# OR/18/012 Appendix 5 – Characteristics of sub-surface hydrocarbon activities


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Oil and gas have been typically extracted from 'conventional' systems whereby they have migrated from the source rock and accumulated in a permeable reservoir. Low permeability 'traps', such a geological fault or rock unit, prevent the oil and gas from migrating further. Recent improvements in extraction technology and an increase in economic viability have allowed for the extraction of hydrocarbons from low permeability rocks, which may be 'tight' rocks within conventional reservoirs or alternatively may be the hydrocarbon source rock, such as coal (CBM and UCG) and shales (shale gas and oil). These are known as 'unconventional hydrocarbons'.

Below is a summary of the extraction techniques referred to in Specific vulnerability .

| **Conventional Hydrocarbons (Figure 5.1)** | |
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| **Background** | There has been onshore drilling for conventional hydrocarbons in the UK since the mid-1800s when oil was discovered in Scotland, followed by gas in England in 1896. There are currently 120 sites with 250 operating wells producing between 20 000 and 25 000 barrels of oil equivalent a day (UKOOG, 2016[1]). |
| **Geological setting** | Sedimentary basins. The hydrocarbon source rock ranges from a few metres to hundreds of metres in thickness and the thickness of reservoir rocks is also variable. |
| **Depth of exploitation** | Reservoirs in the UK range from between 50 m bgl in the Formby Oilfield (DECC, 2013a[2]) and 1550 m at Wytch Farm, Dorset, but are typically between 800 and 1200 m in depth. Elsewhere, exploitation depths can range from 0 to 9 km (Hu et al., 2013[3]). |
| **Boreholes** | Vertical boreholes are typical, but directional boreholes can be used where required, for example, at Wytch Farm, Dorset to gain access to resources away from the borehole location. |
| **Stimulation** | When reservoir pressure decreases, oil and gas can be pumped to the surface (BGS, 2011[4]). Secondary, or Enhanced Oil Recovery (EOR) uses reinjected water to displace and drive out remaining oil or to maintain reservoir pressure (BGS, 2011[4]). Hydraulic fracturing is not commonly required (AMEC, 2013[5]) but has been conducted from vertical wells since the 1940s. Thermal recovery or chemical injection can also be used for reservoir stimulation, although this has not been used in the UK (BGS, 2011[4]). |
| **Lifetime** | In the range of 10–30 years, with an average of 20 years (AMEC, 2013[5]). |
| **Footprint** | Often, multiple boreholes will be drilled into the reservoir but borehole density is lower than for unconventional hydrocarbons (US EPA, 2016[6]). For the UK, AMEC (2013)[5] estimated a future density of three to six well pads per site, with two wells per pad and up to three Ha land per pad. AMEC (2013)[5] used a minimum separation distance between well pads of five km. The sub-surface footprint depends on the size of the reservoir, for example, Wytch Farm has 13 well sites and >100 boreholes. Boreholes here may be <100 m apart. |
| **Shale gas and oil (Figure 5.3)** | |

**Background**

Widespread in the U.S. since the mid-2000s due to technological advances. Initially, explosives or acid etching were used to increase flow from vertical wells (Gallegos and Varela, 2015[7]). Fracking with water began in 1953, and with slick water soon after. Tight oil production began in the U.S. in the 1980s (EIA, 2016[8]). By 1999 nearly one million fracking operations had been applied to vertical wells (Gallegos and Varela, 2015[7]). Directional drilling was developed in the 1980s, maturing in the 1990s and becoming cost-effective in conjunction with hydraulic fracturing in 2001 (US EPA, 2016[6]). In 2000, 6% of hydraulically fractured boreholes were horizontal whereas in 2010 this was 42% (Gallegos and Varela, 2015[7]). Between 25 000 and 30 000 new boreholes are estimated to have been drilled and hydraulically fractured in the U.S. annually between 2011 and 2014 (for tight gas and oil, CBM and shale combined) (US EPA, 2016[6]). In 2015, more than 50% of oil and nearly 70% of gas in the U.S. was produced with the benefit of hydraulic fracturing (US EPA, 2016[6]). There is currently no shale gas production in the UK or Europe. Several countries in Europe have announced moratoria or bans on shale gas, including Scotland, Northern Ireland and Wales. There is active exploration in England for the Bowland-Hodder shale formations in the Fylde of Lancashire and the Vale of Pickering, Yorkshire. A test hydraulic fracture at the Preese Hall site, Lancashire in 2011 was halted due to unexpected induced seismicity (see Clarke et al., 2014[9]).

**Geological setting**

In the UK, shales and tight formations with the potential for shale/tight gas are often found in sedimentary basins. In North America, tight oil and gas can be found in halo plays, around the edges of historical production sites, or in larger geostratigraphic plays (CSUR, 2016[10]). Shale and tight oil and gas formations can be characterised as clastic depositional systems with sandstone, siltstone, mudstone and shale or carbonate systems with limestone, dolomite, shale and halite/anhydrite. The Bowland-Hodder shale formations are locally interbedded with sandstones and/or thin limestones (Harvey et al., 2016[11]). In the UK, the basin and formation structure is likely to be complex (Ward et al., 2015[12]; Harvey et al., 2016[11]) due to the age and deformation history of the rock units. The thickness of shales with gas resources is variable; for example, the Marcellus shale is less than 110 m in thickness (US EPA, 2016[6]), and other formations similar to UK shales are only tens of metres in thickness (Harvey et al., 2016[11]). The thickness of tight formations is variable for oil but for gas plays they are commonly located in deep basins and are very thick with continuous gas saturation (Aguilera & Harding, 2008[13]). In England, potential shale gas units such as the Carboniferous Bowland-Hodder formations are nearly 4 km in thickness in basins and 100 m on platforms. The thicknesses of shales in the Weald Basin are much smaller, from 19 to 300 m in total (Harvey et al., 2016[11]).

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| **Depth of exploitation** | Variable: In the U.S., the average depths of large gas-producing reservoirs in shales are between 2 km (Marcellus shale) and 3.7 km (Haynesville-Bossier shale). The minimum and maximum depths of exploitation range from 200 m in New Albany to 4.12 km in Haynesville-Bossier. 16% of boreholes in the U.S. are <1.6 km deep (US EPA, 2016[6]). Tight oil formations are typically exploited from 1–3 km depth and gas from deep (>4.5 km) basins. Biogenic gas can be <1 km bgl (Naik, 2003[14]). Hybrid plays can be shallow, such as the Antrim biogenic gas play (430 m bgl) and the Niobraran shale oil resource (305 m bgl) (Monaghan, 2014[15]).<br>In the UK, Andrews (2013)[16] used a depth cut-off of 1.5 km for shale gas estimations in the Bowland-Hodder formations and Andrews (2014)[17] used a depth cut-off of 1 km for the Weald. Monaghan (2017)[18] used a shale gas depth cut-off of 805 m bgl in central Scotland — relating to pressure and flow rates and well sample maturity. Shale oil has been found between 67 and 550 m bgl (Andrews et al., 2014[17]). However, the UK 2015 Infrastructure Act states that high volume hydraulic fracturing (more than 1000 $m^3$ fluid at each stage or more than 10 000 $m^3$ of fluid in total) cannot take place <1 km bgl (http://www.legislation.gov.uk/ukpga/2015/7/contents/ enacted) or <1.2 km bgl in protected areas such as National Parks (http://www.legislation.gov.uk/uksi/2016/384/note/made). In the DECC (2013c)[19] report, shale oil resources were assessed from surface to a depth of 1000 m and to 3,500 m for shale gas. |
| **Boreholes** | Extracted via a borehole, which may be deviated or have horizontal sections within the shale (Gallegos and Varela, 2015[7]). By drilling multilateral horizontal boreholes into the shale, a greater rock volume can be accessed (DECC, 2013c[19]) and boreholes are now being drilled with longer horizontal sections and closer spacing (US EPA, 2016[6]). |
| **Stimulation** | High volume hydraulic fracturing (fracking) is used to increase the permeability of the shale, allowing gas to flow from the shale to the borehole in commercial quantities. A high volume of frack fluid (water with chemical additives) is injected into the borehole under a very high pressure in order to create hydraulic fractures in the rock surrounding the borehole. Fractures increase the shale porosity from 1–10%, to 35% (Brownlow et al., 2016[20]). Fractures are kept open using a proppant (sand or ceramics) while the borehole is subsequently depressurised so that the gas flows out of the shale, into the borehole and to the surface (The Royal Society, 2012[21]). Hydraulic fracturing is not always required for oil production from tight formations (US EPA, 2016[6]).<br>The volumes of water and pressures required for high volume hydraulic fracturing depend on the geological conditions and composition of the hydraulic fracturing fluid, but are relatively large. In the U.S., the average water volume injected per horizontal borehole in 2014 was nearly 20 000 $m^3$ (typically between 10 000 to 25 000 $m^3$, AEA (2012[22])) per well for gas and up to 16 000 $m^3$ for oil (Gallegos et al., 2015[7]). The volumes required for vertical boreholes are much lower, with medians of <2,000 $m^3$ and <1,000 $m^3$ for gas and oil respectively (Gallegos et al., 2015[7]), and generally reflect the length of the borehole (Gallegos et al., 2015[7]). Between 40–80% of injected fluids flow back to the surface as flowback (Prpich et al., 2015[23]). In the Marcellus and Haynesville Shales, injection pressures range from 13.8 MPa to 82 MPa (US EPA, 2016[6]). |

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| **Lifetime** | Hydraulic fracturing activities can last from one day to several weeks (US EPA, 2016[6]). If the horizontal wells are too long to maintain pressure along their length, plugs can be used to fracture the well in stages (The Royal Society, 2012[21]). Re-fracturing or re-completions are sometimes required in wells, but this is thought to be for <2% boreholes (US EPA, 2016[6]). The overall lifetime of shale gas wells is not well known because the industry is still immature (US EPA, 2016[6]). AMEC (2013)[5] estimated an average lifetime of 20 years and Prpich et al. (2015)[23] estimated a lifetime of up to 30 years. However, there are some estimates that the production phase in tight gas reservoirs may be from 40 to 60 years, or from 5 to 70 years in shale (US EPA, 2016[6]). |
| **Footprint** | In some cases, more than 20 boreholes can originate from a single well pad (Jackson et al., 2013a[24]). Multi-borehole pads have an average area of 1.4 ha during hydraulic fracturing operations and 0.24 ha during production (NYSDEC, 2011[25]). AMEC (2013)[5] estimated that the minimum distance between well pad sites in the UK would be 5 km. For the 13 years following the start of shale gas development in the UK, they estimate that between 30 and 120 well pads could be developed for low and high activity scenarios, respectively. Each well pad could have 6 to 24 wells and be two to three ha per production pad, resulting in 80 to 2880 wells in total (AMEC, 2013[5]). |
| **Coal bed methane (Figure 5.5)** | |
| **Background** | CBM is well established in the US, Australia, China, India and Canada. Gas has been produced from high rank coals since the 1970s and low rank coals since mid-1990s (Moore, 2012[26]). Commercial production began in the USA in the early 1980s. In 2001, there were 3655 CBM boreholes in the Powder River Basin alone. Production has been ongoing in Australia since 1996 and India since 2009 (Moore, 2012[26]). In the UK, CBM exploration wells have been drilled in the Vale of Clwyd, South Wales and South Lancashire. In Airth, Midland Valley, Scotland, significant, but not economic, gas and water production has been established (Jones et al., 2004[27]). CMM has been exploited in the UK since the 1950s, and all working mines (as of 2004[27]) drained methane (Jones, 2004[27]). AMM was produced at the Old Boston colliery, Lancashire, between 1957 and 1967 at an average rate of 52 l/s and up to 300 l/s (Jones et al., 2004[27]). The Avon Colliery pumped gas to South Wales in 1971 (Ren, 2004[28]). There are also AMM sites in North Staffordshire, the East Midlands and Yorkshire (Jones et al., 2004[27]). Methane is also being extracted for electricity generation from the mine complex at Stillingfleet, Selby, Yorkshire (Younger, 2016[29]). |
| **Geological setting** | Organic material forming coal seams was often deposited in sedimentary basins (US EPA, 2016[6] cyclically with other sedimentary rocks. Therefore, coal seams are generally interbedded with other rock types including mudstones, sandstones, siltstones, conglomerate and limestone (e.g. the Coal Measures and Warwickshire groups in England). In England, coal is predominantly found in basins of Carboniferous age and has often subsequently been uplifted and inverted. Structural features such as faulting and folding in the coal bearing units are thus common. Coal units are sometimes overlain by Permo-Triassic principal aquifers in sedimentary basins in England (Jones et al., 2004[27]).<br>Virgin coal seams in England are only several metres in thickness in comparison to those in the USA and Australia, which may be up to 43 m in thickness (US EPA, 2016[6]). |

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| **Depth of exploitation** | CBM basins in the US range from 0 to >2000 m depth (e.g. in the Black Warrior and Powder River Basins, respectively) (US EPA, 2016[6]). Jones et al. (2004)[27] and Gow et al. (2016)[30] considered Coal Measures in the UK to have potential for CBM between 200 to 1200 m bgl. It is thought that there is a possible increase in methane content with depth (EA, 2014[31]). Shallow workings with opencast sections are not considered to have potential for CBM due to the possibility of major air ingress. CMM and AMM resources are in areas with existing and abandoned mines with methane. |
| **Boreholes** | CBM boreholes may have many subsurface horizontal or multilateral side tracks drilled from one surface location in order to penetrate more coal (DECC, 2013b[32]). Horizontal sections of wells are often 1–3 km in length (The Scottish Government, 2014[33]). There may also be multiple pads per production operation (EA, 2014[31]). |
| **Stimulation** | Where permeability of coal is low, hydraulic fracturing can be used to improve connectivity between the borehole and the cleat system. Pressures required for hydraulic fracturing are 50–70% lower than for shale gas, often of the order of 24–34 MPa, although this is depth dependent (EA, 2014[31]). The volume of fluid injected for fracturing is also smaller than for shale gas, between 200 $m^3$–1500 $m^3$ water per borehole (EA, 2014[31]) due to shorter well lengths (US EPA, 2016[6]). Injected fluids include water, water and sand or nitrogen foam with proppants and other additives (EA, 2014[31]). In the UK, estimated produced water volumes are 1–40 $m^3$/day per well and the water can often be highly saline (EA, 2014[31]). Hydraulic fracturing is not a requirement for CMM or AMM. |
| **Lifetime** | The lifetime of a CBM operation depends on a range of factors such as adjacent wells and the amount of gas available, but is poorly understood at present. Most producers in the Powder River Basin, USA, can produce for 10 to 12 years though it is thought that stimulation could increase lifetimes by 10 to 30 years (De Bruin et al., 2016[34]). For CMM there is typically 6 to 12 months of gas production before mining can take place (Karacan et al., 2011[35]). Production in an AMM project in Pittsburgh declined after 2.7 years (Karacan et al., 2011[35]). |
| **Footprint** | Multiple lateral wells can allow drainage of 7.2 $km^2$ from a single well pad, whilst only 0.3 $km^2$ may be drained from a single vertical well (Al-Jubori et al., 2009[36]). The subsurface footprint of CMM and AMM depends on the size of the pre-existing mines. |
| **Underground Coal Gasification (Figure 5.7)** | |
| **Background** | There have been more than 50 UCG trials and larger schemes over the last half century (Jones et al., 2004[27]). Early trials were small-scale and at relatively shallow depths. In 1959, the Newman Spinney trials were conducted south of Sheffield, UK, within the Fox Earth Coal at a depth of 75 m for one to two months at a time. From 1978–1986, trials were conducted on a thin seam at a depth of 1000 m at Thulin in Belgium. The El Temedal European trial in Spain (1993–1998), confirmed technical feasibility at depths between 500 and 700 m bgl.<br>Further afield, UCG has been taking place in Kuzbass, Siberia, at the Yuzhno-Abinskaya gasification plant since 1955 in a coal seam 1.3 to 3.9 m thick, and at the Angren mine in Uzbekistan within lignite seams 2–20 m in thickness and at depths of 130 to 350 m. A test site at Hanna, Wyoming, involved extensive site characterisation and monitoring for hydrogeological and environmental variables but projects in Wyoming were not found to be commercially viable (Jones et al., 2004[27]). Large-scale air-blown schemes have been undertaken more recently in Russia and Uzbekistan and also at Chinchilla, Australia in 1999, where syngas was produced at 300°C and at a depth of 140 m, though this scheme was mothballed by 2003. Since 1990, there have been 16 known trials in China. Feasibility studies have also been undertaken in Canada, India, Pakistan, Russia, Slovenia and the Ukraine. |

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| **Geological setting** | Organic material forming coal seams was often deposited in sedimentary basins (US EPA, 2016[6]) cyclically with other sedimentary rocks. Therefore coal seams are generally interbedded with other rock types including mudstones, sandstones, siltstones, conglomerate and limestone (e.g. the Coal Measures and Warwickshire groups in England). In England, coal is predominantly found in basins of Carboniferous age and has often subsequently been uplifted and inverted. Structural features such as faulting and folding in the coal bearing units are thus common. Coal units are sometimes overlain by Permo-Triassic principal aquifers in sedimentary basins in England (Jones et al., 2004[27]).<br>It is generally thought that coal units need to be >2 m in thickness for UCG (Jones et al., 2004[27]; Burton et al., 2006[37]; Gow et al., 2016[30]) but coal seams are typically thinner than this in Europe, and seams of 0.5 m in thickness may be feasible (Shafirovich and Varma, 2009[38]). Geological structural complexity is not a significant concern for UCG, strata dips of 5 to 30° are preferable (Jones et al., 2004[27]) and horizontal coal seams would need to be compartmentalised (Olness and Gregg, 1977[39]). |
| **Depth of exploitation** | UCG operations are considered shallow between the surface and 350 m bgl and deep from 600 to 1300 m bgl (Burton et al., 2006[37]; Shafirovitch and Varma, 2009[40]). They are generally located below the water table in order to control burns (e.g. Hoe Creek, Burton et al., 2006[37]). In England, Jones et al. (2004)[27] suggest that UCG is more likely to occur at depths of between 600 m and 1200 m bgl, based on the depths required to reduce environmental impacts and the normal limits for mining. For similar reasons, UCG typically takes place deeper in the subsurface in Europe (Burton et al., 2006[37]). |
| **Boreholes** | At least two boreholes are required for injection and extraction, with between 10 and 60 m separation. Thicker coal seams require fewer boreholes (Burton et al., 2006[37]). Directional drilling enables improved control of the gasification process and although it is not necessary (Shafirovitch and Varma, 2009[40]), it is common in deeper seams (Burton et al., 2006[37]). |
| **Stimulation** | Permeability can be increased artificially with stimulation techniques such as reverse combustion and hydraulic fracturing (Bhutto et al., 2003[41]; Burton et al., 2006[37]; Shafirovitch and Varma, 2009[40]). UCG also requires a strong, dry, impermeable roof rock (Jones et al., 2004[27]).<br>In deeper UCG operations steam is injected at pressures of up to 80 MPa. In shallower sites pressures of only 324 kPa may be required. The optimum 'blast' intensity is suggested to be around 5000 $m^3$/hr, but experiments have ranged from 1500 to 7000 $m^3$/hr with higher intensities improving production (Burton et al., 2006[37]). Temperatures exceeding 200°C have been found to minimise pollutant by-products (Burton et al., 2006) with temperatures of up to 300°C used in Chinchilla, Australia (Jones et al., 2004[27]). |
| **Lifetime** | The lifespan of a UCG operation is variable; for example, a site in Uzbekistan has been operational for 50 years but others in the former USSR were operational for between 5 and 17 years (Burton et al., 2006[37]). |
| **Footprint** | Subsurface footprint is variable, dependent on the coal resource and cavity size. However, little control can be exerted over the cavity size (Burton et al., 2006[37]). |

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