Five unconventional fuels: geology and environment

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Abstract

Unconventional fuels may present a viable partial replacement for conventional fossil fuel reservoirs (such as sandstone and limestone) in rocks onshore and offshore. These alternative fuels are obtained from distinct sources and employ extraction technologies which are very different to those used to extract conventional hydrocarbons.

Oil sands (also known as tar sands or bituminous sands) are loose sand or partially consolidated sandstone containing viscous bitumen. Resources occur in Canada, Kazakhstan and Russia and estimated worldwide deposits represent 2500 billion barrels of oil in place. Oil sands have only recently been considered to be part of the world's oil reserves, as higher oil prices and new technology enable profitable extraction and processing. Converting oil sands to liquid fuels requires energy for steam injection and refining.

Methane from coal includes gas recovered from active (coal mine methane or CMM) and abandoned mines (abandoned mine methane or AMM), as well as methane recovered from

undisturbed or ‘virgin’ coal seams (usually known as coal bed methane or CBM). Gas from these sources is already produced on a modest scale and exploration is ongoing for further prospects. Gas can also be derived from coal by combustion of underground coal seams in situ to produce synthetic gas (‘syngas’). This process is usually known as 'underground coal gasification' (UCG). This technology is also in its infancy both in terms of engineering the subsurface process and in the understanding of subsurface and surface environmental impacts.

Methane hydrates (methane gas trapped in ‘cages’ of water molecules, resembling ice) have been recovered from, or are postulated for, virtually all marine shallow sediment continental margins around the world and a few areas onshore. Volumes of about 2 x $10^{14}m^3$ methane in-place have been estimated for this potential resource. To quantify reserve potential and to identify suitable methods of methane extraction, a full understanding of how hydrates are held within sediments is required.

A less well known unconventional fuel is subsurface hydrogen. Small flows of hydrogen naturally occur in some mines and in deep oceans associated with abiogenic and biogenic methane, nitrogen and helium. The main geological environment that is promising for exploration is the tectonic remnants of ancient ocean floor known as ophiolites. The main accessible onshore areas are where ophiolites are found tectonically emplaced within fold belts.

Though unconventional fuels represent an enormous resource overall, some of the technology is immature and many of the environmental impacts of their exploitation are unknown. Apart from subsurface hydrogen, all are hydrocarbons and thus are constrained in their use in countries which may limit carbon emissions either now or in the future.

Introduction

This article will describe the characteristics, potential, and limitations of five unconventional fuels, but will not include the features of the most important recently-exploited unconventional source of hydrocarbons, shale. This latter subject will be covered elsewhere.

To begin, however, it is first necessary to distinguish between the terms 'conventional' and 'unconventional'. These terms are not well defined and mean different things to different hydrocarbon specialists. According to the consultancy IHS for example, unconventional hydrocarbons are defined in relation to extraction methods: '…hydrocarbon resources that are or could be exploited with techniques other than what are considered conventional methods…'[1]. Other more geologically-focused groups tend to define unconventional hydrocarbons in terms of their habitat in the subsurface, for example their tendency to be associated with low permeability rocks (e.g. [2]), or their ease of development and overall potential (see Fig. 1). In this article the relevant definition of unconventional fuels is broader than both because it encompasses fuels that are not primarily hydrocarbon (for example geological hydrogen); and that come from rocks with rather high primary permeability (for example oil sands).

Figure 1. here

In this article I describe five unconventional fuels with modern potential. In this context 'potential' refers to the possibility that the fuels are present as a significant resource and could at some time in the future be exploited. The five fuels are: oil sands, underground coal syngas, coal bed methane, methane hydrates, and geological hydrogen. For each of these types I will consider the geological environment in which they form and which they reside, their reserves or resources, their methods of extraction, and the environmental effects of their exploitation. For each of the forms of unconventional fuels I describe, it is important to note that there is a considerable tension between the resource and the environmental effects of exploitation, in that one has a strong effect on the other. For example in the case of many unconventional fuels, the effects of exploitation particularly on a large scale, may be either unknown, or be considered to be of doubtful benefit to the environment. In the latter case this may lead to public opposition to exploitation, which in many countries may be enough to prevent exploitation.

Oil sands

Oil sands (also known as tar sands or bituminous sands) are loose sand or partially consolidated sandstone containing viscous bitumen in the pore space. Bitumen is the heavy fraction of petroleum. Resources occur in Canada, Kazakhstan and Russia and estimated worldwide deposits represent 2500 billion barrels of oil in place [3]. Oil sands have only recently been considered to be part of the world's oil reserves, as higher oil prices and new technology enable profitable extraction and processing. Converting oil sands to liquid fuels requires energy for steam injection and refining. The most advanced and developed industry is in northern Alberta and is part of the large Athabasca oil sands complex which holds in-place resources of 1350 billion barrels [4]. In this article I will concentrate on the Athabasca oil sands surveying their geology, extraction methods, resources, and the environmental effects of their exploitation. Such characteristics may differ for other oil sands deposits.

Geology

In-place Athabasca bitumen is much more viscous than conventional crude oil (API gravity 8 to 10° for bitumen compared with 25 to 40° for conventional crude oil), and so under reservoir conditions it is essentially immobile. At Athabasca, most of the oil sand is contained within a single contiguous reservoir comprising the Lower Cretaceous McMurray Formation and Wabiskaw Member. The sands are unconsolidated, and are very fine to fine grained. The grains are dominated by quartz with subordinate feldspar, mica and clay minerals. The quartz gives the sands exceptional abrasive qualities which cause wear on heavy excavation and processing equipment. The grains of sand are moderately well sorted and there is little inter-granular fine material. This accounts for the large effective porosity (25-35%) that can hold the bitumen. An important characteristic of the Athabasca oil sands is that they are hygroscopic in that the constituent sand grains of the supporting matrix are coated with thin layers of water. This has the beneficial effect of making the bitumen more mobile than it would be if it were stuck to sand grains (as it is in other oil sands deposits). This characteristic has made the Athabasca oil sands easier to develop than other deposits [4].

Extraction methods at Athabasca

Two main methods are used and their choice depends on the position of the target oil sands. In the case of deposits close to the surface (less than 100m deep), the oil sands are mined using hydraulic shovels and large trucks which carry material to processing plants. At the plants the material is essentially washed with hot water to separate bitumen and sand. The bitumen requires further refining.

In the case of deposits beneath an unproductive overburden (approximately 90% of Alberta's oil sands), a method involving the in situ heating of bitumen is employed, known as steam assisted gravity drainage (SAGD). In this process, steam is injected from an upper horizontal well into the oil sands (Fig. 2). Wells are drilled from prepared areas cleared of vegetation known as pads and these range in size from one to seven hectares. From a pad multiple pairs of injector and producer wells are drilled. A large SAGD project can have up to 25 well pads spread across 150 km^2. The injected steam increases the mobility of bitumen with the result that it drains downward into the production well below, from which the now-liquid bitumen is pumped. Approximately 2.5 to 4 m^3 of steam are required to produce 1 m^3 of bitumen [5]. The SAGD process recovers between 60 and 80% of the bitumen in the formation [5].

Figure 2 Here.

The mobile bitumen is then upgraded to synthetic crude oil. In the first stage the large bitumen molecules are cracked into smaller molecules using coking or hydrocracking. This is followed by hydro-treating where nitrogen and sulphur are removed.

Resources and reserves

The difference between resource and reserve is highlighted starkly by the Athabasca oil sands. The term 'resource' refers to a total amount that in geological terms constitutes material of potential value. 'Reserves' refers to the proportion of this that is economical to produce, within environmental and social limits. The 'recovery factor' which connects the two concepts is the percentage of the resources that can become reserves. In fact the conversion of resources to reserves is the main business of technologists and scientists working in oil, and gas and minerals companies the world over.

At Athabasca, the chief advance which allowed the resource to become at least partly a reserve was the development of the extraction processes described above, and these were partly enabled by the price of oil being high enough to enable oil sands to be produced.

Global natural bitumen reserves are estimated at 249.67 billion barrels (39.694×10^9 m^3) globally, of which 176.8 billion barrels (28.11×10^9 m^3), or 70.8%, are in Canada [3].

The Athabasca oil sands constitute the world's largest accumulation of petroleum of any kind, and their inclusion into the world's inventory of hydrocarbon resources propelled Canada into the front rank of petroleum resource owners [5], affecting the geographical and geopolitical energy map of the world.

Oil sands and the environment

The oil sands of Athabasca are amongst the most controversial in the world in relation to the environmental effects of their exploitation [5]. Environmentalists' concerns relate to CO_2 emissions of the process by which they extracted, other non- CO_2 air pollutant emissions, the use of water in processing, the effect of exploitation on ground and surface water, and the long term effects on landscape, wildlife and ecology.

SAGD and surface mining and processing use large amounts of energy, in fact the equivalent of 1000 cubic feet of natural gas is required to produce one barrel of bitumen using SAGD [5]. In Alberta much of the energy used is gained from conventional natural gas produced in Alberta. The use of fossil fuel to liberate bitumen means that oil sand extraction and processing is a carbon intensive activity. A Stanford University study [6] commissioned by the EU in 2011 found that oil sands crude was as much as 22% more carbon intensive than other fuels to extract. Non CO_2 pollutants are also produced in greater amounts in bitumen extraction than in conventional oil production, including nitrogen oxides, sulphur dioxide and particulate matter.

In order for pits to be excavated for surface mining, the water table must be lowered from the rather high levels that are typical of northern muskeg environments in Canada. After excavation, and when the pits have been re-filled, the water level does not return quickly and so essentially oil sands development leads to the creation of more 'dryland' than was originally present in the muskeg environment [5]. Very large amounts of freshwater are also used in SAGD processing.

The Government of Alberta is aware of these conditions and to offset high CO_2 emissions it is planned to develop carbon capture and storage (CCS) in Alberta whereby CO_2 from installations will be captured and disposed of in deep underground formations. A first stage is the QUEST CCS Project which is scheduled to capture more than one million tonnes of CO_2 per year from Shell's Scotford Upgrader, located near Fort Saskatchewan, Alberta. The Scotford Upgrader produces 3 million tonnes of CO_2 per year processing Athabasca synthetic crude oil. QUEST will capture up to 35 per cent of the emissions from the Scotford Upgrader. The CO_2 will be transported by pipeline from the Upgrader to injection locations within 80 km north of the facility and CO_2 will be injected more than 2000m underground into the a saline formation known as the Basal Cambrian Sands. The CO_2 will be trapped within tiny pore spaces between the grains of the sandstone rock formation and by dissolving into the brine of the saline formation.

To allay public concerns about the environmental impacts of oil sand extraction, the Alberta Environmental Monitoring Agency has been established. This will oversee environmental monitoring across Alberta - beginning in the oil sands region. It will be a centrally-coordinated system and will integrate the monitoring, evaluation and reporting of air, groundwater, land, water and wildlife and it is intended that the information will be scientifically credible, accessible and open. The benefits of environmental monitoring in the context of all unconventional fuels will be discussed in a later section.

Underground coal syngas

Underground coal syngas is produced by processing of coal in situ in deep seams. Injection into a coal seam of oxygen and steam or water by a borehole results in the partial in-situ combustion of coal to produce a combustible gas mixture consisting of CO_2, CH_4, H_2 and CO, the proportions depending on temperature, pressure conditions and the reactant gases injected. This 'syngas' can to be used as a chemical feedstock or as fuel for electricity generation. One advantage of the process of underground coal gasification (UCG) is that it can be used in coal seams that are too deep to mine or technically too complicated to mine profitably.

There have been around 50 trials of UCG in the last 50 years, but to date there are very few commercial operations. Early UCG trials often took place at shallow depths (<200m) and were for short time periods, for example the Newman Spinney trial in the UK in 1959 which was drilled to the Fox Earth Coal at a depth of 75m [7]. However larger scale tests using injected air were tried in Russia and Uzbekistan and at Chinchilla in Queensland, Australia in December 1999 [8]. China has held 16 trials since 1990 and feasibility studies have also been carried out in Canada, India, Pakistan, Russia, Slovenia and Ukraine. Underground coal gasification has been carried out in Kuzbass, Siberia, at the Yuzhno-Abinskaya gasification plant since 1955. This involves the gasification of bituminous coal producing a low calorific value gas used for heating [9].

Geology

The geological limitations on underground coal gasification (UCG) relate to the depth of the seams and the proximity to other activities such as conventional mining. A comprehensive study of the prospects for UCG and coal bed methane carried out by the British Geological Survey for the British Government [8] used the following limits for UCG:

1. Coal seams between 600 and 1200m from the surface
2. Seams with 500m or more horizontal and vertical separation from underground coal workings and current coal mining licences, and
3. Seams greater than 100m from major aquifers

The minimum depth of 600m was assumed as a reasonable depth to lessen the environmental impact at surface, in terms of hydrogeology, subsidence and gas escape. The 1200m depth represents the normal limit for mining in the UK, and the same figure was used for UCG by Jones et al. [8] on the basis of drilling costs and working pressure at surface.

A seam thickness of 2m or greater was chosen for economic reasons since thinner seams may not be economically viable for in situ gasification. The distance from potable aquifers specified was primarily to prevent contamination from fluids and gases produced in gasification.

The limitations and criteria produced by Jones et al. [8] were applied across the main coalfields of Britain and were used to delimit areas that could be exploited for UCG and CBM.

Extraction

UCG converts coal to gas in situ. The gas (known as syngas) is produced and extracted through wells drilled into the un-mined coal seam (Fig. 3). The oxidants (air, oxygen, or steam) are provided by the injection well and these ignite and fuel combustion. Separate production wells bring the syngas to surface. Combustion occurs at temperatures of 700–900 °C and under the prevailing high pressure at variable depths. The main gases produced are carbon dioxide CO_2, CO, hydrogen, methane, sulphur oxides, nitrogen oxides and hydrogen sulphide.

Fig. 3. Here

There are three main forms of UCG. The first involves drilling a series of vertical boreholes, gasifying the coals and relying on a combination of high pressure air fracturing and the natural permeability of the coals to extract the gas. This type of UCG generally takes place at shallow depths. An example of this is the Chinchilla project in Australia [10].

The second type of UCG takes place in existing or abandoned coal mines (e.g. Liuzhuang Mine, China). In this process mined chambers are sealed off, air is injected into the chambers, the surrounding coal is gasified, and the gaseous products piped up a shaft or borehole to the surface. In the third method employed in European and later US trials production and injection wells are connected by in-seam drilling techniques.

Resources and reserves

It is difficult to estimate the value of UCG because the amount of coal accessible to the process depends on variable factors like depths considered suitable and permitted distances from aquifers. However some estimates suggest that UCG will increase economically recoverable reserves of coal worldwide by 600 billion tonnes [11].

A detailed survey was carried out using the criteria of Jones et al. ([8]; listed above) consistently across all British coalfields. The following areas were considered suitable for UCG: eastern England, the Midland Valley of Scotland, North Wales, the Cheshire Basin, south Lancashire, Canonbie, the Midlands and Warwickshire. The conclusion was that the total area of the country where coals are suitable for gasification is approximately $2.8 \times 10^9 m^2$. Where the criteria for UCG are met, the minimum volume of coal available for gasification (calculated assuming only one 2m thick seam meets the criteria across each area) was approximately $5{,}698 \times 10^6 m^3$. This translates to approximately 7 billion tonnes of British coal that could be gasified in situ [8].

UCG and the environment

The chief environmental concern is contamination of potable aquifers. Materials remain in the underground chamber after combustion and may pass into ground water. The organic toxin phenol is the main hazard due to its high water solubility. Subsidence may also be problem: while UCG leaves ash behind in a cavity, the size of the void left after combustion is typically more than other methods of coal extraction.

For these reasons UCG is perhaps least easy of the unconventional fuels to gain public acceptance.

Coal bed methane

Coal has been known for centuries to contain flammable gas (so called 'firedamp'), but gas from coal was not considered as a separate fuel until relatively recently. Typically it consists of 80-95% methane, 0-8% ethane, 0-4% propane and higher hydrocarbons, 2-8% nitrogen and 0.2-6% carbon dioxide, together with traces of argon, helium and hydrogen [12]. In mines it can be explosive when mixed with air. Coal bed methane (CBM; also known as 'coal seam gas') which is extracted from unmined coal seams by directional drilling can be used alongside other hydrocarbon gases for chemical feedstocks and electricity generation. Coal gas as fuel can also be drained from working mines (known as Coal Mine Methane CMM), and this has been exploited in Britain since at least the 1950s and world-wide before this. Methane drained from abandoned mines, known as Abandoned Mine Methane (AMM) may also be used as fuel. This article concentrates on CBM.

Geology

Whether coal releases the gas that it contains depends largely on the natural structures of the coal that give it permeability and porosity. Gas is present in adsorbed form on surfaces in the pores of the coal, and in fractures. Coal contains a natural network of vertical or sub-vertical fractures known as 'cleat'. The dominant set of fractures (known as the 'face cleat') is orthogonal to the subordinate set (the 'back cleat'). When combined with the sub-horizontal natural bedding planes in coal, these fracture planes divide the coal so that it breaks up into cuboidal shapes at outcrop. The cleat often gives permeability to the coal but sometimes cleat is filled with secondary mineral cements and fillers. If cleat and other natural fractures are abundant and open, gases and water can penetrate coal and, crucially, gases can diffuse out from the solid coal into the cleat. Cleat intensity, defined as the number of fractures per unit distance perpendicular to the cleat, is therefore an important factor in determining permeability (see [13]). The natural porosity of coal seams is usually very low, ranging from 0.1 to 10% and thus the fracture permeability acts as the major channel for the gas to flow. For most coal seams found in the US, the permeability lies in the range of 0.1 to 50 milliDarcies, though British coal seams appear to have lower permeabilties, for example the permeability of the Great Row seam in North Staffordshire was estimated to be between 0.1 and 0.5 millidarcies [14]. Hughes and Logan [15] indicate that the minimum permeability needed to recover methane is generally >1mD.

Like coal intended for UCG, the spatial geological limitations on CBM relate to the depth of the seams and the proximity to other activities. Jones et al. [8] considered that the best CBM resources were defined by the following criteria:

1. Coal seams greater than 0.4m in thickness at depths greater than 200m
2. Gas content in the seam greater than 1m^3/tonne
3. 500 metres or more horizontal separation from underground coal workings
4. Vertical separation of 150m above and 40m below any previously worked coal seam
5. Vertical separation of greater than 100m from major aquifers

On this basis Jones et al. [8] mapped the resources of CBM across British coalfields.

The fracture and pore spaces usually also contain pore water as well as gas and when the coal is drilled, water in the fracture spaces is pumped off first. This leads to a reduction of pressure allowing desorption of gas from the coal

Extraction

A well is drilled into the coal seam and pumped to lower the pressure in the seam. This allows methane to desorb from the internal surfaces of the coal and diffuse into the cleat, where it is able to flow, either as free gas or dissolved in water, towards the production well.

Permeability (imparted mainly by the cleat) is necessary to achieve coalbed methane production. The permeability of coal seams is low, so coalbed methane wells are normally stimulated to improve connectivity between the borehole and the cleat system. The coal seams may be hydrofractured, or they may be cavitated. Hydrofracturing uses pressurised water to initiates and open cracks; in cavitation a part of the seam around the borehole is excavated to improve connectivity to the cleat system and to allow the coal to expand slightly into the cavity, locally improving permeability.

Resources and reserves

For similar reasons to UCG, it is difficult to calculate the worldwide resource or reserve of CBM since this depends on local conditions and the way that resource criteria are applied.

Based on area calculated using the criteria above, and variables such as gas content and coal density, Jones et al [8] calculated the total CBM resource of the UK to be 2900 x 10^9 m^3 of gas, but It is highly unlikely that more than a few percent of this total could be recovered in Britain, because of perceived widespread low seam permeability and planning and other constraints. Jones et al. [8] therefore considered that the upper limit of recoverable gas was 30 x 10^9 m^3.

CBM and the environment

Like UCG, CBM produces a flammable gas that can be used as a chemical feedstock or for electricity generation. The latter being a fossil fuel, its combustion produces the greenhouse gas CO_2. However methane itself is a greenhouse gas with much greater potency than CO_2 which explains why in the case of gas release, flaring is a better option than venting. It is interesting to note that the US Environmental Protection Agency [16] identified methane escaping from coal during mining as producing around 10 % of US methane emissions. Recovery of coal mine methane might therefore be seen as an opportunity to reduce such methane emissions.

The main environmental challenge is 'produced water' brought to the surface as a by-product of CBM extraction. The volume produced may be very large - too large for simple discharge into rivers or streams - and the produced water may vary greatly in quality from area to area, and may contain undesirable concentrations of dissolved substances such as salts, heavy metals and radionuclides. Produced water in these cases would have to be treated before being discharged into surface catchments.

Methane hydrates

Methane hydrates belong to a group of solids known as clathrates which comprise a lattice of a 'host' molecule within which 'guest molecules' are trapped. The most common guest is methane, creating an ice-like substance known as methane hydrate which is believed to be present in many offshore locations in shallow subsea sediments and onshore (associated with permafrost in Siberia, Alaska and the Canadian Arctic). The hydrate 'cage' allows the methane molecules to be held close together, much closer than in a free gas. There is up to 164m^3 of gas at standard temperature and pressure, and 0.8m^3 of water in 1m^3 of solid hydrate [17]. Because of the size of the area postulated for subsea methane hydrates, their global resource is considered very large, greater than for all other hydrocarbon energy sources. However, unlike other resources for example conventional oil and gas or coal bed methane, their occurrence and relationship with host sediments is poorly understood and it is only with improvements in this area that constraints on their exploitation will be reduced [17]. Methane hydrates are thus amongst the most speculative of the unconventional fuels considered in this paper.

Geology

The methane hydrate deposits most likely to be developed occur in offshore continental margins where they are dispersed amongst unconsolidated or poorly consolidated marine sea bottom sediments (Fig. 4). Methane hydrate has been observed in oceanic shallow sediment cores. It cannot be detected directly on seismic but its lower limit is believed to be marked by the presence in shallow seismic of a 'bottom simulating reflector' (BSR). This is a distinct reflector due to a large negative change in acoustic impedance and has a shape sub-parallel to that of the seafloor above. Many researchers believe that it represents the base of the hydrate stability zone beneath which free (methane) gas exists [17].

In geological environments, methane can be generated by recent microbiological activity (biogenic methane) and by longer term geological heating (thermogenic methane), and these types can be distinguished isotopically. In most cases isotopic signatures suggest that naturally occurring sub-seabed hydrates are formed principally from microbial methane [17] probably generated in situ by degradation of marine organic matter trapped in the sediment and then ‘frozen’ into clathrate.

Fig. 4. here

Extraction

Methane hydrates have received considerable attention in parts of Asia, for example Japan and India, where large amounts of conventional gas is not available. However commercial gas production from offshore methane hydrates has not been established anywhere in the world. In Japan where extraction technology is perhaps most advanced, a pilot test was established in March 2013 in the eastern Nankai Trough which is believed to contain 20 tcf (trillion cubic feet) of methane hydrate gas in place (Masuda 2013; personal communication). One production well and two monitoring wells were drilled into sands at a depth of 300m below seafloor and in 1000m of seawater. The method used was depressurisation using an electric submersible pump, and it produced methane for six days at an average rate of 20000 m^3 per day.

Resources and reserves

Global methane hydrate resources are estimated at 2 x 10^{14} m^3 of methane in natural gas hydrate [18]. Since the first commercial test of production was carried out only in March 2013 (see above), it is too early to say what proportion of the worldwide resource may be realised as reserve.

Methane hydrates and the environment

Extraction techniques like those being used in the Nankai Trough in Japan are rather similar to those of offshore conventional oil and gas, using deviated wells drilled into the seabed. Environmental impacts are thus likely to be similar.

Geological hydrogen

This unconventional fuel is the least well known of those discussed in this paper. Very little exploration has taken place worldwide and its potential is unknown. Geological hydrogen is also distinct in that it is not a hydrocarbon in the sense of others described here, since its origin mainly relates to chemical alteration of ultramafic igneous rocks, rather than carbon-rich organic matter. Geological hydrogen is not as common as biogenic or thermogenic methane, which are present in hydrocarbon basins, but has the benefit of burning without producing any CO_2 at all and thus being part of the so-called 'hydrogen economy' which proposes that a proportion of energy needs worldwide - particularly for vehicles - could be met by hydrogen.

Geology

Ultramafic igneous rocks contain shows of hydrogen but their geochemically altered form serpentinite contains the highest levels of hydrogen [19]. Huge volumes of ultramafic igneous rock are present in the Earth's mantle and are therefore inaccessible but masses of ultramafic rocks are sometimes associated with intense fold belts at plate margins where they are explained as fragments of deep crust that have been detached during unsuccessful subduction. Such masses, known as ophiolites, also come into contact with groundwater leading to serpentinization, a process of hydrolysis of ferromagnesian minerals (olivines and pyroxenes) which produces hydrogen gas and the mineral serpentine [$(MgFe)_3Si_2O_5(OH)_4$]. To some extent the amount of serpentinsation will depend on water being able to circulate into fresh ultramafic rocks. Macdonald and Fyfe [20] suggested that the expansion associated with serpentinization may help to repeatedly fracture the rock in turn assisting further serpentinization.

It is likely however that hydrogen would need a subsurface trap (analogous to those that trap hydrocarbons) for it to collect in accumulations large enough to be commercially viable [19]. Because of the small size of the hydrogen molecule it is likely to be able move through overburden rocks, even those that are impermeable to hydrocarbon gases. It is possible therefore that geologically recent generation of hydrogen may be crucial for commercial accumulations, since older accumulations may have escaped through overburden.

Extraction

Shows of hydrogen exist at the surface and in mines in some parts of the world (see review in [21]) but no commercial extraction specifically for hydrogen has taken place. In the circumstances described above, where hydrogen might collect in a trap, conventional drilling and possibly hydraulic fracturing could be a viable extraction method.

Resources and reserves

There are no estimates for the resource of geological hydrogen worldwide though Smith et al. [19] estimated the potential for the Semail ophiolite in south Arabia, the largest in the world. According to Smith et al. [19] the Semail ophiolite has exposed limits of 500 km x 50 km x 5 km thick, comprising perhaps 50% ultramafic rocks. If 50% has been serpentinized, around 3125 cubic kilometres of hydrogen could have been produced.

Environment

In the absence of commercial production, and without an extraction method it is not possible to estimate the environmental impacts of hydrogen extraction. It is interesting to note however that hydrogen used as a fuel produces no CO_2, and therefore might be regarded as the cleanest fuel.

Carbon capture and storage, and unconventional fuels

Coal is a potentially attractive target for CO_2 storage for climate abatement, because the pores and fractures within coal are spaces that could be filled with CO_2, but also because CO_2 is adsorbed and retained in coal preferentially to methane, this is because CO_2 is readily adsorbed onto organic material than is methane. It is also possible therefore that injecting CO_2 into coal seams could enhance coal bed methane production by displacing methane for production with the added benefit that the CO_2 used would be permanently held by coal in fractures as free gas but also more strongly as adsorbed gas. This has lead to the concept of Enhanced Coal Bed Methane (ECBM). ECBM has been trialled at the Allison CBM unit in the San Juan Basin [22]. The unit consisted of four injection wells, 16 producers, and one pressure observation well. During the project over 57 million m^3 of CO_2 were injected into the Fruitland coal seams. The objective was to stimulate coal bed methane production and recovery. The amount of retention of CO_2 was not clear but injection of CO_2 yielded 4.5 $x10^4m^3$ of enhanced gas recovery [8].

There are some challenges to the feasibility of ECBM as a climate abatement technology; not the least the obvious objection that CO_2, though being stored in the process, is also helping to produce a fossil fuel, that will probably be burnt. Other considerations include:

1. Because the CO_2 would effectively be disposed of in the coal, the seam would from that point onward be unavailable for mining, in other words it would be 'sterilized'.

2. The positive aspect of ECBM, involving the disposal of CO_2, could easily be counteracted by any 'fugitive emissions' of methane, or uncontrolled emissions from the ECBM process. This is because methane is a much more potent greenhouse gas than CO_2. Hence it is extremely important to fully capture all fugitive methane emissions to ensure the process resulted in a net reduction in greenhouse warming potential.

3. It is possible that the coal matrix could swell because of CO_2 adsorption [8] which could reduce the permeability of the coal around the injection well slowing down injection.

In the same way that intact coal seams represent a possible storage location for industrial CO_2, so do the voids created by underground coal gasification [23]. The prospect of UCG combined with CCS is being studied.

Geological hydrogen is produced by serpentinisation of ultramafic rocks. As discussed above, it may be that hydrogen produced in this way could collect in traps rather like those that store conventional hydrocarbons, though it may only be accessed by hydraulic fracturing of the serpentinised rock. It is interesting to note that ultramafic rocks and serpentinite are made up partly of magnesium and calcium containing minerals and that these naturally react with atmospheric CO_2 locking it up as solid minerals. This is a form of carbon capture. Over the long term, surface weathering of ultramafic rocks over geological time periods removes large amounts of atmospheric CO_2. The minerals produced are very abundant and are very stable so that re-release of CO_2 into the atmosphere does not happen. It may be that drilling and extraction of hydrogen from ultramafic rocks followed by injection of captured atmospheric or industrial CO_2 might have a dual purpose because it would provide a useful non-fossil fuel, but also a method of permanent disposal of excess CO_2.

Fugitive emissions and unconventional fuels

Most of the unconventional fossil fuels discussed here produce methane as the main combustible gas. As discussed above, methane is a more potent greenhouse gas than CO_2 and so called 'fugitive emissions' involved in extraction techniques are now coming under increased scrutiny, particularly in conventional hydrocarbons and shale gas. Recent studies (e.g. [24]) of shale gas extraction have identified leakage from pneumatic valves that control surface pumps and 'liquid unloading' where liquids in the well are cleared out to increase gas flow. The efficacy of the technologies to extract other unconventional fuels, such as those considered here, without producing fugitive emissions will therefore also be at issue.

Monitoring and baselines

Monitoring and regulation are vital for orderly and sustainable energy development, and public and investor confidence. The oil sands of Alberta, discussed earlier in this article, are a good example. These huge resources are very valuable for Alberta and Canada but there is a big challenge in selling their sustainability to Canadians (for local environmental reasons) and worldwide (for CO_2 emissions). Oil sand extraction and usage have high CO_2, land impacts and water impacts. The planned Alberta Environmental Monitoring Agency is a conscious effort to monitor environmental effects while reassuring the public of the managerial competence of the operators and regulator. It will oversee environmental monitoring across Alberta - beginning in the oil sands region - integrating the monitoring, evaluation and reporting of air quality, groundwater and surface water. The information will be scientifically credible, accessible and open - and some will be in real time. Monitoring in areas before exploitation to establish baseline levels also helps regulators and operators to know when damage or harm has been done to the environment.

It may be that increased use of unconventional fuels, particularly those that involve unfamiliar extraction techniques that the public might find alarming, will need new regulatory environments and better overall understanding of subsurface processes. Detailed and comprehensive monitoring of surface and subsurface environmental systems may therefore be a prerequisite for unconventional fuel exploitation. This is likely to involve seismic and groundwater monitoring, downhole sensors and other downhole techniques such as electrical resistivity tomography, as well as remote sensing. Better understanding of subsurface processes will improve the efficiency and environmental sustainability of unconventional fuel exploitation. It will also help to engender public confidence, and might speed new technology energy options (e.g. compressed air energy storage,) to commercialisation.

Conclusions

Unconventional fuels represent an enormous global resource overall, but much of the technology to extract them is immature and many of the environmental impacts of their exploitation are unknown. In the future, unconventional fuels are likely to remain attractive to countries that do not have conventional fuels and that are trying to improve their energy security and independence.

The most important unconventional fuel, shale gas (dealt with elsewhere in this volume), dominates the emerging energy landscape with enormous impacts on the United States economy, geopolitics and fuel use elsewhere in the world [25]. Shale gas development in the United States is known to have reduced coal –fired electricity reducing overall US CO_2 emissions, while also increasing the take up of unwanted US coal in European markets [26]. It may also act to slow down the development of other unconventional fuels as an easier and more established option, especially as hydraulic fracturing technology matures and is shown to work outside the areas where it was developed in the United States.

For those companies with experience in shale gas development there may be a 'first-mover' head start in commercialisation of the types of unconventional fuels discussed here in that experience in liaising with governments and regulators, as well as with the local population, will be advantageous. Many of the environmental and technical concerns in, for example, drilling for CBM and for syngas in UCG will be similar. The approaches adopted to liaise with local people involved will also likely be similar.

Notwithstanding the prior experience that shale gas development may bring, unconventional fuels are still likely to be limited by the levels of impact that they have on the environment. Apart from subsurface hydrogen, all are hydrocarbons and thus are constrained in their use in countries which may limit carbon emissions either now or in the future.

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Figures

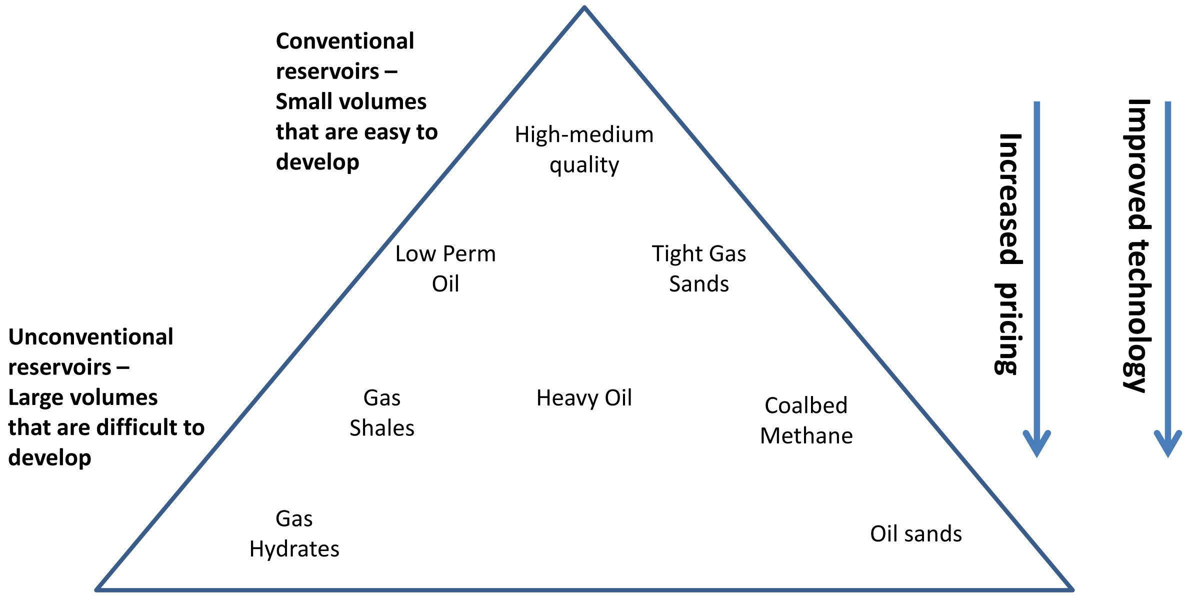

Figure 1. The resource triangle, adapted from [27]

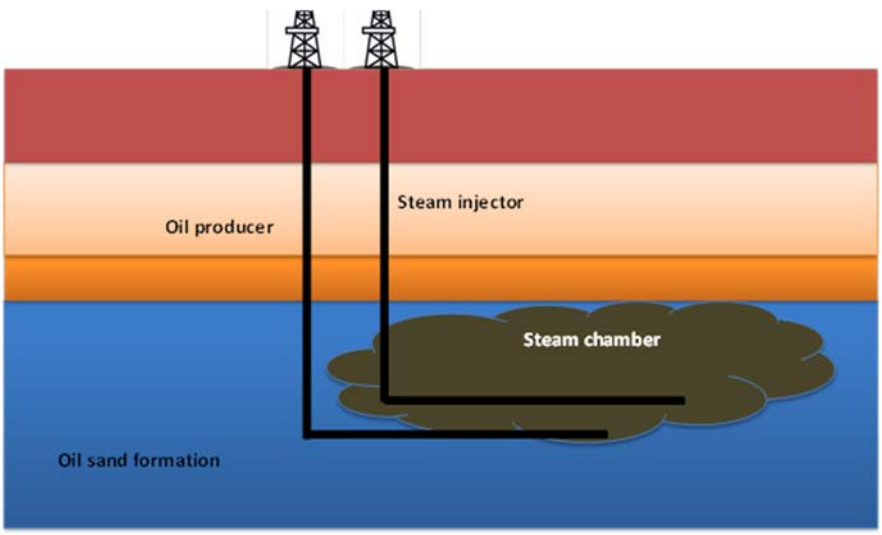

Figure 2. Schematic diagram of SAGD (adapted from [5])

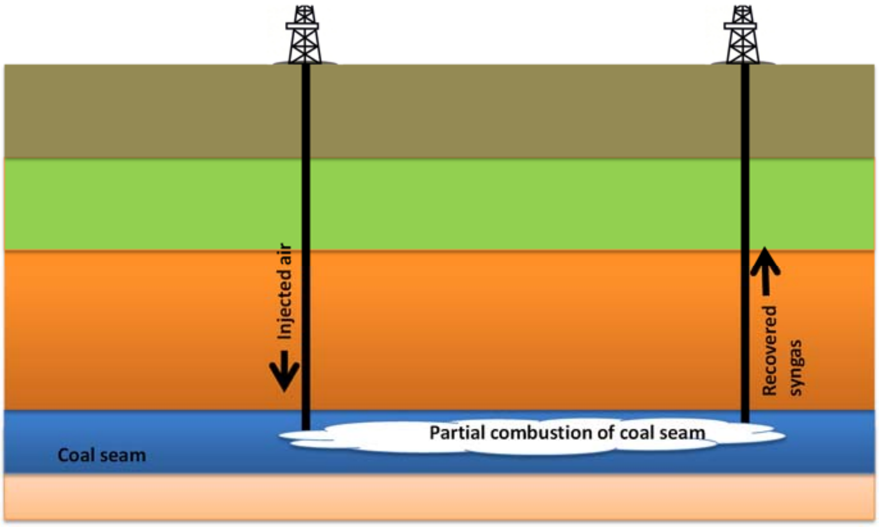

Fig. 3. Schematic diagram of UCG, adapted from the BGS Mineral Planning Factsheet 'Alternative Fossil Fuels'; www.mineralsUK.com

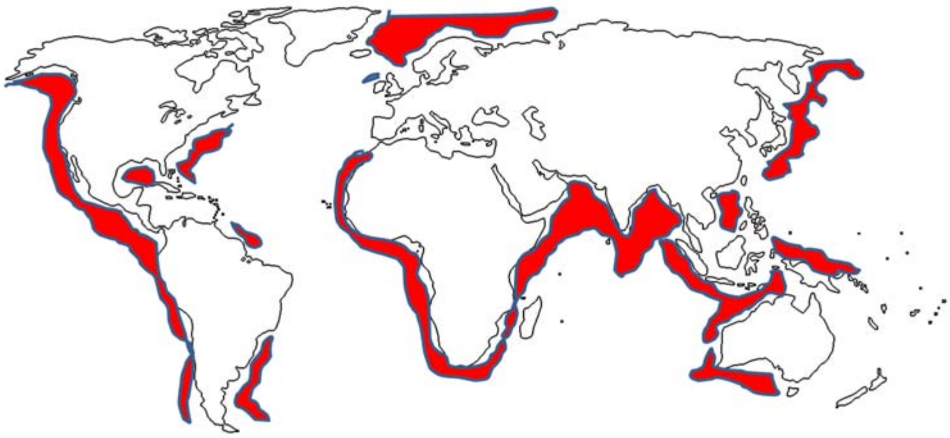

Fig. 4. Main areas of offshore methane hydrates, simplified from [28].

Biography

Mike Stephenson is Director of Science and Technology at the British Geological Survey and the Deputy Director of the Nottingham Centre for Carbon Capture and Storage. He began his career as a schoolteacher in rural Africa and stayed there for ten years but returned to

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