g. by sharing loads), designate appropriate parking and storage areas, and identify transportation routes. Further guidance is provided by API (2011a NPR p17):

- Where appropriate, operators should obtain road use agreements with local authorities.
- Whether agreements are in place or not, in areas with traffic concerns, operators should develop a trucking plan that includes an estimated amount of trucking, hours of operations, appropriate off-road parking/staging areas and routes. Examples of possible measures in a road use agreement or trucking plan include:
  - Route selection to maximize efficient driving and public safety;
  - Avoidance of peak traffic hours, school bus hours, community events and overnight quiet periods;
  - Coordination with local emergency management agencies and highway departments;
  - Upgrades and improvements to roads that will be travelled frequently;
  - Advance public notice of any necessary detours or road/lane closures; and
  - Adequate off-road parking and delivery areas at the site to avoid lane/road blockage.
  - Limiting truck weights

Effectiveness

A transportation plan can be effective in reducing the impact of road traffic. However, further measures may still be necessary depending on local circumstances.

Feasibility

The benefits to be gained from developing a transportation plan will vary from one site and local area to another. The development of transportation plans for individual developments or wider scale projects and plans is established practice for development projects in Europe.

Recommendation

This measure should be considered, in view of the potential effectiveness of a transportation plan in mitigating road traffic impacts

5.3.4 Measures to minimise vehicle emissions

Applying higher standards of emissions control could potentially be effective in reducing the impact of vehicle emissions on air quality in sensitive areas such as those where baseline air quality already approaches or exceeds the relevant standards. However, road transport associated with the development of unconventional gas is likely to have no more than a minor and localised effect on air quality.

Description of measure

There is an extensive programme of regulation of vehicle emissions in Europe. Road vehicles used in relation to any development, including unconventional gas projects, would need to comply with these regulations.

Emissions from truck traffic can be further minimised by using vehicles which conform to the highest currently applicable standards for vehicle emissions. Trucks should be prevented from idling over extended periods, with a presumption that engines will be switched off. Truckload contents should be covered as appropriate to reduce dust and particulate matter emissions. Consideration should be given to the use of low emissions vehicles.

Effectiveness

These measures can be effective in reducing the impact of road traffic on air quality to a limited extent in the vicinity of transportation routes. However, further measures may still be necessary depending on local circumstances.

Feasibility

Emissions from road transportation can be readily reduced by adopting the measures set out above. The use of low emissions vehicles would depend on the development and availability of appropriate technology. The implementation of management measures in relation to vehicle idling and covering of dusty loads is established practice in Europe. The use of low emissions vehicles for individual developments is not widely established practice, but could potentially be implemented as part of a transportation plan (see Section5.3.3), or by the instrument of environmental zoning.

Recommendation

Such measures should be considered, in view of the potential effectiveness of these measures in reducing air quality impacts.

5.3.5 Road maintenance

Intensive use of roads by heavy vehicles can cause damage to roads, particularly where inappropriate roads need to be used for site access. Carrying out road maintenance and repair can be effective in reducing road vehicle noise and dust, as well as protecting sensitive area and improving the experience of other road users.

Description of measure

Proper road maintenance is critical for the performance of roads, to manage erosion and to protect environmentally sensitive areas (API 2011a NPR p17). Operators may be asked to contribute to road maintenance either by carrying out works themselves, or by making payments for repair and maintenance of the road network used by operator vehicles.

Effectiveness

These measures can be effective in reducing the environmental impact of roads and road traffic in general (not just traffic associated with the development), by reducing noise and dust and avoiding impacts due to erosion.

Feasibility

Highway repairs and maintenance can be readily carried out. Placing requirements on operators for highway and site road repair and maintenance is established practice in Europe.

Recommendation

This measure should be considered, in view of its potential effectiveness in mitigating the wider environmental effects of road traffic.

5.4 Land take during site preparation

Surface installations require an area of approximately 3.0 hectares per pad during the fracturing and completion phases (New York State DEC 2011 PR Table 5.1; US DOE 2009 NPR). In addition to the well pads, the associated infrastructure (access roads and pipelines) also results in land take and habitat fragmentation (Lechtenböhmer et al. 2011 NPR page 21; The Nature Conservancy 2011 NPR). The required land-take for development of a shale gas play could amount to approximately 1.4% of the total land area.

5.4.1 Maximize required spacing between wells (Install multiple wells/pad)

Increasing well spacing and using multiple wells per pad reduces the total land disturbed for well pad construction. Fewer pads require fewer roads, pipelines, and other rights of way. A minimum number of wells per pad could be required, but it may be preferable to impose a minimum well spacing. For example, New York State anticipates requiring "*spacing units of up to 640 acres* [2.6 sq km] *with all the horizontal wells in the unit drilled from a common well pad*" (New York State DEC 2011 PR page 5-22).

The pros of this measure are:

- reduces the land take compared to single-well pads
- reduces construction costs (e.g. SEAB 2011a NPR ; US DOE 2009 NPR).
- reduces community impacts

The cons of this measure are:

- requires a developer to acquire rights to larger parcels of land
- may reduce the gas recovered from the formation
- may increase localized impacts during construction, drilling, fracturing, well completion and production operations (API 2011 NPR p15).

Description of measure

Use larger drilling pads for multiple wells, increasing the spacing between wells.

Justification

Increasing well spacing and using multiple wells per pad reduces the total land disturbed for well pad construction. Fewer pads require fewer roads, pipelines, and other rights of way.

Effectiveness

Increasing well pad spacing from one pad per 2.5 sq.km to 1 pad per 5 sq km would reduce the total land disturbance in the drilling phase from 30 hectare to 22.5 hectare per 2,500 hectare area, as set out in the table below. This calculation assumes 6 to 8 horizontal wells per pad at the 2.5 sq km spacing (New York State DEC 2011 PR p 5-23).

Feasibility

Drilling long horizontal legs from a central vertical well is an essential component of economic exploitation of unconventional oil and gas resources. Increased well spacing would be feasible in Europe.

Recommendation

This measure should be considered in relation to the key issues for land-use, in view of the potential significance of land-take by hydraulic fracturing installations. The exploration phase is likely to influence land use for the production phase, and this measure would therefore be effective for both exploration and production phases.

5.4.2 Require Environmental Site Assessment for Optimal Site Selection

Appropriate siting can reduce the amount of land disturbed for constructing roads, pipelines, and other infrastructure. Appropriate siting can also be an important means of avoiding or minimising adverse impacts on sensitive receptors such as residential areas or ecosystems.

Description

This measure would require operators to take environmental and health concerns into account when selecting sites for shale gas extraction facilities. To reduce land take and facilitate ultimate site reclamation, HVHF operations should be located near existing roads, rights of way, and pipelines, so far as practicable. Developers should also select sites which minimize the amount of surface terrain alteration, avoiding sites requiring cut and fill construction (API 2011 NPR page 16). Developers should select sites with the minimum impact on sensitive locations such as residential areas or habitat sites, by virtue of distance, screening or other means.

There are no specific legislative or regulatory initiatives in place regarding proximity to existing gas pipelines, although gas developers in close proximity in British Columbia are obliged to work together to reduce environmental impacts (State of British Columbia, 2011 NPR).

As well as securing environmental benefits, reduced construction and transportation requirements would reduce costs for well installation and site reclamation, although this may be offset by the additional cost and difficulty of acquiring land near roads and rights of way.

Effectiveness and Feasibility

Siting flexibility depends on topography and other site-specific considerations.

The feasibility of this remedy requires a mechanism for implementation, e.g. designation of zones which are off-limits for shale gas development; or enforcement requirement for individual operators to demonstrate optimum selection for each well pad. This would normally be implemented via national spatial planning legislation. If an environmental impact assessment is needed for a specific development, this needs to include an assessment of alternative locations. The outcome of that assessment would give the competent authority the possibility of prohibiting non-optimal site selections. Ensuring that shale gas extraction facilities are included in the scope of the EIA directive as discussed in Chapter 3 would enable the EIA system to deliver protection for sensitive sites.

Recommendation

In view of the potential significance of land-take by hydraulic fracturing installations this measure should be considered. The exploration phase is likely to influence site selection for the production phase, and would therefore be effective for both exploration and production phases.

5.4.3 Limit the use of impoundments

Construction of storage ponds requires excavation and building berms. Temporary tanks can be placed on levelled ground, which requires less land disturbance and is therefore easier to restore during the well production phase. The use of tanks has other benefits as outlined by New York State DEC (2011 PR). However, the tanks may present more of a visual impact.

The land used for infrastructure such as storage ponds should be minimized so that land used for HVHF can be restored to its original form. New York State DEC (2011 PR p7-61) states: "*Tanks, while initially more expensive, experience fewer operational issues associated with liner system leakage… In addition, tanks can be easily covered to control odours and air emissions from the liquids being stored. Precipitation loading in a surface impoundment with a large surface area can, over time, increase the volumes of liquid needing treatment. Lastly above ground tanks also can be dismantled and reused.*"

Effectiveness and Feasibility

The feasibility would depend on the availability of temporary tanks. Temporary tanks are likely to incur an additional cost to operators. This could be taken into account via e.g. the economic evaluation procedures for individual sites.

Recommendation

This measure should be considered in view of the potential significance of land-take by hydraulic fracturing installations and the potential effectiveness of this measure in mitigating the impact.

5.4.4 Use temporary surface pipes to transport water to the well pad

Using temporary surface piping to transport make up water to the well pad reduces the required onsite storage and associated land requirements. This approach can also reduce transportation requirements. If temporary surface pipes can be installed adjacent to the access road or gas collection piping, no additional land disturbance is required.

The pros of this measure are:

- Avoids potential adverse impacts/risks due to trucking and water storage

The cons of this measure are:

- This approach may require additional permitting to cover the pipeline at a national level, for example via national spatial planning regulations.
- The pipeline route may not be available due to land ownership issues or practical constraints.
- The pipeline would need to be maintained during its operational lifetime.
- This measure could result in additional land-take and potential impacts on biodiversity.

Additionally, this approach would typically incur a lower cost than trucking (Auman 2012)

Feasibility

Several operators in the Pennsylvania portion of the Marcellus Shale formation are currently piping make up water over severe terrain (Auman 2012 NPR , Peloquin 2012 NPR , Kepler 2012 NPR ; DiGennaro, 2012 NPR). The use of this technique is evidently feasible in a range of situations.

Recommendation

This measure should be considered, in view of the potential significance of land-take by hydraulic fracturing installations and the potential effectiveness of this measure in mitigating the impact.

5.4.5 Ensure land disturbed during well construction and development is reclaimed

This measure minimises the land taken long term or permanently from alternative uses (e.g., agriculture, wildlife habitat). As soon as practicable, require the removal of temporary equipment and reclamation and restoration of excess areas. This will reduce the location size and overall footprint during the production phase (API 2011 NPR , p15).

During site preparation, require stockpiling of surface soils for all cut and fill areas so that they can be reused during interim and final reclamation. Topsoil should be segregated from subsurface materials to improve the effectiveness of reclamation activities. Require reclamation of non-productive, plugged, and abandoned wells, well pads, roads and other infrastructure areas. Reclamation should be conducted as soon as practicable and should include interim steps to establish appropriate vegetation during substantial periods of inactivity. Native tree, shrub, and grass species should be used in appropriate habitats. (New York State DEC 2011 PR , p7-77)

The pros of this measure are:

- Minimizes the duration of surface disruptions

The cons of this measure are:

- Reclamation may not effectively restore some original uses (e.g., archaeological sites, some sensitive wildlife habitats).

Effectiveness

Reclamation can effectively restore many original land uses, e.g., agriculture. Not all impacts of land taken for construction activities can be remedied. For example, the restored area is not likely to be appropriate for residential use.

Feasibility

Reclamation of the drilling and completion site during the production phase is common industry practice. The regulatory challenge is to ensure that this takes place at the earliest point possible in the lifetime of the site, and to the highest appropriate standard.

Recommendation

The implementation of this measure should be further considered.

5.4.6 Restrict hydraulic fracturing and well pad installation from sensitive areas

This measure could be appropriate to protect sensitive sites from inappropriate development. European sites already benefit from protection under Directive 92/43/EEC, as discussed in Section 3.15. This measure would potentially be used to protect other sensitive features, such as nature conservation resources which are not covered under Directive 92/43/EEC, water catchments, or areas of high agricultural or cultural value.

The measure could prevent or restrict the recovery of shale gas reservoirs beneath the protected areas (other than in areas accessible via horizontal drilling from outside the protected areas).

Description

It may not be possible to fully restore a site in a sensitive area following well completion or well abandonment. For example, sites in areas of high agricultural, natural or cultural value could potentially not be fully restorable following use. Authorities may wish to restrict development in such areas, for instance in the vicinity of sensitive surface water or groundwater resources. For example, New York State DEC recommended that high-volume hydraulic fracturing operations not be permitted in the Syracuse and New York City watersheds or in a protective 1,200 metre buffer area around those watersheds (New York DEC (2011 PR) p1-17).

For this reason, it may be appropriate to prevent HVHF operations from being carried out in identified sensitive areas (see Section 3.4). Depending on the sensitivity of the area and the depth of the shale formation, the ban could be limited to the installation of well pads and supporting structures and drilling, allowing horizontal legs to be installed under the sensitive area.

Effectiveness

This measure would potentially be effective in mitigating impacts and risks in identified sensitive areas.

Feasibility

Measures of this nature are under consideration by New York State DEC:

- *"Well pads for high-volume hydraulic fracturing would be prohibited in the NYC and Syracuse watersheds, and within a 4,000-foot* [1,200 metre]*buffer around those watersheds;*
- *Well pads for high-volume hydraulic fracturing would be prohibited within 500 feet of primary aquifers (subject to reconsideration 2 years after issuance of the first permit for high-volume hydraulic fracturing);*
- *Well pads for high-volume hydraulic fracturing would be prohibited within 2,000 feet of public water supply wells, river or stream intakes and reservoirs (subject to reconsideration 3 years after issuance of the first permit for high-volume hydraulic fracturing);*

  …
- *The Department would not issue permits for proposed high-volume hydraulic fracturing at any proposed well pad within 500 feet* [150 metres]*of a private water well or domestic use spring, unless waived by the owner.*"

No comparable zonal restrictions on drilling beneath sensitive areas are envisaged by the New York State DEC.

Recommendation

This measure should be considered in view of the potential significance of land-take by hydraulic fracturing installations and the potential effectiveness of this measure in mitigating the impact. The exploration phase is likely to influence site selection for the production phase, and this measure is therefore relevant for both exploration and production phases.

5.5 Releases to air during drilling

Drilling operations can lead to air emissions from: 1) diesel exhaust fumes from drill rig engines and site electricity generation; 2) fuel storage tanks; and 3) truck activities near the well pad (New York State DEC 2011 PR page 6-114, Howarth and Ingraffea, 2011 NPR ; Lechtenböhmer et al. 2011 NPR). These emissions could potentially pose significant risks to the environment in the case of development over a wide area.

5.5.1 Require natural gas-fired or electric grid drilling rig engines

Emissions from natural gas combustion are lower than from diesel combustion. Tests with natural gas-fired drilling rigs reduced emissions by over 4,000 tons of VOC and 600 tons of NO_X per year compared with the diesel drilling rigs (Hill, 2011 NPR). It would be expected that emissions of fine particulate matter would also be reduced.

Use of grid-connected electric drilling rig engines effectively transfers emissions from the drilling location to the point of electricity generation. The electricity generating plant may or may not give rise to emissions to air, and would be subject to its own permitting requirements and environmental controls. Moving the emission location in this way may be beneficial in circumstances when drilling occurs in an area that does not meet air quality standards or is of particular sensitivity to air pollution.

Description of measure

Drilling rig engines are typically powered by transportable diesel engines (New York State DEC 2011 PR p6-99). Using natural gas-fired drilling rig engines reduces the visible exhaust typical of diesel engines and emit less than 1.3 gram NO_X/kWhr (Wright, 2011 NPR), which will significantly reduce emissions compared to diesel drilling rig engines.

Natural gas-fired drilling rig engines are only feasible in areas with existing natural gas infrastructure. In the remote Jonah Play in Wyoming, US, an operator replaced diesel powered drilling with natural gas-fired rig engines to make use of excess natural gas production which would otherwise have been wasted. The natural gas extracted throughout the field is sent to a centralized processing facility. Some of the processed natural gas is returned to the drilling rig sites for use in the natural gas powered drilling engines (Wright, 2011 NPR). The quality of the natural gas in other areas may be such that processing is not necessary before use (Hill, 2011 NPR). For drilling rigs in areas without natural gas infrastructure, rigs can run on liquefied natural gas (LNG) (Hill, 2011 NPR).

Using electric grid drilling rig engines, where a grid connection is available, reduces emissions to air by reducing the need for diesel-powered plant at the well pad (WRAP Oil and Gas Scope p42).

Effectiveness

- Reduces truck traffic for hauling diesel fuel to drilling sites
- Reduces emissions and visible haze significantly (Hill, 2011 NPR)
- Runs more quietly (Hill, 2011 NPR)
- If electrically powered plant is less efficient than diesel-fuelled plant, this could result in a net increase in carbon emissions.

Feasibility

Natural gas infrastructure may not exist in new development areas, which would limit the applicability of this measure to the use of liquefied natural gas. This measure may result in higher net costs, depending on the price of natural gas versus diesel fuel and whether the gas used could otherwise have been sold to the collection network. The low availability of natural gas-fired drilling rigs may limit the practical feasibility of this remedy at present, although the market is likely to respond if there is a need for more gas-fired drilling rigs.

Engines fired on natural gas respond more slowly under variable loads than diesel fuelled engines, so technically it would seem more appropriate to use natural gas fired plant for constant load operations (Hill, 2011 NPR).

This measure is only appropriate if the electricity grid is accessible from the site. This measure could potentially result in higher drilling costs depending on the price of electricity versus diesel and plant efficiency. Electrically powered motors are straightforward to retrofit, and can be used interchangeably with diesel or diesel-powered generating plant (Shipley, 2009 NPR). However, there may be difficulties related to the installation of power lines, the use of mobile transformers, and coordination with electric utility company (Shipley, 2009 NPR)

Cost issues are specific to each individual case.

Recommendation

This measure could be considered in view of the potential effectiveness of this measure in mitigating the impact of emissions to air from site infrastructure.

5.5.2 Require emission controls on lean burn and rich burn drilling rig engines

This measure would reduce emissions of NO_X, CO and VOCs (including formaldehyde)

Description of measure

Selective catalytic reduction (SCR) installation on lean-burn drilling rig engines reduces NO_X emissions, while the oxidization catalysts reduce CO, VOCs, and formaldehyde emissions. The SCR systems require industrial grade urea, anhydrous ammonia, or aqueous ammonia injected into the engine exhaust prior to flow through a catalyst. The oxidization catalyst is a dry system (Four Corners AQTF Mitigation Options, 2007 NPR p18; NYSDEC, 2011 NPR p7-102).

Non-selective catalytic reduction (NSCR) or 3-way catalyst installation on rich-burn drilling rig engines reduces NO_X, CO, VOCs, and formaldehyde emissions. The 3-way catalyst includes reduction and oxidation materials to convert NO_X, CO, and hydrocarbons to N_2, H_2O, and CO_2 (Four Corners AQTF Mitigation Options, 2007 NPR p20; NYSDEC, 2011 NPR p7-103).

Effectiveness

- Reduce emissions and visible haze
- Could potentially be installed on natural gas drilling rig engines for additional emission reductions

Feasibility

Selective catalytic reduction has the following characteristics:

- Limited to lean burn engines
- Requires chemical storage, possibly heated depending on chemical and environment
- Possible side effects with ammonia slip (increased efficiency results in increased ammonia slip), which can lead to airborne nitrate formation if there is a NO_X plume, even if NO_X emissions are reduced (Four Corners AQTF 2007 NPR p 18)
- Requires electrical supply or generation to run the SCR system and instrumentation
- Incremental cost is likely to be very high because of the small incremental emission reductions on lean burn engines (Four Corners AQTF 2007 NPR p18). 5-year cost for an SCR on a 3-engine rig in the Wyoming, US was estimated at 5 million US dollars (Four Corners AQTF, 2007 NPR p 18)

Non-selective catalytic reduction and 3-Way Catalytic convertors have the following characteristics:

- Limited to rich burn engines within a narrow air/fuel ratio to maintain catalyst efficiency (Four Corners AQTF Mitigation Options, 2007 NPR p20)
- Limited temperature window for emissions control (Four Corners AQTF Mitigation Options, 2007 NPR p20)
- Possible to retrofit existing engines
- Catalysts lose efficiency through lifespan (lifespan up to 5 years)

Emission limits for off-road combustion plant are already specified via a series of European directives (Directives 97/68/EC, 2002/88/EC, 2004/26/EC and 2010/26/EU. These directives specify limits on emissions of carbon monoxide, oxides of nitrogen, hydrocarbons and particulate matter from engines up to 560 kW and are aligned with the equivalent US emissions standards. As discussed in Section 3.6.1, the position with regard to engines above 560 kW is subject to review.

Compliance with these EU limits would provide control on relevant emissions of potential concern from on-site plant, but would not of itself deliver compliance with standards and guidelines for air quality.

Recommendation

This measure should be considered in view of the potential effectiveness of this measure in mitigating the impact of emissions to air from site infrastructure. It is recommended that careful consideration is given to the interactions with existing European directives relating to emissions from off-road combustion plant, to ensure that any measures are robust and proportionate.

5.6 Noise during drilling

Noise from well drilling could potentially affect residential amenity and wildlife, particularly in sensitive areas (New York State DEC 2011 PR p6-289 to 6-297)

5.6.1 Specification of maximum noise levels at sensitive locations

This measure could be used to deliver effective control on noise impacts at sensitive locations. This would be particularly important in areas of intensive shale gas development, where noise impacts could be almost continuous over a period of months.

Description of measure

Setting limits on maximum permissible noise levels is a potentially appropriate means of protecting local amenity and sensitive ecosystems from noise impacts.

Appropriate noise emissions data, baseline monitoring data, and impact assessment tools would need to be used to demonstrate compliance with specified noise limits.

Effectiveness

Specifying limits in this way allows the operator to deliver the required performance in the most effective and appropriate means taking account of the local context (e.g. background noise levels; topographical influences on noise emissions). It also allows the specific characteristics of drilling noise to be taken into account when setting limits. Experience in other industries is that this approach can be effective in controlling impacts due to noise. An appropriate level of analysis, review, inspection and monitoring would be needed to ensure ongoing compliance with the specified standards.

However, the use of a limits-based approach would not support the philosophy of reducing environmental impacts to the minimum level, as operators would tend to work towards compliance with the limits rather than impact minimisation.

Feasibility

This measure enables operators to select the most appropriate measure for achieving acceptable performance in terms of noise.

Recommendation

This measure should be considered in view of the potential effectiveness of this measure in mitigating the impact of noise during drilling and other stages of shale gas exploration and production. Consideration should be given to the interactions with existing European directives in relation to noise impacts of minerals extraction and industrial installations. .

5.6.2 Separation between drilling operation and sensitive location

This measure could be used to deliver control on noise impacts at sensitive locations. This would be particularly important in areas of intensive shale gas development, where noise impacts could be almost continuous over a period of months.

Description of measure

Noise is mitigated with increasing distance between the source and receptor (New York State DEC 2011 PR p7-128). New York State uses a distance of 305 metres as indicative of the zone within which noise impacts may be significant and detailed investigation is needed. Mitigation can be provided by setting minimum separation distances between wells and sensitive locations, including residential properties, public amenities, and sensitive habitat sites. These separation distances would ideally take account of the planned drilling activities, other mitigation to be provided, and forecast noise levels.

Effectiveness

This approach could be effective in controlling impacts due to noise, as part of a wider programme of noise control measures. Setting specific minimum separation distances would be more straightforward to implement and regulate than a measure based on noise performance (Section 5.6.1).

Feasibility

This measure provides a simple basis for regulation. However, it would be more complex to specify appropriate generic separation distances which take account of site-specific circumstances.

It would be important for this measure to be consistent with existing regulations in relation to noise impacts of minerals extraction and industrial installations.

Recommendation

This measure should be considered, alongside other measures to mitigate the impact of noise during drilling. It is recommended that consideration is given to the interactions with existing European directives such as the Environmental Noise Directive (2002/49/EC) and plans developed under Article 8 of this Directive.

5.6.3 Management and barrier methods to reduce noise impacts

Noise management measures are an important aspect of noise control at any oil and gas, mineral extraction or industrial installation or construction site. This measure would comprise the specification of appropriate controls, which could significantly improve the performance of a site in relation to noise impacts. This would be particularly important in areas of intensive shale gas development, where noise impacts could be almost continuous over a period of months.

A range of potentially applicable management measures is set out in Appendix 7. These measures could be applied to reduce noise impacts as applicable at individual sites

Effectiveness

The use of management and barrier measures is effective in controlling impacts due to noise, as part of a wider programme of noise control measures.

Feasibility

The design and implementation of noise management measures is established practice for oil and gas facility operators. It would be important for this measure to be consistent with existing regulations in relation to noise impacts of minerals extraction and industrial installations.

Effectiveness

The use of management measures is effective in controlling impacts due to noise, as part of a wider programme of noise control measures.

Recommendation

It is recommended that the introduction of management measures is considered, alongside other measures to mitigate the impact of noise during drilling. It is recommended that consideration is given to the interactions with existing European directives. .

5.7 Water resource depletion during fracturing

Significant quantities of water are required for HVHF operations. This section considers measures for management of water resources.

5.7.1 Regional water resource management

Regional management of water resources will be important to ensure that the effects of intensive implementation of high volume hydraulic fracturing can be managed in the context of competing demands on water resources and climatic changes.

Description of measure

As recommended by the US Department of Energy (SEAB, 2011a NPR), under this measure, authorities would evaluate water use at the scale of affected watersheds, and consider declaring unique and/or sensitive areas off-limits to drilling and support infrastructure as determined through an appropriate science-based process.

Effectiveness

Regional water resource management is likely to be effective in balancing competing demands for limited or scarce water resources. The development and use of an integrated water management system has the potential for greatly reducing the environmental footprint and risk of water use in shale gas production.

Feasibility

A North American regulator (consultation response 2012 NPR) considers that it is able to manage watershed impacts on an integrated basis, using modelling techniques and information provided by operators.

Recommendation

It is recommended that the introduction of this measure is considered in view of the potential effectiveness of this measure in mitigating the impact.

5.7.2 Reuse wastewater

Reuse of produced water will reduce the amount of make-up water required for hydraulic fracturing and thus the potential impacts from water resource depletion.

Description of measure

Recovered wastewater (consisting of fracturing fluid and produced water) can replace some or all of fracturing fluid make up water (Yoxtheimer, 2012 NPR).

The pros of this measure are:

- reduces the quantity of fresh water required from water resources
- reduces or eliminates the need for disposal of produced water

The cons of this measure are:

- required treatment may be costly and may generate treatment residuals (sludges and brines) requiring management and disposal
- flowback and produced water must be stored and/or transported prior to reuse
- reuse may require additional transport of produced water

Effectiveness

Less than 100% of fracturing fluid is recovered. Typically, between 30% and 75% of the injected fluid is recovered as flowback (DOE 2009 NPR p66; EPA 2011 NPR p42; Webb 2012 NPR). This means that even if all recovered fracturing fluid is reused, additional make up water is still required.

Feasibility

Technical feasibility depends on the amount and type of salts dissolved in the produced water and the required fracturing fluid chemistry. Reuse is becoming standard practice for shale gas exploitation in the US. Moving wastewater between watersheds and/or political jurisdictions may require additional approvals under jurisdictions such as Regulation (EC) No 1013/2006 on transfrontier waste shipments (depending on the methods used for transferring waste and the nature of the waste materials). It would be important to establish an appropriate regulatory basis for the imposition of requirements with regard to re-use of wastewater which takes account of the technical and site-specific issues.

Recommendation

It is recommended that the introduction of this measure is considered, in view of the potential effectiveness of this measure in mitigating the impact. It will be important for any regulatory regime to be sufficiently flexible to accommodate the range of circumstances and technical issues likely to be encountered in practice. An alternative regulatory regime may need to be adapted or introduced to ensure that water recycling is carried out to the maximum appropriate extent. .

5.7.3 Use of alternative sources of water

Use of lower quality water (e.g. seawater, brackish water) for fracturing fluid make up will reduce the depletion of drinking water sources (fresh groundwater and surface water).

Description of measure

In place of freshwater of drinking water quality, operators can use alternative water supplies, such as non-contact cooling water from power plants and industrial boilers, mine drainage water, and treated wastewater (that is, water which has been treated but is not of sufficient quality to be discharged to the environment) (Alleman, 2012 NPR ; Vidic 2012 NPR). Use of alternative supplies may require transport of the water across watersheds and require adjustment of chemicals used for fracturing as well as treatment to adjust pH and to reduce concentrations of scale-forming cations (e.g., calcium, magnesium). For example, operators can use brackish groundwater (500 – 30,000 mg/L TDS) as fracturing fluid make up water. In coastal locations, operators can use seawater (35,000 mg/L TDS). Use of lower quality water for make up may require adjustment of chemicals used for fracturing as well as treatment to reduce concentrations of scale-forming cations (e.g., calcium, magnesium, barium). Desalination using reverse osmosis has been employed to facilitate use of brackish water for fracturing fluid make up for the Bakken oil shale, North Dakota, U.S. (Kurz 2011 NPR)

The pros of this measure are:

- Reduces the quantity of fresh water required from water resources
- May reduce makeup water transportation impacts if the lower quality water is closer to the well installation than an alternate fresh water supply
- May reduce treatment requirements for other waste water producers
- May reduce costs for shale gas installation operators where it results in reduced transportation needs, and may also reduce costs for other waste water producers.

The cons of this measure are:

- Any required treatment (particularly reverse osmosis) may be costly
- Any required treatment may generate treatment residuals (brine, sludges) requiring management and disposal
- May require additional transport of alternative water supplies, and may involve additional regulatory approval, inspection, and recordkeeping as well as cross-jurisdiction cooperation in watersheds that cross political boundaries

Effectiveness

In appropriate locations, low quality water could completely replace the use of freshwater and eliminate the potential impacts from water resource depletion.

Feasibility

The feasibility of use of alternative water supplies depends on their availability and compatibility with well conditions (Auman 2012 NPR). This may include consideration of access to reduced water quality water source; the amount and type of salts dissolved in the water, and the required fracturing fluid chemistry. For example, acid mine water was used to fracture a well in Tioga County, Pennsylvania (Palone 2010 NPR). Use of seawater at inland locations may not be feasible because of transportation costs, and other sources may not be feasible because of transportation costs and liability concerns (Auman 2012 NPR). Onsite storage in tanks, rather than impoundments, may be required to reduce risk of contamination from impoundment leaks and spills.

It would be important to establish an appropriate regulatory basis for the imposition of requirements with regard to use of alternative sources of water which takes account of the technical and site-specific issues.

Effectiveness

In appropriate locations, alternative sources of water could completely replace the use of freshwater and eliminate the potential impacts from water resource depletion.

Recommendation

It is recommended that the introduction of this measure is considered in view of the potential effectiveness of this measure in mitigating the impact. It will be important for any regulatory regime to be sufficiently flexible to accommodate the range of circumstances and technical issues likely to be encountered in practice. An alternative regulatory regime may need to be adapted or introduced to ensure that water recycling is carried out to the maximum appropriate extent.

5.7.4 Manage water abstraction

Hydraulic fracturing requires large volumes of water, up to 25,000 m^3 per well over a short period of time (see Chapter 1). Withdrawals are intermittent, impermanent, and consumptive (abstractive water is typically not returned to the water source). In addition to protecting the interest of various water users, management of water withdrawal from small surface streams will protect fish and other wildlife habitat.

Description

Manage allocation of surface and groundwater through a regulatory approval process that considers the conditions of the water source and current and future uses. Use hydrologic computer models to manage watershed impacts, including reduction in the assimilative capacity resulting from temporary reduced water flow. For small streams, ensure that the approval requires a minimum pass by flow (i.e., that water withdrawal must be interrupted if stream flow falls to a minimum value). Require screens and filters on intake structures to prevent entrainment of fish and other aquatic organisms, as appropriate for local conditions. Water withdrawals should be metered, recorded, and reported to the appropriate authority.

The pros of this measure are:

- reduces potential impacts on freshwater sources
- may reduce disputes between water users

The cons of this measure are:

- requires active government approval, inspection, and recordkeeping

- may require cross-jurisdiction cooperation in watersheds that cross political boundaries

Effectiveness

Management of freshwater use will maximise its availability to all users.

Feasibility

There are no technical considerations limiting the feasibility of this remedy. Operators may need to schedule fracturing activities around pass by conditions and water can be stockpiled in storage impoundments during wet conditions (Auman, 2011 NPR). Water use should be evaluated on a watershed (or catchment) basis, which may require cross-jurisdictional cooperation.

Effectiveness

Management of freshwater use will maximise its availability to all users.

Recommendation

It is recommended that the introduction of this measure is considered, in view of the potential effectiveness of this measure in mitigating the impact. It will be important for this measure to be sufficiently flexible to accommodate the range of circumstances and issues likely to be encountered in practice. .

5.8 Releases to air during completion

As discussed in Section 2.6.3, relevant emission sources include engines, flares, venting, and truck activities near the well pad. Emitted substances include methane, PM, NO_X, CO, VOCs, SO_2, and HAPs.

5.8.1 Require reduced emission completions to eliminate natural gas venting during fracturing from flowback and wastewater

This method can deliver significant reductions in emissions to air, combined with an unusually short payback period because captured natural gas can be sold.

Description of measure

Reduced emission completions (RECs), or green completions, reduce natural gas venting during fracturing. The wastewater, natural gas, and condensate produced from the wellhead are collected so the solids (e.g., proppant) and liquids are separated from the natural gas. The natural gas is delivered to the sales pipeline rather than venting or flaring, reducing methane, VOC, and HAP emissions (US EPA Natural Gas Star Lessons Learned website, accessed 2012 NPR). British Columbia Oil and Gas Commission requires connection to a sales pipeline if the pipeline is within 1.5 km from the well (BCOGC, 2011 NPR). RECs may include a dehydrator depending on the natural gas quality from the well and in the sales pipeline (US EPA Natural Gas Star Lessons Learned website). The dehydrator is also a source of air emissions, see Sections 5.11.5 and 5.11.6 for recommendations on emission reductions for dehydrators.

Effectiveness

- Estimated produced gas savings 14,000-57,000 m^3/day/well (US EPA Gas Star Lessons Learned)
- US EPA Natural Gas STAR partner companies reported capturing for sale over 6.2 million m^3 natural gas using RECs in 2009

Feasibility

The feasibility of Reduced Emissions Completion is enhanced because it results in the production of saleable natural gas. This results in a short payback period. The estimated payback periods when using REC on 25 wells/year are as follows (US EPA Gas Star Lessons Learned):

- Natural gas at $0.11/m^3 = 7 months
- Natural gas at $0.18/m^3 = 5 months
- Natural gas at $0.25/m^3 = 4 months
- Natural Gas at $0.35/m^3 = 3 months

RECs cannot be used in areas without sales pipelines in close proximity (e.g., exploratory and delineation wells) (US EPA Gas Star Lessons Learned; Smith 2011 NPR). The use of green completion in low pressure fields requires a compressor to boost the gas to the sales pipeline pressure (US EPA Gas Star Lessons Learned). This approach is still under development and may not be cost effective in every situation.

Hydraulic fracturing with inert gases requires specialized RECs to separate the inert gas from sales natural gas (US EPA Gas Star Lessons Learned). Portable acid gas removal membranes can be used, if carbon dioxide is used as the fracturing fluid (US EPA Gas Star Lessons Learned)

The US EPA has proposed a rule which requires flaring or RECs for all new wells and recompletions up to the end of 2014. From 2015, operators must capture the gas generated during the completion period and make it available for use or sale. Exceptions exist for exploratory or delineation wells and low pressure wells. Operators must use combustion, unless combustion is a safety hazard or is prohibited by state or local laws.

Recommendation

It is recommended that the introduction of this measure is considered, in view of the potential effectiveness of this measure in mitigating the impact. It will be important for any regulatory regime to be sufficiently flexible to accommodate the range of circumstances and technical issues likely to be encountered in practice.

5.8.2 Require flares or incinerators to control emissions from fracturing wastewater storage tank vents

Reduced fugitive emissions of methane and other VOCs from fracturing wastewater

Description of measure

Traditionally, fracturing wastewater that flows back from the wellhead is sent to a surface impoundment (pit) or tank, where the water, hydrocarbon liquids, and sand are separated and natural gas is vented to the atmosphere or combusted by a flare or incinerator. A flare combusts natural gas at the end of an elevated flare stack, resulting in a characteristic flame. An incinerator mixes the natural gas with oxygen in an enclosed chamber, and does not result in a visible flame (EnerFAQ Flaring p1). British Columbia Oil and Gas Commission does not permit venting from fracturing wastewater storage tank vents (BCOGC, 2011 NPR).

Requiring flares or incinerators where gas cannot be collected and transferred to the collection network would reduce methane, VOC, and HAP emissions (US EPA Gas Star Lessons Learned).

Effectiveness

- Open flaring can create visible impacts (US EPA Gas Star Lessons Learned)
- Flaring may not be an appropriate option in populated areas

- There would potentially be an increased risk of grass or forest fires (US EPA Gas Star Lessons Learned)
- It is typically assumed that flares have the potential to be highly efficient (98-99%), but studies on oil and gas field flares have found lower efficiencies (62-84%) (Four Corners AQTF Mitigation Options, 2007 NPR p94)
- Flares reduce emissions of methane and volatile organic compounds, but result in increased emissions of CO_2, SO_X, NO_X, PM, and CO (US EPA Gas Star Lessons Learned)
- Flares used during hydraulic fracturing could remain in place to control emissions from produced water and condensate tanks during production
- Flares minimise the risk of explosion by providing a controlled burn of surplus natural gas

Feasibility

The US EPA has proposed regulations requiring flaring emissions from wastewater storage tank for hydraulically fractured exploratory and delineation wells unless there is a safety hazard (US EPA Proposed NSPS Fact Sheet, 2011d NPR).

Proposed permit conditions set out in the New York State Draft Supplemental Generic Environmental Impact Statement would prohibit flaring during completion operations if a gathering line is in place (New York State DEC 2011 PR p5-135). British Columbia OGC requires gas collection and transfer to pipeline where appropriate, or flaring in situations where a pipeline connection is not available in the vicinity of the site. Operators are required to co-operate to deliver the most effective solution for control of fugitive gas (British Columbia OGC, 2011 NPR).

Recommendation

It is recommended that the introduction of this measure is considered, in view of the potential effectiveness of this measure in mitigating the impact. .

5.9 Groundwater contamination during fracturing and completion

There are three mechanisms that could potentially result in contact between fluids from drilling and fracturing, and sensitive groundwater. Firstly, the down hole flow and flowback of the fracturing fluids, drilling fluids, produced water and gases in the well could result in contact with groundwater if the wells are not properly constructed. Secondly, subsurface drinking water supplies could also be contaminated during surface events, such as accidental spills and leakage from surface impoundment used to store fracturing fluid and flow back. Thirdly, groundwater could potentially be contaminated in the event that fractures extend beyond the production zone. The likelihood of aquifer contamination through fractures is remote where there is more than 600 metres separation between the drinking water sources and the producing zone. However, where there is no such large depth separation, the risks are greater.

5.9.1 Monitoring of groundwater quality

Requirements for systematic groundwater quality monitoring will not prevent pollution by themselves, but will be an important element in identifying any contamination issues which arise, and enabling remedial actions to be taken, should pollution occur.

Description

Issues have been identified in the US whereby groundwater contamination has been tentatively identified (US EPA, 2011c NPR ; Osborn et al., 2011 PR), but establishing the source of contamination is highly complex because of the absence of baseline monitoring data. It would therefore be important to carry out regular monitoring of baseline groundwater quality throughout the stages of a shale gas extraction programme:

- Prior to exploration, in vicinity of exploration wells (to identify potential receptors)
- During exploration, in vicinity of exploration wells (to identify potential receptors)
- Prior to production phase, throughout area of planned production focusing in particular on potentially sensitive groundwaters and over a period sufficient to identify baseline conditions
- During production phase, throughout area of production focusing in particular on potentially sensitive groundwaters
- Following production phase, throughout area of production focusing in particular on potentially sensitive groundwaters until surrender of site (analogous to monitoring carried out in relation to landfill sites under the terms of operating permits issued under the IPPCD)
- Regular monitoring of pressure heads in sensitive aquifers, during all stages, at locations in the vicinity of exploration wells and in the vicinity of drinking water wells, to provide information about ground water flow direction and velocity.

The monitoring programme would need to have regard to the pollutants of potential concern, including methane, fracturing fluid constituents, and contaminants likely to be present in produced waters as determinants to indicate any unacceptable discharges to controlled water.

Effectiveness

Requirements for systematic groundwater quality monitoring will be effective as part of a wider set of measures of prevention of groundwater pollution and ongoing assessment and monitoring of shale gas extraction installations.

Feasibility

Groundwater monitoring is an established feature of hydrocarbons, mineral extraction and industrial process operations in Europe at present, but is often carried out only in the event of a pollution event occurring or being suspected. For other installations such as landfill sites, groundwater monitoring takes place routinely. Some drinking water wells may be private wells which do not meet relevant construction standards. This may compromise the ability to take representative samples.

Recommendation

It is recommended that the introduction of this measure is considered, in view of the potential effectiveness of this measure in mitigating the impact. It will be important for any regulatory regime to be sufficiently flexible to accommodate the range of circumstances likely to be encountered in practice. This impact was identified as potentially of concern with regard to individual site impacts, and a monitoring programme may also need to be carried out before and during the exploration phases to establish a baseline. Consequently it is relevant for both the exploration and production phases.

5.9.2 Restrict hydraulic fracturing in areas with potentially significant groundwater risks

Many shale gas developments are insulated from potential effects on groundwater contamination due to the depth of the producing zone, occurrence of low permeable geological strata between the producing zone and aquifers, and absence of natural or man-made pathways in the geological strata. However, these conditions are not uniform (US Department of Energy, 2011 NPR). Impacts could potentially occur in the event of fracturing extending outside the target formation, potentially providing pathways to near-surface groundwater.

Description

This measure would comprise a restriction on or prevention of the use of HVHF in zones at greater risk of groundwater contamination by virtue of the geological features. The use of HVHF would be limited to formations at a significant depth with low permeability strata above the formation, and the absence of pathways to near-surface groundwater. This measure would comprise the specification of criteria that must be met before HVHF can be permitted for use for shale gas exploration or extraction. For example, based on Davies et al. (2012 PR), an appropriate vertical separation between shale gas extraction and aquifer may be considered to be 600 metres, slightly longer than the maximum recorded vertical fracture length of 588 m. A minimum vertical separation was recommended by the International Energy Agency (2012 NPR p13), and restriction of hydraulic fracturing in sensitive areas (aquifers and mineral resources) was proposed by the German Environment Ministry (Umweltbundesamt 2011 NPR p23).

Effectiveness

This measure would potentially be effective in mitigating risks of groundwater contamination in areas potentially at higher risk.

Feasibility

Criteria of this nature are under consideration with respect to the protection of surface waters (see Section5.4.6).

Recommendation

It is recommended that the introduction of this measure is considered, in view of the potential uncertainties associated with the control of the hydraulic fracturing process (e.g. USEPA 2011a PR , p30), and additional uncertainties that may be introduced by transferring techniques developed for use in the US to the European context. This impact was identified as potentially of concern with regard to individual site impacts, and consequently it is relevant for both the exploration and production phases.

5.9.3 Appropriate standard and quality assurance of well casing

Proper installation and quality assurance of well casings is essential for long-term protection of groundwater and surface water resources, and indirectly for ensuring ongoing protection of drinking water quality and natural ecosystems.

Description

The following sequence of casing is a minimum requirement:

- Conductor (for wellhead)
- Surface casing (to isolate near-surface aquifer from production)
- Intermediate casing (to provide isolation of deeper aquifers from production)
- Production casing (in target formation)

With regards to casing quality the following recommendations are made:

- Casing material must be compatible with fracking chemicals (e.g., acids)
- Casing material must also withstand the higher pressure from fracturing multiple stages, and from re-fracturing on up to four occasions

- The casing shall be properly centred to enable complete cementing of the annulus (space between casing and borehole wall)

With regards to cement quality the following recommendations are made:

- Sufficient time shall be allowed for the cement to harden
- Tests shall be carried out to determine in situ cement quality
- Regulations and inspections are needed to confirm that operators have taken prompt action to repair defective cementing

Effectiveness

An adequately installed casing throughout the entire well, together with ongoing inspection, monitoring and maintenance, provides sufficient protection against groundwater pollution.

Feasibility

The full installation and cementation of casings in this way is already standard practice in European conventional hydrocarbon operations, particularly onshore. However, the use of hydraulic fracturing may require a higher standard of installation and quality assurance.

Installation and cementation of well casings are routine for well-established oil and gas contracting companies and operators. Additional design, verification and monitoring measures may be needed for high volume hydraulic fracturing operations. These measures are established practice in this industry in the US and could be adapted for use in Europe.

Recommendation

It is recommended that the introduction of this measure is considered in view of the potential effectiveness of this measure in mitigating the impact. It will be important for any regulatory regime to be sufficiently flexible to accommodate the range of circumstances and technical issues likely to be encountered in practice. Because of the limited experience of relation to HVHF in Europe and absence of relevant standards specific to HVHF, this measure may require the development of new safeguards for application in Europe as described in Section5.2. This impact was identified as potentially of concern with regard to individual site impacts, and consequently it is relevant for both the exploration and production phases.

5.9.4 Surface impoundment construction standards

Proper liner construction will prevent infiltration of stored fluids to the subsurface. Proper impoundment design and construction will prevent a failure or unintended discharge off site.

Description of measure

To prevent migration of fluid stored in surface impoundments to groundwater, requirements or a programme to review and approve surface impoundment construction and operation could be established. Elements may include [API HF3 2011 NPR , page 11]

- Initial review of site topography, geology, and hydrogeology
- Identification of the distance between the proposed impoundment and ground water features such as public or private water wells and domestic supply springs and surface water features (wetland, lake, pond, etc.)
- Requirements for impermeable liners, either compacted clay or synthetic materials such as polyethylene, to prevent groundwater contamination
- Design and construction requirements for structural integrity
- Documentation of materials placed in the impoundment

The pros of this measure are:

- Requirements are similar to existing programmes for wastewater impoundment construction and operation, and use established techniques

The cons of this measure are:

- Short term storage in clay soils may not justify the cost of impermeable liners. This would need to be taken into account via the appropriate permitting process.

Effectiveness

Lined impoundments can reduce potential for groundwater contamination from stored fracturing fluids. A similarly effective alternative would be storage in above ground storage tanks with secondary containment. Tanks used in this way should also meet relevant established standards.

Feasibility

Requirements are similar to existing programs for wastewater impoundment construction and operation.

Recommendation

This measure should be further considered. It will be important for the regulatory regime to be operated in a sufficiently flexible way to accommodate the range of circumstances and technical issues likely to be encountered in practice. This impact was identified as potentially of concern with regard to individual site impacts, and consequently it is relevant for both the exploration and production phases.

5.9.5 Leak and spill prevention, detection, and control

Description of measure

Establish requirements or a program to review and approve operator plans for spill incident prevention, detection, and containment. Such requirements may be patterned on oil spill prevention control and countermeasure requirements. This measure is discussed in detail in Section 5.10.4.

5.9.6 Control of fracturing process

During fracturing, leakage of fracturing liquid through fractures into the ground water could be possible. Furthermore hydraulic fracturing can affect the mobility of naturally occurring fluids, gases, trace-elements, radio-active and organic material. Since there is an uncertainty in fracture location, fracture may lead to local geologic or man-made features potentially creating pathways that allow fluids of gases to contaminate drinking water resources. Besides leakage through artificial pathways there is also a possibility of leakage through natural pathways, such as cracks, fissures or interconnected pore spaces.

Control of the hydraulic fracturing process is important to ensure that leakage via extended fractures into the groundwater zone does not take place.

Description

Appropriate technical measures for control of hydraulic fracturing are set out in Section A6.3.2, in the section headed "*Control of fracturing operation*".

Effectiveness

There is little evidence of failures in the hydraulic fracturing operations in the US resulting in contamination of groundwater. If substantiated, the examples which may exist (US EPA 2011c NPR , Osborn et al. 2011 PR) relate to poor practice which would be identified and addressed via the implementation of appropriate controls on the well design, fracturing and gas extraction processes. However, groundwater contamination remains a potential risk and an area of uncertainty in view of the risk of fractures extending beyond the planned zone.

Feasibility

Appropriate standards and controls for the hydraulic fracturing process could be implemented, drawing on sources such as API methodologies (API, 2009 NPR and API, 2011 NPR). These measures are established practice in this industry in the US and could be adapted for use in Europe.

Recommendation

It is recommended that the introduction of this measure is considered, in view of the potential effectiveness of this measure in mitigating the impact. It will be important for any regulatory regime to be sufficiently flexible to accommodate the range of circumstances and technical issues likely to be encountered in practice. This impact was identified as potentially of concern with regard to individual site impacts, and consequently it is relevant for both the exploration and production phases.

5.10 Surface water contamination during fracturing and completion

Surface water may be contaminated during high volume hydraulic fracturing by

- discharges of well site wastewater to surface streams
    - directly from the fracturing operation, or
    - via discharge to wastewater treatment plants
- accidental leaks and spills of well site wastewater (returned fracturing fluid (flowback) and produced water)
- site-contaminated runoff

5.10.1 Monitoring of surface water quality

Requirements for surface water quality monitoring will not of themselves prevent pollution, but will be an important element in identifying any contamination issues which arise, and assisting in identifying and mitigating the sources of any contamination. Targeted monitoring focused on the substances and areas of potential concern with regard to proposed or ongoing unconventional hydrocarbon extraction will add significant value to established surface water monitoring programmes at river basin level.

Description

It would be helpful to carry out monitoring of baseline surface water quality throughout the stages of a shale gas extraction development:

- Prior to exploration, in vicinity of exploration wells
- During exploration, in vicinity of exploration wells
- Prior to production phase, throughout area of planned production focusing in particular on potentially sensitive surface waters
- During production phase, throughout area of production focusing in particular on potentially sensitive surface waters
- Following production phase, throughout area of production focusing in particular on potentially sensitive surface waters

Monitoring would need to have regard to the pollutants of potential concern, including methane, fracturing fluid constituents, and contaminants likely to be present in produced waters.

Effectiveness

Requirements for surface water quality monitoring will be effective as part of a wider set of measures for prevention of water pollution and ongoing assessment and monitoring of shale gas extraction installations.

Feasibility

Surface water monitoring requirements are an established feature of hydrocarbons, mineral extraction and industrial process operations in Europe at present under the terms of site operating permits.

Recommendation

It is recommended that the introduction of this measure is considered, in view of the potential effectiveness of this measure in mitigating the impact. It will be important for any regulatory regime to be sufficiently flexible to accommodate the range of circumstances likely to be encountered in practice. Monitoring may need to be carried out before and during the exploration phases to establish a baseline, and consequently it is relevant for both the exploration and production phases.

5.10.2 Limit pollutant concentrations in wastewater discharges

Limiting discharged pollutant concentrations will protect receiving stream ecosystems and also protect municipal sewage treatment plants. Sewage treatment plants are designed to remove dissolved organic constituents, nitrogen compounds, and phosphates, but not the dissolved salts contained in untreated HVHF wastewater. As a result, the dissolved salts will pass through the municipal plant untreated and may also reduce the overall effectiveness of the sewage works. Limits already exist on a range of substances under the Water Framework Directive and can be applied to individual installations under permitting regimes such as IPPC, but it may be beneficial to extend the range of wastewater discharge concentration limits to include the substances of potential concern with regard to wastewater from unconventional gas operations.

Description of measure

Contamination can be controlled by limiting the mass and/or concentrations of pollutants of concern in wastewaters discharged to surface waters. (Alternatively, discharges may be prohibited, as discussed in 5.2.3.) Allowable discharge concentrations may be determined based on existing water quality criteria or the capacity of the receiving water to assimilate the pollutants. Another approach is to base allowable discharge concentrations on feasible treatment technology, i.e., “best available treatment.” Either approach requires detailed understanding of the identity and concentrations of pollutants present in the wastewater. Following SEAB (2011a NPR), it is recommended that measurement of the chemical composition of produced water should be a routine industry practice

The pros of this measure are:

- Properly designed limitations will protect water quality
- Pollutant discharge limitations, rather than discharge prohibition, provides operators with flexibility in managing wastewater
- If pollutant discharge limitations allow the operator to discharge near the well site, this alternative could reduce impacts of transporting HVHF wastewater.

The cons of this measure are:

- Development of limitations requires detailed knowledge of wastewater pollutants, their impacts on receiving streams, and effective treatment. Industry heterogeneity increases the required information
- Development of limitations can be a lengthy (and expensive) process

- Wastewater treatment generates residuals, such as brines and sludges, that require further disposal
- Implementation of discharge limitations requires industry self-monitoring and active government approval (permitting), inspection, and recordkeeping.

Any controls introduced in this way would need to conform with existing requirements for water treatment and discharge.

Effectiveness

Limitations on TDS and other specific pollutants will prevent surface water contamination from known pollutants. However, a wide range of other constituents are used in fracturing fluids in low concentrations. The toxicity and environmental effects of many constituents are not known and also there may be no methods to monitor their presence in wastewater. Limitations for TDS and other pollutants may not be protective if they do not also control concentrations of these unidentified fracturing fluid constituents.

Feasibility

Sodium chloride (salt) is the pollutant present in highest concentration in HVHF wastewater. Depending on the geologic formation, concentrations of total dissolved solids (TDS) average 60,000 to 110,000 mg/L (Acharya 2011 NPR , Hayes 2011 NPR , Mantell 2011 NPR). For comparison, seawater salinity is approximately 35,000 mg/L. Technologies available to reduce TDS concentration include reverse osmosis (for TDS <50,000 mg/L) and evaporation plus crystallization. These technologies are expensive, energy intensive, and generate treatment residuals (brine and salt crystals) that require disposal. Attention would also need to be given to the treatment and disposal of water and sludges containing NORM.

Development of limitations requires detailed knowledge of wastewater pollutants, their impacts on receiving streams, and identification of effective and affordable treatment. Industry heterogeneity increases the required information. Development of limitations can be a lengthy (and expensive) process. Enforcement requires active government approval (permitting), inspection, and recordkeeping.

Recommendation

It is recommended that the introduction of this measure is considered, in view of the potential effectiveness of this measure in mitigating the impact. It will be important for any controls to be consistent with existing measures for control of discharges to water, and to be sufficiently flexible to accommodate the range of circumstances and technical issues likely to be encountered in practice. This impact was identified as potentially of concern with regard to cumulative impacts, and consequently it is primarily relevant for the production phase.

5.10.3 Prohibit wastewater discharges

Prohibiting discharges protects surface water and sewage treatment plants while providing an incentive for wastewater reuse, which will reduce demands on water resources.

Description of measure

The Mining Waste Directive (2006/21/EC) specifies that a permit and waste management plan are required for any relevant facility. These together ensure that the necessary measures are in place to prevent environmental impacts due to the waste facility. This would require avoidance of discharge of untreated or treated effluent, if the effluent posed a significant environmental hazard. Article 10 of the WFD advises that BAT should be used for control of discharges to water, or emissions standards should be applied.

The risk of contamination could theoretically also be controlled by prohibiting HVHF wastewater discharges to surface waters (Kline 2012 NPR , p 23 – 32). Operators would then need to manage wastewater by other means such as:

- Reuse as fracturing fluid make up
- Injection in disposal well (would only be permitted in non-aquifers in Europe)
- Other use (e.g., recovery of useful dissolved salts)

The pros of this measure are:

- Wastewater reuse will reduce required freshwater and reduce demands on water resources
- Discharge prohibition is more straightforward to implement than pollutant limitations

The cons of this measure are:

- Reuse of wastewater may require changes to fracturing fluid chemistry
- Prohibition of discharge may require wastewater disposal by alternative means, which would have associated environmental impacts if wastewater must be hauled longer distances to disposal facilities
- Underground injection requires regulatory management, including control of well locations and the amount of fluid injected, in order to protect groundwater quality and prevent induced seismicity. The European Commission's legal interpretation of the EU environmental framework applicable to HVHF, of December 2011, concluded that disposal of wastewater through underground injection into geological formations is prohibited under the Water Framework Directive.
- Feasible uses for HVHF wastewater salts have not yet been developed (Silva et al. 2011 NPR , p3)

Effectiveness

Prohibiting discharges protects surface water from impacts of all pollutants present in the wastewater, those known and measurable as well as pollutants that may be present but not measureable.

Feasibility

Reuse of fracturing fluid flowback and high salt produced water is dependent on fracturing chemistry requirements. Some jurisdictions do not allow (or are phasing out) underground injection (see discussion in Section 4.2.8). If there is a lack of alternative disposal or re-use options, prevention of discharge of treated HVHF waste waters to surface water could effectively prevent the development of hydraulic fracturing in Europe.

Recommendation

This measure would go beyond the provisions of the Mining Waste Directive and Water Framework Directive, and the discussion in Chapter 2 suggests that it is not likely to be required. It is recommended that implementation of this measure is not pursued.

5.10.4 Leak and spill prevention, detection, and control

US EPA (2011a PR page 29) cites numerous media reports of spills, though robust data on their frequency is not available. Spill prevention is much more cost-effective and preferable in principle to clean-up following spillages

Description of measure

Establish requirements to review and approve operator plans for spill incident prevention, detection, and containment. Such measures may be patterned on oil spill prevention control and countermeasure requirements. The principles and approaches to managing leak and spill risks are established generic good practice in the oil and gas industry.

Elements may include [API HF3 2011 NPR , p11]

- Spill prevention practices
    - Equipment maintenance and corrosion abatement programs
    - Tests and inspections of lines, vessels, valves, and hoses
    - Proper storage of fracturing chemicals
    - Inspection of fracturing chemical containers before and during the fracturing operation
- Spill detection practices
    - Routine visual inspection
    - Tank level indicators
    - Groundwater monitoring
- Spill containment practices
    - Sloping the well pad away from surface water
    - Positioning absorbent mats between active sites and surface water
    - Perimeter trenching and catchments
    - Enclosing tanks in secondary containment adequate to hold tank volume
    - Positioning of buffers around potentially sensitive surface water resources
- Spill response procedures
    - Notification requirements
    - Clean up kits and practices

The pros of this measure are:

- Elements of a spill prevention plan will be familiar to operators who have developed oil spill prevention and control plans
- Spill prevention measures are effective at avoiding impacts which arise from spillage of potentially hazardous materials.

The cons of this measure are:

- Spill prevention measures cannot fully eliminate the risk of spillage
- A high standard of management and operation is required, which could not be the subject of frequent inspection at every site in the event of intensive development.

Effectiveness

Preventing spills is a cost effective means of protecting surface water from HVHF contamination.

Feasibility

Spill prevention and containment is standard practice for chemical and oil storage.

Recommendation

It is recommended that the introduction of this measure is considered. This impact was identified as potentially of concern with regard to cumulative impacts, and consequently it is primarily relevant for the production phase.

5.10.5 Erosion and run on/run off control

Minimizing the storm water or precipitation that flows across the well site will minimize the potential to transport contaminants to surface water.

Description of measure

Establish a program to review and approve operator plans for stormwater management and control. Plan elements may include (API HF3, 2011 NPR , p 13; Polzella 2011 NPR , p 5-6).

- Installation of systems to control stormwater coming on to the location (run-on) and escaping from the location (runoff)
- Location of equipment, pads, and impoundments away from natural drainage so stormwater runoff does not erode base material (which could lead to failure of impoundments and release of wastewater to local surface waters)
- Use erosion control devices, such as
  - Straw mulching
  - Hydromulch/hydroseeding
  - Geotextiles
  - Straw erosion blankets
  - Terracing, Soil Roughening
  - Chemical Stabilization/Soil Binders
  - Rock armouring
  - Compost filter socks
  - Silt fence
  - Sediment traps and sediment basins
  - Inlet protection
  - Hay bale dikes
- Inspection of site control devices both on a regular bases and following each significant storm event, to identify needed repairs to stormwater control systems
- Prompt completion of any necessary repairs

The pros of this measure are:

- Stormwater management practices are widely known and applied in the oil and gas exploration and production industry.

The cons of this measure are:

- In the event of intensive shale gas development, a formal review program may overextend the resources of regulatory authorities.

Effectiveness

Preventing run on, run off, and erosion is a cost effective means of protecting surface water from HVHF contamination.

Feasibility

Stormwater management practices are widely known and applied in the oil and gas exploration and production industry.

Recommendation

It is recommended that the introduction of this measure is considered, in view of the potential effectiveness of this measure in mitigating the impact. This impact was identified as potentially of concern with regard to cumulative impacts, and consequently it is relevant for the production phase.

5.11 Groundwater contamination during production

Measures for protection of groundwater contamination during production are similar to those described in relation to the fracturing and completion stages in Section5.9.

Additionally, it is recommended that consideration is given to adapting the relevant provisions of the Carbon Capture and Storage directive (2009/31/EC), and the recommendations of the World Resources Institute (2010 NPR), with regard to hydraulic fracturing fluid remaining in the shale gas formation, as described in Section 5.2.

5.12 Releases to air during production

Production emission sources include tank vents, pneumatic controllers, and glycol dehydrators. Emissions of methane, volatile organic compounds and hazardous air pollutants during production are of most significant concern, together with the potential for contributing to the formation of low-level ozone.

5.12.1 Monitoring of air quality

A programme of air quality monitoring will not itself prevent pollution, but will be an important element in identifying any air quality issues which arise, and assisting in identifying and mitigating the sources of any significant levels of air pollutants. Targeted monitoring focused on the substances and areas of potential concern with regard to proposed or ongoing unconventional hydrocarbon extraction will add significant value to established air quality monitoring programmes.

While it would be difficult to establish the effect of an individual site on air quality, the overall influence of multiple sites on air quality has become apparent in some areas, and an appropriate monitoring programme would be able to identify any significant effects on air quality of extensive shale gas development.

Description

It would be helpful to design and carry out monitoring of air quality throughout the stages of a shale gas extraction programme:

- Prior to exploration, in the vicinity of exploration wells
- During exploration, in the vicinity of exploration wells
- Prior to production phase, throughout area of planned production focusing in particular on potentially sensitive areas (e.g. residential areas downwind of intensive production zones)
- During production phase, throughout area of production focusing in particular on potentially sensitive areas
- Following production phase, throughout area of production focusing in particular on potentially sensitive areas

The monitoring programme would need to have regard to the pollutants of potential concern and associated indicator substances, including methane, volatile organic compounds, oxides of nitrogen, particulate matter, and ozone.

Effectiveness

Requirements for air quality monitoring will be effective as part of a wider set of measures, or a programme of minimisation of emissions to air and ongoing assessment and monitoring of shale gas extraction installations.

Feasibility

Air quality monitoring requirements are an established feature of hydrocarbons, mineral extraction and industrial process operations in Europe at present under the relevant permitting regimes.

Recommendation

It is recommended that the introduction of this measure is considered as a precautionary step in the event of intensive development of shale gas installations. Monitoring may need to be carried out before and during the exploration phases to establish a baseline, and consequently it is relevant for both the exploration and production phases.

5.12.2 Require vapour recovery units for tank emissions

This measure would result in reduced methane and VOC emissions, with potential benefits for formation of secondary pollutants such as ozone and visible haze. There are no specific requirements for such measures in Europe at present.

Description of measure

Install vapour recovery units on produced water and condensate tanks to capture the flash emissions that occur because of the pressure drop between the separator and atmospheric storage tanks (Four Corners AQTF p80). The recovered gas can be compressed and sold, used as fuel gas for equipment at the site, or piped to a stripper unit to separate out natural gas liquids and methane (US EPA Gas STAR Program VRU; Richards 2011 NPR).

Effectiveness

VRUs can recover 95% of the vapours (US EPA (2012c NPR) Gas STAR Program VRU)

Feasibility

- Requires steady source of tank vapours and information on vapour quantity for sizing (US EPA Gas STAR Program VRU)
- Installation depends on availability of a use for the vapours (US EPA Gas STAR Program VRU; Richards 2011 NPR)
- When gas gathering systems operate at a high pressure, VRU requires additional gas compression

This method may incur additional costs.

Recommendation

It is recommended that the introduction of this measure is proposed, in view of the potential effectiveness of this measure in mitigating the impact, having regard to potential site-specific issues relevant to the applicability of this measure. This impact was identified as potentially of concern with regard to cumulative impacts, and consequently it is relevant for the production phase.

5.12.3 Require low-bleed or no-bleed pneumatic controllers

Reduced emissions of methane and VOCs

Description of measure

Hydraulically fractured wells are typically located at remote sites that do not have access to a compressed air supply ("plant air"). As a result, operators typically use natural gas pneumatic controllers, which can come in "high-bleed," "low-bleed," or "no-bleed" options. US EPA Natural Gas STAR Program defines "high-bleed" as devices that bleed over 0.17 m^3 per hour (1500 m^3/year) (US EPA Gas Star Pneumatics). The constant bleed of natural gas is one of the largest sources of methane emissions from HVHF installations (Four Corners AQTF p118).

Feasibility

- Low-bleed controllers are readily available and commonly used by the natural gas production industry (Four Corners AQTF p111)
- No-bleed controllers are only available in locations that can use plant air or have electricity (Four Corners AQTF p111)

Effectiveness

- EPA reported payback for retrofitting high-bleed to low-bleed units is 5-21 months (Four Corners AQTF p112)
- EPA reported emissions reductions of 1400 - 7400 m^3 per year per controller (Four Corners AQTF p112)
- Field testing of low-bleed pneumatic controllers by CETAC-WEST at six sites in Western Canada resulted in 70% reduction in natural gas consumption (CETAC-WEST, 2005 NPR)

Recommendation

It is recommended that the introduction of this measure is proposed, in view of the potential effectiveness of this measure in mitigating the impact, having regard to potential site-specific issues relevant to the applicability of this measure. This impact was identified as potentially of concern with regard to cumulative impacts, and consequently it is relevant for the production phase.

5.12.4 Require desiccant rather than glycol dehydrators

Reduced methane, VOC, and hazardous air pollutant emissions as compared to glycol dehydrators

Description of measure

Dehydration removes water from the natural gas prior to sale. Some natural gas does not require dehydration. Desiccant dehydration uses moisture-absorbing salts (e.g., calcium, potassium, or lithium chlorides) to remove the water. The wet natural gas passes through a bed of desiccant tablets that remove moisture and form a brine solution. The brine solution must be drained when required and the bed must be refilled. Operators typically operate two desiccant dehydrators in parallel so maintenance can be performed on one without shutting down production. Emissions from desiccant dehydrators may occur when the vessel is depressurized and re-filled (Four Corners AQTF p85).

Effectiveness

- Conventional glycol dehydrators continuously release methane, VOCs, and HAPs. Some operators found 99% decrease in emissions of these gasses when they converted to a desiccant dehydrator (Four Corners AQTF p85)
- US EPA Natural Gas STAR Program estimated 280 m^3/year total emissions from a desiccant dehydrator compared to 30,000 m^3/year total emissions from a glycol dehydrator with a flow rate of 28,000 m^3/day natural gas operating at 31 bar and 8°C (US EPA Gas Star Desiccant Dehydrator p9)
- Additional beneficial impacts: reduced ground contamination because no glycol, reduced fire hazard, lower maintenance (no moveable parts), no need for external power (Four Corners AQTF p85)

Feasibility

- Desiccant dehydrators work best when operating at higher pressure, lower temperature, and comparably low flow rates (US EPA Gas Star Zero Emissions Dehydrators p2):
  - Gas to be dried is 140,000 m^3/day or less (Four Corners AQTF p85)
  - Wellhead gas temperature is low (<15°C for calcium chloride and <21°C for lithium chloride) to avoid forming hydrates that can precipice in the brine solution and cause problems. If the gas is too hot, it can be cooled or compressed, but this increases the system cost (Four Corners AQTF p85)
  - Wellhead gas pressure is high (>17 bar for calcium chloride and >7 bar for lithium chloride) (Four Corners AQTF p85)
- Estimated capital cost for one 50 cm vessel with 28,000 m^3/day gas flow is approximately $8,100 with operating costs approximately $4,700/year ; estimated payback 21 months (US EPA Gas STAR Dehydration 2007 NPR , slides 19, 22). The global market in gas production equipment indicates that equipment capital costs are likely to be similar in Europe. Operating costs may differ due to differences in gas production expertise and methods in Europe compared to the US.

Recommendation

It is recommended that the introduction of this measure is considered, in view of the potential effectiveness of this measure in mitigating the impact, having regard to potential site-specific issues relevant to the applicability of this measure. This impact was identified as potentially of concern with regard to cumulative impacts, and consequently it is relevant for the production phase.

5.12.5 Require zero emission glycol dehydrators

Reduced methane, VOC, and HAP emissions as compared to standard glycol dehydrators. Existing glycol dehydrators can be retrofitted with zero emissions technology through modifications of the gas stream piping, valves, pumps, and controllers, as well as modification of the fuel used, and/or the dehydrating media. (Natural Gas Star PR O Fact Sheet No. 206).

Description of measure

Glycol dehydrator technology can be adapted to eliminate emissions by combining emission reduction technologies into one system. The glycol still vapours include water and condensable and non-condensable hydrocarbons. In a standard glycol dehydrator these vapours are directly vented. In a zero emissions dehydrator, the vapours are condensed and separated. The water is disposed of with other wastewater; the condensable hydrocarbons are sold as condensate; and the non-condensable hydrocarbons (e.g., methane and ethane) are used as fuel in the glycol reboiler. The only emissions source for the zero emissions dehydrator is the glycol reboiler.

Feasibility

- Require electric utilities or an engine-generator set
- More appropriate than desiccant dehydrators for lower pressure, higher temperature, and higher flow rates
- Can reduce emissions more using an electric glycol circulation pump, but requires electrical source (Four Corners AQTF p91)
- Results in condensate collection, which can be sold (Four Corners AQTF p91)

- Cost of zero emissions dehydrators are comparable to glycol dehydrators; EPA estimates 1 year payback (Four Corners AQTF p91). Payback times may be longer in Europe because of potentially higher purchase and operational costs, particularly in the early stages of development of the shale gas market.

Effectiveness

- HAP destruction efficiency of 98% (Four Corners AQTF p91)
- Data from the U.S. Environmental Technology Verification Program (ETV Zero Emissions Dehydrator p4-5):
  - Average NO_X emissions: 65 ppm; 0.037 kg/hr
  - Average CO emissions: 0.6 ppm; 0.00023 kg/hr
  - Average VOC emissions: 0.6 ppm; 0.00014 kg/hr
  - Average emissions of hazardous air pollutants: below detection limit of 0.1 ppm
  - No methane detected
- US EPA Natural Gas STAR Program estimated 890,000 m^3 annual methane emissions reduction from zero emission dehydrators compared to conventional glycol dehydrators (US EPA Gas STAR Zero Emission Dehydrators p1-2)

Recommendation

It is recommended that the introduction of this measure is considered, in view of the potential effectiveness of this measure in mitigating the impact, having regard to potential site-specific issues relevant to the applicability of this measure. This impact was identified as potentially of concern with regard to cumulative impacts, and consequently it is relevant for the production phase.

5.13 Biodiversity impacts during production

Risks are posed to biodiversity by potential impacts such as surface water pollution and water resource depletion. These are addressed in the appropriate sections of this chapter (see Sections 5.4.2, 5.4.5, 5.6.2, 5.7.1and 5.7.4.)

Other than these pollution-related issues, the key issue for biodiversity impacts is the risk posed by habitat degradation and fragmentation, and introduction of invasive species (New York State DEC 2011 PR Section 6.4). Habitat fragmentation can be minimised during the design stage, as described in Section 5.4.

5.13.1 Minimise risks posed by invasive species

Invasive species can present risk of adverse impacts on sensitive habitat sites (Heatley 2011 NPR ; Brittingham 2011 NPR). It is appropriate for operators to take all feasible measures to reduce the risk of such impacts.

Description of measure

New York State DEC (2011 PR p7-88 to 7-94) sets out a range of measures to minimise the introduction and spread of invasive species, and to encourage restoration of native vegetation. These measures would be set out in an agreed site specific invasive species mitigation plan, and may include the following:

- All machinery and equipment to be washed with high pressure hoses and hot water prior to delivery to the project site;

- All trucks, machinery and equipment to be checked prior to entry and exit of the project site;
- All fill and/or construction material from offsite locations should be inspected for invasive species and should only be utilized if no invasive species are found growing in or adjacent to the fill/material source; and
- Only certified weed-free straw should be utilized for erosion control.
- Native vegetation should be re-established and weed-free mulch should be used on bare surfaces to minimize weed germination;
- Only native (non-invasive) seeds or plant material should be used for re-vegetation
- All seed should be from local sources to the extent possible;
- Re-vegetation should occur as quickly as possible at each project site;
- Any top soil brought to the site for reclamation activities should be obtained from a source known to be free of invasive species;
- The site should be monitored for new occurrences of invasive plant species following partial reclamation.
- Any new invasive species occurrences found at the project location should be removed and disposed of appropriately.
- Prior to any ground disturbance, any invasive plant species encountered at the site should be stripped and removed.
- Run-off resulting from washing operations should not be allowed to directly enter any water bodies or wetlands.
- Loose plant and soil material that has been removed from clothing, boots and equipment, or generated from cleaning operations would be destroyed or appropriately disposed of off-site.
- Water should not be transferred from one water body to another.

Effectiveness

Measures such as those set out above are effective in reducing the risk and extent of spread of invasive species. Close attention and management would need to be paid to ensure that impacts have been reduced to the maximum extent possible. However, measures such as these could not fully eliminate the risk of spreading of invasive species. This risk would be more acute for development of numerous sites in a sensitive habitat area.

Feasibility

Measures to reduce the spread of invasive species are established for use in the US in relation to unconventional gas extraction, and in Europe for a wide range of developments.

Recommendation

It is recommended that the introduction of controls on invasive species via a site-specific mitigation plan should be considered. This impact was identified as potentially of concern with regard to cumulative impacts, and consequently it is primarily relevant for the production phase.

5.14 Lower priority impacts

The impacts identified as being of moderate significance are listed in Section 2.10.

Similar impacts to all these "moderate" significance issues are addressed in the sections above, in relation to different stages of the gas exploration and production process, and/or in relation to cumulative effects in some cases where the effects of individual installations are considered to be of moderate significance. The recommendations in the discussion set out above addresses all the issues identified as being of "medium" significance, in addition to the "high" and "very high" significance issues.

5.15 Summary table

Table 11 below provides a summary of the identified measures, and highlights measures which would bring synergistic effects in addressing multiple potential impacts. The table highlights that a wide range of measures would potentially have a beneficial impact on protection of biodiversity.

Measures which envisage the construction of additional pipework infrastructure to transfer water to and from shale gas extraction sites bring a potential negative impact on biodiversity and land take associated with the additional pipeline infrastructure. Hence, the use of alternative means of transportation of water could result in beneficial effects on biodiversity due to reduced traffic impacts, but also adverse effects due to the construction of new pipelines.

5.16 Recommendations for further consideration and research

It is recommended that consideration is given to research recommendations made by SEAB (2011a NPR) which would be relevant to hydraulic fracturing in Europe:

- The use of micro-seismic monitoring in relation to hydraulic fracturing
- Determination of the chemical interactions between fracturing fluids and different shale rocks
- Induced seismicity triggered by hydraulic fracturing
- Development of less environmentally hazardous drilling and fracturing fluids
- Development of improved casing and cementing methods.

It is recommended that a readily accessible database on hydraulic fracturing fluid composition is developed for European high volume hydraulic fracturing projects (developing a recommendation presented to the European Parliament, Lechtenböhmer et al., 2011 NPR p61). To be valuable, completion of the database would need to be a requirement for all high volume hydraulic fracturing activities, and it should be fully searchable by geographic location and by chemical species/additive name. This would be useful for regulators and would also be of interest to researchers and local communities.

The SEAB (2011a NPR p20) recommends that research should be carried out into the risks and causes of methane migration into groundwater from shale gas extraction. This was supported by an academic consultee, who also recommended research into the potential health effects of chronic exposure to methane via ingestion (Academic sector consultation response 2012 NPR).

Further consideration and research pertain to the long-term fate of hydraulic fracturing fluid remaining in the shale gas formation during the production and post-closure phases, for instance in relation to provisions of the Carbon Capture and Storage Directive (2009/31/EC).

Based on the discussion of potential impacts of high volume hydraulic fracturing in Chapter 2, further research is recommended into the potential for increased risk of methane migration to groundwater with air drilling compared to drilling using liquid muds. It is recommended that further research is carried out into well cementing methods and practices for HVHF. It is recommended that further research is carried out into the risks which could not be classified based on the available information:

- Potential impacts on biodiversity due to cumulative development in the European context
- Frequency of surface spillages during hydraulic fracturing
- Potential frequency and significance of road accidents involving trucks carrying hazardous substances in support of HVHF operations
- Noise impacts due to flaring, and associated controls
- Risks of groundwater contamination following abandonment
- Land take following abandonment
- Risks to biodiversity following abandonment

It is recommended that further research is carried out to improve the viability of techniques for recycling of wastewater, to ensure that wastewater recycling can be applied in Europe, and to enable a higher proportion of wastewater to be recycled in this way.

The Pennsylvania Governor's Marcellus Shale Advisory Commission recommended the development of voluntary ecological initiatives within critical habitats that would generate mitigation credits which are eligible for use to offset future development. It is recommended that the applicability of similar initiatives in Europe should be investigated.

Table 11: Summary of identified measures

Measure		Land take during site preparation	Releases to air during drilling	Noise during drilling	Water resource depletion during fracturing	Releases to air during fracturing and completion	Traffic during fracturing	Groundwater contamination during fracturing, completion and production	Surface water contamination during fracturing and completion	Releases to air during production	Biodiversity impacts during production
5.3.1	Maximize required spacing between wells (Install multiple wells/pad)	M		+			+				+
5.3.2	Require Environmental Site Assessment for Optimal Site Selection	M		+			+				+
5.3.3	Limit the use of impoundments	M							+		+
5.3.4	Use temporary surface pipes to transport water to the well pad	M					+				+/-
5.3.5	Ensure land disturbed during well construction and development is reclaimed	M									+
5.3.6	Restrict hydraulic fracturing and well pad installation from sensitive areas	M		+				+	+		+
5.4.1	Require natural gas-fired, or electric-grid drilling rig engines		M	+							
5.4.2	Require emission controls on lean burn and rich burn drilling rig engines		M								
5.5.1	Specification of maximum noise levels at sensitive locations			M							+
5.5.2	Separation between drilling operation and sensitive location			M							+
5.5.3	Management methods to reduce noise impacts			M							+
5.5.4	Screening of noise-generating equipment			M							+
5.6.1	Regional water resource management				M						
5.6.2	Reuse wastewater				M		+				
5.6.3	Use lower quality water (seawater, brackish water) for fracturing fluid make up				M						
5.6.4	Manage water abstraction				M						
5.6.5	Use alternative water resources				M						
5.7.1	Require reduced emission completions to eliminate natural gas venting during fracturing from flowback					M					
5.7.2	Require flares or incinerators to control emissions from fracturing wastewater storage tank vents					M					

Measure		Land take during site preparation	Releases to air during drilling	Noise during drilling	Water resource depletion during fracturing	Releases to air during fracturing and completion	Traffic during fracturing	Groundwater contamination during fracturing, completion and production	Surface water contamination during fracturing and completion	Releases to air during production	Biodiversity impacts during production
5.8.1	Site selection and design	+		+			M				+
5.8.2	Using alternatives to road transportation					+	M				+/-
5.8.3	Development of transportation plan						M				
5.8.4	Measures to minimise vehicle emissions					+	M				
5.8.5	Road maintenance						M				
5.9.1	Monitoring of groundwater quality							M			
5.9.2	Appropriate standard and quality assurance of well casing							M	+		+
5.9.3	Surface impoundment construction standards							M	+		+
5.9.4	Leak and spill prevention, detection, and control							M	+		+
5.9.5	Monitoring and control of fracturing process							M	+		+
5.10.1	Monitoring of surface water quality								M		
5.10.2	Limit pollutant concentrations in wastewater discharges								M		
5.10.3	Prohibit wastewater discharges (not recommended)										
5.10.4	Leak and spill prevention, detection, and control							+	M		+
5.10.5	Erosion and run on/run off control							+	M		+
5.12.1	Monitoring of air quality									M	
5.12.2	Require vapour recovery units for tank emissions									M	
5.12.3	Require low-bleed or no-bleed pneumatic controllers									M	
5.12.4	Require desiccant rather than glycol dehydrators									M	
5.12.5	Require zero emission glycol dehydrators									M	
5.13.1	Minimise risks posed by invasive species										M

Key M: Main reason for proposal of measure

+: Potential synergistic effect

-: Potential counter-productive effect

+ / -: Potential for both synergistic and counter-productive effects

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Appendices

Appendix 1: Glossary and Abbreviations

Glossary adapted in part from New York DEC (2011 PR). The majority of terms in this glossary are referred to in the report. Some additional terms are included to assist in wider discussion of unconventional gas operations.

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

Annular Space or Annulus: Space between casing and the wellbore, or between the tubing and casing or wellbore, or between two strings of casing.

Anticline: A fold with strata sloping downward on both sides from a common crest.

Aquifer: A zone of permeable, water saturated rock material below the surface of the earth capable of producing significant quantities of water.

Bactericides: Also known as a "Biocide." An additive that kills bacteria.

Barrel: A volumetric unit of measurement equivalent to 42 U.S. gallons or 0.159 m^3

bbl/yr: Barrels per year.

bbl: Barrel.

Bcf: Billion cubic feet. A unit of measurement for large volumes of gas. 1 bcf is equivalent to 28.3 million cubic metres

BCOGC: British Columbia Oil and Gas Commission.

Best Management Practice: Current state-of-the-art mitigation measures applied to oil and natural gas drilling and production to help ensure that development is conducted in an environmentally responsible manner

Biocides: See "Bactericides".

Black shale: shale that was laid down in especially anoxic conditions on the floors of stagnant seas and is rich in organic compounds derived from bacterial, plant and animal matter.

BLM: United States Federal Bureau of Land Management

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

BMP: Best Management Practice

Breaker: A chemical used to reduce the viscosity of a fluid (break it down) after the thickened fluid has finished the job it was designed for.

Brine: Water displaced from the geological formation which contains elevated levels of dissolved solids;

Buffer agent: A weak acid or base used to maintain the pH of a solution at or close to a chosen value.

CAS Number: Chemicals Abstract Service number, assigned by Chemical Abstracts Service.

Casing: Steel pipe placed in a well.

CBM: Coal bed methane

CFR: Code of Federal Regulations.

Chemical Additive: A product composed of one or more chemical constituents that is added to a primary carrier fluid to modify its properties in order to form hydraulic fracturing fluid.

Chemical Constituent: A discrete chemical with its own specific name or identity, such as a CAS Number, which is contained within an additive product.

Coal-bed methane: natural gas trapped in coal seams that can be extracted by similar methods to those used for shale gas. The term refers to methane adsorbed onto the solid matrix of the coal. (Coal bed methane requires less fracturing fluid and so extraction of this gas falls outside the definition of "high volume hydraulic fracturing")

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

Compressor: A facility which increases the pressure of natural gas to move it in pipelines or into storage.

Condensate: Liquid hydrocarbons that were originally in the reservoir gas and are recovered by surface separation.

Conventional reservoir: a high permeability (greater than 1 milliDarcy) formation, usually sandstone, containing oil and/or gas, which can be more readily extracted than hydrocarbons from unconventional reservoirs.

Corrosion Inhibitor: A chemical substance that minimizes or prevents corrosion in metal equipment.

Crosslinker: A compound, typically a metallic salt, mixed with a base-gel fluid, such as a guar-gel system, to create a viscous gel used in some stimulation or pipeline cleaning treatments. The crosslinker reacts with the multiplestrand polymer to couple the molecules, creating a fluid of high viscosity.

Darcy: A unit of permeability. A medium with a permeability of 1 darcy permits a flow of 1 cm^3/s of a fluid with viscosity 1 cP (1 mPa·s) under a pressure gradient of 1 atm/cm acting across an area of 1 cm^2.

DEC: New York State Department of Environmental Conservation.

Directional drilling: Deviation of the borehole from vertical so that the borehole penetrates a productive formation in a manner parallel to the formation, although not necessarily horizontally.

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

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

Economically recoverable reserves: technically recoverable petroleum for which the costs of discovery, development, production, and transport, including a return to capital, can be recovered at a given market price.

Ecosystem: The system composed of interacting organisms and their environments.

EIS: Environmental Impact Statement.

EPA: The (U.S.) Environmental Protection Agency.

Fault: A fracture or fracture zone along which there has been displacement of the sides relative to each other.

Field: The general area underlain by one or more pools.

Flare: The burning of unwanted gas through a pipe.

Flashing: evaporation of volatile substances due to a reduction in pressure

Flowback Fluids: fluid returned to the surface after hydraulic fracturing has occurred, but before the well is placed into production. It typically consists of returned fracturing fluids in the first few days following hydraulic fracturing which are progressively replaced by produced water.

Fold: A bend in rock strata.

Footwall: The mass of rock beneath a fault plane.

Formation: A rock body distinguishable from other rock bodies and useful for mapping or description. Formations may be combined into groups or subdivided into members.

Fossil methane / fossil fuel: A natural fuel such as coal or gas, formed in the geological past from the remains of living organisms.

Fracking or Fracing (pronounced “fracking”): informal abbreviation for "Hydraulic Fracturing".

Friction Reducer/Friction Reducing Agent: A chemical additive which alters the hydraulic fracturing fluid allowing it to be pumped into the target formation at a higher rate & reduced pressure.

GEIS: Generic Environmental Impact Statement.

Gelling Agents: Polymers used to thicken fluid so that it can carry a significant amount of proppants into the formation.

Geothermal Well: A well drilled to explore for or produce heat from the subsurface.

gpd: Gallons per day.

gpm: Gallons per minute.

Green Completion: see Reduced Emissions Completion

Groundwater: Water in the subsurface below the water table. Groundwater is held in the pores of rocks, and can be connate (that is, trapped in the rocks at the time of formation), from meteorological sources, or associated with igneous intrusions.

HAPS: Hazardous Air Pollutants as defined under the Clean Air Act (see http://www.epa.gov/ttn/atw/188polls.html)

High Volume Hydraulic Fracturing: The stimulation of a well (normally a shale gas well using horizontal drilling techniques with multiple fracturing stages) with high volumes of fracturing fluid. Defined as fracturing using 1,000 m^3 or more of water per stage as the base fluid in fracturing fluid.

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

Horizontal Leg: The part of the wellbore that deviates significantly from the vertical; it may or may not be perfectly parallel with formational layering.

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

Hydraulic Fracturing: The act of pumping hydraulic fracturing fluid into a formation to increase its permeability. Hydraulic fracturing is understood within the scope of this study as the full lifecycle of operations, from the upstream acquisition of water, to chemical mixing of the fracturing fluid, injection of the fluid into the formation, the production and management of flowback and produced water, and the ultimate treatment and disposal of hydraulic fracturing wastewater.

Iron Inhibitors: Chemicals used to bind the metal ions and prevent a number of different types of problems that iron can cause (for example, scaling problems in pipe).

Limestone: A sedimentary rock consisting chiefly of calcium carbonate ($CaCO_3$).

Make-up water: water in which proppant and chemical additives are mixed to make fracturing fluids for use in hydraulic fracturing

Mcf: Thousand cubic feet (equivalent to 28.3 cubic metres).

md: Millidarcy.

Millidarcy: A unit of permeability, equivalent to one thousandth of a Darcy

MMcf: Million cubic feet (equivalent to 28,300 cubic metres).

NORM: Naturally Occurring Radioactive Materials. Low-level radioactivity that can exist naturally in native materials, like some shales and may be present in drill cuttings and other wastes from a well.

Operator: Any person or organization in charge of the development of a lease or drilling and operation of a producing well.

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

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

Permeability: A measure of a material's ability to allow passage of gas or liquid through pores, fractures, or other openings. The unit of measurement is the Darcy or millidarcy.

Polymer: Chemical compound of unusually high molecular weight composed of numerous repeated, linked molecular units.

Pool: An underground reservoir containing a common accumulation of oil and/or gas. Each zone of a structure which is completely separated from any other zone in the same structure is a pool.

Porosity: Volume of pore space expressed as a percent of the total bulk volume of the rock.

Primary Carrier Fluid: The base fluid, such as water, into which additives are mixed to form the hydraulic fracturing fluid which transports proppant.

Primary Production: Production of a reservoir by natural energy in the reservoir.

Product: A hydraulic fracturing fluid additive that is manufactured using precise amounts of specific chemical constituents and is assigned a commercial name under which the substance is sold or utilized.

Production Casing: Casing set above or through the producing zone through which the well produces.

Produced water: fluids displaced from the geological formation, which can contain substances that are found in the formation, and may include dissolved solids (e.g. salt), gases (e.g. methane, ethane), trace metals, naturally occurring radioactive elements (e.g. radium, uranium), and organic compounds,

Proppant or Propping Agent: A granular substance (sand grains, aluminium pellets, or other material) that is carried in suspension by the fracturing fluid and that serves to keep the cracks open when fracturing fluid is withdrawn after a fracture treatment.

Proved reserves: The quantity of energy sources estimated with reasonable certainty, from the analysis of geologic and engineering data, to be recoverable from well-established or known reservoirs with the existing equipment and under the existing operating conditions

REC: Reduced Emissions Completion.

Reduced Emissions Completion (also known as green completion): a term used to describe a practice that captures gas produced during well completions and well workovers following hydraulic fracturing. Portable equipment is brought on site to separate the gas from the solids and liquids produced during the high-rate flowback, and produce gas that can be delivered into the sales pipeline. RECs help to reduce methane, VOC, and HAP emissions during well cleanup and can eliminate or significantly reduce the need for flaring.

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

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

Sandstone: A variously coloured sedimentary rock composed chiefly of sandlike quartz grains cemented by lime, silica or other materials.

Scale Inhibitor: A chemical substance which prevents the accumulation of a mineral deposit (for example, calcium carbonate) that precipitates out of water and adheres to the inside of pipes, heaters, and other equipment.

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

SEIS: Supplemental Environmental Impact Statement.

Seismic: Related to earth vibrations produced naturally or artificially.

SGEIS: Supplemental Generic Environmental Impact Statement.

Shale oil: Oil shale, also known as kerogen shale, is an organic-rich fine-grained sedimentary rock containing kerogen (a solid mixture of organic chemical compounds) from which liquid hydrocarbons called shale oil can be produced. Crude oil which occurs naturally in shales is referred to as “tight oil”.

Shale: A sedimentary rock consisting of thinly laminated claystone, siltstone or mud stone. Shale is formed from deposits of mud, silt, clay, and organic matter laid down in calm seas or lakes.

Shale gas: natural gas that remains tightly trapped in shale and consists chiefly of methane, but with ethane, propane, butane and other organic compounds mixed in. It forms when black shale has been subjected to heat and pressure over millions of years, usually at depths of 1,500 to 4,500 metres

Show: Small quantity of oil or gas, not enough for commercial production.

Siltstone: Rock in which the constituent particles are predominantly silt size.

Slickwater Fracturing (or slick-water): A type of hydraulic fracturing which utilizes water-based fracturing fluid mixed with a friction reducing agent and other chemical additives.

Spudding: The breaking of the earth’s surface in the initial stage of drilling a well.

Squeeze: Technique where cement is forced under pressure into the annular space between casing and the wellbore, between two strings of pipe, or into the casing-hole annulus.

Stage Plug: A device used to mechanically isolate a specific interval of the wellbore and the formation for the purpose of maintaining sufficient fracturing pressure.

Stage: Isolation of a specific interval of the wellbore and the associated interval of the formation for the purpose of maintaining sufficient fracturing pressure.

Stimulation: The act of increasing a well's productivity by artificial means such as hydraulic fracturing or acidizing.

Stratum (plural strata): Sedimentary rock layer, typically referred to as a formation, member, or bed.

Surface Casing: Casing extending from the surface through the potable fresh water zone.

Surfactants: Chemical additives that reduce surface tension; or a surface active substance. Detergent added to hydraulic fracturing fluid is a surfactant.

Target Formation: The reservoir that the driller is trying to reach when drilling the well.

Tcf: Trillion cubic feet, equivalent to 28.3 billion cubic metres

Technically recoverable reserves: The proportion of assessed in-place petroleum that may be recoverable using current recovery technology, without regard to cost.

Tight Formation: Formation with very low (less than 1 milliDarcy) permeability.

Tight gas: natural gas held in sandstone reservoirs that are unusually impermeable; it can be extracted by fracturing the rock (tight gas is typically extracted using vertical wells which require less fracturing fluid and so extraction of this gas falls outside the definition of "high volume hydraulic fracturing").

tpy: Tonnes per year

Unconventional gas: Gas contained in rocks (which may or may not contain natural fractures) which exhibit in-situ gas permeability of less than 1 millidarcy.

USDW - Underground Source of Drinking Water: An aquifer or portion of an aquifer that supplies any public water system or that contains a sufficient quantity of ground water to supply a public water system, and currently supplies drinking water for human consumption, or that contains fewer than 10,000 mg/L total dissolved solids and is not an exempted aquifer.

USEPA: United States Environmental Protection Agency.

USGS: United States Geological Survey.

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

VOC: Volatile Organic Compound.

Wastewaters: term used to designate collectively returned fracturing fluids and produced water which are sent for disposal or treatment and re-use.

Water Well: Any residential well used to supply potable water.

Watershed: The region drained by, or contributing water to, a stream, lake, or other body of water.

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

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

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

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

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

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

Appendix 2: Types of artificial stimulation treatments

High volume hydraulic fracturing (known also as "slickwater" fracturing)

In the late 1990s, operators developed a technology known as "slickwater fracturing" to develop shale formations, primarily by increasing the amount and proportion of water used, reducing the use of gelling agents and adding friction reducers (New York State DEC 2011 PR p5-39). The additives typically used in hydraulic fracturing fluids are of the following types (King, 2012 PR):

- Scale inhibitor
- Acid (usually hydrochloric acid)
- Biocide
- Friction reducer, typically polyacrylamide.

Multi-stage horizontal drilling techniques were developed, which enabled shale gas reservoirs to be developed in a more cost-effective way. The quantity of fracturing fluid used in these treatments is more than 1,000 m^3 of water per stage.

The following sections describe other hydraulic fracturing treatments for reference.

Acidising

Acid treatments are used to dissolve carbonate materials in the reservoir host rock and to widen a flow path, either natural or artificially created. Acid is also used to clean up scale build-up, rust and cement that may occur from the drilling or production of the well. Acidising can be carried out as a fracture treatment, as a pre-treatment prior to a fracture and/or as general maintenance to clean up a well. Acidising may use the chemical action of the acid alone (described as "matrix fracturing"), or the acid may act under pressure to physically fracture the rock matrix.

Water gel hydraulic fracturing

Hydraulic fracturing has been carried out on conventional oil and gas wells using a mixture of diesel fuel or water, together with sand and chemical additives since the 1940s (New York State DEC 2011 PR p6-289). Typically, these processes involved the use of 90 to 360 m^3 of water per well, and are now used mainly for shale oil and tight sands. These higher viscosity fluids use gellants or thickeners to create viscous gelled fluids with a high carrying capacity. Gellant selection is based on formation characteristics such as pressure, temperature, permeability, porosity, and zone thickness, with guar gum a widely used additive in current operations. Linear and cross-linked gels are available: borate additives are used to create the cross-linkages. Breaker additives are mixed in with the fluid which break these linkages after hydraulic fracturing to reduce viscosity and facilitate the return of fluid to the surface.

Propane gel

The use of propane gel as a hydraulic fracturing fluid has been trialled at over 1,000 sites in North America. The gel is typically made up of 90% propane and a phosphoric acid diester gelling agent together with proppant and other additives. After the fracturing stage, the gel is broken, and propane is returned to the surface as a gas. Consequently, the fluid additives tend to remain in the formation rather than being returned to the surface. This approach removes the need to dispose of water-based fracturing fluids, and the propane can be collected and transferred to production pipeline or flared.

Little data on the application of this technology has been made publicly available. The initial costs can be 20-40% more than water-based fracking, but this could potentially be offset by increased gas production efficiency and reduced costs associated with the disposal of water (Royal Society of Chemistry, 2011).

Foamed gels

Nitrogen or carbon dioxide gas is blended with fluid to create a foam (approximately 70-75% nitrogen or carbon dioxide) to transport and place proppant into fractures (EPA 2004 NPR p4-5). Nitrogen fracture operations require higher surface pressures due to the lower hydrostatic weight of the foam, but use much less water (only 25-30% of injected fluid) to fracture the rock and then pump in the foam/sand mixture. Operators have successfully used nitrogen foam fractures in the UK in CBM reservoirs, to improve proppant-carrying capabilities and to minimize the amount of liquid placed in the formation which improves the clean-up and flow back (UK Department for Energy and Climate Change, 2012 NPR). It is unlikely that this technique could be used for shale gas, because of the viscosity of the fluid.

High Rate Nitrogen

High Rate Nitrogen involves the pumping of nitrogen gas into a formation at high rates and pressures. High Rate Nitrogen treatments are used for shallow applications, typically coalbed methane (CBM) where reservoir pressures may be low and the flowback of fracture fluids may be difficult. The purpose of this treatment is to open cleats or natural fractures in the coal and to remove damage in order for natural gas to be able to flow more easily into the well.

Occasionally a proppant is added to the nitrogen. The amounts added are typically much lower than used in liquid treatments (CSUR, 2012 NPR). No further additives are added during the fracturing process. During the flowback period, the nitrogen is vented to the atmosphere while any produced water encountered is captured in on site tank storage for later disposal.

Thermal fracturing

Water injection wells for enhanced oil recovery are commonly hydraulically fractured by a combination of pressure and temperature. Typically, seawater at ambient temperature or produced water at around 50^{o}C is injected into warmer rocks in the subsurface, resulting in cracking of the buried rocks when they are flushed with the colder water.

Liquid carbon dioxide

Liquid carbon dioxide fracture treatments involve pumping liquid carbon dioxide into the formation without any added chemicals. Most liquid carbon dioxide fracture treatments are carried out for research and development on a well, because this method is considered to have a low risk of damaging the formation.

Appendix 3: Hydraulic fracturing additives used in high volume hydraulic fracturing in the UK, 2011

Hydraulic fracturing additives used in the UK (see table below)

Composition of Components in Bowland Shale Hydraulic Fracturing Fluid for Preese Hall-1 Well

Frac Stage	Common Name	Supplier	Supplier Chemical Name	Purpose	Country of Origin	Components Listed on MSDS	Total Volume	Volume Unit	MSDS Component Weight % of Chemical	Volume of Component in Well meters^3	Concentration of Total Volume Injected	Comments
1	Fresh Water	United Utilities	Water	Carry sand, open fractures	UK		1,969.0	meters^3		1969.00	22.96%	
1	Congleton Sand	Sibelco UK	HST-80	Prop open fractures	UK		23.0	metric ton	100%	8.62	0.101%	
1	Chelford Sand	Sibelco UK	CH-52	Prop open fractures	UK		78.0	metric ton	100%	29.24	0.341%	
1	Friction Reducer	CESI Chemical	FR-40	Reduce pressure required to pump down pipe	Netherlands	Polyacrylamide Emulsion in Hydrocarbon Oil	0.920	meters^3	100%	0.92	0.011%	This product does not contain any reportable hazardous components as defined in 29 CFR 1910. 1200
1	Chem Tracer	Spectrachem	Chem Tracer	Identify frac water in flowback	USA	Water	-	grams	90%	0.00000	0.000000%	
						Sodium Salt		grams	10%	0.00000	0.000000%	
2	Fresh Water	United Utilities	Water	Carry sand, open fractures	UK		2,338.6	meters^3		2338.60	27.27%	
2	Congleton Sand	Sibelco UK	HST-80	Prop open fractures	UK		31.3	metric ton	100%	11.73	0.137%	
2	Chelford Sand	Sibelco UK	CH-52	Prop open fractures	UK		85.3	metric ton	100%	31.98	0.373%	
2	Friction Reducer	CESI Chemical	FR-40	Reduce pressure required to pump down pipe	Netherlands	Polyacrylamide Emulsion in Hydrocarbon Oil	1.079	meters^3	100%	1.08	0.013%	This product does not contain any reportable hazardous components as defined in 29 CFR 1910. 1200
2	Chem Tracer	Spectrachem	Chem Tracer	Identify frac water in flowback	USA	Water	1,395	grams	90%	0.00126	0.000015%	
						Sodium Salt		grams	10%	0.00014	0.000002%	
3	Fresh Water	United Utilities	Water	Carry sand, open fractures	UK		799.8	meters^3		799.80	9.33%	
3	Congleton Sand	Sibelco UK	HST-80	Prop open fractures	UK		14.6	metric ton	100%	5.47	0.064%	
3	Chelford Sand	Sibelco UK	CH-52	Prop open fractures	UK		37.6	metric ton	100%	14.10	0.164%	
3	Friction Reducer	CESI Chemical	FR-40	Reduce pressure required to pump down pipe	Netherlands	Polyacrylamide Emulsion in Hydrocarbon Oil	0.394	meters^3	100%	0.39	0.005%	This product does not contain any reportable hazardous components as defined in 29 CFR 1910. 1200
3	Chem Tracer	Spectrachem	Chem Tracer	Identify frac water in flowback	USA	Water	578	grams	90%	0.00052	0.000006%	
						Sodium Salt		grams	10%	0.00006	0.000001%	
4	Fresh Water	United Utilities	Water	Carry sand, open fractures	UK		1,683.6	meters^3		1683.60	19.63%	
4	Congleton Sand	Sibelco UK	HST-80	Prop open fractures	UK		11.5	metric ton	100%	4.31	0.050%	
4	Chelford Sand	Sibelco UK	CH-52	Prop open fractures	UK		70.7	metric ton	100%	26.51	0.309%	
4	Friction Reducer	CESI Chemical	FR-40	Reduce pressure required to pump down pipe	Netherlands	Polyacrylamide Emulsion in Hydrocarbon Oil	0.655	meters^3	100%	0.66	0.008%	This product does not contain any reportable hazardous components as defined in 29 CFR 1910. 1200
4	Chem Tracer	Spectrachem	Chem Tracer	Identify frac water in flowback	USA	Water	1,164	grams	90%	0.00105	0.000012%	
						Sodium Salt		grams	10%	0.00012	0.000001%	
5	Fresh Water	United Utilities	Water	Carry sand, open fractures	UK		1,569.2	meters^3		1569.20	18.30%	
5	Congleton Sand	Sibelco UK	HST-80	Prop open fractures	UK		27.7	metric ton	100%	10.38	0.121%	
5	Chelford Sand	Sibelco UK	CH-52	Prop open fractures	UK		83.0	metric ton	100%	31.12	0.363%	
5	Friction Reducer	CESI Chemical	FR-40	Reduce pressure required to pump down pipe	Netherlands	Polyacrylamide Emulsion in Hydrocarbon Oil	0.628	meters^3	100%	0.63	0.007%	This product does not contain any reportable hazardous components as defined in 29 CFR 1910. 1200
5	Chem Tracer	Spectrachem	Chem Tracer	Identify frac water in flowback	USA	Water	1,115	grams	90%	0.00100	0.000012%	
						Sodium Salt		grams	10%	0.00011	0.000001%	
6	Fresh Water	United Utilities	Water	Carry sand, open fractures	UK		39.0	meters^3		39.00	0.45%	
6	Congleton Sand	Sibelco UK	HST-80	Prop open fractures	UK		-	metric ton	100%	0.00	0.000%	
6	Chelford Sand	Sibelco UK	CH-52	Prop open fractures	UK		-	metric ton	100%	0.00	0.000%	
6	Friction Reducer	CESI Chemical	FR-40	Reduce pressure required to pump down pipe	Netherlands	Polyacrylamide Emulsion in Hydrocarbon Oil	-	meters^3	100%	0.00	0.000%	This product does not contain any reportable hazardous components as defined in 29 CFR 1910. 1200
6	Chem Tracer	Spectrachem	Chem Tracer	Identify frac water in flowback	USA	Water	-	grams	90%	0.00000	0.000000%	
						Sodium Salt		grams	10%	0.00000	0.000000%	
Total	Fresh Water	United Utilities	Water	Carry sand, open fractures	UK		8,399.2	meters^3		8399.20	97.93%	
Total	Congleton Sand	Sibelco UK	HST-80	Prop open fractures	UK		108.1	metric ton	100%	40.53	0.473%	
Total	Chelford Sand	Sibelco UK	CH-52	Prop open fractures	UK		354.6	metric ton	100%	132.94	1.550%	
Total	Friction Reducer	CESI Chemical	FR-40	Reduce pressure required to pump down pipe	Netherlands	Polyacrylamide Emulsion in Hydrocarbon Oil	3.7	meters^3	100%	3.68	0.043%	This product does not contain any reportable hazardous components as defined in 29 CFR 1910. 1200
Total	Chem Tracer	Spectrachem	Chem Tracer	Identify frac water in flowback	USA	Water	4,252	grams	90%	0.00383	0.000045%	
Total						Sodium Salt		grams	10%	0.00043	0.000005%	

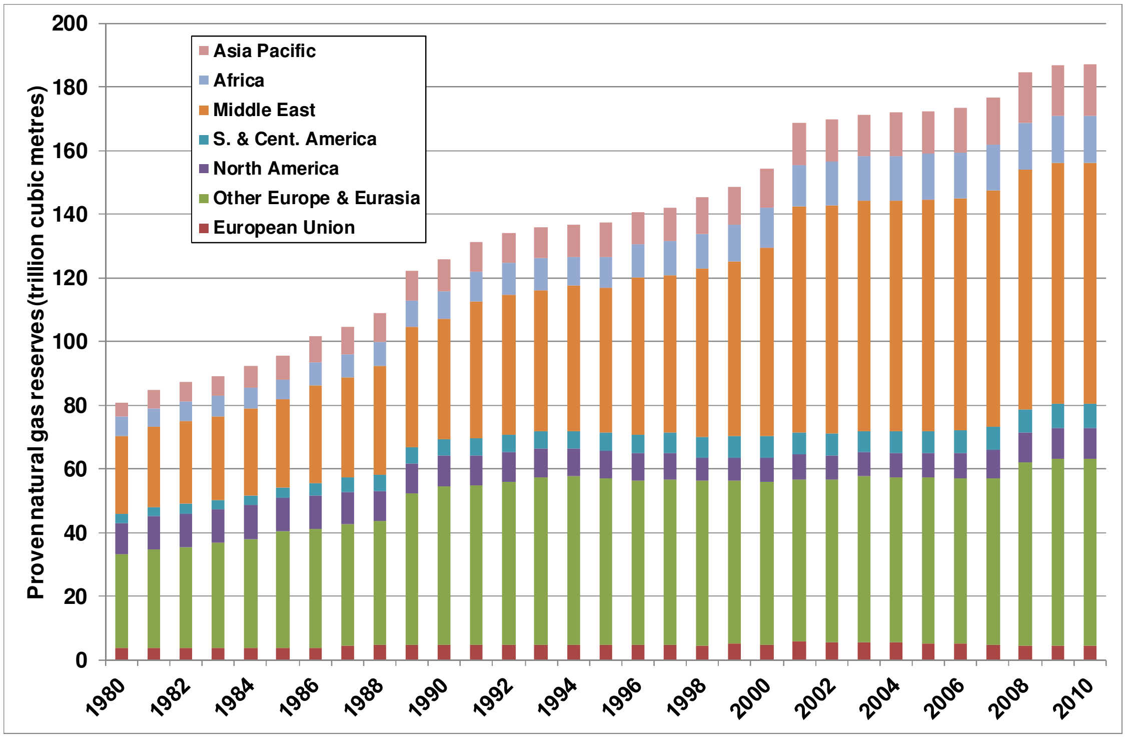
Data for Preese Hall-1 well, obtained from
http://www.cuadrillaresources.com/what-we-do/hydraulic-fracturing/fracturing-fluid/

Appendix 4: Hydrocarbon extraction in Europe

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

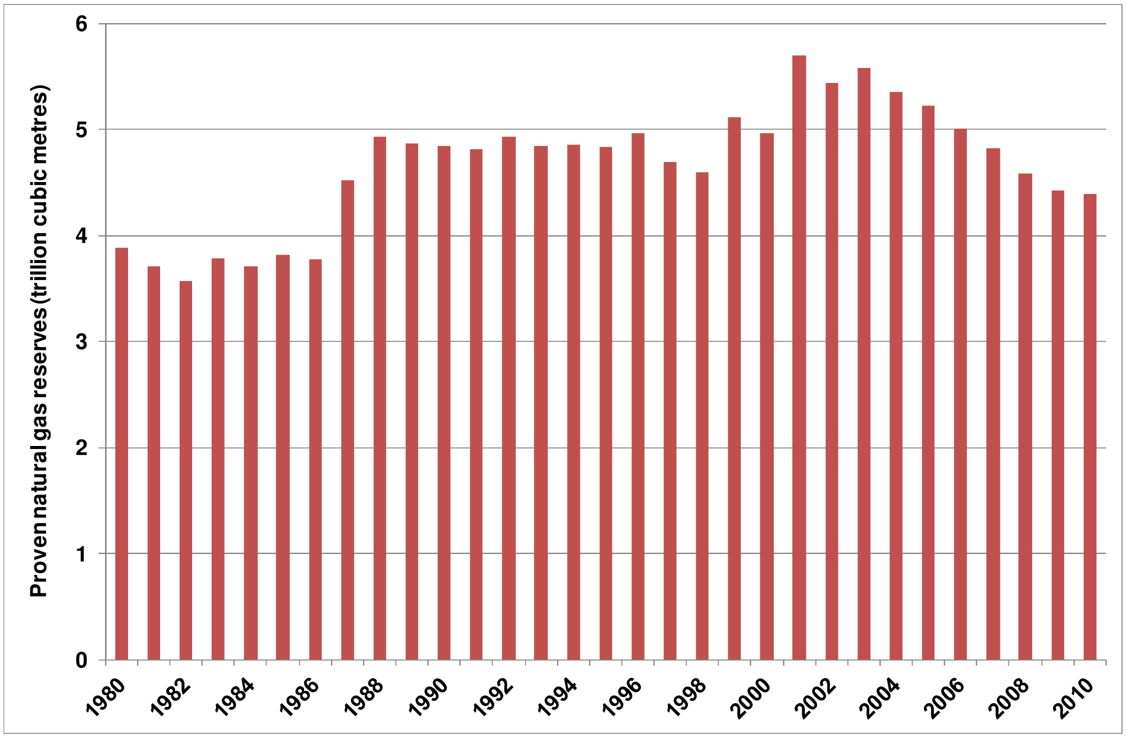
Proven gas reserves in the Europe Union have started to decline since around 2002 (see Figures A4.1a and A4.1b).

Figure A4.1a: Worldwide proven natural gas reserves 1980 – 2010



(Source: Data taken from BP (2011 NPR))

Figure A4.1b: European Union proven natural gas reserves 1980 - 2010



(Source: Data taken from BP (2011 NPR))

This change coincided with the development and application of techniques in the United States for extraction of gas from reserves which were previously uneconomic or impractical. In this context, gas producers in Europe have begun to investigate unconventional oil and gas resources. In Europe, preliminary indications are that these resources comprise extensive shale gas reserves, although this will not be confirmed until further exploratory drilling has been carried out. Preliminary estimates of shale gas reserves in Europe are summarised in Table A4.1.

Table A4.1. Estimated shale gas recoverable resources for select basins in Europe

State	2009 Natural Gas Market [1] (trillion cubic metres, dry basis)			Proved Natural Gas Reserves [2] (trillion cubic metres)	Technically Recoverable Shale Gas Resources (trillion cubic metres)
	Production	Consumption	Imports (exports)		
France	0.00085	0.049	98%	0.006	5.10
Germany	0.0144	0.093	84%	0.18	0.23
Netherlands	0.0790	0.049	(62%)	1.39	0.48
Norway	0.103	0.0045	(2156%)	2.04	2.4
U.K.	0.059	0.088	33%	0.255	0.57
Denmark	0.0085	0.0045	(91%)	0.059	0.65
Sweden	-	0.0011	100%		1.16
Poland	0.0059	0.016	64%	0.164	5.30
Turkey	0.00085	0.035	98%	0.006	0.42
Ukraine	0.020	0.044	54%	1.10	1.19
Lithuania	-	0.0028	100%		0.113
Others[2]	0.014	0.027	50%	0.077	0.54
Total	**0.305**	**0.365**		**5.27**	**13.0**

(1) Dry production and consumption (EIA, 2011 NPR).

(2) Romania, Hungary, Bulgaria.

Coal bed methane

Coal bed methane (CBM) is present in varying quantities in all coal measures. As in shale gas formations, the natural gas is trapped with the strata, in this case within the coal itself, with only 5-9% present as free gas. Because relatively low volumes of fluid are required for extraction of CBM, this lies outside the scope of this project (see Section 1.3.3).

Estimated global coal-bed methane reserves are summarised in Table A4.2 (IFP, 2007 NPR). This indicates that in the European context, coal-bed methane could also comprise a significant proportion of unconventional gas resources. However, there is at present no significant forecast expansion in extraction of CBM in Europe.

Table A4.2: Estimated world CBM reserves

Area	Estimated recoverable reserves (Tm^3) Low end	Estimated recoverable reserves (Tm^3) High end
Asia	18.3	95.1
North America	26.9	124.1
South America	0.4	0.9
Commonwealth of Independent States[5]	113.3	456.3
Europe other than CIS	4.6	7.6

5 Armenia, Azerbaijan, Belarus, Kazakhstan, Kyrgyzstan, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine, Uzbekistan

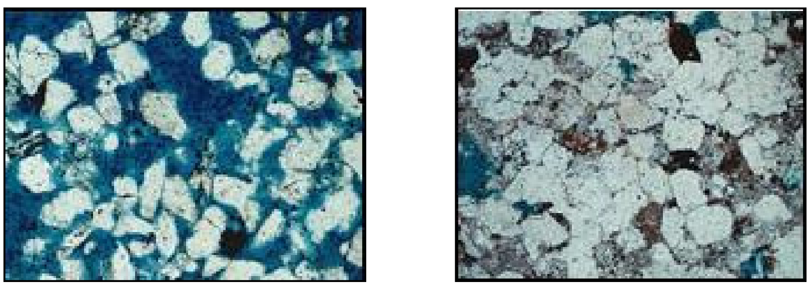
Africa	0.8	1.6
World	164.2	685.7

Tight gas

"Tight gas" refers to gas which is produced from a very low permeability and porosity reservoir rock with a permeability of less than 1 milliDarcy (Veeken et al., 2007 NPR). Hydrocarbon production from tight reservoirs can be difficult without stimulation operations. The term is generally used for reservoirs other than shales.

Tight gas is typically at depths greater than 3,500 metres below the surface (BP, 2012c NPR). In a conventional sandstone the pores are interconnected so gas is able to flow easily from the rock. In tight sandstones there are smaller pores, which are poorly connected by very narrow capillaries, resulting in very low permeability (see Figure 2).

Figure 6: Microscopic sandstone sections



Conventional sandstone (left) has well- connected pores (dark blue). The pores of tight gas sandstone (right) are irregularly distributed and poorly connected by very narrow capillaries (NETL, 2011b NPR).

Tight gas is currently being produced in Europe, most notably in Germany (Europe Unconventional Gas website accessed 2012 NPR). Data published by the German regulators LBEG and BRG do not distinguish between tight gas extraction and conventional natural gas extraction, and so it has not been possible to quantify the quantities of tight gas produced in Europe. Because relatively low volumes of fluid are required for extraction of tight gas, this lies outside the scope of this project (see Section1.3.3).

Unconventional gas production in Europe

Having searched the documents assembled for this project and carried out a search of scientific literature via www.sciencedirect.com as well as a more general internet search, no specific figures could be identified for unconventional gas production in Europe. Indications from regulators or industry indicates that some hydraulic fracturing (though not high volume hydraulic fracturing) has been carried out on a total of approximately 800 conventional and unconventional wells in Europe. This compares to approximately 400,000 producing gas wells in the US (no figures are available for the number of wells in Europe). Currently, CBM and tight gas make an insignificant contribution to EU natural gas production and consumption with some potential for an increased contribution in future years (BP, 2011 NPR ; BGR, 2009 NPR).

Table A4.3 provides a preliminary evaluation of shale gas formations in Europe

Table A4.3: Preliminary summary of European shale gas plays

Region	Basin	Formation	Risked Gas In-place (Tcm)	Technically Recoverable Resource (Tcm)	Depth interval (m)		Depth (average) (m)
Poland	Baltic Basin	Silurian Shales	14.6	3.7	2500	5000	3750
	Lublin Basin	Silurian Shales	6.3	1.2	2000	4100	3050
	Podlasie Depression	Silurian Shales	1.6	0.4	1750	3450	2605
		Sub-total	***22.4***	***5.3***			
Other Eastern Europe	Baltic Basin *Lithuania, Latvia, Estonia*	Silurian Shales	2.6	0.7	1800	2299	2049
	Dnieper-Donets Basin *Ukraine*	Silurian Shales	1.4	0.3	Ukraine – outside EU		
	Lublin Basin *Ukraine*	Silurian Shales	4.2	0.8	Ukraine – outside EU		
	Pannonian-Transylvanian Basin *Slovenia, Hungary, Slovakia and Romania*	"Neogene age"	Not assessed		Limited information -very complex geology - recent deposits on multiple upfaulted rocks but shale gas potential		
	Carpathian-Balkanian Basin *Romania and Bulgaria*	Jurassic Dogger Balls / Lias Etropole formations	Not assessed		Limited information - complex geology with nappe structures - example cross-section show potential target areas <1km deep but other cross-section could show deposits closer to surface		
	Carpathian-Balkanian Basin *Romania and Bulgaria*	Silurian Tandarei	Not assessed		Limited information - complex geology with nappe structures		
		Sub-total	***8.2***	***1.8***			
Western Europe	North Sea-German Basin *Belgium, Netherlands, Germany*	Posidonia Shale	0.7	0.2	1000	5000	3000
		Namurian Shale	1.8	0.5	2500	5000	3750
		Wealden Shale	0.3	0.1	1000	3000	2000
	Paris Basin *France*	Permo-Carboniferous	8.6	2.2	2600	4000	3300
	Scandinavia Region *Sweden and Denmark*	Alum Shale	16.7	4.2	<100	Not stated	1000
	South-East French Basin *France*	Terres Niores	3.2	0.8	1000	1999	1500
		Liassic Shale	8.6	2.2	2499	4999	3749
	North UK Petroleum System *UK*	Bowland Shale	2.7	0.5	1000	1920	1460
	South UK Petroleum System *UK*	Liassic Shale	0.1	0.0	3500	4720	4110
		Sub-total	***42.6***	***10.5***			
		Total	***73.3***	***17.7***			

Source: US Energy Administration Information, 2011 NPR

Appendix 5: Shale gas exploration in Europe

The limited history of exploration for shale gas in Europe is summarised in Table A5.1 below, together with information on planned future developments. This is based on data collected between November 2011 and April 2012.

Due to the high costs involved, horizontal drilling and hydraulic fracturing have in the past not routinely been used for conventional hydrocarbon extraction in Europe. The use of hydraulic fracturing for hydrocarbon extraction in Europe has been limited to lower volume fracturing of some tight gas and conventional reservoirs in the southern part of the North Sea and in onshore Germany, Netherlands, Denmark and the UK. These activities did not in general constitute High Volume hydraulic fracturing as defined in Section 1.3.3below.

- The Soehlingen field, in onshore Northwest Germany has several tight gas reservoirs which, after discovery in 1980, were developed using hydraulic fracturing. The development started in the early 1980s with hydraulic fracturing in vertical wells. In 1999 and 2000 multi-stage hydraulic fracturing in horizontal wells was performed, resulting in increased and economic production (Rodrigues and Neumann, 2007 NPR). A fracturing test was carried out on coal-bed methane field in North-Rhine Westphalia in 1994, but this was not pursued as it was not commercially successful (European regulator consultation response, 2012 NPR). It is estimated that a total of approximately 300 wells have been fractured in Germany between 1977 and 2010 (Reinicke 2011 NPR p11).
- In the Danish sector of the North Sea, it is estimated that stimulation using hydraulic fracturing has been carried out at approximately 130 wells (Danish energy ministry, 2012 NPR). Most of these wells have 10 to 20 fracture stages each. Approximately twice as many wells have been stimulated using acid fracturing or matrix acidizing, which lies outside the scope of this study. The wells are drilled in a tight gas chalk reservoir with a grain size in the clay fraction.
- In the Netherlands, over 200 unconventional gas wells have been fractured since the 1950s, of which about half are onshore and half offshore (NOGEPA, 2012 NPR). Fracturing has been used at depths of between 1,600 and 4,000 metres. Between 2007 and 2011, 9 onshore wells and 13 offshore wells were fractured. NOGEPA (2012 NPR) quotes an example fracturing operation which used 250 m^3 of fracturing fluid, suggesting that these operations were low volume, below the threshold adopted for HVHF.
- In the UK, approximately 200 onshore wells have so far been hydraulically fractured (UK Department of Energy and Climate Change, 2012 NPR). These are mainly conventional wells with a few coal-bed methane wells and one exploratory shale gas well (Preese Hall, Lancashire). No fracturing of tight gas wells has been carried out in the UK, and the majority of treatments were acidisation. High volume fracturing was only carried out at the Preese Hall-1 well. The programme at this site was cut short following minor earth tremors. It is estimated that at least 3,000 offshore wells have been fractured. Although specific data on fluid volumes are not available, the majority of these are likely to have been below the threshold of high volume fracturing (see Section1.3.3). These are likely to have been almost entirely conventional oil or gas formations, although some sandstone formations would be regarded as "tight" by European standards.

No information was identified from the literature search in relation to the environmental impacts of these hydraulic fracturing activities. The use of hydraulic fracturing in Europe has been the subject of technical and scientific publications, but this has not extended to an analysis of potential environmental or health effects. The environmental impacts of natural gas extraction in Europe have been studied, but the contribution to these impacts from hydraulic fracturing have not been separately analysed.

At the time of preparation of this report (March 2012), the following high volume hydraulic fracturing operations for shale gas had taken place:

- UK (Cuadrilla Resources Ltd): Preese Hall Lancashire: 8,600 m^3 over 6 stages (Broderick et al 2011 NPR Table 2.4)
- Poland: Siekierki Blocks 207 & 208 (Multi Fractured Horizontal Wells T-2 and T-3) (Ref. Aurelian company website, accessed 2012 NPR); no information on fluid volumes.
- Poland: Łebień LE-1 single-stage horizontal well (2010). Łebień LE-2H and Warblino LE-1H2 multi-stage horizontal wells (2011). (Ref. 3 Legs Resources company website, accessed 2012 NPR); no information on fluid volumes
- Poland: Horizontal fracturing of Lubocino-1 well near Wejherowo: 1600 m^3 fluid (Ref. PGNiG company website, accessed 2012 NPR)
- Poland: Incomplete fracture stimulations performed on the Cambrian & Ordovician intervals in the Lebork S-1 well in 2011 (insufficient proppant) (Ref. BNK company website, accessed 2012 NPR); no information on fluid volumes
- Poland: Hydraulic fracturing procedures carried out by PGNiG SA in July 2010 in the Markowola-1 well in Zwola (Volumes and directionality not known but likely to have been high volume horizontal fracturing) (PGNiG company website, accessed 2012 NPR)

Table A5.1: Overview of shale gas exploration involving high volume hydraulic fracturing in Europe (as of February 2012)

Date	Location	Description	Company	Status (based on information from company websites)	Reference
United Kingdom					
Nov 2009	Preese Hall Farm, Weeton, Preston Lancashire	Exploratory well	Cuadrilla resources	Completed on 8 Dec 2010	Broderick et al 2011 NPR
Jan 2011	Grange Hill	Exploratory well	Cuadrilla resources	Not known	
-	Anna's Road	Exploratory well	Cuadrilla resources	Planning approved	
-	Balcombe well site (drilled by Conoco in 1986)	West Sussex licence area held by its investment partner AJ Lucas.	Cuadrilla resources	No plans	Cuadrilla Resources, 2012 NPR
-	Point of Ayr	Potential shale resource	IGL	review of hydrocarbon potential	Island Gas Limited company website, 2012 NPR
Poland (2011: over 100 licences have been granted, rapid developments)					
-	Milejow	Milejow is adjacent to several blocks held by ExxonMobil, shale strategy and work programme pending the outcome of shale drilling on nearby blocks	Dart Energy	Direct award licence issued to Composite in November 2010 Dart intends to undertake an independent resource certification exercise during 2011.	Composite Energy - Dart Energy company website, 2012 NPR
Sept 2011	Siennica	In the Lublin Basin, Exxon is operating in partnership with French oil major Total, which	ExxonMobil (ExxonMobil has six licenses to explore for shale gas in Poland.)	Initial drilling and hydraulic fracturing carried out at Krupe 1 and Siennica 1 wells.	Natural Gas Europe website, 2012 NPR

Date	Location	Description	Company	Status (based on information from company websites)	Reference
		holds a 49% stake in the licenses. In the Podlasie Basin, Exxon has partnered with Hutton Energy.		Reported to be not commercially viable.	
Q2/Q3 2011.	Baltic Basin	including Gdansk-W, Braniewo-S, Szczawno - with a pending application on the Czersk concession.	San Leon Energy (The company has shale gas concessions in the Baltic Basin) - in joint-venture with Talisman energy	Company website indicates that initial drilling is expected Q2/Q3 2011, but press release suggests that drilling has been carried out at Rogity-1 well in February 2012.	San Leon Energy company website, 2012 NPR
2011	South-East Poland	Chevron conducted seismic programs and drilled an exploration well	Chevron Corp		Chevron company website, 2012b NPR
2011	Poland	Research of hydrocarbons in tight sands and shale	Cuadrilla Poland	Licences for research of hydrocarbons in tight sands and shale have been awarded	Polish Exploration and Production Industry Organisation, 2011 NPR
2011	Siekierki Project (Block 207 & Block 208)	Testing Multi-stage fractured horizontal Wells T-2 and T-3	Aurelian Oil and Gas PLC	Final results were anticipated at the end of January 2012.	Aurelian Oil company website, 2012 NPR
2010/2011	Baltic Basin	Łebień LE-2H horizontal well drilled Warblino LE-1H2 horizontal well drilled	3legresources (9 licenses) / Lane Energy Poland/ ConocoPhilllips	A seven stage hydraulic fracture stimulation programme was successfully executed across the 500 metre horizontal section in the deeper lower Palaeozoic shales. Further testing in 2012.	3 leg resources company website, 2012 NPR
2010	Baltic Basin	fracture stimulations were performed on both the Cambrian and Ordovician intervals in the Lebork S-1 well	BNK Petroleum (6 licenses)	Company plans to restimulate Lebork S-1 well and stimulate Starogard and Wytowno wells	
2010-2011	Zwola	hydraulic fracturing procedures is carried out by PGNiG SA in July 2010 in the Markowola-1 well in Zwola	PGNiG (15 licenses)	Company studies have highlighted no environmental issues (not independently verified)	PGNiG company website, 2012 NPR
2011	Wejherowo	Lubocino-1 well near Wejherowo Tests carried out after completion of the fracturing operation indicate that there are potentially significant amounts of shale gas in the Wejherowo licence area	PGNiG	PGNiG SA is the first Polish company to have commenced works towards commercial production of shale gas in Europe, aiming to commence production in 2014. Further horizontal drilling and further fracturing treatments are planned for 2012.	PGNiG company website, 2012 NPR
2011	Baltic Depression	The Company began drilling operations in the Łeczna and Siedlce districts in the fourth quarter of 2011,	Marathon Oil (11 concessions)	Plans to drill seven to eight wells by the end of 2012. Early stages of exploring and evaluating the full potential of these holdings.	Marathon Oil company website, 2012 NPR

Date	Location	Description	Company	Status (based on information from company websites)	Reference
Germany					
2008-2011	Damme 3 Shale well	Testing Hydraulic Fracturing	ExxonMobil	Hydraulic Fracturing has been carried out; no environmental impacts reported by operator (not independently verified). Evaluating gas potential	ExxonMobil Deutschland company website, 2012 NPR
2009-2010	- 2 concessions in North Rhine-Westphalia - concession in Lower Saxony - 2 concessions in Thuringia	geological survey / seismic survey	BNK Petroleum	Horizontal wells to be drilled not earlier than 2015	
2010	concessions "Rhineland" and "Ruhr"	received permission	Wintershall	conduct geological investigations in two license areas	Wintershall company website, 2012 NPR
France					
2010/11	Nant (Aveyron)and Villeneuve-de-Berg (Ardèche) Montélimar	 4,328 km^2 concession awarded in 2010	Schuepbach Total/Devon	France has banned hydraulic fracturing for shale gas exploration and exploitation (June 2011) (research projects under public supervision may however be allowed); three exploration permits granted previously to Schuepbach, Total & Devon for shale gas exploration were abrogated	Company websites
Netherlands					
	Boxtel	Planned exploratory well	Cuadrilla Resources	Drill activities suspended by court order	
Bulgaria					
2015/2016	Shale gas deposit in a large section of Dobrudzha in the north east of the country,	Planned two exploratory drillings in 2015 and two more in 2016.	Chevron Corp	Bulgarian government has imposed a ban on the use of hydraulic fracturing for oil and gas exploration and/or extraction on the Bulgarian territory (24th January 2012) and cancelled an exploration permit for shale gas exploration granted June 2011 to Chevron Corp (Jan 2012). Chevron can proceed with operations on the Novi Pazar concession in northeastern Bulgaria, but only by using conventional drilling techniques and not hydraulic fracturing	
Sweden					
2008-2010	Skane	Drilling three test wells	Royal Dutch Shell (two exploration licenses)	Limited resources of gas in the Alum shale.	Shell company website, 2012

Date	Location	Description	Company	Status (based on information from company websites)	Reference
				No further developments.	NPR
2012	Östergötland and Öland	Biogenic gas (shallow formations)	Gripen Gas	Four wells drilled and tested.	Gripen Gas website
2012	Motala project	planned test drilling in Alum shale	Aura Energy	Company plans to start drilling at the Motala site (3 - 5 wells)	Aura Energy company website, 2012 NPR
Norway					
2010	Alum Shale			2010: The Norwegian Petroleum Directorate (NPD) confirms the existence of shale gas on the Norwegian shelf and onshore, but no plans for extraction.	
Denmark					
2010	Bornholm	Scientific drilling to investigate natural gas in the Alum shale, seismic research	GEUS (Geological Survey Denmark and Greenland), cooperation with GASH		Geological Survey Denmark and Greenland, 2010 NPR
2010	Nordjylland Nordsjælland	Two onshore licences to explore for subsurface oil and gas in Denmark were granted in 2010	Total E&P Denmark B.V., an affiliate of Total, and the Danish state-owned oil and gas company Nordsøfonden (2 exploration licenses)	The exploration licenses run from 2010 to 2016. Total E&P Denmark B.V. and Nordsøfonden are currently working on the first of three exploration phases. The full exploration process is due for completion in 2016.	Skifergas company website

Appendix 6: Matrix of potential impacts

Tables A6.1, A6.2 and A6.3 summarise the potential environmental impacts and risks of shale gas extraction using high-volume hydraulic fracturing (adapted from USEPA 2011a PR and other sources identified in chapter 2).

Table A6.1: Matrix of impacts (groundwater, surface water and water resources)

Impacts specific to HVHF/Unconventional gas extraction are underlined

Development & Production Stage	Step	Groundwater contamination and other risks and impacts	Surface water contamination risks and impacts	Water resource depletion
Site Selection and Preparation	Site identific-ation			
	Site selection			
	Site preparation		Runoff and erosion during site construction may lead to silt accumulation in surface waters (greater potential risk in HVHF because of larger well pads and storage impoundment construction)	
Well Design	Deep well (directional) Shallow vertical	Inadequate design could result in aquifer pollution. Risk of pollution via casing of inadequate depth and/or quality		
Well drilling, casing and cementing	Drilling	Inadequate control of drilling process and associated wastes could result in groundwater or surface water pollution.	Leaks/spills of drilling mud and cuttings could result in SW pollution	
	Casing	Inadequate casing quality or depth could result in pollution of groundwater during hydraulic fracturing, flowback, and gas production		
	Cementing	Inadequate quality of cementation could result in pollution of groundwater during hydraulic fracturing, flowback, and gas production		
Hydraulic Fracturing	Water sourcing: surface water and ground water withdrawals	<u>Surface water abstraction could affect groundwater flow pathways, or quantity or quality</u>	<u>Temporary structures (hoses and pipes) used to remove source water from surface stream could cause bank erosion, potential for silt contamination of the stream.</u>	<u>Withdrawal from ground water resources may have the following impacts:</u> • <u>Lowering of water table</u> • <u>Dewatering drinking water aquifers</u> • <u>Changes in water quality resultant from water use:</u> • <u>Changes to salinity of water</u> • <u>Chemical contamination resulting from mineral exposure to aerobic environment</u> • <u>Lowering of water table may result in bacterial growth, taste or odour problems</u> • <u>Lowering of water table may lead to release of biogenic methane into superficial aquifers</u> • <u>Aquifer depletion may lead to upwelling of lower quality water or other substances (e.g.</u>

Development & Production Stage	Step	Groundwater contamination and other risks and impacts	Surface water contamination risks and impacts	Water resource depletion
				methane – shallow deposits) from deeper and subsidence or destabilization of geology • Withdrawal from surface water resources (streams , ponds and lakes) can affect hydrology and hydrodynamics altering flow regime (depth, velocity and temperature), can reduce dilution and increase contaminants
	Water sourcing: Reuse of flowback and produced water	Flowback stored in surface impoundments prior to reuse can leak and cause GW contamination. Risk of indirect effects following spillage and contamination of surface waters	Surface impoundments that store flowback prior to reuse can fail and cause SW contamination. Flowback transported to another location: Accidents and spillages in transit can result in surface and/or ground water contamination.	
	Chemical additive transportation and storage; mixing of chemicals with water and proppant	Accidents and spillages on site can result in surface and/or ground water contamination, e.g. as a result of: • Tank ruptures • Equipment / surface impoundment failures • Overfills • Vandalism • Accidents • Fires • Improper operations If storage arrangements are inappropriate, rainfall can transfer materials offsite in run-off		
	Perforating casing	Inappropriate charge used to perforate casing could affect well integrity (e.g., crack cement and casing)		
	Well injection of hydraulic fracturing fluid	Fluid contaminants could be transferred to aquifers: • via induced fractures extending beyond target formation to aquifer as a result of hydraulic fracturing operations and/or • through complex biogeochemical reactions with chemical additives in fracturing fluid and/or • via pre-existing fracture or fault zones and/or • via pre-existing man-made structures where these intersect an injection zone or in vicinity of hydraulically fractured well serving as conduits Sites close to, or hydraulically linked to water resources pose a greater risk	Risk of indirect impacts via groundwater contamination. Risks may result from HF fluid chemicals, contaminants in produced water, and/or gas migration. Sites close to, or hydraulically linked to water resources pose a greater risk	
	Pressure	Risk of pollution due to spillage	Risk of direct impacts via spillage	

Development & Production Stage	Step	Groundwater contamination and other risks and impacts	Surface water contamination risks and impacts	Water resource depletion
	reduction in well to reverse fluid flow, recovering flowback and produced water	of flowback and produced water via • Tank ruptures • Equipment or surface impoundment failures • Overfills • Improper operations These waters contain HF fluid, naturally occurring materials, as well as potentially reaction and degradation products including radioactive materials. Risk of disruption to groundwater flows	of flowback water; indirect impacts via groundwater contamination. Risks may result from HF fluid chemicals, contaminants in produced water, and/or gas migration. Sites close to, or hydraulically linked to water resources pose a greater risk	
Well Completion	Handling of waste water during completion (planned management)		If permitted, direct discharge to surface streams can affect water quality, particularly from the high salt content (this practice is banned in the U.S.) Treatment in municipal sewage treatment plant can affect the plant due to slugs of saline wastewater which can pass through the plant untreated. Treatment in Centralized Waste Treatment facility: risks depend on the treatment process.	
	Handling of waste water during completion (accident risks)	Risk of pollution due to spillage of flowback and produced water via • Tank ruptures • Equipment or surface impoundment failures • Overfills • Vandalism • Fires • Improper operations Risk of pollution if wastewater is re-used or disposed inappropriately If flowback water is used to make up fracturing fluid, this would increase the risk of introducing naturally occurring chemical contaminants and radioactive materials to groundwater. Relevant naturally occurring substances could include: • Salt • Trace elements (mercury, lead, arsenic) • NORM (radium, thorium and uranium) • Organic material (organic acids, polycyclic aromatic hydrocarbons)		
	Connection of well pipe to production pipeline			
	Well pad removal		Improper grading may cause runoff and erosion and lead to silt accumulation in surface waters. Drainage and removal of impoundment facilities could potentially result in accidental	

Development & Production Stage	Step	Groundwater contamination and other risks and impacts	Surface water contamination risks and impacts	Water resource depletion
			discharge to surface waters.	
Well Production	Production (including produced water management)	Risks posed by failure or inadequate design of well casing leading to potential aquifer contamination Surface spills or release of produced water during storage on site could affect groundwater and surface waters, as for "Hydraulic Fracturing" above. At the beginning of the production phase, flowback will comprise mainly fracturing fluid, changing to produced water after a few days, with increased salt concentration. Risk of pollution if wastewater is re-used or disposed inappropriately, as for "Hydraulic Fracturing" above		
	Pipeline construction and operation	Risks due to spillage of materials during construction of pipeline		
	Re-fracturing	Similar to "Hydraulic Fracturing" above	Similar to "Hydraulic Fracturing" above	Similar to "Hydraulic Fracturing" above
Well / Site Abandonment	Remove pumps and downhole equipment			
Well / Site Abandonment	Plugging to seal well	Inadequate sealing of well could result in subsurface pathways for contaminant migration leading to groundwater pollution, and potentially surface water pollution Existence of well could result in increased risks of pollution associated with future subsurface activity.		

Table A6.2: Matrix of impacts (air emissions, land take and biodiversity)

Impacts specific to HVHF/Unconventional gas extraction are underlined

Development & Production Stage	**Step**	**Release to air of HAPs/ O_3 precursors/ odours**	**Land take**	**Biodiversity risks and impacts**
Site Selection and Preparation	Site identification			
	Site selection			
	Site preparation	Diesel emissions from site construction equipment. Minor risk due to fugitive emissions in the event of equipment fuel or oil spillage	Typical well head would remove an area of approx. 3ha from other uses (eg agriculture, natural habitat) for the duration of exploration and production (US Department of Energy 2009 NPR). It may not be possible to restore a sensitive habitat following operational phase	Risk of impacts on sensitive species during site preparation due to removal of habitat, introduction of invasive species; noise, disturbance, particularly in sensitive areas Emissions, noise, human activity, traffic, land-take, habitat degradation, introduction of invasive species etc. could result in disturbance to natural ecosystems, particularly in sensitive areas
Well Design	Deep well (directional) Shallow vertical			
Well drilling, casing and cementing	Drilling	Diesel emissions from well drilling equipment. Minor risk due to fugitive emissions in the event of equipment fuel or oil spillage		Noise or plant movement during drilling could affect wildlife, particularly in sensitive areas
	Casing			
	Cementing			
Hydraulic Fracturing	Water sourcing: surface water and ground water withdrawals		<u>On-site storage of water for hydraulic fracturing requires land-take</u>	<u>On-site storage and transportation of water can affect biodiversity due to land take, disturbance and/or by the introduction of non-native invasive species</u>
	Reuse of flowback and produced water	Risk of emissions to air of HAPs/ozone precursors/ odours, from inadequate control of gas leakage during completion, or from release of gases dissolved in liquids Possible fugitive emissions of methane or HAPs from flowback or produced water. Direct effects more severe in the vicinity of residential locations. Indirect effects may be more severe in rural areas		
	Chemical additive transportation and storage; mixing of chemicals with water and proppant			<u>Accidents and spillages can result in harmful effects on natural ecosystems</u>
	Perforating casing (where present)			
	Well injection of hydraulic fracturing fluid	Diesel emissions from fracturing fluid pumps. Risks posed by movement of naturally occurring substances to groundwater as described for groundwater contamination. Relevant naturally occurring		

		substances could include: • Gases (natural gas (methane, ethane), carbon dioxide, hydrogen sulphide, nitrogen and helium) • Organic material (volatile and semi-volatile organic compounds)		
	Pressure reduction in well to reverse fluid flow, recovering flowback and produced water	Volatile and semi-volatile chemicals may be released from flowback and produced waters during recovery (EPA, 2011b NPR). Direct effects more severe in the vicinity of residential locations. Indirect effects may be more severe in rural areas Fugitive emissions may take place from routeing gas generated during completion to the sales pipeline. This is likely to be more severe from exploratory pre-pipeline wells than from developmental wells (pipeline in place)	Storage of flowback water and produced water requires land take	
Well Completion	Handling of waste water during completion (planned management)			
	Handling of waste water during completion (accident risks)			Spillages of waste water could result in pollution or other disruption to habitats
	Connection of well pipe to production pipeline			
	Well pad removal		(Return of land used for well pad to prior use or other uses)	
Well Production	Production (including produced water management)	Fugitive losses could occur during production phase via valve leakage etc Collect and treat gases dissolved in produced water along with methane	(After fracturing, the well pad may be removed or made smaller, reducing the footprint.)	Slight potential for disturbance to natural ecosystems during production phase due to human activity, traffic, land-take, habitat degradation, introduction of invasive species etc., particularly in sensitive areas
	Pipeline construction and operation	Risk of fugitive losses during production phase via valve or flange leakage	Pipeline requires land-take during construction and operation	Construction of new linear feature could adversely affect biodiversity, particularly in sensitive ecosystems
	Re-fracturing Re-fracturing	Similar to "Hydraulic Fracturing" above, but should be possible to route emissions to the pipeline	Similar to "Hydraulic Fracturing" above	Similar to "Hydraulic Fracturing" above
Well / Site Abandonment	Plugging to seal well	Inadequate sealing of well could result in fugitive emissions following site abandonment	It may not be possible to return the entire site to beneficial use following abandonment, e.g. due to concerns regarding public safety	It may not be possible to return the site and any other affected areas to its previous state, which could be particularly significant for sites located in sensitive areas

Table A6.3: Matrix of impacts (noise, seismicity, visual impacts and traffic)

Impacts specific to HVHF/Unconventional gas extraction are underlined

Development & Production Stage	Step	Noise	Seismicity	Visual impacts	Traffic
Site Selection and Preparation	Site identification				
	Site selection				
	Site preparation	Noise from excavation, earth moving, other plant and vehicle transport could affect residential amenity and wildlife, particularly in sensitive areas		Heavy plant, stockpiles, fencing, site buildings etc could result in adverse visual intrusion during site preparation	Transportation to/from well heads during site preparation can have significant adverse effects as above. Impact likely to be more severe on unsuitable roads and for longer haulage distances
Well Design	Deep well (directional) Shallow vertical	Noise emissions from wellhead could affect residential amenity and wildlife, particularly in sensitive areas		Well heads constitute a potentially significant visual intrusion, particularly in non-industrial settings as above	
Well drilling, casing and cementing	Drilling	Noise emissions from drilling or associated activity could affect residential amenity and wildlife, particularly in sensitive areas		Drilling activity and associated plant could constitute a potentially significant visual intrusion, particularly in non-industrial settings as above	
	Casing				
	Cementing				
Hydraulic Fracturing Reuse of flowback and produced water Chemical additive transportation and storage; mixing of chemicals with water and proppant Perforating casing (where present) Well injection of hydraulic fracturing fluid Pressure reduction in well to reverse fluid flow, recovering flowback and produced water	Water sourcing: surface water and ground water withdrawals	<u>Noise from use of pumps to handle water for hydraulic fracturing could affect residential amenity and wildlife, particularly in sensitive areas</u>			<u>Transportation of water to the site can have significant adverse effects due to noise, community severance, air emissions, accident/spillage risk etc. Impact likely to be more severe on unsuitable roads and for longer haulage distances</u>
	Reuse of flowback and produced water	<u>Noise from use of pumps to handle water for hydraulic fracturing could affect residential amenity and wildlife, particularly in sensitive areas</u>			
	Chemical additive transportation and storage; mixing of chemicals with water and proppant			<u>Chemicals storage tanks and related plant could constitute a potentially significant visual intrusion, particularly in non-industrial settings as above</u>	<u>Transportation of chemicals to the site can have significant adverse effects due to noise, community severance, air emissions, accident/spillage risk etc. Impact likely to be more severe on unsuitable roads and for longer haulage distances</u>
	Perforating casing (where present)				
	Well injection of hydraulic fracturing fluid		<u>Hydraulic fracturing could be associated</u>	<u>Hydraulic fracturing plant could constitute a potentially</u>	

Development & Production Stage	**Step**	**Noise**	**Seismicity**	**Visual impacts**	**Traffic**
			with minor earth tremors up to 4.0 on Richter scale	significant visual intrusion, particularly in non-industrial settings as above	
	Pressure reduction in well to reverse fluid flow, recovering flowback and produced water	Noise emissions associated with operation of well and associated equipment could affect residential amenity and wildlife, particularly in sensitive areas			
Well Completion	Handling of waste water during completion (planned management)		Injection of waste water could potentially be associated with minor earth tremors	Waste water tanks and related plant could constitute a potentially significant visual intrusion, particularly in non-industrial settings as above	Transportation of waste water to treatment/disposal facility can have significant adverse effects due to noise, community severance, air emissions etc. Impact likely to be more severe on unsuitable roads and for longer haulage distances
	Handling of waste water during completion (accident risks)				Transportation of waste water to treatment/disposal facility can have significant adverse effects due to accident/spillage risk. Impact likely to be more severe on unsuitable roads and for longer haulage distances
	Connection of well pipe to production pipeline				
	Well pad removal	Noise from construction/demolition machinery		(Benefit from removal of site infrastructure)	
Well Production	Production			Site plant and equipment could have a visual impact, particularly in residential areas or high landscape value areas, but much less than during fracturing	
	Pipeline construction and operation	Noise from pipeline construction could affect residential amenity and wildlife, particularly in sensitive areas		Pipeline could have a significant visual impact, particularly in residential areas or high landscape value areas	Transportation of materials and equipment could have adverse effects due to noise, community severance etc during construction phase
	Re-fracturing	Similar to “Hydraulic Fracturing” above	Similar to “Hydraulic Fracturing” above	Similar to “Hydraulic Fracturing” above	Similar to “Hydraulic Fracturing” above
Well / Site Abandonment	Plugging to seal well			It may not be possible to remove all wellhead equipment from site	

Appendix 7: Evaluation of risk control measures

This section presents risk control measures broken down by the stages in the hydraulic fracturing process identified in Chapter 2. Within these stages, regulatory control measures are presented first, covering both measures currently implemented, those which are proposed for implementation, and those recommended to regulatory authorities. Industry control measures are then presented, with attention focused firstly on those which are established practice (e.g. those which are laid down in guidelines published by the oil and gas industry), and then on measures which are recommended or proposed for implementation by industry.

A7.1 Overarching risk management measures

A7.1.1 Regulatory measures

The US Department of Energy (SEAB, 2011a NPR) recommended that regulatory authorities should take a strategic overview of potential impacts. SEAB recommended the creation of a national database of public sources of information relating to shale gas. This database would contain information on industry trends (production, well numbers and location etc), geological records, chemical usage, regulatory activity, and historical records of environmental quality, protection and safety. The cost for the US was estimated as approximately $20 million to create the database, with an annual maintenance cost of about $5 million. A geological survey consultee concurred that the primary need for the US is to have a database of baseline water quality and quantity, and geologic information across the entire shale gas formation, prior to the commencement of HVHF (North American geological survey consultation response 2012 NPR). Such a database would have similar advantages for the UK. Rahm (2011 p2980 PR) emphasises the need for a strong regulatory approach, and highlights difficulties caused due to differences of approach between state and federal regulatory authorities in the US.

It was also recommended that funding should be provided for the existing STRONGER initiative to provide peer review of regulatory activities, and for information resources to assist in consistent regulation and evaluation (total cost estimated to be $5 million per year).

Academic consultees confirmed that well cementing methods and practices needs further research (Consultation response from Professor R Vidic, University of Pittsburgh 2012 NPR). European regulators emphasised the importance of research focusing on unknown features of shale gas geology in Europe (European regulator consultation responses 2012 NPR):

- Amount and distribution of gas in the different target horizons
- Permeabilities of source rocks and barriers for fluids and gases; estimate of fracture patterns
- Localisation of faults and estimation of their hydraulic effects
- Origin and risk of migration of methane in the overburden of the gas shales

Depending on the circumstances, a regulatory authority may choose to take a wider or a narrower view of the impacts of a new shale gas development industry. For example, New York State's Supplemental Generic Environmental Impact Statement (SGEIS) (2011 PR) addresses not just the potential impacts from HVHF, but the potential impacts for state-wide exploitation of the Marcellus Shale. There is a wide range of impacts which are potentially associated with the industry (e.g. habitat fragmentation) which are not directly the result of HVHF, but result from the industry that HVHF enables.

A report to the European Parliament (Lechtenböhmer et al., 2011 NPR) suggested that authorities should consider identifying zones which are off-limits to hydraulic fracturing if required to protect drinking water supplies, prevent groundwater contamination and protect ecosystems and wildlife from endangerment and invasive species.

In March 2011, the Governor of Pennsylvania established the "Governor's Marcellus Shale Advisory Commission." The purpose of the Advisory Commission was to develop a comprehensive, strategic proposal for the responsible and environmentally sound development of Marcellus Shale. The Commission issued its report in July 2011 (Pennsylvania State, 2011 NPR). The report provides extensive information on the history of hydraulic fracturing and drilling in the Marcellus Shale formation including the role of all state and local agencies. It also provides an overview of the Pennsylvania state regulatory changes prompted by Marcellus Shale activity, case studies on the potential for impacts to ground water and surface water, and a detailed discussion on the economic impacts of hydraulic fracturing in Pennsylvania.

The Advisory Commission reviewed and developed recommendations to mitigate environmental impacts; enhance emergency response; identify and mitigate uncompensated local and community impacts; and provide for appropriate public health monitoring and analysis. Their recommendations included:

- increased permitting,
- pre-drilling notification
- operator liability requirements.
- additional conditions for locating wells and storing hazardous chemicals. These recommendations included:
    - 9.2.11 - Increase the minimum setback distance from a private water well from 60 m to 150 m (200 feet to 500 feet) and establish a minimum setback distance from a public water supply (water well, surface water intake or reservoir) of 300 m(1,000 feet) unless waived in writing by the owner or public water supply operator.
    - 9.2.12 - Provide regulator with additional authority to establish further protective measures for the storage of hazardous chemicals or materials on a well site located within a floodplain.
    - 9.2.13 - Impose additional conditions for locating well sites in floodplains, including prohibiting where appropriate.
    - 9.2.24 -The setback standard for an unconventional well shall be increased to 90 metres (300 feet) from the wellbore to a stream or water body as provided in section 205(b) of the Oil and Gas Act. A 30 m (100 foot) setback from the stream or water body to the edge of disturbance shall also be implemented. … For High Quality and Exceptional Value streams, however, additional setbacks or BMPs may be required by the regulator.
- additional well stimulation and completion reporting requirements
- voluntary ecological initiatives within critical habitats that would generate mitigation credits which are eligible for use to offset future development.

The current international standard for environmental management systems (ISO 14000 series, 2004) is widely adopted by operators in the oil and gas industry on a voluntary basis (ISO, accessed 2011). This standard is also applicable for the management of HVHF operations. ISO 14001:2004 and ISO 14004:2004 deal with environmental management systems. The ISO 14000 series of standards are designed to enable organisations to minimise the adverse effects of their operations on the environment, and to deliver ongoing improvements in environmental performance. Accreditation to ISO 14000 provides a framework for an organisation to assess, monitor and improve its environmental performance. Accreditation should be encouraged for shale gas installation operators as a means of ensuring ongoing improvements in all aspects of environmental performance.

The SEAB (2011a NPR p27) recommended the creation of a shale gas industry production organization dedicated to continuous improvement of best practice in the industry through development and promulgation of appropriate standards, and assessment of compliance among its members. It recommended that this work should initially focus on five priority areas:

- Measurement and disclosure of air emissions including VOCs, methane and air toxics
- Reduction of methane emissions to air from all shale gas operations
- Integrated water management systems
- Well completion – casing and cementing
- Characterization and disclosure of flow back and other produced water

Disclosure of hydraulic fracturing fluid additives and flowback composition was also recommended by the German environment ministry (Umweltbundesamt 2011 NPR p23)

Consultees recommended that further research into the control of cumulative impacts associated with shale gas development is needed (North American geological survey consultation response; European regulator consultation response 2012 NPR).

A7.2 Well pad site identification and preparation

A7.2.1 Regulatory measures

Baseline surveys

The SEAB (2011a NPR p23) recommended that systems for measurement and reporting of background surface and ground water quality should be implemented in advance of shale gas production activity. Indicator species such as bromides may be useful components of a baseline survey (Consultation response from Professor R Vidic University of Pittsburgh 2012 NPR). The need for systematic and independent data on baseline groundwater quality was supported by Osborn et al. (2011 PR p5). The SEAB went on to recommend monitoring for wider community and cumulative impact issues (SEAB (2011a NPR p26), and further recommended a "*science-based characterization of important landscapes, habitats and corridors to inform planning, prevention, mitigation and reclamation of surface impacts.*"

Similarly, two European regulators and one North American geological survey consultee recommended groundwater monitoring before, during and after shale gas exploration works (consultation responses 2012 NPR). Osborn et al. (2011 PR p4) recommended long-term, coordinated sampling and monitoring of the quality of water provided to industry and private homeowners.

Groundwater level monitoring networks are being used in the US to monitor groundwater depletion in areas where groundwater is used as water supply for drilling and hydraulic fracturing purposes. GIS and remote sensing technologies linked to ground-truth studies of targeted species and existing studies of land-use alteration can be used to evaluate land cover changes due to concentrated development and its possible effects on flora and fauna. This is particularly useful in remote or heavily forested areas (North American geological survey consultation response 2012 NPR).

Prohibit high volume hydraulic fracturing in drinking watersheds

<u>New York</u>: New York State DEC (2011 PR) concluded that high-volume hydraulic fracturing activity is not consistent with the preservation of unique unfiltered water supplies that depend

on strict land use and development controls to ensure that water quality is protected. It was concluded that high-volume hydraulic fracturing activities could result in a degradation of drinking water supplies from accidents and surface spills and that large scale industrial activity is not compatible with the use of this area as a drinking watershed. Accordingly, NY DEC recommended that high-volume hydraulic fracturing operations not be permitted in the Syracuse and New York City watersheds or in a protective 4,000 foot (1,200 metre) buffer area around those watersheds (New York DEC (2011 PR) p1-17)

The SEAB (2011 NPR p26) supported the declaration of unique and/or sensitive areas off-limits to drilling and support infrastructure, based on an appropriate science-based process.

Ensure new wells are installed away from abandoned wells and other potential conduits for fluid migration (site selection and permitting)

Michigan: The Michigan Department of Environmental Quality, Office of Geological Survey, Permits and Bonding Unit reviews applications for "Permits to Drill and Operate" oil and gas wells that may be hydraulically fractured. During this review, staff are required to "identify recorded existing or permitted well bores within [specified] radii of the proposed well…determine whether the [identified] well may provide a conduit for movement of hydraulic fracturing fluids or produced fluids into a stratum containing fresh water. The determination shall take into account the anticipated radius of influence of the potential hydraulic fracturing….[if such wells are identified, require the applicant to] [r]elocate the proposed well to a location such that all potential conduits are outside the area of review." (Michigan Office of Geological Survey, 2011a NPR)

New York: "To ensure that abandoned wells do not provide a conduit for contamination of fresh water aquifers, the Department proposes to require that the operator consult the Department's Oil and Gas database as well as property owners and tenants in the proposed spacing unit to determine whether any abandoned wells are present. If

1. the operator has property access rights,
2. the well is accessible, and
3. it is reasonable to believe based on available records and history of drilling in the area that the well's total depth may be as deep or deeper than the target formation for high-volume hydraulic fracturing,

then the Department would require the operator to enter and evaluate the well, and properly plug it prior to high-volume hydraulic fracturing if the evaluation shows the well is open to the target formation or is otherwise an immediate threat to the environment." (New York State DEC 2011 PR , p7-58)

Requirement for pit liners (construction specifications)

As an example, pit specification requirements are set out in the State of Louisiana Administrative Code Title 43 Part XIX §307.A.1.a:

> "*For natural liners: A liner along the bottom and sides of pits which has the equivalent of 3 continuous feet [0.9 m] of recompacted or natural clay having a hydraulic conductivity no greater than 1 x 10^{-7} cm/sec.*
>
> *For synthetic liners: Pits constructed with a manufactured liner must have side slopes of 3:1 and the liner at the top of the pit must be buried in a 1-inch wide and 1-inch deep trench.*
>
> *Freeboard Requirement: Liquid levels in pits shall not be permitted to rise within 2 feet [0.6 m] of top of pit levees or walls.*
>
> *Additional Requirements: Pits shall be protected from surface waters by levees or walls and by drainage ditches, where needed, and no siphon or openings will be placed in or over levees or walls that would permit escaping of contents so as to cause pollution or contamination.*"

Requirement for secondary containment for storage tanks and spill control plans

These measures will also reduce risk of surface water contamination.

US EPA, Office of Emergency Management: For fuel oils, diesel, produced oil, and certain produced water containers: The Federal Spill Prevention, Control, and Countermeasure (SPCC) rule includes requirements for oil spill prevention, preparedness, and response to prevent oil discharges to navigable waters and adjoining shorelines. The rule requires specific facilities to prepare, amend, and implement SPCC Plans. The SPCC rule is part of the Oil Pollution Prevention regulation (EPA, 2012c NPR), which also includes the Facility Response Plan (FRP) rule (EPA, 2012d NPR).

Colorado: New oil and gas locations within 2640 feet [800 m] of surface water supply locations shall use pitless drilling systems; berms or other containment around crude oil, condensate, and produced water storage tanks; and conduct surface water sampling pre-drilling and three months after drilling immediately downgradient of the oil and gas location (COGCC 317B(c), (d), (e)).

Restrict hydraulic fracturing and well pad installation from sensitive areas

New York: NYDEC proposes that certain sensitive areas of New York State should be off-limits to surface drilling for natural gas using high-volume hydraulic fracturing technology…these areas include

- watersheds associated with unfiltered water supplied to the New York City and Syracuse areas (because these are unfiltered water supplies that depend on strict land use and development controls to ensure that water quality is protected)
- reforestation areas
- wildlife management areas
- "primary" aquifers (which are highly productive aquifers presently used municipal water supplies) and
- additional setback and buffer areas.

Delaware River Basin Commission: In order to protect high value water resource landscapes and special protection waters, the Delaware River Basin Commission proposed to require that any natural gas development project sponsor with natural gas leaseholds in the basin encompassing a total of over 3,200 acres (1300 hectares) or who intends to construct more than five natural gas wellpads must prepare a plan (Natural Gas Development Plan) for siting and accessing its natural gas development projects. The goal of the requirement is to protect the natural character of the watershed and the project area by encouraging facility siting that minimizes land disturbance, including forest clearing and fragmentation (Section 7.5). Among other requirements, the commission proposed to restrict development from flood plains, steep slopes, the river corridor itself, and proposed that development meet the following set-backs (7.5(d)):

- Stream, waterbody or wetland – the greater of 300 ft. (90 m) from the wellbore or 100 ft. (30 m) from the nearest disturbance.
- Surface water supply intake – 1,000 ft. (300 m) from nearest disturbance
- Water supply reservoir – 1,000 ft. (300 m) from nearest disturbance
- Public water systems – 1,000 ft. (300 m) from nearest disturbance
- Private water supply well – 500 ft. (150 m) from nearest disturbance

Set minimum well spacing

New York: As described in New York State DEC (2011 PR) Section 5, developing a shale formation using horizontal wells drilled from a multi-well pad will result in a reduced number of well pads within a given area and the need for only a single access road and gas gathering system to service multiple wells on a single pad. Consequently, a smaller total area of land disturbance is associated with horizontal wells for shale gas development than that for vertical wells. Land take can be minimized by setting a larger minimum well spacing. For vertical wells, well spacing is typically 40 acres (16 hectares). New York State anticipates requiring “spacing units of up to 640 acres (260 hectares or 2.6 sq km) with all the horizontal wells in the unit drilled from a common well pad” (New York State DEC (2011 PR) page 5-22). Installing 16 vertical wells to develop a 260 hectare site would disturb 31.1 hectare. The same site could be developed using a well pad with four horizontal wells, requiring 3.2 hectare of land disturbance. Installing more wells per pad would further reduce the required land area. The use of higher numbers of wells could enable up to 5 square kilometres to be developed per pad, as set out in Table 12.

Table 12: Land take for a 25 square km development

Spacing Option	Multi-Well 2.5 sq km	Multi-Well 5 sq km
Number of pads	10	5
Total Disturbance – Drilling/fracturing Phase	30 hectare (3 hectare per pad)	22.5 hectare (4.5 hectare per pad)
% Disturbance – Drilling/fracturing Phase	1.2% (30 hectare /2,500 hectare area)	0.89% (22.5 hectare/2,500 hectare area)
Total Disturbance – Production Phase	5 hectare (0.5 hectare per pad)	4 hectare (0.8 hectare per pad)
% Disturbance Production Phase	0.2%	0.16%

(Adapted from New York State DEC 2011 PR Table 5.1)

The SEAB (2011 NPR p26) also recommends the use of multi-well pads to reduce community impacts such as traffic and new road construction.

Require strategies to minimize onsite water storage (produced water reuse, use of temporary pipe networks)

No specific legislative or regulatory initiatives discouraging onsite water storage could be identified in the course of this study.

Locate sites close to existing gas pipelines

No specific legislative or regulatory initiatives regarding proximity to existing gas pipelines could be identified in the course of this study.

Minimisation of habitat fragmentation and destruction

<u>New York:</u> The NY SGEIS (Section 7.4.1) includes proposed practices to mitigate harm from fragmentation of existing habitats:

- Require multiple wells on single pads wherever possible
- Design well pads to fit the available landscape and minimize tree removal
- Require soft edges around forest clearings by either maintaining existing shrubs or planting shrubs, or allowing shrub areas to grow
- Require lighting used at wellpads to shine downward during bird migration periods
- Limit the total area of disturbed ground, number of well pads, and especially, the linear distance of roads, where practicable
- Require roads, water lines, and well pads to follow existing road networks and be located as close as possible to existing road networks to minimize disturbance

- Require reclamation of non-productive, plugged, and abandoned wells, well pads, roads and other infrastructure areas.

The NYSGEIS proposes additional strategies for controlling habitat fragmentation that are specific to habitats of concern in the Marcellus Shale area of New York State. For example, where operators request permits to conduct HVHF operations in areas where there are contiguous habitats of 30 acres (12.1 hectares) or more of grassland or 150 acres (60.7 hectares) or more of forest, the applicant must conduct a site-specific ecological assessment, develop a site-specific mitigation plan, and monitor the effects of disturbance during activities and for two years following well completion.

Practices to reduce risk of introduction of non-native species.

<u>New York:</u> The NY SGEIS (Section 7.4.2) includes proposed practices to mitigate harm from invasive species caused by HVHF activities. The SGEIS called for a site- specific and species-specific invasive species mitigation plan. The plan would include practices for mitigating harm from terrestrial (plant) and aquatic invasive species. Recommended practices include, among others:

- Preventing the Spread of Invasive Species: Machinery and equipment - pressure-wash and clean with water (no soaps or chemicals) prior to leaving the invasive species affected area to prevent the spread of seeds, roots or other viable plant parts. This includes all machinery, equipment, and tools used in the stripping, removal, and disposal of invasive plant species.
- Preventing New Invasive Species Introductions: Fill and/or construction material (e.g. gravel, crushed stone, top soil, etc.) from offsite locations - only use material after inspection if no invasive species are found growing in or adjacent to the fill/material source.
- Restoration and Preservation of Native Vegetation: Use only native (non-invasive) seeds or plant material for re-vegetation during site reclamation.

Site selection to minimise noise

<u>New York</u>: NYSGEIS identified noise mitigation measures for HVHF operations (New York State DEC 2011 PR p7-130). These measures are not required in regulations but could be added to specific permits and enforced through binding permit conditions. With regard to site selection, it was recommended that the well site and access road should be located as far as practical from occupied structures and places of assembly.

Minimisation and control of potential seismic impacts

European regulators recommended carrying out monitoring with respect to potential seismic events (European regulator consultation response 2012 NPR). A North American geological survey regulator suggested that it would be helpful for data held by the industry to be available to regulators. A method for monitoring and management of potentially significant seismic events was proposed by the UK Government (UK DECC, 2012 NPR)

The state of Arkansas does not have regulations addressing potential seismic risks from hydraulically fracturing shale gas and oil wells. However, Arkansas experienced a series of very small earthquakes in 2010 (Guy-Greenbrier earthquake swarm) (Arkansas Sun Times, 2011 NPR). The Arkansas Oil and Gas Commission, Arkansas Geological Survey, and the Center for Earthquake Research and Information (CERI) concluded the earthquakes correlated with underground injection of wastewater from Fayetteville shale gas wells. In response, the Arkansas Oil and Gas commission initiated a moratorium on Class II disposal wells (Arkansas State, 2012 NPR).Unless otherwise approved by the Arkansas Oil and Gas Commission after notice and a hearing, no permit to drill or re-enter, a new Class II Disposal or Class II Commercial Disposal Well may be granted within one (1) mile of a Regional Fault or within five (5) miles of a known or identified Moratorium Zone Deep Fault.

The State of Ohio is proposing to introduce reforms with regard to management of potential seismic impacts associated with wastewater injection wells (Ohio Department of Natural Resources, 2012 NPR):

- Review of existing geologic data to identify known faulted areas within the state and avoid the locating of new disposal wells within these areas;
- Require a complete suite of geophysical logs to be run on newly drilled disposal wells.
- Evaluate the potential for conducting seismic surveys;
- Require the submission, at time of permit application, of any information available concerning the existence of known geological faults, and submission of a plan for monitoring any seismic activity that may occur;
- Require a measurement or calculation of original downhole reservoir pressure;
- Require conducting a step-rate injection test;
- Require the installation of a continuous pressure monitoring system;
- Require the installation of an automatic shut-off system;

Injection of waste water into aquifers would not be permitted in Europe (European Commission, 2011a NPR ; see Section 3.17).

Minimisation of visual impacts

New York: From New York State DEC (2011 PR):

- Siting: Use multi-well pads; avoid ridgelines or other areas where aboveground equipment and facilities break the skyline;
- Lighting: should be the minimum necessary for safe working conditions and public safety, and should be sited and directed to minimize off-site light migration, glare, and “sky glow” light pollution.
- Camouflage: Use forms and colours to mimic surroundings (e.g., paint fracturing fluid tanks so as to blend with surroundings)

Site-specific remedies for traffic issues

Other site-specific remedies for traffic issues could include

- limiting truck weights,
- road use agreements,
- payments by industry to repair damaged roads.

A7.2.2Industry measures

Established measures

For sites developed in accordance with the API guidelines, a comprehensive pre-site assessment must be carried out to ensure that the most appropriate sites are developed (ALL Consulting, 2010a NPR p12; API 2011a NPR p15). Site selection should take into account aspects such as the following:

- Geological considerations
- Potential presence of other wells which could affect the integrity of the proposed well
- Water sourcing
- Locate equipment and well pads to use existing features (e.g., hillsides, trees) to contain noise and preserve views.

- Locate site so it is accessible by existing roads and other infrastructure (e.g., pipelines) to minimize construction impacts.
- Potential environmental constraints such as floodplains, wetlands, fluid makeup, depth to the quality of groundwater, surface topography, proximity to drinking water supplies and wells, proximity to surface water, proximity to geological hazards, proximity to residential or commercial buildings, and proximity to other environmentally sensitive areas.

Developers should incorporate best design and management practices and train employees in why good management is important, including the need to prevent or minimise risks to health and the environment (STRONGER, 2010 NPR ; API 2011a NPR p9, p10). Providing a sufficient number of on-site staff throughout drilling, completions, and production operations is important to ensure that environmental management and safety procedures can be properly implemented.

Before and during exploration and production, it is important to design and implement an appropriate baseline environmental survey. This is likely to include consideration of baseline testing of ambient air before well pad construction commences, and baseline testing of water wells and boreholes before commencing drilling. A plan for air and water well monitoring should be developed and implemented during the construction, drilling, and production phases. For sites developed in accordance with the API guidance, water samples from any nearby source of water (rivers, creeks, lakes, ponds, and water wells) should be obtained and tested (API, 2009 NPR). The area of sampling should be based on the anticipated fracture length plus a safety factor. This procedure will establish the baseline conditions in the surface and groundwater prior to any drilling or hydraulic fracturing operations. If subsequent testing reveals changes, this baseline data will allow the operator to determine the potential sources causing any changes. Because the constituents of the hydraulic fracturing fluid are known to the operator and can be made available to the regulatory authorities via the permitting processes described in Chapter 2, a determination can be made regarding the source of the changes in the groundwater composition.

Guidance on impoundment construction is provided in API (2011a NPR p11).

Recommended measures

The International Energy Agency (2012 NPR p13) emphasised the importance of site selection to minimise environmental impacts and community disturbance.

ALL Consulting (2009b NPR) suggest a separation of 1 mile (1.6 km) between well pads and sensitive residential areas where possible.

The impact of transportation and other impacts can be minimised by selecting an appropriate location, and by managing traffic routeing to and from the site. Developers should also consider the impacts of potential access road locations at the planning stage, and preferably, locate access roads away from homes and businesses.

Risks to groundwater can be minimised by limiting development to appropriate zones specified to protect groundwater (Pochon et al., 2008 PR).

Limiting the pace of development may be effective in reducing the more acute impacts of HVHF activities (New York State DEC 2011 PR p6-317). This needs to be balanced against the longer development period that would result from slower development.

In the past, shale gas development in the US has taken place via single-well pads. More recently, there has been a trend towards the use of multi-well pads with typically 6 to 10 wells per pad (New York State DEC 2011 PR p3-3) and up to 20 wells per pad in some instances (SEAB 2011a NPR p33). The use of multi-well pads is effective in reducing a wide range of potential impacts compared to the use of single-well pads. This measure also reduces construction costs (e.g. SEAB 2011a NPR p33; ALL Consulting 2009 NPR). For example, land-take and habitat fragmentation can be minimised in this way. ALL Consulting (2009b

NPR) estimates that surface disturbance can be reduced by 85% in this way compared to single well pads. Similarly, New York State DEC (2011 PR p5-23) suggests that the use of multi-well pads can reduce surface disturbance compared to single well pads by 90% during the drilling/fracturing phase, and by 80% during the production phase.

The land used for infrastructure such as storage ponds should be minimised. It is important that land used for gas extraction is maintained to a suitable standard so that it can be restored to its original form, so far as possible. However, as noted in Chapter 2, it may not be possible to fully restore a site in a sensitive area. For example, sites in areas of high agricultural, natural or cultural value could potentially not be fully restorable following use.

During the planning stage, it will be helpful to investigate and review the history of nearby wells to determine if any unusual problems were encountered (e.g., significant flowback or lost cementing returns). These can then be addressed in future well development.

Proper supply chain and transportation management can mitigate equipment, chemicals, and storage tank availability. Measures include:

- Develop a transportation plan to reduce truck traffic, designate parking and storage areas, and identify transportation routes. If possible, use temporary surface pipes to transport water to the well pad and flowback and produced water to storage, treatment, or injection points.
- Centralise gathering facilities to reduce truck traffic, including the liquids gathering system.

At the planning stage, preliminary lighting surveys should be carried out to enable site lighting to be arranged in order to minimize or eliminate any visual disturbance for local residents or wildlife, while still providing sufficient light to provide a safe workplace for on-site employees (ALL Consulting 2009b NPR p15).

During site preparation, surface soils should be stockpiled for all cut and fill areas so that they can be reused during interim and final reclamation. Topsoil should be segregated from subsurface materials to improve the effectiveness of reclamation activities. By using cut areas for surface impoundment construction, unnecessary increases in facility footprint can be avoided. Fill slopes should be compacted to reduce the risk of subsidence and slope failure.

Primary and secondary containment of chemical, water and waste storage facilities can be utilised at the well site to ensure the surface environment is not exposed to materials that could pose harm to the surrounding area. Barriers can be implemented as needed to ensure surface disruptions such as potential erosion at the drill site do not affect the surrounding environment. Buffer zones can also be used around surface water resources to provide further protection against water pollution risks (see example buffer zones in Section A7.1).

Surface impoundments and reserve pits should be avoided where possible (Oil and Gas Accountability Project, 2012 NPR). If unavoidable, surface impoundments should not be constructed in sensitive areas such as natural water courses, karst topography, source water protection areas used for public water supplies, areas with shallow groundwater, and in porous soils. These should be located in cut areas when possible. Impoundments and pits should not be constructed in areas within a flood risk zone, to reduce the risk of overtopping due to external flood events. Synthetic liners and/or compacted clay can be used to reduce the risk of groundwater impacts. Before installing synthetic liners, operators should consider using sand, clay or felt liners to protect the synthetic liner from being punctured by rock material. It is important that surface impoundments and storage tanks are managed so as to provide sufficient freeboard to avoid overtopping. Secondary containment and liners should be used as appropriate around storage tanks to avoid potential soil and groundwater contamination due to storage tank leaks or spills.

The key control measures during the design of site access roads include the following

- Construct roads along natural contours or in flatter terrain where possible.
- Avoid constructing roads to a higher standard than the necessary to minimize environmental impacts. For example, basic two-track roads can be used where appropriate to avoid the impacts associated with tarmac road construction.
- Avoid construction of shorter roads on steep slopes: these can create greater environmental impacts at higher cost than longer roads with lower gradients.

When work is being carried out near residential areas, it is important to provide residents in local communities sufficient information on the site layout and potential hazards. This can be a useful means of reducing the perceived impacts associated with drilling activities (International Energy Agency 2012 NPR p13). Emergency response policies and procedures should be developed to enable any community risks when incidents occur to be properly handled and managed.

During site selection, developers should consider opportunities to avoid water quality impacts by locating facilities where pollutant transport into surface and groundwater will be limited. It is important to consider spill pathways, erosion and sedimentation issues, and stormwater runoff when selecting well pad and auxiliary facility locations.

Where possible, facilities should not be located adjacent to or near surface water bodies or within source water protection areas for public water supplies, in order to reduce pollutant transport pathways. Similarly, facilities should not be located in or near sensitive environments (e.g., riparian areas, wetlands, sensitive species habitats, karst areas) (see example buffer zones in Section A7.1).

Silt fences, sediment traps or basins, hay bales, mulch, earth bunds, filter strips or grassed swales can be used to slow runoff and trap sediment from leaving the site. Loose soil should be covered with geotextiles or other materials. Where possible, activities should be staged to reduce soil exposure and coincide with a season of low rainfall.

The risk of impacts on water quality can be mitigated by:

- Periodically monitoring down-gradient of surface impoundments.
- Immediate notification of public water suppliers in the event of spills or leaks.
- Use of near real-time water quality monitors for specific conductance which can be used to provide an initial assessment of water quality impacts from spills (North American geological survey consultation response 2012 NPR)
- Installation and use of groundwater monitoring wells up-gradient and down-gradient of the well pad to ensure that drilling, hydraulic fracturing, and other operations do not compromise ground water.
- Installation of a liner and secondary containment around the well pad to minimize the potential for surface water and shallow ground water contamination.

Pipelines should not be located on steep hillsides or within watercourses. Pipelines constructed across watercourses should be built high enough to provide clearance for high-flow events. Pipelines can be located along road corridors to minimize surface disturbance and promote leak detection. Secondary containment may be appropriate for pipelines and valves conveying potentially toxic substances.

Sites should be located to maximise the benefit of natural noise attenuation features such as land-form and vegetation. As described in Section A7.1, sites should be located as far away from sensitive residential or habitat areas as possible. New York State DEC (2011 PR p7-128) uses a distance of 305 metres as indicative of the zone within which noise impacts may be significant and detailed investigation is needed.

Baseline monitoring for key environmental indicators, such as groundwater quality, was recommended by the International Energy Agency (2012 NPR p13).

Site selection is an important factor in minimising road traffic impacts. Further guidance is provided by API (2011a NPR p17):

- Existing roads that meet transportation needs should be utilized, where feasible
- When it is necessary to build new roadways, they should be developed with potential impacts and purpose in mind. Mitigation options should be considered prior to construction and landowner recommendations should be part of the planning process.
- Proper road maintenance is critical for the performance of roads, to manage erosion and to protect environmentally sensitive areas.
- Where appropriate, operators should obtain road use agreements with local authorities.
- Whether agreements are in place or not, in areas with traffic concerns, operators should develop a trucking plan that includes an estimated amount of trucking, hours of operations, appropriate off-road parking/staging areas and routes. Examples of possible measures in a road use agreement or trucking plan include:
    - route selection to maximize efficient driving and public safety;
    - avoidance of peak traffic hours, school bus hours, community events and overnight quiet periods;
    - coordination with local emergency management agencies and highway departments;
    - upgrades and improvements to roads that will be travelled frequently;
    - advance public notice of any necessary detours or road/lane closures; and
    - adequate off-road parking and delivery areas at the site to avoid lane/road blockage.

A7.2.3 Summary

The site identification and preparation stage provides the opportunity to implement many of the key preventive controls on potential environmental and health risks. As described in Section 2, the key issue associated with site preparation is that of cumulative land take. There may also be less significant issues associated with surface water contamination risks; biodiversity impacts; visual impact; and traffic during this stage. However, the decisions taken and actions carried out at this stage are likely to be beneficial in mitigating risks throughout the lifetime of the site.

A wide range of regulatory measures can be applied at the site identification and preparation stage. Similar measures are planned to be implemented in Québec (North American regulator consultation response 2012 NPR). The key measures identified for implementation in Québec include:

- Specifying appropriate buffer distances to sensitive locations such as surface waters, groundwater, residential locations or protected habitats
- Specifying a minimum separation or maximum development density to minimise impacts on biodiversity and visual impacts
- Setting appropriate emissions or environmental performance standards – e.g. with regard to contaminants in waste water, noise or air pollution
- Setting appropriate environmental monitoring programmes in place to ensure that any impacts can be tracked

Operators will be subject to a number of potentially conflicting constraints with regard to site selection. In some cases, commercial considerations will align with good environmental performance – e.g. minimising vehicle mileage will typically be beneficial both to the operator and for the environment. In other cases, good environmental performance may need to be enforced via appropriate regulatory measures.

The issues with regard to site preparation and levelling are common to many development projects and do not require special consideration with regard to hydrocarbons operations involving HVHF.

The control measures set out in this section are implemented by regulators and the industry in areas where HVHF is established – that is, North America. Under these conditions, they are considered to be affordable. The cost and affordability of such measures in a European context cannot be evaluated at this stage, and will depend on the forecast revenues from shale gas extraction in Europe.

The control measures set out in this chapter are considered likely to be effective in delivering control of the impacts under consideration. For example, noise impacts can be effectively controlled by appropriate siting and design. Containment of water can be designed to reduce the risk of significant impacts in the event of a spillage to an insignificant level.

However, some impacts cannot be fully mitigated. For example:

- It may not be possible to return land used for shale gas development to its former use in some locations – e.g. if the land was a valuable habitat site or historical/cultural resource.
- Good site selection and design can reduce traffic impacts, but a significant number of traffic movements is inevitable.

A7.3 Well design, drilling, casing and cementing

A7.3.1 Regulatory measures

Isolate well from underground source of drinking water

Surface casing and cementing requirements (well construction and development, field inspection)

Examples of State Requirements for casing placement to ensure aquifer protection are as follows.

Colorado: In areas where subsurface conditions are unknown, the surface casing shall be set in or through an impervious formation and cemented in place (COGCC 317(e)). In areas where subsurface conditions are known through drilling experience, the surface casing shall be set and cemented to protect all fresh water (COGCC 317(f)). In areas where fresh water aquifers are of such depths as to make it impractical or uneconomical to set the surface casing the total depth, the intermediate and/or production string shall be cemented from a minimum of 50 feet [15 m] above to 50 feet [15 m] below any freshwater aquifer (COGCC 317(g)).

Illinois: Surface casings shall be set to a depth of at least 100 feet [30 m], or 50 feet [15 m] below the base of a freshwater aquifer (whichever is deeper). Alternative casing methods are available in the regulations; however, all methods require a minimum of 50 feet [15 m] below the freshwater aquifer. (62 Illinois Administrative Code Section 240.710)

Pennsylvania: The operator shall drill to approximately 50 feet [15 m] below the deepest fresh groundwater or at least 50 feet [15 m] into consolidated rock (whichever is deeper), and immediately set and permanently cement a string of surface casing to that depth. (25 PA Code §78.83)

Oklahoma: Suitable and sufficient surface casing shall be run and cemented from bottom to top with a minimum setting depth which is the greater of 90 feet [27 m] below the surface, or 50 feet [15 m] below the base of treatable water. The operator must run and cement the surface casing string before reaching a depth of 250 feet [76 m] below treatable water. (OK Reg 165:10-3-4(c)).

Montana: Suitable and safe surface casing must be used in all wells. Sufficient surface casing must be run to reach a depth below all fresh water located at levels reasonably accessible for agricultural and domestic use (Administrative Rules of Montana 36.22.1001(1)).

Ohio: Surface casings must be set at least 50 feet [15 m] below Underground Source of Drinking Water (USDW)s(*Draft* Ohio Oil and Gas Well Construction Rules 1501:9-1-08(M)(4)(a), dated 2/8/2012. The Ohio Department of Natural Resources drafted the rules pursuant to Senate Bill 165, effective 6/30/2010. The comment period was extended to 3/5/2012).

US Department of Energy (SEAB 2011a NPR) indicates that pressure tests of the casing and state-of-the-art cement bond logs should be performed to confirm that the methods being used achieve the desired degree of formation isolation. Regulations and inspections are needed to confirm that operators have taken prompt action to repair defective cementing(referred to as "squeeze jobs").

State requirements for cement testing are designed to measure compressive strength with benchmarks between 2.1 and 8.3 MPa, and specify setting times between 4 hours and 72 hours for different tests:

Example state requirements for cement testing are as follows:

Colorado: Cement placed behind the surface and intermediate casing shall be allowed to set a minimum of 8 hours before resuming drilling, or until it has developed a minimum calculated compressive strength of 300 psi [2.1 MPa] (COGCC 317(h). Cement placed behind the production casing shall be allowed to set a minimum of 72 hours before resuming drilling, or until it has developed a minimum calculated compressive strength of 800 psi [5.5 MPa](COGCC 317(i). Surface, intermediate, and production casing cement shall achieve a minimum compressive strength of 300 psi [2.1 MPa] after 24 hours and 800 psi [5.5 MPa](after 72 hours (when measured at 95°F [35°C]) (COGCC 317(h)).

Illinois: Surface casing cement shall be allowed to set in place until it has developed sufficient strength to allow drilling to resume, but no less than 4 hours. (62 Illinois Administrative Code Section 240.710)

Texas: Surface casing strings must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi [3.4 MPa] in the zone of critical cement before drilling plug or initiating a test. The cement mixture in the zone of critical cement shall have a 72-hour compressive strength of at least 1,200 psi [8.3 MPa]. (16 TAC §3.13(b)(C)).

Pennsylvania: Cement should set to a minimum compressive strength of 350 psi [2.4 MPa]in accordance with American Petroleum Institute (API) Specification 10. Cement should be allowed to set for at least 8 hours before the operator resumes drilling activities. (25 PA Code §78.85)

Montana: All casing strings must be cemented and properly tested by the pressure method before cement plugs are drilled and shall stand under pressure until the cement has reached a compressive strength of 300 pounds per square inch; provided, however, that no tests shall be commenced until the cement has been in place for at least 8 hours (Administrative Rules of Montana 36.22.1001(2)).

Ohio: Cement must be allowed to set undisturbed until an initial compressive strength of 500 psi [3.4 MPa] has been achieved (*Draft* Ohio Oil and Gas Well Construction Rules 1501:9-1-08(J)(2)).

Well casing and cementing programmes can be included in site permits (ALL Consulting, 2010a NPR p13). As discussed in Chapter 3, the mining framework directive is a potential means of specifying standards for drilling and well construction in Europe.

Minimum permitted depth between underground source of drinking water and hydraulic fracture

Groundwater could potentially be protected by preventing hydraulic fracturing from taking place in zones where the shale gas formation does not have adequate separation from the aquifers. The following criteria have been adopted regarding the zones which are and are not acceptable for gas extraction via high-volume hydraulic fracturing. An alternative approach would be for member states to prohibit shale gas extraction in specified areas where there is a risk that the separation between fracturing operations and aquifers may not be acceptable.

British Columbia: "A well permit holder must not conduct a fracturing operation at a depth less than 600 m below ground level unless the operations are permitted by the well permit." B.C.Reg. 282/2010, Drilling and Production Regulation, Part 3 — Well Position, Spacing and Target Areas, Division 4 — Procedures, 21. Fracturing operations.

New York: In its draft SGEIS, New York proposes that where the assumptions about vertical separation used in the SGEIS are not met, additional site-specific SEQRA (State Environmental Quality Review Act) review would be required for the state to respond to a permit application. Depending on the outcome of that review, the state could require a site-specific SEIS (supplemental environmental impact statement).

> "*As explained in Section 6.1.5.2, the conclusion that harm from fracturing fluid migration up from the horizontal wellbore is not reasonably anticipated is contingent upon the presence of certain natural conditions, including 1,000 feet [300 m] of vertical separation between the bottom of a potential aquifer and the top of the target fracture zone. The presence of 1,000 feet [300 m]of low-permeability rocks between the fracture zone and a drinking water source serves as a natural or inherent mitigation measure that protects against groundwater contamination from hydraulic fracturing. As stated in Section 8.4.1.1, GWPC recommended a higher level of scrutiny and protection for shallow hydraulic fracturing or when the target formation is in close proximity to underground sources of drinking water. Therefore, the Department proposes that site-specific SEQRA review be required for the following projects:*
>
> > *1) any proposed high-volume hydraulic fracturing where the top of the target fracture zone at any point along any part of the proposed length of the wellbore is shallower than 2,000 feet [600 m] below the ground surface; and*
> >
> > *2) any proposed high-volume hydraulic fracturing where the top of the target fracture zone at any point along any part of the proposed length of the wellbore is less than 1,000 feet [300m] below the base of a known freshwater supply."*

Review would focus on local topographic, geologic, and hydrogeological conditions, along with proposed fracturing procedures to determine the potential for a significant adverse impact to fresh groundwater. The need for a site-specific SEIS would be determined based upon the outcome of the review." (New York State DEC 2011 PR p7-58). Recent research suggests a potentially significant risk of fractures extending 350 m or more in a vertical direction, suggesting that the second criterion may not be fully protective of groundwater resources.

Michigan: In Michigan, since the 1960s, more than 12,000 wells have been hydraulically fractured. Most of these are Antrim Shale Formation gas wells in the northern Lower Peninsula (Michigan Office of Geological Survey, 2011b NPR). Existing wells are shallow and typically use only 50,000 gallons [190 m^3] of water in the fracturing process (Nicholson and Fair, 2011 NPR).

Michigan has developed new regulations for hydraulic fracturing, in anticipation of development of the Utica shale formation that underlies the Antrim shale. These new regulations require that the surface casing must extend a minimum of 100 feet [30 m] below any freshwater zones, and fracturing is not permitted within 50 feet [15 m] of the surface casing, so the spacing between freshwater and fracturing must be at least 150 feet [46 m]:

> "*The installation of steel pipe ("casing"), encased in cement, is key to preventing migration of gas or fluids. Michigan regulations require that each oil and gas well have a casing and cementing plan that will effectively contain gas and other fluids within the wellbore, whether related to fracturing or not. Surface casing must be set a minimum of 100 feet [30 m] into the bedrock and 100 feet [30 m] below any fresh water zones and cemented from the base of the casing to the ground surface. Before fracturing or other operations can take place to complete a well for production, an additional string of production casing must be set to the depth of the reservoir and cemented in place. Depending on depth, additional protective casing may be required. To provide additional protection for aquifers and well integrity, the DEQ imposes a permit condition for wells in shallow reservoirs prohibiting hydraulic fracturing within 50 feet [15 m] of the base of the surface casing*." (Michigan Office of Geological Survey, 2011b NPR)

General requirements

US Department of Interior, Bureau of Land Management (BLM): manages the use of natural resources on Federal Lands, including mining and oil and gas extraction. In spring 2012, BLM plans to propose rules to require oil and gas operators to submit (US BLM, 2012a NPR):

- well integrity information prior to well stimulation (e.g., hydraulic fracturing)
- disclosure of the chemical constituents of hydraulic fracturing fluids.

The draft BLM regulations are not yet available, although press articles have been published based on leaked information. At this stage, it appears that companies will have to report the trade names, additive purposes with specific chemicals in each additive, and volumes used. The draft regulation includes a trade-secret exemption, but it is not clear whether companies will have to report trade-secret information. There is no confirmation regarding when BLM will propose the regulation.

British Columbia:B.C.Reg. 282/2010, Drilling and Production Regulation, Part 3 — Well Position, Spacing and Target Areas, Division 4 — Procedures, 22. Hydraulic isolation states that a well permit holder must establish and maintain hydraulic isolation between all porous zones in a well, except for zones in which commingled production is permitted or authorized as described in section 23.

Plant operation to minimise noise

New York: NYSGEIS identified noise mitigation measures for HVHF operations (New York State DEC 2011 PR p7-130). These measures are not required in regulations but could be added to specific permits and enforced through binding permit conditions.

- Direction - Noise-generating equipment, such as high-pressure discharge pipes, should be directed away from occupied structures and places of assembly.
- Timing - Significant noise-generating operations should occur during daylight hours.

A7.3.2 Industry measures

Established measures

Because of the importance of well integrity, the majority of relevant industry measures are laid down in established guidance such as API guidance Document HF1 (2009 NPR).

Air emissions

Emissions from truck traffic can be minimised by using vehicles which conform with the highest currently applicable standards for vehicle emissions. Trucks should be prevented from idling over extended periods, with a presumption that engines will be switched off. Truckload contents should be covered as appropriate to reduce dust and PM emissions.

For conventional diesel-powered plant, drilling rig engines should conform with the highest currently applicable emissions standards (Tier 2 (or better) standards are used in the US).

Well integrity

Detailed guidance for well construction is provided by the American Petroleum Institute (2009 NPR) Guidance Document HF1, "Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines." This sets out general principles for groundwater protection, well design and construction, drilling and completion.

Complete cementing and isolation of underground sources of drinking water must be carried out prior to further drilling. API Standards for casing include:

- API Spec 5CT for casing design, manufacturing, testing, and transportation
- API Spec 5B for casing and coupling threads
- API Spec 10A and API RP 10B-2 for selection and use of cementing products

Casing centralizers should be used to centre the casing in the hole, which will allow for good mud removal and cement placement.

Testing of well integrity should take place at construction, and throughout the lifetime of the well (API 2009 NPR p22).

Surface, intermediate and production casings should extend at least 30 metres deep or 15 metres below all underground sources of drinking water (whichever is deeper). Surface casings should be cemented before reaching a depth of 75 metres below underground sources of drinking water. Production casing should be cemented up to at least 150 metres above the formation where hydraulic fracturing will be carried out (API 2009 NPR p11-12).

A minimum of 8 hours is needed for cement to set prior to resuming drilling operations. Testing should then be carried out to ensure that the cement exceeds a minimum compressive strength prior to resuming drilling operations. For production casing, the cement should exceed the anticipated hydraulic fracturing pressure. API RP 10B-2 includes cement testing specifications that recommends testing for slurry density, thickening time, fluid loss control, free fluid, compressive strength development, and fluid compatibility.

Drilling fluids and cuttings

Drillers should carefully consider fluid choices to minimize the environmental hazard posed by drilling wastes. Aspects to consider include (New York State DEC 2011 PR):

- Use water-based muds with additives (e.g., mineral oil) rather than diesel-based muds.
- Prioritize reusing brine base fluid from flowback and produced waters for drilling fluids.
- Prioritize using less hazardous biocides (e.g., isothiazoline, amines).
- Conserve water by using low-solids, nondispersed drilling fluid systems instead of dispersed systems.
- Return unused additives to suppliers or use at other wells.
- Use air rotary drilling through surface casing zones to avoid drilling mud contacting fresh water aquifers. Air rotary drilling can be used as much as possible to reduce drilling waste

- Separated solids must be transported off-site for disposal.

Noise control

Noise control measures are outlined by ALL Consulting (2009b NPR p14), New York State DEC (2011 PR p7-130 to 7-132) and the API (2011a NPR p17):

- Limiting operations to certain hours (e.g. perform noisier activities, when practicable, after 7 pm and before 7 pm);
- Limiting drill pipe cleaning (“hammering”) to certain hours;
- Running of casing during certain hours to minimize noise from elevator operation;
- Using higher or larger-diameter stacks for flare testing operations;
- Placing redundant permanent ignition devices at the terminus of the flow line to minimize noise events of flare re-ignition;
- Providing advance notification of the drilling schedule to nearby receptors;
- Placing conditions on air rotary drilling discharge pipe noise, including:
  - orienting high-pressure discharge pipes away from noise receptors;
  - having the air connection blowdown manifolded into the flow line. This would provide the air with a larger-diameter aperture at the discharge point;
  - having a 2-inch connection air blowdown line connected to a larger-diameter line near the discharge point or manifolded into multiple 2-inch discharges;
  - shrouding the discharge point by sliding open-ended pieces of larger-diameter pipe over them; or
  - rerouting piping so that unusually large compressed air releases (such as connection blowdown on air drilling) would be routed into the larger-diameter pit flow line to muffle the noise of any release.
- Using rubber hammer covers on the sledges when clearing drill pipe;
- Laying down pipe during daylight hours;
- Scheduling drilling operations to avoid simultaneous effects of multiple rigs on common receptors;
- The use of sound barriers, blankets and walls to supplement attenuation from natural features. Encasing compressor stations with specifically-designed walls to minimize or even eliminate noise in the area has reduced the level of sound pollution associated with compressor stations.
- Limiting hydraulic fracturing operations to a single well at a time; and
- Employing electric pumps.

Recommended measures

Drilling fluids and cuttings

Drilling fluids need to be carefully managed. Speciality muds which might only be used over short intervals can be segregated into separate tanks so that they can be reused in other wells. Where pits must be used, liner systems can be installed to an appropriate standard of quality assurance. Monitoring using piezometers can be carried out to verify the liner’s efficacy. Drilling fluids can be processed to separate liquids and solids in order to generate recycled drilling fluid.

Measures under consideration

Drilling fluids and cuttings

Closed-loop systems with storage tanks can be used instead of open pits. Closed loop systems reduce drilling time, drill bit and water usage, and total surface disturbance (Oil and Gas Accountability Project, 2007 NPR ; Smith-Heavenrich 2008 NPR).

Air emissions

Consideration should be given to the use of natural gas powered engines.

Pilot studies are expected to commence in 2012 to investigate the use of natural gas in drilling rig engines in the US (Uintah Basin, Utah) (Kerr-McGee Oil & Gas, 2012 NPR). This would be appropriate in established fields where there is an abundant local supply of natural gas. Alternatively, electric drilling rigs can be used. Similarly, electric compressors or gas turbines can be used rather than internal combustion engines for compression.

Selective catalytic reduction (SCR) and/or fuel additives can be used to reduce emissions from drilling rig engines.

Wyoming Federal Lands (Managed by US Department of Interior, Bureau of Land Management): This project is working towards achieving zero days of modelled visibility impairment from drilling operations using mitigation controls on engines (US BLM 2008 NPR), including:

- Require centralisation of production facilities to reduce truck traffic,
- Reduce the pace of development

A7.3.3 Summary

The well design, drilling, casing and cementing stage provides the opportunity to implement the key preventive controls on emissions to groundwater during hydraulic fracturing and operation. As described in Section 2, the potentially significant issues associated with this stage itself are noise and air quality impacts associated with drilling. There may also be less significant issues associated with surface water contamination risks and visual impact during this stage.

There is a well-defined set of industry standards that can be referenced by regulators during the well design, drilling, casing and cementing stage. These standards set out the design parameters for new well construction, and specify the testing that needs to be carried out to verify well integrity. These standards could potentially be adapted by an individual regulator if it was considered that site-specific issues warranted a different (typically higher) standard of control.

The issues with regard to well design and construction contain some features which are specific to hydrocarbons operations involving HVHF.

The control measures set out in this section are implemented by regulators and the industry in areas where HVHF is established. Under these conditions, they are considered to be affordable. Such measures are considered on balance likely to be affordable in a European context, but the potential influence of these costs on shale gas project viability cannot be evaluated at this stage, and will depend on the forecast revenues from shale gas extraction in Europe.

Under specific geological conditions and fracturing techniques, there is a risk that HVHF could potentially cause contamination of shallow ground water, due to the chemical additives in hydraulic fracturing fluid, or due to the release of naturally occurring substances. There is only a material risk of this taking place for extraction from shallow shale gas formations. In the event that this occurs, remediation measures such as the use of Permeable Reactive Barriers or interception wells can be used.

If contamination is suspected, tracer studies can be used to evaluate migration of hydraulic fracturing fluids from the target hydrocarbon zone along fractures/faults and possibly into freshwater aquifers for any processes which take place at shallower depths (North American geological survey consultation response 2012 NPR). A geological survey consultee recommended further research into potential impacts associated with shale gas extraction in shallower shale gas formations (North American geological survey consultation response 2012 NPR).

These measures have not been addressed further in this report, which focuses on the specification of appropriate measures to prevent pollution occurring.

A7.4 Technical hydraulic fracturing stage

A7.4.1 Regulatory measures

Controls on chemicals used for hydraulic fracturing

Disclosure of fluid composition is beneficial for regulatory authorities and to assist emergency response in the event of a spillage (API 2011a NPR p8). The US EPA is currently developing requirements under the Toxic Substances Control Act for hydraulic fracturing chemical manufacturers to report data on environmental or health effects and exposures, and health and safety studies. The US EPA's action in this area is currently under review by the Office of Management and Budget. Publication of an Advanced Notice of Proposed Rulemaking was planned for May - June 2012.

The US Bureau of Land Management has developed a proposed rule which would require oil and gas operators to disclose hydraulic fracturing fluids used in their operations and to submit well integrity information prior to well stimulation (e.g. hydraulic fracturing) (Bureau of Land Management, 2012b NPR). The proposed rule was published in May 2012, with the final rule to be published following the close of the public comment period in September 2012.

New York State DEC (2011 PR p8-30) proposes to require operators to identify additive products, by product name and purpose/type; proposed composition of fracturing fluid by weight; and proposed volume of each additive. This requirement matches the requirements used in the five US states with the most demanding requirements (New York State DEC 2011 PR p1-9). Similarly, British Columbia Oil and Gas Commission is planning on moving to complete disclosure (North American regulator consultation response 2012 NPR). A similar recommendation was made to the US Department of Energy (SEAB 2011a NPR p24).

<u>US EPA, Office of Groundwater and Drinking Water</u>: under the authority of the Safe Drinking Water Act, EPA's Underground Injection Control Program is considering guidance for additional permit conditions for oil and gas hydraulic fracturing using diesel fuels. EPA planned to publish guidance for public comment in 2012. The guidance may:

- define diesel fuels for this application
- address siting consideration including ensuring there are no conduits for fluid migration
- provide well construction, operation, mechanical integrity, monitoring, and reporting requirements
- detail plugging and abandonment provisions.

USEPA's authority to regulate materials used for hydraulic fracturing is limited to diesel fuels.

A state has the option of requesting primacy for Class II wells under either section 1422 or 1425 of the Safe Drinking Water Act:

- **Section 1422** requires states to meet EPA's minimum requirements for UIC programs. Programs authorized under section 1422 must include construction, operating, monitoring and testing, reporting, and abandonment requirements for well owners or operators. Enhanced oil and gas recovery wells may either be issued permits or be authorized by rule. Disposal wells are issued permits. The owners or operators of the wells must meet all applicable requirements, including strict construction and conversion standards and regular testing and inspection.
- **Section 1425** allows states to demonstrate that their existing standards are effective in preventing endangerment of USDWs. These programs must include permitting, inspection, monitoring, and record-keeping and reporting that demonstrates the effectiveness of their requirements.

The following Federal UIC Regulations describes the minimum federal requirements for injection operations:

- **Part 144: Underground Injection Control Program**, provides minimum requirements for the UIC Program promulgated under the SDWA.
- **Part 145: State UIC Program Requirements**, outlines the procedures for EPA to approve, revise, and withdraw UIC Programs that have been delegated to the states.
- **Part 146: Underground Injection Control Program: Criteria and Standards**, includes technical standards for various classes of injection wells.
- **Part 147: State Underground Injection Control Programs**, outlines the applicable UIC Programs for each state.
- **Part 148: Hazardous Waste Injection Restrictions**, describes the requirements for Class I hazardous waste injection wells.

EPA is currently developing Underground Injection Control (UIC) permitting guidance under the Safe Drinking Water Act for hydraulic fracturing activities that use diesel fuels in fracturing fluids (USEPA 2012b NPR). Draft guidance for additional permit conditions for oil and gas hydraulic fracturing using diesel fuels has been published for comment. The EPA sets out a definition of diesel fuels for this application based on six CAS numbers for Diesel fuels. This guidance is to be implemented by EPA permit writers for 11 states (the remaining 39 states have their own UIC permit programs). The guidance addresses how regulations may be tailored to address the risks of diesel fuels injection during hydraulic fracturing. Draft guidance was published in May 2012, with final guidance to be issued after the close of the public comment period in August 2012.

The SEAB (2011a NPR p25) recommended that the use of diesel as an additive to hydraulic fracturing fluid should be eliminated.

In the absence of authority to regulate materials used for hydraulic fracturing, EPA, other federal agencies, and some states have developed requirements for operators to disclose the chemicals used for hydraulic fracture. It should be noted that the mere disclosure of the use of toxic chemicals does nothing to manage the potential risks posed by their use. Examples of state disclosure requirements are as follows:

Texas: 16 Texas Administrative Code §3.16 Hydraulic Fracturing Chemical Disclosure Requirements: This section applies to a hydraulic fracturing treatment performed on a well in the State of Texas for which the Commission has issued an initial drilling permit on or after February 1, 2012. Operators are currently allowed to report to www.FracFocus.org. This resource enables oil and gas companies to upload information about the chemicals used on each hydraulic fracturing job conducted on or after January 1, 2011. The website is managed by the Ground Water Protection Council (GWPC) and Interstate Oil and Gas Compact Commission (IOGCC). The GWPC is a non-profit national association of state ground water and underground injection control agencies, while the IOGCC is a multi-state government agency of governors and appointed representatives. The registry is voluntary and does not include reporting proprietary or trade secret chemicals. It includes the well location, total water volume, and additive information (trade name, supplier, purpose, ingredients, maximum chemical concentrations in the additive and fracturing fluid). Although the registry is voluntary, it has 234 participant companies.

Colorado: COGCC 205A: Hydraulic Fracturing Chemical Disclosure: Rule 205a applies to hydraulic fracturing treatments performed on or after April 1, 2012. Within 60 days following the conclusion of a hydraulic fracturing treatment, and in no case later than 120 days after the commencement of such hydraulic fracturing treatment, the operator of the well must complete the chemical disclosure registry form and post the form on the chemical disclosure registry. Some exclusions are specified. Operators are currently allowed to report to www.FracFocus.org.

Wyoming: WYOGCC Section 45. Well Stimulation requires that The Owner or Operator shall provide detailed information to the Supervisor as to the base stimulation fluid source. The Owner or Operator or service company shall provide to the Supervisor, for each stage of the well stimulation program, the chemical additives, compounds and concentrations or rates proposed to be mixed and injected, including:

(i) Stimulation fluid identified by additive type (such as but not limited to acid, biocide, breaker, brine, corrosion inhibitor, crosslinker, de-emulsifier, friction reducer, gel, iron control, oxygen scavenger, pH adjusting agent, proppant, scale inhibitor, surfactant);

(ii) The chemical compound name and Chemical Abstracts Service (CAS) number shall be identified (such as the additive biocide is glutaraldehyde, or the additive breaker is aluminium persulphate, or the proppant is silica or quartz sand, and so on for each additive used);

(iii) The proposed rate or concentration for each additive shall be provided (such as gel as pounds per thousand gallons, or biocide at gallons per thousand gallons, or proppant at pounds per gallon, or expressed as percent by weight or percent by volume, or parts per million, or parts per billion);

(iv) The Owner or Operator or service company may also provide a copy of the contractor’s proposed well stimulation program design including the above detail;

(v) The Supervisor may request additional information under this subsection prior to the approval of the Application for Permit to Drill (Form 1) or of the Sundry Notice (Form 4);

(vi) The Supervisor retains discretion to request from the Owner or Operator and/or the service company, the formulary disclosure for the chemical compounds used in the well stimulation(s).

The injection of volatile organic compounds, such as benzene, toluene, ethylbenzene and xylene, also known as BTEX compounds or any petroleum distillates, into groundwater is prohibited. The proposed use of volatile organic compounds, such as benzene, toluene, ethylbenzene and xylene, also known as BTEX compounds or any petroleum distillates for well stimulation into hydrocarbon bearing zones is authorized with prior approval of the Supervisor. It is accepted practice to use produced water that may contain small amounts of naturally occurring petroleum distillates as well stimulation fluid in hydrocarbon bearing zones.

WYOGCC is not using www.FracFocus.org because trade secret information is required to be submitted.

US Department of Energy SEAB (2011a NPR p25) recommends that regulatory entities develop rules to require disclosure of all chemicals used in hydraulic fracturing fluids on both public and private lands.

The study commissioned by the Environment Committee of the European Parliament recommended that requirements should be placed on operators to declare publicly the chemicals used in hydraulic fracturing fluids (Lechtenböhmer et al., 2011 NPR p61).

Manage water abstraction

The SEAB (2011a NPR p22) considered that "*the development and use of an integrated water management system has the potential for greatly reducing the environmental footprint and risk of water use in shale gas production and recommends that regulators begin working with industry and other stakeholders to develop and implement such systems.*" The SEAB recommended that authorities evaluate water use at the scale of affected watersheds, and consider declaring unique and/or sensitive areas off-limits to drilling and support infrastructure as determined through an appropriate science-based process.

A North American geological survey consultee expressed concern that water used during hydraulic fracturing is 'consumptive': that is, the water is not returned to the hydrologic system (North American geological survey consultation response 2012 NPR). This aspect of HVHF requires further research.

British Columbia: The British Columbia Oil and Gas Activities Act was implemented in October, 2010, in response to anticipated increased production of natural gas from shale, tight sands, and coal beds. This act consolidated existing regulations, but also increased protection of surface and ground water quality and fish and wildlife habitat. In BC, water is a Crown resource, and the use of water for oil and gas activity requires approval from the BC Oil and Gas Commission (Commission) which administers short term use of water by the oil and gas industry through section 8 of the Water Act. Any oil and gas operator wishing to withdraw water from a lake, stream, dugout or other water source for the purposes of oil and gas activity is required to apply for and obtain a Section 8 approval. Applicants must provide the proposed volume (m^3) of water per day, total volume (m^3) of water being applied for, and the length of time for which the water withdrawal is being requested. Applicants must also consult with First Nations. Water withdrawal data must be reported for each approved withdrawal location. The provisions of this Act enable the British Columbia Oil and Gas Commission to manage ground water and surface water withdrawals used for hydraulic fracturing fluid make up. The commission ensures that the water drawdown does not affect shoreline or aquatic habitat. A north American regulator considers that it is able to manage watershed impacts on an integrated basis, using modelling techniques and information provided by operators (Consultation Response 2012 NPR).

Susquehanna River Basin Commission (Pennsylvania, Maryland, New York, U.S. Army Corps of Engineers) (SRBC) :SRBC regulates water withdrawals and consumptive water uses. Natural gas companies need SRBC approval for surface water and groundwater withdrawals and consumptive water uses. Many approvals require the withdrawal to be interrupted at a prescribed low flow (called a passby flow condition). SRBC also assesses the potential for adverse cumulative impacts from multiple withdrawals and could cap quantities approved within a watershed to protect the water resources and downstream uses (SRBC, 2012a NPR)

Delaware River Basin Commission (Delaware, New Jersey, New York, Pennsylvania, U.S. Army Corps of Engineers) (DRBC) : DRBC developed draft regulations for natural gas development in the Delaware River Basin to mitigate depletion and degradation of surface and groundwater resources. The draft regulations were proposed in December 2010 and revised in November 2011, but promulgation was postponed to allow additional time for review by the DRBC organisations.

To reduce the risk of potential water source depletion, the draft regulations would require the Commission to approve the use of basin water sources for natural gas development activities. Approval would require that the proposed withdrawal

- Not reduce the stream flow to less than the Q7-10 flow (an indicator of flow conditions during a drought) or a more stringent value recommended by the appropriate host state agency.
- Not create short-term swings in surface flow volumes.
- Not have a significant adverse effect on upstream or downstream dischargers (due to loss of assimilative capacity), downstream withdrawers, wetlands, or aquatic life. Nor may it adversely affect groundwater levels in the vicinity of the withdrawal or diversion.

The draft regulations also required that water withdrawals be metered and recorded by means of an automatic continuous recording device, or flow meter, and measured to within 5% of actual flow (DRBC, 2011 NPR).

Texas - Surface water is owned and managed by the State. Operators using surface water must obtain a water rights permit from the Texas Commission on Environmental Quality. An applicant may apply for a Temporary Water Right permit for short-term use of surface water. Temporary Water Rights permits authorizing use of 10 acre feet [1,200 m^3] or less and for one year or less may be issued by a TCEQ Regional Office. In times of drought, the TCEQ may suspend all temporary water rights permits. Water Rights permits for more water quantity or longer time periods must be obtained through TCEQ Headquarters (Texas Railroad Commission, 2012 NPR).

In Texas, groundwater is managed by landowners or groundwater conservation districts. The groundwater wells are grouped into the following categories, each with different permitting requirements:

- Rig supply wells that do not penetrate the base of useable quality water;
- Rig supply wells that penetrate the base of useable quality water;
- Injection water supply wells that do not penetrate the base of useable quality water; and
- Injection water supply wells that penetrate the base of useable quality water.
- Rig supply well: a water well drilled to supply water for a drilling rig
- Injection water supply well: a water well drilled to produce water for hydrocarbon recovery

Minimize water use (e.g. reuse produced water) and encourage use of lower quality water

DRBC: In order to encourage the use of sources other than fresh water for hydraulic fracturing of natural gas wells, the revised draft regulations provide for approvals for the diversion into the basin (importation) of non-contact cooling water, treated wastewater that meets certain criteria, mine drainage water, and recovered flowback and production water (if within the same state) to be used in hydraulic fracturing. (DRBC, 2011 NPR)

US Department of Energy (SEAB 2011a NPR): Development and use of an integrated water management system has the potential for greatly reducing the environmental footprint and risk of water use in shale gas production and recommends that regulators begin working with industry and other stakeholders to develop and implement such systems in their jurisdictions and regionally.

Minimise impacts on biodiversity due to water use

When water is stored in surface impoundments, implement precautions to preclude the transfer of invasive species into new habitats or watersheds.

For moving fresh water between sites and/or discharges, transport unused fresh water via truck or pipeline to other drilling locations where it can be discharged into tanks or for subsequent use; if fresh water cannot be used at another drilling location, dispose of unused fresh water over land (not in surface water or in manner that drains directly to surface water), preferably in same drainage area as collected, and using appropriate erosion control measures.

For vehicles and equipment used to withdraw and transport fresh water - Drain all hoses and equipment at collection site after use; clean all mud, vegetation, organisms and debris and dispose on site if the contaminants originated at site and dispose of properly. Before moving to another water body, decontaminate equipment that has come in contact with surface water using appropriate protocols (Pressure wash with hot water at contact point for 3 minutes or disinfect with 200 ppm chlorine for 10 minutes; keep disinfection solution from entering surface waters; and dry) (New York State DEC 2011 PR p7-97).

Control impacts due to disposal of treated waste water

Existing US guidelines under the Clean Water Act prohibit the discharge of oil and gas extraction wastewater directly to surface waters. The US EPA is developing pretreatment standards for discharges of shale gas extraction wastewater (flowback and produced water) to municipal wastewater treatment plants (US EPA 2012g). The US EPA is also developing effluent limitation guidelines for discharges of wastewater from coalbed methane extraction. A proposal for unconventional gas extraction wastewater pretreatment standards is planned for 2014.

Minimise truck traffic

Alternative approaches for reducing truck traffic could include:

- waterless (or reduced water) fracturing
- well pads that act as a hub to serve multiple well pads through a temporary piping system
- onsite treatment and reuse of produced water

A7.4.2 Industry measures

Established measures

Because of the importance of control of the hydraulic fracturing process, the majority of relevant industry measures are laid down in established industry guidance such as API guidance Document HF3 (2011 NPR).

Water source selection

The authority responsible for management of water resources should be able to advise on acceptable levels of water abstraction on the basis of water resource modelling and management techniques.

Fluid additives

Appropriate selection of hydraulic fracturing fluid is important to minimise risks of environmental impacts (API 2011a NPR p7).

Spill prevention and mitigation

Prevention of spillage of waste waters is important. Spillage prevention and mitigation measures are specified by API (2011a NPR p11). These include:

- Planning and training. Contingency plan elements might include the following.
    - Modification of site layout or installation of new equipment or instrumentation, as needed, including the use of alarms, automatic shutdown, fail-safe equipment to prevent, control or minimize potential spills resulting from equipment failure or human error.

    - Maintenance and/or corrosion abatement programs to provide for continued sound operation of all equipment.
    - Tests and inspections of lines, vessels, dump valves, hoses and other pollution prevention equipment where failure(s) and/or malfunction(s) could result in a potential spill incident.
    - Operating procedures that minimize potential spills.
    - Examination of field drainage patterns and installation of containment, barriers or response equipment
- Fracturing materials should be stored in such a way to prevent any accidental release to the environment. Primary containment methods commonly used include tanks, hoppers, blenders, sand separators, lines and impoundments. It is recommended these primary containers be visually inspected before and during the fracturing operation to ensure integrity.
- The use of techniques such as sloping the well location away from surface water locations, positioning absorbent pads between sites and surface waters, and perimeter trenching systems and catchments may be used to contain and collect any spilled fluids.
- Operators should evaluate the potential for spills and damages and use this information to determine the type and size of primary and secondary containment necessary. Contingency elements might include the location of emergency equipment, the type(s) of materials and products that can be used effectively for clean-up, and sources and procedures for using these chemicals. Spill response drills/simulations should include participation of relevant contractor personnel.
- In the event a spill occurs, the source of the spill should be controlled, or reduced to the extent possible, in a safe manner. The release should be confined or contained to minimize potentially adverse effects. Methods to control and contain spilled substances include:
    - retaining walls or dikes around tanks;
    - sluice gates;
    - secondary catchment basins designed to prevent the spread of fluids that escape the primary wall or dike;
    - absorbent pads;
    - booms in water basins adjoining the facility;
    - use of chemicals to gel or bio-degrade the spilled fluids.

Control of fracturing operation

Predictive modelling is used in conjunction with drillers' logs and available geological data to optimize fracture strategies (e.g. Yang, 2011 PR). Planning activities can be limited by a lack of detailed geologic data. Useful data can often be obtained from previous well completions in nearby areas. Operators should plan the hydraulic fracturing process to ensure that fracturing takes place only in the target reservoir using techniques such as the following (ALL Consulting 2009b NPR p17). This has both commercial/technical and environmental benefits:

- Geology & lithology studies
- Coring and core analysis
- Geophysical logging
- 3D Seismic surveys

- Correlation Analysis
- Fracture gradient analysis

Well integrity should be tested prior to perforation. Testing assures that all equipment is operating properly and is providing accurate reporting. Pressure testing should be conducted on mechanical pumps and piping to the fracturing pressure before fracturing commences (API 2011a NPR p9). Chemical additive pump assurance tests should be carried out before fracturing.

A pumping schedule should be designed which specifies the quantity of fluid and each chemical being pumped into the perforations and below the packer. Pre-job safety meetings with on-site staff should be carried out, to cover issues such as maximum pumping rates, downhole pressure, annulus pressure, safety precautions, and the order of operations.

Contingency planning should be carried out to address equipment failures and unexpected fracture progression. Specific responsibilities should be allocated to on-site staff to ensure that corrective actions are taken immediately and effectively to address problems that arise during fracturing. The quantity of fluid required for a fracturing process can usually be accurately forecast, but unforeseen circumstances can occur which result in unpredictable changes in the quantity of required fluid during the middle of an operation (API 2011a NPR p10). Spillage prevention measures are described by API (2011a NPR p11).

Downhole pressure and acid storage tank pressure should be monitored when applying an acidizing matrix before pumping fracturing fluid. The wellhead, annulus, and downhole pressures, pumping rates, fracturing fluid density, and additive/proppant volumes and rates should be monitored during fracturing to identify potential issues.

Geophysical methods (e.g., microseismic fracture mapping, tilt-meter analysis) should be used to track fracturing progress and identify potential issues (SEAB, 2011a NPR).

Action levels for monitored parameters should be specified and agreed prior to initiating fracturing process. It is important to develop action levels for monitored parameters before fracturing activities begin, so that on-site personnel can identify problems and take action immediately. For example, field personnel should be aware of maximum allowable downhole pressures during each stage of fracturing, so that corrective action can be taken immediately if necessary. Based on the designated action levels for monitored parameters, ensure action is taken when appropriate.

Piping, equipment and liner materials must be compatible with the injectate and produced water. Chemical treatments and cathodic protection can be used to minimize scale and corrosion. Chemical corrosion inhibitors are potentially harmful, so it is important to use these treatments conservatively. Lead-free pipe dope materials should be used where possible. The quantity used should be minimised. If excess dope material is used, it must be chemically treated and eliminated to prevent the possibility of this material reaching the wellbore.

Treatment of waste waters

For any re-use/treatment/disposal option, it is important to verify that the approach is able to handle the waters produced to a satisfactory standard of treatment. Any treatment method must take account of the potential presence of naturally occurring radioactive material (NORM).

Waste waters can be discharged to existing industrial or municipal sewage works. This introduces a requirement to transport waste waters to the disposal facility. Again, it is important to verify that the receiving works is able to handle the waters produced to a satisfactory standard of treatment. The availability of capacity and adequacy of treatment methods has been raised as a matter of concern by the EPA in relation to areas of intensive shale gas development in the US (EPA 2011a PR p49-53).

Finally, if disposal by reinjection is required, appropriate practices for reinjection are set out in the US EPA's Underground Injection Control (UIC) Program (USEPA 2012b NPR ; ALL Consulting, 2010a NPR). The UIC Program is responsible for regulating the construction, operation, permitting, and abandonment of injection wells that place fluids underground for storage or disposal. However, injection into aquifers would not be permitted in Europe (European Commission 2011a NPR ; see Section 3.17).

Recommended measures

Control of hydraulic fracturing

The International Energy Agency (2012 NPR p13) recommended that monitoring should be carried out to ensure that fractures do not extend beyond the target formation.

Water source selection

The following approaches can be used to manage environmental impacts at the water source selection stage:

- Working with local water resource planners to optimize source selection. Some well sites may be close enough to one another to justify reuse of produced water in nearby wells.
- Avoiding sensitive areas for water withdrawals (e.g., headwater tributaries, small surface water bodies, sensitive ecosystems).
- Developing strategies to eliminate or reduce the potential for transferring invasive species between sources.

Use of temporary pipeline

Water can in some cases be transported by pipeline rather than by road to reduce environmental impacts (API 2011a NPR p8; Peloquin, 2012 NPR). When temporary surface pipes are installed adjacent to the access road or gas collection piping, no additional land disturbance is required.

Hydraulic fracturing can require up to 25,000 cubic meters of make-up water per well. At 90 m^3 per storage tank, 280 tanks would be required to store this volume. Assuming tank footprint of 13.6 m × 2.4 m (Adler Tank Rentals, 2012 NPR), make up water tanks would require at least 9,200 square metres (0.92 hectares) of cleared, levelled land. Assuming 7 wells per pad, development of 70 wells would require 9.2 hectares for water storage. Piped water can be stored in a central location and piped to each well site during the hydraulic fracturing stage (Kepler 2012 NPR). For example, a US operator developed a single impoundment with a footprint of approximately 4 hectares, to serve a 70-well development project. Thus, piping water reduced land take for storage from 9.2 hectares (or more) to 4 hectares. The main motivation from an operator perspective for piping water is to eliminate hauling water by truck (Kepler 2012 NPR).

Water storage

Water storage should be carefully planned to consider land use, impacts on invasive and endangered species, and mosquito control.

Treatment of waste waters

SEAB (2011a NPR) recommends that measurement of the composition of the stored return water should be a routine industry practice. The International Energy Agency (2012 NPR p14) recommended that water should be reused or recycled wherever possible.

The ability to treat water on-site and reuse in later fracturing operations is becoming more widespread. Techniques used to treat water at the well site include thermal evaporation, crystallization and destabilization technology. Using these systems, some companies in the Marcellus Shale are able to recycle more than 90% of their return water, although not all the fracturing fluids are returned to the surface. The elevated salinity of recycled waters can adversely affect the performance of friction reducers (ALL Consulting 2011 NPR p21), but recent innovations have addressed this problem (Consultation response Prof. R Vidic, University of Pittsburgh, 2012 NPR). Other beneficial uses may also be available for produced water, to minimize treatment requirements (e.g. biofuels production).

If storage tanks are not available and surface impoundments/pits are required for produced water, run-on/runoff control should be used. Pond locations should take account of the local topography, in order to minimise surface drainage into ponds. Purpose built lagoons with double liners should be used to hold fracturing waters prior to treatment and reuse (Rassenfoss, 2011 NPR).

Dust control

Mobile bag houses can be used to control dust emissions from potentially dust-generating proppants such as sand (Kellam, 2012 NPR).

Measures under consideration

Water source selection

The following approaches can be used to manage environmental impacts at the water source selection stage:

- Identifying opportunities for reusing produced water, industrial wastewater, or other impacted, low-quality water sources.
- Considering the location and timing of water withdrawals to minimize resource impacts. For example, withdrawals could be made during high-flow seasons and stored in surface impoundments.
- Abstract water from saline aquifers, if the salt content can be managed via pre-treatment, as has been carried out at Marcellus Shale gas wells in Pennsylvania(Rassenfoss 2011 NPR p49).
- Abstract water from seawater (North American regulator consultation response 2012 NPR), if appropriate to the location. Research is currently being carried out in Canada and Europe into the use of seawater for hydraulic fracturing (Bukovac et al, 2009 NPR).
- Use acid mine drainage (AMD) as make-up water (Consultation response Professor R Vidic, University of Pittsburgh 2012 NPR). This is problematic because of the low pH; sulphate levels potentially leading to the formation of hydrogen sulphide or barium sulphates; and risks associated with storage of AMD. Research is being carried out into treatment processes for blending AMD and flowback water to produce a liquid suitable for fracturing.

Fracturing fluid additives

A number of suppliers have begun developing hydraulic fracturing fluids that could exclude the use of toxic chemicals. For example, hydraulic fracturing fluids utilizing additives sourced from the food industry are being developed by the industry. The chemical composition of these fluids has not been published by the manufacturers.

Many biocides used in fracturing fluids are potentially harmful to aquatic life, even at low concentrations. It is preferable to avoid these additives if possible, and generally minimize biocide usage. Alternative non-chemical treatments are available such as UV disinfection. UV light can be used to control bacteria growth in the wellbore, reducing the need for biocides in hydraulic fracturing fluid.

Viscoelastic based fluids can be used in place of polymer based fluids in order to reduce the wellbore damage and the elimination of subsurface leakage.

Selection of proppants which increase porosity inside the fracture can be beneficial in reducing the extent of treatment required. A sieve analysis can be carried out to assist in identifying the most appropriate proppant for use in a specific application.

Operators should continue to research and evaluate new fracturing fluid products which provide improved environmental protection opportunities (API 2011a NPR p7).

One option for disposal of produced waters is to install a treatment system to reduce the chlorides and total dissolved solids in produced water (ALL Consulting 2011 NPR p30). Treatment options include: distillation, ion exchange, membrane treatment such as reverse osmosis, and drying technologies such as vapour compression and evaporation (ALL Consulting 2009b NPR p25; ALL Consulting 2011 NPR p26). By allowing local re-use or disposal, this approach can reduce the requirement for off-site transportation of produced water. It is important to be confident that any on-site treatment facilities deliver an appropriate standard of treatment for the waters produced, and the intended end-use.

The International Energy Agency (2012 NPR p13) recommended that operational data on fracturing fluid additives and volumes, water usage, and the quantity and nature of waste water should be published.

Treatment of waste waters

Where possible, produced waters should be considered for re-use in future drilling and fracturing operations (Howarth and Ingraffea, 2011 NPR ; Lior, 2011 PR ; Rassenfoss, 2011 NPR). Produced water that is unsuitable for reuse may be treated using a variety of technologies. Treating a portion of produced water and blending it with fresh water may lead to a suitable option for reuse.

Closed loop management systems significantly reduce the footprint of a well pad by removing the need for storage pits on location as all drilling and water wastes are channelled through mechanical systems and stored in steel containers on-site (Oil and Gas Accountability Project, 2012 NPR). This process not only reduces land needed but also removes any opportunity for drill cuttings and produced water to come into contact with the natural environment.

The availability of capacity and adequacy of treatment methods has been raised as a matter of concern by the EPA in relation to areas of intensive shale gas development in the US, and future EPA research will be focused in this area (EPA 2011a PR p49-53).

A7.4.3 Summary

As described in Section 2, the potentially significant issues associated with Technical Hydraulic Fracturing stage are water resource depletion, emissions to air, groundwater contamination risks, and road traffic. There may also be less significant issues associated with surface water contamination risks, biodiversity, noise and visual impacts during this stage.

Sourcing of water for hydraulic fracturing is a potentially significant feature of HVHF operations. Measures can be taken to reduce the impact of water sourcing, including water resource management by regulators, use of water from saline aquifers or seawater if practicable, the use of temporary pipelines to transport water; and the recycling of flowback waters for use in hydraulic fracturing. However, there will remain a potentially significant need for water during the hydraulic fracturing stage which cannot be completely eliminated. For this reason, there is likely to be an ongoing requirement for road transportation which cannot be fully eliminated. Plant and equipment at the site will give rise to emissions to air, which could potentially be mitigated by the use of gas-powered plant if appropriate plant and fuels are available, but cannot be completely eliminated.

Established procedures are available for regulators to be notified of and agree the chemicals to be used during hydraulic fracturing and the control to be applied during the fracturing stage (e.g. via permitting arrangements).

Experience in the US is that hydraulic fracturing operations can normally be carried out without significant environmental or health impacts, provided appropriate measures are taken to control impacts. Unforeseen events can occur which result in unexpected impacts, such as a gas blowout. Contingency measures should be in place to deal with events such as this. Also, where design, operation or monitoring falls below the appropriate standard, the risk of impacts could increase.

The control measures set out in this section are implemented by regulators and the industry in areas where HVHF is established. Under these conditions, they are considered to be affordable. Such measures are considered on balance likely to be affordable in a European context, but the potential influence of these costs on shale gas project viability cannot be evaluated at this stage, and will depend on the forecast revenues from shale gas extraction in Europe.

A7.5 Well Completion

A7.5.1 Regulatory measures

Control of emissions to air

The SEAB (2011a NPR p16-18) recommends the development and adoption of air emission standards for methane, air toxics, ozone-forming pollutants, and other airborne contaminants. It was recommended that regulators should support projects to design and rapidly implement measurement systems to collect comprehensive methane and other air emissions data. Industry and regulators should expand efforts to reduce air emissions using proven technologies and practices. It was recommended that the emissions rules adopted in the state of Wyoming represent a good starting point for establishing regulatory frameworks and for encouraging industry best practices.

Reduced Emission completion

US EPA Office of Air and Radiation, Office of Air Quality Planning and Standards: under the authority of the Clean Air Act, the EPA issued New Source Performance Standards (NSPS) and Amendments to National Emission Standards for Hazardous Air Pollutants (NESHAPs) for the Oil and Natural Gas industry on 17 April 2012 (see USEPA 2011b NPR). This will become effective 60 days after publication in the Federal Register, which is expected in the near future. The NSPS include standards for volatile organic compounds from gas well completions, based on “reduced emission completion” where gas flowback that is otherwise vented is captured, cleaned, and routed to the sales line. This would potentially be effective in:

- Reducing emissions of VOCs
- When gas cannot be collected, VOCs would be reduced through pit flaring, unless it is a safety hazard.
- Methane, a potent greenhouse gas, also would be significantly reduced as a co-benefit of reducing VOCs.

Industry consultation responses to EPA’s draft NESHAPs document suggest that the EPA has overestimated the methane reductions that can be expected to arise from these measures.

The green completion requirements would not apply to exploratory wells or delineation wells (used to define the borders of a natural gas reservoir), because they are not near a sales line. Those wells must use pit flaring to burn off their emissions, unless it is a safety hazard

(US EPA 2012c NPR) or on the case of low pressure wells where gas cannot be routed to the gathering line. Howarth and Ingraffea (2011 NPR) suggest that minimisation of fugitive emissions to air requires the application of strict regulatory controls to ensure a high standard of control and maintenance.

US Department of Energy SEAB (2011a NPR) supports this approach: Methane leakage and uncontrolled venting of methane and other air contaminants in the shale gas production should be eliminated except in cases where operators demonstrate capture is technically infeasible, or where venting is necessary for safety reasons and where there is no alternative for capturing emissions. When methane emissions cannot be captured, they should be flared whenever volumes are sufficient to do so.

British Columbia: Venting is generally prohibited and flaring must be minimized: B.C. Reg. 282/2010, Drilling and Production Regulation, Part 7 — Safety, Security and Pollution Prevention, 41. “Venting and fugitive emissions” states that a permit holder must not vent gas unless the gas heating value, volume or flow rate is insufficient to support stable combustion. Section 42 “Flaring limits” states that a permit holder must ensure that the duration of flaring and the quantity of gas that is flared is minimized (British Columbia State, 2010 NPR). There is a further commitment to eliminate routine flaring at oil and gas wells and production facilities in British Columbia by 2016 (British Columbia OGC 2009 NPR).

Degas produced water prior to reuse

No government requirements to degas produced water prior to reuse were identified.

Limit use of open tanks and pits for produced water storage

US EPA: combustion controls must be applied to any tank emitting more than 6 tons VOCs per year.

Wyoming – Limits are applied for concentrated development areas (that is, seven specified counties in Wyoming) and the Jonah Pinedale Anticline Development Area (defined as specific sections of Sublette County, Wyoming). Open-top or blow down tanks shall not be used as active produced water tanks but may be used for blow down or for temporary storage during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, and do not have to be tied into 98% control systems. (Wyoming State, 2010 NPR)

Controls on produced water storage tank vents

Colorado: Colorado Department of Public Health and Environment requires 90% reduction in uncontrolled VOC emissions during the ozone season (May 1 to September 30) and 70% reduction in uncontrolled VOC emissions during non-ozone season in non-attainment areas. Operators are required to meet the reductions system-wide (i.e., not every tank must be controlled). Tank batteries (i.e., groups of tanks) with combustion devices for VOC control must have auto-igniters. Tank batteries with uncontrolled VOC emissions greater than 100 tons per year [91 metric ton/year] shall have electronic or manual surveillance systems to monitor the combustion device daily. Statewide, condensate storage tanks with >20 tpy [18 metric ton/year] uncontrolled VOC emissions must control emissions by 95% (CODPHE, 2011 NPR).

Wyoming: In concentrated development areas and the Jonah Pinedale Anticline Development Area, new and modified facilities shall control VOC and HAP emissions from all active produced water tanks by at least 98%. (Wyoming State, 2010 NPR)

Replacement of diesel-powered engines

Natural gas powered engines and electric motors can be used in place of diesel engines in some applications.

US Department of Energy, Secretary of Energy Advisory Board: recommends reducing the use of diesel engines for surface power in favour of natural gas engines or electricity where available (SEAB, 2011a NPR p24).

Wyoming Federal Lands (Managed by US Department of Interior, Bureau of Land Management): This project is working towards achieving zero days of modelled visibility impairment from drilling operations using mitigation controls on engines, including (BLM, 2008 NPR):

- Replacing diesel-fired drilling rig engines with natural gas-fired drilling rig engines,
- Requiring Tier 2 equivalent (or better) emissions on drilling rig engines,
- Installing selective catalytic reduction on drilling rig engines,
- Using electric drilling rigs.

Use low-bleed or no-bleed pneumatic controllers

US EPA: A New Source Performance Standard (NSPS) now applies to pneumatic controllers in the US, requiring emissions to be limited to 0.17 m^3/hour.

Colorado: CODPHE requires pneumatic controllers installed in non-attainment areas after 2/1/2009 shall emit ≤6 scfh[0.17 m^3 per hour] of natural gas (low bleed definition). Existing pneumatic controllers shall be retrofit to meet the low bleed definition by 5/1/2009. (CODPHE 2011 NPR)

Prohibit discharge of untreated produced water to surface water and to POTWs

US EPA Office of Water, Office of Science and Technology establishes regulations to control wastewater discharges to surface water, under the authority of the Clean Water Act. Existing guidelines prohibit discharge of oil and gas extraction wastewater directly to receiving streams. The EPA is (US EPA 2012d NPR):

- Developing pre-treatment standards for discharges of shale gas extraction wastewater (flowback and produced water) to municipal wastewater treatment plants, including evaluating economic impacts. Draft standards are scheduled for proposal in 2014.
- Developing effluent limitations guidelines for discharges of coalbed methane wastewater, including evaluating economic impacts. Draft regulations are scheduled for proposal in 2013.

British Columbia: prohibits discharges of oil and gas wastewaters to surface waters: B.C. Reg. 282/2010, Drilling and Production Regulation, Part 3 — Well Position, Spacing and Target Areas, Division 4 – Procedures, 51. Storage and disposal of wastes (1) A well permit holder must ensure that produced water, oil, drilling fluid, completion fluid, waste, chemical substances or refuse from a well, tank or other facility do not do any of the following:….(b) run into or contaminate any water supply well, usable aquifer or water body or remain in a place from which it might contaminate any water supply well, usable aquifer or water body; (British Columbia State, 2010 NPR).

Rassenfoss (2011 NPR) suggests that authorities could prohibit discharge of produced water to treatment works if necessary. Because of the lack of proven alternatives to treatment and disposal, this could present a significant barrier to the development of shale gas resources in Europe. Re-use remains an option for produced water, but it may not be possible to re-use all the water produced because of its chemical characteristics, and/or if there are insufficient new wells being development to accommodate the produced water from existing wells (Consultation response Professor R Vidic, University of Pittsburgh 2012 NPR).

Establish treatment requirements/discharge limitations for produced water

Pennsylvania: In August 2010, Pennsylvania finalized regulations limiting discharges of total dissolved solids, total chlorides, barium, and strontium to surface waters in the state. These regulations are codified at PA Code §95.10. The regulations apply to discharges from commercial waste treatment (CWT) plants to municipal wastewater treatment plants as well as from CWT plants directly to receiving streams. The PA limits are (Pennsylvania State, 2010 NPR):

Table 13: Pennsylvania Regulations for Unconventional Gas Production Wastewaters

Parameter	Maximum monthly average (mg/L)
Total Dissolved Solids	500
Total Chlorides	250
Barium	10
Strontium	10

A7.5.2Industry measures

Established measures

No specific required industry measures for completion were identified.

Recommended measures

Reduced Emission Completions (see USEPA, 2012c NPR) can be used to minimise emissions to air from flowback and produced water. The flowback, natural gas, and condensate are collected, and dissolved gas is separated from the waters. Gas collected in this way is routed to the sales line. If a sales line is unavailable, emissions should be routed through a flare. VOC and HAP emissions from produced water can be minimised by the use of equipment such as closed tanks, hydrocyclones and water tank blankets. Hydrocyclones separate gas from water below the surface, reinjecting the water into a lower lying disposal aquifer and sending the methane to the surface. CO_2-rich produced gas is ideal for water tank blankets. Reduced Emission Completions are not always applicable, and can be particularly problematic and even counter-productive for low-pressure wells (BP, 2012b NPR).

Flash losses can be minimised by reducing the operating pressure of low-pressure separators that dump to storage tanks. The use of pressure tanks for storage should be minimised. Vapour recovery technology should be used when available; alternatively, emissions can be discharged to a flare with an auto-igniter.

Flaring is likely to be necessary for sites where exploratory drilling is being carried out in advance of the availability of gas collection infrastructure. Flaring may be required in response to plant failure, or if back-pressure from gas compressor plant and pipeline infrastructure causes problems with the flow of gas and waters from the well. This can be a particular issue at wells with lower gas pressures than expected (BP 2012b NPR), and hence the EPA excluded low pressure wells from the requirement to use reduced emission completion or flaring to eliminate VOC venting in the April 2012 NSPS. Flaring should be minimised and, where possible, eliminated (Dogwood Initiative, undated; British Columbia OGC, 2009 NPR ; International Energy Agency 2012 NPR p14). British Columbia OGC prohibits flaring of gas during completion at wells within 1.5 km of a collection pipeline (North American regulator consultation response 2012 NPR).

Measures under consideration

Emissions to air

Emissions from dehydrators can be minimised by replacing glycol systems with desiccant dehydrators, low/zero emissions dehydrators (ZED) or solar methanol injection systems. If possible, it is preferable to avoid using a glycol dehydration system, which continuously vents methane, VOCs, and HAPs. Operators can choose Zero Emissions Dehydrators or solar methanol injection systems. ZEDs have several advantages:

- By using a desiccant dehydrator, operators also save on costs: desiccant dehydrators require less capital investment and less operations and maintenance.
- In a desiccant dehydrator, wet gas passes through a drying bed of desiccant tablets. The tablets pull moisture from the gas and gradually dissolve in the process. Since the unit is fully enclosed, gas emissions occur only when the vessel is opened, such as when new desiccant tablets are added.
- ZED collect condensable components from the still column vapour and use non-condensable still vapour (methane and ethane) as fuel for the glycol re-boiler. A water exhauster is used to yield high glycol concentrations without the use of a gas stripper.

In contrast, glycol dehydrators have several disadvantages (USEPA, 2006 NPR ; Natural Gas Star 2011 NPR):

- Methane absorbed and vented is directly proportional to the glycol circulation rate. Many wells produce gas below design capacity and circulate glycol at rates higher than necessary. This results in marginally lower gas moisture but much higher methane emissions and fuel use.
- Maintenance of glycol dehydrators often requires a complete shutdown. During maintenance, production wells are shut in or vented. Low pressure wells are often vented because it can be difficult to resume flow once they are shut in.
- Gas-assisted glycol pumps increase emissions from dehydrator systems by passing the pneumatic driver gas to the reboiler.

Flash tank separators can be installed on glycol dehydrators to reduce methane, volatile organic compound (VOC), and hazardous air pollutant (HAP) emissions. Recovered gas can be recycled to the compressor suction and/or used as a fuel for the glycol reboiler and compressor engine. Non-condensable still vent and glycol flash separator vapours can be routed to a combustion unit, or can be used as fuel for process equipment burners. Portable desiccant dehydrators can be used during glycol dehydrator maintenance.

Cyclone separators and in-line heaters can be used in place of glycol recirculation units. The separators use refrigeration to enhance water condensation and separation, and the gas is then reheated so that it will be below dew point anywhere in the system.

It was recommended that monitoring for verification of emissions inventories should be carried out by independent regulatory authorities (Academic sector consultation response 2012 NPR).

A7.5.3 Summary

As described in Section 2, the potentially significant issues associated with this stage are risks of groundwater and surface water pollution. There may also be less significant issues associated with biodiversity and traffic-related impacts during this stage.

The key issues during this stage are the handling and disposal of flowback water. The control of spillages and other accidental discharges is important. Risks posed by spillages can be minimised by measures taken during the site identification and development stage.

Emissions to air from pollutants entrained in the flowback water can be controlled by using reduced emission completions. Other air emissions are also controlled via measures which are common to conventional oil and gas production facilities. However, the nature of shale gas formations is that the use of hydraulic fracturing techniques could potentially open up developments over a wide area. This could potentially give rise to cumulative effects on air quality during the production phase. Measures to assess and reduce emissions to air are available, but intensive development in some areas could potentially mean that it may not be possible to reduce emissions sufficiently to avoid air quality issues. In Europe, air quality issues such as this may be managed via the permitting and strategic planning process, deriving standards for air quality from the relevant Air Quality Framework and Daughter Directives, although this would require further analysis as the examination of national requirements was not in the scope of this study.

The control measures set out in this section are implemented by regulators and the industry in areas where HVHF is established (i.e. North America). Under these conditions, they are considered to be affordable. Such measures are considered on balance likely to be affordable in a European context, but the potential influence of these costs on shale gas project viability cannot be evaluated at this stage, and will depend on the forecast revenues from shale gas extraction in Europe.

A7.6 Well Production

A7.6.2 Industry measures

Fugitive emissions controls

Detailed methods for fugitive emissions controls are provided via EPA's Natural Gas Star Program (Natural Gas Star, 2012 NPR). These methods include:

- Survey for leaking components in the first year of a directed inspection and maintenance program. In subsequent years, focus inspection and repair on components that are the most likely to leak and that represent cost-effective emissions reduction.
- Use of enhanced sensing to locate leaks where appropriate. Enhanced sensing includes technologies such as Infrared, Differential Absorption Lidar, Tunable Diode Laser Absorption Spectroscopy, and ultrasound
- Replace equipment with low-leak components (e.g., low or no-bleed pneumatic controllers, electronic valve systems, compressed air).
- Construct pipelines with automatic cutoff valves that isolate sections when pressure drops. Trip-wires laid on top of the pipelines will break and activate cutoff valves when severed
- Spray gravel roads near populated areas with dust suppressant during dry periods.
- Reduce the number of storage tanks containing VOCs.

Automatic control systems (e.g., programmable compressor ignition systems) can be used to reduce startups and shutdowns. Programmable Logic Controllers (PLCs) are used to increase the operational efficiency and reliability of the compressor and also reduce methane emissions. PLCs incorporate features such as unit performance, process calculations, unit load management, independent safety shutdown, and automated backup control.

A7.6.3 Summary

As described in Section 2, the potentially significant issues associated with the production stage are groundwater contamination risks and emissions to air. There may also be less significant issues associated with surface water contamination risks and land take during this stage.

The risks to groundwater are associated with ongoing well integrity. This may be a particularly significant issue if re-fracturing is carried out: it is estimated that this may take place up to four times during a 40 years well lifetime. Well integrity needs to be maintained and monitored on an ongoing basis. Measures for ongoing well maintenance are not specific to HVHF processes, and have not been addressed specifically in this report.

Land take impacts can be mitigated by the measures described in Section A7.1. Additionally, regulators can require the rapid restoration of land which is no longer needed during the production stage. However, as noted in Section A7.1, it may not be possible to fully restore some sites to their previous use, resulting in a potentially significant ongoing impact.

The control measures set out in this section are implemented by regulators and the industry in areas where HVHF is established. Under these conditions, they are considered to be affordable. Such measures are considered on balance likely to be affordable in a European context, but the potential influence of these costs on shale gas project viability cannot be evaluated at this stage, and will depend on the forecast revenues from shale gas extraction in Europe.

A7.7 Well / Site abandonment

A7.7.1 Regulatory measures

A geological survey consultee commented that the current information base extends over approximately 10 years only, and recommended that ongoing research would be required in the post-abandonment phase to ensure that any long-term impacts associated with HVHF can be identified and addressed (North American geological survey consultation response 2012 NPR).

Procedures for well pad removal (site restoration)

British Columbia: B.C. Reg. 282/2010, Drilling and Production Regulation, Part 3 — Well Position, Spacing and Target Areas, Division 4 — Procedures, 28,“Surface restoration of wells and associated sites.” This state that immediately after ceasing drilling or workover operations, or as soon after cessation as weather and ground conditions permit, a well permit holder must restore the ground surface of those areas of the well site and associated remote sumps and camp sites that will not be required for future operations to a state that eliminates hazards, enables control of weeds and runoff and prevents erosion.

Plugging of abandoned wells, with permitting and inspection requirements.

Operators in the US may stop production from a well either temporarily or permanently. States have developed different requirements for temporary shut-in and permanently abandoned wells; shut-in wells have monitoring requirements, while abandoned wells are completely reclaimed. States limit the length of time an operator can shut-in a well. Of the state regulations reviewed, most did not distinguish between conventional and horizontal/directional or hydraulically fractured wells. Only Wyoming had specific provisions for plugging horizontal wells.

Shut-In (Temporary) wells: This is defined as a well which is capable of production, but which is not being produced for various reasons (e.g., lack of production facilities, lack of market, maintenance) (16 TAC §9.31(b)(9); COGCC §100(G)).

Plugging Requirements:

<u>Colorado</u>: Close the well to the atmosphere with a swedge and valve or packer (COGCC §319(b)(1))

Post-Shut-In Monitoring Requirements:

Colorado: Requires shut-in wells pass a mechanical integrity test within 2 years of initial shut-in and every 5 years thereafter (COGCC §326(b)).

Pennsylvania: Requires good well construction; monitoring of liquid in the well for TDS to determine if surface casing is deep enough and not leaking; every 90 days, monitor flow of gas from annulus (25 PA Code §78.102); annual mechanical integrity monitoring (25 PA Code §78.103).

Wyoming: May require shut-in wells requesting extension of temporary status to pass a mechanical integrity test (WYOGCC 16(c)).

Abandonment (Permanent): This is defined as a well which has been cemented in, associated production facilities (e.g., tanks, flare, gas pipelines) have been removed, and the well pad has been reclaimed (COGCC §100(F)).

Examples of State Requirements for Abandonment are as follows:

Wyoming: Wells without production casing must be filled with fluid consistent to what was used to drill the well and plugged with at least 100 feet [30 m] of cement over the open hole porous and permeable formations, at least every 2500 feet [760 m] if nonporous and impermeable, base of the surface casing. Wells with production casing must be plugged with at least 100 feet [30 m] of cement every 2500 feet [760 m] in the base of the surface casing and at least 100 feet [30 m] in the casing at the surface, and cement isolating the perforated zones, with drilling fluid between all plugs. **Horizontal wells shall have a continuous cement plug 100 feet**[30 m] **into the lateral and 100 feet** [30 m] **into the vertical portion of the wellbore; remaining vertical wellbore shall be plugged in accordance with the preceding requirements**. (WYOGCC 18)

Colorado: Cement plugs should be at least 50 feet [15 m] in length and extend a minimum of 50 feet [15m] above each zone to be protected. Plugs should be made of neat cement slurry mixed to API standards with at least 300 psi [2.1 MPa] compressive strength after 24 hours and 800 psi [5.5 MPa](after 72 hours measured at 95 °F [35°C] and at 800 psi[5.5 MPa]. Abandonment must be completed within six months. (COGC §319(a))

Illinois: Cement plugs must extend 50 feet [15 m] below the deepest perforation, and extend to 50 feet[15 m] above the shallowest perforation. The plug should extend 50 feet [15 m] above and below the exposed zone in uncased wells. (62 Illinois Administrative Code Section 240.1150)

Texas: Cement plugs in surface and production casings shall extend at least 50 feet [15 m] above and below the base of the deepest usable aquifer. Plugs in intermediate casings must be placed extend no less than 50 feet [15 m] above and below the base of the deepest usable aquifer. (16 Texas Administrative Code §3.14)

Pennsylvania: Cement plugs shall be set in the cemented portion of the production casing extending at least 50 feet [15 m] below and 100 feet [30 m] above each fluid-bearing stratum. (25 PA Code §78.91 through 97)

Oklahoma: Before or after running a plug, the operator shall remove all fluid from the wellbore, and fill the wellbore and/or casing with plug mud. The minimum mud weight shall be nine pounds per gallon with a minimum viscosity of 36 using the API Full Funnel Method. The wellbore shall be filled with cement from 50 feet [15 m] below to 50 feet [15 m] above the base of the treatable water zone (or to three feet [0.9 m]below surface). (OK Reg 165:10-11-6(e))

Bonding

All operators are required to have financial security for the wells through performance bonds on an individual well or a field of wells.

In the US, bonding requirements are laid down by the permitting authority –in most instances this is the State, but may be tribal or federal authority depending on whether the federal program was delegated to the states or tribes. Each state has different bonding requirements (e.g., bond structure (well, lease, statewide), what types of bonds they can receive, the amount required, what they cover, when they are released). No bond requirements were identified which are specific to hydraulically fractured wells. Federal requirements are laid down in 43 CFR §3104. These requirements were most recently updated in 1988, prior to the boom in hydraulic fracturing in the US. Sections 3104.2 and 3104.3 describe the bond structure and include minimum bond amounts of up to USD $150,000.

Bonds cover issues related to pit construction, seismic operations, inactive wells, plugging and abandonment. Bonds are normally linked to plugging liability (ALL Consulting, 2010a NPR p24). The bond period is normally specified to end when the well is permanently plugged and abandoned, and would therefore not cover post-abandonment issues under US arrangements.

Financial arrangements in relation to Carbon Capture and Storage projects are discussed in Section A7.9.

A7.7.2 Industry measures

Established measures

The following measures are adopted by industry in relation to idle wells

- Maintain wellheads during layup.
- Conduct site inspections every 90 days where possible to identify any visual signs of damage to the wellhead or pad area. Idle wells may be located in remote areas, making regular inspections of the well site difficult.
- Idle wells should be constantly re-evaluated to ensure that they are closed as soon as necessary.

A combination of cement plugs and mud is placed in the wellbore prior to abandonment. It is important that the plugs are designed to prevent a micro-annulus from forming. Materials used should be appropriate for the local hydrogeology. Typically, natural bentonite mud is ideal for abandonment because it has good gel-shear strength and is less likely to separate with time. As well as achieving a high standard of sealing, it is important that an ongoing monitoring programme is carried out, and clear records of well location and depth are maintained indefinitely.

Recommended measures

Any surface impoundments can be closed in a timely and effective manner after a well has ceased to be active in producing gas.

Well pads can be remediated on an ongoing basis so that when operations cease the land and water resources can be successfully returned to their original condition (Dogwood Initiative, undated).

A7.7.3 Summary

As described in Section 2, the potentially significant issues associated with this stage are those associated with land take and biodiversity during this stage (moderate significance only).

Land take and biodiversity impacts can be mitigated by the measures described in Section A7.1. Additionally, regulators can require the rapid restoration of land which is no longer needed during the production stage. However, as noted in Section A7.1, it may not be possible to fully restore some sites to their previous use, resulting in a potentially significant ongoing impact.

The control measures set out in this section are considered on balance likely to be affordable in a European context, but the potential influence of these costs on shale gas project viability cannot be evaluated at this stage, and will depend on the forecast revenues from shale gas extraction in Europe.

A7.8 Wider area development

API (2011a NPR p6) highlights the potential significance of cumulative effects of development over a wider area. Examples are provided of collaborative initiatives undertaken by the oil and natural gas industry to inform its members on best practices, working cooperatively with regulatory agencies and other stakeholders to promote best practices, and improve communication with local communities. Neighbouring operators in British Columbia are required to work together to ensure efficient provision of gas collection and water treatment infrastructure (British Columbia OGC, 2011 NPR).

A7.9 Measures derived from other regulatory contexts

Potentially relevant best practice technologies and regulatory requirements have been laid down in relation to the use of hydraulic fracturing in similar/comparable contexts.

A7.9.1 Carbon capture and storage

Carbon capture and storage differs significantly from high-volume hydraulic fracturing. However, both operations involve the injection of large volumes of potentially harmful substances in the subsurface.

The Carbon Capture and Storage Directive (2009/31/EC) includes the following potentially relevant provisions:

- Requirements for site characterisation following a 3-dimensional approach (Directive Annex I)
- Requirement for permits to cover both exploration and storage phases. The storage permit would cover the operational and post-abandonment phases
- Requirements for a monitoring plan as part of the storage permit (Article 13)
- Requirement for proof of financial security as part of the storage permit (article 19)
- Requirement to assess potential displacement of produced water and seismicity risks (Annex 1 Step 3)
- After satisfactory abandonment, an installation can be transferred to the competent authority (Article 18). This provides long-term assurance of management of facilities
- For transboundary installations, competent authorities are required to co-operate in jointly meeting the directive requirements (Article 24)

This directive does not cover hydraulic fracturing specifically, and requires operators to assess the risk of fracturing the storage formation. However, the measures set out in this Directive could potentially inform the Commission's approach in relation to high volume hydraulic fracturing facilities.

Some of the issues and recommendations in World Resources Institute (2010 NPR) are also relevant for consideration in relation to hydraulic fracturing processes. The relevant issues and recommendations have been summarised below:

1. Non-permanence, including long-term permanence

2. Measuring, reporting and verification (MRV): It is recommended to have an environmental regulatory framework established that:
    - Covers the area of injected CO_2 and any displaced fluids
    - Requires operators to monitor and report key data and information
    - Establish criteria for determining when monitoring can end
3. Environmental impacts - the following recommendations are given:
    - Ensure that an environmental regulatory frameworks provides for a compositional analysis of the CO_2 stream, which is then used in the site-specific risk assessment
    - Conduct a comprehensive EIS analysis for any CCS effort, which includes a risk analysis and public participation.
4. Project activity boundaries -The following recommendations are given:
    - Ensure an environmental regulatory framework for CCS that requires a monitoring area and project footprint be established based on site specific data, simulations, and risk assessment.
    - Establish national methodologies for MMV of CCS projects.
5. International law - it is recommended for national governments to follow the rules and best practices of the London Protocol and OSPAR, where applicable.
6. Liability - The lack of established procedures for addressing short- and long-term liability for CCS has been raised as a concern. It is recommended to:
    - Develop and agree to clear rules and procedures for managing liability in a CCS project.
    - Develop and agree to criteria for proving that the CCS project does not endanger human health or the environment, and use these as the basis for transfer of liability and stewardship responsibilities.
7. Safety - For national governments it is recommended to:
    - Apply to CCS projects laws that protect worker safety.
    - Ensure a regulatory framework that prioritizes human and ecosystem safety.
8. Insurance coverage and compensation for damages caused due to seepage or leakage - The recommendations are to:
    - Require operators to have insurance during operational project phases.
    - Develop a national trust fund or other mechanism for long term stewardship.

A7.9.2 Artificial recharge

Procedures for well construction are specified in relation to Artificial Recharge (AR) of aquifers. AR is a process by which liquid is introduced into the sub-surface by anthropogenic means (McAlistar and Arunakumaren, 2001 NPR). Practices for reinjection are set out in the US EPA's Underground Injection Control (UIC) Program (USEPA 2012b NPR ; ALL Consulting, 2010a NPR). However, because AR takes place in shallow, moderate to high permeable aquifers, there are limited parallels to the use of HVHF in highly impermeable formations.

However, guidance produced under the UIC program could potentially be useful for the development of regulatory measures and statutory guidance in relation to high volume hydraulic fracturing.

In the Netherlands, desalinated brackish groundwater is used for agricultural purposes in low-lying areas below sea level. Residual brines have been injected into deep (saline) aquifers under strict conditions including monitoring of quality and quantity of the brine-discharge and well-design and well-abandonment (Provincie Zuid-Holland, 2009 NPR). This activity will be banned from 2013 in view of concerns regarding sustainability and the potential for environmental harm. This further highlights the potential for environmental impacts if hydraulic fracturing were to take place in zones which could potentially affect aquifers.

A7.9.3 Coal bed methane

Alternative methods for treating produced waters are described in the US National Research Council's 2010 publication on "*Management and Effects of Coalbed Methane Produced Water in the United States*" (http://www.nap.edu/catalog.php?record_id=12915) (academic sector consultation response, 2012 NPR). However, substantial developments have been made in treatment and re-use of produced waters from HVHF activities related to shale gas in the US which are more relevant to the use of HVHF in Europe (see Sections 2.6.3 and 2.7.2; see Yoxtheimer, 2012 NPR).

A7.9 Measures effective for multiple impacts

The following measures have been identified as effective in addressing more than one potential environmental or health risk.

1. Hydraulic fracturing chemicals – use of lower toxicity fracturing chemicals, and minimizing the required quantities of chemicals
    a. Reduces impacts of any spills, leaks, or other releases
    b. Reduces transportation costs and risks
    c. Can also reduce costs to the operator
2. Reuse produced water
    a. Reduces potential water resource depletion (at lower cost for well operator)
    b. Reduces truck traffic, if the produced water is reused close to the point of generation,
        i. for transporting make up water to well site
        ii. for transporting wastewater to disposal site
    c. Reduces risks from wastewater disposal (surface water and underground injection)
3. Increase the required well spacing (i.e., install fewer well pads with more wells per pad)
    a. Reduces land take, biodiversity impacts
    b. Reduces visual impact
    c. Reduces truck traffic (including community impacts, noise, air pollution)
    d. Consolidates noise to fewer locations, reducing community impacts
4. Transport make-up water to site via (temporary) pipeline
    a. Reduces truck traffic (including community impacts, noise, air pollution)
5. Transport produced water to centralized collection point via (temporary) pipeline
    a. Reduces truck traffic (including community impacts, noise, air pollution)

A7.10 Matrix of potentially effective controls

Tables A7.1, A7.2 and A7.3 summarise the potentially effective controls available to address the potential environmental impacts of shale gas extraction using high-volume hydraulic fracturing.

Table A7.1: Matrix of controls (groundwater, surface water and water resources)

Impacts specific to HVHF/Unconventional gas extraction are underlined

Development & Production Stage	Step	Groundwater contamination and other risks	Surface water contamination risks	Water resource depletion
Site Selection and Preparation	Site identific-ation	Identify sites away from aquifers and/or with impervious cap	Identify sites away from sensitive surface waters	
	Site selection	Select sites away from aquifers	Select sites away from sensitive surface waters	
	Site preparation		Normal good practice measures to control run-off and erosion during site preparation	
Well Design	Deep well (directional) Shallow vertical	Ensure well design appropriate and adequate to protect any aquifers		Design well and HF process to minimise use of HF fluids
Well drilling, casing and cementing	Drilling	Procedures to prevent spillage of water or oil-based drilling fluids leading to contamination of surface water body or near-surface aquifer	Normal good practice measures to prevent discharge and ensure proper disposal of drilling mud and cuttings	
	Casing	QA/QC on well design to ensure proper well construction and avoid risk of subsurface contaminant migration pathways for groundwater pollution Design of well casings to withstand potentially repeated hydraulic fracturing		
	Cementing	Ensure complete cement delivery to isolate aquifers from target formation		
Hydraulic Fracturing	Water sourcing: surface water and ground water withdrawals	Assess potential for changes in groundwater quantity or quality due to surface water abstraction, and manage abstraction accordingly	Assess potential for changes in surface water quality due to surface water abstraction, and manage abstraction accordingly	Minimise HF water volumes by monitoring and control of operation and manage water abstraction to avoid potentially significant impacts.
	Water sourcing: Reuse of flowback and produced water	Proper design, construction and inspection/maintenance of surface impoundments. High operating standards to minimise risk of spillages with consequent risk of indirect effects	Proper design, construction and inspection/maintenance of surface impoundments. High operating standards to minimise risk of spillages with consequent risk of effects on surface water quality Ensure appropriate road vehicle design and operational standards to minimise accident risk during transportation of flowback waters for re-use offsite	Re-use of fracturing fluids where appropriate Use of lower quality waters where appropriate
	Chemical additive transportation and storage; mixing of chemicals with water and proppant	Minimise risk of spillages as described for surface water impacts.	Minimise risk of chemical transportation accidents Procedures and bunding to minimise risk of surface spill contaminating aquifer via infiltration into soil or surface water from: • Tank ruptures • Equipment / surface impoundment failures • Overfills • Vandalism	

Development & Production Stage	Step	Groundwater contamination and other risks	Surface water contamination risks	Water resource depletion
			• Accidents • Fires • Improper operations Provision of adequate toxicological information on hydraulic fracturing fluid Appropriate storage to avoid surface water run-off	
	Perforating casing (where present)	Ensure appropriate charge used to perforate casing to avoid impacts on well integrity Ensure additional chemicals from introduction of explosives into geologic environment do not have significant environmental effects		
	Well injection of hydraulic fracturing fluid	Prevent movement of naturally occurring substances to aquifers • via induced fractures extending beyond target formation to aquifer • through biogeochemical reactions with chemical additives • via pre-existing fracture or fault zones and/or • via pre-existing man-made structures Ensure potential effects of reusing flowback containing dissolved elements for further hydraulic fracturing operations are properly addressed	Avoid pollution risk to surface water as described for groundwater Ensure proper treatment and disposal of flowback containing these substances in solution Proper disposal of water treatment residues (potentially containing NORM)	
	Pressure reduction in well to reverse fluid flow, recovering flowback and produced water	Avoidance of surface spill or releases of flowback and produced water via • Tank ruptures • Equipment or surface impoundment failures • Overfills • Vandalism • Fires • Improper operations Wastewaters contain HF fluid, naturally occurring materials as well as potentially reaction and degradation products including radioactive materials. Ensure no disruption to groundwater flows Avoid wastewater uses which pose risks due to inappropriate use or disposal of produced water	Avoid pollution risk to surface water as described for groundwater	
Well Completion	Handling of waste water during completion (planned management)	Implementation of measures to prevent inappropriate re-use of waste water, having regard to risks posed by: • Salinity • Trace elements (mercury, lead, arsenic) • NORM • Organic material (organic acids, polycyclic aromatic hydrocarbons)	Prevention of direct discharge to surface streams Management of discharges to municipal sewage treatment plant or centralised waste treatment.	
	Handling of waste water		Implementation of measures to avoid surface spill or releases of	

Development & Production Stage	Step	Groundwater contamination and other risks	Surface water contamination risks	Water resource depletion
	during completion (accident risks)		flowback and produced water via • Tank ruptures • Equipment or surface impoundment failures • Overfills • Vandalism • Fires • Improper operations	
	Connection to production pipeline			
	Well pad removal		Normal good practice measures to prevent runoff, erosion and silt accumulation in surface waters from well pad and impoundment facilities.	
Well Production	Production (including produced water management)	Inspect and maintain well to avoid failure of mechanical integrity of well leading to potential aquifer contamination	Prevent surface spill or release of produced water during storage on site Avoid uses which pose risks due to inappropriate use or disposal of produced water	
	Pipeline construction and operation		Implement procedures and controls to minimise risk of spillage of materials during construction of pipeline	
	Re-fracturing	Similar to “Hydraulic Fracturing” above	Similar to “Hydraulic Fracturing” above	Similar to “Hydraulic Fracturing” above
Well / Site Abandonment	Remove pumps and downhole equipment			
Well / Site Abandonment	Plugging to seal well	Ensure proper well abandonment (e.g. adequate and properly installed cement plugs) to avoid subsurface pathways for contaminant migration leading to groundwater pollution	Ensure no contamination of surface water resources as described in relation to groundwater	

Table A7.2: Matrix of controls (air emissions, land take and biodiversity)

<u>Impacts specific to HVHF/Unconventional gas extraction are underlined</u>

Development & Production Stage	Step	Release to air of HAPs/ O_3 precursors/ odours	Land take	Biodiversity impacts
Site Selection and Preparation	Site identification	Identify sites away from sensitive locations such as residential areas	Identify sites of low agricultural/ ecological value	Identify sites away from protected/ sensitive areas
	Site selection	Select sites away from sensitive locations such as residential areas	Select sites of low agricultural/ ecological value	Select sites away from protected/ sensitive areas
	Site preparation	Minimise number of wellheads to facilitate capture of fugitive emissions	Design site layout to minimise area of land take	Minimise disturbance to wildlife during site preparation e.g. due to traffic, noise, heavy plant Take care not to introduce new/invasive species
Well Design	Deep well (directional) Shallow vertical			
Well drilling, casing and cementing	Drilling	Normal good practice procedures to prevent oil spillage		Minimise disturbance to wildlife during drilling e.g. due to excessive noise
	Casing			
	Cementing			

Development & Production Stage	Step	Release to air of HAPs/ O_3 precursors/ odours	Land take	Biodiversity impacts
Hydraulic Fracturing	Water sourcing: surface water and ground water withdrawals		Minimise water volumes used to minimise requirement for on-site water storage	Minimise distances to surface water resources to minimise traffic movements Avoid introduction of invasive species to water bodies from use of make-up water from a different catchment
	Reuse of flowback and produced water	Ensure flowback/produced water fully degassed and trace contaminants collected prior to re-use		
	Chemical additive transportation and storage; mixing of chemicals with water and proppant			Minimise risks to natural ecosystems from spillages etc
	Perforating casing (where present)			
	Well injection of hydraulic fracturing fluid	Prevent movement of naturally occurring substances to aquifers Affected naturally occurring substances could include: • Gases (natural gas (methane, ethane), carbon dioxide, hydrogen sulphide, nitrogen and helium) • Organic material (volatile and semi-volatile organic compounds) • helium Ensure proper treatment and disposal of flowback containing these substances in solution		
	Pressure reduction in well to reverse fluid flow, recovering flowback and produced water	Capture and treatment of organic vapours from flowback and produced waters	Minimise requirements for storage of flowback water and produced water	
Well Completion	Handling of waste water during completion (planned management)	Use of green completion techniques to minimise emissions to air	Minimise flowback water storage requirement	
	Handling of waste water during completion (accident risks)			Implementation of measures to avoid surface spill or releases of flowback and produced water as for surface water
Well Production	Production (including produced water management)	Minimise fugitive losses during production phase via program of leak checking etc. Collect and treat gases dissolved in produced water along with methane	Ensure no encroachment from site during operational lifetime	Operate facility to minimise disturbance to natural ecosystems. End operations at the earliest opportunity
	Pipeline construction and operation	Minimise fugitive losses from pipeline via program of leak checking etc.	Locate sites close to existing pipeline infrastructure	Design and construct pipelines to minimise impacts on sensitive habitats

Development & Production Stage	Step	Release to air of HAPs/ O_3 precursors/ odours	Land take	Biodiversity impacts
	Re-fracturing Re-fracturing	Similar to "Hydraulic Fracturing" above, but should be possible to route emissions to the pipeline	Similar to "Hydraulic Fracturing" above	Similar to "Hydraulic Fracturing" above
Well / Site Abandonment	Plugging to seal well	Ensure integrity of seals to minimise vapour losses	Return maximum proportion of site to state prior to development or other beneficial use	Return maximum proportion of site to state prior to development or other beneficial use

Table A7.3: Matrix of controls (noise, seismicity, visual impacts and traffic)

<u>Impacts specific to HVHF/Unconventional gas extraction are underlined</u>

Development & Production Stage	Step	Noise	Seismicity	Visual impact	Traffic
Site Selection and Preparation	Site identific-ation	Identify sites away from sensitive locations	<u>Avoid high seismicity risk areas</u>	Identify sites with low visual impact	Identify sites close to transportation routes and sources of water
	Site selection	Select sites away from sensitive locations	<u>Avoid high seismicity risk areas</u>	Select sites with low visual impact	Select sites close to transportation routes and sources of water
	Site preparation	Minimise plant noise during site preparation using established techniques.		Minimise visual intrusion during site preparation using established techniques.	Minimise traffic impacts during site preparation using established techniques. Minimise length and properly design access roads
Well Design	Deep well (directional) Shallow vertical	Design well to minimise operational noise via location/ screening etc		Design well to minimise visual impacts via location/ screening etc	
Well drilling, casing and cementing	Drilling	Minimise operational noise via location/ screening/ use of low-noise plant etc		Minimise visual impacts via location/ screening etc	
	Casing				
	Cementing				
Hydraulic Fracturing Reuse of flowback and produced water Chemical additive transportation and storage; mixing of chemicals with water and proppant Perforating casing (where present) Well injection of hydraulic fracturing fluid Pressure reduction in well to reverse fluid flow, recovering flowback and produced water	Water sourcing: surface water and ground water withdrawals	<u>Design and operate plant to minimise noise levels</u>			<u>Ensure road design and vehicle operational standards to minimise emissions, noise and accident risk during transportation to site</u>
	Reuse of flowback and produced water				<u>(Potential benefit in reduced water usage)</u>
	Chemical additive transportation and storage; mixing of chemicals with water and proppant			<u>Minimise visual impact of chemical additive storage infrastructure via location/sizing/ screening</u>	<u>Ensure road design and vehicle operational standards to minimise risks of spillage of chemicals during transportation to site</u>
	Perforating casing (where present)		Monitor well to detect any potentially significant events and halt operations if any detected.		
	Well injection of hydraulic fracturing fluid		<u>Monitor well to detect any potentially significant events and halt operations if any detected.</u>	<u>Minimise visual impact of hydraulic fracturing fluid injection plant via location/sizing/ screening</u>	
	Pressure reduction in well to reverse fluid flow, recovering flowback and produced water	Operate well so as to minimise noise			
Well Completion	Handling of waste water			<u>Waste water tanks and related plant could</u>	Minimise distance to water disposal facilities

Development & Production Stage	Step	Noise	Seismicity	Visual impact	Traffic
	during completion (planned management)			constitute a potentially significant visual intrusion, particularly in non-industrial settings as above	Ensure road design and vehicle operational standards to minimise risks of spillage of produced water during offsite transportation
	Handling of waste water during completion (accident risks)				Minimise distance to water disposal facilities Ensure road design and vehicle operational standards to minimise risks of spillage of produced water during offsite transportation
Well Production	Production	Operate facility to minimise noise	Monitor well to detect any potentially significant events and halt operations if any detected.	Ensure visual screening maintained to a high standard during operational lifetime	Ensure road design and vehicle operational standards to minimise risks of spillage of produced water during offsite transportation
	Pipeline construction and operation	Design pipelines to avoid sensitive residential areas. Carry out construction programme to minimise noise		Design route to avoid sensitive areas. Bury pipelines where appropriate to minimise visual impact	Ensure road design and vehicle operational standards to minimise noise, accident risk etc
	Re-fracturing	Similar to “Hydraulic Fracturing” above	Similar to “Hydraulic Fracturing” above	Similar to “Hydraulic Fracturing” above	Similar to “Hydraulic Fracturing” above
Well / Site Abandonment	Plugging to seal well			Ensure site restored to a high standard to avoid residual visual impacts	

Appendix 8: List of relevant ISO standards applicable in the hydrocarbons industry

General

ISO 13879 Content and drafting of a functional specification

ISO 13880 Content and drafting of a technical specification

ISO 13881 Classification and conformity assessment of products, processes and services

ISO/TS 29001 Sector-specific quality management systems – requirements for product and service supply organizations

ISO 14224 Collection and exchange of reliability and maintenance data for equipment

ISO 15156 series: Materials for use in H_2S-containing environments in oil and gas production:

ISO 15156-1: General principles for selection of cracking-resistant material

ISO 15156-2: Cracking-resistant carbon and low alloy steels, and the use of cast irons

ISO 15156-3: Cracking-resistant CRAs (corrosion-resistant alloys) and other alloys

ISO 15663 series: Life cycle costing:

ISO 15663-1: Methodology

ISO 15663-2: Guidance on application of methodology and calculation methods

ISO 15663-3: Implementation guidelines

Pipeline transportation systems

ISO 13623 Pipeline transportation systems

ISO 13847 Welding of pipelines

ISO 14313 Pipeline valves

ISO 14723 Subsea pipeline valves

ISO 16708 Reliability-based limit state methods

ISO 15590 series: Induction bends, fittings & flanges for pipeline transportation systems:

ISO 15590-1 Induction bends

ISO 15590-2 Fittings

ISO 15590-3 Flanges

ISO 15589 series: Cathodic protection of pipeline transportation systems:

ISO 15589-1 On-land pipelines

ISO 15589-2 Offshore pipelines

ISO 3183 Steel pipe for pipeline – Transportation systems

ISO 21329 Pipelines Repairs – Test procedures for mechanical connectors

Fluids

ISO 10414 series: Field testing of drilling fluids:

ISO 10414-1 Water-based fluids

ISO 10414-2 Oil-based fluids

ISO 10416 Drilling fluids laboratory testing

ISO 13500 Drilling fluid materials – Specifications and tests

ISO 13501 Drilling fluids

ISO 10426 series: Cements & materials for well cementing:

ISO 10426-1 Specification

ISO 10426-2 Testing of well cements

ISO 10426-3 Testing of deep-water well cement formulations

ISO 10426-4 Preparation and testing of atmospheric foam cement slurries at atmospheric pressure

ISO 10426-5 Shrinkage & expansion of well cement

ISO 10427 series: Equipment for well cementing:

ISO 10427-1 Bow-spring casing centralizers

ISO 10427-2 Centralizer placement & stop collar testing

ISO 10427-3 Performance testing of cementing float equipment

ISO 13503 series: Completion fluids & materials:

ISO 13503-1 Measurement of viscous properties of completion fluids

ISO 13503-2 Measurement of properties of proppants used in hydraulic fracturing & gravel-packing operations

ISO 13503-3 Testing of heavy brines

ISO 13503-4 Measuring stimulation & gravelpack fluid leakoff

ISO 13503-5 Measuring long-term conductivity of proppants

Drilling and production equipment

ISO 10423 Wellhead & christmas tree equipment

ISO 10424-1 Rotary drilling equipment

ISO 10424-2 Threading, gauging & testing of rotary connections

ISO 13533 Drill through equipment

ISO 13534 Inspection, maintenance repair & remanufacture of hoisting equipment

ISO 13535 Hoisting equipment

ISO 13625 Marine drilling riser couplings

ISO 13626 Drilling & well-servicing structures

ISO 14693 Drilling & well-servicing equipment

Subsurface safety valve systems:

ISO 10417 Design, installation, operation & repair

Downhole equipment:

ISO 10432 Subsurface safety valve equipment

ISO 14310 Packers & bridge plugs

ISO 16070 Lock mandrels & landing nipples

ISO 17078-1 Slide-pocket mandrels

Progressing cavity pump systems for artificial lift:

ISO 15136-1 Pumps

ISO 15136-2 Drive heads

Casing, tubing & drill pipes for wells

ISO 10405 Care and use of casing & tubing

ISO 11960 Steel pipes for use as casing or tubing for wells

ISO 11961 Steel pipes for use as drill pipe – Specification

ISO 15463 Field inspection of new casing, tubing & plain end drill pipe

ISO 13679 Procedures for testing casing & tubing connections

ISO 13680 Corrosion resistant alloy seamless tubes for use as casing, tubing, & coupling stock

ISO 13678 Evaluation & testing of thread compounds for use with casing, tubing & line pipe

ISO 15546 Aluminium alloy drill pipe

Rotating equipment

ISO 10437 Steam turbines – Special purpose applications

ISO 10438 series: Lubrication, shaft-sealing & control-oil systems & auxiliaries:

ISO 10438-1 General requirements

ISO 10438-2 Special purpose oil systems

ISO 10438-3 General purpose oil systems

ISO 10438-4 Self-acting gas seal support systems

Flexible couplings for mechanical power transmission:

ISO 10441 Special purpose applications

ISO 14691 General purpose applications

ISO 13691 Gears – High-speed special purpose gear units

ISO 13709 Centrifugal pumps for petroleum, petrochemical & natural gas industries

ISO 13710 Reciprocating positive displacement pumps

ISO 21049 Shaft sealing systems for centrifugal & rotary pumps

Petroleum, chemical & gas service industries:

ISO 10439 Centrifugal compressors

ISO 10442 Packaged, integrally geared centrifugal air compressors

ISO 13631 Packaged reciprocating gas compressors

ISO 13707 Reciprocating compressors

ISO 10440-1 series: Rotary-type positive-displacement compressors:

ISO 10440-1 Process compressors

ISO 10440-2 Packaged air compressors (oil-free)

Gas turbines – Procurement:

ISO 3977-5 Applications for petroleum & natural gas industries

Static equipment

ISO 13703 Design & installation of piping systems on offshore production platforms

ISO 14692 series: Glass-reinforced plastic (GRP) piping:

ISO 14692-1 Vocabulary, symbols, applications & materials

ISO 14692-2 Qualification & manufacture

ISO 14692-3 System design

ISO 14692-4 Fabrication, installation & operation

ISO 15649 Piping

ISO 13704 Calculation of heater-tube thickness in petroleum refineries

ISO 13705 Fired heaters for general refinery service

ISO 13706 Air-cooled heat exchangers

ISO 15547-1 Plate heat exchangers

ISO 15547-2 Brazed aluminium platefin type heat exchangers

ISO 16812 Shell-and-tube heat exchangers

ISO 10434 Bolted bonnet steel gate valves for petroleum & natural gas industries

ISO 15761 Steel gate, globe & check valves for sizes DN 100 & smaller, for petroleum & natural gas industries

ISO 17292 Metal Gall Valves

AEA
The Gemini Building
Fermi Avenue
Harwell
Didcot
Oxfordshire
OX11 0QR

Tel: 0870 190 1900
Fax: 0870 190 6318

www.aeat.co.uk