

Shale gas extraction in the UK: a review of hydraulic fracturing

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Summary

The health, safety and environmental risks associated with hydraulic fracturing (often termed 'fracking') as a means to extract shale gas can be managed effectively in the UK as long as operational best practices are implemented and enforced through regulation. Hydraulic fracturing is an established technology that has been used in the oil and gas industries for many decades. The UK has 60 years' experience of regulating onshore and offshore oil and gas industries.

Concerns have been raised about the risk of fractures propagating from shale formations to reach overlying aquifers. The available evidence indicates that this risk is very low provided that shale gas extraction takes place at depths of many hundreds of metres or several kilometres. Geological mechanisms constrain the distances that fractures may propagate vertically. Even if communication with overlying aquifers were possible, suitable pressure conditions would still be necessary for contaminants to flow through fractures. More likely causes of possible environmental contamination include faulty wells, and leaks and spills associated with surface operations. Neither cause is unique to shale gas. Both are common to all oil and gas wells and extractive activities.

Ensuring well integrity must remain the highest priority to prevent contamination. The probability of well failure is low for a single well if it is designed, constructed and abandoned according to best practice. The UK's well examination scheme was set up so that the design of offshore wells could be reviewed by independent, specialist experts. This scheme must be made fit for purpose for onshore activities. Effects of unforeseen leaks or spills can be mitigated by proper site construction and impermeable lining. Disclosure of the constituents of fracturing fluid is already mandatory in the UK. Ensuring, where possible, that chemical additives are non-hazardous would help to mitigate the impact of any leak or spill.

Concerns have also been raised about seismicity induced by hydraulic fracturing. Natural seismicity in the UK is low by world standards. On average, the UK experiences seismicity of magnitude 5 M_L (felt by everyone nearby) every twenty years, and of magnitude 4 M_L (felt by many people) every three to four years. The UK has lived with seismicity induced by coal mining activities or the settlement of abandoned mines for a long time. British Geological Survey records indicate that coal mining-related seismicity is generally of smaller magnitude than natural seismicity and no larger than 4 M_L . Seismicity induced by hydraulic fracturing is likely to be of even smaller magnitude. There is an emerging consensus that the magnitude of seismicity induced by hydraulic fracturing would be no greater than 3 M_L (felt by few people and resulting in negligible, if any, surface impacts). Recent seismicity induced by hydraulic fracturing in the UK was of magnitude 2.3 M_L and 1.5 M_L (unlikely to be felt by anyone). The risk of seismicity induced by hydraulic fracturing can be reduced by traffic light monitoring systems that use real-time seismic monitoring so that operators can respond promptly.

Monitoring should be carried out before, during and after shale gas operations to inform risk assessments. Methane and other contaminants in groundwater should be monitored, as well as potential leakages of methane and other gases into the atmosphere. The geology of sites should be characterised and faults identified. Monitoring data should be submitted to the UK's regulators to manage potential hazards, inform local planning processes and address wider concerns. Monitoring of any potential leaks of methane would provide data to assess the carbon footprint of shale gas extraction.

The UK's goal based approach to regulation is to be commended, requiring operators to identify and assess risks in a way that fosters innovation and continuous improvement in risk management. The UK's health and safety regulators and environmental regulators should work together to develop guidelines specific to shale gas extraction to help operators carry out goal based risk assessments according to the principle of reducing risks to As Low As Reasonably Practicable (ALARP). Risk assessments should be submitted to the regulators for scrutiny and then enforced through monitoring activities and inspections. It is mandatory for operators to report well failures, as well as other accidents and incidents to the UK's regulators. Mechanisms should be put in place so that reports can also be shared between operators to improve risk assessments and promote best practices across the industry.

An Environmental Risk Assessment (ERA) should be mandatory for all shale gas operations. Risks should be assessed across the entire lifecycle of shale gas extraction, including risks associated with the disposal of wastes and abandonment of wells. Seismic risks should also feature as part of the ERA.

Water requirements can be managed through integrated operational practices, such as recycling and reusing wastewaters where possible. Options for disposing of wastes should be planned from the outset. Should any onshore disposal wells be necessary in the UK, their construction, regulation and siting would need further consideration.

Wastewaters may contain Naturally Occurring Radioactive Material (NORM) that are present in shales at levels significantly lower than safe limits of exposure. These wastewaters are in need of careful management should NORM become

more concentrated during waste treatment. NORM management is not unique to shale gas extraction. NORM is present in waste fluids from the conventional oil and gas industries, as well as in mining industries, such as coal and potash. Much work has been carried out globally on monitoring levels of radioactivity and handling NORMs in these industries.

Shale gas extraction in the UK is presently at a very small scale, involving only exploratory activities. Uncertainties can be addressed through robust monitoring systems and research activities identified in this report. There is greater uncertainty about the scale of production activities should a future shale gas industry develop nationwide. Attention must be paid to the way in which risks scale up. Co-ordination of the numerous bodies with regulatory responsibilities for shale gas extraction must be maintained. Regulatory capacity may need to be increased.

Decisions are soon to be made about shale gas extraction continuing in the UK. The next round of issuing Petroleum Exploration and Development Licences is also pending. This report has not attempted to determine whether shale gas extraction should go ahead. This remains the responsibility of the Government. This report has analysed the technical aspects of the environmental, health and safety risks associated with shale gas extraction to inform decision making. Neither risks associated with the subsequent use of shale gas nor climate risks have been analysed. Decision making would benefit from research into the climate risks associated with both the extraction and use of shale gas. Further benefit would also be derived from research into the public acceptability of all these risks in the context of the UK's energy, climate and economic policies.

Recommendations

Recommendation 1

To detect groundwater contamination:

- The UK's environmental regulators should work with the British Geological Survey (BGS) to carry out comprehensive national baseline surveys of methane and other contaminants in groundwater.
- Operators should carry out site-specific monitoring of methane and other contaminants in groundwater before, during and after shale gas operations.
- Arrangements for monitoring abandoned wells need to be developed. Funding of this monitoring and any remediation work needs further consideration.
- The data collected by operators should be submitted to the appropriate regulator.

Recommendation 2

To ensure well integrity:

- Guidelines should be clarified to ensure the independence of the well examiner from the operator.
- Well designs should be reviewed by the well examiner from both a health and safety perspective and an environmental perspective.
- The well examiner should carry out onsite inspections as appropriate to ensure that wells are constructed according to the agreed design.
- Operators should ensure that well integrity tests are carried out as appropriate, such as pressure tests and cement bond logs.
- The results of well tests and the reports of well examinations should be submitted to the Department of Energy and Climate Change (DECC).

Recommendation 3

To mitigate induced seismicity:

- BGS or other appropriate bodies should carry out national surveys to characterise stresses and identify faults in UK shales. Operators should carry out site-specific surveys to characterise and identify local stresses and faults.
- Seismicity should be monitored before, during and after hydraulic fracturing.
- Traffic light monitoring systems should be implemented and data fed back to well injection operations so that action can be taken to mitigate any induced seismicity.
- DECC should consider how induced seismicity is to be regulated. Operators should share data with DECC and BGS to establish a national database of shale stress and fault properties so that suitable well locations can be identified.

Recommendation 4

To detect potential leakages of gas:

- Operators should monitor potential leakages of methane or other emissions to the atmosphere before, during and after shale gas operations.
- The data collected by operators should be submitted to the appropriate regulator. These data could inform wider assessments, such as the carbon footprint of shale gas extraction.

Recommendation 5

Water should be managed in an integrated way:

- Techniques and operational practices should be implemented to minimise water use and avoid abstracting water from supplies that may be under stress.
 - Wastewater should be recycled and reused where possible.
 - Options for treating and disposing of wastes should be planned from the outset. The construction, regulation and siting of any future onshore disposal wells need further investigation.
-

Recommendation 6

To manage environmental risks:

- An Environmental Risk Assessment (ERA) should be mandatory for all shale gas operations, involving the participation of local communities at the earliest possible opportunity.
- The ERA should assess risks across the entire lifecycle of shale gas extraction, including the disposal of wastes and well abandonment. Seismic risks should also feature as part of the ERA.

Recommendation 7

Best practice for risk management should be implemented:

- Operators should carry out goal based risk assessments according to the principle of reducing risks to As Low As Reasonably Practicable (ALARP). The UK's health and safety regulators and environmental regulators should work together to develop guidelines specific to shale gas extraction to help operators do so.
- Operators should ensure mechanisms are put in place to audit their risk management processes.
- Risk assessments should be submitted to the regulators for scrutiny and then enforced through monitoring activities and inspections.
- Mechanisms should be put in place to allow the reporting of well failures, as well as other accidents and incidents, between operators. The information collected should then be shared to improve risk assessments and promote best practices across the industry.

Recommendation 8

The UK's regulators should determine their requirements to regulate a shale gas industry should it develop nationwide in the future. Skills gaps and relevant training should be identified. Additional resources may be necessary.

Recommendation 9

Co-ordination of the numerous bodies with regulatory responsibilities for shale gas extraction should be maintained. A single body should take the lead. Consideration should be given to:

- Clarity on roles and responsibilities.
- Mechanisms to support integrated ways of working.
- More formal mechanisms to share information.
- Joined-up engagement of local communities.
- Mechanisms to learn from operational and regulatory best practice internationally.

Recommendation 10

The Research Councils, especially the Natural Environment Research Council, the Engineering and Physical Sciences Research Council and the Economic and Social Research Council, should consider including shale gas extraction in their research programmes, and possibly a cross-Research Council programme. Priorities should include research into the public acceptability of the extraction and use of shale gas in the context of UK policies on climate change, energy and the wider economy.

Terms of reference

The UK Government's Chief Scientific Adviser, Sir John Beddington FRS, asked the Royal Society and the Royal Academy of Engineering to carry out an independent review of the scientific and engineering evidence relating to the technical aspects of the risks associated with hydraulic fracturing to inform government policymaking about shale gas extraction in the UK.

The terms of reference of this review were:

- What are the major risks associated with hydraulic fracturing as a means to extract shale gas in the UK, including geological risks, such as seismicity, and environmental risks, such as groundwater contamination?
- Can these risks be effectively managed? If so, how?

This report has analysed environmental and health and safety risks. Climate risks have not been analysed. The risks addressed in this report are restricted to those associated with the onshore extraction of shale gas. The subsequent use of shale gas has not been addressed.

Methodology

A Working Group was set up to oversee this project (see Appendix 1). The Working Group met on six occasions when it was briefed by other experts. Consultations with other experts and stakeholders were held between meetings. Submissions were received from a number of individuals and learned societies (see Appendix 2). This report has been reviewed by an expert Review Panel (see Appendix 3) and approved by the Engineering Policy Committee of the Royal Academy of Engineering and the Council of the Royal Society.

The Royal Academy of Engineering and The Royal Society are grateful to the Government Office for Science for its financial support for this review.

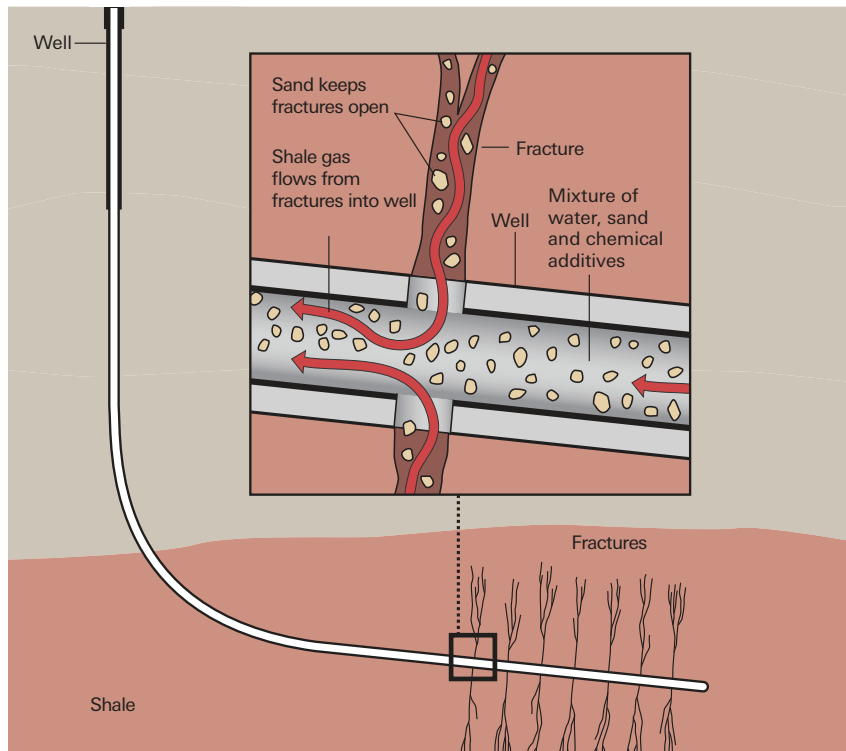
Introduction

1.1 Hydraulic fracturing

Shale is a common type of sedimentary rock formed from deposits of mud, silt, clay and organic matter. Shale gas mainly consists of methane, although other gases may also be present, trapped in shale with very low permeability. Shale gas does not readily flow into a well ('produce'). Additional stimulation by hydraulic fracturing (often termed 'fracking') is required to increase permeability (see Figure 1). Once a well has been drilled and cased ('completed'), explosive charges fired by an electric current perforate holes along selected intervals of the well within the shale formation from which shale gas is produced ('production zone'). Pumps are used to inject fracturing fluids, consisting of water, sand ('proppant') and chemicals, under high pressure into the well. The injection pressure generates stresses in the shale that exceed its strength, opening up existing fractures or creating new ones. The fractures extend a few hundred metres into the rock and the newly created fractures are propped open by the sand. Additional fluids are

pumped into the well to maintain the pressure in the well so that fracture development can continue and proppant can be carried deeper into the formation (API 2009). A well may be too long to maintain sufficient pressure to stimulate fractures across its entire length. Plugs may be inserted to divide the well into smaller sections ('stages'). Stages are fractured sequentially, beginning with the stage furthest away and moving towards the start of the well. After fracturing, the plugs are drilled through and the well is depressurised. This creates a pressure gradient so that gas flows out of the shale into the well. Fracturing fluid flows back to the surface ('flowback water') but it now also contains saline water with dissolved minerals from the shale formation ('formation water'). Fracturing fluid and formation water returns to the surface over the lifetime of the well as it continues to produce shale gas ('produced water'). Although definitions vary, flowback water and produced water collectively constitute 'wastewaters' (EPA 2011).

Figure 1 An illustration of hydraulic fracturing (Al Granberg/ProPublica) Fracturing fluids are injected under pressure to stimulate fractures in the shale. The fractures are propped open by sand contained in the fracturing fluid so that shale gas can flow out of the shale into the well.



1.2 Stages of shale gas extraction

Shale gas extraction consists of three stages:

- **Exploration.** A small number of vertical wells (perhaps only two or three) are drilled and fractured to determine if shale gas is present and can be extracted. This exploration stage may include an appraisal phase where more wells (perhaps 10 to 15) are drilled and fractured to characterise the shale; examine how fractures will tend to propagate; and establish if the shale could produce gas economically. Further wells may be drilled (perhaps reaching a total of 30) to ascertain the long-term economic viability of the shale.
- **Production.** The production stage involves the commercial production of shale gas. Shales with commercial reserves of gas will typically be greater than a hundred metres thick and will persist laterally over hundreds of square kilometres. These shales will normally have shallow dips, meaning they are almost horizontal. Vertical drilling would tend to pass straight

through them and access only a small volume of the shale. Horizontal wells are likely to be drilled and fractured. Once a shale formation is reached by vertical drilling, the drill bit can be deviated to run horizontally or at any angle.

- **Abandonment.** Like any other well, a shale gas well is abandoned once it reaches the end of its producing life when extraction is no longer economic. Sections of the well are filled with cement to prevent gas flowing into water-bearing zones or up to the surface. A cap is welded into place and then buried.

1.3 The global policy context

1.3.1 Potential global shale gas resources

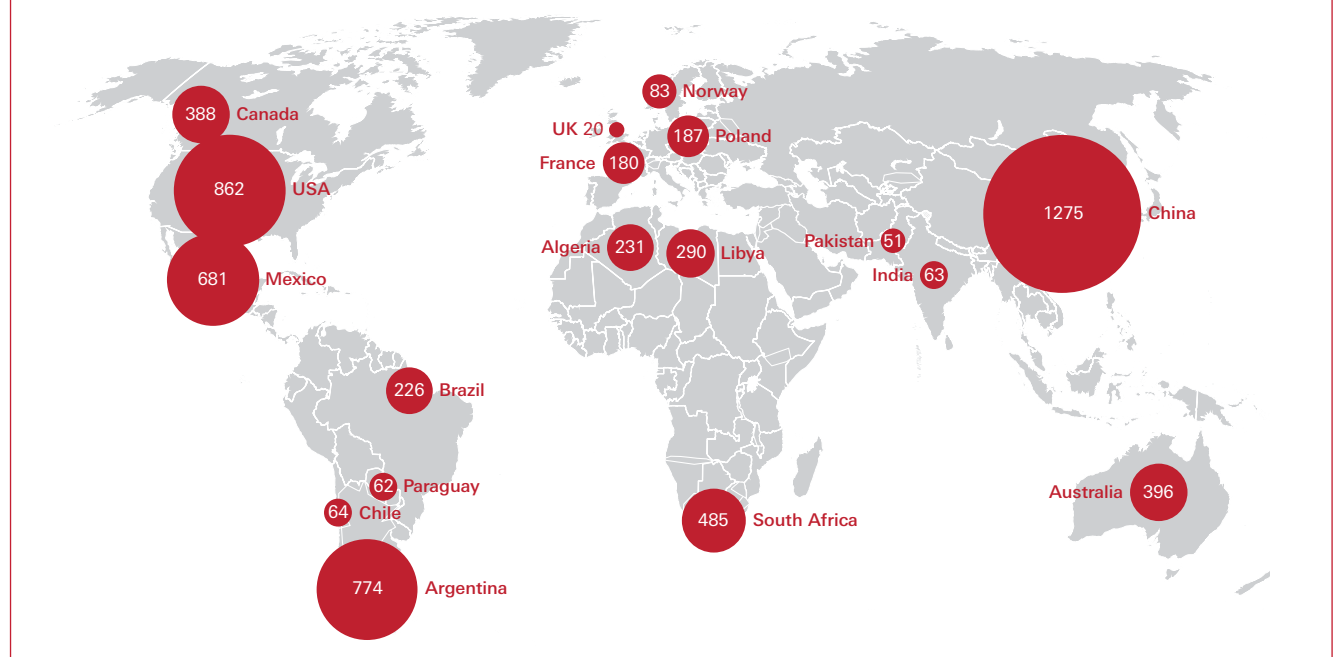
'Gas in place' refers to the entire volume of gas contained in a rock formation regardless of the ability to produce it. 'Technically recoverable resources' refers to the volume of gas considered to be recoverable with available technology. 'Proved reserves' refers to that volume of technically

recoverable resources demonstrated to be economically and legally producible under existing economic and operating conditions.

Shale gas could increase global natural gas resources by approximately 40%. The US Energy Information Administration (EIA) estimates the global technically recoverable resources of natural gas (largely excluding shale gas) to be approximately 16,000 trillion cubic feet (tcf) (EIA 2011). The EIA

estimates the total volume of technically recoverable shale gas worldwide to be 6,622 tcf. The USA has approximately 862 tcf, and China 1,275 tcf (see Figure 2). In Europe, Poland and France are two of the most promising shale gas countries with 187 tcf and 180 tcf of technically recoverable resources, respectively. Norway, Ukraine and Sweden may also possess large technically recoverable resources. The EIA estimates the UK's technically recoverable resources to be 20 tcf (EIA 2011)

Figure 2 Estimates of technically recoverable shale gas resources (trillion cubic feet, tcf) based on 48 major shale formations in 32 countries (EIA 2011) Russia, Central Asia, Middle East, South East Asia and central Africa were not addressed in the Energy Information Administration report from which this data was taken.



1.3.2 Global climate change and energy security

Shale gas is championed by some commentators as a 'transition fuel' in the move towards a low carbon economy, helping to displace higher-emitting fuels, such as coal (Brinded 2011). Others argue that shale gas could supplement rather than displace coal use, further locking in countries to a fossil fuel economy (Broderick *et al* 2011). The development of shale gas could also reduce and/or delay the incentive to invest in zero- and low-carbon technologies and renewable energy (Broderick *et al* 2011, Stevens 2010).

There are concerns that even small leakages of methane during shale gas extraction may offset the effects of lower carbon dioxide emissions (Howarth *et al* 2011). The global warming potential of a

molecule of methane is greater than that of carbon dioxide, but its lifetime in the atmosphere is shorter. On a 20-year timescale, the global warming potential of methane is 72 times greater than that of carbon dioxide. On a century timescale, it is 25 times greater (IPCC 2007).

1.4 Environmental concerns in the USA

Hydraulic fracturing was pioneered in the 1930s and first used after the Second World War in the USA to exploit the relatively shallow Devonian Shale in the eastern US and Antrim Shale in the Midwest. The first well to be hydraulically fractured was in 1949. Only a modest volume of gas was recovered. Advances in technology in the late 1980s and early 1990s led to directional drilling and hydraulic fracturing in the

Barnett Shale in Texas (Selley 2012). An important turning point came in the 1990s. Geochemical studies of the Antrim Shale of the Michigan Basin revealed that the gas being released was not thermogenic (produced by the alteration of organic matter under high temperatures and pressures over long time periods) but was biogenic (produced by bacteria) (Martini *et al* 1998). This discovery opened up new areas for exploration where the shale had previously been deemed either immature or over-mature for thermogenic gas generation. At the same time, progress was being made in methods of drilling, such as directional drilling that could steer the drill bit to exploit regions with high concentrations of carbon and where the shale is most amenable to being fractured. By 2002-03, the combination of hydraulic fracturing and directional drilling made shale gas commercially viable.

Shale gas production has been enhanced by US lease regulations that require a leaseholder to commence operations within a primary term period (normally five years) or lose the lease regardless of price. Shale gas production in the USA has caused gas prices to fall as supply has outstripped demand. Shale gas has diversified domestic energy supplies and reduced US dependence on imports of liquefied natural gas. Shale gas rose from 2% of US gas production in 2000 to 14% in 2009, and is projected to rise to more than 30% by 2020 (EIA 2011).

1.4.1 Improper operational practices

There has been widespread concern in the USA about the environmental impact of hydraulic fracturing. One cause for concern has been improper operational practices. A US Environmental Protection Agency (EPA) study reported that hydraulic fracturing had contaminated groundwater and drinking water supplies in Pavillion, Wyoming (DiGiulio *et al* 2011). The well casing was poorly constructed, and the shale formations that were fractured were as shallow as 372m. Many claims of contaminated water wells due to shale gas extraction have been made. None has shown evidence of chemicals found in hydraulic fracturing fluids. Water wells in areas of shale gas extraction have historically shown high levels of naturally occurring methane before operations began. Methane detected in water wells with the onset of drilling may also be mobilised by vibrations and pressure pulses associated with the drilling (Groat and Grimshaw 2012). In 2011, the EPA was directed by Congress to undertake a study to better understand the potential impacts of hydraulic fracturing on drinking water resources. This EPA study is examining impacts from the acquisition of water and its mixing with chemicals to create fracture fluid, through to the management of flowback and produced water, including disposal. A first report is expected at the end of 2012. The final results are due in 2014. In 2011, the Secretary of Energy Advisory Board Natural Gas Subcommittee submitted its recommendations to improve the safety and environmental performance of shale gas extraction (see Textbox 1).

Textbox 1 Recommendations of the US Secretary of Energy Advisory Board Natural Gas Subcommittee (DoE 2011a, DoE 2011b)

Recommendations ready for implementation primarily by federal agencies

- Communication among federal and state regulators should be improved. Federal funds should be provided to support the non-profit State Review of Oil and Natural Gas Environmental Regulations (STRONGER) and Ground Water Protection Council (GWPC). STRONGER began as a voluntary programme developed to improve state regulations and has since emerged as a partnership between industry, non-profit groups and regulators that develops best practice, including through new guidelines.
- Incentives should be provided for states to offer their regulation framework to peer review under STRONGER. Extra funding would allow GWPC to expand its Risk Based Data Management System that helps states collect and publicly share data, such as environmental monitoring of shale gas operations.
- Operators should disclose all chemicals used in fracturing fluid and not just those that appear on Material Safety Data Sheets. Disclosure should be reported on a well-by-well basis and made publicly available. Extra funding would support GWPC's fracturing fluid chemical disclosure registry, Frac Focus, so that information can be accessed, according to chemical, well, company and geography.
- Operators and regulators should be encouraged to reduce air emissions using proven technologies and practices. Systems should be implemented to monitor air emissions from shale gas operations, the results of which should be made publicly available. The data collected should be used to assess the carbon footprint of shale gas extraction compared to other fuels.

Recommendations ready for implementation primarily by state agencies

- Measurements of groundwater should be made prior to any shale gas operations to provide a baseline to assess any claims of water contamination.
- Microseismic monitoring should be carried out to assure that fracture growth is constrained to producing formations.
- Best practice for well construction should be developed and implemented, including pressure testing and cement bond logs, to verify rock formations have been properly isolated.
- Inspections should be carried out to confirm that operators have remediated any defective well cementation effectively. Inspections should also be carried out at safety-critical stages of well construction and hydraulic fracturing.
- The composition of water should be monitored and publicly reported at each stage of shale gas extraction, including the transport of water and waste fluids to, and from, well sites.

Recommendations whose implementation require new partnerships

- A systems approach to water management should be adopted, requiring more effective sharing of federal and state responsibilities.
- Mechanisms should be established to engage regulators, operators and local communities to discuss measures to minimise operational impacts, including scientific studies to assess impacts on local water resources, land use, wildlife and ecology.

1.4.2 Exemptions from regulation

Another cause for concern was a number of exemptions granted to shale gas extraction from federal regulations. The 2005 Energy Act exempted hydraulic fracturing from being considered an 'underground injection' under the Safe Drinking Water Act. Compliance with various federal requirements to prevent water contamination was not necessary. Fracturing wastes are exempt from disposal restrictions under the Resource Conservation and Recovery Act. Operators are exempt from certain liabilities and reporting requirements relating to waste disposal under the Comprehensive Environmental Responsibility, Compensation, and Liability Act. Exemption from the Emergency Planning and Community Right to Know Act means the type and quantity of chemicals to be used in fracturing do not need to be disclosed to the EPA. In 2010, the Fracturing Responsibility

and Awareness of Chemicals Act (FRAC ACT) bills were introduced in the House of Representatives and Senate. The FRAC ACT would have required companies to disclose such details, although not the proprietary formula. These bills had been proposed in the previous session of Congress but never became law.

Environmental protection remains mainly a state responsibility. In some states, requirements exempted from federal regulation are still imposed through state regulation. Some states are revising their regulations with a particular focus on three areas of concern: water abstraction and disclosure of fracturing fluid composition; well construction; and wastewater management (Groat and Grimshaw 2012). Some states may have more capacity and experience to regulate shale gas operations than other states (see Textbox 2).

Textbox 2 Complications of US state and federal regulation

A study by the University of Texas at Austin reviewed state regulations and enforcement capabilities in 16 US states where shale gas extraction is currently underway, or is anticipated (Groat and Grimshaw 2012). This study concluded that variation exists among states in the regulation of:

- **Water abstraction and disclosure of fracturing fluid composition.** In some states, groundwater is privately owned and subject to different requirements than in other states where groundwater is owned by the state and subject to state abstraction permits. More uniform disclosure of the composition of fracturing fluids may be needed among state regulators.
- **Well construction.** Some states are updating provisions for well construction, according to site-specific operational and geological conditions.
- **Wastewater management.** Some states are requiring operators to formulate disposal plans. In some states, disposal is primarily by underground injection. In others with less suitable subsurface conditions disposal is via discharge into publicly owned treatment works. The latter method has been prohibited by some states. Other states require pre-treatment before discharge. In some shale gas areas, wastes from multiple well sites are managed at a centralised disposal site.

1.5 Environmental concerns in Europe

Shale gas extraction in Europe is at the exploration stage. It is many years away from US levels of commercial production, especially in the light of differences in geology, public acceptability, population density, tax breaks and environmental regulation (Stevens 2010). In 2011, European Union (EU) Heads of State concluded that Europe's

potential to extract and use unconventional fossil fuel resources, including shale gas, should be assessed (European Council 2011). In 2012, the European Commission (EC) judged that its existing legal framework was adequate to address shale gas extraction (Vopel 2012). Shale gas could reduce some European countries' dependence on natural gas imports (European Parliament 2012b).

The EC Directorate-General for the Environment is conducting a desk study on environmental and health risks associated with hydraulic fracturing to identify knowledge gaps. The EC Directorate-General for Climate Action is carrying out a similar study focused on gas emissions associated with shale gas extraction, including potential leakages of methane. The EC Directorate-General for Energy has carried out a project on licensing, authorising and the issuing of operational permits for shale gas. The Joint Research Centre (JRC) is examining whether the exposure scenarios of Chemical Safety Reports under Registration, Evaluation, Authorisation and Restriction of Chemicals regulation are adequate for shale gas extraction. The JRC is also assessing the potential impacts on water and land use under various national and EU-wide scenarios. Results of these studies should be available by the end of 2012.

All EU member states are members of an Ad Hoc Technical Working Group on Environmental Aspects of Unconventional Fossil Fuels, In Particular Shale Gas. The Working Group seeks to exchange information; identify best practice; assess the adequacy of regulation and legislation; and provide clarity to operators. It met for the first time in January 2012 and was attended by representatives of approximately two thirds of member states. The Working Group may meet again in summer 2012 when the results of some of the aforementioned EC research are published. It is unclear whether the Working Group will continue to meet thereafter.

1.6 Moratoria

Environmental concerns have led to moratoria on hydraulic fracturing for shale gas extraction in parts of the USA and in other countries. In May 2010, the Marcellus Shale Bill was passed in Pennsylvania, enforcing a three-year moratorium while a comprehensive environmental impact assessment is carried out. In August 2010, New York State imposed a temporary moratorium, pending further research into environmental impacts. Moratoria have also been imposed elsewhere, including in the province of Quebec, Canada (March 2011), France (July 2011), South Africa (August 2011) and Bulgaria (January 2012).

1.7 Concerns about seismicity

Concerns in the UK have focused on seismicity induced by hydraulic fracturing. 'Seismicity' or 'seismic events' refer to sudden phenomena that release energy in the form of vibrations that travel through the Earth as sound (seismic) waves. Energy may be released when rocks break and slide past each other on surfaces or cracks ('faults'). Energy may also be released when rocks break in tension, opening up cracks or fractures. The passage and reflection of seismic waves can be monitored by seismometers at seismic stations. Geophones are used along regular lines ('seismic lines') or grids to obtain two- or three- dimensional profiles of the Earth's subsurface structure ('seismic reflection surveys'). Seismicity is measured according to the amount of energy released (magnitude) or the effect that energy release has at the Earth's surface (intensity) (see Textbox 3).

On 1st April 2011, the Blackpool area in north England experienced seismicity of magnitude 2.3 M_L shortly after Cuadrilla Resources ('Cuadrilla', hereafter) hydraulically fractured a well at its Preese Hall site. Seismicity of magnitude 1.5 M_L occurred on 27th May 2011 following renewed fracturing of the same well. Hydraulic fracturing was suspended. Cuadrilla commissioned a set of reports to investigate the cause of seismicity (de Pater and Baisch 2011). The Department of Energy and Climate Change (DECC) also commissioned an independent report that was published for public comment (Green *et al* 2012).

Textbox 3 Measuring seismic magnitude and intensity

Magnitude scales are calibrated to Richter's magnitude scale. The scale is logarithmic so the smallest events can have negative magnitudes. Each unit step in the scale indicates a 32-fold increase in the energy released. Seismic intensity is an indication of how much a seismic event affects structures, people and landscapes at the Earth's surface. Surface effects are compared to a scale originally developed by Mercalli that considers who can feel an event along with visual and structural effects. The Mercalli scale has been superseded by the European Macroseismic Scale that incorporates new knowledge about how buildings behave during seismic events.

The effect a given seismic event will have at the earth's surface depends on several factors. The deeper a seismic event occurs the more its radiated energy is attenuated. A deeper seismic event will have a lower intensity than a shallower event of the same magnitude. Different materials attenuate seismic waves to different degrees. Soft rocks, such as shale, attenuate seismic waves more than hard rocks, such as granite. Different buildings and structures respond differently depending on how they are constructed. The response of a building to a seismic event also depends on the frequency of the ground shaking. High frequencies (above 20-30 Hz) will do relatively little damage.

The frequency of the radiated seismic waves is proportional to the size of the fracture. Since engineered hydraulic fractures are typically small, seismic events induced by hydraulic fracturing only produce high frequency radiated seismic waves, and so do not produce ground shaking that will damage buildings. The number of people who feel small seismic events is dependent on the background noise.

The British Geological Survey (BGS) runs a network of approximately 100 stations to monitor seismicity in the UK. The Atomic Weapons Establishment also has a limited number of stations to monitor international compliance with the Comprehensive Nuclear Test Ban Treaty. Other seismic stations include those maintained for research by universities. The detection limit of this national network is a function of background noise that may include traffic, trains and other industrial noise, as well as natural noise, such as wind. Given average background noise conditions in mainland UK, a realistic detection limit of BGS' network is magnitude 1.5 M_L . For regions with more background noise, the detection limit may be closer to magnitude 2-2.5 M_L . Vibrations from a seismic event of magnitude 2.5 M_L are broadly equivalent to the general traffic, industrial and other noise experienced daily (see Table 1).

Table 1 The average annual frequency of seismic events in the UK

Magnitude (M _L)	Frequency in the UK	Felt effects at the surface
-3.0	Not detected by BGS' network	Not felt
-2.0	Not detected by BGS' network	Not felt
-1.0	Not detected by BGS' network	Not felt
0.0	Not detected by BGS' network	Not felt
1.0	100s each year	Not felt, except by a very few under especially favourable conditions.
2.0	25 each year	Not felt, except by a very few under especially favourable conditions.
3.0	3 each year	Felt by few people at rest or in the upper floors of buildings; similar to the passing of a truck.
4.0	1 every 3-4 years	Felt by many people, often up to tens of kilometres away; some dishes broken; pendulum clocks may stop.
5.0	1 every 20 years	Felt by all people nearby; damage negligible in buildings of good design and construction; few instances of fallen plaster; some chimneys broken.

1.8 The UK policy context

The UK has experience of hydraulic fracturing and directional drilling for non-shale gas applications. Over the last 30 years, more than 2,000 wells have been drilled onshore in the UK, approximately 200 (10%) of which have been hydraulically fractured to enhance recovery. The combination of hydraulic fracturing and directional drilling allowed the development of Wytch Farm field in Dorset in 1979. Discovered by British Gas in the 1970s and operated by British Petroleum since 1984, the field is responsible for the majority of UK onshore oil production and is Europe's largest onshore oil field. Over 200 wells have been drilled. Drilling vertically onshore then horizontally out to sea has proved more cost-effective than building offshore platforms, allowing oil to be produced beneath the Sandbanks estate, Bournemouth, from oil reservoirs 10km away. In 1996, British Gas hydraulically fractured a well in the Elswick Gas field in Lancashire (4.5km from Cuadrilla's Preese Hall well). Gas has been produced from it ever since. In the 1990s, several wells were also fractured in the UK to extract coal bed methane.

The first UK well to encounter shale gas was drilled in 1875. Its significance at the time went unnoticed as abundant conventional reservoirs made shale gas extraction uneconomic. It was not until the mid-1980s that research began into the potential for gas production from UK shales. In 2003, the Petroleum Revenue Act was repealed, exempting shale gas production from the Petroleum Revenue Tax (Selley 2012). In 2008, 97 Petroleum Exploration and Development Licences were awarded for shale gas exploration in the UK during the 13th Round of Onshore Licensing (see chapter 7). A 14th licensing round is pending.

Industry interest in shale gas extraction in the UK includes:

- **England.** Five potential shale gas exploration well sites have been identified by Cuadrilla in Lancashire. The first test well was drilled in August 2010 at Preese Hall; a second at Grange Hill Farm later that year; and a third near the village of Banks in August 2011. Hydraulic fracturing has

been undertaken at only one site. DECC has also granted a license for a site in Balcombe, West Sussex identified by Cuadrilla. Three possible sites have been identified in the Mendip Hills by UK Methane and Eden Energy. Planning permission has been sought for boreholes for geological samples. UK Methane has stated it has no interest in hydraulic fracturing at this stage. One site has been identified in Woodnesborough, Kent, by Coastal Oil and Gas Ltd. Planning permission has been granted. Neither Cuadrilla's West Sussex nor Coastal Oil and Gas Ltd's Kent sites have yet been granted permission for drilling or hydraulic fracturing.

- **Wales.** Three sites have been identified by Coastal Oil and Gas Ltd. DECC has given permission for drilling at two of these sites, but not hydraulic fracturing. Planning permission has been granted for the sites at Neath and Maesteg where wells will be deepened to obtain geological samples. Planning permission was refused at Llandow, Vale of Glamorgan. The decision is being appealed with a public inquiry.
- **Scotland.** Although potential shale formations do exist in Scotland, to date there has been no interest in shale gas extraction. Consent for hydraulic fracturing has been provided to one operator with an interest in extracting coal bed methane.
- **Northern Ireland.** Tamboran Resources has an interest to extract shale gas in an area that extends across the border between Northern Ireland and the Republic of Ireland.

The Environment Agency (EA), serving England and Wales, has been reviewing the adequacy of existing regulation. In 2011, the Scottish Environmental Protection Agency (SEPA) published a position statement based on its preliminary views of shale gas extraction (SEPA 2011). The Northern Ireland Environment Agency is working with the Irish environmental regulator to develop a regulatory framework suitable for transboundary activities.

1.8.1 UK climate change and energy security

The UK government has agreed to meet a number of domestic and European targets to decarbonise the UK economy (Moore 2012). The Climate Change Act 2008 calls for an 80% reduction in greenhouse gas emissions by 2050. This includes an interim target of a 34% reduction in emissions by 2020 and a 50% reduction in emissions by the 2023–2027 budget (all from a baseline of 1990). The EU has a target to reduce EU-wide greenhouse gas emissions by 20% between 1990 and 2020. It has also agreed that 20% of total energy production across the EU should be generated by renewable sources, and so the UK has committed to sourcing 15% of its energy from renewables.

The House of Commons Energy and Climate Change Committee carried out an inquiry into shale gas in 2011. The inquiry considered the prospects for shale gas in the UK; risks and hazards involved; potential carbon footprint of large-scale shale gas extraction; and implications for the UK of large-scale shale gas production around the world (HoC 2011). The Committee concluded that if a significant amount of shale gas enters the UK market (whether from domestic or foreign sources), it will probably discourage investment in more expensive, lower carbon emission renewables (HoC 2011).

Over the last decade, the UK has experienced reduced domestic production from the North Sea and an increased reliance on natural gas imports. New pipelines from Norway and the Netherlands and liquefied natural gas make up the difference. The House of Commons Energy and Climate Change Committee also concluded that domestic resources could reduce the UK's dependence on imports, but the effect on energy security may be 'unlikely to be enormous' (HoC 2011). The UK has an open gas market with large new import infrastructure and a diversity of potential gas suppliers (Moore 2012).

1.8.2 Joint academies review

The UK Government's Chief Scientific Adviser, Sir John Beddington FRS, asked the Royal Society and the Royal Academy of Engineering to carry out an independent review of the scientific and engineering evidence to inform government policymaking about shale gas extraction in the UK. The following chapters analyse environmental and health and safety risks associated with the onshore extraction of shale gas.

Surface operations

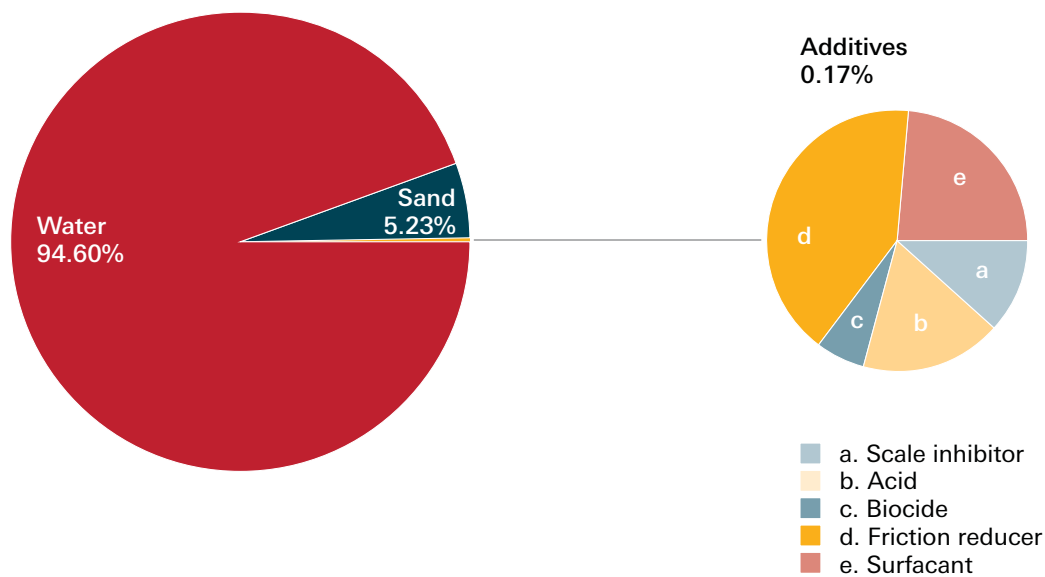
2.1 Fracturing fluid

The fluids most commonly used for hydraulic fracturing are water-based. The water can be abstracted from surfacewater bodies, such as rivers and lakes, or from groundwater bodies, such as aquifers or public and private water sources. Sand is added as a proppant to keep fractures open. Various chemicals are also added (see Figure 3). During multistage fracturing, a series of different volumes of fracturing fluids is injected with specific concentrations of proppant and other additives,

allowing each stage to address local conditions, such as shale thickness; presence of natural faults; and proximity to other well systems (API 2009). Operations require specialised equipment, including fluid storage tanks, proppant transport equipment and blending and pumping equipment. These components are assembled and linked to monitoring systems so that adjustments can be made to fluid volume and composition, fluid injection rate and pressure.

Figure 3 Typical composition of fracturing fluid by volume (source: British Geological Survey)

The 0.17% of chemical additives may include scale inhibitor to prevent the build up of scale on the walls of the well; acid to help initiate fractures; biocide to kill bacteria that can produce hydrogen sulphide and lead to corrosion; friction reducer to reduce friction between the well and fluid injected into it; and surfactant to reduce the viscosity of the fracturing fluid.



2.1.1 Disclosing the composition of fracturing fluid

In the USA, there are calls for operators to disclose fully the composition of fracturing fluid additives (see section 1.4.2). This is already required in the UK. In the UK, the environmental regulator has the power under the Water Resources Act 1991 to demand the disclosure of the composition of fracturing fluids.

2.1.2 Spills of fracturing fluid

Surface spills of fracturing fluid may pose a greater contamination risk than hydraulic fracturing itself (Goat and Grimshaw 2012). The impact of any spills

of fracturing fluid (or wastewaters) onsite can be mitigated using established best practices. In the UK, installing impermeable site lining ('bunding') is typically a condition of local planning permission. The impact of fracturing fluid spills can be further mitigated by using non-hazardous chemicals where possible. In the UK, there is no generic list of approved chemicals for use in fracturing fluid. The environmental regulators use a methodology developed by the Joint Agencies Groundwater Directive Advisory Group to assess the hazard potential of any chemical to be used, according to the specific site and local hydrogeological conditions.

2.2 Water requirements

There are concerns that hydraulic fracturing could require volumes of water that would significantly deplete local water resources (Entrekin *et al* 2011). Reported estimates for the volumes of water required for shale gas extraction vary according to local geology, well depth and length and the number of hydraulic fracturing stages. In the UK, under the Water Resources Act 1991, an operator is required to seek an abstraction permit from the environmental regulator if more than 20m³ of water is to be abstracted per day from surface or groundwater bodies. If water is instead sourced from a mains supply, the water company will need to ensure it can still meet the conditions of the abstraction permit that it will already be operating under.

Overall water use is important. Estimates indicate that the amount needed to operate a hydraulically fractured shale gas well for a decade may be equivalent to the amount needed to water a golf course for a month; the amount needed to run a 1,000 MW coal-fired power plant for 12 hours; and the amount lost to leaks in United Utilities' region in north west England every hour (Moore 2012). The rate of abstraction is also important. Hydraulic fracturing is not a continuous process. Water is required periodically during drilling and then at each fracturing stage. Operators could consult water utilities companies to schedule operations to avoid periods when water supplies are more likely to be under stress (Moore 2012).

2.2.1 Alternative sources of water

Water stress can be avoided by using alternative sources of water. Freshwater was necessary early in the development of certain US shales when friction reducers, scale inhibitors, and particularly surfactants, showed performance difficulties when mixed in saline water (King 2010). Technologies developed to overcome these problems in offshore hydraulic fracturing (where the use of seawater is more prevalent) are now being applied to onshore operations (Harris and van Batenburg 1999). The use of saline water from deep aquifers is being considered in some US shales (Yost 2011).

2.2.2 Alternatives to water

Another option would be to use waterless fracturing fluids. These include gels, and carbon dioxide and nitrogen gas foams (King 2010). These techniques are important where shales are susceptible to damage from water-based fracturing (King 2010). Gelled liquid petroleum gas (LPG) fracturing fluids could boost initial production rates and allow near full recovery of the fracturing fluids within days of stimulation. The use of these fluids, particularly propane-based LPG, could reduce the toxicity of wastewaters since they do not dissolve salts, heavy metals or Naturally Occurring Radioactive Material (NORM) in shales to the extent that water does.

2.3 Managing wastewaters

Approximately 25% to 75% of the injected fracturing fluid flows back to the surface when the well is depressurised. This fluid is mixed with methane and saline water containing minerals from the shale formation. The volume of flowback water depends on the properties of the shale, the fracturing design and the type of fracturing fluid used (King 2010). Produced water will continue to return to the surface over the well's lifetime. These wastewaters typically contain salt, natural organic and inorganic compounds, chemical additives used in fracturing fluid and NORM (NPC 2011). Very little is currently known about the properties of UK shales to explain what fraction of fracture fluid will return as flowback water, as well as the composition of formation waters and produced water.¹

2.3.1 Storing wastewaters

In the USA, wastewaters have historically been stored onsite in open pits, such as excavated and lined containment ponds (API 2009). The possible leakage of liners has led to calls to avoid the use of pits in favour of closed loop steel tanks and piping systems (Groat and Grimshaw 2012). Open storage ponds are not permitted in the UK. Wastewaters are instead stored in closed metal tanks before being treated. Leaks or spills of wastewaters can be managed in the same way as spills of fracturing fluid (see section 2.1.2). This hazard is not unique to shale gas extraction but common to many industrial processes.

¹ Contribution from Professor Richard Davies, Director of Energy Institute, University of Durham (private correspondence)

2.3.2 Reuse of wastewaters

Integrated operational practices should be adopted to minimise water use and avoid abstracting water from supplies that may be under stress. Recycling wastewater where possible would reduce the volumes of wastewater in need of disposal, although it could concentrate contaminants and thereby complicate disposal.

Wastewaters can be diluted with freshwater and then reused in subsequent fracturing operations. Pre-treatment may be necessary. The composition of wastewaters changes over the lifetime of a well. The most appropriate treatment will depend on the waters' degree of salinity (King 2010). The environment in which some shales were initially deposited was marine (King 2012). Produced water in the latter stages of shale gas extraction is more saline owing to the increased amount of saline formation water that it contains. Desalination technologies are being developed to control salinity and support reuse of wastewaters. These technologies concentrate salt and recover water through evaporation, distillation, electric separation or chemical treatment. The most common treatment uses selective membranes that filter out salt ions when high pressure is applied across them. As well as producing pure water, these desalination technologies typically produce a small amount of brine slurry that may be converted to solid waste in a crystalliser before disposal (ALL Consulting 2005). Microorganisms, such as bacteria, can exist even in deep shale formations, and so may be present in the formation water within wastewaters. These microorganisms need to be removed for health and safety and commercial reasons. Bacteria can produce hydrogen sulphide and acids that corrode well casings, and so potentially contribute to well failure. Disinfection techniques include filtration techniques, as well as ultraviolet light, chlorine, iodine, ozone and acid treatments (ALL Consulting 2005).

Pre-treatment could take place onsite, although this is currently expensive. Technologies could build on those already used to treat waste fluid from offshore oil and gas extraction. Alternatively, wastewaters could be transported to a treatment facility offsite. Numerous facilities exist in the UK with extensive experience of treating similar wastes from a range of industrial sectors.

2.3.4 Transporting wastewaters

The transport of wastewaters offsite is carried out by road haulage companies licensed by the UK's health and safety regulators with experience of transporting hazardous substances. The UK's environmental regulators issue carrier registration certificates and the Department of Transport and Vehicle and Operator Services Agency are responsible for vehicle licensing and testing.

2.4 Disposal of wastewaters

Disposal wells may be necessary if wastewater volumes exceed the capabilities of onsite, closed-loop storage tank systems. Injection of waste fluids into porous and permeable rock formations has been the primary disposal option for waste fluids from the US oil and gas industry (DoE 2009). Disposal wells are often depleted oil and gas wells, but wells can be drilled specifically for disposal if it is economic to do so. The site of disposal wells depends on geological conditions and regulation. In the USA, some wastes are transported to disposal sites by truck or pipeline (DoE 2009).

2.4.1 Disposing of fluids

Wastewaters are considered to be an 'extractive waste', and so are regulated under the Mining Waste Directive. Operators are required to formulate waste management plans that identify how wastes are to be minimised, treated, recovered and disposed of. This includes identifying environmental and health impacts and measures to address them, including control and monitoring activities. Disposal would be regulated in the UK under the Mining Waste Directive and Water Framework Directive. An environmental permit would be necessary, as well as pre-treatment, before discharge into a disposal well. If wastewaters contain NORM above specified limits, a further permit would be required. The Radioactive Substances Regulation would also apply. Currently, a disposal well would be constructed in the UK according to the Borehole Sites and Operations Regulations 1995 if the disposal well was in a mining area and to a depth of 30m or greater. Offshore disposal would involve extra environmental regulations, such as those under the Convention for the Protection of the Marine Environment of the North-East Atlantic (the OSPAR Convention).

2.5 Disposal of solid wastes

Shale tends to contain more uranium than other types of rocks. The radioactive decay of uranium-238 produces radium-226 that decays to radon-222 gas. Other NORM found in shales includes thorium and lead-210, concentrations of which vary from formation to formation. NORM in shales is usually at levels significantly lower than safe limits of exposure. NORM dissolves in formation water, so wastewaters need careful management should NORM become more concentrated during treatment (King 2012). Dissolved NORM may settle out to form solid wastes, such as mineral scale on the inside of wells and pipes or sludge that accumulates in storage or treatment tanks. Scale is composed primarily of insoluble barium, calcium and strontium compounds that precipitate out of wastewaters due to changes in temperature and pressure. Radium is chemically similar to these elements, and so is incorporated into the scales. Sludge settles out of wastewaters and consists of oily solids often containing silica compounds and barium.

NORM management is not unique to shale gas extraction. NORM is present in waste fluids from the conventional oil and gas industries, as well as in mining industries, such as coal and potash. Much work has been carried out globally on monitoring levels of radioactivity and handling NORMs in the oil and gas industries. For example, it is standard practice to sandblast pipes to remove scale or to use a rotating drill bit. The removed scale is then placed in sealed containers for later disposal. Scale can also be removed by dissolving NORM in an aqueous solvent before re-injecting the NORM-containing solution into a disposal well (ALL Consulting 2005).

In the UK, solid NORM wastes fall into one of three categories: very low concentration ('out of scope'); low concentration; medium or high concentration (requires an EPR permit). An environmental permit is required for disposing of NORM wastes that exceed 'out of scope' concentrations. Disposal in landfill is typical for solid wastes of low and medium concentrations. Some offshore oil production facilities have permits allowing some NORM wastes to be discharged directly to sea.

RECOMMENDATION

Water should be managed in an integrated way:

- **Techniques and operational practices should be implemented to minimise water use and avoid abstracting water from supplies that may be under stress.**
- **Wastewater should be recycled and reused where possible.**
- **Options for treating and disposing of wastes should be planned from the outset. The construction, regulation and siting of any future onshore disposal wells need further investigation.**

2.6 Managing methane and other emissions

Venting and flaring of methane and other emissions are controlled through conditions of Petroleum Exploration and Development Licences. The health and safety regulator places similar controls under the Borehole Sites and Operations Regulations 1995 and Offshore Installations and Wells (Design and Construction) Regulations 1996. Local authorities are responsible under the Environmental Protection Act 1990 to inspect sites for odour and noise associated with the venting or flaring of gas. Local authorities also have a statutory duty under the Air Quality Standards Regulations 2007 to monitor emissions to ensure they do not breach local air quality standards. Methane contained in wastewater can be regulated by the environmental regulator placing controls on operators' waste management plans (see section 2.4.1).

The Industrial Emissions Directive would apply if shale gas is processed before injection into the gas pipeline or combusted to generate electricity and/or heat onsite. A permit would then be needed, requiring the operator to monitor emissions of methane (and other air pollutants). Shale gas in the UK is expected to be of high quality, so large scale processing may not be necessary. Operators

should still monitor potential leakages of methane and other emissions before, during and after shale gas operations. Monitoring before operations would indicate the effects of methane due to non-shale gas operations in the area or natural seepage (methane is released naturally from alluvium soils, landfill sites and peat deposits). One option would be to construct semi-permanent monitoring stations around the perimeter of a drilling site. Alternatively, emissions could be monitored near to the well. Both options face complications. Gas emissions would be diluted in the atmosphere before reaching monitoring stations, limiting their detection accuracy. Monitoring equipment near to the well could be disturbed due to surface equipment being changed at different stages of operations. Monitoring data should be submitted to the appropriate regulator. Reliable data would be available to inform assessments of health impacts on local populations (McKenzie *et al* 2012). These data could also inform assessments of the carbon footprint of shale gas extraction (see section 8.2.2).

'Green completion technologies' are used in the USA to capture and then sell (rather than vent or flare) any methane and other gases emitted from flowback water (DoE 2011b). These technologies separate out gas, water and sand in flowback fluid before directing the recovered gas into pipelines. Methane and carbon dioxide emissions are reduced compared to venting and flaring methane, respectively. Green completion technologies could allow emissions levels similar to those associated with natural gas extraction (Broderick *et al* 2011). The EPA has issued federal regulations making green completion technologies mandatory for hydraulic fracturing of all gas wells in the USA from 2015 onwards. No such requirements exist in the UK for exploratory activities. Consideration should be given the possible use of green completion technologies, especially for any future production activities in the UK, based on best available technologies and operational best practices.

RECOMMENDATION

To detect potential leakages of gas:

- **Operators should monitor potential leakages of methane or other emissions to the atmosphere before, during and after shale gas operations.**
- **The data collected by operators should be submitted to the appropriate regulator. These data could inform wider assessments, such as the carbon footprint of shale gas extraction.**

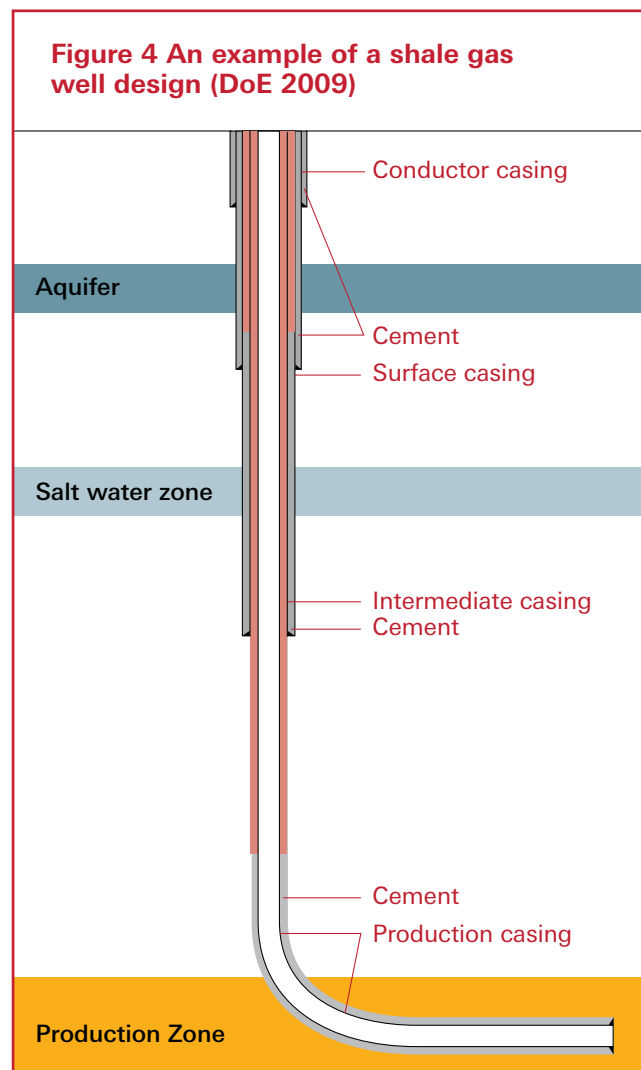
Well integrity

'Well integrity' refers to preventing shale gas from leaking out of the well by isolating it from other subsurface formations (API 2009). The isolation is provided according to how the well is constructed. A series of holes ('wellbores') of decreasing diameter and increasing depth are drilled and lined with steel casing joined together to form continuous 'strings' of casing (see Figure 4):

- **Conductor casing.** Set into the ground to a depth of approximately 30 metres, the conductor casing serves as a foundation for the well and prevents caving in of surface soils.
- **Surface casing.** The next wellbore is drilled and sealed with a casing that runs past the bottom of any freshwater bearing zones (including but not limited to drinking water aquifers) and extends all the way back to the surface. Cement is pumped down the wellbore and up between the casing and the rock until it reaches the surface.
- **Intermediate casing.** Another wellbore is drilled and lined by an intermediate casing to isolate the well from non-freshwater zones that may cause instability or be abnormally pressurised. The casing may be sealed with cement typically either up to the base of the surface casing or all the way to the surface.
- **Production casing.** A final wellbore is drilled into the target rock formation or zone containing shale gas. Once fractured, the shale gas produces into the well. This wellbore is lined with a production casing that may be sealed with cement either to a safe height above the target formation up to the base of the intermediate casing; or all the way to the surface, depending on well depths and local geological conditions.

Well failure may arise from poor well integrity resulting from:

- **Blowout.** A blowout is any sudden and uncontrolled escape of fluids from a well to the surface.
- **Annular leak.** Poor cementation allows contaminants to move vertically through the well either between casings or between casings and rock formations.
- **Radial leak.** Casing failures allow fluid to move horizontally out of the well and migrate into the surrounding rock formations.



3.1 Preventing well failure

3.1.1 Preventing blowout

Blowouts are rare. Blowouts can occur when drilling encounters an over-pressurised, highly permeable formation. Some shales can be over-pressurised, but even then blowout is unlikely because shale has very low permeability. A recent blowout from a Chesapeake well in Wyoming, USA, resulted from gas that had leaked up from the Niobrara Shale into a shallower, more permeable formation.

Blowouts are a major safety hazard to workers. They may also result in escapes of fluid into nearby surface water. The environmental impacts of blowout depend on (Groat and Grimshaw 2012):

- timing relative to well activities (determining whether pressurised fracturing fluid or shale gas is released);
- whether escape is through the surface casing or deeper in the well;
- the nature of the risk receptor (whether freshwater aquifer or water well).

A blowout preventer (BOP) is placed at the top of a well during drilling to automatically shut down fluid flow in the wellbore should there be any sudden or uncontrolled escape of fluids. During production, the BOP is replaced with a series of valves to connect the well to the gas export pipeline. The BOP is the final resort when a blowout occurs. When the BOP closes, vulnerabilities in casing and cement below could fail, allowing fluid to escape into surrounding subsurface formations (an underground blowout). Proper design to maintain subsurface well integrity remains vital.

3.1.2 Preventing casing failures

Once drilled, but before casings are installed and cemented, instruments can be run down the wellbore to detect naturally occurring (gamma) radiation and measure the density and porosity of the formation (API 2009). The diameter of the wellbore can be measured using callipers so that casings are installed accurately. Once installed and prior to further drilling, casings are pressure tested to ensure sufficient mechanical integrity and strength so that they can withstand pressures exerted at different phases of the well's life, such as those exerted during the fracturing process (API 2009). Immediately after drilling out of each casing, a formation pressure test ('leak off test') is carried out.

3.1.3 Preventing poor cementation

Cementation provides structural support, as well as isolation of different rock formations. Cements may be tested in advance to ensure their properties meet the requirements of particular well designs (API 2009). Cement needs to completely surround casings to provide a continuous annular seal between casings and the rock formation, as well as between casings. A cement bond log (CBL) is an acoustic device run inside casings to detect the presence of cement according to the absorption/reflection of transmitted sound signals. CBL tests the quality of cement bond between casings and formation and indicates if cement has reached the specified height. If any section of the well does not meet ideal specifications, a remedial cement job can be completed before subsequent sections are drilled. Casings can be similarly tested and repaired following each fracturing stage. Well integrity is inferred during operations by pressure testing. This is confirmed by monitoring annular pressures, as well as testing seals and valves at casing joints (API 2009).

Despite the quality of the initial cementation (indicated by an adequate CBL test), some wells can still leak over time. One possible explanation is the tendency of cement to shrink (Dusseault *et al* 2000). Cement shrinkage may be caused by one (or a combination) of several distinct mechanisms associated with drying, cooling and autogenous (sealed system) effects. A cement formulation that is resistant to one mechanism will not necessarily be resistant to another (The Concrete Society 2010). Shrinkage can reduce radial stresses, weakening cement bonds with the surrounding rock and

leading to circumferential cracks. These cracks can grow vertically due to resulting changes in horizontal stresses and pressure gradients. Gas and other contaminants may accumulate slowly in these cracks, enter shallow strata or even leak at the surface many years after production or well abandonment. Even the presence of surface casing provides no assurance against gas leakage at the surface from the surrounding ground. The problems of cement shrinkage and cracking over time have led to the development of new resistant cement formulations (Bentz and Jensen 2004).

3.1.4 Best practice for well construction

Studies in North America have used well data to identify key factors affecting leakage, especially the number of casings and the extent to which these casings were cemented. Some of the leaky wells in a Canadian study had only a single casing or were left uncased except in the section from the surface casing down to just below the aquifer (Watson and Bachu 2009). Others had not been cemented at all or the cementation had not reached the required height (Watson and Bachu 2009). Several percent of older oil and gas wells leaked, while fewer than 0.5% of those constructed since 2000 according to stricter standards were found to be leaky (Watson and Bacchu 2009).

In the USA, it is common to have two strings of casings. When intermediate casing is not installed, cementing the production casing to the surface should be considered (API 2009). Intermediate casing is not always cemented all the way back to the surface. At a minimum, the cement should extend above any exposed water or hydrocarbon bearing zones (API 2009). In some states, such as Pennsylvania and Texas, there is a requirement to cement casing to approximately 75 ft below any aquifers. Failure to do this can lead to groundwater contamination as occurred in Pavillion, Wyoming (DiGiulio *et al* 2011). In the UK, standard practice is to have three strings of casing with at least two (intermediate and production casing) passing through and thereby isolating any freshwater zones. Best practice is to cement casings all the way back to the surface, depending on local geology and hydrogeology conditions.

In the USA, the American Petroleum Institute and American National Standards Institute accredited guidance documents exist for shale gas extraction. In the UK, guidelines exist for certain aspects of hydraulic fracturing, such as proppant use, and guidance for directional drilling is under development. Guidelines across the lifecycle of shale gas extraction may be required (Pereira 2011).

3.2 Improving the well examination scheme

The UK's well examination scheme is highly valuable, allowing well designs to be reviewed by specialised experts that may not be directly available to the health and safety regulator. The Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996 requires the design and construction of offshore and onshore wells to be examined by an 'independent and competent person' ('well examiner'). The examiner can ask for results of well integrity tests, such as pressure tests and CBLs, and can raise any health and safety concerns with the operator. The examiner does not have the power to give consent to, or prohibit, activities. The examiner can inform the health and safety regulator if he is unsatisfied that the operator has addressed his concerns.

The operator commissions and pays for the services of the well examiner. The Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996 states that the well examiner should be 'sufficiently knowledgeable and separate from the immediate line management of the well operations involved ... This might be someone employed by the well operator's organisation. It is important that those carrying out examination work have appropriate levels of impartiality and independence from pressures, especially of a financial nature. Promotion, pay and reward systems should not compromise professional judgement'. The guidelines should be clarified to ensure the well examiner is an employee of a separate company. The independence of the scheme must not be compromised.

The Offshore Installations and Wells (Design and Construction, etc) Regulations 1996 state that wells should be designed and constructed so that ‘as far as is reasonably practicable, there can be no unplanned escape of fluids from the well; and risks to the health and safety of persons from it or anything in it, or in strata to which it is connected, are as low as is reasonably practicable’. The scheme should be widened so that well integrity is also considered from an environmental perspective. Wider expertise within or outside of the oil and gas sector may need to be drawn on.

During operations, the well examiner will receive reports for review to ensure the well is constructed according to the agreed design. Examination by paper trail is standard practice since the scheme has its origin in reviewing offshore wells. Inspections should be made onsite as appropriate to review that onshore wells are constructed according to the agreed design. There is currently no legislative requirement for pressure tests or CBLs to be carried out. Operators should carry out such tests as appropriate to ensure well integrity.

The operator keeps the reports of the well examination scheme for a minimum of six months after a well has been abandoned so that they are available for health and safety regulator to consider on request. The Department of Energy and Climate Change (DECC) already has a database that documents the location of wells. The results of well tests and the reports of well examinations should be submitted to DECC so that this database includes information about the history of every well’s integrity. This would be important when addressing any possible well failures, especially post-abandonment.

RECOMMENDATION

To ensure well integrity:

- **Guidelines should be clarified to ensure the independence of the well examiner from the operator.**
- **Well designs should be reviewed by the well examiner from both a health and safety perspective and an environmental perspective.**
- **The well examiner should carry out onsite inspections as appropriate to ensure that wells are constructed according to the agreed design.**
- **Operators should ensure that well integrity tests are carried out as appropriate, such as pressure tests and cement bond logs.**
- **The results of well tests and the reports of well examinations should be submitted to the Department of Energy and Climate Change (DECC).**

3.3 Detecting well failure

Once a well has been constructed, operators can continue to carry out appropriate tests, such as pressure tests and CBLs, to verify well integrity during operations. Continuous monitoring of ground gas emissions can also be implemented using monitoring wells around the well pad to detect any gas migrating outside the surface casing and into the surrounding ground. This scenario could arise from cement failure between casings, or between casings and the shale formation. Regular sampling of near surface aquifers could also detect well failure of this sort.

3.3.1 Methods to distinguish sources of methane

Methane in shale gas is derived by two distinct processes that leave characteristic chemical and isotopic signatures. Biogenic methane is generated by bacteria typically in shallow anaerobic locations, such as wetlands and landfill sites. Thermogenic methane is generated by organic matter changing under high temperatures and pressures over long time periods. Thermogenic methane can be found in both shallow and deep formations.

Biogenic shale gas consists mostly of methane, while thermogenic shale gas consists of methane and other gases. The detection of higher chain hydrocarbons (owing to the presence of other gases) can be used to distinguish between biogenic and thermogenic methane (Révész *et al* 2010). Isotope analyses can provide additional evidence. Biogenic methane has low values of the isotopes $\delta^{13}\text{C}$ and $\delta^2\text{H}$. Thermogenic methane has higher $\delta^{13}\text{C}$ and $\delta^2\text{H}$ values (Révész *et al* 2010). Detecting radioactive ^{14}C can also be used as a distinguishing tool. Unlike biogenic gas, thermogenic gas does not contain ^{14}C due to its generation from deeply buried older organic material over thousands of years (allowing time for the radioactive carbon isotope to decay). The isotopic values of thermogenic and biogenic shale gas can be altered if they come into contact with water. Combined gas and water analyses can be carried out to understand the origin of gases in aquifers. This involves analysing both the isotopes of carbon in the water, and the isotopes of hydrogen and oxygen constituting the water (Osborn and McIntosh 2010). Since shale gas can be formed by both thermogenic and biogenic processes, distinguishing between these two types of gas is not in itself conclusive. To determine the origin of methane in groundwater, its chemical and isotopic compositions need to be compared to those of the gas extracted from nearby shale formations.

3.3.2 Adding tracers to fracture fluid

Tracers can assist understanding of fracture propagation (see section 4.1). They also provide evidence for determining whether hydraulic fracturing has led to groundwater contamination. The distinct elemental composition and isotopic signatures of flowback water provide opportunities for tracer studies that could indicate contamination of groundwater or surface waters (Entrekin *et al* 2011).

3.3.3 Baseline surveys of UK groundwater

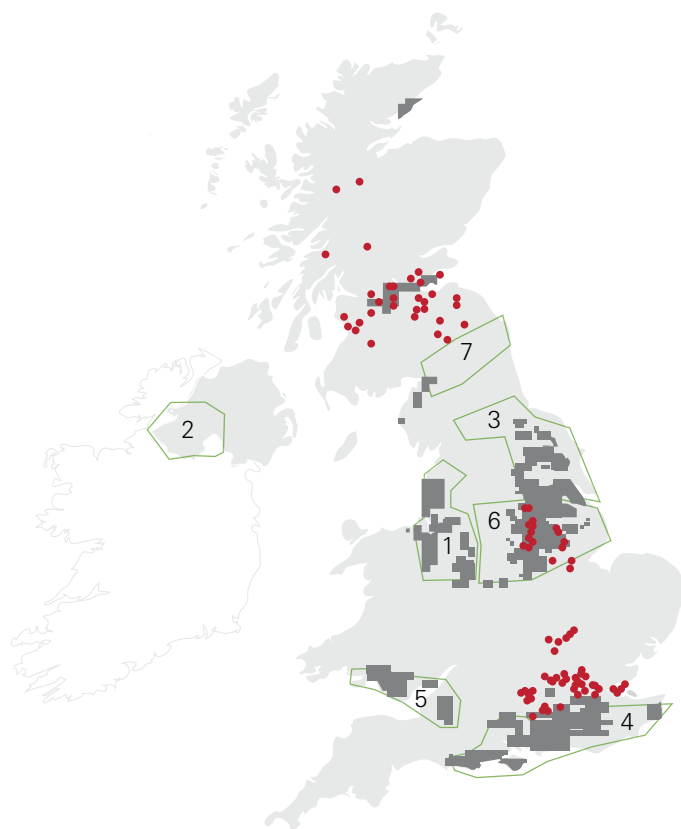
One US study by Duke University sought to evaluate the impact of shale gas extraction on groundwater by analysing samples from active and non-active areas of shale gas extraction (Osborn *et al* 2011). Methane in samples from active areas was determined to be from deep, thermogenic sources compared to methane in samples from non-active areas determined to be of biogenic origin. The study concluded there was evidence of methane contamination of certain aquifers overlying the Marcellus and Utica shale formations in north eastern Pennsylvania and upstate New York associated with hydraulic fracturing (Osborn *et al* 2011). This conclusion has been contested. An alternative topographical and geological explanation has been provided (Molofsky *et al* 2011). The analysis of the samples could be consistent with thermogenic methane from the formations overlying the Marcellus Shale rather than from hydraulic fracturing within the Marcellus shale itself (Molofsky *et al* 2011). This highlights the importance of baseline surveys of naturally occurring methane and underlying geological topography. In the absence of such baselines, the conclusion of the Duke University study is unverifiable. The availability of measurements in advance of fracturing would have provided an objective baseline for determining whether shale gas extraction had been the source of contamination (Williams 2010). No evidence of contamination with deep saline brines or fracturing fluids was found in any of the groundwater sampling in the study.

The British Geological Survey (BGS) has carried out some work on background levels of methane in UK groundwaters unrelated to shale gas extraction (Goody and Darling 2005). In late 2011, BGS carried out a limited review of the potential impact of shale gas extraction on UK groundwater (Stuart 2011). BGS is now establishing a more comprehensive baseline survey of methane in groundwater in areas likely to be investigated for shale gas extraction in the UK. The first phase involves sampling groundwater at various locations in the UK, monitoring dissolved concentrations of methane and carbon dioxide. If elevated concentrations are detected, repeat

samples will be taken to measure stable isotope ratios to distinguish between thermogenic and biogenic sources of methane (see section 3.3.1). Other chemical and biological signatures useful for attribution purposes will also be monitored (see section 3.3.2). Groundwater residence time will be measured to improve understanding of the age of groundwater. Approximately 200-250 samples at existing boreholes are planned to be taken over the course of FY2012-2013 (see Figure 5). The results are expected to be available before the end of March 2013.

Figure 5 British Geological Survey baseline survey of UK groundwater

The red circles represent locations of existing groundwater methane analyses. The grey areas highlight current onshore UK Petroleum Exploration and Development Licences. The green lines highlight areas of shale gas interest. The numbered areas are those prioritised by the British Geological Survey (BGS) where baseline surveys of UK groundwater should be carried out, according to the possible order in which shale gas activities may take place while also considering logistics and BGS's own operational practices.



Areas prioritised for baseline groundwater methane survey

- 1 West Lancashire and Cheshire Basins
- 2 Northern Ireland
- 3 Stainmore Trough and Cleveland Basin
- 4 Wessex and Weald Basins
- 5 South Wales Coast
- 6 Midlands (Edale and Widmerpool Gulf; Gainsborough Trough)
- 7 Northumberland Trough

3.3.4 Detecting well failure post-abandonment

DECC requires operators to submit an abandonment plan and obtain consent before operations to abandon a well are commenced. Abandonment requirements are considered in the initial design of the well to ensure the well is left in a satisfactory condition to prevent future leakage. Operators are required to design, construct and operate wells so that they can be suspended or abandoned in a safe manner, after which there can be no unplanned escapes of fluids (Schoenmakers *et al* 2009). HSE would be notified of the abandonment, and receive weekly reports of the abandonment process. The abandonment would also be reviewed under the well examination scheme (see section 3.2). Unless there is unusual or adverse development during the abandonment process, no subsequent monitoring is currently required.

Monitoring arrangements should be developed to detect possible well failure post abandonment. Continuous ground gas monitoring and aquifer sampling could be similar to that carried out before and during fracturing operations. Temporary monitoring equipment could be used, such as that used to monitor emissions from landfill sites or even semi-permanent monitoring stations could be installed. Monitoring would be at a reduced frequency, perhaps every few years. This requires techniques that can reliably distinguish between methane from non-shale operations in the areas of abandoned wells. Operators are responsible for wells once abandoned. Operators have an open-ended liability to remediate any ineffective abandonment operations. Consideration should be given to establishing mechanisms, such as a common liability fund, to ensure funds are available to respond to well failure post-abandonment in the case that the operator can no longer be identified.

RECOMMENDATION

To detect groundwater contamination:

- **The UK's environmental regulators should work with the British Geological Survey (BGS) to carry out comprehensive national baseline surveys of methane and other contaminants in groundwater.**
- **Operators should carry out site-specific monitoring of methane and other contaminants in groundwater before, during and after shale gas operations.**
- **Arrangements for monitoring abandoned wells need to be developed. Funding of this monitoring and any remediation work needs further consideration.**
- **The data collected by operators should be submitted to the appropriate regulator.**

Fracture propagation

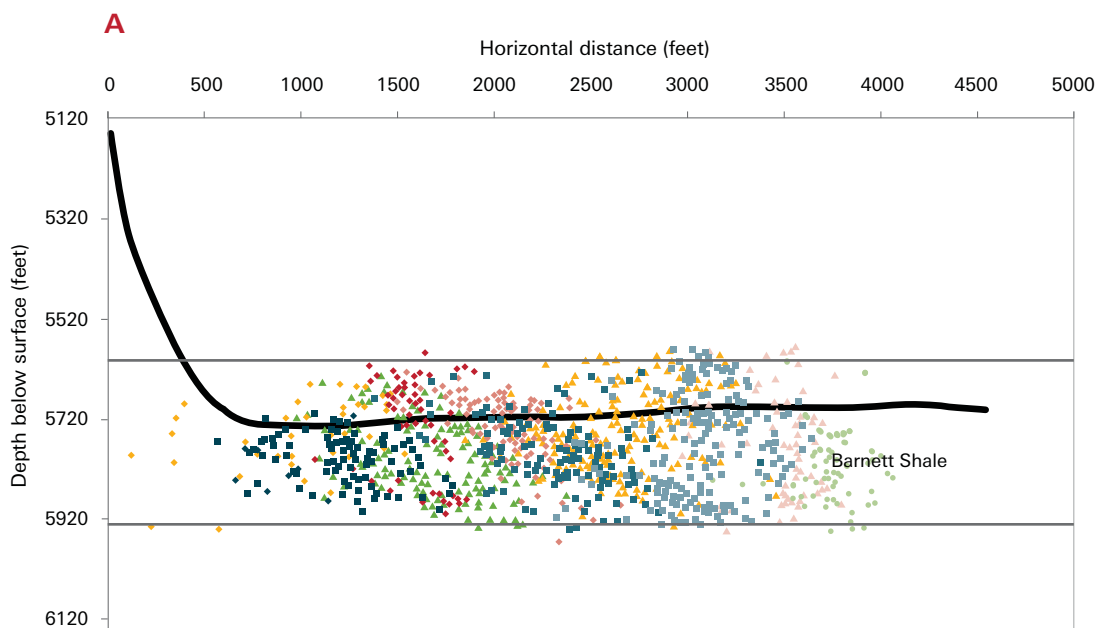
4.1 Monitoring fractures

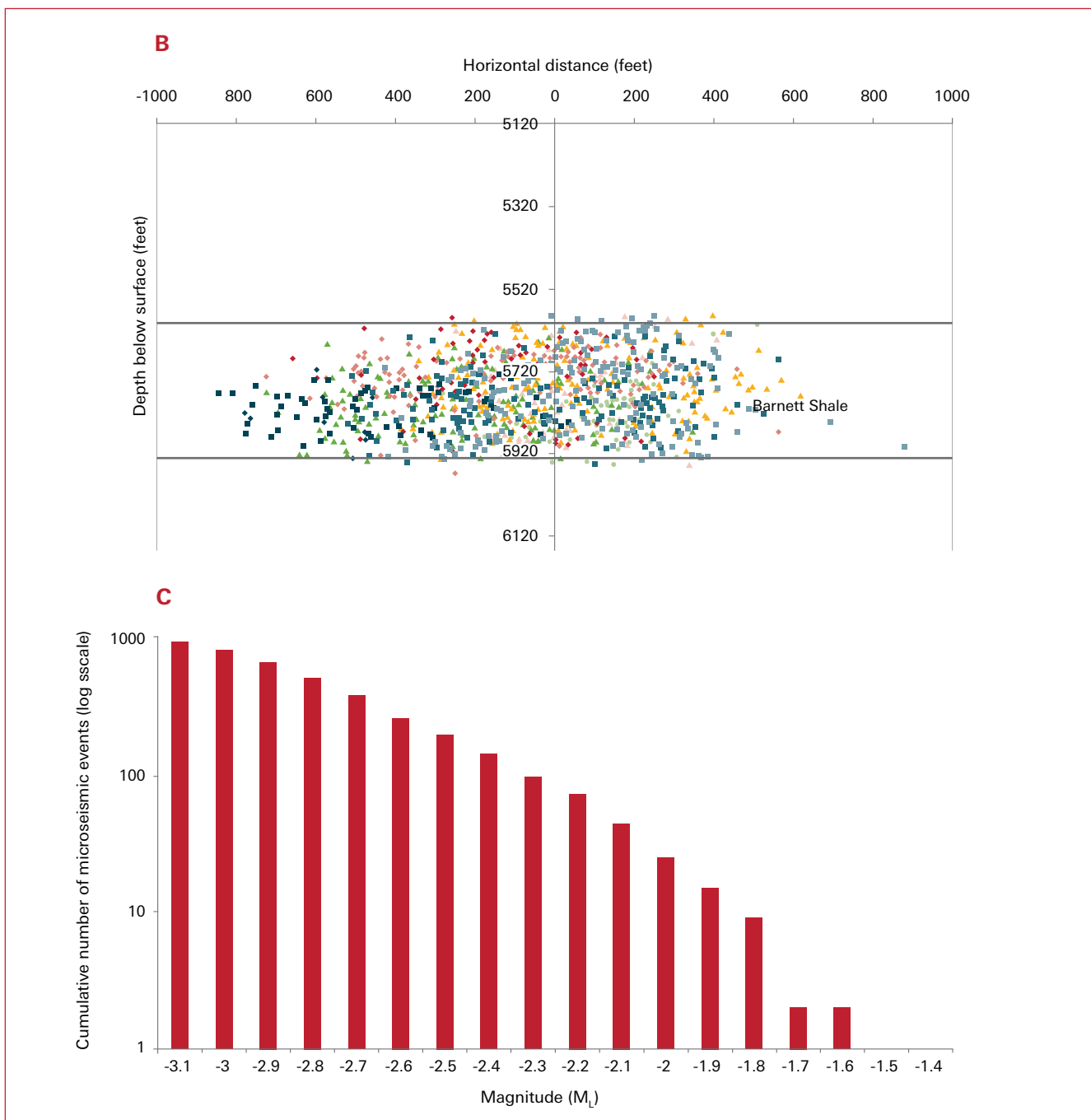
Operators have an incentive to carefully monitor and ensure fractures propagate in a controlled manner and remain within the target shale formation (see Figure 6). Excessive, uncontrolled fracture growth is uneconomic, wasting resources on the extra chemicals, pumping equipment and manpower needed. Various methods are available to monitor fracture growth before, during and after operations (Bennett *et al* 2006). Chemical tracers can be added to fracturing fluid. The performance of the fracturing process stage by stage can be inferred from the concentration of specific tracers combined with the recovery time and volumes of flowback water. The dilution of the tracers can improve understanding of fracture fluid loss and flowback efficiency. Proppant can be tagged with a radioactive tracer. Detection of the tracers can confirm whether proppant was placed as intended and identify leakage points (King 2010). An alternative is to rely on naturally occurring isotopic signatures. Many shale formations contain elevated levels of naturally occurring radioactive materials (NORMs), such as isotopes of radon and radium (Genereux and Hemond 1990). Shale formations are

at higher temperature than fracturing fluid (at the surface). Cooling due to the injected fluids can be detected to provide extra data about the fracturing performance. Fluid flow and density can also be measured to identify perforation intervals that contribute to flowback.

The most successful monitoring techniques have been tiltmeters and microseismic monitoring. Tiltmeters detect microdeformation in surrounding rock that radiates outwards as fractures open. Tiltmeters can be placed in an array of shallow boreholes or in monitoring wells at depths to estimate fracture geometry. Seismometers can be placed in similar configurations to detect microseismic events created as energy is released when each fracture opens. These events typically have a magnitude less than $-1.5 M_L$ (see Figure 6, C). Advances in tiltmeter and microseismic sensitivity and computer processing allow fracturing to be monitored in three dimensions and in real time (API 2009). These data allow fracturing models to be refined and future treatments to be optimised.

Figure 6 Microseismic monitoring of a typical hydraulic fracturing operation in the Barnett Shale, Texas, USA (Zoback *et al* 2010). 'A' displays a horizontal view of microseismic events along the horizontal well. The thick black line represents the horizontal well. Note that the vertical axis does not begin at the surface but at depth (5120 feet). Each dot represents a separate microseismic event. Each colour represents a distinct fracturing event. 'B' displays a cross sectional view of the microseismic events. 'C' displays the distribution of these microseismic events by magnitude.





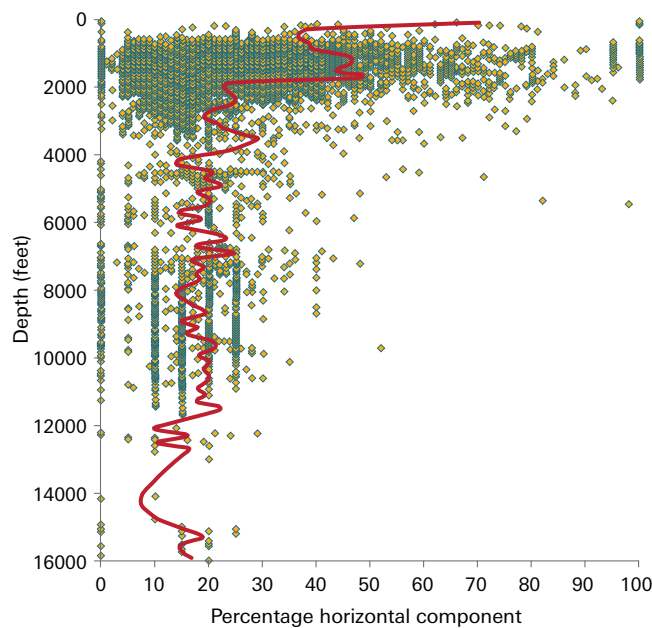
4.2 Constraining fracture growth

4.2.1 Geological stresses

Geological stresses are the most significant source of constraint on fracture growth (Fisher and Warpinski 2012). Fractures propagate perpendicularly to the direction of least principal stress, following the direction of maximum principal stress (API 2009). The weight of the overlying rock formations is one component of the total geological stress. This weight increases with depth, meaning that the direction of

maximum principal stress, and hence the direction of fracture propagation, tends to be vertical. At shallower depths, where the direction of maximum principal stress tends to be horizontal, fractures will tend to propagate more horizontally (see Figure 7). The directions of maximum and minimum stress vary across the UK (Baptie 2010). Characterising the stresses at a prospective site for shale gas extraction is an important means of determining the direction in which fractures will tend to propagate.

Figure 7 The relationship between depth and orientation of fracture growth in sedimentary formations (Fisher and Warpinski 2012) Each point on the figure represents a separate fracture treatment from more than 10,000 fractures mapped using tiltmeters throughout the past decade in numerous sedimentary formations (including shale) across North America. Each point is plotted against depth and percentage of horizontal component. The red line shows the average of all fractures. 0% horizontal component represents a purely vertical fracture. 100% would be a purely horizontal fracture.



4.2.2 Well pressure

It may be theoretically possible to create a pressure that could overcome geological stresses so that a fracture could grow vertically to shallow depths or even the surface. Practically, this is not feasible. The volume of fluid injected during operations is simply insufficient by orders of magnitude to create these pressures. Even then, such an enormous pressure could not be sustained. Leak off of fluid would soon reach a point where the leak off rate would equal the injection rate. The fracture simply could not grow any further (King 2010, Fisher and Warpinski 2012).

4.2.3 Geological structure

Models of fracture propagation often assume that the geological layers through which fractures propagate are homogenous, depicting fractures as single linear or planar cracks. However, the structure of overlying geology is heterogeneous, giving rise to fractures of a more complex, branching nature (Fisher and Warpinski 2012). Complexity in the

induced fracture network is desirable to maximise the fracture surface area so that as much gas as possible will flow out of the shale into the well. Complexity is influenced through operational means, such as slowly increasing the rate of fluid injection, which also helps to keep fractures within the formation zone (King 2010). Complexity is also influenced through natural mechanisms. Intersection with local structural features can be a strong determinant of fracture growth (King 2010). Layers with different material properties, such as strength and shear modulus (elastic stiffness), support complex growth. Weak interfaces and discontinuities between layers or even slippage along the layers can blunt, kink, bifurcate and terminate growth. Should fractures enter higher permeability layers, fluid may leak off into the formation, stunting fracture growth further.

4.3 Hydraulic fracturing below aquifers

4.3.1 Groundwater permits

The injection of fracturing fluids into shales is regulated in the UK under the Water Framework Directive and Environmental Permitting Regulations (EPR) 2010. The environmental regulator is responsible for deciding whether this activity poses a contamination risk to groundwater and if an environmental permit is necessary to set limits on the activity to manage the risk to an acceptable level. If an activity poses an unacceptable risk, the activity would be prohibited. Cuadrilla's fracturing at the Preese Hall site was deemed to pose no risk, so an environmental permit was not deemed to be necessary. The nearby Sherwood aquifer is saline and not connected to, or used for, public water supplies. The nearest sensitive groundwater is many kilometres away. Should Cuadrilla's operations change, the environmental regulator would reassess whether the new activities posed a risk and if an environmental permit would be required.

At present, the environmental regulator does not permit fracturing below freshwater aquifers. If this policy were to change, consideration should be given to:

- composition of the fracturing fluids (see section 2.1);
- well design (see Chapter 3);
- evidence of fracture height growth;
- hydrogeological conditions for fluid flow;
- site specific geology of UK shales;
- better understanding of UK shales and overlying geology;

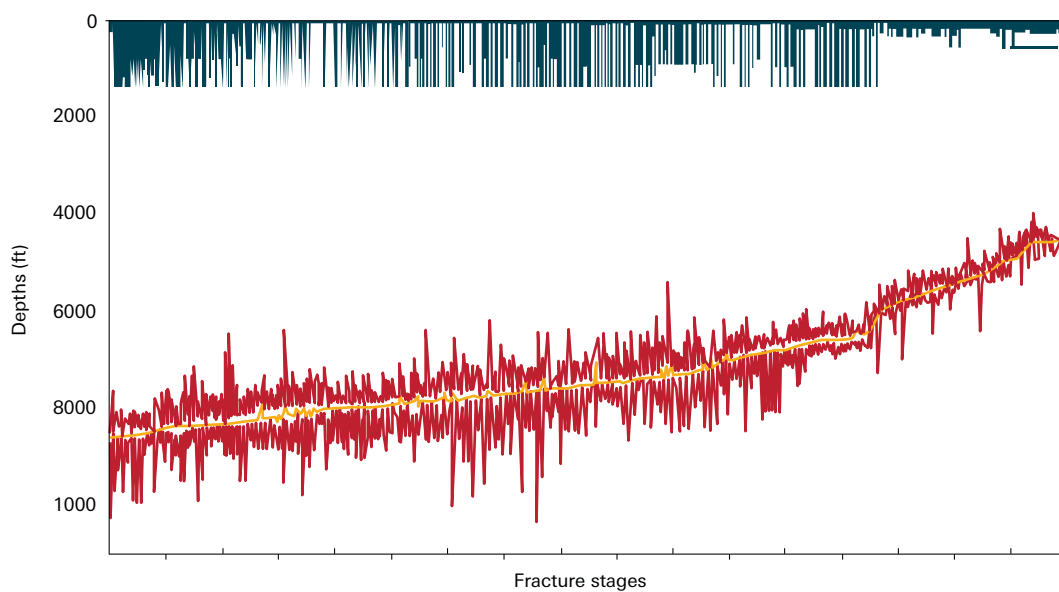
4.3.2 Evidence of fracture height growth

US microseismic data shows that fractures created by hydraulic fracturing are very unlikely to propagate vertically more than one kilometre (see Figure 8). One recent UK study examined vertical fracture growth based on datasets of recorded natural and artificially created fracture growth from the USA, Europe and Africa (Davies *et al* 2012). The maximum vertical height of artificially created fractures examined in this study was less than 600m. The height of only 1% of these fractures was greater than 350m (see Figure 9). The vertical height of most of natural fractures examined in this study was between 200-400m. Very few natural fractures extended beyond 700m, and it was extremely rare that any extended beyond 1000m. It is not clear that these natural fractures propagate by the same mechanisms as engineered hydraulic fractures, although there may be similarities.

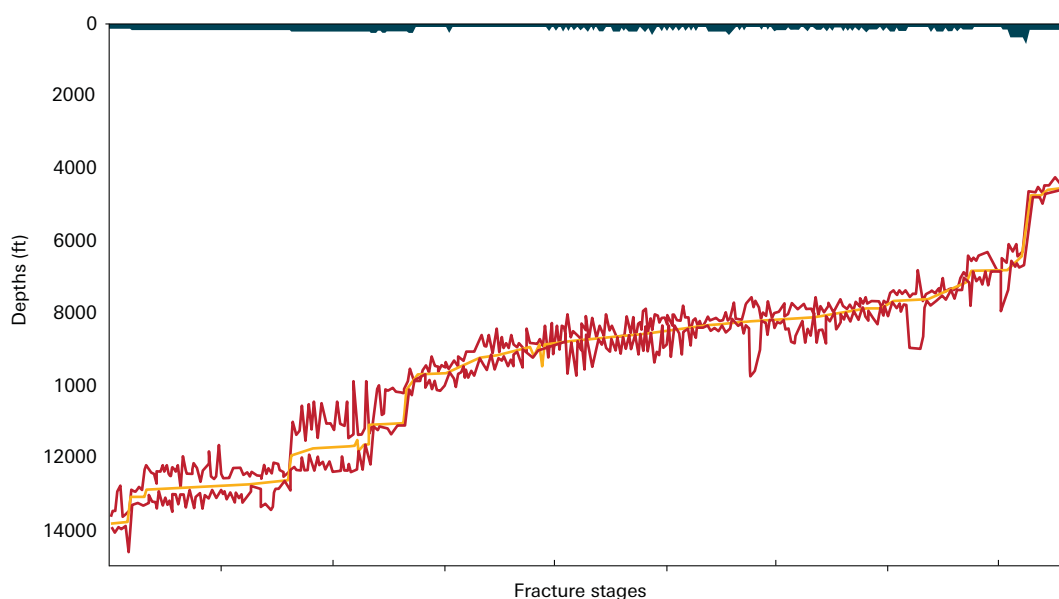
The largest vertical growth may arise when fractures intercept faults. Even then, faults do not assist propagation in an unconstrained way. Some conclude that rather than being 'open' and providing a pathway towards the surface, faults in shales must be closed. Were faults 'open', any gas present would have escaped over geological time, leaving no resource to exploit (Fisher and Warpinski 2012). This explanation may hold for conventional hydrocarbons where faults have been found to cut through 'sealing units' (assemblages of low permeability rock that halt or retard the flow of hydrocarbons), thereby conducting flow over geological timescales (Cartwright *et al* 2007). This explanation does not necessarily apply to shale gas. The low permeability of shale means that gas does not flow without suitable pressure conditions even in the presence of an 'open' fault. This is why shale needs to be hydraulically fractured to stimulate gas production.

Figure 8 Comparisons of fracture growth and depth of overlying water sources (aquifers or water wells) (Fisher and Warpinski 2012) Each of the four figures illustrates fracture height for fracture treatments performed in four major US shale formations between 2001 and 2010. The depth of each fracture treatment is illustrated by the yellow line and sorted by depth. The red spikes represent the extent of upward and downward fracture growth. The dark blue bars at the top of each figure illustrate the depth of overlying water sources.

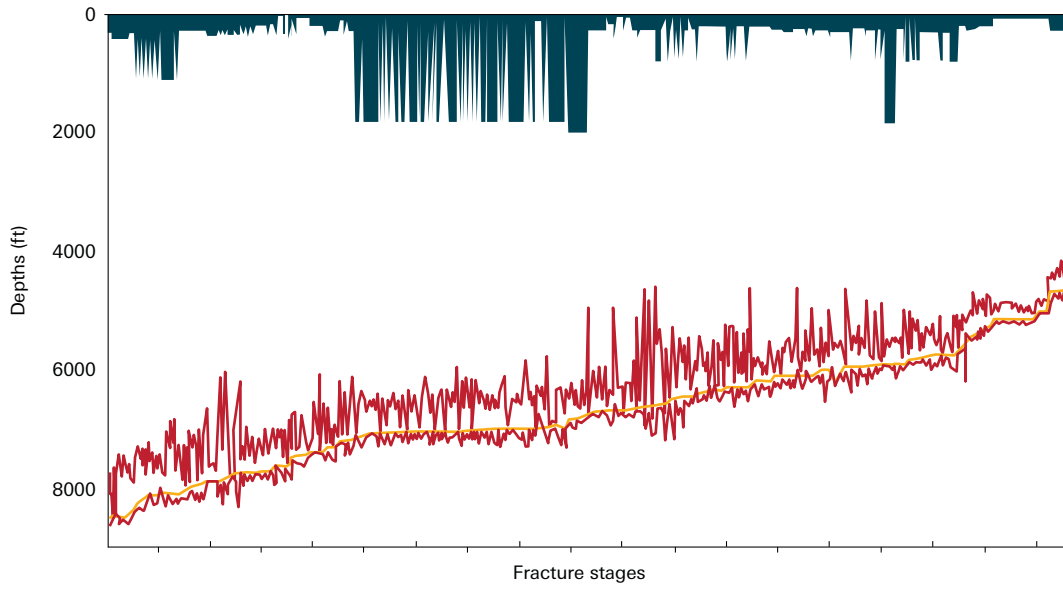
Barnett Shale



Woodford Shale



Marcellus Shale



Eagle Ford Shale

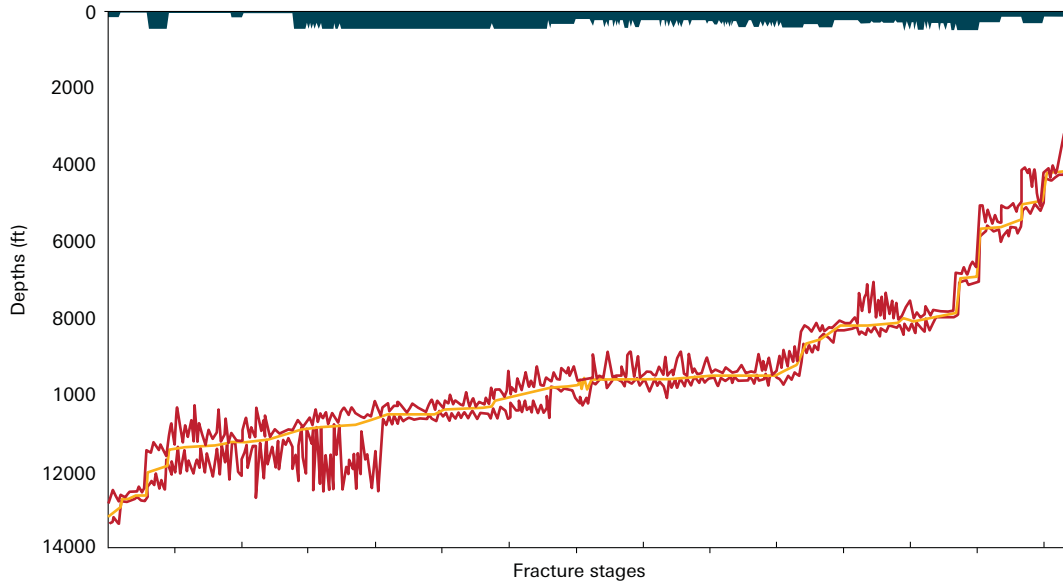
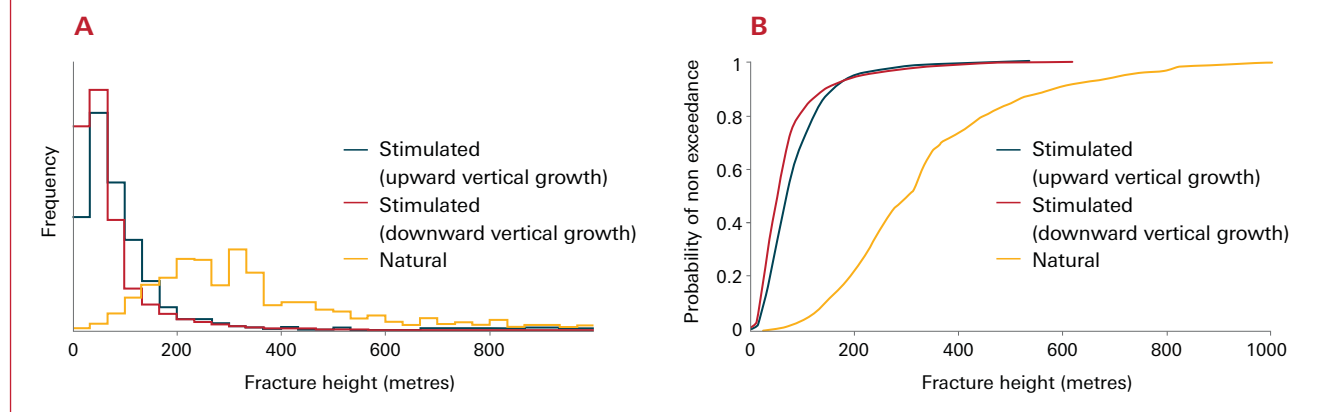


Figure 9 Frequency of fracture height for artificial and natural fractures (A) and probability of fracture height not being exceeded (non-exceedance) for artificial (stimulated) and natural fractures (B) (Davies *et al* 2012)



4.3.3 Hydrogeological conditions for fluid flow

The very unlikely event of fractures propagating all the way to overlying aquifers would provide a possible route for fracture fluids to flow. However, suitable pressure and permeability conditions would also be necessary for fluids to flow (Younger 2007). Sufficiently high upward pressures would be required during the fracturing process and then sustained afterwards over the long term once the fracturing process had ceased. It is very difficult to conceive of how this might occur given the UK's shale gas hydrogeological environments. Even if this were the case, the permeability of the fractures would still need to be similar to that of the overlying aquifer for any significant quantity of fluid to flow. In reality, the permeability of the aquifer is likely to be several orders of magnitude greater than the permeability of the fractures. Upward flow of fluids from the zone of shale gas extraction to overlying aquifers via fractures in the intervening strata is highly unlikely.

4.3.4 Site-specific geology of UK shales

4.3.4.1 Thickness of UK shales

In a typical situation, a shale formation may have a gross thickness of several hundred metres within which there may be a net interval of one or more organic-rich zones that may generate shale gas (or

oil). These zones may be drilled into and fractured, leaving overlying thicknesses of impermeable, un-fractured shale undisturbed.

There are approximately nine Lower Carboniferous shale basins of particular interest to shale gas extraction in northern England, including the Bowland, Edale, Widmerpool and Gainsborough troughs, as well as the Liassic (Lower Jurassic) and Kimmeridge Clay (Upper Jurassic) of the Wessex and Weald Basins in southern England.² The Lower Carboniferous Shale in the Bowland basin is approximately 800m thick, although the organic rich potential source rock is probably 250m thick (see Table 2). It is overlain by a formation of siltstones and mudstones (the Manchester Marl) between 180m and 300m thick that acts as an impermeable seal. Above the Manchester Marl lie sandstone formations. Although they contain water, these formations are located beneath another impermeable formation (the Mercia Mudstone) that is between 100m and 500m thick.

4.3.4.2 Depth of UK shales

Shale gas is likely to be extracted at depths of many hundreds of metres or even several kilometres to ensure reservoir pressures sufficiently high to allow gas to flow to the surface. Fracturing of the Bowland Shale (Cuadrilla's target for shale gas extraction

² Contribution from Professor Al Fraser, Chair in Petroleum Geosciences, Imperial College London

in Lancashire) took place at depths of 1700m and 3100m. Extracting shale gas from much shallower shales is unlikely since reservoir pressures would be too low for gas to flow at commercial rates. Shales containing gas are exposed at the surface in places. Some 200 natural oil and gas seeps are known across the UK (Selley 1992). There are oil seeps in Liverpool

and Formby, and gas seeps at Stouretton, Wigan and Abbeystead. Apart from Abbeystead, these seeps have been geochemically matched with the Bowland Shale (Harriman and Miles 1995). Gas seeping at locations (other than Abbeystead) is thermogenic rather than biogenic (HMSO 1985).

Table 2 Thickness and depth of UK shales of interest to shale gas extraction (Harvey and Gray 2010)

Formation thicknesses and depth vary widely across basins so all thickness and depth figures are generalised values. In A, 'gross thickness' refers to the entire shale and 'net thickness' refers to that part of the shale of particular interest for shale gas extraction (where known). In B, 'gross thickness' includes impermeable and permeable strata. 'Net thickness' refers to impermeable strata.

A Shales of interest in the UK			B Strata overlying these shales		
	Depths at which these shales are located	Shale thickness		Depths at which these strata are located	Thickness of these strata
JURASSIC					
Upper Jurassic, Kimmeridge Clay of the Weald basin	400 - 75m	600m gross 150m net	Weald Clay	Surface - 1000m	900m gross 600m net
Lower Jurassic Lias of the Wessex basin	Surface - 2000m	150m gross	Oxford Clay and Kimmeridge Clay (where preserved)	Surface - 2000m	660m gross 600m net
CARBONIFEROUS					
Bowland trough	1700 - 3100m	800 gross 250m net	Bowland Shale and Manchester Marl (MM)	3500m - surface (MM only)	700m (MM only)
Edale trough	Surface - 5000m	2000m gross	Edale (Bowland equivalent) and Namurian shales	5000m - surface	>2000m gross 1500m net
Widmerpool trough	1000 - 4000m	3000 gross	Bowland equivalent and Namurian shales	4000m - 500m	>3000m gross 2500m net
Gainsborough trough	200 - 4500m	2000 gross	Bowland equivalent and Namurian shales	2000m	1000m gross 500m net

4.3.5 Better understanding of UK shales and overlying geology

There is a lack of data on the mechanical and flow properties of shales, such as permeability and gas migration potential. The majority of data has been collected during hydraulic fracturing operations (King 2010). Relatively little research has been undertaken on how hydraulic fracturing could affect the rate at which contaminants migrate vertically from shale formations (Myers 2012). Characterising shale to better understand its behaviour before, during and after hydraulic fracturing remains difficult. When measuring the mechanical properties of shale, experimental measurements need to take into account the elevated pressure and change in temperature at depth. The low permeability of shale means that coupled mechanical and hydraulic experiments tend to take a long time to complete.

Research into the properties of clay-rich rocks as potential sites for radioactive waste disposal

has produced an extensive literature on their geomechanical and transport properties. In Europe, the waste management organisations Andra (France), Nagra (Switzerland) and Ondraf Niras (Belgium) have active research programmes examining the Callovo-Oxfordian Claystone, Opallinus Clay and Boom Clay, respectively, as candidate geologies for the disposal of radioactive waste. These organisations have extensive databases covering permeability, strength and rock deformation properties. These target formations are generally claystones with no silt or sandstone component, and so are not direct analogues of the target formations for shale gas extraction.

The British Geological Survey is developing a hydrogeological model to gain a better understanding of the depth of potential shale gas reservoirs and location of any overlying aquifers. BGS is also investigating the properties of the intervening rock that will control the movement of water, such as permeability, porosity and fracture density.

Induced seismicity

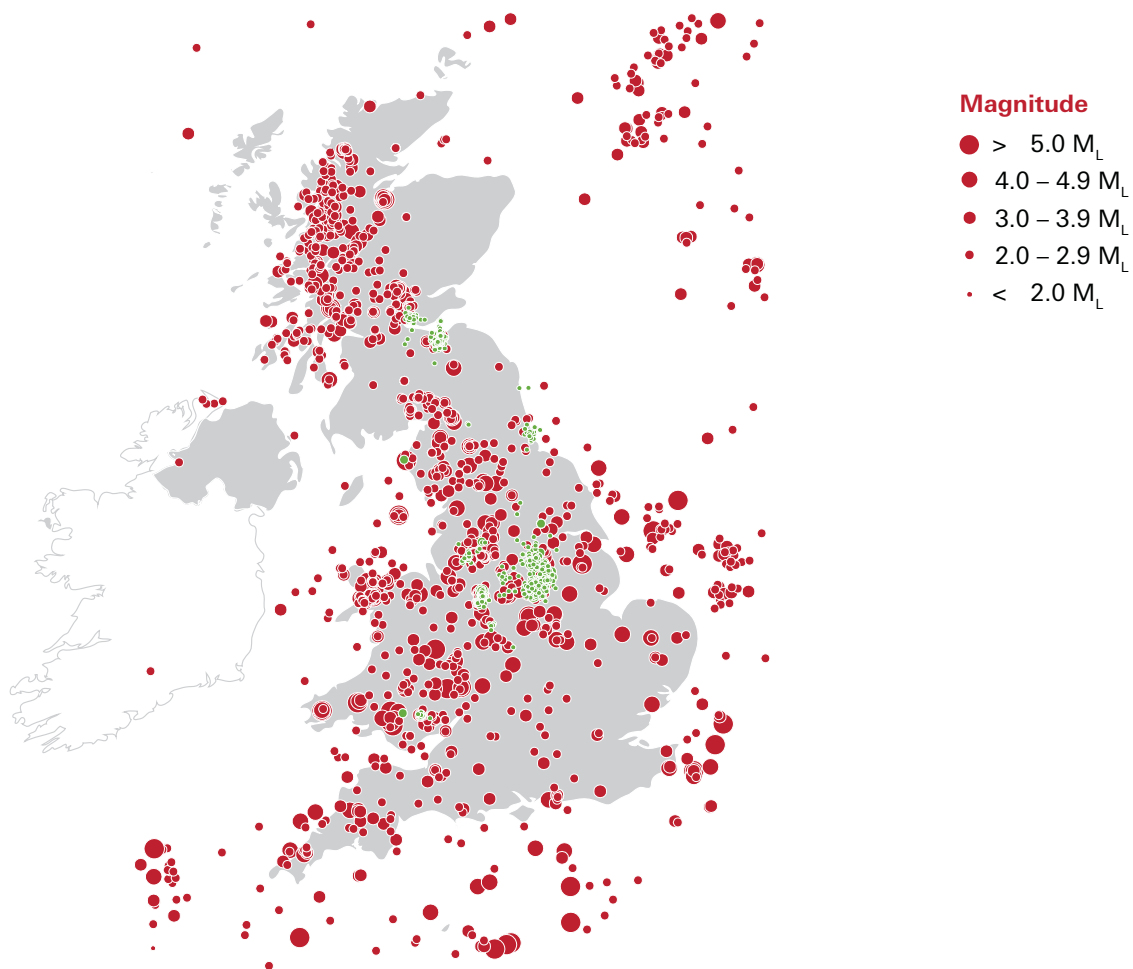
5.1 Natural seismicity

UK seismicity is low by world standards. Historical records suggest that the largest seismic events in the UK are likely to be less than magnitude 5 M_L , causing limited damage at the surface (see Table 1). On average, the UK experiences seismicity of magnitude 5 M_L every twenty years, and of magnitude 4 M_L every three to four years (Green 2012). Most seismic events in the UK occur at depths of over 10km, limiting the extent to which they are felt at the surface. No onshore seismicity in the UK is known to have produced a surface rupture.

5.2 Seismicity induced by coal mining

A subset of seismic events in the UK is related to coal mining activities or the settlement of abandoned mine workings. Seismicity induced by coal mining is generally smaller than naturally occurring seismicity, perhaps no greater than magnitude 4 M_L (see Figure 10).

Figure 10 Natural seismicity (red) and coal mining-induced seismicity (green) in the UK from 1382 to 2012 (Source: British Geological Survey)



5.3 Seismicity induced by hydraulic fracturing

There are two types of seismicity associated with hydraulic fracturing. Microseismic events are a routine feature of hydraulic fracturing and are due to the propagation of engineered fractures (see Chapter 4). Larger seismic events are generally rare but can be induced by hydraulic fracturing in the presence of a pre-stressed fault.

The energy released during hydraulic fracturing is less than the energy released by the collapse of open voids in rock formations, as occurs during coal mining. The intensity of seismicity induced by hydraulic fracturing is likely to be smaller due to the greater depth at which shale gas is extracted compared to the shallower depth of coal mining. Magnitude 3 M_L may be a realistic upper limit for seismicity induced by hydraulic fracturing (Green *et al* 2012). If a seismic event of magnitude 3 M_L occurs at depths of 2-3km, structural damage at the surface is unlikely.

On 1st April 2011, the Blackpool area experienced a seismic event of magnitude 2.3 M_L shortly after Cuadrilla's Preese Hall well in the Bowland Shale was hydraulically fractured. Another seismic event of magnitude 1.5 M_L occurred on 27th May 2011 following renewed hydraulic fracturing of the same well. These events were detected by the British Geological Survey's national seismic network (see Textbox 3). The Blackpool region is an area of low natural seismicity even by UK standards. In 1970, a seismic event of magnitude 2.5 M_L occurred 5 km southwest of Blackpool. The 3.7 M_L Ulverston seismic event on 28th April 2009 was also felt in the region. Historically, the largest seismic event in the region was of magnitude 4.4 M_L near Lancaster in 1835 with a maximum intensity of 6 EMS.

Cuadrilla suspended its hydraulic fracturing operations at the Preese Hall well and commissioned a set of reports to investigate the cause of the seismic events (de Pater and Baisch 2011). DECC also commissioned an independent report into the events (Green *et al* 2012). Both reports attribute the two seismic events to Cuadrilla's fracturing operations. The most likely cause of the events was the transmission of injected fluid to a nearby (but previously unidentified) pre-stressed fault, reducing the effective stress to the point where the fault slipped and released its stored energy (de Pater and Baisch 2011; Green *et al* 2012). The energy released was several orders of magnitude greater than the microseismic energy associated with routine hydraulic fracturing.

Analysis of the seismic data suggests that the two events were due to the reactivation of a pre-stressed fault. In the absence of further data it is difficult to determine whether the fault was directly intersected by the well, or whether hydraulic fracturing led to pressure changes that induced a distant fault to slip. Subsequent geomechanical tests suggest that bedding planes in the Bowland Shale are weak enough to have slipped and provided a conduit for fluid to flow out of the well and into the fault zone (de Pater and Baisch 2011).

5.4 Factors affecting seismicity induced by hydraulic fracturing

5.4.1 Fault and shale properties

The properties of shale provide natural constraints on the magnitude of seismicity induced by hydraulic fracturing. Different materials require different amounts of energy to break. Shale is relatively weak. Stronger rocks will generally allow more energy to build up before they break, generating seismic events of larger magnitude.

The magnitude of induced seismicity is also determined by the properties of the fault, namely:

- The surface area. The larger the fault, the greater the seismicity.
- The degree to which the fault is pre-stressed. The more pre-stressed the fault, the greater the seismicity.

5.4.2 Pressure constraints

The magnitude of seismicity induced by hydraulic fracturing is affected by pressure changes in the shale formation near to the well. The hydraulic fracturing process fundamentally constrains these pressure changes (Zoback 2012):

- Pressurisation takes place across a limited volume of rock, typically only a few hundred metres in any direction.
- Pressurisation only takes place over a limited timescale, typically only a few hours.
- Pressure dissipates into the surrounding geology as more fractures are created, limiting the pressure that can build up.

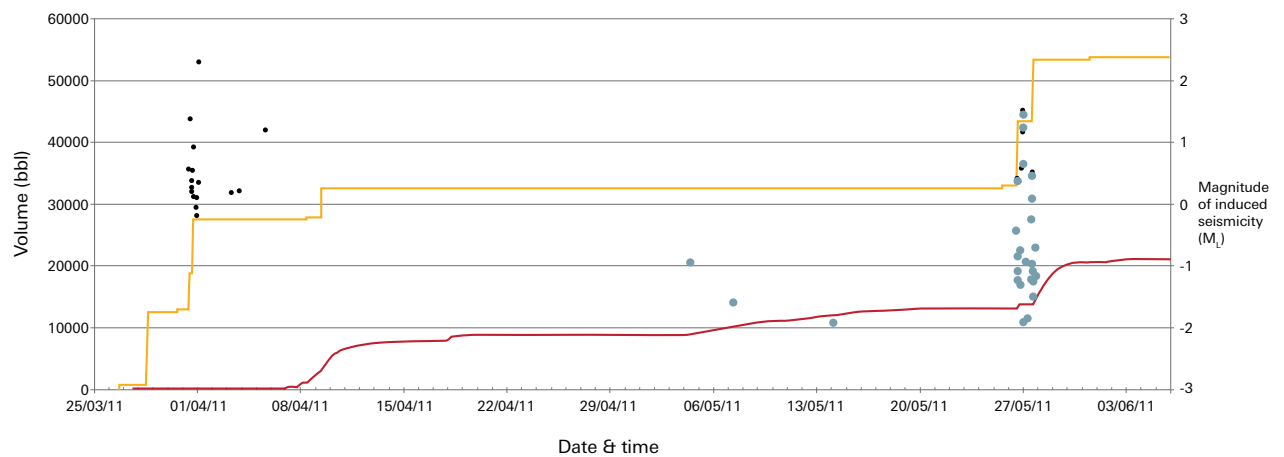
The pressure in the well is also a key determinant of induced seismicity, and is affected by:

- **The volume of injected fluid.** Larger volumes generate higher pressures.
- **The volume of flowback fluid.** Larger flowback volumes reduce the pressure.
- **The injection rate.** More rapid injection generates higher pressures.
- **The flowback rate.** More rapid flowback reduces the pressure.

Although six fracturing stages were planned at Preese Hall, Cuadrilla only completed five before ceasing its operations. Seismicity was only induced following hydraulic fracturing stages where larger volumes of fluid were injected and/or where there was little or no flowback of fluids (de Pater and Baisch 2011). Stages 2 and 4 were associated with the 2.3 M_L and 1.5 M_L seismic events, respectively. They involved relatively large volumes of injected fluid and little (if any) flowback. Stage 3 involved a smaller volume of injected fluid and an increased flowback rate. Stage 5 involved high volumes of injected fluid but involved flowback rates that limited the seismicity induced (see Figure 11). Controlling the pressure in the well is an important measure to mitigate induced seismicity. Feeding seismic monitoring data back to operations allows the injection volume and rate to be reduced and the flowback volume and rate increased.

Figure 11 The relationship between injection volume (yellow line), flowback volume (red line) and magnitude of induced seismicity (circles) (de Pater and Baisch 2011).

The figure shows all five fracturing stages at Preese Hall. More small events were recorded in May because the monitoring system was improved with local stations.



5.5 Mitigating induced seismicity

5.5.1 Geological surveys to characterise stresses and identify faults

Faults are ubiquitous in the Earth's crust. In many areas of the UK, only the largest faults have been mapped, and then only at the surface. Predicting the presence of subsurface faults requires detailed surface mapping, development of validated geological models, and if available, the data from seismic reflection surveys (Hennings *et al* 2012). There are insufficient data on faults in the Bowland Shale to support a definitive conclusion about whether seismic events similar to those at Preese Hall might occur in the future (Green *et al* 2012). Extensive areas of the Bowland Shale have not been mapped by seismic reflection surveys. The seismic reflection survey line nearest to Preese Hall is a few kilometres away. For those faults already mapped by seismic reflection surveys, more data are needed on their mechanical properties and permeabilities. Data are also needed in other prospective areas where no seismic reflection data currently exist.

The BGS or other appropriate bodies should carry out national surveys to characterise stresses and identify faults in UK shales. Operators should also carry out site-specific surveys prior to hydraulic fracturing to characterise local stresses and identify nearby

faults. Site characterisations could include desk-based studies of existing geological maps, seismic reflection data, background seismicity data from the BGS. Stress data are relatively complicated to collect and many techniques require a borehole to be drilled. Operators are likely to collect stress data as a matter of course. Stresses are a strong determinant of well design and fracturing strategy.

Operators should not overlook the potential presence of faults that cannot be detected given the limits of seismic reflection survey. These small faults will have caused geological strata to slip less than 10m relative to one another. There is no reliable way of detecting them but it may be possible to statistically predict the presence of such faults (Rotevatn and Fossen 2011). These faults tend to have relatively small surface areas so are less likely to lead to seismic events that can be felt at the surface.

Once faults have been identified and geological stresses characterised, operators can draw on well-understood tools used in the oil and gas and mining industries to assess the orientation and slip tendency of faults and bedding planes (Hennings *et al* 2012, Lisle and Srivastava 2004, Morris *et al* 1996, Rutqvist *et al* 2007). Hydraulic fracturing near a fault with a high slip tendency should be avoided.

5.5.2 Pre-fracturing injection test

It is difficult to predict exactly what will happen in a particular shale formation once hydraulic fracturing commences. The fracture behaviour of a particular formation is commonly characterised using small pre-fracturing injection tests with microseismic monitoring. Subsequent operations can then be modified accordingly (API 2009). A reasonable period of time should be allowed to elapse following a pre-fracturing injection test to ensure no seismic activity occurs as the injected fluid diffuses away from the well and pressure changes in surrounding rock formations are redistributed (Green *et al* 2012).

5.5.3 Traffic light monitoring systems

Enhanced Geothermal Systems (EGS) use methods, such as hydraulic fracturing, to enhance the recovery of heat by increasing the permeability of rock that is hot but has low permeability (Majer *et al* 2007). The injection or subsequent circulation of fluids can change stress patterns in the rock, inducing seismicity. EGS in Basel, Switzerland has been associated with induced seismicity as large as magnitude 3.5 M_L (Bachmann *et al* 2011).

Traffic light monitoring systems are implemented as best practice in EGS. Data are fed back to operations so that action can be taken to mitigate induced seismicity (Majer *et al* 2007):

- **Green.** Injection proceeds as planned.
- **Amber.** Injection proceeds with caution, possibly at reduced rates. Monitoring is intensified.
- **Red.** Injection is suspended immediately.

Traffic light monitoring systems should be implemented in the UK for shale gas extraction. The Cuadrilla-commissioned report into the seismic events at Preese Hall suggested the following thresholds (de Pater and Baisch 2011):

- **Magnitude smaller than 0 M_L .**
Regular operations.
- **Magnitude between 0 and 1.7 M_L .**
Continue monitoring after injection for at least two days until the seismicity rate falls below one event per day.
- **Magnitude greater than 1.7 M_L .**
Stop injection and employ flowback, while continuing monitoring.

Had the above thresholds been in place for Cuadrilla's operations, no mitigating action would have been taken preceding the 2.3 M_L event on 1st April 2011 (Green *et al* 2012). The report commissioned by the Department of Energy and Climate Change (DECC) into the seismic events at Preese Hall proposed a more precautionary set of lower magnitude thresholds (Green *et al* 2012).

The thresholds of traffic light monitoring systems need not be magnitude-based (NRC 2012). Traffic light monitoring system thresholds used in EGS are based on ground motions, focusing on peak ground acceleration and velocity in conjunction with frequency (Majer *et al* 2007). Other industries that give rise to ground motion, such as construction, quarrying and mining, are regulated by maximum vibration levels rather than maximum magnitude levels. A small event close to a structure can be just as disruptive in terms of vibration as a large event further away (Majer *et al* 2008). Ground motion systems have been developed by the Dutch oil and gas industry, government and research communities to mitigate induced seismicity (van Eck *et al* 2006).

Traffic light monitoring systems are limited by the need for, and expense of, real-time seismic monitoring. These systems also rely on the extrapolation of statistical relationships observed in natural seismicity that may not necessarily apply to induced seismicity. More research is needed to better understand the precise relationship between well pressure and seismicity induced in shales. Traffic light monitoring systems are also affected by natural delays within geological systems, such as the slow movement of fluids through faults (Bachmann *et al* 2010). The two seismic events at Preese Hall both occurred ten hours after the injection of fluid. One solution may be to continue monitoring of the site after operations have ceased (DoE 2012). Another approach would be to use more advanced statistical models to forecast future seismicity rates based on historic rates (Bachmann *et al* 2010). Further research is required but these models could be used in conjunction with traffic light monitoring systems.³

5.6 Damage to well integrity

Discussions about the magnitude of seismicity induced by hydraulic fracturing often focus on the limited (if any) damage at the surface. Attention should also be given to any damage to well integrity. Tests carried out after Cuadrilla's second fracturing stage and 2.3 M_L seismic event revealed deformation of the Preese Hall well casing. The extent of the well casing deformation at Preese Hall was greater than 0.5 inches over a depth range between 8480 and 8640 feet (de Pater and Basich 2011). Because of its location deep in the well and within the already heavily perforated section of casing, this deformation was considered to pose no more risk to the integrity of higher sections of the well than the perforations themselves (Green *et al* 2012).

DECC should consider the conditions under which repeat pressure tests and/or cement bond logs (CBLs) would be required to provide evidence about whether well integrity had been compromised following unexpected levels of induced seismicity. A repeat pressure test and/or CBL should be reviewed by an independent well examiner and the results submitted to DECC.

5.7 Seismicity induced by disposal

Waste fluids produced during shale gas extraction may be disposed of through injection into disposal wells (see section 2.4). Pressure in disposal wells can build up over time, inducing seismicity. Between 20th November and 1st December 2008, 11 small seismic events were detected near Dallas-Fort Worth Airport, Texas. They were attributed to the same focus point at an estimated depth of 4.4 km and less than 0.5 km from a well drilled a few months previously at a depth of 4.2 km to dispose of waste fluids from shale gas operations (Frohlich *et al* 2011).

3 Contribution from Mark Naylor, University of Edinburgh (private correspondence)

The magnitude of seismicity induced by disposal tends to be greater than that induced by hydraulic fracturing (Zoback 2012). Disposal involves a longer length of time over which larger volumes of fluid can allow greater pressures to build up. The magnitude of seismicity induced by disposal does not typically exceed magnitude 5 M_L (Majer *et al* 2007, Nicholson and Wesson 1990, Suckale 2010). Induced seismicity could be mitigated using similar practices as those outlined above (Zoback 2012):

- **Avoid injection into active faults and faults in brittle rock.** Seismic imaging methods can identify faults and characterise local stresses (see section 5.5.1).
- **Minimise pressure changes at depth.** The volumes of fluid to be disposed could be reduced, and/or more wells constructed into which smaller volumes of fluid could be injected. Highly permeable rock formations could be used that can accommodate large volumes of fluid without experiencing significant pressure changes. Highly permeable rock formations could be used that deform plastically and so do not store large amounts of energy.
- **Establish modification protocols in advance.** Traffic light monitoring systems can be deployed to respond to seismicity (see section 5.5.3).
- **Be prepared to alter plans.** Injection rates may need to be reduced or wells may even need to be abandoned should the seismicity induced be too great.

A recent study by the US National Research Council outlines protocols for mitigating seismicity induced by disposal, as well as a range of energy technologies. These protocols require operators to check their plans against a comprehensive list of criteria (including historical seismicity, local geology, regional stress, and the nature of the proposed injection) to determine whether injection could induce seismicity (NRC 2012).

5.8 Regulating induced seismicity

DECC should consider how induced seismicity is to be regulated. Since 2003, Dutch mining legislation has required onshore operators to carry out seismic

risk assessments for each new exploitation licence before operations can begin. These assessments set out both the expected maximum magnitude of potential seismic events and the anticipated mitigation measures. A monitoring plan has to be submitted and approved by the authorities. If seismic events occur with magnitudes or impacts exceeding what is described or approved by the plans, the authorities can intervene (Eck *et al* 2006).

Operators should carry out a seismic risk assessment (see Textbox 4) as part of their Environmental Risk Assessments (see section 6.3). Measures to mitigate induced seismicity would therefore be scrutinised when the ERA is submitted to the regulators and enforced through monitoring activities and inspections (see section 6.3). In the UK, the protection of groundwater and the underground injection of fluids is regulated under the Water Framework Directive and Environmental Permitting Regulations (see section 4.3.1). DECC should consult with the UK's environmental regulators and Mineral Planning Authorities to consider the adequacy of these regulations to address induced seismicity, and how requirements for measures to mitigate induced seismicity could feature in the conditions of environmental permits or local planning permission (see section 7.2.1.2).

The US National Research Council (NRC) calls for operators to publicly disclose and discuss with local communities how measures to mitigate induced seismicity are to be implemented (NRC 2012). In the UK, this would be addressed by ensuring that the ERA involves the participation of local communities at the earliest possible opportunity (see section 6.2). The thresholds of traffic light systems should be updated in the light of operational experience. Thresholds may need to be site specific, depending on local geology, local population density, past seismicity and the scale of operations in the area. A traffic light monitoring system for a particular well may be limited by other operations nearby should fluid leak from multiple wells into the same fault. Operators should share data with DECC and BGS to establish a national database of shale stress and fault properties so that suitable well locations can be identified. Stress data could also be shared with the World Stress Map Project that compiles global stress data.

Textbox 4 Elements of a risk assessment for seismicity induced by Enhanced Geothermal Systems (DoE 2012)

1. **Carry out a preliminary screening evaluation.** Screen out sites with low measures of acceptability through consultation with local communities and reviews of relevant regulations. Impacts and the area to be affected should be identified.
2. **Implement an outreach and communications programme.** Transparency and participation of local communities should be maintained
3. **Identify criteria for ground vibration and noise risk assessment.** Operators should review ground-borne noise and vibration impact assessments and monitoring systems used in relevant industries, such as construction, quarrying, and mining. Building damage criteria, structural damage criteria and human exposure to vibration should be reviewed to determine ground motion and vibration limits. A baseline of ground vibration and noise should also be established.
4. **Establish local seismic monitoring to provide site specific baseline data.** Background seismicity should be characterised in advance of operations (perhaps even one to two years beforehand) to increase understanding of mechanisms of stress build up and release and to identify faults.
5. **Assess the ground shaking hazards at the site.** Use data from step 4 to carry out a quantitative assessment using probabilistic seismic hazard analysis.
6. **Carry out induced seismicity risk assessment.** Update step 1 in the light of data collected in steps 2-5. A probabilistic risk analysis could be carried out. The vulnerability of risk receptors should also be considered, such as the robustness of the structures in the area to be impacted.
7. **Develop a mitigation plan.** A traffic light monitoring system could be implemented based on a plot of ground motion as a function of injection rates and time. If any damage is caused by induced seismicity, then compensation may be required. Operators should review legislation relevant to other sectors to consider whether they are liable and if insurance is required due to any damage or nuisance.

RECOMMENDATION

To mitigate induced seismicity:

- **BGS or other appropriate bodies should carry out national surveys to characterise stresses and identify faults in UK shales. Operators should carry out site-specific surveys to characterise and identify local stresses and faults.**
- **Seismicity should be monitored before, during and after hydraulic fracturing.**
- **Traffic light monitoring systems should be implemented and data fed back to well injection operations so that action can be taken to mitigate any induced seismicity.**
- **DECC should consider how induced seismicity is to be regulated. Operators should share data with DECC and BGS to establish a national database of shale stress and fault properties so that suitable well locations can be identified.**

Risk management

6.1 The UK's goal based approach to regulation

The UK's approach to managing health and safety risks is goal based. Regulators set out goals but operators are responsible for considering the means to achieve them according to the following framework (HoL 2006):

- A lower bound below which risks are considered acceptable and no further significant action is required.
- An upper bound above which risks are deemed unacceptable, requiring that the activity giving rise to the risk should be discontinued or action taken to reduce the risk.
- An intermediate range where risks are regarded as acceptable provided they are reduced to As Low As Reasonably Practicable (ALARP).

The Offshore Installations and Wells (Design and Construction, etc) Regulations 1996 state that wells should be designed and constructed so that 'as far as is reasonably practicable, there can be no unplanned escape of fluids from the well; and risks to the health and safety of persons from it or anything in it, or in strata to which it is connected, are as low as is reasonably practicable'. The well should also be designed and constructed so that as 'far as is reasonably practicable, it can be suspended or abandoned in a safe manner; and after its suspension or abandonment there can be no unplanned escape of fluids from it or from the reservoir to which it led'.

A recent review of the Macondo (Deepwater Horizon) incident recommended that the Department of Energy and Climate Change and the UK's offshore oil and gas industry should develop a more goal-based approach to environmental regulation (Maitland *et al* 2011). Oil & Gas UK (which represents the offshore industry) is developing the concept of an Environmental Assurance Plan that could identify baseline performance standards and targets, leaving operators responsible for the means to achieve them (Maitland *et al* 2011). The UK already adopts

a goal based approach for offshore activities under the Convention for the Protection of the Marine Environment of the North East Atlantic (OSPAR). OSPAR recommends setting environmental goals to be met by operators through internationally recognised and independently audited Environmental Management Systems (OSPAR 2003).

A goal based approach to offshore and onshore regulation is to be commended. Operators are forced to identify and assess risks in a way that fosters innovation and continuous improvements in risk management. Some argue that this approach is limited to the extent that 'reasonably practicable' is only defined in the UK by case law. An alternative to a goal based approach would be a more prescriptive one adopted in other countries, such as the USA, setting out specific universal standards to be met. This approach has its limitations. It tends to support routine practices and limit innovation in risk management. A prescriptive approach may also be less proportionate and flexible than a goal-based approach to local, site specific risks, as well as changing circumstances, such as the introduction of new technologies or best practices. Another option is to develop sector specific guidelines (HoL 2006). Given common sources of health, safety and environmental risk, the UK's health and safety regulators and environmental regulators should work together to develop guidelines that help shale gas operators carry out risk assessments based on the ALARP principle. These guidelines could help familiarise foreign operators with the UK's goal based approach to risk management.⁴ Operators should put in place internal processes to explain how risks can be managed according to the ALARP principle so that contracted service companies carry out consistent risk assessments. Operators should also ensure mechanisms are put in place to audit their risk management processes (see Textbox 5). Risk assessments should be submitted to the regulators for scrutiny and then enforced through monitoring activities and inspections.

4 Contribution from Professor Ragnar Lofstedt, Director, Centre for Risk Management, Kings College London

Textbox 5 An example of industry best practice for risk management

The International Safety Rating System (ISRS) marketed by Det Norske Veritas (DnV) was developed in partnership with the nuclear, chemical, petrochemical and other industries (ISRS 2012). ISRS provides tools to audit risk management processes in a variety of organisations across sectors. Having initially focused on occupational health and safety, ISRS now also addresses environmental risks. In 2009, ISRS' scope was expanded to address major accidents, such as fire, explosion or release of flammable or toxic materials. Auditors trained to score the ISRS system have enabled benchmarking of risk management processes between companies and between groups within the same company:

- The Risk Evaluation audit section reviews how health, safety and environmental risks are identified and assessed.
- The Risk Control audit section reviews the measures put in place to manage these risks.
- The Emergency Preparedness audit section reviews the comprehensiveness and categorisation of emergency scenarios, testing the quality of on- and offsite emergency plans.
- The Learning from Events audit section reviews the reporting and investigation of events, allocation of corrective actions and follow up.
- The Risk Monitoring audit section reviews the robustness of monitoring systems to ensure the management system in place remains fit for purpose.

6.2 Collecting data to improve risk assessments

It is mandatory for operators to submit reports about accidents and incidents to the UK's regulators (see Textbox 6). Reports should also be shared between operators. Reliable data on failures of well integrity, as well as failures or shortcomings in procedures carried out during well construction, operation and abandonment, are not readily available. These data should not be proprietary to any one company. Commercial confidentiality or the prospect of adverse publicity should not become barriers to sharing data and learning from incident experience (Maitland *et al* 2011). Mechanisms should be established so that workers can confidentially report accidents and incidents, especially well and operational failures before, during and after operations. Once collected, the information should be shared anonymously to improve risk assessments and promote best practices across the industry. Precedents for such mechanisms exist in other sectors (see Textbox 7).

Historically, major accidents in other sectors have led to subsequent operational and regulatory improvements. Any UK shale gas industry must not wait for an incident or accident but should seek to identify and share best practice from the outset. The importance of an open sharing and learning culture is clear from investigations into past oil and gas incidents, such as the Macondo (Deepwater Horizon) accident in the Gulf of Mexico (Maitland *et al* 2011). Systems should be in place so that when incidents happen with the potential to become major accidents, they are promptly investigated by operating companies. Regulators should scrutinise the effectiveness with which companies monitor, investigate and learn from events and share information within and across companies (Maitland *et al* 2011).

Textbox 6 Accident and incident reports submitted to the UK's regulators

The Reporting of Injuries Diseases and Dangerous Occurrences Regulations 1995 (RIDDOR) requires employers to report workplace incidents and accidents (unintentional events leading to health and safety concerns), including near misses, to local authorities and the health and safety regulators. Regulation 3 of RIDDOR has a specific set of Dangerous Occurrences for wells (Schedule 2, Part I) that the well operator must report, including: blowouts; unplanned uses of blowout prevention equipment; unexpected detection of hydrogen sulphide; failure to maintain minimum separation distance between wells; and mechanical failure of safety critical elements of a well. The UK's health and safety regulators publish annual statistics so that the industry and others can consider trends in the information reported under RIDDOR. Operators can voluntarily provide information about offshore hydrocarbon release incidents to the hydrocarbon releases (HCR) system to supplement the information

reported under RIDDOR. Jointly funded by the UK's health and safety regulators and the UK Offshore Operators Association, the HCR system allows users to submit incident reports online. Outputs based on data in the HCR database are generic and non-attributable.

The Environment Agency collects information on reported incidents, including incidents self reported by operators, using a National Incident Reporting System (NIRS). A record starts when the Incident Communication Service or Regional Communications Centre Wales receives a report of a potential incident. The report is then passed to the appropriate competent officer in the locality to assess the incident response based on a Common Incident Classification Scheme. The assessment, along with details of the incident response and post incident activities, such as legal action and cost recovery, is recorded on NIRS.

Textbox 7 Confidential reporting of accidents from the aviation and maritime sectors

The aviation Confidential Human Factors Incident Reporting Programme (CHIRP) has been running since 1982 (CHIRP 2012). In 1996, it was restructured into a charitable company limited by guarantee to ensure its independence so that management and fiscal responsibilities are held by an independent Board of Trustees. CHIRP complements other formal reporting systems operated by other UK organisations, such as the Civil Aviation Authority Mandatory Occurrence Reporting, by providing a means through which individuals can report concerns without being identified to their peer group, management or the regulators at all levels of seniority across the aviation sector.

Reporters are identified so that reports can be validated and action taken. Reporters' identities are not revealed outside CHIRP without their consent, allowing key information to be circulated anonymously. The Mariners' Alerting and Reporting Scheme (MARS) is a confidential reporting system run by the Nautical Institute to allow full reporting of accidents (and near misses) without fear of identification or litigation (Nautical Institute 2012). MARS reports are held in a publicly-accessible database. MARS reports regularly comprise alerts so that actions from recent incidents can be relayed to the mariner on board a vessel.

RECOMMENDATION

Best practice for risk management should be implemented:

- **Operators should carry out goal based risk assessments according to the principle of reducing risks to As Low As Reasonably Practicable (ALARP). The UK's health and safety regulators and environmental regulators should work together to develop guidelines specific to shale gas extraction to help operators do so.**
- **Operators should ensure mechanisms are put in place to audit their risk management processes.**
- **Risk assessments should be submitted to the regulators for scrutiny and then enforced through monitoring activities and inspections.**
- **Mechanisms should be put in place to allow the reporting of well failures, as well as other accidents and incidents, between operators. The information collected should then be shared to improve risk assessments and promote best practices across the industry.**

6.3 Environmental Risk Assessments

Currently, an operator may need to carry out an Environmental Impact Assessment when seeking local planning permission. The Schedules attached to Town and Country Planning (Environmental Impact Assessment) England and Wales Regulations 1999 suggest an Environmental Impact Assessment is required if the area of operations exceeds one hectare. Environmental Risk Assessment (ERA) has become best practice in non-shale gas industries assisted by sector-specific guidelines.⁵ An ERA should be mandatory for all shale gas operations assisted by guidelines specific to shale gas extraction developed by the UK's regulators (see section 6.1). Unlike an Environmental Impact Assessment, an ERA would assess not just the impacts of hazards but also their likelihood. This would help to prioritise risks and support more proportional risk management. The ERA should assess risks across the entire lifecycle of shale gas extraction, including disposal, the abandonment process and the monitoring of abandoned wells. Seismic risks should also feature as part of the ERA (see section 5.8).

ALARP does not formally apply to ERAs. A principle of reducing risks to As Low As Reasonably Achievable (ALARA) is formally applied to the

radioactive waste management under the Radioactive Substances Act 1993. ERAs draw on a 'source-pathway-receptor' model that has proved to be flexible across a range of environmental risks (Gormley *et al* 2011). This model forces operators to consider carefully the relationships between the source of an environmental hazard; the pathways through which it can impact the environment; and those objects within the environment that could be harmed ('receptors'). Guidelines developed by the UK's regulators should help shale gas operators carry out ERAs according to the ALARP principle (see section 6.1).

Late involvement of public consultation in environmental decision-making process has often led to public frustration and demands for earlier engagement. Participatory risk assessments are best practice (Stern and Fineberg 1996). An ERA for shale gas operations should allow stakeholders to participate in the framing of environmental problems; identifying and assessing risks; and evaluating different means of managing them (Gormley *et al* 2011). This would complement the new National Planning Policy Framework that encourages early engagement between operators and local communities even pre-application (DCLG 2012).

⁵ Contribution from Professor Simon Pollard, Head of Department, Environmental Science and Technology, Cranfield University

RECOMMENDATION

To manage environmental risks:

- **An Environmental Risk Assessment (ERA) should be mandatory for all shale gas operations, involving the participation of local communities at the earliest possible opportunity.**
- **The ERA should assess risks across the entire lifecycle of shale gas extraction, including the disposal of wastes and well abandonment. Seismic risks should also feature as part of the ERA.**

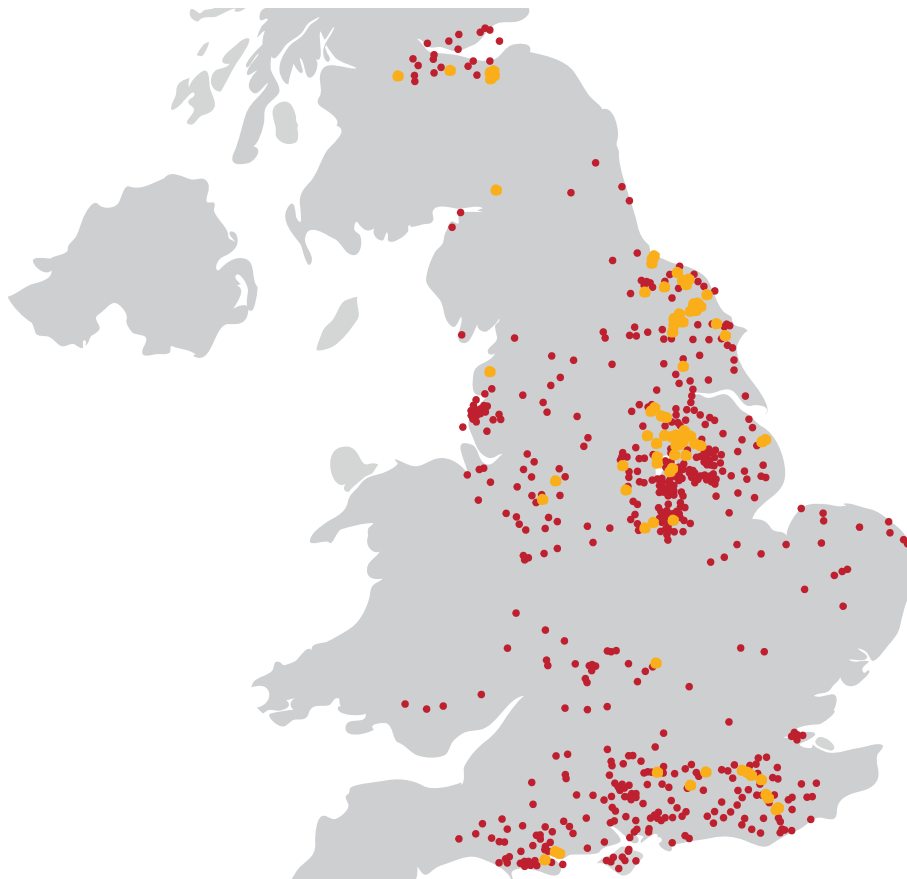
Regulating shale gas

The regulation of shale gas extraction in the UK draws on the experience of onshore and offshore oil and gas industries over the last 60 years. Currently, there are 28 UK onshore oil fields and 10 onshore gas fields in production, producing 19,000 barrels per day of oil and 250,000m³/d of gas or approximately 1500 barrels per day oil equivalent (see Figure 12). Risks posed by exploratory activities are managed at various stages of the UK's regulatory system:

- Conditions of Petroleum Exploration and Development Licences;
- Conditions of local planning permission;
- Notification of well construction and the well examination scheme;
- Conditions of environmental permits.

Figure 12 Existing onshore conventional oil and gas wells in the UK (Harvey and Gray 2010)

The red circles represent conventional wells that have been drilled. The yellow circles represent conventional wells that have been drilled and from which gas has flowed.



7.1 Conditions of Petroleum Exploration and Development Licences

In some countries, such as the USA, landowners own the hydrocarbons under their land and thereby hold the rights to exploit them. In the UK, ownership is conferred on the state. In England, Scotland and Wales, licences to exploit hydrocarbons are issued by the Department of Energy and Climate Change (DECC) through Petroleum Exploration and Development Licences (PEDL) rounds. In Northern Ireland, onshore licenses are granted by the Energy

Division of the Department of Enterprise, Trade and Investment. Shale gas extraction was not considered when regulations for conventional gas extraction were formulated in the 1990s. There is no specific mention of shale gas in UK legislation. Licences specific to hydraulic fracturing or directional drilling are not awarded *per se*. Rather, PEDL licenses are issued along with consents for particular activities and controls can be imposed accordingly (for example, see section 2.6).

7.2 Conditions of local planning permission

PEDL licences grant exclusivity to operators in the licence area. They do not give immediate consent for drilling an exploration well or any other operation. An operator must negotiate access with landowners; seek permission from the Coal Authority if operations will penetrate coal seams; and be granted local planning permission from the Minerals Planning Authority (MPA). In England, Wales and Scotland, the MPA involves local authorities, including representatives from districts and county councils. In Northern Ireland, the Planning and Local Government Group (within the Department of Environment) is responsible for shale gas planning.

Proposals will be screened by MPAs to identify whether an Environmental Impact Assessment is required (see section 6.3). Even if an Environmental Impact Assessment is not required, environmental and health impacts can be addressed through the conditions of planning permission. MPAs are responsible for ensuring operators comply with these conditions.

Local planning conditions can also address aesthetic impacts, as well as contributions to local noise, traffic and air pollution. The UK has the experience of best practice to draw on. Wytch Farm oil field is located in one of the world's most famous regions of outstanding natural beauty and of special scientific interest. This includes the Jurassic Coast and World Heritage sites; designated wetlands of international importance; and national nature reserves. Post-operations site restitution may also be included as a condition of the planning permission.

The density of local population areas may also be considered in the local planning permission process, although many operations are likely to be located on farmland where population density is low. Drilling multiple wells can be useful where there is limited surface area for operation. Up to 20 wells or more can be drilled from a single pad, reducing the size of the surface footprint and requiring less surface equipment.

7.2.1 Informing local planning processes with scientific advice

7.2.1.1 Health effects on local populations

The UK's environmental regulators are statutory consultees to the local planning process, and so can advise on the environmental conditions of

local planning permissions. The Environment Agency (EA) serves England and Wales, although a single environmental body for Wales is due to become operational in 2013. The Scottish Environmental Protection Agency (SEPA) serves Scotland, and the Northern Ireland Environment Agency (NIEA) serves Northern Ireland. The EA has a statutory requirement to safeguard public health, so seeks expert advice from health professionals, such as the Health Protection Agency (HPA). The EA has an agreement with the HPA about when and how the HPA is consulted when permitting an activity.

Under current planning arrangements, it is the decision of the local planning authority to decide who to consult. Health professionals should be consulted to advise on local health impacts whether directly or indirectly through the EA. The HPA has established a Working Group of chemical and radiation specialists to collate and review literature, including national and international studies, about the potential health impacts of shale gas extraction. Its terms of reference are yet to be established. The results of this HPA review should inform local planning processes.

7.2.1.2 Induced seismicity

MPAs should consult the British Geological Survey (BGS) to advise on induced seismicity and help to identify suitable locations for wells, drawing on a national and site-specific understanding of geology. BGS has provided MPAs with technical documents to provide guidance on certain issues, such as safeguarding mineral resources (Wrighton *et al* 2011). BGS could provide similar technical assistance to help operators carry out consistent seismic risk assessments and to help MPAs oversee the implementation of traffic light monitoring systems and other mitigation measures.

7.3 Notification of well construction and the well examination scheme

The Borehole Sites and Operations Regulations 1995 require an operator to notify the UK's health and safety regulators at least 21 days in advance of any drilling operations: the Health and Safety Executive (HSE) in England, Wales and Scotland, and Health and Safety Executive for Northern Ireland (HSENI) in Northern Ireland. This provides an opportunity to review the operator's plans for the design, construction and operation of the well, as well as ensuring a suitable well examination scheme is in place (see section 3.2). As the well is being constructed, the health and safety regulators

inspect the weekly operations reports submitted by the operator. During operations, the UK's health and safety regulators receive no information from the operator unless an event is reported according to Reporting of Injuries Diseases and Dangerous Occurrences Regulations 1995 (see Textbox 6). Onsite inspections may be carried out as required. Under the Water Resources Act 1991, the operator is required to notify the Environment Agency about the intention to drill a well along with details of its construction.

7.4 Conditions of environmental permits

Once the MPA has granted planning permission, DECC will check with the relevant health and safety and environmental regulators before giving consent to the drilling of an exploration well. An operator must also seek a set of environmental permits before operations can begin under the Environmental Permitting (England and Wales) Regulations 2010 (for example, see section 4.3.1). The conditions to be placed on operations as part of the granting of a permit are informed by a specific risk profile for each site based on an Operational Risk Assessment (OPRA) methodology developed by the UK's environmental regulators. The OPRA methodology considers the type of facility; type and quantity of wastes involved; type and levels of emissions released; risk receptors in the area; and the environmental management system to be implemented. Once a site is awarded a permit, the environmental regulators continue to use the OPRA methodology and rating system to monitor a site's performance and compliance with permit conditions.

7.5 Regulating production activities on a nationwide scale

An operator can seek permission for a production well, according to a similar process for an exploration well, although a new PEDL licence is not required. The operator would need to submit a Field Development Plan for DECC's consent. DECC would check with the regulators before issuing a Field Development Consent, setting limits on the quantities of gas to be produced, vented or flared. Local planning permission may need to be sought again, possibly placing new conditions on production activities.

Existing UK regulation contains the necessary elements to manage the risks associated with small-scale activities. Attention must be paid to the way in which risks scale up if a shale gas industry develops nationwide (IEA 2012). For example, the probability of an instance of a failed well would increase if

hundreds of wells were to be drilled in the UK. The significant volumes of flowback water generated may exceed the capabilities of onsite, closed-loop storage tank systems, in which case, disposal wells may be necessary (see section 2.4). Other impacts, including transportation, loss of biodiversity (due to habitat loss and fragmentation), visual impacts, effects on air quality, would warrant more attention.

7.5.1 Maintaining co-ordination

A single body should take leadership to ensure co-ordination of the numerous central and devolved bodies with responsibilities for regulating shale gas extraction in the UK. Consideration should be given to:

- **Clarity on roles and responsibilities.** Local planning permissions tend to focus on impacts on the local environment. Environmental permits tend to focus on the processes giving rise to these impacts. Clarity would help to ensure efforts are not duplicated and to avoid the management of any risk falling between responsibilities. For example, more consideration needs to be given to how exactly measures to mitigate induced seismicity are to be regulated (see section 5.8).
- **Mechanisms to support integrated ways of working.** Under the Control of Major Accident Hazards (COMAH) regulations, the 'competent authority' that enforces the regulations is the joint responsibility of the HSE and EA. Operators of onshore installations that fall under COMAH's remit effectively interface with a unified regulatory authority. This mechanism could be useful for the UK's environmental regulators to tap into the specialist expertise of the well examination scheme (see section 3.2). Wider application of this and other mechanisms could help streamline activities, minimise bureaucracy and reduce pressures on limited resources.
- **More formal mechanisms to share information.** Operators provide data to the UK's regulators (see Textbox 6). Different regulators may not have direct access to each other's databases beyond informal relationships. EA and DECC co-convene a joint regulators forum on shale gas to exchange information and share best practice. It has been meeting regularly since early 2011, consisting of officials from government departments (DECC; Department

for Environment, Food and Rural Affairs; Department of Communities and Local Government; Welsh Government; Scottish Executive; Department of the Environment NI; and Department of Enterprise, Trade and Investment NI) and regulatory agencies (EA, SEPA, NIEA, HSE and HSENI). This forum could become more a formal body. Information could also be shared through participation at relevant Advisory Groups of the Planning Officers Society.

- **Joined-up engagement of local communities.** MPAs have to write a Statement of Community Involvement to explain how local communities will be engaged. Co-ordinated approaches would help to ensure that consultation by different bodies at various stages does not confuse the purpose of consultation to local communities.
- **Learning from operational and regulatory best practice internationally.** The USA is a priority partner. Lessons should be learned from the USA and taken into account in the development of UK regulations (see section 1.4). The EU is another priority (European Parliament 2012a). The UK should ensure any changes at the EU level do not dilute the strengths of the UK's approach to regulation or frustrate the activities of the UK's regulators (Maitland *et al* 2011).

RECOMMENDATION

Co-ordination of the numerous bodies with regulatory responsibilities for shale gas extraction should be maintained. A single body should take the lead. Consideration should be given to:

- **Clarity on roles and responsibilities.**
- **Mechanisms to support integrated ways of working.**
- **More formal mechanisms to share information.**
- **Joined-up engagement of local communities.**
- **Mechanisms to learn from operational and regulatory best practice internationally.**

7.5.2 Increasing capacity

The UK's regulators should now begin to determine their requirements to regulate a shale gas industry should it develop in the UK. Skills gaps and relevant training should be identified. Some local authorities have in-house expertise while others need to reach out to external expertise. Training events with other regulators could at the same time help to clarify roles and responsibilities. Extra resources may also be necessary to support BGS' activities that regulators may need to draw on (see sections 3.3.3, 5.5 and 7.2.1.2).

The EA uses the risk rating provided by its OPRA methodology to determine the charge for a site's permit. An operator with a higher risk is charged a higher fee to cover the resources needed to assess the site's proposed risk. The EA then works on a receipt-based funding model. If an operator is successful in gaining permission for exploration or production, the operator is charged to cover the costs of the EA's activities. If unsuccessful, the costs can be recovered through alternative mechanisms, such as public funds. When an operator notifies HSE about an intention to construct and operate a well, HSE assesses the design and verifies the well is operated safely through inspections (see section 7.3). HSE currently carries out these activities without recovering the costs involved. Under proposed legislative changes, HSE is looking to introduce a Fee For Intervention Model so that HSE could recover these costs (HSE 2011). This mechanism provides an incentive for operators to meet their obligations. This mechanism could be applied more widely so that the UK's regulators remain sufficiently resourced.

RECOMMENDATION

The UK's regulators should determine their requirements to regulate a shale gas industry should it develop nationwide in the future. Skills gaps should and relevant training should be identified. Additional resources may be necessary.

Research on shale gas

8.1 Uncertainties affecting small scale exploratory activities

Uncertainties affecting the small scale exploratory activities in the UK can be addressed through effective monitoring systems and research programmes before shale gas extraction commences on any significant scale. Research priorities include:

- technologies to reduce water requirements for hydraulic fracturing (see section 2.2.2);
- improving understanding of UK shales and the composition of wastewaters (see section 2.3);
- technologies to treat wastewaters (see section 2.4);
- methods to determine sources of methane (see section 3.3.1);
- monitoring the long term behaviour of wells, including after abandonment (see section 3.3.4);
- improving understanding of mechanical and flow properties of shale (see section 4.3.5);
- improving the effectiveness of traffic light monitoring systems and statistical models to forecast induced seismicity (see section 5.5.3).

8.2 Uncertainties affecting large scale production activities

More significant uncertainties concern the scale of production activities should a shale gas industry develop nationwide. The potential scale will be dictated by the UK's potential shale gas resources, as well as government policy making. This report has addressed environmental, health and safety risks associated with shale gas extraction. Policymaking would benefit from research into the climate risks associated with the extraction and subsequent use of shale gas. This report has focused on the technical aspects of the risks associated with hydraulic fracturing. Policy making would also benefit from research into the public acceptability of shale gas extraction and use in the context of wider UK policies, including:

- climate change policy, especially the impact of shale gas extraction on the UK meeting its emissions targets (see section 1.8.1);
- energy policy, especially the impact of shale gas development on investment in renewable energy (see section 1.8.1);
- economic policy, including socioeconomic benefits from employment to tax revenue and from shale gas use.

8.2.1 The UK's proven reserves of shale gas

Various estimates of the extent of certain areas in the UK with shale gas resources have been provided (see Textbox 8). It will be some years before shale gas production data and the impact of regulatory and economic conditions allow a rigorous estimate of the UK's proven reserves of shale gas.

Textbox 8 Estimates of shale gas resources in the Bowland Shale

In a 2010 report commissioned by the Department of Energy and Climate Change (DECC), the British Geological Survey (BGS) estimated that the Bowland Shale could potentially yield up to 4.7 trillion cubic feet (tcf) of technically recoverable gas (Harvey and Gray 2010). This is equivalent to roughly 1.5 years of UK gas consumption (HoC 2011). This recoverable gas estimate was an area based assessment, drawing upon comparisons between the Bowland basin and Barnett Shale in Texas, USA, given similarities in age and palaeo-environmental character. Cuadrilla has published a gas-in-place estimate of approximately 200 tcf for its Bowland Shale license area. From the US experience, and based on current technological capability, it is expected that only 10% of this value (20 tcf) is likely to be technically recoverable. Cuadrilla's estimate was a volumetric based assessment. It drew on

measured data from two wells for permeability, gas content and other key parameters (Broderick et al 2011). Other operators, including Island Gas Ltd, Eden Energy, Greenpark Energy and Composite Energy, have estimated the size of shale gas resources within their respective licence areas (Broderick et al 2011). Only the estimate by Cuadrilla has been informed by measured data (in Cuadrilla's case, from two wells). A new DECC-commissioned BGS study will estimate the gas-in-place estimate related to the area where Cuadrilla has exploration rights and for the greater Bowland Shale prospective area by the end of 2012. BGS is using 3D modelling to estimate the UK's total shale gas resource. This is likely to help identify potential sweet spots where there are high concentrations of carbon and where the rock's mineralogy and existing fractures make it most amenable to hydraulic fracturing.

8.2.2 The carbon footprint of shale gas extraction

There are few reliable estimates of the carbon footprint of shale gas extraction and use in the peer reviewed literature. One US study from Cornell University concluded that the carbon footprint of shale gas extraction is significantly larger than from conventional gas extraction owing to potential leakages of methane (Howarth *et al* 2011). The same study recognised the large uncertainty in quantifying these methane leakages, highlighting that further research is needed. Data collected from methane monitoring submitted to the UK's regulators could be used to inform assessments to reduce this uncertainty (see section 2.6).

8.2.3 The public acceptability of shale gas extraction

The Economic and Social Research Council has funded extensive research to better understand the public views of low carbon fuels, such as nuclear power (Whitmarsh *et al* 2011). Government decision making would benefit from similar research into the public acceptability of shale gas extraction within the context of wider government policies. Opportunities should be created to allow expert understanding about risks to be challenged and 'blind spots' to be explored (Whitmarsh *et al* 2011).

Different perspectives on hydraulic fracturing do not neatly divide into views held by experts and those held by 'the public'. 'The public at large', civil society organisations, those who adopt more sceptical perspectives on technological developments, as well as protest groups should all be involved in this research. This will help ensure the government addresses issues of actual, rather than assumed, public concern. This research should also investigate what makes a regulator trustworthy. Concerns tend to focus less on a particular technology *per se* and more on how the technology is governed in real world circumstances. This is problematic in the light of a lack of trust in the government to act in the public interest and ensure adequate regulatory oversight (Chilvers and Macnaghten 2011).

8.3 Funding research on shale gas

The majority of shale gas research is carried out by the industry where most expertise is located. Publicly funded research may be necessary to ensure confidence that decision making is informed by independent, evidence-based research. There is currently no cross-Research Council or Technology Strategy Board (TSB) programme specifically addressing shale gas extraction. Such a programme could provide an integrated and interdisciplinary

assessment of the risks and opportunities associated with shale gas extraction and use in the UK. It could help to focus efforts and ensure that national needs are met while drawing on research efforts elsewhere, especially in the USA and in Europe (see Textbox 9).

A cross-Research Council programme could be based on existing precedents. Involving 15 UK higher education partners and institutes, the UK Carbon Capture and Storage Consortium was set up in 2005 to rapidly expand a UK research capacity for carbon capture and storage, involving engineers, natural and social scientists. Launched in 2008 as a 10-year partnership, the Living With Environmental Change (LWEC) partnership includes research councils, government departments, devolved administrations and government agencies.

LWEC fosters collaboration between projects that can deliver benefits to multiple partners. Member organisations with their own budgets can pay an annual subscription, contribute staff resources to run a small directorate or contribute to common needs.

The Geological Society of London has established a Geosciences Skills Forum (GSF) in partnership with the Petroleum Exploration Society of Great Britain, British Geological Survey and other partners. GSF could broker a dialogue between the Research Councils, TSB, DECC, Department for Communities and Local Government, Department for Environment, Food and Rural Affairs and Environment Agency and the wider geosciences community about research priorities and capacity needs.

Textbox 9 Emerging European research efforts into shale gas extraction

Gas Shales of Europe (GASH) is Europe's first interdisciplinary shale gas research initiative sponsored by a number of industrial companies. Established in 2009, GASH is developing a GIS database of European black shales, including their location, as well as biological, chemical and physical properties. This also includes identifying sweet spots and predicting the formation of shales. GASH has a particular focus on Denmark and Germany. Under the initiative, 12 research projects are being undertaken, drawing on research institutions, national geological surveys, including the British Geological Survey, universities and industry experts. The European Sustainable Operating Practices (E-SOP)

Initiative for Unconventional Resources is managed by the German Research Centre for Geosciences at the Helmholtz Centre Potsdam. E-SOP combines Europe-specific research with relevant US experience to develop best practice for shale gas extraction to address environmental impacts and public concerns. E-SOP will establish a 'field laboratory' to test and demonstrate best practices independently funded by entities not actively involved in oil and gas extraction. The Shale Gas Information Platform (SHIP) does not carry out its own research. SHIP is a public platform for sharing information on shale gas.

RECOMMENDATION

The Research Councils, especially the Natural Environment Research Council, the Engineering and Physical Sciences Research Council and the Economic and Social Research Council, should consider including shale gas extraction in their

research programmes, and possibly a cross-Research Council programme. Priorities should include research into the public acceptability of the extraction and use of shale gas in the context of UK policies on climate change, energy and the wider economy.

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Acronyms

ALARA	As Low As Reasonably Achievable
ALARP	As Low As Reasonably Practicable
ANSI	American National Standards Institute
API	American Petroleum Institute
BGS	British Geological Survey
BOP	Blowout preventer
CBL	Cement Bond Log
CHIRP	Confidential Human Factors Incident Reporting Programme
COMAH	Control of Major Accident Hazards
DCLG	Department for Communities and Local Government
DECC	Department of Energy and Climate Change
DEFRA	The Department for Environment, Food and Rural Affairs
EA	Environment Agency
EIA	Energy Information Administration (US)
EGS	Enhanced Geothermal Systems
EMS	European Macroseismic Scale
EPA	US Environmental Protection Agency
EPR	Environmental Permitting Regulations
ERA	Environmental Risk Assessment
E-SOP	European Sustainable Operating Practices
EU	European Union
ft	feet
GASH	Gas Shales of Europe
GIS	Geographical Information System
GSF	Geosciences Skills Forum
GWPC	Ground Water Protection Council
HPA	Health Protection Agency
HSE	Health and Safety Executive
HSENI	The Health and Safety Executive for Northern Ireland
ISRS	International Safety Rating System
JRC	Joint Research Centre
LPG	Liquid Petroleum Gas
LWEC	Living With Environmental Change
M _L	Local Magnitude scale
MARS	Mariners' Alerting and Reporting Scheme
MI	Megalitres (1x10 ⁶ litres)
MPA	Mineral Planning Authority
NIEA	Northern Ireland Environment Agency
NORM	Naturally Occurring Radioactive Material
NPPF	National Planning Policy Framework
OPRA	Operational Risk Assessment
OSPAR	The Convention for the Protection of the Marine Environment of the North-East Atlantic
PEDL	Petroleum Exploration and Development Licence
REACH	Registration, Evaluation, Authorisation and Restriction of Chemicals
RIDDOR	Reporting of Injuries, Diseases and Dangerous Occurrences Regulations 1995
SEAB	US Secretary of Energy Advisory Board

Acronyms

SEPA	Scottish Environment Protection Agency
SHIP	Shale Gas Information Platform
STRONGER	State Review of Oil and Natural Gas Environmental Regulations
TSB	Technology Strategy Board
tcf	Trillion cubic feet
UKCCSC	UK Carbon Capture and Storage Consortium

Glossary

Term	Definition
Baseline survey	A survey carried out prior to any operations to determine the natural background levels of certain substances.
Biocide	An additive that kills bacteria.
Biogenic	Produced by bacteria.
Blowout	A sudden and uncontrolled escape of fluids from a well up to the surface.
Blowout preventer	High pressure wellhead valves, designed to shut off the uncontrolled flow of hydrocarbons.
Borehole	See 'wellbore'.
Bundling	A secondary enclosure to contain leaks and spills.
Cap rock	A layer of relatively impermeable rock overlying an oil- or gas-bearing rock.
Carbon footprint	A measurement of the impact of activities on the environment by the amount of greenhouse gases they produce. It is measured in units of carbon dioxide equivalent.
Casing	Metal pipe inserted into a wellbore and cemented in place to protect both subsurface formations and the wellbore.
Cement bond log	A method of testing the integrity of cement used in the construction of the well, especially whether the cement is adhering effectively to both sides of the annulus between casings or between the outer casing and the rock sides.
Coal bed methane	A form of natural gas found along with coal seams underground.
Directional drilling	The intentional deviation of a wellbore from the path it would naturally take.
Disposal well	A well, sometimes a depleted oil or gas well, into which waste fluids can be injected for safe disposal.
Enhanced Geothermal Systems	A geothermal system that uses heat from deep in the ground to generate energy. An enhanced geothermal system is one where the natural connectivity does not permit sufficient flow and additional stimulation is required.
Flowback water	The fluid that flows back to surface following a fracturing treatment. It is a mixture of the original fracturing fluid and saline water containing dissolved minerals from the shale formation.
Gas in place	The entire volume of gas contained in a formation regardless of the ability to produce it.
Global Warming Potential	A measure of how much a given mass of a greenhouse gas is estimated to contribute to global warming relative to carbon dioxide.
Groundwater	Water found beneath the earth's surface.
Hazard	A hazard is something (e.g. an object, a property of a substance, a phenomenon or an activity) that can cause adverse effects.
Horizontal drilling	A special case of directional drilling where the well is deviated onto a horizontal plane.
Hydraulic fracturing	A means of increasing the flow of oil or gas from a rock formation by pumping fluid at high pressure into the well, causing fractures to open in the formation and increase its permeability.
Hydrogeology	The geology of groundwater, especially concerning the physical, biological and chemical properties of its occurrence and movement.
Leakoff test	A test used to determine the pressure required to initiate fracturing of the rock formation.
Microseismic	Very small seismic events, normally below -1.5 ML.
Naturally Occurring Radioactive Material	Radioactive elements and their decay products found in the environment that have been generated from natural processes.
Permeability	A measure of the ability of a rock to transmit fluid through pore spaces.
Porosity	A ratio between the volume of the pore space in reservoir rock and the total bulk volume of the rock. The pore space determines the amount of space available for fluids.
Pressure test	A method of testing well integrity by raising the internal pressure of the well up to maximum expected design parameters.
Produced water	The fluid that returns to the surface during the production phase of a well that contains both fracturing fluid and saline water from the rock formation.
Proppant	Particles (normally sand) mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment.
Proved reserves	The volume of technically recoverable resources demonstrated to be economically and legally producible.

Reservoir	A subsurface body of rock that acts as a store for hydrocarbons.
Risk	A risk is the likelihood that a hazard will actually cause its adverse effects, together with a measure of the effect.
Scale inhibitor	A chemical treatment used to control or prevent deposits building up in the well.
Seismicity	Sudden geological phenomena that release energy in the form of vibrations that travel through the earth as compression (primary) or shear (secondary) waves.
Seismic reflection surveys	A technique that uses reflected seismic waves to map the structure of rock layers in two- or three-dimensions.
Surfactant	A chemical that lowers the surface tension or interfacial tension between fluids or between a fluid and a solid.
Sweet spot	Regions in oil and gas reservoirs with high concentrations of carbon that are most amenable to production.
Technically recoverable resource	The volume of gas within a formation considered to be recoverable with existing technology.
Thermogenic methane	Methane produced by the alteration of organic matter under high temperatures and pressures over long time periods.
Tiltmeter	An instrument used to detect microdeformations in surrounding rock.
Tracer	A chemical additive that can be used to identify the presence of the fracturing fluid by subsequent monitoring.
Traffic light system	An early warning monitoring system with thresholds to indicate when operations should proceed with caution or halt.
Unconventional gas	Gas found in a reservoir of low or zero permeability.
Wellbore	The hole created by drilling operations, also known as the 'borehole'.
Well integrity	The ability of the well to prevent hydrocarbons or operational fluids leaking into the surrounding environment.
Well pad	The surface infrastructure of the drilling operations.

Appendix 1: Working Group

The following Working Group was set up to oversee this project. Members of the Working Group acted in an individual and not a representative capacity, and declared any potential conflicts of interest. The Working Group Members contributed to the project on the basis of their own expertise and good judgement.

Professor Michael Bickle FRS

Mike Bickle is based in the Department of Earth Sciences at Cambridge University. His research focuses on tectonics and geochemistry, with his most recent work examining fluid-mineral reaction kinetics associated with geological carbon sequestration. He is Director of the Cambridge Centre for Carbon Capture and Storage and is also the NERC Chair of the UK Integrated Ocean Drilling Programme (IODP) advisory committee.

Dr Dougal Goodman OBE FEng

Dougal Goodman is Chief Executive of The Foundation for Science and Technology. He is also non-executive Chairman of the Lighthill Risk Network, a consortium of insurance companies working to bridge the gap between the insurance market and the research community. He was formerly Deputy Director of the British Antarctic Survey and a General Manager at BP during which time he was Head of Safety. He holds visiting chairs at University College London and Cranfield University.

Professor Robert Mair CBE FEng FRS (Chair)

Robert Mair is the Sir Kirby Laing Professor of Civil Engineering at Cambridge University and was Master of Jesus College 2001-11. He was Senior Vice-President of the Royal Academy of Engineering 2008-11, and is a founding Director of the Geotechnical Consulting Group, an international consulting company based in London. He has specialised throughout his career in underground construction, including soft ground tunnelling, retaining structures, deep excavations and foundations and has advised on many projects worldwide. In the UK he has been closely involved with the design and construction of the Jubilee Line Extension for London Underground, and with the Channel Tunnel Rail Link (now HS1) and Crossrail projects. He is Chief Engineering Adviser to the Laing O'Rourke Group.

Dr John Roberts CBE FEng

John Roberts has been the Chairman of the Royal Bank of Canada (Europe) Limited since 2009. He is also currently Chairman of Halite Energy Group Limited, which champions underground gas storage, as well as Bluebay Asset Management Limited, which specialises in fixed income and alternative investment products, and Blackrock New Energy Investment Trust. He is an advisor to Fortis European Clean Energy Fund, Trustee of Ecofin Research Foundation, and Deputy Lieutenant of the County of Merseyside.

Professor Richard Selley

Dick Selley is Emeritus Professor of Petroleum Geology and a Senior Research Fellow at Imperial College London. He has researched, taught and practiced petroleum exploration for fifty years, and in the mid 1980s he identified the scale and location of the UK's shale gas resources. He has spent most of his career at Imperial College, with the exception of several years working for oil companies in Libya, Greenland and the North Sea. He was a member of Conoco's exploration team that found the Lyell, Murchison and Hutton fields. He has provided consultancy services across the world, and is currently a consultant on shale gas to the Crown Estate Commissioners via the Energy Contract Company Limited.

Professor Zoe Shipton

Zoe Shipton is a Professor within the Department of Civil Engineering at the University of Strathclyde, with previous lectureships at the University of Glasgow and Trinity College Dublin. Her current research focuses on the 3D structure and permeability architecture of faults, with the aim of better understanding the evolution of fault zone structures and the migration of fluids through the Earth's crust. She has carried out consultancy work for Cluff Geothermal Limited, BHP Billiton and StatoilHydro.

Professor Hywel Thomas FREng FRS

Hywel Thomas is a Professor within the Institute of Environment and Sustainability at Cardiff University, where he is also Pro-Vice Chancellor for Engagement, and Director of the Geoenvironmental Research Centre. His research focuses on generating an improved understanding of the engineering behaviour of unsaturated soil, with the application of research to industry being one of his main priorities. He is currently Principal Investigator for a Welsh European Funding Office project on Earth energy related problems, including underground gas flows. He has experience working with consulting engineers Scott Wilson Kirkpatrick and Partners.

Professor Paul Younger FREng

Paul Younger is a Professor at the Institute for Research on Sustainability at Newcastle University. He is a hydrogeologist and environmental engineer, and is renowned for his pioneering research and outreach programme in community based ecologically integrated remediation techniques for water pollution and abandoned mines. He is a Director at Cluff Geothermal Limited, which focuses on geothermal energy, and Five-Quarter Energy Limited, which champions the extraction of coal gas in the UK.

Project management and research team

The Royal Academy of Engineering and the Royal Society acknowledge the contributions of the following members of staff in managing this project, carrying out research and analysis, and drafting the report:

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- Dr Alan Walker, Senior Policy Adviser,
The Royal Academy of Engineering
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Appendix 2: Evidence gathering

1 Evidence sessions

Evidence session 1 – UK regulation and licensing process

- Simon Toole, Director, Licensing, Exploration and Development, Department of Energy and Climate Change
- Tony Grayling, Head of Climate Change and Communities, Environment Agency
- Allan Green, Well Operations Inspector, Health and Safety Executive

Evidence session 2 – British Geological Survey (BGS) project on shale gas

- Dr Rob Ward, Head of Groundwater Science, BGS
- Professor Mike Stephenson, Head of Energy Science, BGS

Evidence session 3 – Industry perspectives

- Dr Graeme Smith, Vice President for Unconventional Gas and Oil, Shell
- Martin Cox, Aberdeen Drilling Management Ltd
- Nick Hooper, Head of Science and Innovation, British Consulate General, Boston (via teleconference)

Evidence session 4 – NGO perspectives

- Dr Doug Parr, Chief Scientist, Greenpeace
- Tony Bosworth, Senior Climate Change Campaigner, Friends of the Earth (via teleconference)

Evidence session 5 – Operational risks

- Eric Vaughan, Chief Technology Officer, Cuadrilla Resources
- Adrian Topham, Baker Hughes
- Peter Robinson, NRG Well Examination Ltd
- Professor Ray Orbach, Energy Institute, University of Texas at Austin, USA

Evidence session 6 – Environmental risks

- Stuart Rolley, Head of Environment, Coal Authority
- David Allan, Chair of Safety, Environment and Technical Committee, British Drilling Association
- Ian Davey, Senior Advisor in Environment and Business, Environment Agency

Evidence briefing 7 – Seismic risks

- Dr Brian Baptie, Head of Seismology, BGS
- Professor Mike Kendal, Head, Department of Earth Sciences, Bristol University
- Professor Philip Meredith, Department of Earth Sciences, University College London
- Martin Rylance, Engineering Manager for Fracking and Stimulation, BP

Evidence session 8 – Risk management

- Judy Knights, Marine and Energy Class of Business Executive, Performance Management Directorate, Lloyd's
- Richard Palengat, Senior Underwriter, Head of Marine and Energy, AEGIS London
- Andrew Kibble, Head of Unit, Chemical Hazards and Poisons Division, Health Protection Agency
- Martyn Evans, Climate Change and Energy Advisor, Environment Agency (via teleconference)
- Jeanne Briskin, Office of Science Policy, US Environmental Protection Agency (via teleconference)

2 Other consultations

We are grateful for opportunities to consult with the following individuals:

- John Arnott, Head of Policy, Department of Energy and Climate Change
- Tristan Asprey, Exploration Operations Manager for Europe and Greenland, Exxon Mobil
- Jenny Banks, Energy and Climate Change Policy Officer, WWF-UK
- Roy Baria, Technical Director, EGS Energy
- Professor Richard Davies, Director of Energy Institute, University of Durham
- Martin Diaper, Climate Change Advisor, Environment Agency
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- Lillian Harrison, Minerals and Waste Planning Policy Manager, Kent County Council
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- Sir Bob Watson FRS, Chief Scientific Adviser, Department for Environment, Food and Rural Affairs
- Professor Mark Zoback, Professor of Geophysics, Stanford University, USA

3 Written submissions

We are grateful for receiving written submissions from:

- Professor Al Fraser, Chair in Petroleum Geoscience, Imperial College London
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- The Geological Society of London
- Petroleum Exploration Society of Great Britain
- Mike Hill, Director, Gemini Control and Automation Ltd
- Professor Simon Pollard, Dean, Faculty of Environment and Science, Cranfield University
- Daniel Lawrence, Counsel (Environment, Planning and Regulatory Practice Group), Freshfields Bruckhaus Deringer LLP
- Halliburton

Appendix 3: Review Panel

This report has been reviewed by an independent panel of experts. Members of the Review Panel were not asked to endorse the report's conclusions and recommendations. They acted in a personal and not an organisational capacity and were asked to declare any potential conflicts of interest. The Royal Academy of Engineering and the Royal Society gratefully acknowledge their contribution.

The report has been approved by The Royal Academy of Engineering's Engineering Policy Committee and the Royal Society's Council. Members of both bodies were asked to declare any potential conflicts of interest. Like many UK companies and charities, the Royal Society and the Royal Academy of Engineering invest their portfolios in a range of companies and funds, including equity holdings in oil and gas companies.

- **Paul Golby FEng**
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