Environment Agency

Evidence

Review of assessment procedures for shale gas well casing installation

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Author(s):
Ben Fretwell
Tim Haines
Judith Glazier
Tony Marsland

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Research Contractor:
AMEC Environment and Infrastructure Limited
Canon Court
Abbey Foregate
Shrewsbury
SY2 5DE
01743 342000

Environment Agency’s Project Manager:
Ian Davey, Environment and Business Directorate

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Miranda Kavanagh

Director of Evidence

Executive Summary

This report presents information on the assessment procedures for well casing installations used in the exploration and development particularly in regard to shale gas. This information was obtained by reviewing practices for protecting groundwater when installing, developing, maintaining and decommissioning onshore shale gas exploration and production wells. The aim of the project was to inform Environment Agency staff of current practices in this field.

The shale gas industry is most developed in the USA with currently more limited exploration in Europe. In the UK, exploration to date has focused on the Sabden and Bowland shales of NW England, which lie 1600–2800 metres below ground. Other types of unconventional resources include coal bed methane and underground coal gasification.

The exploration and production of unconventional gases is based on techniques developed by the conventional oil and gas industry. Drilling of deep onshore wells for oil and gas is not new to the UK but there are differences in the way that the techniques are applied. The main differences are that unconventional gas exploitation requires a larger number of closely spaced wells, which are normally extended by horizontal or directional drilling. More use is also made of hydraulic fracturing

The gas-bearing shale formation is hydraulically fractured by injection of fluid under pressure to break it up and release gas via the well. A proppant, typically sand, is added to the fluid to hold the fractures open. Chemicals may be added to the fluid to help the hydraulic fracturing process.

The well is cased using steel pipe cemented into the borehole as it is drilled. This:

- permits control of pressure;
- prevents the formation from caving into the well;
- prevents flow between formations and isolates them;
- provides a means of preventing the entry of formation fluids into the well;
- provides a means to install downhole equipment;
- provides protection to any groundwater that the well passes through.

Wells are plugged and abandoned when they no longer provide beneficial use.

The exploration and development of onshore unconventional gases requires a Petroleum Exploration and Development licence (PEDL) from the Department of Energy and Climate Change (DECC) and further consents to drill exploration boreholes and to develop a field. Drilling and production are also regulated by the Health and Safety Executive (HSE) under The Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996 and The Borehole Sites and Operations Regulations 1995, to minimise risks to workers and others. Planning consent is required from the Minerals Planning Authority (MPA).

Risks to groundwater

The geological formations in which hydrocarbons are present are generally very deep and at some distance vertically below formations containing good quality groundwater, frequently used to provide water supplies. The vertical separation between unconventional gas host rocks and aquifers, combined with appropriate borehole construction, should mean that risks to this groundwater are low. However, boreholes drilled through aquifers may provide a pathway for movement of pollutants and therefore need to be constructed to a high standard.

There is the potential to pollute groundwater with drilling muds, cements, hydraulic fracture fluid, hydrocarbons and deeper formation water as a result of:

- spills and leaks of liquids stored at the surface;
- leakage into aquifers of fracturing fluids and drilling muds from exploration and production boreholes;
- leakage into aquifers via natural discontinuities (joints and fractures) as a result of the introduction of fluids under high pressure;
- leakage into aquifers via induced discontinuities as a result of the high-pressure injection of fracturing fluids;
- well failure due to poor construction or loss of well control, with the potential for the damaging release of fluids;
- borehole or well damage as a result of induced seismicity from the high pressure fracturing operations;
- interference between closely spaced wells or abandoned water wells, mine shafts and so on.

Good practice

This review has found that the following is considered currently to be good practice:

- The well should be designed to protect groundwater, particularly through the design and placement of casing.
- Good use should be made of modelling to aid the well design and the design of hydraulic fracturing.
- The well should be drilled carefully to ensure that drilling fluids do not invade the formations, to avoid flow into the well during drilling and to create a wellbore of known dimensions.
- The wellbore should be conditioned (that is, cleaned to remove contaminants by circulating fresh drilling fluid) before casing installation.
- Casing must be installed in stages, with casing strings of decreasing diameter installed inside each other as the well is drilled to greater depths.
- Casing should be cemented in place. Cement should fill the annulus of surface casing and must prevent movement of fluids and gases from permeable formations at all depths.
- The quality of cementing should be demonstrated by pressure testing and supplemented, where necessary by geophysical methods.
- Real-time monitoring should be undertaken during drilling, cementing and hydraulic fracturing to allow response to adverse effects.
- The well should be pressure tested before hydraulic fracturing and periodically to demonstrate well integrity.
- Well abandonment (that is, the activities involved in decommissioning) should be undertaken to ensure that all hydrocarbon bearing formations are separated from the surface by at least two permanent plugs; and

- Flowing horizons should be isolated from other permeable and porous formations to prevent cross flow between them after abandonment.

Contents

1 Introduction

1.1 Background

Shale gas is a type of 'unconventional' energy source (as opposed to 'conventional' sources in which gas and/or oil has migrated to a structural trap and can be exploited using wells). Other types of unconventional resources include:

- coal bed methane (CBM);
- coal gasification (the production of gas in-situ from coal);
- deep natural gas;
- tight gas (similar to shale gas but bound in lower permeability formations);
- gas in pressurised zones;
- methane hydrates, in which the gas is bound in a water molecule.

This report considers in particular shale gas.

The shale gas industry is most developed in the USA, where in recent years an increase in shale gas production has offset declining conventional gas production. Shale gas production in the USA began in the 1970s, but did not contribute considerably to energy production until the turn of the 21st century. As a result of new shale gas discoveries, US natural gas reserve estimates increased by 35 per cent between 2006 and 2008, with a further threefold increase between 2008 and 2010. Shale gas reserves in the USA are now estimated to amount to a 110-year supply for the country.

The exploration and exploitation of shale gas and other unconventional gases is currently an immature industry in Europe. In the UK, exploration in Lancashire by Cuadrilla Resources Limited has targeted the Sabden and Bowland shales 1,600–2,800 metres below ground, and a number of other projects are in the planning and feasibility stages. A conservative estimate by the British Geological Survey (BGS) on behalf of the Department of Energy and Climate Change (DECC 2010) is that shale gas in the UK might provide 150 billion cubic metres (bcm) of gas. In contrast, Cuadrilla Resource's estimate of recoverable resource from the Bowland Shales alone is 1,132 bcm (Broderick et al. 2011).

The exploration and production of unconventional gases uses techniques developed for, and commonly practised by, the conventional oil and gas industry. Drilling of deep onshore exploration and production boreholes for oil and gas is not a new phenomenon in the UK. There are, however, differences in the way that these techniques are applied and in the extent to which some techniques are used.

These differences arise because, in general terms, conventional oil and gas are found in relatively permeable formations in which the oil or gas will flow towards a production well. In contrast, unconventional gas exploitation targets low permeability formations. This requires additional work (stimulation) to increase the permeability of the formation using high volume hydraulic fracturing, which involves injecting fluid under pressure to fracture the target formation. It also requires a larger number of boreholes because the zone of influence of individual boreholes is more limited. Hydraulic fracturing is also used for conventional oil and gas to enhance recovery, but unconventional gas makes greater use of this technique and also uses larger volumes of fluid to promote fracturing.

In summary, the principal differences between conventional and unconventional gas exploitation are that unconventional gas exploitation:

- involves drilling a larger number of wells at closer spacing;
- makes much greater use of hydraulic fracturing, consuming greater volumes of fluid in the process;
- makes wider use of horizontal/directional drilling to increase the surface area of wells open to the target formation.

Concerns have been expressed about the exploitation of shale gas and in particular the extensive use of hydraulic fracturing. These concerns include:

- the potential for the pollution of groundwater by substances used to develop wells by hydraulic fracturing;
- induced seismicity as a result of hydraulic fracturing;
- the potential for upwards leakage of gas and contaminated fluids into overlying aquifers and water supplies.

1.2 Objectives

The project was undertaken to inform Environment Agency staff of current practices for unconventional gas exploration and production, and to support them in their regulatory duties.

The main task was to carry out a review of the processes and requirements for protecting groundwater when installing, developing, maintaining and decommissioning onshore shale gas exploration and production wells.

The report includes recommendations for consideration by the Environment Agency of requirements to ensure that groundwater resources are protected. The Environment Agency's terms of reference indicated that, although some bespoke recommendations were appropriate, the study was not to be novel or exhaustive. The review therefore concentrates on industry good practice and information in the public domain.

The information presented is derived primarily from reports that document international experience and should be considered in the context of geological and other conditions that prevail in the UK. The recommendations in the report have been prepared by the contractor for the Environment Agency's consideration and are not intended to set out the Environment Agency's current requirements for groundwater protection in relation to unconventional gas activity.

1.3 Structure of the report

Section 2 describes the typical sequence of events and the activities involved in unconventional gas exploration and production including design, drilling, hydraulic fracturing, well completion, production and decommissioning.

Section 3 considers the risks to groundwater associated with unconventional gas exploration and production. It provides an overview of groundwater protection and outlines the hazards to groundwater and the various potential pathways through which a groundwater source could be contaminated during exploration and production.

Section 4 identifies the requirements of the licensing body (DECC) and the Health and Safety Executive (HSE) relating to casing installation and compares them to those in the USA, Canada and Europe. Although UK health and safety legislation and HSE guidelines are designed to protect people rather than the environment, compliance with their requirements will afford a significant degree of protection to groundwater. The extent to which compliance with DECC and HSE requirements will protect groundwater is reviewed and areas where there might be a need for additional guidance for Environment Agency staff and others to ensure the protection of groundwater are highlighted.

Section 5 considers approaches to casing design, installation and monitoring used elsewhere in the world (principally the USA) and identifies good industry practice.

Section 6 sets out recommendations and key performance objectives for groundwater protection, including when the Environment Agency should seek information and stages at which it needs to take action.

A glossary of terms and list of references are given at the end of the report.

1.4 Sources and applicability of data

As there is very limited experience of shale gas exploration in Europe and no experience of production, the majority of base data and information (for example, water and chemical usage) quoted in this report are derived from US sources, where over 50,000 shale gas boreholes have been drilled to date. However, care should be taken when translating these data into a UK or European context. Initial indications from the exploration in Lancashire suggest that the industry in the UK could achieve resource consumption and an environmental footprint at or below the lower end of typical US figures.

Similarly, many of the construction methods, procedures and underlying standards described are derived from US experience. Many of these will need to be adapted to site-specific circumstances reflecting local geological conditions, local practice and UK regulatory requirements.

1.5 Glossary of terms

Hydrocarbon exploration and production uses oil industry methods and techniques. Oil industry terminology is somewhat different from that used for other (non-hydrocarbon) onshore drilling operations and may be unfamiliar to some readers. A glossary of terms is therefore included at the end of the report for those terms not explained in the text. Note that several terms may have more than one definition. Examples are ‘casing string’, ‘wellbore’ and ‘well completion’.

2 Drilling operations overview

This section provides an overview of the main activities involved in drilling wells, casing installation and hydraulic fracturing for exploration and production of unconventional hydrocarbons. Further details on standards and good practice in casing design, installation and monitoring are provided in Section 5.

2.1 Unconventional gases

There are various unconventional gas sources with potential resource value. This review focuses on techniques used for shale gas.

2.1.1 Shale gas

Shale gas consists of gas accumulations in low permeability shale formations. However, the gas will be released if the rock is fractured.

The brittle and fissile nature of shale allows for effective fracturing using high pressure hydraulic fracturing techniques (often referred to as ‘fracking’) to stimulate the target formation. Hydraulic fracturing creates pathways to allow the shale gas to flow out of the formation. A fracture fluid is pumped into the formation at a pressure sufficient to propagate networks of fractures. A ‘proppant’ (usually sand), which is entrained in the fracturing fluid, is used to ‘prop’ open the fractures once the pressure has reduced. The resulting fracture network permits the gas to be extracted.

Shale gas exploitation generally requires the use of horizontal drilling to maximise the length of the well exposed to the formation.

The hydraulic fracturing used in shale gas has been termed ‘high volume hydraulic fracturing’ to distinguish it from hydraulic fracturing techniques used in conventional oil and gas (and water resources) exploitation.

2.2 Stages and programme

2.2.1 Licensing

The Crown owns methane associated with coal and shale gas. The rights to the gas are regulated by the Department of Energy and Climate Change (DECC) under the Petroleum Act 1998. Exploration for hydrocarbons, including methane, is licensed by DECC.

A UK Petroleum Exploration and Development Licence (PEDL) is required from DECC to explore for and to undertake production of unconventional gases. Licensing requirements are detailed in Section 4.2. The holder of the licence either undertakes exploration and development themselves, or appoints an operator to do this.

2.2.2 Non-intrusive exploration

Unconventional gas exploration makes use of non-intrusive geophysical techniques such as seismic surveys to identify potential sources of gas. Existing sources of information, such as borehole logs and core samples, are also used in determining where to undertake exploration activities.

2.2.3 Drilling

This section sets out the main activities associated with drilling exploration and production boreholes. The whole activity, from exploration through to production, will involve different levels of exploration and resource assessment prior to production, depending on the particular case. For example, in some cases core samples may be taken from exploration boreholes before these are backfilled, with dedicated production boreholes drilled subsequently.

Planning and mobilisation

Exploration requires the drilling of wells into the target formation to gain information on the exploitable resource. This will require selection of a site for location of the drilling rig. The site operator will need to make access arrangements with the landowner, obtain planning permission from the local mineral planning authority for a drilling site and then obtain consent from DECC to drill the well.

Prior to starting drilling, the operator needs to notify the Health and Safety Executive (HSE) at least 21 days in advance. This notification needs to include sufficient particulars of the well design to demonstrate the well is safe and designed to prevent unplanned flow from the well either at surface or subsurface (see Section 4.3). DECC also require notification at the time that drilling starts.

At this stage the operator will need to identify sources of water and disposal routes for used hydraulic fracturing fluid and other wastes that might arise, including naturally occurring radioactive material (NORM).

Additional wells will be required to appraise the resource and each requires appropriate consents and permissions. Approval of a Field Development Plan may be granted by DECC, after LPA consent, with EA consultation and required permits and permissions.

Pad development

Wells are drilled from a well pad. This is an area of level ground where vegetation and topsoil are stripped (which may be stockpiled for reclamation) and an area of hard standing is constructed. The well pad needs to be of sufficient size to accommodate drilling and geophysical logging equipment, hydraulic fracturing equipment, fluid storage, gas processing equipment, offices, storage and parking, while also providing adequate space for emergency egress. The pad is constructed in advance of mobilisation of the drilling rig and equipment.

Many shale gas wells are drilled vertically to just above the target horizon and then drilled horizontally within the target formation. During production, several wells are typically drilled from a single pad. For example, in the Marcellus Shale developments in the USA, up to 16 (but more typically eight) boreholes are drilled from a single pad, with each well 5–8 metres apart.

Several well pads will be required to exploit the target formation. A well pad density of nine pads per square mile is suggested by the New York State Department of Environment Conservation (NYSDEC 2011). In the UK, Composite Energy has estimated that 1–1.5 pads per km^2 should be sufficient (cited in Broderick et al. 2011).

In the USA, a typical multi-well pad is between 1.5 and 2.0 hectares (ha) during construction and drilling. The pad size can then be reduced during production to 0.4–1.2 ha (NYSDEC 2011). In the UK, Cuadrilla Resources is planning to develop 10 wells on a 0.7 ha well pad.

Well pads are typically restored to their original state at the end of their life.

Drilling

Following pad construction, well drilling equipment, consisting of a drilling rig, mud circulation system, power supply and so on, is brought to the site and set up.

The vertical section of each borehole is advanced using a rotary drilling system, which uses a rotating drill bit on the end of a drill string. The rock cuttings are returned to ground surface by a drilling fluid or ‘mud’, which is pumped down the drill string and back up the annulus of the hole created by the bit. The mud also serves to overcome the hydrostatic pressure of the formation to control pressures and prevent blowouts. Mud composition and properties (such as weight) can be adjusted to cope with changes in formation pressure.

Unconventional gas exploration and production make extensive use of horizontal or directional drilling. Wells commence vertically, but are then deviated to run within the target formation, horizontally or following the formation dip. A different rig may be used for horizontal/directional drilling. Also, the drill bit may be powered by mud circulation.

At the surface, blowout preventers (BOPs) are required to permit the well to be closed off quickly should a formation give rise to a sudden increase in pressure (a ‘kick’) until this can be compensated for by varying the drilling fluid.

Casing installation

Casing is the usual name for steel pipe lowered into and generally cemented into the borehole as it is being drilled. The casing serves a number of functions, as follows:

- to permit control of pressure;
- to prevent the formation from collapsing into the well;
- to isolate different formations from each other to prevent crossflow of formation or other fluids and gases;
- to provide a means of controlling formation fluids.

Casing also provides a foundation for surface well completion equipment and the means to install downhole equipment.

Each full length of casing of a given diameter, comprising welded or threaded sections, is called a ‘casing string’. Casing strings are installed in stages, starting with the largest diameter at the surface. Most casing strings are cemented in place, with the possible exception of the final casing string (production casing). The cementing or grouting process involves pumping cement down the centre of the casing into the annulus between the outside of the casing and the borehole wall. Surface casing should be cemented to ground surface, but in some instances, deeper strings may instead only be cemented some distance back inside the previous casing string.

Casing comes in a variety of diameters (up to 50 inches/1,270 mm) and grades. Each casing string in a well is run from the ground surface so that the near surface sections of a well may consist of as many as four or five casing strings of decreasing diameter nested inside each other. Where a number of casing strings are used, the upper part of the well will comprise several layers of steel casing and cement.

Table 2.1 lists the principal types of casing and their functions. A schematic of a typical casing is shown in Figure 2.1 and a schematic of the layout of a horizontal well is given in Figure 2.2.

Table 2.1 Casing elements and their function

Casing type	Purpose	Design and construction details/good practice
Well conductor	Case off shallow (unstable) formations. Permit returns of drilling fluid to surface. Provide a foundation for BOP and wellhead equipment.	This casing string is generally short in length. It can be driven into the ground where the conditions are favourable but is generally installed in a drilled hole. The depth of the casing base (shoe depth) should be sufficient to isolate any shallow unconsolidated strata and to allow drilling fluid returns as the next section of hole is drilled. Conductor casing may extend above ground surface to the drilling floor.
Surface casing	Protect groundwater. Prevent blowout of well fluids at surface or underground. Prevent the unplanned release of well fluids to the subsurface.	Surface casing runs inside the well conductor and is generally cemented into place.
Intermediate casing	Provide protection against weak or high-pressure formations. Enable use of drilling fluids with different densities necessary for formation control as the borehole progresses. Isolate flowing horizons.	Intermediate casing runs inside the surface casing and is generally cemented into place. Design requirements are the same as surface casing. In deep wells there may be several strings of intermediate casing and each will be smaller in diameter than the last. However, in certain circumstances, no intermediate casing will be required.
Production casing	Enable extraction of hydrocarbons.	Design requirements as surface casing. The casing is set across the target formation. It is perforated to allow the flow of fluid or gas into the well, and contains the completion components necessary for the production of oil or gas. The casing may be pre-perforated or perforated in situ.
Production tubing	Enable extraction of hydrocarbons.	Similar to production casing but is hung in the hole (from the tubing hanger) and not cemented in place.
Casing shoe	Guide the casing string past obstructions in the borehole when lowering casing.	Typically a steel collar with a profiled cement interior.
Casing collar	Join two lengths of casing.	Threaded or welded collar used to join two lengths of casing. The design of threaded connections to join sections of casing should be appropriate for the service of the casing. Production casing should have gas tight (premium) connections.
Packers	Downhole device that provides a seal within an open wellbore or within casing.	Packers are lowered into the hole and then inflated or expanded in the hole. They have expanding elements that seal against the

Casing type	Purpose	Design and construction details/good practice
	Production or test packers may be set in cased holes to seal the production zone from the casing annulus.	wall to provide a seal. Some packers are designed to be removable, while others are permanent. Permanent packers are constructed of materials that are easy to drill out.
Centralisers	Hold casing in the centre of the wellbore so that cement can be placed all the way around the casing.	Centralisers should be fitted to all casing that will be cemented. The interval between centralisers should be short enough to ensure the casing cannot bow in between them.

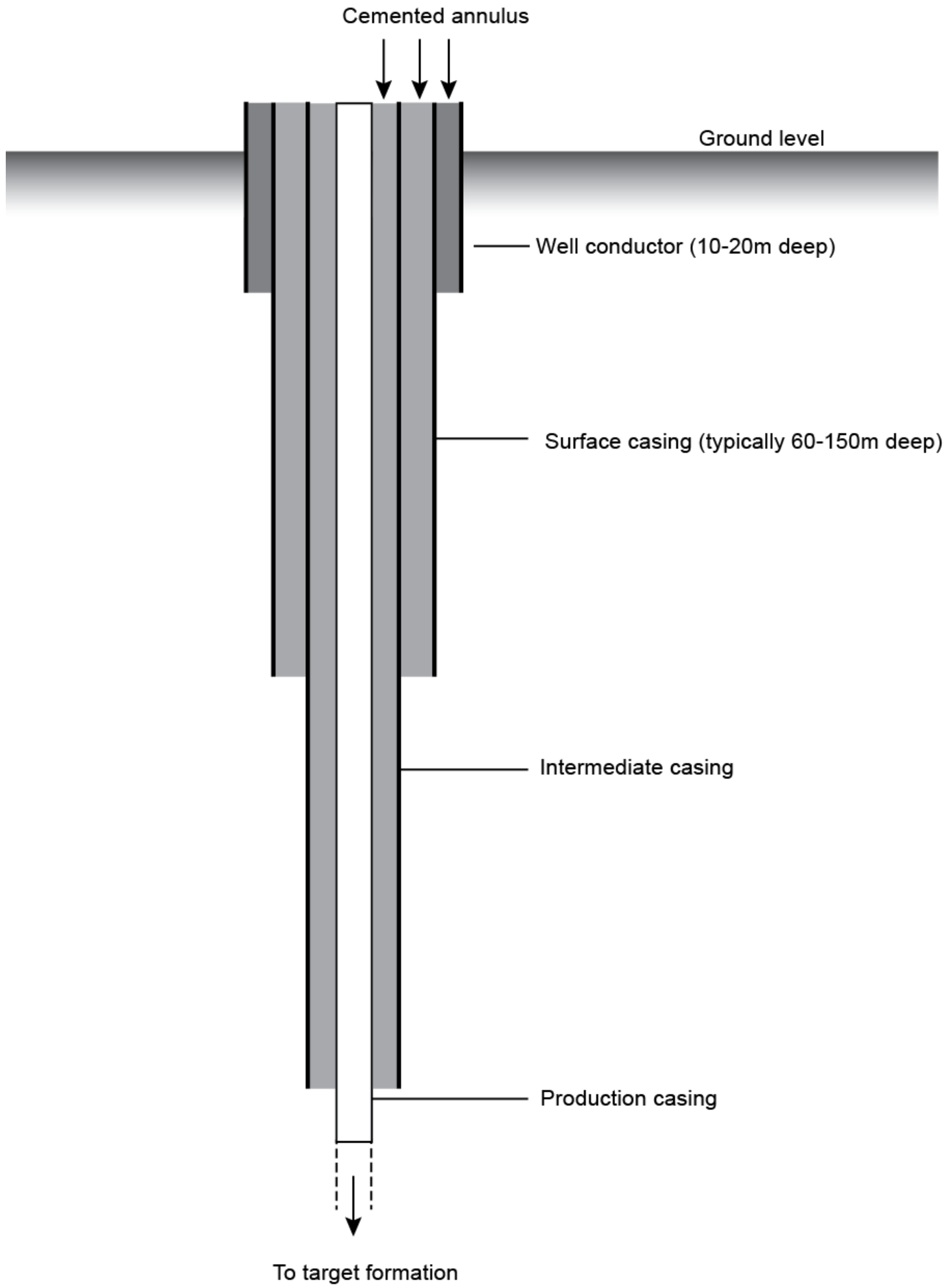

Figure 2.1 Schematic of a typical casing

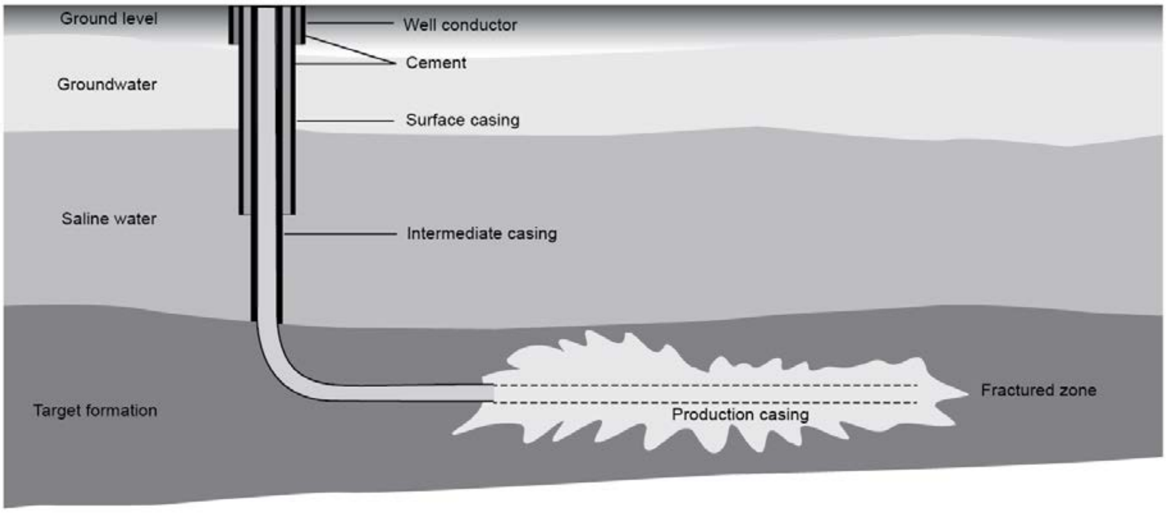

Figure 2.2 Schematic of a horizontal well

Sequence of events

The first phase of drilling and casing involves drilling an initial hole into which the conductor casing is set and cemented. After the conductor casing is set, drilling continues to below the lowest fresh groundwater zone (subject to good practice/regulatory requirements). Surface casing is then run from the surface to just above the bottom of the hole and cemented back to the surface. Prior to cementing the wellbore is 'conditioned' by circulating fresh mud through the well to remove contaminants that could interfere with the cement bond. During cementing, cement is pumped down the inside of the casing, forcing it up from the bottom of the casing into the annular space between the outside of the casing and the borehole wall. Once a sufficient volume of cement to fill the annulus plus a prudent excess has been pumped into the casing, it is usually followed by pumping a volume of drilling fluid down the casing until the cement begins to return to the surface in the annulus. This method of cementing of casing from bottom to top is called circulation. The circulation of cement behind surface casing is used to ensure that the entire annular space fills with cement from below the deepest ground water zone to the surface.

The type of cement used may vary during cementing to meet particular requirements of the well; typically, lighter cement is used first, followed by denser cement.

Once the surface casing is set and the cement has had time to cure, the borehole is advanced to the next zone where the process of conditioning, casing installation and cementing is repeated. This second string is referred to as intermediate casing. More than one string of intermediate casing may be used in deep wells.

After the surface and intermediate casing strings are set, the well is drilled to the target formation, which may involve horizontal drilling. Horizontal drilling requires the well to deviate from the vertical. Typically deviation is started some 150 metres above the top of the target formation. A different rig may be used for horizontal drilling. Upon completion of drilling, production casing is typically set at either the top of, or into, the producing formation depending upon whether the well will be completed as open hole or with perforated casing. Production casing is typically set into place with cement using the same method as surface and intermediate casing.

Centralisers are used to ensure that casing is centred in the hole prior to cementing so that cement will completely surround the casing.

Production tubing may be installed inside production casing to collect gas. This typically consists of steel pipe similar to casing. The principal difference between casing and tubing is that tubing is not cemented into the well. A packer or seal is placed at the bottom of the tubing to prevent gas entering the space between the casing and tubing. A tubing hanger close to surface holds the tubing in place and includes well controls to prevent escape of gas.

In an undated report,[1] Cuadrilla Resources provides a schematic of one of its wells at Preese Hall, Lancashire, that also includes a well cellar – a large diameter (three metres) concrete cylinder, three metres deep, which is built into the ground to provide work space below the rig floor to accommodate the BOP equipment and to reduce the overall height of the wellhead.

Testing and monitoring

The quality of the cement bond can be checked through use of geophysical methods such as cement bond logs (CBLs) and variable density logs (VDLs), where these are effective. These logs measure the amplitude of sound waves through the casing and cement to the formation. The CBL shows the quality of bonding between the casing and the cement, while the VDL measures the quality of the cement. By measuring the quality of the cement to casing bond and of the cement itself, the sealing quality of the cement in the annulus can be evaluated. Alternative cement evaluation tools, such as the Ultrasonic Imaging Tool (USIT) provide a 360^{o} scan of the casing to cement bond; they can be run in tandem with the CBL/VDL. These acoustic tools do not measure hydraulic seal directly and should not be considered to provide a definitive test. (Douglas Boyd et al, reported in Journal of Petroleum Technology[2]).

Above ground and downhole equipment involved in injection, and casing are subject to pressure testing to ensure their integrity.

Pressure monitoring is maintained throughout drilling and hydraulic fracturing to provide information on well pressure and to ensure well control is maintained.

2.2.4 Well development (high volume hydraulic fracturing)

Following drilling and casing installation, the drilling rig is removed and hydraulic fracturing equipment brought to site and installed, including a high pressure wellhead ('frac tree') at the surface.

Wells are then developed to permit extraction of gas. For shale gas the development process is typically by high volume hydraulic fracturing. This involves pumping fluid into a formation under sufficient pressure to create fractures or enhance natural fracturing in the rock matrix, allowing gas to flow through the fractures more freely to the well.

The process of hydraulic fracturing is critical to the development of shale gas resources as it increases the open area of the formation, which increases the permeability of the formation to gases and liquids and allows them to flow more easily into the well. Without hydraulic fracturing there is unlikely to be sustained gas flow to the well.

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[1] *Wellbore integrity – Cuadrilla land based wells,* Cuadrilla Resources Limited.

[2] *Reliability of Cement-Bond-Log Interpretations Compared to Physical Communication Tests Between Formations*, by Douglas Boyd, SPE, Salah Al-Kubti, SPE, Osama Hamdy Khedr, SPE, Naeem Khan, and Kholoud Al-Nayadi, SPE, Zadco; Didier Degouy, Adma-Opco; and Antoine Elkadi and Zaid Al Kindi, SPE, Schlumberger, Abu Dhabi International Petroleum Exhibition and Conference, 5–8 November 2006. in Journal of Petroleum Technology, February 2007.

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Hydraulic fracturing fluid

The fluid used in hydraulic fracturing operations comprises mainly water and inert proppant, such as sand, which together often make up more than 99 per cent of the fluid. The proppant is usually quartz sand or ceramic beads, but may be sintered bauxite which has a very high compressive strength. In some cases crushed walnuts have also been proposed as a proppant.

Chemicals are added in very small proportions to enhance the performance of the fluid under the high pressure conditions, to aid gas recovery and to prevent biofouling. They vary widely in composition and concentration depending on site-specific conditions (see Section 3.3.1). Both hazardous and non-hazardous are available for use as additives.

Nitrogen gas has been used as a fracturing fluid in CBM (USEPA 2011) without the use of proppants.

High volume hydraulic fracturing

The hydraulic fracturing process involves pumping hydraulic fracturing fluid at very high pressure into the well target zone, which will have been completed either as 'open hole' or with perforated production casing. This creates fractures or enhances those that exist naturally in the gas-bearing rock that propagate outwards from the well. The proppant holds the fractures open following the initial fracturing, thereby allowing the gas to flow to the well through a pressure gradient once the fracturing fluids have been removed from the well.

Fracturing is often performed in stages on an individual well. Multi-stage hydraulic fracturing involves isolation of a section of the production casing or open hole using packers and fracturing only that section, starting at the end of the hole and working back. Perforation of the production casing may be undertaken immediately prior to fracturing so that only a small section of casing is open to high pressures. The typical length of a section involved in fracturing an individual stage is from 100 to 150 metres (Broderick et al. 2011) and the typical fluid volume used during a fracture stage is 1,100-2,200 m^3. Several stages are generally performed on an individual well. Multi-stage fracturing allows improved control of the fracturing process.

Returns of fracturing fluid to the surface are termed 'flowback'. Flowback can constitute between 15 and 80 per cent of the volume of fluid injected, depending on the site and geology (USEPA 2011); for example, flowback recovery in the Marcellus Shale in the USA is typically 15-20 per cent. The fracture fluid left in the ground may be trapped in pores or behind healed fractures.

In Lancashire, Cuadrilla used around 8,400 m^3 in total for six stages of hydraulic fracturing at a single exploration well. The fracture fluid contained around 0.05 per cent of chemical additives.

In many cases, prior to initiation of the fracturing process, an extended 'pre-pad'[3] stage is undertaken that permits analysis to determine if the hydraulic fracture treatment should be undertaken as planned or whether it needs to altered. This is often referred to as a 'mini frac' (API 2009b) and constitutes a short duration hydraulic fracturing stimulation followed by pressure monitoring. The test is designed to initiate fracturing during the injection period and then to observe closure of the fracture system during the ensuing falloff period as pressure declines.

[3] Injection of the initial volume of fracturing fluid is termed the pad. Other fluids may be injected prior to this, at the pre-pad stage.

Typically, specific high-pressure wellhead and downhole equipment is used for the fracturing process. All equipment used in the process must be pressure tested before use.

In the field, the process of hydraulic fracturing is called the ‘treatment’ or the ‘job’. The process is carried out in stages.

- The ‘pad’ is the first stage of the job. The fracture is initiated in the target formation and then propagated with the high-pressure injection of fluid. Typically, no proppant is injected during the pad but the pressure must be maintained.
- Once sufficient fracture propagation has occurred, a proppant is added to the fluid.
- The displacement stage flushes the proppant-laden fluid to depth.

The process of fracturing a well or a stage in a well can take between two hours and two days.

The programme of hydraulic fracturing is typically modelled in advance based on the geomechanical properties of the target formation and the pressure to be applied.

Each stage is monitored and controlled using real-time monitoring of injection pressure, flow rates into the well and the concentration of proppants. Microseismic activity may also be measured using downhole geophones in adjacent boreholes or using a near-surface array of geophones, and interpretation of the fracturing effectiveness and fracture growth

In a fully cased well, the pressures used during hydraulic fracturing are only applied to the formation and the production casing. The surface and intermediate casing are protected by the production casing. The production casing must, therefore, have sufficient strength (including a factor of safety) to hold the intended pressure safely.

2.2.5 Production

Once a production well has been drilled, hydraulically fractured, completed and tested, a production wellhead is installed. This contains equipment necessary for the collection and distribution (via pipelines) of gas from the well. An individual well can be put into production while others on the pad have yet to be completed (Broderick et al. 2011).

In terms of production volumes, an operator-postulated long-term production for a single Marcellus well in New York State (NYSDEC 2011) is:

- Year 1: initial production rate of 2,800 million cubic feet per day (mcf/d) declining to 900 mcf/d;
- Years 2–4: production of 900 mcf/d declining to 550 mcf/d;
- Years 5–10: production of 550 mcf/d declining to 225 mcf/d;
- Year 11 and after: production of 225 mcf/d declining at 3 per cent/year.

Because of the natural decline in production from a well, operators may decide to hydraulically re-fracture a well to increase its production life. This can occur at any time, including within the first five years, and may be done more than once on an individual well (Broderick et al. 2011). Operators often state that shale plays have about a 30–40 year production life, but the average commercial life for horizontal wells is about 7–8 years, with the mode being four years. There are many wells that should give 8–12 years of production but few that will extend beyond 15 years (Berman 2009). The process of re-fracturing is the same as the original process.

As the unconventional gas industry is relatively young, it is likely that there will be changes to the production process over time as understanding is improved.

2.2.6 Abandonment

Wells may be temporarily or permanently abandoned. Temporary abandonment retains a well for future production following periods when there may be no production. Permanent abandonment, or well plugging, seals the inside of the well permanently. The process involves the placement of plugs in the well or wellbore in a manner that prevents the upward or downward migration of formation fluids within the casing or annulus.

Wells can be plugged using a variety of materials and techniques including cement, clay and gel. Plugs in the casing need to be placed where there is also a seal in the annulus to ensure a good seal. Wells in the UK have to be abandoned to comply with the UK Oil and Gas Guidelines for the suspension and abandonment of wells. Cement is generally the only plugging material accepted although cases have been made for the use of shales and salt but only on a case by case basis[4].

[4] HSE, pers. comm.

3 Risks to groundwater

For an environmental risk to be realised there must be a connection between an identified hazard (or source) and the receptor of concern via a pathway. Risk management measures seek to either eliminate the hazard or otherwise break this source–pathway–receptor relationship.

This report focuses on risks to groundwater (as a receptor) from shale gas exploration and development, in particular those risks associated with boreholes and wells during drilling, testing, fracturing and production. Other hazards, pathways and receptors are not considered in detail.

3.1 Overview

In simple terms, groundwater is derived from precipitation that infiltrates the ground surface and moves (with a velocity dependent on the geology) through layers of soil and rock until it reaches the water table, a changing surface that represents the depth below which all pore spaces in the subsurface are fully saturated with water (groundwater).

Rocks that bear usable quantities of groundwater are aquifers. Most groundwater in an aquifer circulates in the top 100–200 metres of the saturated zone. Circulation of groundwater is influenced by topography, and although fresh water occasionally exists at depths of up to 2,000 metres, at these depths it is more likely to be mineralised. Water found in rocks at depth may also contain water from the time of the rock's formation. The deeper that groundwater flows within an aquifer system, the more time it is in contact with minerals and the more opportunity it has to dissolve them; eventually it will become non-potable and saline. Saline groundwater can still be a valuable resource as it may have industrial uses and can be blended with fresher groundwater to make it usable.[5]

In general terms, onshore hydrocarbon exploration and production takes place at depth at some distance vertically below aquifers. CBM is a potential exception as coal seams can lie closer to surface. Most easily usable groundwater resources in the UK tend to occur at shallow depths (less than 200 metres), and permeability and water quality typically decline with depth. There are, however, areas where groundwater resources may extend to much greater depths, in areas of deep circulation and where they may be exploited for geothermal energy.

The vertical separation of unconventional gas host rocks and aquifers, combined with appropriate borehole construction, should mean that risks to groundwater are low. However, boreholes drilled from the ground surface through aquifers provide a potential pathway for movement of pollutants and therefore need to be constructed to a high standard. There is also a debate about the extent to which the influence of hydraulic fracturing can extend upwards from the host strata and the extent to which the injected fluids can migrate via induced fractures.

There is limited publicly available information on the migration of fracturing fluid within the host rock. A recent review of hydraulic fracturing (Davies et al. 2012) found that the maximum reported upward propagation of a fracture as a result of hydraulic fracturing was 588 metres. They estimated that the likelihood of fractures propagating more than 350 metres was less than 1 per cent. This research suggested that the vertical separation between groundwater and hydraulic fracturing operations should exceed

[5] See the UK Groundwater Forum website (http://www.groundwater.org).

500 metres in sedimentary sequences. This figure is based on observed data derived from different circumstances and fracture propagation will be affected by various factors such as lithology, the in-situ stress field, faulting and how the activity itself is carried out.

DECC will expect operators wishing to conduct fracturing in regard to shale gas to fully understand the potential for fracture growth height by examining log-derived stress data including borehole imaging, historical seismicity, integrated with geological evaluation of the subsurface geology and faulting.

Hydrocarbon exploration and production has the potential to pollute groundwater with drilling muds, cements, hydraulic fracture fluid, hydrocarbons and deeper formation water as a result of:

- spills and leaks of liquids stored at surface (fracturing fluid, drilling fluid, drilling fluid returns, fracturing fluid returns, produced fluid, fuels and so on);
- leakage of fracturing fluids and drilling muds (which can contain a variety of organic and inorganic compounds that would pollute groundwater should they enter it) into aquifers from exploration and production boreholes; (shallow formations where good quality groundwater is encountered are generally drilled with water and simple drilling fluids composed of water and clay)[6];
- leakage into aquifers via natural discontinuities (joints and fractures) as a result of the introduction of high pressure fluids;
- leakage into aquifers via induced discontinuities as a result of the high-pressure injection of fracturing fluids;
- well failure due to poor construction or loss of well control, with the potential for the damaging release of fluids;
- borehole or well damage as a result of induced seismicity from the high-pressure fracturing operations;
- interference between closely spaced wells or abandoned water wells, mine shafts and so on.

The statutory definition and the overall requirements for the protection of groundwater are described in the next section. Hazards and pathways are described in detail in Sections 3.3 and 3.4, while legislative controls and risk management measures are considered in Sections 4 and 5 respectively.

3.2 Groundwater protection

Groundwater is defined in EU and domestic legislation as 'all water which is below the surface of the ground in the saturation zone and in direct contact with the ground or subsoil'.

All groundwater is subject to the 'prevent or limit' requirements of the Groundwater Daughter Directive[7] (GWDD) – as implemented in England and Wales by the Environmental Permitting Regulations 2010 (EPR) – and therefore requires protection from inputs of pollutants (substances liable to cause pollution). This means that the

[6] HSE, pers. comm.

[7] Directive 2006/118/EC of the European Parliament and of the Council of 12 December 2006 on the protection of groundwater against pollution and deterioration. *Official Journal of the European Union*, L372, 27.12.2006, pp. 19-31.

entry of hazardous substances into groundwater should be prevented and the entry of non-hazardous pollutants should be limited to prevent pollution or significant or sustained upward trends in pollutant concentrations in groundwater.

A ‘groundwater body’ as defined under the Water Framework Directive[8] (WFD) is ‘a distinct volume of groundwater in an aquifer or aquifers.’ In practice, groundwater bodies are extensive volumes of groundwater as defined by the national environment agencies and their locations are noted in River Basin Management Plans. However, groundwater can occur outside a groundwater body as noted in the Environment Agency’s suite of Groundwater Protection Principles and Practice (GP3) guidance (Environment Agency 2008, 2011) and guidance issued by the United Kingdom Technical Advisory Group for the Water Framework Directive (UKTAG). Additional requirements are attached to groundwater bodies in terms of their assessment and maintenance of good chemical and quantitative status over and above the so-called ‘prevent or limit’ requirements noted above.

The chemical constituents of hydraulic fracturing fluid include pollutants and are therefore subject to the ‘prevent or limit’ requirements. In addition, gas and formation fluids are also potential pollutants and their entry into groundwater as a consequence of anthropogenic activity is also subject to these requirements.

The first recital[9] to the GWDD describes groundwater as:

> ‘a valuable natural resource and as such it should be protected from deterioration and chemical pollution. This is particularly important for groundwater dependent ecosystems and for the use of groundwater in water supply for human consumption’.

Further descriptions in both the GWDD and the WFD emphasise:

- water as a renewable natural resource;
- the provision of sufficient quantities of good quality water for all (human) purposes;
- the protection of ecosystems.

This suggests that the ability to make use of a water resource is a driving factor in the requirement to protect that resource and implies that not all subsurface water is groundwater in the sense intended in the legislation.

This position is reflected in guidance issued by the Department for Environment, Food and Rural Affairs (Defra) on groundwater activities under the Environmental Permitting Regulations (Defra 2011, p. 9), which notes that:

> ‘It will continue to be a technical decision for the Environment Agency to determine what is groundwater in certain circumstances for the purposes of the Regulations. For example, in very low permeability strata such as clays, evaporites and dense crystalline rocks it may not be possible to define a zone of saturation because the water is bound to the rock or is relatively immobile’.

[8] Directive 2000/60/EC of the European Parliament and of the Council of 23 October 2000 establishing a framework for Community action in the field of water policy. *Official Journal of the European Communities*, L327, 22.12.2000, pp. 1-72.

[9] A recital consists of the descriptive text accompanying a directive that describes or illustrates the intention of the directive.

On this basis, for example, if it is difficult to define a water table because of low permeability, then the strata may not contain groundwater that needs protection under EPR. It is understood that this policy steer was included in the Defra guidance to:

- avoid the situation where, for example, water in clay with no resource value could be given the same degree of protection as water in an aquifer;
- enable the setting of compliance points that had environmental relevance and not arbitrarily in formations that contained environmentally trivial amounts of water.

Factors that indicate the presence of groundwater is present could include:

- the water lies within a groundwater body as defined under the WFD;
- there is sufficient resource (in terms of quality and quantity) to maintain a supply of water for human consumption or other human uses with or without treatment;
- there is sufficient subsurface water flow to maintain groundwater dependent ecosystems at the surface or to support stygofauna (mainly invertebrates living in caves and fissures in aquifers).

The decision on whether groundwater is present or not will be specific to the site and the formation. It must be underpinned by hydrogeological data (site-specific or representative generic) and reasonable extrapolations of the nature of human activity.

For unconventional gas exploration and development, a further consideration is that fluids within the well casing will be under pressure and therefore have the potential to disturb pre-existing conditions.

3.3 Hazards to groundwater

3.3.1 Hydraulic fracturing fluid

Hydraulic fracturing fluid usually contains potential pollutants. The composition of the fluid used in any given fracturing operation is dependent on the host formation and may be as simple as water, gas or a mixture of water and proppant (sand), although it is more likely the fluid will include chemical additives. These additives, which typically make up between 0.5 per cent and 2 per cent of the total fluid volume, are included to act as lubricants, biocides, stabilisers, gelling agents, surfactants, scale inhibitors, pH adjusting agents and non-emulsifiers, among other functions. (Note that the percentages quoted in much of the literature are derived from US data. In the UK Cuadrilla has used 0.05 per cent in Lancashire).

A list of typical additives and their purpose, as used in the USA, is given in Appendix A. A US Committee on Energy and Commerce (2011) report, based on a survey of 14 oil and gas service companies, provides a more detailed list that includes some 750 chemicals. The most widely used chemicals are:

- alcohols (methanol, isopropanol);
- ethylene glycol;
- petroleum distillates;
- caustic soda.

High-volume hydraulic fracturing used in shale gas exploitation requires large volumes of water. US data indicate that each stage in a multi-stage fracturing operation requires between 1,100 and 2,200 m^3 of water. Therefore, the entire fracturing operation for one well may require 9,000–29,000 m^3 of water and 180–580 m^3 of chemical additives. Considering that many well pads have multiple wells, large quantities of water must be brought to, stored, used and disposed of at each site (Broderick et al. 2011). Some efficiencies in water use can be achieved by capturing flowback from one well or stage and then re-using it in another well or stage.

At the end of operations, any remaining unused fracturing fluid and flowback water will need to be disposed of via a permitted route.

Hazard assessment

May be high due to the high volumes and the presence of chemical additives. Prior knowledge of composition (CAS numbers) and the ability to analyse for these substances are crucial considerations.

The hazard can be minimised by restricting the number, type and concentration of additives and, where substitutes are available, using less persistent, bioaccumulative and toxic (PBT) substances (that is, avoiding the use of hazardous substances).

Note that hydraulic fracturing in the UK to date has not used hazardous substances.

3.3.2 Disturbance due to drilling

The act of drilling can disturb ground conditions in terms of generating suspended matter, releasing biogenic gas and through contamination by materials used in drilling. These effects (from drilling alone) are usually limited to the immediate vicinity of the well but may extend some distance in fractured, permeable strata. There are reports from the USA that some shale gas wells have been sunk in close proximity to private water supplies and drilling disturbance has impacted supplies.

With good drilling practice these effects can be minimised, but it is also recognised good practice not to locate drilling activities close to groundwater abstractions or groundwater-dependent ecosystems as noted in the Environment Agency's GP3 guidance (Environment Agency 2008, 2011).

For unconventional gas developments, the volume of drilling at each well pad is considerable and occurs over a prolonged period; offset distances therefore need to be considered carefully.

Hazard assessment

High but readily mitigated by offset distances and good drilling practice.

3.3.3 Flowback

Following hydraulic fracturing operations, the pressure on a well is relieved and a percentage of the injected fluid returns to surface as flowback. This fluid is treated, recycled and/or disposed of. The flowback fluid is a mixture of hydraulic fracturing fluid and formation water (produced water). The formation water is usually saline and may contain NORM (naturally occurring radioactive materials).

The discharge or disposal of flowback water is an activity that may require control under the Environmental Permitting Regulations 2010.

The amount of injected fluid that is recovered during flowback ranges widely from 15 to 80 per cent. Demand for water for hydraulic fracturing operations should decrease as operators are encouraged, and are able, to recycle more of this fluid.

Management of flowback and produced water is a major element in the public perception of shale gas (Groat and Grimshaw 2012).

Hazard assessment

Potentially high due to the volume and composition of flowback, particularly if well integrity is compromised and flowback water is allowed to move into an aquifer. Otherwise the main environmental risks arise from surface storage and disposal.

3.3.4 Gas

Natural gas, principally comprising methane, is present in the target shale formation and will therefore also be present in the well during production. Methane from this source is termed thermogenic. Thermogenic methane is generated by thermal decomposition of buried organic material within the target formation. Other thermogenic methane sources may also be present in formations above the host rock and may be encountered during drilling. In addition, methane may be present at higher levels as a result of natural releases from the target formation over time.

Hydrogen sulphide (H_2S) gas may also be encountered during drilling operations or at any stage of gas production and processing. H_2S is soluble in water and generally acts as a reducing agent. Under the Borehole Sites and Operations Regulations 1995, which apply to Great Britain, the atmosphere at the well site must, by regulation, be monitored for the presence of toxic substances such as H_2S. Where it may be encountered, it is normal practice to add H_2S scavenger to the drilling mud to chemically remove it. (There are similar requirements in Northern Ireland).

Biogenic methane, generated by bacterial decomposition of organic matter, may also be present in shallow formations from a range of sources such as decomposing organic matter.

Thermogenic and recent biogenic gases can be distinguished using stable isotope analysis. However, older biogenic gases undergo further change and may come to resemble thermogenic gases.

Methane can migrate as dissolved gas within groundwater to be released when that water reaches the surface naturally or due to pumping. Methane can create an explosion and suffocation risk in confined spaces.

Hazard assessment

Moderate due to the mobility and explosive potential of methane.

3.3.5 Formation water at depth

Groundwater quality almost universally declines with depth, characterised by an increase in the total dissolved solids (TDS) content until the water becomes non-potable and eventually saline. Water at depth also tends to be under high hydraulic pressure and any breach in the strata that confine this deep, saline groundwater can result in its up-welling under pressure and the consequent cross-contamination of shallower, fresher, groundwater.

Hazard assessment

Low to moderate and should be considered in tandem with flowback fluid.

3.3.6 Drilling fluids

The specification of drilling fluids is a critical decision and is an extensive topic beyond the scope of this document. Drilling mud serves a number of functions including:

- removing cuttings from the well;
- controlling formation pressures (well control);
- temporarily sealing off permeable formations during drilling to maintain circulation;
- maintaining the borehole wall (wellbore) stability;
- minimising formation damage to provide a wellbore of uniform dimensions;
- cooling, lubricating and supporting the drill bit;
- driving downhole tools;
- permitting the collection of cuttings and examination to allow logging of the borehole;
- controlling or preventing corrosion of downhole equipment.

A very wide range of drilling fluids is available to deal with the range of well conditions that might be encountered. The choice of mud will depend on a range of factors including:

- site location and environmental sensitivity;
- geology (how formation will interact with mud, rock strength);
- pressure environment (pore pressure);
- well design (diameter, hole angle, length of open hole).

Broadly speaking, drilling fluids can be divided into four classes:

- gas-based (including compressed air);
- water-based muds (WBM);
- oil-based mud (OBM) based on a petroleum product such as diesel. OBMs have better lubrication properties, lower viscosity and enhanced shale inhibition compared with water-based muds. They can also withstand greater heat without breaking down but are more expensive and more hazardous; (note: OBM using petroleum products is not used in the UK)[10];
- synthetic-based fluid (SBM) has a base fluid of synthetic oil consisting of, for example, esters, ethers, olefins and alkyl benzenes. It shares the characteristics of OBM but has reduced (human) toxicity.

Like hydraulic fracturing fluids, drilling muds can be composed of a multitude of constituents, although the most common are water-based muds containing bentonite (clay) with additives such as barite, chalk or haematite to give the mud the weight

[10] HSE, pers. comm.

properties necessary for well control and drill cuttings return. Table 3.1 lists examples of additives that may be found in WBM.

The composition of muds will be adjusted during drilling as conditions in the well change and is therefore variable.

Hazard assessment

Low to moderate depending on the permeability of the formation

Drilling mud is generally designed to avoid losses to groundwater.

Table 3.1 Drilling mud additives in water-based muds

Name	Purpose	Composition
Clay	Provide suitable viscosity and a filter cake on the borehole wall.	Bentonite is commonly used in WBM.
Surfactants	Emulsification of other additives, wetting agents.	Varied
Weighting agents	Control pressure.	Barite, haematite
Bridging agent	Seal formation in the borehole wall.	Calcium carbonate Cellulose Asphalt Gilsonites
Loss of circulation materials	Fill large voids in the borehole wall.	Various (e.g. walnut shells, xanthum gum)
Biocides	Prevent microbial activity.	Variable
Oxygen scavengers	Eliminate oxygen.	Variable
Corrosion inhibitors	Prevent or limit corrosion.	Variable
Deflocculants	Prevent flocs from occurring.	Variable
Lubricants	Improve flow	Variable
Shale inhibitors	Control interactions between mud and shale formations that can lead to swelling, erosion, collapse and so on.	Calcium, potassium chloride, salt, polymers, asphalt, glycols, oil

3.3.7 Cement

Cement-based grout is used to seal the annulus between casing and the borehole walls and between casing strings.

The most common cement is referred to as API Oilwell Cement. Cement used in wells must be highly pumpable to move around the well into the annulus over large distances. Additives are used to control cement density to control formation pressure during setting (similar to mud; see Table 3.1), setting time, strength and flow properties. Cement is formed into a slurry before being pumped into place and allowed to solidify.

Typically 12–24 hours' curing time has to elapse to allow cement to achieve adequate strength before drilling or other activities can resume.

Hazard assessment

Low

3.3.8 Spacer fluid

A spacer fluid is pumped down the wellbore prior to cementing to displace mud from the hole. This avoids contamination of the cement with mud by separating mud from cement. Water is commonly used as a spacer fluid. However, additives may be included to provide well control and enhance performance.

Hazard assessment

Low

3.3.9 Induced seismicity

Induced seismic activity is a well-known phenomenon associated with hydraulic fracturing though the magnitude is generally below zero on the Richter scale and cannot be detected at the surface (De Pater and Baisch 2011). However, higher magnitude events can occur.

A well-known example occurred at the Cuadrilla Resources' Preese Hall-1 well in Lancashire. Between 31 March and 6 June 2011, seismic events with a Richter magnitude (M_L) of up to 2.3 were recorded in the vicinity of the well. Two large events were reported by the British Geological Survey at magnitude 2.3 and 1.5 respectively, and a further 48 much weaker events were recorded. Subsequent studies to determine the causes and the likelihood of recurrence were carried out (De Pater and Baisch 2011; Harper 2011).

The three-dimensional (3D) finite element reservoir model developed by De Pater and Baisch (2011) demonstrated that a number of factors had to coincide to produce the abnormally strong events at Preese Hall-1. They determined that the chance for any single factor to occur is small and that the combined probability of a repeat occurrence of such a large magnitude fracture induced seismic event is quite low. Therefore, the 'seismic response' of the hydraulic treatment (stage 2) in the Preese Hall-1 well was classified as being close to a 'worst case scenario' because the well is very close to a large-scale, critically stressed geological fault plane that failed seismically. They concluded that future developments of the Bowland Shale would show less seismicity. However, a review undertaken for DECC (Green et al. 2012) did not agree that there was a low probability of further seismic events.

De Pater and Baisch (2011) proposed a 'traffic light' system to ensure that induced seismicity during future treatments will not cause any material damage at the surface; any events with a magnitude of greater than 1.7 M_L will necessitate suspension of fracturing operations rapid flowback after the treatment of the well while the situation is monitored. Green et al. (2012) suggested a lower limit of 0.5 M_L as a trigger for suspension of fracturing operations.

Post hydraulic fracturing investigations identified damage to the production casing, likely to be caused by the seismic event, within the open section of the casing but not in the upper sections (De Pater and Baisch 2011). It was concluded that the upper sections of the borehole were undamaged by the seismic event.

There appears to be a correlation between the strength of an induced seismic event and the volume of fluid injected during the fracturing operation (De Pater and Baisch 2011). However, even in the USA where much more data are available than in the UK, magnitudes exceeding 0.8 M_L have generally not been recorded even for a fracture fluid injection volume of 1,800 m^3. There are only two documented cases of a high volume hydraulic fracturing treatment causing stronger events up to magnitude 1.9 and 2.8 ML. Caution should be exercised in translating US experience to the UK due to the different geological conditions, for example, the Bowland Shales are much thicker than the Marcellus Shale. However, many of the principles and techniques will be similar.

Hazard assessment

Moderate due to the potential for damage to well integrity.

Seismic activity not induced by hydraulic fracturing may also have the potential to cause damage to wells, although the UK is not noted for frequent significant activity.

3.3.10 Blowouts

Blowouts are unplanned releases of fluids or gases that happen because unexpectedly high pressures are encountered in the subsurface or because of the failure of mechanical devices and valves.

Blowouts can take place at the wellhead or at any place in the well, and can result in casing or cement integrity failure so that high-pressure fluids migrate up the wellbore and into the subsurface. Blowout preventers (BOPs) are designed to shut down fluid flow automatically when high pressures are encountered, though they do fail on occasion. Data are not available on the frequency of blowouts for onshore oil and gas wells, but data from offshore wells indicate that the frequency is 1–10 per 10,000 wells drilled. UK land wells are generally much shallower and subject to lower pressures than UK offshore wells. An unplanned well flow (known as a 'kick'), the precursor to a potential blowout, is rare in UK land well operations[11].

Wellhead blowouts are a safety hazard. Subsurface blowouts also pose an environmental hazard, with consequences dependent on:

- the activity taking place at the time;
- the depth of the occurrence;
- the risk receptors at that location.

It can be hard to determine what happens during a subsurface blowout.

Blowouts happen in both conventional and unconventional wells, with shale gas wells having the additional risk of blowouts during high-pressure hydraulic fracturing operations (Groat and Grimshaw 2012).

Hazard assessment

Moderate due to the potential to create subsurface pathways and the difficulty in detecting subsurface effects

3.3.11 Casing and equipment

Most downhole equipment is made of steel and is therefore unlikely to constitute a significant hazard. Casing threads and other equipment may be lubricated.

Hazard assessment

Low

[11] HSE, pers. comm.

3.4 Pathways

3.4.1 Geological pathway

In most shale gas plays, there is a considerable thickness of low permeability strata between the host rock and aquifers. For CBM, the distance between shallow fresh groundwater and the gas host strata may be less.

The thickness and low permeability of the intervening strata provide a geological barrier to the migration of fluids and gases from depth to freshwater.

It is a general industry assumption that a considerable thickness of intervening strata provides adequate protection from activities at depth. A recent review by Davies et al. (2012) suggests a separation of more than 500 metres is required between the location of hydraulic fracturing and fresh groundwater. However, there is limited information in the public domain to demonstrate that this is the case; that is, there does not appear to have been research to investigate and/or determine the thickness of overlying rock required to give adequate protection. The process of hydraulic fracturing may disturb conditions at some distance above the host rock. Operators can model these effects.

3.4.2 Existing anthropogenic pathways

Aquifers and underlying strata may have been previously penetrated by boreholes, wells and shafts to exploit water and mineral resources. These perforations, if not adequately sealed, can represent a pathway for the migration of gas and other fluids to the surface or to aquifers at higher levels. For example, there are believed to be on the order of 184,000 old, undocumented oil and gas wells in the US state of Pennsylvania (Groat and Grimshaw 2012).

In general, contamination by an improperly plugged and abandoned well can occur in two ways:

- The abandoned well can act as a conduit for fluid flow from depth to aquifers.
- Contaminated water can enter the abandoned wellbore at the surface and migrate downwards into aquifers (API 2009a).

In the UK, where there are limited numbers of deep wells, the presence of mining voids is likely to be a particular problem for CBM, although CBM is typically targeted to avoid mined strata because of problems of excess water.

Should shale gas be developed, and if wells are drilled and abandoned, additional potential pathways will be created over the area of the host rock.

3.4.3 Wells and boreholes

Wells and boreholes drilled through the strata separating freshwater from the host rock represent a potential pathway for introduced material to enter groundwater and for gas and formation water to migrate upwards into groundwater.

Well control and casing are used to provide barriers to prevent activation of this pathway.

The greatest potential for impacts from a shale gas well appears to be from failure of the well integrity (Groat and Grimshaw 2012). However, the physical failure of both the casing itself and the cement is unlikely (US DOE 2009), and the greatest risk comes from failure in the annulus between any uncemented casing and the formation during the fracturing process. The solution to this is the proper cementation of well casing vertically across impermeable zones and groundwater zones.

Casing may collapse due to pressure differentials between the inside and outside of the casing. This can be due to:

- naturally high formation pressure (and inadequate casing strength), which increases with depth, although high formation pressures have not historically been encountered in UK land wells;
- induced pressure due to depressurisation of a formation causing subsidence of the overlying formation(s), although this would not be expected with the low formation pressures encountered in UK land wells;
- movement of plastic formations such as evaporite sequences;
- displacement along fault planes, either natural or due to induced seismicity;
- drilling mud pressure acting on the outside of the casing.

The resistance of a section of casing to collapse is a function of the pressure acting on the casing and the ability of the casing material to resist that pressure.

An example of casing deformation occurred in the UK at Cuadrilla's Preese Hall-1 well during stage 2 hydraulic fracturing on 31 March 2011. This caused deformation of the wellbore in the 5½-inch production casing (casing diameters are specified as the outside diameter; the internal diameter can be determined from the wall thickness or 'schedule') at a depth of 2,578 metres. This deformation was measured by a caliper log as 0.5 inches over an interval of 140 metres. Specialist software was used to visualise the damage and this showed that the deformation ranged from barely detectable ovalisation to local buckling of the casing wall.

Casing damage in this instance was concluded to have occurred partly as a result of seismically induced bedrock plane shear stress. The transport direction associated with the casing damage was approximately parallel to the strike of bedding. Changes in the magnitude of deformation correlated well with interfaces between limestone-rich (calcareous) and mudstone-rich (argillaceous) layers (De Pater and Baisch 2011), which have spacing of little more than a metre (Harper 2011). Widespread casing deformation (limited to ovalisation and not offset) due to strike-slip failures has also been documented in variably dipping sandstones and shales in Colombia, an area of higher seismic activity than that experienced in the UK.

The bedding plane failure was attributed to increased pore pressure during hydraulic fracturing being sufficient to open bedding interfaces in the bedrock, resulting in their having no resistance to sliding. These were not regarded as catastrophic failure – rather they were distributed, small magnitude slips.

Further study on the deformed casing concluded that the overall wellbore integrity was not affected and there was no risk to shallow groundwater zones (De Pater and Baisch 2011), primarily because the well casing deformation occurred in the perforated production casing and therefore posed no more threat to the integrity of the wellbore than the perforations themselves.

A second explanation for wellbore deformation is simply that the high-pressure fracturing fluid injections cause slip at the wellbore. The relative magnitudes of the two categories of well casing displacement are as yet undetermined.

3.4.4 Movement via well annulus

Casing and/or cement failure could lead to leakage into an aquifer of fluids that flow upward in the annulus between the casing and the borehole. Groat and Grimshaw (2012) note, with reference to (Feather 2011), that a significant percentage of offshore oil and gas wells may have some degree of well integrity issues such as high gas pressures in the annulus. They also note that there is limited information on which to base an assessment of how many shale gas wells now have or are likely in the future to have significant well integrity issues.

HSE requires well operators to have procedures to monitor well integrity and to take the necessary action. HSE wells specialists routinely inspect for compliance with these procedures during inspections of offshore and land well sites.

The gas industry and service companies are actively developing improved cement types to seal well casing and prevent annular migration of fluid (Groat and Grimshaw 2012).

4 Licensing and regulation of well drilling, installation and testing

This section describes the regulatory regime for well drilling installation and testing.

The main controls available to the Environment Agency are summarised in Section 4.1. The other sections outline the controls put in place by other bodies and the situation in the USA, Canada and Europe.

4.1 Environment Agency control mechanisms

The main control mechanisms available to the Environment Agency are as follows:

- **The Environmental Permitting England and Wales) Regulations 2010:** these implement a range of European directives and include a wide range of pollution controls, including discharges or inputs to water, and waste and radioactive substances management, all via a single site permitting framework.
- **Section 199 of the Water Resources Act (WRA) 1991 (as amended by the Water Act 2003):** any person proposing to construct or extend a well/borehole for the purpose of searching for or extracting minerals (and gas is considered to be a mineral for these purposes) must give prior notice to the Environment Agency of their intention to do so in a prescribed form. The Environment Agency may then serve a Conservation Notice under Section 30 of the WRA requiring that person to take reasonable measures for conserving water. For example, in the case of unconventional gas wells, this could include a requirement to fully case out all groundwater-bearing horizons.

In addition, the Environment Agency provides guidance on groundwater protection and management and a number of relevant position statements in its GP3 suite of documents including statements on the protection of potable sources and stand-off distances (Environment Agency 2008, 2011).

4.2 Environment Agency position statements

Draft Environment Agency position statements on unconventional gas included in the EA's consultation on its approach to groundwater protection (Environment Agency 2011) suggest that the direct discharges of hazardous substances may be authorised for some activities involving geothermal, mining, oil and gas production, civil engineering, gas storage and scientific activities (WFD Article 11.3.(j)). (The European Commission has given a view that Article 11.3(j) does not apply to shale gas activities)[12]. The draft position statements state that:

> 'We wish to facilitate development of sustainable sources of energy, working in partnerships on initiatives where appropriate. However, we will

[12] Letter from European Commission Directorate General for the Environment to the Permanent Representative of the UK to the European Union

object to [underground coal gasification] UCG, CBM or shale gas extraction infrastructure or activity within SPZ1. Outside SPZ1, we will also object when the activity in the subsurface would have an unacceptable effect on groundwater. Where development does proceed, we expect [best available technology] BAT to protect groundwater to be applied where any associated drilling or operation of the boreholes/shafts passes through a groundwater resource. Elsewhere, established good practice should be followed. Where the activities are very deep (below the depth whereby groundwater is used by man or supports surface ecosystems), and the activity at depth will not cause interaction with usable groundwater resources, we would not seek to apply the same degree of groundwater protection and would be primarily concerned with the effects of disturbance from drilling and pipework to near surface groundwater systems'.

4.2 Exploration licensing – DECC

4.2.1 Licensing process

Exploration

DECC issues Petroleum Exploration and Development Licences (PEDLs) under powers granted by the Petroleum Act 1998. These licences confer the right to search for, bore for and secure hydrocarbons.

DECC issues a licence in competitive offerings (licensing rounds) which grant exclusivity to operators in a licence area. The licences do not give consent for drilling or any other operations. The process of obtaining consent to drill a well is the same whether the well is targeted at conventional or unconventional gas.

The last onshore licensing round, the 13th Onshore Oil and Gas Licensing Round, in 2008 awarded 55 new licences covering more than 7,000 km^2 (DECC 2010). The 14th Onshore Licensing Round (under consultation) is likely to considerably increase the area covered by onshore licences.

Licences are only granted to operators who are able to meet DECC's financial and technical criteria and who can demonstrate awareness of environmental issues. Licences are issued for an initial term of six years, a second term of five years and a third term of 20 years.

A licence does not confer any exemption from other legal or regulatory requirements such as health and safety requirements, planning permission (obtained from the local planning authority) or environmental regulations. Permission must also be granted from the Coal Authority where exploration encroaches on coal seams (for example, for coal bed methane). An operator will have to arrange access with landowners for drilling and other exploration activities and secure planning permission from the local mineral planning authority (MPA).

Once the MPA has granted permission to drill, additional consent to drill is required from DECC. Before providing this consent, DECC requires:

- evidence of planning permission;
- geotechnical information;
- operational plans.

DECC have also agreed that it is appropriate to keep HSE and the Environment Agency informed of progress with issuing consents.

Once DECC has assessed the information provided, it may consent to drilling.

If the well needs more than 96 hours of testing to evaluate its potential to produce hydrocarbons, the operator can apply to DECC for an extended well test of up to 90 days provided that the licensee can demonstrate that the test will provide improved technical understanding or confidence in the performance of the field needed to progress towards a development.

Development

If the licensee wishes to develop a field (an area of oil or gas production), they must submit a Field Development Plan to DECC in support an application for development and production authorisation. The plan should contain:

- a brief description of the hydrocarbon reservoir, estimated reserves, development strategy, facilities and pipelines;
- an outline map showing the field limits, field determination boundary, development area boundary (that part of the field to which the development proposals refer), contours of fluid contacts, existing and proposed wells, and licence boundaries;
- a project schedule, total capital cost and a statement of licence interests;
- a central estimate of ultimate recovery and the minimum, central and maximum hydrocarbon production profiles of oil and gas;
- a statement of intent towards any parts of the field not addressed by the plan including any commitment to later development of that area, or to the later stages of a phased development – any provision for the development of other hydrocarbons in the area should also be identified;
- the basic elements of the Field Management Plan, which describes how the field will be worked, including potential requirements for further wells and workover operations;
- a copy of the relevant planning consent(s);
- a statement undertaking that the field will be decommissioned in accordance with the requirements of the applicable planning approval.

The field must be determined by DECC before development can take place. Field determination involves DECC issuing a proposal for the field boundary to:

- all licensees with an interest in the licence blocks in which the field is situated;
- licensees in adjacent blocks.

There is then a consultation period with licensees before a final field determination.

Fields may be subject to re-determination at any time at the request of any party following the acquisition of new information (for example, from seismic information or from wells) that indicates the original determination is no longer valid.

DECC approval for further drilling and development will also require landowner permissions, planning consent, Environment Agency consultation and HSE notification.

If an operator suspends operations, they must gain DECC approval before recommencing operations.

The development and management plan should be reviewed at least annually and submitted to DECC.

DECC permission is required before production can cease. A cessation of production report is required at this stage.

Abandonment

Abandonment of wells must be approved by DECC. The application must include an abandonment plan and specification for the abandoned well.

4.2.2 Licence information requirements

DECC requires the following details for a licence application:

- company details:
  - registered name and address;
  - company number;
  - location of main UK place of business;
- previous operating experience of supervising or carrying out drilling or production operations within the past two years including the location;
- a description of the proposed operator's responsibilities for the operations and their in-house geotechnical and drilling management expertise;
- lists of the skills that exist in-house and the skills to be contracted;
- list of key personnel involved in decision-making (including their role) including previous experience and the basis on which they are employed; and the key contact point in an emergency;
- use of contractors:
  - name(s) of contractor(s);
  - list of areas of drilling and production management activity to be outsourced to contractors;
  - description of operator's relationship with the contractor;
  - details of contractor's experience of planning and/or drilling wells and production facilities, especially where relevant to the operations currently proposed;
- proposed operator's presence during drilling operations including written confirmation that at least one qualified representative from the proposed operator will be present, usually in the UK, for the duration of drilling operations;
- insurance – list of contingencies covered by insurance.

4.2.3 Licence requirements

DECC licences contain a number of requirements including:

- keeping accurate records of the drilling, deepening, plugging or abandonment of all wells and of any alterations in the casing, including:
  - the site of, number and name (if any) assigned to every well;
  - the strata through which the well was drilled;
  - the casing inserted in any well and any alteration to such casing;
  - any petroleum, water, mines or workable seams of coal encountered in the course of such activities;
- providing an annual return/report giving:
  - details of all geological work, including surveys and tests carried out;
  - the number and name (if any) assigned to each well;
  - a statement of the depth drilled in each well;
  - a statement of any petroleum, water, mines or workable seams of coal or other minerals encountered in the course of the operations.

The Petroleum Operations Notice no. 9b describes the record and sample requirements for onshore geophysical surveys and wells which includes the requirement to submit a complete set of logs and end of well report to DECC

4.2.4 Well numbers

DECC operates a well registration numbering system, which provides an unambiguous reference for all wells. The full DECC well number must be quoted on all returns, well logs, reports and correspondence related to a well. Onshore wells may also have a name as a secondary identifier. An operator’s internal well-numbering system should avoid confusion with the DECC well registration number.

4.2.5 Groundwater protection

Typical licensing requirements include a provision to prevent the escape of petroleum into any waters in or in the vicinity of the licensed area.

4.3 Health and Safety Executive (HSE)

The wells team of HSE regulates the safety of exploration, drilling and production operations. HSE’s specific requirements with respect to the design, drilling, testing, development and abandonment of wells are summarised below with particular reference to the extent to which compliance with HSE requirements is likely to be protective of the environment. The potential additional measures or requirements to protect the environment that are not contained within HSE’s regulations (for example well design, drilling practice and completions not covered by HSE are highlighted in Section 4.3.5.

In addition to general workplace legislation (for example, the Health and Safety at Work Regulations), two specific regulations apply to boreholes and wells. These are:

- The Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996 (SI 1996/913). These are generally abbreviated to DCR. The relevant parts are:
  - Part IV (wells);

- Regulation 13 (general duty);
- Regulation 14 (assessment of conditions below ground);
- Regulation 15 (design with a view to suspension and abandonment);
- Regulation 16 (materials);
- Regulation 18 (arrangements for examination).

- The Borehole Sites and Operations Regulations 1995 (BSOR) (SI 1995/2038). These regulations apply to all onshore operations involving prospecting for, or extraction of, oil, gas or coal bed methane by borehole.

The DCR apply to aspects of onshore drilling not covered by the BSOR. The over-riding principle of the DCR is that wells should be designed, constructed and maintained such that the risk of unplanned escape of fluids from a well is reduced to 'as low as is reasonably practicable' (the ALARP principle). This requirement applies throughout the life of the well until it is finally plugged and abandoned.

Guidance is available from HSE on both the DCR (HSE 2008a) and BSOR (HSE 2008b) to explain their requirements. Additional guidance is provided on well construction and casing (HSE 2012) and on control of wells during intervention operations (HSE 2007). A summary of the requirements of the Regulations and of HSE guidance relevant to well casing is provided below.

Oil & Gas UK (OGUK), a trade body representing the UK offshore oil and gas industry, has published guidelines on well abandonment (OGUK 2009) and will shortly be publishing guidelines on well integrity to help operators comply with DCR and BSOR requirements.

4.3.1 Roles and responsibilities

The owner is the holder of the exploration licence. An operator is either the owner, or a person or organisation appointed by the owner to undertake the works. The operator exercises overall control of the borehole site and to co-ordinates operations.

The owner must ensure that the operator has:

- the knowledge, skills and capacity to undertake the work required;
- previous experience of the type of borehole site and the borehole operations to be carried out there.

Where the operator is an organisation, responsibility and authority for individual sites and particular borehole operations must be clearly defined, specified and allocated to competent individual staff.

At large drilling operations on a production site, the site may be demarcated between drilling and production sites with separate operators for each operation.

HSE recommends that an individual person should not be expected to exercise overall control of more than one deep drilling operation at any time. However, an individual person may be appointed as the operator for a drilling operation while at the same time being the appointed operator for a number of sites where drilling is not being carried out.

Site operators should ensure there are sufficient competent persons on-site to perform those functions required for its safe operation.

4.3.2 Offshore Installations and Wells (Design and Construction, etc.) Regulations

The wells requirements of DCR apply to onshore borehole operations, with the exception of Regulation 17 on well control, which applies offshore only. The requirements of Regulation 17 are, however, covered by Regulation 9 of the BSOR (see Section 4.3.3).

The main duties placed on operators by the DCR are to:

- ensure that a well is designed, modified, commissioned, constructed, equipped, operated, maintained, suspended and abandoned so that risks are as low as is reasonably practicable (ALARP);
- conduct an assessment of conditions below ground before starting a well;
- ensure that the design and construction of a well address satisfactorily its subsequent suspension and abandonment;
- ensure that before the design of a well is begun or adopted, a well examination scheme is in place for ensuring that the well is designed and constructed so that so far as is reasonably practicable there can be no unplanned escape of fluids[13] and that the risks to people's health and safety are as low as is reasonably practicable;
- provide regular reports of well operations activity to HSE;
- promote competence in those who carry out well operations by ensuring they receive appropriate information, instruction, training and supervision.

HSE guidance on the DCR (HSE 2008a) uses the concept of the pressure containment boundary. The maintenance of the pressure containment boundary provides well integrity by placing barriers between the hazards in the well and the surface. Any equipment that is vital to controlling the pressure within the well is therefore part of this boundary, including downhole pressure-containing equipment and the pressure-containing equipment on top of the well such as BOPs. A well intervention operation is an operation which involves entering the pressure boundary of the well.

The operator must gather and assess information on the geological strata and the formations and fluids within them that will be encountered in order to identify any hazards that such strata and formations may contain. These factors will then inform the well design but any changes encountered during drilling must be taken into account and, where necessary, changes made.

The well operator is then required to predict the subsurface environment that could be expected in the well, being conservative in their predictions where there is insufficient information. The assessment should include all potential hazards and circumstances likely to lead to unsafe well conditions. It should include not only formations that may pose a hazard directly, but also those which may affect the ability to control a hazardous situation such as:

- potential zones of circulation loss;
- zones with the potential for causing stuck drill pipe;

[13] Regulation 13 of the Offshore Installations and Wells (Design and Construction, etc) Regulations 1996. This requirement is interpreted as covering escape subsurface (e.g. to aquifers) as well as at surface. The regulations apply to onshore oil and gas wells as well as offshore wells. HSE, pers. comm.

- over-pressured plastic salt formations (that is, formations that will flow/deform in the wellbore).

Wells should be designed and constructed so that they can be safely suspended (temporarily abandoned) or permanently abandoned.

The DCR require operators to provide weekly progress reports to HSE during drilling and testing, and other intervention operations. These reports should include information on:

- well number;
- activity since the previous report;
- diameter and true vertical and measured depths of any hole drilled and any casing installed;
- drilling fluid density immediately before making the report;
- current operational state of existing wells.

4.3.3 The Borehole Sites and Operations Regulations 1995

This section identifies the requirements of the BSOR likely to be relevant to understanding and managing risks to the subsurface environment.

Notification

Regulation 6 requires that the operator gives HSE 21 days' notice of the commencement of drilling operations and the abandonment of boreholes.

Notification is required for all operations that would make a significant alteration to the well or involve a risk of the accidental release of fluids from the well or reservoir. Notification must include:

- operator's name and address;
- details of the type of well, its number and its name;
- details of the rig or other plant to be used;
- details of surface equipment and circulation fluids to be used to control pressure in the well;
- details, including scale diagrams, where appropriate, of:
  - National Grid Reference of the top of the well;
  - directional path of the borehole;
  - terminal depth and its location;
  - position of the well and that of nearby wells and mine workings relative to each other.
- a description of the planned operations and a programme of works including:
  - starting and finishing dates;
  - a diagram showing details of the intended final completion or recompletion of the well.

- a description of any activities during operations on the well that would involve a risk of the accidental release of fluids from the well or reservoir, and the nature of such hazards;
- in the case of drilling works:
  - the geological strata and formations and fluids within them through which the borehole may pass and of any hazards with the potential to cause fire, explosion or a blowout which they may contain;
  - the procedures for effectively monitoring the direction of the borehole and the effects of intersecting nearby wells;
  - the design of the well in sufficient detail to show that it takes account of the geological strata, fluids and so on, and that it will so far as is reasonably practicable be safe.
- for work on existing wells:
  - a diagram of the well;
  - a brief history of the well including a summary of previous operations and any problems encountered;
  - the well's present status and condition.
- in the case of an abandonment operation, details of the proposed sealing or treatment.

Health and safety document

Regulation 7 requires a health and safety (H&S) document to be prepared before operations start. The H&S document must demonstrate that:

- the risks to which persons at the borehole site are exposed have been assessed;
- adequate measures, including measures concerning the design, use and maintenance of the borehole site and of its plant, will be taken to safeguard the health and safety of those at work at the borehole site. The H&S document must include a statement of how the measures will be co-ordinated.

The H&S document must include a plan for the prevention of fire and explosions, including provisions for preventing blowouts and any uncontrolled escape of flammable gases and for detecting the presence of flammable atmospheres.

The document must be kept up-to-date and revised to reflect any changes at the site or operations.

For operations with clearly defined stages (for example, drilling followed by testing and then production), the H&S document may be compiled in stages but must be complete at the start of each stage.

Although focused on the safety of site workers, the measures in the H&S document that are likely to provide protection to the environment include requirements to prevent the release of liquids, vapours or gases in circumstances or in quantities that could endanger persons by fire, explosion or any other means.

The H&S document should detail the well control arrangements and the type of equipment required for each stage of the borehole operations.

Well control

The BSOR require that well control is in place at all times. The purpose of well control is to reduce the risks to persons on site and in adjoining areas by preventing uncontrolled escapes from wells (blowouts) of flammable, explosive or toxic fluids by safely disposing of influxes of hazardous fluids from wells and by mitigating the consequences of any blowout.

Not all wells covered by the BSOR require well control as it covers boreholes drilled for a range of different purposes. However, all wells drilled for the exploration or production for oil, gas and CBM will require well control.

Well control requirements should be determined by risk assessment based on knowledge of:

- the underground strata through which the borehole is intended to pass;
- the permeability and porosity of the formations;
- the likelihood of the formations' containing fluids under pressure.

This will require a pre-drilling assessment of available relevant information such as:

- records from previous boreholes through the same formations, particularly those local to the site;
- location and proximity of other boreholes;
- location and proximity of underground workings.

All permeable formations in areas where there are known or suspected deposits of oil, natural gas or coal should be considered to contain hazardous fluids except those that are so shallow that it is unlikely that the overlying rock formations could trap the fluids under pressure.

Effective well control requires a suitably designed and constructed borehole to ensure the prevention of uncontrolled release of formation fluids to other formations, other underground voids and the surface. This includes all equipment used to:

- detect unplanned influxes of formation fluids into the well – including instrumentation that monitors drilling fluid levels, flow detection, low and high pressure measurement and so on in order to recognise change in well parameters that could result in a loss of well control;
- prevent, control or divert the flow of fluids from the well;
- purge formation fluids from the well;
- separate formation fluids from the drilling fluid.

Well control equipment includes equipment to contain and control fluids under pressure. It can include:

- surface, downhole and internal blowout preventers (BOPs);
- drilling heads, pumps, plugs valves and so on used to control pressure in the well;
- all associated pipework.

Well control equipment must be suitable for the type of operation being carried out in terms of:

- size;
- connection type;
- pressure and temperature;
- chemical properties of the formation fluids that may be encountered.

The equipment should be designed, constructed, installed, commissioned, used and maintained in accordance with appropriate standards. It should have in-built redundancy to minimise the consequences of a failure.

4.3.4 HSE circulars

The guidance given in HSE Semi-Permanent Circular (SPC) 42 (HSE 2012) on what should be considered acceptable in terms of well construction and casing is summarised below.

Casing design and installation

Table 4.1 gives details of material standards and the key requirements of HSE guidance on casing design. SPC42 also requires that:

- All surface, intermediate and production casings should be pressure tested to an appropriate value for the well being constructed prior to drilling out the shoe track (this takes place after cementing) or perforating the casing.
- Up-to-date records are kept during drilling operations showing the configuration and depth of casing strings, formation tops, particularly porous zones and all hydrocarbon-bearing zones and cement tops and cement specification behind the casings.
- All hydrocarbon-bearing zones should be isolated from surface.
- For all cementing operations, the cement should be placed and checks carried out to ensure that the cementing objectives are achieved.
- The quantity of cement must be sufficient for the operation. A prudent excess is required to account for possible losses during placement and variation in the diameter of the open hole. The conductor and surface casing should normally be cemented back to the surface. Intermediate and production casing should, where appropriate, be cemented back to the previous casing shoe and preferably back to surface for shallow strings. Production casing should, where appropriate, be cemented to an acceptable height inside the previous shoe.
- Exceptions to the requirement for cementing back to the previous casing shoe or to surface are:
    - where it precludes a later well sidetrack (that is, the drilling of a spur off the first well);
    - to prevent losses or breakdown of weak formations;
    - to allow cuttings injection down a well annulus.
- The density of cement must be suitable and the formations should be capable of withstanding the hydrostatic head of the cement column. Primary well control must be maintained while the cement is curing.

Cement and spacer fluid density should be sufficient to prevent influx of well fluids.

- The class of cement must be suitable for the proposed use in terms of the formation properties and temperatures anticipated or measured.
- The use of cement bond logs for verification of cement bonding represents good practice for production casing and intermediate casing strings covering hydrocarbon bearing zones.

Table 4.1 Material standards and requirements

Material	Standards	HSE requirements
Wellhead equipment	ISO 10423 (API Spec 6A) Specification for wellhead and Christmas tree equipment (ISO 2009a)	All wellhead equipment should be manufactured, inspected and tested to the Standard. Surface wellheads must have side outlet access to all annuli to allow pressure to be monitored and bled off or fluids pumped from the annulus. Gauges must be capable of reading the full range of annulus pressures accurately.
Casing	Casing should be manufactured, inspected and tested to ISO 11960 (API Spec 5CT) Specification for casing and tubing (ISO 2011)	Casing should be suitable for the environment into which it is placed and for the fluids and gases that it will come into contact with. Casing should be designed and constructed to minimise risk of crossflow between formations or the uncontrolled release of wellbore fluids to surface throughout the life of the well. Casing setting depths should provide an adequate safety margin between the formation fracture pressure and pressures anticipated during well control or cementing operations. Limitations on well control pressures should be detailed in the design of the well. The design should make allowance for deterioration in service as a result of wear, corrosion and erosion. Casing should be able to withstand the pressure of a full gas column or gas from the weakest exposed formation, whichever is less, with an adequate safety factor as set out in the OGUK guidance on well integrity being prepared by the Well Life Cycle Practices Forum. Production casing should be able to accommodate a leak in the production tubing at the wellhead and withstand closed-in wellhead pressure plus a head of packer fluid. Where there is a possibility of casing failing in tension or collapse under worst case conditions, then the likelihood should be minimised by the use of suitable procedures. The annulus should be monitored continuously. Instrumentation and gauges should be calibrated on a regular basis. Casing void spaces should be tested at the time of wellhead installation and at regularly thereafter to ensure the continued integrity of seals.

Material	Standards	HSE requirements
Casing in sour environments	ISO 15156 (NACE MR 0175) Materials for use in H_2S-containing environments in oil and gas production (ISO 2009b)	Casing should be suitable for the environment into which it is placed and for the fluids and gases that it will come into contact with. Where hydrogen sulphide is anticipated (sour environment), materials should conform to the requirements of ISO 15156.
Packers	ISO 14310 (API 11D1) Specification for packers and bridge plugs (ISO 2008a)	Packers should be manufactured, inspected and tested to the appropriate ISO specification. Straddle packers can be used to isolate tubing leaks in the production casing. However, they must not compromise the safe operation of the well. Use of a straddle packer should not prevent good abandonment practice. Tubing repairs should be tested with an internally applied pressure greater than maximum shut-in wellhead pressure. Completion packers should be tested from above, to a pressure exceeding the worst case annulus pressure.
Well completions	ISO 10432 (API Spec 14A) Specification for subsurface safety valve equipment (ISO 2004a)	All wells used for production or injection must incorporate a dedicated completion string. Well completions should incorporate at least two barriers to flow between the reservoir and the surface; normally these constitute the tubing hanger and packer or polished bore receptacle and seal assembly. The completion should include the facility to plug the well immediately above the reservoir and at the wellhead. There should be additional provision for plugging the well beneath potential intersection points. All completions should incorporate a subsurface safety valve at an appropriate depth to minimise the inventory of well fluids that could be released in the event of wellhead failure. The valve should meet ISO 10432. Suitable arrangements should allow the wellbore to be adequately swept of well fluids by circulation. For open-hole completions, formations between reservoir and previous casing shoe must be impermeable and competent. The previous casing shoe must have a competent seal with cement verified and tested to a known leak-off pressure. The shoe should be set close to the reservoir. The completion must incorporate a packer inside the casing and as close to the casing shoe as possible. Production tubing incorporated in a well must be of a specification, including connection type, which is fit for the purpose of the well.
Subsurface	ISO 10417 (API RP 14B)	Valves must be function and pressure tested at

Material	Standards	HSE requirements
(or downhole) safety valves (SSSV/ DHSV)	Design, installation, repair and operation of subsurface safety valve systems (ISO 2004b)	appropriate intervals as recommended in ISO 10417, which specifies a maximum testing interval of six months, unless local regulations, conditions or documented historical data indicate a different testing frequency. Testing procedures must include clearly defined acceptable leak rates.
Production wells		All wells used for production or injection must have procedures in place for monitoring all annulus pressures and tubing/ annulus communication. The procedures should take full account of the specific circumstances of the well and must specify allowable leakage rates and anomaly reporting criteria. Where there is an anomaly, production or injection should not continue unless the situation has been fully risk assessed and the conclusion reached that it is safe to continue.

4.3.5 Potential requirements for additional risk mitigation

Compliance with HSE requirements would seem to give a large measure of protection to groundwater, particularly from the mitigation measures to prevent of loss of control/maintain well integrity and most importantly from the sealing of the surface casing within the well. However, the EA may need to give additional consideration to the following areas:

- **Well design**. Requirements for groundwater protection should be explicitly included in the well design, including:
  - the use of appropriate drilling fluids;
  - identification of zones where inflows are expected;
  - depth of surface casing;
  - measures to avoid losses of drilling fluids and grouts to formations;
  - measures to avoid cross-connection of aquifers.
- **Depth to base of surface casing**. Surface casing forms the primary barrier to prevent substances inside the well casing entering near-surface groundwater. It is therefore crucial that the surface casing extends well below the base of any such groundwater body and into underlying low permeability strata. (This should be taken to be a fundamental principle of well design and so would normally be considered to be covered by DCR13)
- **Materials**. Emphasis is placed on the suitability of materials in providing adequate control and having resistance to aggressive environments within and outside the well. However, no consideration is given to the pollution potential of introduced materials.
- **Leakages**. The emphasis of the guidance is on preventing loss of control, particularly at the surface. There is less emphasis on preventing losses to ground, though DCR 13 should be taken to cover escape of fluids both to surface and subsurface (escapes subsurface may either find their way to

surface or provide a risk to safety to the drilling of wells in the vicinity in the future).

- **Drilling fluid/mud control.** The guidance discusses requirements to maintain control through the weight of mud in the casing and the need for vigilance to ensure that control is maintained where there is loss of circulation. It does not consider the potential detrimental effects of mud invading the formation, although shallow formations where high quality groundwater may be expected are drilled with water and simple drilling fluids composed of water and clay.
- **Use of drill cuttings as backfill.** This is mentioned briefly. Drilling cuttings are potentially contaminated with hydrocarbons, mud and/or radioactivity (NORMs) and their use could result in pollution of groundwater, although it is unusual to use cuttings as backfill.
- **Testing and monitoring**. Minimum testing and monitoring requirements are not specified; (HSE regulations are goal setting and do not detail minimum testing and monitoring requirements. The Well Operator proposes the monitoring standards, which are subject to agreement with the regulator, and HSE inspect to ensure the standards are met).

4.4 Coal Authority

The consent of the Coal Authority is required before any works take place that intersect any coal and/or coal mine vested in the Authority. The Authority grants access agreements to enter its property for coal methane exploitation.

The Coal Authority has a specific duty in the exercise and performance of its powers and duties with respect to its land and other property to have regard to the desirability of the exploitation, so far as that is economically viable of coal bed methane in Great Britain (Coal Industry Act 1994, Section 3(5)).

4.5 Planning permission

Drilling will require planning permission from the local mineral planning authority (MPA). The MPA will also determine if an environmental impact assessment (EIA) is required. An environmental permit from the appropriate environment agency may also be required. Notification of an intention to drill has to be served to the Environment Agency under Section 199 of the Water Resources Act 1991.

4.6 The position in the USA

Shale gas has been commercially exploited in the USA for a number of years. US legislators and regulators thus have valuable experience in regulating this comparatively new industry.

Shale units capable of producing natural gas in large quantities are found in five regions of the continental USA. These regions are listed below with the shale plays and percentage of US resources (Groat and Grimshaw 2012, p. 7):

- Northeast (Pennsylvania, New York State, West Virginia, Virginia, Maryland, Ohio): primarily Marcellus (63 per cent);
- Gulf Coast (East Texas, Louisiana): Haynesville, Eagle Ford (13 per cent);

- Southwest (Texas): Barnett and Barnett-Woodford (10 per cent);
- Mid-Continent (Arkansas): Fayetteville, Woodford (8 per cent);
- Rocky Mountain (Colorado, Wyoming, Montana): primarily Mancos and Lewis (6 per cent).

Some 33 states currently have some form of oil or shale gas production within their boundaries (USDOE 2009).

The federal nature of the USA means that legislation and policy take place at a number of levels. The two main levels are federal (national) and state, but some rule making is devolved to lower tiers of government such as counties or cities. Constitutional and federal law, ratified by Congress at a national level, is the 'supreme law of the land' and overrides any conflicting state or local level law. State governments have the power to make laws on anything not covered by the federal constitution. Most state laws are based on English common law. At a local level, states have delegated law-making powers to thousands of agencies, townships, counties, cities and special districts.

Congressional environmental law is enforced through regulations produced by USEPA. USEPA sets national standards that states and tribes may enforce through their own regulations. Statutes and regulations have been implemented in every oil and gas producing state to ensure that operations are conducted in an environmentally responsible manner (API 2009a).

State requirements as detailed in a Department of Energy (DOE) review (US DOE 2009) are summarised in Section 4.6.1. The applicable legislation in two states, Pennsylvania and Colorado, is described separately in Sections 4.6.2 and 4.6.3 respectively. These were selected on the basis that Pennsylvania has the greatest experience of shale gas and a long history of oil production while Colorado reputedly has the most stringent legislation. Links to individual state legislation can be found on the FracFocus website (http://fracfocus.org), the hydraulic fracturing chemical registry website. This website is a joint project of the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.

4.6.1 State requirements

In a review of state legislation for 27 states (USDOE 2009), all oil and gas producing states were found to require permits governing the locating, drilling, completion and operation of wells. The granting of permits was found to be delegated by the state legislature – typically to an oil and gas division.

The USDOE review also considered individual state requirements for casing installation and abandonment. The main findings are detailed below.

Casing installation

Nearly all states require the circulation of cement behind surface casing but it is not a universal requirement. In some states, cement is required across the deepest groundwater zone but not all groundwater zones. However, such variations from the circulation of cement on surface casing are still designed to ensure that groundwater zones are isolated from production zones.

Intermediate casing is usually required only for specific reasons such as additional control of fluid flow and pressure effects, or for the protection of other resources such as mineable coals or gas storage zones. Intermediate casing can also be required where there is a need for well control of pressure.

Production casing is required in all cases. Some states require complete circulation of cement from the bottom to the top of the production casing, but most states require only an amount of cement calculated to raise the cement top behind the casing to a certain level above the producing formation. This means that part of the annulus around production casing may not be cement filled.

Cement circulation from bottom to top on production casing is not always required for two reasons:

- In very deep wells, the circulation of cement is difficult to accomplish. Cementing must be handled in multiple stages, which can result in a poor cement job or damage to the casing if not performed properly.
- Circulation of cement on production casing prevents the ultimate recovery and potential reuse of the casing when the well is plugged. It also prevents the replacement of casing during the life of the well.

Some, but not all, states require the use of production tubing in addition to casing.

Abandonment

Most states require an authorisation from the regulator before a well can be left in a temporarily abandoned state. Many states also require the operator to do one of the following:

- Demonstrate the integrity of the well by a casing pressure test or other means (some for initial temporary abandonment status and others upon renewal); or
- Construct and/or maintain a well in a specific way. For example, renewal of temporary abandonment status in Indiana requires an operator to either place a bridge plug in the well or demonstrate that the fluid level in the casing is 100 feet (30 metres) below the deepest drinking water supply.

All states reviewed by USDOE (2009) regulate the practice of well plugging. Most states have specific requirements regarding the materials and placement method for plugs. To control this activity, most states require operators to submit a plugging plan in advance of the work. Most states allow clay to be used as a spacer between cement plugs but not as a primary plugging material.

Cast iron bridge plugs (CIBPs) are recognised as providing a good well seal, especially when there is significant bottom hole pressure. However, they are subject to corrosion over time and need to be capped with an appropriate cement plug to assure the long-term integrity of the plugged well.

Most states require a combination of plugs at multiple intervals to assure long-term protection from fluid migration and to compensate for various downhole geological and hydrogeological conditions that might render plugging materials ineffective. This includes requirements for a cement bottom plug through and/or above producing formations and the placement of a top plug across the deepest groundwater zone.

Additionally, the majority of states require either the pulling of uncemented casing or that it is cemented in place. A smaller number of states also require that cement plugs be placed using specific methods that allow regulators to ascertain the location of plugs. Most states also require a plugging report detailing the methods used and the location of plugs.

4.6.2 Commonwealth of Pennsylvania

In Pennsylvania, oil and gas exploration is regulated under:

- the state's oil and gas laws:
  - Oil and Gas Act;
  - Coal and Gas Resource Coordination Act;
  - Oil and Gas Conservation Law;
- its environmental protection laws including:
  - Clean Streams Law;
  - Dam Safety and Encroachments Act;
  - Solid Waste Management Act;
  - Water Resources Planning Act;
  - Community Right to Know Act.

The Pennsylvania Code is an official publication of the Commonwealth of Pennsylvania containing regulations and other documents filed with the Legislative Reference Bureau. Title 25 of the Pennsylvania Code addresses environmental protection. Within Title 25, Chapter 78 covers oil and gas wells.[14] The relevant section on casing installation and assessment is Subchapter D 'Well drilling, operation and plugging'. This provides relevant requirements, which are summarised in Section 5 (although these regulations are under review and likely to change).

The conditions set out in the Code are generally in line with good practice set out in Section 5. However, Chapter 78.83 contains specific provisions regarding the depths of casing shoes for surface casing as set out below:

- The operator is required to drill to 50 feet (15 metres) below the deepest fresh groundwater (proven or reasonably estimated), or at least 50 feet into consolidated rock and immediately setting and cementing surface casing to that depth.
- Surface casing may not be set more than 200 feet (60 metres) below the deepest fresh groundwater except if necessary to set the casing in consolidated rock.
- Surface casing should be cemented to the surface.
- If additional fresh groundwater is encountered in drilling below the permanently cemented surface casing, it must be protected by installing and cementing a subsequent string of casing.
- Other flowing horizons should also be isolated with cement in the annular space.
- Where the surface casing cannot be cemented back to surface due to lost circulation, a cement basket (used to infill washouts and so on) may be installed immediately above the depth of the anticipated lost circulation zone.

The Code also incorporates specific provisions relating to the protection of coal reserves and plugging worked coal seams.

[14] http://www.pacode.com/secure/data/025/chapter78/chap78toc.html

The Code specifies contingency measures to be undertaken in the event that cementing of surface casing does not result in cement being circulated to the surface despite pumping a volume of cement equal to or greater than 120 per cent of the calculated annular space. The operator must fill the annulus from the surface and install and cement additional casing.

The Code also contains specific abandonment provisions relating to the placement of cement plugs to isolate hydrocarbon, gas and water bearing horizons. The entire hole is required to be filled either with cement plugs or a combination of cement plugs and non-porous materials.

Pennsylvania regulatory regime tends may be considered to be prescriptive unlike the goal-setting approach used in the UK and Norway. Following the Gulf of Mexico blowout in 2010, the US authorities are moving to a goal-setting approach to regulation of offshore operations; it is considered that a goal-setting approach can adapt well to new technology and as best practice develops[15].

4.6.3 Colorado

The oil and gas industry in Colorado is regulated by the Colorado Oil and Gas Conservation Commission (COGCC), a division of the Colorado Department of Natural Resources. COGCC issues permits for the drilling and operation of oil and gas wells, and enforces rules and regulations for the spacing of wells, wellbore construction and well site reclamation. Rules are also enforced for the abandonment of wells and for the treatment and disposal of oil and gas exploration and production waste.

COGCC has a number of rules and policies in place; the 300 Series Rules govern drilling, development, production and abandonment (COGCC 2012). As with Pennsylvania, these generally reflect the good practice set out in Section 5.

Fresh water occurs at great depth in Colorado and there are specific provisions in the Rules for such cases (COGCC 2012, p. 23):

> '... sufficient surface casing shall be run to reach a depth below all known or reasonably estimated utilizable domestic fresh water levels ... Surface casing shall be set in or through an impervious formation and shall be cemented to fill the annulus to the top of the hole ...'

For deep fresh water aquifers an alternative option given in the 300 Series Rules is to stage cement the intermediate and/or production string to provide protection.

4.7 The position in Canada

The Canadian shale gas industry is not yet producing on a large scale. However, there are several large plays in British Columbia, Quebec and Ontario (including the northernmost limit of the Marcellus Shale) which have recently increased estimated recoverable gas reserves in Canada. The major increase in exploration in Canada has been prompted by the economic success of shale gas in the USA. Of primary concern to stakeholders and regulators is the availability of the large volumes of water required for hydraulic fracturing, with an industry focus on the use and re-use of non-surface and non-potable water sources.

For instance, the Energy Resources Conservation Board (ERCB) of the Province of Alberta has identified a 'Base of Groundwater Protection' (BGP) across the province. The BGP is defined as the depth below which the TDS concentration in groundwater

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[15] HSE, pers. comm.

exceeds 4,000 mg/L. The groundwater below this depth is generally considered to be useable only with treatment. Any wells drilled and completed below the BGP, which can be determined for any given location across the province using a web portal,[16] must have cement behind their surface and/or production casing from ground surface to below the BGP.

4.8 The position in Europe

To date, there has been some limited exploration for shale gas in a number of EU Member States but unconventional gas has not yet been developed for production.

A review of legislation in relation to unconventional gas commissioned by the European Commission (Philippe and Partners 2011) concluded that:

- existing EU and national legislation is sufficient to control shale gas (and presumably other unconventional gas), with particular reference to environmental aspects;
- there was no requirement for further legislation.

In a survey of France, Germany, Poland and Sweden, the review also found that:

- no specific legislation had been passed by these countries to control unconventional gas;
- the countries surveyed made use of existing legislation developed in relation to conventional hydrocarbons.

The review also noted the possible need for some adjustments in implementation by Member States to:

- increase public participation;
- reduce the thresholds at which EIAs are required (at the same time addressing the combined impact of separate schemes or creeping development);
- facilitate a more integrated approach by the different regulatory bodies.

[16] https://www3.eub.gov.ab.ca/Eub/COM/BGP/UI/BGP-Main.aspx

5 Good industry practice for well casing installation and monitoring

The exploration and development of hydrocarbon resources is a complex multi-stage process. This section considers only those stages of the process relevant to the design, construction, testing and abandonment of well casing. Guidance is provided on what information and testing requirements constitute current good practice.

The understanding of good industry practice has been drawn from a number of sources but principally:

- The Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996 (DCR);[17]
- The Borehole Sites and Operations Regulations 1995 (BSOR);[18]
- HSE guidance on DCR and BSOR (HSE 2008a, 2008b);
- HSE Semi-Permanent Circulars:
  - SPC 42: Well construction standards (HSE 2012)
  - SPC 20 Control of wells during intervention operations (HSE 2007);
- Oil and Gas UK guidance:
  - draft well integrity guidelines (OGUK)
  - *Guidelines for the suspension and abandonment of wells* (OGUK 2009);
- API guidance on hydraulic fracturing (API 2009b).

In addition, the requirements of the legislation enacted in the US states of Pennsylvania and Colorado legislation have been taken into account. It is also understood that the UK Onshore Operators Group (UKOOG) is developing guidance on well integrity and hydraulic fracturing.

Some of the requirements noted here as good practice are required by:

- DECC as part of licensing;
- the local planning authority as part of a planning application;
- HSE to comply with the DCR and BSOR.

These mandatory requirements are identified in the text and it is recognised that although these requirements can mitigate risks to the environment, their main goal is not the protection of groundwater.

Mandatory requirements are those expressed as 'must', 'shall' or 'will'. Recommended good practice is expressed as should. These good practice requirements are those that are required or expected of competent operators; they are not requirements of the Environment Agency.

[17] http://www.legislation.gov.uk/uksi/1996/913/contents/made
[18] http://www.legislation.gov.uk/uksi/1995/2038/contents/made

Operators have their own internal procedures, which may vary from the practices described here. However, those procedures should provide similar levels of protection to groundwater.

Additional care will be required when drilling the first borehole in a field, or the first well on a multi-well pad to ensure high quality data acquisition to inform future wells and to undertake adequate testing to demonstrate that the well design is appropriate to the geological conditions encountered. In addition to permitting improved designs, such information can be used to avoid potentially adverse effects from, for example, induced seismicity or the development of fractures outside the target formation. The design of subsequent wells should take into account the information collected from the first well.

Computer simulation methods are available for many design and operational requirements (including casing string design, cementing and hydraulic fracturing). They should be used to aid design and construction but should be supported by site-specific data.

Current good practice appears to be regarded by the industry and regulators in the USA as sufficient to protect groundwater from pollution and there is little, if any, evidence that wells installed in accordance with good practice have resulted in groundwater pollution. However, there is ongoing research (for example USEPA 2011) to investigate well integrity and the potential for contaminants to migrate to groundwater via the well casing or natural geological features. This research has the potential to result in changes to good practice.

5.1 Standards

There is no published national or international standard for the design and construction of oil and gas wells. Standards exist only for the manufacture of the components of wells such as casing, tubing and wellheads. Well operators therefore have tended to rely on their own corporate standards (HSE 2012). However, it is understood that DECC propose to consider guidance currently understood to be in preparation by the UK Onshore Operators Group (UKOOG) along with the Oil and Gas UK Well Life Cycle Integrity Guidelines in defining the good oilfield practice under which all onshore licence owners would be required to operate.

Standards for equipment and materials in the oil and gas industry are generally referenced to the American Petroleum Institute (API). API has published industry standards (API Standards) on many aspects of oil and gas exploration and production and many API standards have been incorporated into US state and federal regulations. API standards also form the basis of many International Standards Organization (ISO) standards. HSE guidance refers to API standards for casing and downhole equipment.

There is a range of ISO/API specifications covering materials and equipment used in well drilling and construction. The principal specifications are listed in Table 4.1; additional relevant specifications are as follows:

- ISO 10427-1:2001 (API 10D) Specification for bow-spring casing centralizers (ISO 2001);
- ISO 10426-1:2009 (API 10A) Specification for cements and materials for well cementing (ISO 2009c);
- ISO 13500:2008 (API 13A) Specification for drilling fluid materials (ISO 2008).

All materials used in well construction, testing and abandonment should meet the specifications set out in Table 4.1 and should be tested to demonstrate compliance.

Regulation 16 of the DCR requires the well-operator to ensure that every part of a well is composed of material suitable for preventing unplanned escapes and reducing risks to personnel to ALARP.

5.2 Stages

Hydrocarbon exploration and development is a multi-stage process and many of the stages will be undertaken several times (for example, during exploration and then during development). Drilling of multiple wells per drilling pad and drilling from multiple pads mean that activities could be repeated many times. This section considers the stages for drilling and installing casing for a single well.

Exploration and production require owners to obtain a licence from DECC and planning permission from the local planning authority. Permits may also be required for specific activities and waste streams generated by drilling.

The licence holder (owner) will have to select a site (or sites) within the licence area for a drilling pad and make access arrangements with the landowner and obtain planning permission.

The stages of drilling, completing, testing and putting a well into production are set out below based on API (2009a). Subsequent sections provide details about these activities in relation to casing installation and monitoring:

- planning and design;
- mobilisation of equipment to site;
- setting up and testing equipment;
- drilling the hole (repeated after each casing string has been installed);
- logging the hole (repeated after each casing string has been installed);
- casing installation (repeated for each casing string):
    - running casing;
    - cementing the casing;
    - logging the casing.
- perforating the casing;
- hydraulic fracturing/well stimulation (repeated up to 20 times);
- installing production equipment and putting the well into production;
- monitoring well performance and integrity;
- abandonment.

5.3 Pre-drilling activity

5.3.1 Licensing

A licence will be required from DECC for all activity associated with the exploration and production of hydrocarbons, including gas (see Section 4.2). DECC will inform the

Environment Agency and HSE when a licence has been awarded and also when consent to drill has been granted.

5.3.2 Site selection and planning permission

Site selection will be limited by:

- the area of a licence;
- the extent of the target formation;
- the accessibility of a suitable land area (that is, land needs to be level, accessible for equipment and so on)

In addition, the licence owner will need to make access arrangements with landowners.

Planning permission from the local planning authority will be required for drilling activities. The Environment Agency will be a consultee to planning applications.

Groundwater protection should be considered during the site selection process and sensitive aquifers (or sensitive parts of aquifers) should be avoided.

The extensive use of horizontal drilling in the exploitation of unconventional gases gives some flexibility in the choice of location from which to drill. Horizontal sections of up to 2 km are reported to have been used. This means that drilling pads, and the vertical sections of wells that pass through groundwater, can be located away from sensitive locations such as inner source protection zones, as set out in the GP3 guidance (Environment Agency 2008).

Though the onus should be on the developer to liaise with the Environment Agency over potential site constraints from an environmental perspective, the Environment Agency should seek to influence site selection through discussions with the owner/operator before planning applications are made.

5.3.3 Baseline assessment

Once a well location has been selected but prior to drilling, a baseline assessment should be undertaken to establish pre-construction conditions.

For the water environment, this should identify all water features such as rivers, springs, lakes, wetlands, ponds and water wells within an agreed radius of the well location (a water features survey).

The baseline assessment should identify, catalogue and sample water features to provide a baseline in terms of water levels and water quality. Groundwater quality analysis should include:

- barium (as used in muds);
- organic substances potentially attributable/used in hydraulic fracturing (this should be specific to the substances being used) including:
  - volatile organic compounds (VOCs);
  - benzene, toluene, ethylbenzene, xylene (BTEX);
  - surfactants;
  - phenols.
- dissolved gases (methane, ethane and so on);

- radioactivity.

Consideration should also be given to testing for range of parameters that indicate the overall water quality including:

- indicators (pH, electrical conductivity);
- metals;
- major ions (calcium, magnesium, potassium, sodium, chloride, sulphate, alkalinity, nitrate).

The depth and areal extent of baseline monitoring will vary but should reflect the sensitivity of the setting.

Where an environmental impact assessment (EIA) is required, a baseline assessment will generally be required.

The baseline assessment permits any changes in conditions to be identified against starting conditions and provides a defence against any subsequent water quality issues. In the USA, a lack of baseline monitoring in early developments was an impediment to rebutting claims of damage made by private well owners. It is therefore in an operator's interest to undertake baseline monitoring.

Some new monitoring points may be required to provide suitable locations for baseline monitoring. This may require the drilling of monitoring wells in advance of development.

There are no publicly available, published guidelines on the scope and extent of baseline monitoring suitable for use in the UK. Some states in the USA have particular requirements regarding the extent of baseline monitoring, which is principally aimed at sampling of private water supplies.

It should be noted that it is possible to install groundwater sampling and pressure monitoring equipment in boreholes to depths of 2,000 metres and thus, in principle, depth should not be an impediment to effective monitoring. However, deep ground investigations and monitoring boreholes may not be financially viable and may present their own environmental issues (for example, by providing an additional pathway for migration). Direct intrusive monitoring is in practice probably limited to the shallow subsurface together with non-intrusive methods and monitoring operational processes on-site.

The British Geological Survey is undertaking a national survey of the presence of methane/natural gas in aquifers. This will provide national and regional baselines and indicate areas where methane is likely to be encountered in groundwater. While this information will be helpful, it will not be a substitute for site-specific baseline assessments.

5.4 Well design and casing programme

5.4.1 Pre-design information

During the planning stage, it is crucial to collate and review all available data and information on the subsurface within a specified search radius of the well site and the horizontal section of the well. In addition, information should be gathered on experience in drilling into the same formation at more distant locations.

The review of information should determine:

- the depths and lithologies of the formations likely to be encountered;

- the location of aquifers, groundwater and flowing horizons;
- the location, orientation and morphology of any subsurface faults and fractures that may cause lost circulation during drilling or cementing;
- whether any corrosive environments might be encountered that would require the use of corrosion-resistant casing;
- the most appropriate drilling fluid(s), taking into account the importance and sensitivity of aquifers that will be penetrated and any horizons where increased formation pressure might require a heavy fluid;
- the minimum depth to which groundwater needs to be protected with a fully cemented casing string.

5.4.2 Design

A well design is required in advance of drilling. Regulation 13 of the DCR requires that the operator must ensure that a well designed, commissioned, constructed, equipped, operated, maintained, suspended and abandoned so that:

- so far as is reasonably practicable (ALARP), 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 ALARP.

DCR 13 is taken to cover escape of fluids both to surface and subsurface. Well integrity must be maintained at all times and therefore the well must be designed to ensure this.

The well design should specify, with reference to casing installation:

- size of the well;
- depth and location of the well;
- well trajectory;
- type of casing to be used (diameter, strength, materials);
- depth at which each casing string will be set;
- drilling fluids to be used and cementing programme;
- estimated casing wear;
- depth of each casing string;
- testing and monitoring to be undertaken.

The well design and construction must take into consideration (DCR Regulations 14 and 15):

- the geological strata and formations, and fluids within them, through which the well may pass;
- any hazards which such strata and formations may contain (to be assessed);
- well abandonment requirements. The well must be designed and constructed that, so far as is reasonably practicable: (a) it can be suspended or abandoned in a safe manner; and (b) after its suspensions or

abandonment, there can be no unplanned escape of fluids from it or from the reservoir to which it led.

The operator must also ensure that:

- the geology and hazards are kept under review;
- the design is modified to take into account any changes (where appropriate).

The well design should be based on an assessment of:

- the depth and location of aquifers;
- the location of any low permeability layers (aquicludes) that separate permeable (flowing) horizons;
- anticipated worst-case formation pressures and the pressure gradient with depth;
- anticipated formation strength including the presence and location of weak formations (potential circulation loss zones);
- likely changes in formation pressure due to temperature;
- induced loads during operations;
- completion design requirements;
- formation evaluation requirements (for example, well logging);
- the limitations of the proposed equipment (that is, can the hole be drilled in accordance with the design);
- the geochemical environment and the possibility of corrosive (sour) conditions (presence of H_2S and CO_2);
- potential for seismic activity.

The casing should be designed to withstand the anticipated hydraulic fracturing pressure, production pressures, and corrosive conditions with an adequate factor of safety.

Regulation 18 of the DCR requires the design to be reviewed before drilling commences, by a third party appointed by the operator.

A well needs to have one or more strings of casing of sufficient cemented length and strength to attach proper well control equipment and to prevent blowouts, fires, explosions and casing failures at any time during the life of the well. The casing and cementing plan should be designed to prevent fluid (water, gas, oil, brine) from migrating from one horizon to another and to prevent pollution of fresh groundwater (COGCC and Pennsylvania Code).

It is the responsibility of the operator to determine the amount and type of casing and cement in accordance with current industry good practice, taking into consideration successful local practices for similar wells, anticipated pressures, collapse resistance, tensile strength, the chemical environment and potential mechanical damage.

All materials used for casing must be specified to meet the requirements of the DCR and should be manufactured, inspected and tested to the standards set out in Table 4.1. A degree of corrosion (more in the case of anticipation of particularly corrosive environments such as the presence of hydrogen sulphide gas) and deterioration should be expected and accounted for in the design.

The well design should incorporate measures to demonstrate that installation meets the design requirements, including testing procedures and pass and fail criteria. The design and planning of the well should incorporate appropriate contingency measures in the event of failure to meet the design.

Centralisers should be fitted to all casing that will be cemented. The centraliser holds the casing in the centre of the wellbore during cementing to ensure there is an annulus all the way around the wellbore and that therefore cement can be placed all the way around the casing. The interval between centralisers should be short enough to ensure the casing cannot bow in between. Chapter 78.83(c) of the Pennsylvania Code specifies that the deepest centraliser should be placed within 50 feet (15 metres) of the bottom of the casing with intervals of no greater than 150 feet (45 metres) between shallower centralisers. ERCB Directive 009 states that 'surface casing shall be adequately centralized at the top and bottom and at 50-metre intervals' (ERCB 1990).

HSE note there are variables that should be considered such as the nature of the formation the casing is being run through and the angle of the well when determining where to place centralisers[19]. The company carrying out the cement job would normally be expected to advise on this.

The draft well integrity guidelines under preparation by OGUK recommend that the casing should have greater than 70 per cent standoff from the wellbore (that is, the casing should not be in contact with the wellbore over more than 30 per cent of its length).

5.4.3 Casing design

Surface casing

The primary protection for groundwater is surface casing. Surface casing should extend below any identified groundwater and into low permeability formations. Surface casing should be fully cemented back to surface.

OGUK's draft well integrity guidelines recommend the maximum depth of surface casing to be the shallower of:

- just above formations with potential for hydrocarbons; and
- shallowest anomaly that cannot be avoided identified by shallow seismic review (that is, shallowest potential occurrence of hydrocarbons).

For operational reasons, however, the surface casing may be shallower (for example to reduce the length of large diameter drilling or to avoid applying excessive pressure to formations while drilling).

API (2009b) recommends that:

> 'surface casing is set at least 100 feet [30 metres] below the deepest USDW [underground source of drinking water] encountered while drilling the well'.

Other casing

OGUK's draft well integrity guidelines recommend that intermediate and production casing should be cemented back to the previous casing string except where it would

[19] HSE, pers. comm.

prevent a side track or where cementing would breakdown weak formations or where it is planned to inject cuttings into the annulus.

5.4.4 HSE notification

The BSOR require the operator to notify HSE at least 21 days in advance of drilling. This notification will need to include sufficient particulars of the well design to demonstrate the well is safe. The operator must also submit their well design and health and safety document to HSE in advance of drilling. Any changes to the plans must be notified to HSE as soon as practicable.

The BSOR also require HSE to be notified of details of abandonment at least 21 days in advance of works. The notification must include the details set out in Section 4.3.3 on borehole sites and operations.

5.4.5 Reporting to HSE

Weekly progress reports to the HSE are required by Regulation 19 of the DCR.

5.4.6 DECC notification

DECC requires notification of the start of drilling.

5.4.7 Drilling fluid

Drilling will take place in stages, followed by casing installation. After each casing string has been installed, drilling resumes at a smaller diameter. To permit good quality casing installation, drilling should endeavour to create a hole of uniform characteristics. Mud control is vital to achieving this.

The hole is supported during drilling by the drilling fluid (see Section 3.3.6). The drilling fluid used in the presence of groundwater should be air, water or water-based (‘fresh water mud’). The fluid must be designed to:

- provide well control (pressure control);
- prevent the walls from fracturing or breaking up;
- return cuttings to the surface.

All additives used in the drilling fluid should be:

- planned in advance;
- recorded at the time of use (including quantities) and when in the operation they were used.

During drilling, the formations encountered should be logged and zones of lost circulation recorded.

Correct selection of the drilling fluid is vital in order to obtain a good cement seal. A drilling fluid filter ‘cake’ on the inside of the borehole may impact on the cement’s compatibility and ability to bond to the borehole. Drilling fluids that provide a thin, low permeability cake are more effectively displaced and removed during cementing (API 2010).

A formation pressure test (formation integrity test) should be undertaken after drilling out cement at the base of casing following casing installation. This tests the cement seal and demonstrates that an annular seal has been achieved.

5.4.8 Drilling multiple wells

When drilling multiple closely spaced wells, the well trajectory of each well needs to be controlled to avoid intersection or interference with existing wells. This requires the location of wells to be known accurately. Accurate location is also required to avoid geological hazards and to effectively reach the target formation. The well location is also required to drill relief wells.

5.5 Casing installation

The primary objectives of casing installation are to:

- stabilise the hole and to provide well integrity;
- isolate the annular space between the casing and the borehole;
- prevent fluid migration into and through the annular space.

The choice of barriers to flow used will be specific to a particular well, its use and setting but may include seals, cements, packers and hydrostatic fluids. Flows need to be controlled at two stages:

- immediately prior to, during and immediately after the setting of casing and cement seals;
- for long-term system integrity (API 2010).

5.5.1 Caliper log

It is good practice to run a caliper log in advance of cementing. The log provides:

- a measure of the wellbore diameter with depth;
- an indication of the borehole wall condition and stability.

The data from the log are integrated to determine the volume of the borehole and therefore how much cement will be required in the annulus.

5.5.2 Cleaning and conditioning

Mud deposits within the hole need to be removed to:

- prevent contamination of cement;
- ensure good cement adhesion to the borehole walls.

Mud cleaning within open holes is achieved by use of a spacer fluid and by mechanical devices. Within the formation, scratchers may be used which are simple devices resembling heavy-duty bottlebrushes (Schlumberger 2012).

Within existing casing, plugs should be used to sweep the casing of mud ahead of the cement. OGUK’s draft well integrity guidelines recommend the use of a dual plug assembly for this purpose. The contaminated cement and mud is held in the shoe track.

5.5.3 Handling

Prior to it being installed in the borehole, the casing should be protected from any physical damage that may make it susceptible to further deformation and/or corrosion once it is subjected to conditions downhole.

The casing must be lowered into the hole in a manner that prevents installation damage.

5.5.4 Casing string

Lengths of casing must be attached using an approved method to ensure structural integrity, either threaded or welded.

A casing shoe is attached to the lowermost length of casing.

5.5.5 Cementing

Cement seals the annulus between the well casing and the borehole wall, protects the casing from corrosion and provides mechanical support to the casing. Many factors need to be considered in the design of a cementing programme, including:

- temperature;
- hydrostatic pressures and abnormal/unexpected pressure changes;
- fluid zones (hydrocarbons, fresh water, salt water);
- fractures and fault systems.

API (2009b) recommends the following list of practices for a cement job:

- Prior to drilling, review the history of nearby wells for cementing problems (lost returns, poor hole cleaning and so on).
- Conduct computer simulation to optimise cement placement procedures.
- Use drilling practices that are effective in achieving a uniform, stable wellbore.
- Ensure that drilling fluid selection is appropriate for the geology and well design.
- Ensure the necessary casing hardware is selected and available.
- Ensure the appropriate selection and placement of casing centralisers.
- Conduct appropriate cement testing procedures in advance of cementing.
- Test the cement to confirm setting times.

The top plug of the dual plug assembly used to remove mud from the casing should ‘bottom out’, leaving contaminated cement and mud in the shoe track.

Where cementing is back to the surface, cement returns must be observed at surface once the required cement volume (plus contingency, usually 20 per cent) has been injected. If they are not, the top of the cement and the zone in which circulation was lost must be determined (for example, by a cement bond log) and any remedial cementing and/or casing installation should be carried out.

The water used to make up the cement should be of an appropriate quality.

Fillers or additives that reduce the compressive strength of the cement should not be used.

Where gas is present, the cement mixture should be suitable for preventing migration of gas.

The annulus of the conductor and surface casing should be fully cemented from the casing shoe back to ground surface (API 2009b; Pennsylvania Code). After the surface casing cement has achieved the required compressive strength, the cemented casing should be pressure tested (casing pressure test). A formation pressure integrity test should also be carried out after drilling out the surface casing, together with a short section of formation below it, to a pressure appropriate to the expected formation pressures. Formation Integrity Tests (FIT) or Leak of Tests (LOT) are conducted to establish that the next section of hole can be safely drilled.

Intermediate casing should also be cemented back to ground surface wherever possible, or to the previous casing shoe if not possible (for example, Pennsylvania Code). COGCC (2012) specifies that:

- the intermediate casing needs to be cemented to at least 200 feet above the shallowest production horizon;
- the cement needs to be allowed to set for a minimum of eight hours or until it reaches a particular compressive strength – before drilling operations can proceed.

Cementing the entire length of intermediate casing back to ground surface can result in lost circulation (API 2009b) and so is not always necessary. At a minimum, the intermediate casing should be cemented above any exposed groundwater or hydrocarbon-bearing zone (API 2009b).

The production casing should be cemented to within the previous casing shoe (Pennsylvania Code). COGCC (2012) requires that it is cemented from at least 200 feet (60 metres) above the shallowest production horizon. If intermediate casing has not been installed, cementing the production casing to ground surface or, at a minimum, to 500 feet (152 metres) above the highest formation where hydraulic fracturing will take place, should be considered (API 2009a). If drilling operations are suspended before production casing is run, the operator is responsible for ensuring no 'alien' fluid enters the oil, gas or fresh water bearing strata during suspended periods (COGCC 2012).

Cement must be allowed to set before drilling operations continue so that it has reached the required compressive strength. The setting time can vary.

5.6 High volume hydraulic fracturing

The fracture fluid is designed in advance of fracturing. All additives should be listed in terms of their chemical constituents and the volumes to be used. The use of proprietary names should be avoided, or explanations of their constituents provided.

The casing subject to high pressure should be pressure tested prior to hydraulic fracturing taking place. All equipment to be used should be pressure tested before use to appropriate pressures using water.

The fluid used in hydraulic fracturing should contain the minimum of substances required to meet the performance objectives. Additives should be selected and preference given on the basis of their low environmental impact.

For CBM, the fracture fluid would normally be water because of the potential close proximity to groundwater and the much thinner target formation.

5.7 Monitoring and testing

5.7.1 Wireline testing

Well logs are data gathering tools that are run downhole (often called wireline logs) for a variety of reasons. They are used in formation evaluation, well design and construction, and well and cement evaluation. Wireline logs should be run prior to casing installation to provide geological information.

It is good practice to run a caliper log before casing installation to permit calculation of the volume of grout required and to identify any zones requiring additional treatment.

Wireline techniques are also used to monitor the cement job. The main techniques used in casing installation are listed in Table 5.1.

Cement bond logs (CBL) may be run after a cementing job to provide information on the quality of the cementing, though are not always required if the cementing operation goes to plan. A CBL should be run for the production casing.

All elements of the well casing that could form part of a pressure containment boundary should be pressure tested following installation and may be carried out periodically thereafter (although this is unusual; the condition of the production tubing can be checked with caliper logs[20]). The pressure test must be undertaken in the same direction as any pressure the element will experience in service, where possible. OGUK's draft well integrity guidelines provide guidance on procedures for pressure testing where this is not possible.

All testing should be undertaken to written procedures and should have clear evaluation criteria. The results of all tests should be included in reports.

Table 5.1 Wireline logging techniques for cement evaluation

Method	Purpose
Caliper log	The caliper log has a post-completion purpose in that it can be used to determine if the casing has buckled or deformed in any way. It should be run if deformation is suspected for any reason.
Cement bond log (CBL) and variable density log (VDL)	These logging techniques are used to determine the integrity of the cement seal after it has been placed. The log uses a sonic tool on a wireline to record acoustic wave propagation and reflection from the formation. The log records the loss of acoustic energy as the wave propagates through the system. More sophisticated logging tools integrate the collected data to give a 360° representation of the integrity of the cement job, whereas older CBLs display a single line representing the integrated integrity around the casing. The acoustic signal will be more attenuated in the presence of cement than if the casing were uncemented. VDLs measure the bond between the cement and the borehole. By measuring the quality of the cement to casing and cement to formation bond, the sealing quality of the cement in the annulus can be evaluated.

[20] HSE, pers. comm.

5.7.2 Monitoring and testing during drilling

During drilling monitoring should be undertaken of:

- drilling rates and any significant changes that might indicate changes in pressure;
- mud volumes (flows into and out of hole and any discrepancies that indicate loss or gain);
- mud pressures and pressure losses;
- presence of gas;
- mud properties and composition and any changes;
- estimated pore pressures;
- pressure in any uncemented annuli.

In addition, cuttings should be described to identify formations encountered.

5.7.3 Monitoring and testing during casing installation and cementing

There should be evidence that cementing plugs have bumped. This means that the top cement plug has made contact with the bottom plug and has reached the base of the casing. This is observed as a pressure increase at the pump.

Cement, any additives and water should be tested in advance of operations to ensure that they meet design requirements.

A range of tests should be undertaken on cement to:

- determine whether it meets the design requirements (see list in API 2009b) in terms of its density, setting time, strength and strength development time;
- ensure that it is compatible with other fluids such as mud and spacer fluid.

The following should be recorded during cementing:

- quantity of cement and additives used;
- volume of make-up water used;
- cement density;
- volume of cement returned to surface;
- pumping rates;
- pressures.

A cement–material balance should be calculated at the end of the job to demonstrate that sufficient cement was added to the hole.

5.7.4 Monitoring and testing during fracturing

Hydraulic fracturing operations are typically designed using sophisticated software. The same software should be used for monitoring during the process for comparison with the model and real-time control. The software should make good use of site-specific or local information.

Surface injection pressure, slurry rate, proppant concentration, fluid rate and proppant rate should all be continuously monitored during fracturing. The other parameters that are monitored will depend on the specific operation. Pressure is normally monitored at the pump and in the pipe that connects the pump to the wellhead.

If the annulus between the production casing and the intermediate casing is not cemented to surface, it should also be monitored. During hydraulic fracturing, any deviation in behaviour from the design should be detected and analysed before operations continue. Problems such as a leak in the casing string should be immediately apparent and, where observed, operations should be suspended immediately. Casing pressure relief should then be installed (API 2009a).

Microseismic and tiltmeter surveys are not used on every well, but the technology is emerging for operators to map three-dimensional microseismic events associated with hydraulic fracturing operations. The technology requires geophones to be placed in observation wells or near-surface arrays; seismic events recorded on them can be modelled to maintain the vertical and lateral extent of fracturing within the desired reservoir unit. This can even be done in real-time to control the fracturing operation and maximise its propagation without letting the fractures get too long (API 2009b).

5.7.5 Post fracturing

Prior to a hydraulic fracturing operation, the proppant can be tagged with a tracer. Radioactive tracers have been used and some non-radioactive tracers have been developed, but their formulations are not in the public domain. After the procedure, a cased-hole log capable of detecting the tracer is run to provide information on which perforations accepted proppant in the near vicinity of the well.

A temperature log can also indicate the success of the fracturing operation because the formation is cooled considerably during fracturing (API 2009b).

5.7.6 During production

When a well is producing, well conditions should be monitored constantly to make sure the well and well equipment maintain integrity. Annular pressures should be monitored (where uncemented) and ‘do not exceed’ thresholds that represent the safe working range of pressures for the well during normal operation should be established.

5.8 Abandonment

An abandoned well is defined here as one that will not be re-entered in the future and is permanently abandoned. A gas well may be ‘suspended’, ‘shut in’ or ‘temporarily abandoned’ during periods of its otherwise productive life, but when this comes to an end, it must be properly plugged so that it does not represent a conduit for gas release to the subsurface or surface.

Wells may be temporarily abandoned (suspended) when the well may have use in the future, such as for enhanced oil recovery in an oil well, and it must be maintained so that a routine workover could restore it to service (API 2009a).

Abandonment of wells must be approved by DECC. An operator’s application for abandonment must include an abandonment plan and a specification for the abandoned well.

HSE must be notified 21 days in advance of abandonment.

Wells must be designed and constructed for abandonment at the outset (DCR; HSE 2008b; draft OGUK well integrity guidelines). The design should include plans to remove downhole equipment, including any equipment added to mitigate earlier problems or the use of equipment that can be milled out or safely left in the well.

Well abandonment must be undertaken in a manner that prevents unplanned releases of hydrocarbons from the well or the reservoir and should prevent the migration of fluids between permeable flowing zones, thereby preventing the contamination of groundwater and conserving hydrocarbon resources.

OGUK's draft well integrity guidelines provide minimum criteria to ensure full and adequate isolation of formation fluids within the wellbore and from surface. It is expected that if an operator intends to suspend a well, the measures will last the duration of the suspension. In the case of an indefinite suspension, the procedures for abandonment should be adopted. The intent of the well integrity guidelines is to help operators comply with the DCR.

Local authorities may apply additional requirements.

It is recognised that the key to a successful suspension or abandonment lies partly with the effectiveness of the original casing and cementing programme.

The principal relevant abandonment requirements of OGUK's draft well integrity guidelines and API (2009a) guidelines are summarised below:

- All distinct permeable zones (where a distinct permeable zone is a group of zones originally in the same pressure regime and between which uncontrolled flow is acceptable) penetrated by the well should be isolated, both from each other and from surface by a minimum of one permanent barrier (also known as a cement plug). This permanent barrier must be one that will provide a permanent seal and must extend across the full cross-section of the well, including all annuli.

- A barrier should be set at the base of groundwater, which should be determined during drilling and/or from other local information. This barrier will also protect surface soils and surface water from fluids originating from the well. Many US state and federal agencies require cement plugs across the base of the surface casing and in or between each producing and potential producing zone.

- If a permeable zone is hydrocarbon bearing, two permanent barriers are required. The two may be combined into one long permanent barrier provided the objectives are met.

- The first barrier to a given zone is at a lower elevation than the second barrier to the same zone (that is, the first barrier is closer to the top of the zone). The first barrier to a shallower zone can also be the second barrier to a deeper zone.

- Cement is generally used to form the barrier, although other materials can be used as long as they meet requirements of permeability, integrity, non-shrinkage, ductility and brittleness, chemical resistance and bonding.

- A cement column of at least 30 metres (100 feet) is recommended to constitute a permanent barrier. Where possible, 150 metres (500 feet) long barriers should be used.

- Where distinct permeable zones are less than 30 metres apart, a 30-metre thick column of cement below the base of the upper zone is recommended. The top of the first barrier should extend at least 30 metres above the highest point of potential inflow.
- When two permanent barriers are combined into one, the cement column should be at least 60 metres in length. A 250-metre (800 foot) cement column is typically used. The top of this barrier should be at least 60 metres above the highest point of potential inflow;
- The annulus adjacent to the cement plug must also be fully cemented to create a seal.
- In an open hole completion (that is, no casing in the well), a single open hole cement barrier is not sufficient and either the first barrier should extend at least 60 metres inside the lowermost casing shoe or, if the first barrier is in the open hole, a second barrier should be installed at least 30 metres inside the lowermost casing shoe.
- Cemented casing is not considered to constitute a permanent barrier to flow into or out of the wellbore due to the potential for cement and casing leaks. In a cased hole completion, there must be sufficient confidence in the quality of the cement in the annulus. Any indication of a problem with the cement may necessitate remedial cementing. Cement can be placed in the annulus by milling out sections of casing or by perforating the casing and inserting cement (cement squeezing).
- The performance of permanent barriers should be verified to ensure that they are in the correct location and that they have adequate sealing capacity. This can be achieved through a variety of strength tests and careful review of all placement records.
- A cement plug should also be placed to seal off any irretrievable radioactive sources. These should be surveyed, tagged and reported.
- The removal of downhole equipment is not a requirement provided the zone isolations are achieved. However, cables and lines should not form part of a permanent barrier as they are a potential flow path.
- When well completion tubulars (for example, production casing, production packers) are left down the hole because they cannot be recovered, additional precautions are likely to be required to ensure a good seal and to verify the performance of the barrier.
- Barriers placed in wells with significant concentrations of acidic gases (CO_2 or H_2S) in their gas issue should be designed to withstand the corrosion associated with these gases.
- Potentially polluting fluids (muds, hydrocarbons and so on) above the uppermost barrier in a well should be removed as far as is reasonably practical.
- A surface plug should be installed to prevent surface water runoff from entering the well.
- At the surface, abandonment should include cutting off the well casing below ground level so that it does not interfere with future uses, welding on a casing stub (plate), filling in the well cellar or other surface voids, and restoring surface conditions so that they closely represent the baseline

conditions before the well was drilled. The location of the well should be marked and recorded.

5.9 Intervention/workover

Workover operations are major remedial operations to maintain production or to repair downhole equipment. In the context of unconventional gas, workover may be required to undertake additional hydraulic fracturing. DECC must consent to completions of new zones or be notified of re-completions.

Well control will be required during workover. This may necessitate use of a drilling mud or other fluid (workover fluid) with sufficient weight to counteract the formation pressure.

Workover will involve removal of wellhead equipment to gain entry to the well and removal or milling out of downhole equipment that could interfere with hydraulic fracturing.

The well should be pressure tested prior to hydraulic fracturing and again following fracturing to demonstrate that well integrity is retained.

5.10 Repairs, mitigation and so on

A number of problems can occur during drilling, casing installation, testing, production and abandonment that may affect well integrity and therefore that require mitigation measures to be taken. Common problems and possible solutions are identified in Table 5.2. Equipment and materials to support mitigation measures for common problems should be held on-site during drilling and fracturing operations.

Table 5.2 Common problems and mitigation measures

Activity	Common problems and possible impacts on groundwater	Mitigation measures
Drilling	Washout/ lost circulation in weak formations leading to mud invading aquifers Washouts making grouting difficult	This is an immediate problem for maintaining well control, ensuring drilling returns and so on. Analysis prior to drilling should identify weak formations and therefore allow an element of planning in determining appropriate drilling fluid composition. Where the weak formation is also an aquifer, care needs to be taken in terms of the composition of the drilling fluid to avoid the use of hazardous substances. Loss of circulation requires the use of additional drilling fluid and also that the composition of the drilling fluid is altered to reduce losses and maintain fluid weight. Additional treatment can be added as a remedial treatment or as a preventative treatment during drilling. Washouts may also need to be packed off prior to casing installation.
Casing installation	Incomplete cementing of casing annulus due to: • channelling • bridging.	Pre-cementing – placing of packing materials in voids prior to cementing Post-cementing – cement squeezing, which involves cutting holes in the casing and inserting cement
	Contamination of cement by drilling fluid	Adequate cleaning of casing
	Channelling of cement within the annulus resulting in voids	
Hydraulic fracturing	Microseismic events that could damage the production casing	Planning to identify potential for seismic events through evaluation of the geological information. Monitoring and evaluation of seismic events Suspension of operations
Production	Formation damage leading to clogging of the production well	Workover to restore well performance (see above)
	Corrosion can result from the presence of brines and acid gases (CO_2 and H_2S).	Corrosion should be taken into account during construction and the use of corrosion-resistant materials specified where aggressive conditions are anticipated or encountered at the time of drilling. Post construction, corrosion inhibitors can be used. However, some degree of corrosion is likely to be inevitable and may be a determining factor in the life of a well.
	Leaks in production tubing	Leaks in production tubing can be sealed with straddle packers. These should be pressure tested before being put into service.

Activity	Common problems and possible impacts on groundwater	Mitigation measures
Abandonment	Failure to recover downhole equipment (production tubing, production packer) that should have been recoverable	Equipment should, as far as is practicable, be removed from the well to permit a high quality abandonment. However, contingency measures should be in place to permit adequate plugs to be set even where equipment cannot be retrieved. Where downhole equipment is left in place, additional care is required to ensure good seals. In some instances, the equipment may need to be milled out.
	Failure to set adequate seals (pressure test failure	
Post abandonment	Corrosion and connection between flowing strata	

6 Recommendations and key performance objectives for groundwater protection

A small number of key performance objectives and measures can be defined to facilitate groundwater protection during drilling and casing installation for unconventional gas exploration and production. These key performance indicators are the basis for the recommended good practice described in Section 5.

The drilling and hydraulic fracturing of exploration and production wells for unconventional gas poses a potential risk to groundwater in the formations through which it is drilled. There may be risks associated with drilling fluids, formation fluids, hydraulic fracturing fluids and gas. The well provides a potential pathway for those fluids to enter groundwater.

Risks to groundwater can be mitigated through good practice in the planning, design, drilling, installation, hydraulic fracturing, monitoring and abandonment of wells. A review of good practice has identified a range of requirements for the protection of groundwater. The recommendations made below are derived from international experience and should be considered in the context of geological and other conditions that prevail in the UK.

6.1 Recommendations for the Environment Agency's consideration

Many of the good practices identified are requirements of licences and consents issued by DECC and of the HSE via the DCR and BSOR. Compliance with these will go a long way towards ensuring that risks to groundwater are adequately mitigated. However, where there are potential gaps in protecting groundwater, the EA should take steps to ensure that when appropriate such requirements are put in place:

- The well should be designed to protect groundwater, particularly through the design and placement of casing;
- Good use should be made of modelling to aid the well design and the design of hydraulic fracturing;
- The well should be drilled carefully to ensure that drilling fluids do not invade the formations; to avoid flow within the well during drilling and to create a wellbore of known dimensions;
- The wellbore should be conditioned (that is, cleaned to remove contaminants by circulating fresh drilling fluid) before casing installation.
- Casing installation must be done in stages;
- The casing should be cemented in place. Cement should fill the annulus of surface casing and must also prevent movement of fluids and gases from permeable formations at all depths;
- The quality of the cement job should be demonstrated by pressure testing and geophysical methods;
- Real-time monitoring should be undertaken during drilling, cementing and hydraulic fracturing to allow response to adverse effects, such as induced seismicity;
- The well should be pressure tested before hydraulic fracturing to demonstrate well integrity;

- The well should be pressure tested periodically to demonstrate continued integrity;
- Well abandonment (that is, the activities involved in decommissioning) should be undertaken to ensure that the target formation is separated from the surface by at least two plugs;
- Producing horizons should be isolated from other permeable and porous formations to prevent cross flow

It is also important that sufficient monitoring is undertaken prior to drilling and during drilling to provide reassurance that mitigation measures are adequate.

6.2 Performance objectives

A small number of key performance objectives and the measures to achieve them defined to facilitate groundwater protection during drilling and casing installation for unconventional gas exploration and production and are set out in Table 6.1. These key performance indicators are the basis for the good practice described in Section 5.

Table 6.1 Objectives and measures

Objective	Measure
The chemical footprint of drilling and fracturing should be kept to a reasonable minimum.	Minimise the addition of chemical additives to hydraulic fracturing fluid and drilling muds in terms of range and concentration of hazardous substances used. Where substitutes are available the least hazardous (in terms of toxicity, mobility, persistence and bioaccumulation) should be selected. All chemical additives used should be capable of quantitative analysis in waste drilling mud and flowback fluids. Full prior disclosure of all chemicals, including ingredients of mixtures, used in the drilling/fracturing process (with CAS numbers) and the concentration and mass used. Tracers may require separate agreement to avoid their deliberate introduction should a determined objector try to cause contamination with the same substances.
Well pads to be located to avoid sensitive receptors suffering direct interference during drilling.	No drilling within groundwater Source Protection Zone 1 (SPZ1) or within 250 metres (whichever is the greater) of any existing well, borehole or spring used for abstraction of water for human consumption or any recognised groundwater-dependent terrestrial ecosystem. Horizontal boreholes can extend below these receptors providing there is a substantial natural sealing layer between the target layer and overlying aquifers.
Wells should be cased and cemented through all groundwater-bearing horizons and other flowing horizons such that ,on completion and during/subsequent to hydraulic fracturing: • there is no exchange of liquid or gas between the borehole and aquifers; • there is no interconnection between flowing horizons via the drilling or hydraulic fracturing process that could	Adequacy of well design: well design and construction methods to be reviewed independently of the operator to check whether these can in principle meet the performance objectives. Well integrity testing: the integrity of well casing to be tested at key stages in the drilling process, as well as subsequent to hydraulic fracturing operations, after any significant seismic events and periodically during the life of the well, to demonstrate the above. Testing to be made

Objective	Measure
cause leakage of fluids or gas into, from or between flowing horizons in environmentally significant quantities. WRA Section 199 permits the Environment Agency to condition a conservation notice if required.	available to the Environment Agency on request.
Wells should be abandoned such that there is no unplanned escape of fluids from the well or from the reservoir to which it led. Well abandonment should be undertaken to ensure that the target formation is separated from the surface by at least two plugs.	No escape of fluid at the surface No subsurface movement of fluids within the well.

In addition to the key performance objectives and measures and operator good practice identified above, some additional actions that the Environment Agency could take to avoid or mitigate risks to groundwater are as follows.

- Arrange for all relevant information submitted to DECC and HSE to be also provided to the Environment Agency. This would give the Environment Agency advanced notice of planned activities and provide the Environment Agency with information on those activities, allowing it to assess the risks to groundwater. In addition, compliance with many of HSE's requirements will achieve a substantial degree of groundwater protection. Access to data submitted to HSE would therefore be very helpful in any checking by the Environment Agency and could avoid repetition of effort by the regulatory bodies and the operator[21].
- Maintain contact with DECC and HSE throughout the lifetime of a well and field so that any requirements imposed on operators are communicated between them, thus ensuring regulation is joined up.
- Highlight Environment Agency guidance and position statements applicable to unconventional gas exploration and exploitation (Environment Agency 2008, 2011)to potential operators/developers at an early stage (preferably on acquisition of an exploration or development licence and at the latest on submission of any planning application).
- Take account of the following in Environment Agency guidance/ position statements:
  - A good conceptual model of the hydrogeological environment is an essential component of well design and assessment of the significance of any subsequent failures.
  - Gas is a potential pollutant and any input of pollutants to groundwater above de minimis levels requires an EPR permit. Inputs of gas could arise from the deep target formation or the disturbance of biogenic gas by drilling.

[21] Formal access to data submitted to the HSE for a well notification may require legislation to be modified. HSE currently advise DECC of completion of inspection of notifications and any issues raised and a similar process could be put in place to also advise the EA. HSE, pers. comm.

  - Similarly, artificially induced cross-connections of aquifers that lead to contamination of fresh water by, for example, saline water can also be regarded as an input of pollutants.

- Emphasise in Environment Agency guidance and position statements the importance of subsurface blowouts or of contamination and cross-contamination of aquifers and the detection of these events. This is not currently well recognised in existing good practice guidance. Recognition of these issues in other guidance (for example, HSE guidance) and the independent design review advised in Table 6.1 would also be helpful.
- Request that references to key Environment Agency documents are made in HSE/DECC guidance.

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List of abbreviations

ALARP	as low as is reasonably practicable
bcm	billion cubic metres
BGP	Base of Groundwater Protection [Alberta]
BGS	British Geological Survey
BOP	blowout preventer
BSOR	The Borehole Sites and Operations Regulations 1995
BTEX	benzene, toluene, ethylbenzene, xylenes
CBD	coal bed methane
CBL	cement bond log
CIBP	Cast iron bridge plug
COGCC	Colorado Oil and Gas Conservation Commission
DCR	The Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996
DECC	Department of Energy and Climate Change
Defra	Department for Environment, Food and Rural Affairs
DHSV	downhole safety value
EIA	environmental impact assessment
EPR	Environmental Permitting Regulations
ERCB	Energy Resources Conservation Board [Province of Alberta, Canada]
GWDD	Groundwater Daughter Directive
H&S	health and safety
HSE	Health and Safety Executive
M_L	Richter magnitude
MPA	mineral planning authority
NORM	naturally occurring radioactive material
OBM	oil-based mud
PBT	persistent, bioaccumulative and toxic
PEDL	Petroleum Exploration and Development Licence
SBM	synthetic-based mud
SPC	Semi-Permanent Circular [HSE]
SPZ	Source Protection Zone
SSSV	subsurface safety valve
TDS	total dissolved solids

UKTAG	United Kingdom Technical Advisory Group for the Water Framework Directive
USEPA	US Environmental Protection Agency
VDL	variable density log
VOCs	volatile organic compounds
WBM	water-based mud
WFD	Water Framework Directive
WRA	Water Resources Act

Glossary of terms

Annular space/ Annulus	The space between the casing and the wellbore
Blowout	See Section 3.3.10
Blowout preventer (BOP)	One or more valves installed at the wellhead to prevent the escape of pressure either in the annular space between the casing and the drill pipe or in open hole (for example, a hole with no drill pipe) during drilling or completion operations.
Borehole site	A place at which a borehole operation: (a) is being or is to be undertaken; or (b) has been undertaken, save where all borehole operations have ceased and all boreholes have been abandoned. Source: The Borehole Sites and Operations Regulations 1995
Bottom plug	A cement wiper plug that precedes cement slurry down the casing. The plug wipes drilling mud off the walls of the casing and prevents it from contaminating the cement.
Casing	See Section 2.2.3 and Table 2.1
Casing hanger	The subassembly of a wellhead that supports the casing string when it is run into the wellbore. The casing hanger provides a means of ensuring that the string is correctly located and generally incorporates a sealing device or system to isolate the casing annulus from upper wellhead components.
Casting shoe	See Table 2.1
Cement bond	The adherence of casing to cement and cement to formation. When casing is run in a well, it is set or bonded to the formation by means of cement.
Cement bond log (CBL)	An acoustic survey or sonic logging method that records the quality or hardness of the cement used in the annulus to bond the casing and the formation. Casing that is well bonded to the formation transmits an acoustic signal quickly; poorly bonded casing transmits a signal slowly.
Centraliser	A device to keep the casing or liner in the centre of the wellbore to help ensure efficient placement of a cement sheath around the casing string.
Christmas tree	The control valves, pressure gauges and chokes assembled at the top of a well to control flow of oil and/or gas after the well has been drilled and completed. It is used when reservoir pressure is sufficient to cause reservoir fluids to rise to the surface.
Coal bed methane (CBM)	See Section 2.1.2

Conditioning	Preparation of the wellbore and casing for cementing
Flowback	See Section 3.3.3
Formation water	See Section 3.3.5
Hydraulic fracturing	See Section 2.2.4
Mud	A drilling fluid – see Section 3.2.6
Packer	See Table 2.1
Packer fluid	The fluid that remains in the tubing-casing annulus above the packer after the completion has been run and all circulation devices have been isolated. Packer fluids are prepared for the requirements of the given completion. Generally, they should be of sufficient density to control the producing formation, free of solids, resistant to viscosity changes over long periods of time and non-corrosive to the wellbore and completion components.
Production casing	See Table 2.1
Production tubing	See Table 2.1
Well pad	See Section 2.2.3
Sour	Contaminated with sulphur or sulphur compounds, especially hydrogen sulphide
Spacer fluid	Any liquid used to physically separate one special-purpose liquid (e.g. mud or cement) from another. The most common spacer is water, although some additives may be used to improve performance. See Section 3.3.8
Shale gas	See Section 2.1.1
Surface casing	See Table 2.1
Tight gas	Gas from low permeability conventional reservoirs that requires hydraulic fracturing to exploit the resource.
Tubing hanger	A device attached to the tubing at the wellhead to support the tubing string. The tubing hanger incorporates a sealing system to ensure that the tubing and annulus are hydraulically isolated.
Well bore	The open hole or uncased portion of the well
Variable density log (VDL)	Geophysical log to measure the bond between cement and the borehole wall
Well completion	A generic term used to describe the assembly of downhole tubulars and equipment required to enable safe and efficient production from an oil or gas well. The point at which the completion process begins may depend on the type and design of well. However, there are many options applied or actions performed during the construction phase of a well that have significant impact on the productivity of the well.
Well conductor	See Table 2.1

Workover	Post-drilling well intervention involving invasive techniques

Appendix: Potential components of hydraulic fracture fluid (from US data)

Table A1 Potential components of hydraulic fracture fluid (from US data)

Product function	Percentage composition of fracking fluid (up to)	Purpose	Fate	Typical chemical(s) used (also known as)	CAS No.
Water	90.5000	Fluid			
Proppant	9.0000	Holds fractures open.	Remains in fractures.	Sand Aluminium shot Ceramic beads	
Acid	0.5000	Used to help dissolve the minerals in the rock.	Reacts with minerals and generates salts, water and carbon (is neutralised).	Hydrochloric acid (hydrogen chloride)	007647-01-0
				Formic acid	000064-18-6
Anti-bacterial agent (biocide)	0.0045	React with micro-organisms in the formation and the treatment fluid to eliminate bacteria in the water that produce corrosive by-products / breakdown other ingredients of the fracturing fluid.	Consumed	Glutaraldehyde (glutaral) (1,5-pentanedial)	000111-30-8
				Quaternary ammonium chloride (ammonium chloride)	012125-02-9
				Quaternary ammonium chloride (ammonium chloride)	061789-71-1
				Tetrakis hydroxymethyl-phosphonium sulphate	055566-30-8
Breaker	0.0405	Reacts with the crosslinker and gel once in the formation to enhance flow.	Produced ammonia and sulphates are returned to the surface in produced water or remains in the target formation.	Ammonium persulphate (diammonium peroxodisulphate)	007727-54-0
				Sodium chloride (common salt)	007647-14-5
				Magnesium peroxide (magnesium dioxide)	014452-57-4
				Magnesium oxide	001309-48-4
				Calcium chloride	010043-52-4

Table A1 (continued) Potential components of hydraulic fracture fluid (from US data)

Product function	Percentage composition of fracking fluid (up to)	Purpose	Fate	Typical chemical(s) used (also known as)	CAS No.
Clay stabiliser	No information	Reacts with formation clays to prevent swelling.	Creates sodium chloride which is returned in the produced water or remains in the target formation.	Choline chloride	000067-48-1
				Tetramethyl ammonium chloride	000075-57-0
				Sodium chloride (common salt)	007647-14-5
Corrosion inhibitor	0.0045	Bonds to metal to prevent corrosion of pipes.	Attached to downhole pipes. Residual product is broken down by micro-organisms and returned in produced water. or remains in the target formation	Isopropanol (propan-2-ol) (isopropyl alcohol)	000067-63-0
				Methanol	000067-56-1
				Formic acid	000064-18-6
				Acetaldehyde	000075-07-0
Crosslinker	0.0270	Combines with the breaker to maintain fluid viscosity as temperature increases.	Creates salts that are returned to the surface in produced water or remain in the target formation	Petroleum distillate	064741-85-1
				Hydrotreated light petroleum distillate	064742-47-8
				Potassium metaborate	013709-94-9
				Triethanolamine zirconate (tetrakis[[2,2',2''-nitrilotris[ethanolato]](1-)-N,O]zirconium)	101033-44-7
				Sodium tetraborate (disodium tetraborate decahydrate) (borax decahydrate)	001303-96-4
				Boric acid	001333-73-9 010043-35-3 011113-50-1
				Zirconium complex	113184-20-6

Table A1 (continued) Potential components of hydraulic fracture fluid (from US data)

Product function	Percentage composition of fracking fluid (up to)	Purpose	Fate	Typical chemical(s) used (also known as)	CAS No.
Crosslinker (continued)				Borate salts	N/A
				Ethylene glycol	000107-21-1
				Methanol	000067-56-1
Foaming agent	No information	Can create a high viscosity fluid and is used in some operations.	Returned to the surface in produced water or remains in the target formation.	Isopropanol (propan-2-ol) (isopropyl alcohol)	000067-63-0
				Salt of alkyl amines	
				Diethanolamine (2,2'-iminodiethanol)	000111-42-2
				Ethanol	000064-17-5
				2-Butoxyethanol (ethylene glycol monobutyl ether) (butyl cellosolve)	000111-76-2
				Ester salt	(group of compounds)
				Polyglycol ether	(group of compounds)
Friction reducer	0.0360	Makes water 'slippery' to minimise friction.	Remains in the formation where it is broken down; a small amount is returned with the produced water.	Polyacrylamide	009003-05-8
				Petroleum dDistillate	064741-85-1
				Hydrotreate light petroleum distillate	064742-47-8
				Methanol	000067-56-1
				Ethylene glycol (ethane-1,2-diol)	000107-21-1

Table A1 (continued) Potential components of hydraulic fracture fluid (from US data)

Product function	Percentage composition of fracking fluid (up to)	Purpose	Fate	Typical chemical(s) used (also known as)	CAS No.
Gelling agent	0.2250	Thickens water to enable it to suspend the sand.	Combines with the breaker in the formation, making it easier for the fluid to flow to the borehole and return to the surface in produced water or remains in the target formation.	Guar gum	009000-30-0
				Petroleum distillate	064741-85-1
				Hydrotreated light petroleum distillate	064742-47-8
				Diesel (gasoil)	068334-30-5
				Diesel oil #2	068476-34-6
				Fumaric acid	000110-17-8
				Adipic acid	000124-04-9
				Methanol	000067-56-1
				Polysaccharide blend	068130-15-4
				Ethylene glycol (ethane-1,2-diol)	000107-21-1
Iron control	0.0040	Prevents precipitation of metal in the pipe.	Reacts with minerals in the formation to create simple salts, carbon dioxide and water all of which are returned in produced water.	Citric acid	000077-92-9
				Acetic acid	000064-19-7
				Thioglycolic acid (mercaptoacetic acid)	000068-11-1
				Sodium erythorbate (2,3-didehydro-3-O-sodio-D-erythro-hexono-1,4-lactone)	006381-77-7

Table A1 (continued) Potential components of hydraulic fracture fluid (from US data)

Product function	Percentage composition of fracking fluid (up to)	Purpose	Fate	Typical chemical(s) used (also known as)	CAS No.
Non-emulsifier	No information	Prevents the formation of emulsion in the fracturing fluid	See surfactant.	Lauryl sulphate (sodium dodecyl sulphate)	000151-21-3
				Isopropanol (propan-2-ol) (isopropyl alcohol)	000067-63-0
				Ethylene glycol (ethane-1,2-diol)	000107-21-1
pH adjusting agent	0.0450	Maintains the effectiveness of other components, such as crosslinkers.	Reacts with acidic agents in the treatment fluid to maintain a neutral pH. This reaction results in mineral salts, water and carbon dioxide; a portion of each is returned to the surface in produced water.	Sodium hydroxide (caustic soda)	001310-73-2
				Potassium hydroxide (caustic potash)	001310-58-3
				Acetic acid	000064-19-7
				Sodium carbonate	000497-19-8
				Potassium carbonate	000584-08-7
Scale inhibitor	0.1800	Used to prevent scale deposition in downhole and surface equipment.	Attaches to the formation downhole; returns to the surface with the produced water, consumed by micro-organisms.	Copolymer of acrylamide and sodium acrylate	025987-30-8
				Sodium polycarboxylate	N/A
				Phosphonic acid salt	N/A

Table A1 (continued) Potential components of hydraulic fracture fluid (from US data)

Product function	Percentage composition of fracking fluid (up to)	Purpose	Fate	Typical chemical(s) used (also known as)	CAS No.
Surfactant	0.0360	Used to increase fracture fluid viscosity to assist with carrying proppants into the fractures.	Generally returns to the surface or remains in the target formation, but in some formations it may enter the natural gas stream and return in the produced natural gas	Lauryl sulphate (sodium dodecyl sulphate)	000151-21-3
				Ethanol	000064-17-5
				Naphthalene	000091-20-3
				Methanol	000067-56-1
				Isopropanol (propan-2-ol) (isopropyl alcohol)	000067-63-0
				2-Butoxyethanol (ethylene glycol monobutyl ether) (butyl cellosolve)	000111-76-2

Notes: Table collated from information in:

Hydraulic Fracturing Facts (http://hydraulicfracturing.aitrk.com/Fracturing-Ingredients/Pages/information.aspx)

FracFocus Chemical Disclosure Registry (http://fracfocus.org/chemical-use/what-chemicals-are-used)

Shale Gas Wiki (http://www.shalegaswiki.com/)

International Union of Pure and Applied Chemistry (http://sitem.herts.ac.uk/aeru/iupac/Reports/1353.htm)

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