Monetisation of Coal Assets

Briefing paper
Coal is the world's most abundant fossil fuel with 847 billion tonnes of proved reserves. Coal has long been used as an energy resource traditionally for heating and power generation. However the dynamics and opportunity set for utilising coal is changing. There is increasing convergence and competition amongst different value-chains which means coal may have a more diverse role to play in the energy mix going forward.

The climate change agenda and uncertain long term price expectations are causing a re-examination of extraction, production, transportation and end-user markets across a range of fuels.

Alternative extraction methods and resources (e.g. oil sands, coal seam methane) may increase in significance to compliment the more traditional mining and oil and gas production techniques. The cost of production per unit of energy and the scale of accessible resources are key determinants for the attractiveness of various technologies / resources.

There are a range of conversion technologies for example: coal to syn-gas; coal to thermal power; syn-gas to power; syn-gas to middle distillates; syn-gas to methanol. Some of these conversion techniques are proprietary, others can be licensed. Again the costs, scale and efficiency of alternatives are important.

Moving down the value chain – access and cost of transportation to markets are also important. The majority of coal reserves are located in the United States and Russia (together nearly half of global coal reserves) followed by China, Australia, India, South Africa, Ukraine and Kazakhstan, whereas key energy markets are the US, Europe and emerging markets. Bulk movement by ship, rail, road, pipelines, conversion to liquid (e.g. LNG), the choice between local versus regional markets, and the cost and scale of transportation investments are factors which need to be taken into consideration. If you are interested in finding out more around broader market opportunities for gas we refer you to the PricewaterhouseCoopers (PwC) publication ‘Value and Growth in the liquefied natural gas market.’

Moving to end-users there is significant competition between different technologies within end-user market segments and indeed competition between different end-user markets. For example in the power generation market, traditional thermal coal-fired generation needs to compete against, gas, nuclear, oil and renewables. The playing field is not always level as government policies covering fiscal incentives, subsidies as well as those covering security and diversity of supply will alter the relative economics attractiveness of each technology.

Technology also gives the choice between exposure to different end-user markets for coal resources (e.g. coal to power; coal to gas; coal to liquid fuels; coal to petrochemical). Similarly, inter-fuel competition can come from gas, oil, etc where there are similar end-user market choices. Thus there are a whole variety of alternatives and choices which means that each investment case will be different and project specific.

In addition to technology and access to markets there are a number of other very important factors which affect the choice of which energy resource to develop and how best to develop it. The importance of carbon and other emissions / by-products is critical. The amount of carbon emissions by the technology itself – or elsewhere down the value-chain – over the project lifecycle is of ever-increasing importance. There is considerable uncertainty around levels and timings surrounding the impact and costs of carbon on different projects. Costs of direct abatement or sequestration as well as indirect costs from offsets can have a substantial effect of choice on technology and resource.
Another real and very current set of issues relates to the constraints in delivering large capital projects in the mining and energy sectors. The considerable capital investments required, the difficulty in accessing skilled labour and overcoming bottlenecks in the supply chain, along with more recent constraints around availability of financing mean that it is difficult to get an accurate picture of the costs and timing of such projects. Even with known standardised technologies (for example LNG liquefaction trains), it appears that new-build costs have escalated a significant amount over the last few years. In the current environment where costs are not stable, getting an accurate picture of the new-build cost of an existing technology is difficult enough whilst obtaining a good comparative picture of non-traditional alternatives is very challenging without direct EPC quotes.

The preceding preface shows the great potential that there is in looking at coal in a different way, but also highlights some of the complexities and difficulties in making straight comparisons between alternative techniques. In our briefing paper, we describe the alternative methods for creating value from coal assets and look to make some semi-qualitative comparisons across a number of dimensions. We restricted our data to public domain sources which has the advantage that the reader can easily follow up and get more detailed information, but has the disadvantage that economic data are not always current – especially given rapid changes in costs and prices over the last couple of years (note, we have not sought to re-base economic information, but use it for illustrative purposes).

Coal performs and will continue to perform an important role in the overall energy mix. I do hope you find this briefing paper informative and of interest and I would like to thank a number of anonymous reviewers from a number of energy and mining companies for their useful and constructive comments.

Michael Hurley
Global Energy, Utilities & Mining Advisory Leader
PricewaterhouseCoopers LLP
1. Introduction
2. Coal
3. Technologies – Coal mining followed by Surface Coal Gasification (SCG)
   3.1. Description of technology
   3.2. Brief history
   3.3. Commercialisation status
   3.4. Technical issues
   3.5. Environmental issues
   3.6. Illustrative economic analysis
      3.6.1. Energy performance
      3.6.2. Market
4. Technologies – Underground Coal Gasification (UCG)
   4.1. Description of technology
   4.2. Brief history
   4.3. Commercialisation status
   4.4. Technical issues
   4.5. Environmental issues
   4.6. Illustrative economic analysis
      4.6.1. Energy performance
      4.6.2. Market
5. Technologies – Coal Bed Methane (CBM)
   5.1. Description of technology
   5.2. Brief history
   5.3. Commercialisation status
   5.4. Technical issues
   5.5. Environmental issues
   5.6. Illustrative economic analysis
      5.6.1. Market
6. Conclusion
Appendix
   Comparison of techniques
1. Introduction

Amongst the major energy sources, coal is the most rapidly growing fuel by consumption on a global basis. Whilst there are questions regarding the adequacy of the reserves of oil and conventional gas, with demand for these fuels threatening to outpace supply, coal reserves remain abundant and broadly distributed around the world.

Current high energy prices have given rise to a focus on alternative sources of energy. For coal, this has given impetus to a renewed focus on technologies for extracting gas from coal beds as well as various technologies for converting coal to gas, Liquified Natural Gas (LNG) and to liquid fuels.

This discussion paper considers some of the alternatives available for monetising coal assets, including:

- Conventional coal mining
- Coal mining followed by Coal to Gas or Surface Coal Gasification (SCG)
- Underground Coal Gasification (UCG)
- Coal Bed Methane (CBM)

Aside from conventional mining, the options chosen reflect monetising coal assets through production of gas. Converting this gas to liquid fuels or LNG is widely practised and may be more economically advantageous than leaving the product in the gaseous phase. It is important to note that once coal has been converted to syngas, or CBM has been produced, there are a number of markets that can potentially be accessed: for example, gas/syngas to diesel, gas/syngas to LNG, gas/syngas to petrochemical feedstocks. Due to the additional processing costs and paucity of data around these, we have limited our qualitative economic analysis of coal to gas/syngas to the production of electricity and have mentioned these other opportunities in the relevant market sections.

SCG and UCG both use coal in a way that fundamentally changes the way its energy is exploited from the traditional burning of coal to heat steam and to produce power. Both SCG and UCG concern gasification of coal whereby coal is not burnt directly, but is physically broken down, usually by subjecting it to high temperature and pressure, using steam and oxygen. This leads to the production of syngas, a mixture consisting mainly of carbon monoxide \((\text{CO})\), hydrogen \((\text{H}_2)\), methane \((\text{CH}_4)\), carbon dioxide \((\text{CO}_2)\), and other products such as hydrogen sulphide \((\text{H}_2\text{S})\). Syngas is cleaned and can then be burned in a gas turbine to generate electricity and to produce steam to drive a steam turbine, also for electricity. Syngas can also be processed to form a liquid fuel e.g. diesel or chemicals, fertilisers, etc.

CBM, on the other hand releases the gas that is trapped in coal seams and does not utilise the coal itself, preserving the coal for potential future use. Methane is released and can be used as any other source of natural gas e.g. in direct burning in local industry, in gas-fired power stations to produce electricity or it can be condensed into LNG or Compressed Natural Gas (CNG).

The alternatives to conventional coal mining (which is usually followed by the sale of coal to power generators to produce electricity) have and continue to be developed for several reasons:

- To take advantage of the fact that there is gas contained within the coal seams. This gas was originally considered to be a hazardous waste product of mining coal but now is sold and used in the same manner as traditional natural gas
- To address environmental concerns surrounding coal utilisation and in particular the cost of burning coal in a carbon constrained world
- To utilise coal that may never be mined
- To address safety concerns regarding sending people underground
- To take advantage of other growing markets e.g. the developing LNG market

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5 Safety concerns are important but will not be considered further in the remainder of this document
Coal is an extremely important fuel and is expected to remain so. Globally, some 23% of primary energy needs are met by coal and 39% of electricity is generated from coal. About 70% of world steel production depends on coal feedstock.

The reasons for the importance of coal are:

- **Coal is the world’s most abundant fossil fuel source.** Coal is widely distributed. Economically recoverable reserves of coal are available in more than 70 countries worldwide, and in each major world region.

- **The wide availability of coal and the advanced stage and commoditisation of coal mining make it a cheap resource.** This is especially relevant in the 2008 climate of rising energy prices.

However, burning coal releases about 9 billion tonnes of CO$_2$ into the atmosphere each year. About 70% of this is due to power generation. As such, coal mined and used for power generation in the traditional way is now widely acknowledged to adversely impact the environment.

The traditional method of monetising coal is through mining the coal followed by burning it in a coal-fired power station. When coal is used for fuel in power generation, it is referred to as steam or thermal coal. The most economical method of coal extraction from coal seams depends on the depth and quality of the seams, and also the geology and environmental factors of the area being mined.

Coal mining has been around for many years with the first US commercial coal mines in Virginia in 1748. Coal mining processes are generally differentiated by whether they operate on the surface (opencast or surface mining) or underground. Two underground mining techniques are:

- **Bord/Room and Pillar** – This involves cutting a network of ‘rooms’ or panels into the coal seam and leaving behind ‘pillars’ of coal to support the roof of the mine. Initially, recoveries are reduced (to 50-60%) because of the coal left in the pillars although some of this coal can sometimes be recovered at a later stage of mine life. This technique currently accounts for about 50% of underground production.

- **Longwall** – Longwall mining involves essentially the complete extraction of the coal contained in a large rectangular block or “panel” of coal and the roof in the mined-out area is allowed to collapse. Longwall systems allow a 60 to 100% coal recovery rate where the surrounding geology allows their use.

Generally, opencast mining is more productive than underground mining with the recovery of up to 95% of coal reserves in all seams (≥ -0.5m thick), and, with new operations in developing countries coming online, it is estimated that opencast will grow to about half of total coal production in the future. It is believed that opencast mining is currently functioning at its highest possible productivity. Underground techniques, however, especially bord and pillar and longwall mining, will probably gain in productivity from dissemination of existing technical innovations but underground mining can only extract the thicker seams (perhaps >1.5m-2m).

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6 World Nuclear Association: Cleaner Coal Technologies, 2008
7 IEA website: www.iea.org
8 Kentucky Coal Association website: www.coaleducation.org
9 Australian Coal Association
10 EIA
For opencast and underground mining the restrictions are as follows:

Table 1: Opencast and underground mining restrictions

<table>
<thead>
<tr>
<th></th>
<th>Opencast mining</th>
<th>Underground mining</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Depth</strong></td>
<td>&lt;150m</td>
<td>500m+</td>
</tr>
<tr>
<td><strong>Thickness</strong></td>
<td>Generally &gt;0.5m</td>
<td>&gt;2m preferred</td>
</tr>
<tr>
<td><strong>Coal type preferred</strong></td>
<td>All coals and lignites (or brown coals)</td>
<td>Bituminous coal and anthracite</td>
</tr>
<tr>
<td><strong>Thermal value preferred</strong></td>
<td>20 to 30MJ/kg(^{11}) (Brown coal is \sim10-15MJ/kg)</td>
<td>20 to 30MJ/kg (Brown coal is \sim10-15MJ/kg)</td>
</tr>
<tr>
<td><strong>Recovery</strong></td>
<td>75% – 95%</td>
<td>Varied – 50-90% (in mined seams only)</td>
</tr>
</tbody>
</table>

Source: Australian Coal Association and other coal association websites, PwC analysis

The table below shows the different ranks of coal and their characteristics:

Table 2: Ranks of coal and their characteristics

<table>
<thead>
<tr>
<th>Coal rank</th>
<th>Typical characteristics</th>
<th>Uses</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lignite (also known as</td>
<td>• Appearance: Soft, brown</td>
<td>• Steam-electric power generation</td>
</tr>
<tr>
<td>Brown Coal)</td>
<td>• Carbon content: Low, 20-35%</td>
<td>• Jet – ornamental sone</td>
</tr>
<tr>
<td></td>
<td>• Water content: 30-60%</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Oxygen content: High, up to 30%</td>
<td></td>
</tr>
<tr>
<td>Sub-bituminous</td>
<td>• Appearance: Dull black, waxy</td>
<td>• Steam-electric power generation</td>
</tr>
<tr>
<td></td>
<td>• Carbon content: 35-45%</td>
<td>• Source of light aromatic hydrocarbons for the chemical synthesis industry</td>
</tr>
<tr>
<td></td>
<td>• Water content: Up to 15-25%</td>
<td></td>
</tr>
<tr>
<td>Bituminous</td>
<td>• Appearance: Dense, black, frequently containing bands with brilliant colours</td>
<td>• Steam-electric power generation</td>
</tr>
<tr>
<td></td>
<td>• Carbon content: 45-86%</td>
<td>• Heat and power applications in manufacturing</td>
</tr>
<tr>
<td></td>
<td>• Water content: 3-15%</td>
<td>• Some bituminous coal can be used to make coke</td>
</tr>
<tr>
<td>Anthracite</td>
<td>• Appearance: Dense, hard, shiny</td>
<td>• Residential and commercial space heating</td>
</tr>
<tr>
<td></td>
<td>• Carbon content: High, more than 86%</td>
<td>• Some metallurgical applications</td>
</tr>
<tr>
<td></td>
<td>• Less than 1% of world’s total reserves</td>
<td></td>
</tr>
<tr>
<td>Graphite</td>
<td>• Appearance: Black to grey, hard, opaque, metallic earthy lustre</td>
<td>• Pencils</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Lubricant (when powdered)</td>
</tr>
</tbody>
</table>

Source: US Department of Energy : Coal Bed Methane Primer, 2004

\(^{11}\) MJ/kg = Megajoules/kilogram
3. Technologies – Coal mining followed by Surface Coal Gasification (SCG)

3.1. Description of technology

New "clean coal" technologies are being used to address the problem of high emissions of greenhouse gases, sulphur oxides (SO\(_2\)) and nitrogen oxides (NO\(_x\)) produced by burning coal and to provide an alternative to oil in the production of transport fuels. SCG used for power generation, often called integrated gasification combined cycle (IGCC), is a new coal technology which has a number of benefits over coal-fired power generation.

Coal gasification takes place in the presence of a controlled 'shortage' of air/oxygen, thus maintaining conditions to reduce the coal to gas. The process is carried out in an enclosed pressurized reactor, and the product is syngas (a mixture of CO + CH\(_4\) + H\(_2\)). The gas is cleaned and then can be burned with either oxygen or air, generating products at high temperature and pressure. A gas turbine is used to generate electricity, with waste heat being used to raise steam for a secondary steam turbine, thus the term combined cycle. Not only are efficiencies raised in doing so – thereby reducing emissions of CO\(_2\) – but pollutant emissions are also significantly reduced, even compared to advanced conventional technologies, with 33% less NO\(_x\), 75% less SO\(_x\) and almost no particulate emissions. A plant using SCG uses 30-40% less water than a conventional plant and up to 90% of mercury emissions from the coal can be captured (at typically one-tenth of the costs for a conventional plant).

The syngas is produced at temperatures up to 1,700°C, while the gas clean-up systems operate at a maximum temperature of 600°C. Large heat exchangers are required, and there is the possibility of solids deposition in these exchangers which reduces heat transfer. The heat exchangers thus do not work optimally due to solids deposition and also require additional equipment. It seems that unless it is possible to develop hot gas cleaning as a reliable procedure, the comparative economics of IGCC is likely to remain unattractive.

SCG may be able to use coals that would otherwise be difficult to use, such as those with a high sulphur content, or high ash content. The thermal efficiency of IGCC plants is relatively attractive at 45%.

Figure 1 below shows the value chain of coal mining followed by SCG and power generation.

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12 Information taken from IEA Clean Coal Centre; European Commission: Coal of the future, 2007; World Energy Council (WEC): Survey of Energy Resources, 2007; Australian Commonwealth Scientific and Research Organisation (CSIRO) website: www.csiro.au
3.2. Brief history

In 1887, the first patent for a gasifier was granted to Lurgi GmbH in Germany. By 1930, coal gasification had become more widespread with towns developing applications to use it by 1940 i.e. commercial coal gasification providing cities with gas for streetlights and domestic consumption in Europe and the US.

In 1970, key studies began with the US Department of Energy (DOE) funding studies to evaluate the feasibility of gasifying coal and using the synthetic gas product as a gas turbine fuel. These studies showed good economics, resulting in funding for the IGCC pilot plant, Coolwater, commissioned in 1984.

For SCG, historically, most gasifiers have been oxygen blown because of the costs of handling large amounts of nitrogen (N$_2$) and the effect it has in diluting the product syngas. Japanese development, however, is concentrating on air blown systems.

There are advantages and disadvantages to oxygen blown gasification. The advantages are namely reduced gasifier size and syngas volume, reducing the cost of pre and post gasification equipment. Additionally the heating value of the cooled and purified syngas is higher.

The disadvantage of oxygen blowing is that the degree of plant integration required is considerably increased. This means that controlling and operating the plant is more like running a complex chemical plant than a traditional power station. Matching the requirements for availability, reliability and flexibility of operation (for example, to display flexibility in load) at a competitive cost over a long period are the major challenges.

Development in Japan on a 200 tonnes per day (t/d) pilot scale has been based on the air blown route, and a design has been developed for a commercial size demonstration unit to use 2000 t/d of coal.

There are two IGCC plants generating power in the US and several new plants are expected to come online. The DOE Clean Coal Demonstration Project helped construct 3 IGCC plants: Wabash River Power Station in West Terre Haute, Indiana, Polk Power Station in Tampa, Florida (online in 1996), and Pinon Pine in Reno, Nevada.

3.3. Commercialisation status

Limitations for SCG in terms of the coal resource are the same as those for conventional mining. The most economical method of coal extraction from coal seams depends on the depth and quality of the seams, and also the geology and environmental factors of the area being mined. The attractiveness of a coal seam to be mined is assessed by considering the depth and thickness of the seam and the type of coal and its thermal value.

Large-scale demonstrations of IGCC are ongoing in the US, Europe, Canada and Australia, and demonstrations and pilot CO$_2$ storage projects are under way in Norway, Algeria, Canada and the US. As part of these projects, the syngas is quenched and cleaned. The syngas is ‘shifted’ using steam to convert CO to CO$_2$, which is then separated for possible long-term sequestration. This addition of carbon capture and storage (CCS) facilities to the plant would make it more attractive although for this to be commercially viable the cost of CCS would have to fall and/or the price of carbon increase.

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14 Information taken from IEA Clean Coal Centre; European Commission: Coal of the future, 2007; WEC survey of energy resources 2007; CSIRO website; Power Engineering Magazine; GE Energy; Western Governors’ Association: Deploying Near-Zero Technologies for Coal: A Path Forward, June 2008; MIT: The future of coal, 2007
All the current coal-fuelled SCG demonstration power plants are subsidised. The European plants are part of the Thermie programme, and, in the US, the DOE is part funding the design and construction, as well as the operating costs for the first few years.

For the reasons described above, SCG followed by power generation is not yet a fully commercially viable technology. However, although most plants are subsidised, the commercialisation of CCS would greatly increase the commercial viability of SCG.

Outside the power generation sphere there are companies who gasify many millions of tonnes of coal per annum in order to liquefy them subsequently and use the liquid for fuels, fertiliser, etc.

3.4. Technical issues

There are significant technical challenges for this technology which may have limited the deployment and commercialisation of the technology:

- Highly integrated plants tend to have long start-up times, and hence may only be suitable for base-load operation
- With pressurised gasification, the supply of coal into the system is complex. Some gasifiers use bulky and costly "lock hopper" systems to inject the coal, while others have the coal fed in as a water-based slurry
- Streams of by-products have to be depressurized, while heat exchangers and gas cleaning units for the intermediate product syngas must themselves be pressurized
- There have been performance related issues with the gasifiers in IGCC plants and these issues have not been resolved in all cases
- There is also an issue as to whether the plant can have CCS enabled

3.5. Environmental issues

The direct effects on the environment of coal mining are well understood. The key risk areas are:

- Land degradation and subsidence of land surfaces due to collapse of mine workings
- Soil erosion, dust and noise pollution, impacts on local biodiversity and; risks of water pollution from acidic runoff
- Methane, a potent greenhouse gas estimated to account for 18% of the overall global warming effect arising from human activities (CO₂ is estimated to contribute 50%), is emitted. It is worth noting that using the methane from coal mines as described below not only uses a by-product of coal mining activity as an energy resource in its own right but also reduces the environmental impact of coal mining

In well-developed mining operations with reputable operators these risks are generally effectively managed.

The process of SCG followed by power generation is seen to have significant environmental advantages over traditional coal to power generation:

- It provides for efficient removal of sulphur compounds, particulates and mercury before the gas is burned instead of removing the compounds from the exhaust gases following combustion
- Nitrogen oxide (NOₓ) emissions are much lower than coal combustion and are improving to rival natural gas combustion
- Emissions of carbon dioxide are comparable to emissions from a conventional coal plant. However, an IGCC plant can separate and sequester carbon dioxide from the process at a significantly lower cost than conventional technologies
- The process requires about one-third less water than a pulverized coal plant
- The process generates less solid waste than a conventional coal plant

15 IEA Clean Coal Centre; Clean Air Task Force: IGCC Barriers & Opportunities, February 2007
16 Alliant Energy website, Renewable Energy World website, American Electric Power website
If the lifecycle greenhouse gas emissions from an IGCC plant producing electricity are considered, the result is approximately 760 kgCO$_2$e/MWh. This is less than the lifecycle emissions from even supercritical pulsed fuel which is approximately 830 kgCO$_2$e/MWh.  

3.6. Illustrative economic analysis$^{18,19}$

One of the main barriers to the widespread uptake of SCG in the past has been cost. SCG power plants have been significantly more expensive than conventional coal-fired power plant – typical comparisons carried out by the World Energy Council in their 2007 “Survey of Energy Resources” have suggested US$1,500/kW$^{20}$ compared with US$750/kW for conventional plants and US$1,000/kW for advanced conventional systems such as supercritical power plants. The Department of Trade and Industry (DTI) in their review of the feasibility of UCG in the UK reported the cost of electricity for IGCC plants as being between 2.3-3.2 pence/kWh compared with 2pence/kWh for natural gas (see Table 5 below). Of course this was based on fuel costs and capital costs of projects when the report was published in 2004. Many IGCC plants have since been cancelled due to capital cost increases.$^{21}$ Before the technology can be widely deployed, its costs and the costs of CO$_2$ capture must be reduced.

In 2004, the Electric Power Research Institute (EPRI) considered pulverized coal and IGCC plant costs and performance estimates. They provided a comparison of gasification technologies and the corresponding cost of electricity for different sources of coal. Overall, capital costs for IGCC plants account for 55-65% of the cost of producing electricity, operating costs 15-20% and fuel costs the remaining 15-30%. For natural gas the split is highly weighted towards fuel costs, with these accounting for 65-80% of costs, operating costs approximately 5% and capital costs 15-30%. The table below shows the cost and performance for 50MW power plants from a report provided to the National Coal Council.

Table 3: Illustrative – Cost and performance for 50MW power plants$^{19}$

<table>
<thead>
<tr>
<th></th>
<th>IGCC</th>
<th>NGCC$^{22}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total plant cost $/kW</td>
<td>1,350</td>
<td>440</td>
</tr>
<tr>
<td>Total capital requirement $/kW</td>
<td>1,610</td>
<td>475</td>
</tr>
<tr>
<td>Fixed O&amp;M $/kW-yr</td>
<td>56.1</td>
<td>5.1</td>
</tr>
<tr>
<td>Variable O&amp;M $/MWh</td>
<td>0.9</td>
<td>2.1</td>
</tr>
<tr>
<td>Average heat rate Btu$^{23}$/kWh (HHV)</td>
<td>8,630</td>
<td>7,200</td>
</tr>
<tr>
<td>Capacity factor %</td>
<td>80</td>
<td>80/40</td>
</tr>
<tr>
<td>Levelised fuel cost $/MBtu</td>
<td>1.50</td>
<td>5.00</td>
</tr>
<tr>
<td>Levelised COE $/MWh (2003$)</td>
<td>49.9</td>
<td>47.3/56.5</td>
</tr>
</tbody>
</table>

Source: Report provided by EPRI to National Coal Council: Cost Comparison IGCC and Advanced Coal, July 2004

Table 3 shows that IGCC is more costly than natural gas on a $/MWh$^{24}$ basis (in 2003$). It can also be seen that the capacity factor is higher – a restriction to baseload operation and capital cost is higher. The capital cost of IGCC is expected to become competitive from around 2015. However, recent studies in the US (IGCC Alliance) have shown that the cost of IGCC is similar to that of supercritical plant, on a cost-of-electricity (COE) basis, once the cost of SO$_x$, NO$_x$ and mercury emission allowances are taken into account. Where a price for CO$_2$ must also be factored in, IGCC is significantly more competitive.

3.6.1 Energy performance

Syngas has a lower heating value than natural gas (~23 vs. 28Btu/m$^{3}$). This means that more fuel must be injected in an IGCC turbine than a natural gas turbine.

3.6.2 Market

As discussed above in general the gasification of mined coal is optimised as part of a power generation plant. As such the end product is electricity which can be sold into power markets. The location of the coal mine and the cost of transport of coal will determine the location of the power station. This in turn determines the electricity prices and market. Globally the price of energy is increasing – linked to the increase in the prices of oil and gas. However, unlike gas, both coal power plants and IGCC power plants typically provide baseload capacity. Natural gas combined cycle plants generally provide baseload/intermediate and to a lesser extent peaking capacity.

Additionally the syngas can be put to other uses e.g. condensation to form other fuels such as diesel or Synthetic Natural Gas (SNG) (these can then be transported).
4. Technologies – Underground Coal Gasification (UCG)

4.1. Description of technology

Underground coal gasification (UCG) refers to the process in which coal reacts in situ with an oxidant to produce a combustible gas, called synthesis gas or syngas. In contrast to SCG, no coal mining needs to take place and hence UCG has the potential to access unmineable coal.

The basic set up for UCG involves two vertical boreholes drilled into the coal seam, one of which functions as an injection well and the other as a production well. An oxidant (air, oxygen, steam or any combination of these) is pumped into the injection well. Underground, the coal is ignited and partial combustion results. This is maintained by a constant injection of oxidants. The syngas that is produced flows through the natural and induced fissures and cavities in the coal seam and is extracted from the production well. The figure below shows the UCG process.

The reaction is controlled by the flow of gases between the injection and production wells. Coal can vary considerably in its resistance to flow, even within a given coal seam. Lower rank coal such as lignite may have sufficient permeability for a satisfactory connection between the injection and production wells over short distances ranging from 20 to 50m, but most other coals are too compact or variable in resistance for natural fissures to act as pathways for the gases. In such cases, the coal seam needs to be opened up between the wells. Methods which have been employed include breaking up the coal with water (called hydro-fracturing), drilling an in-seam channel (used in Europe and the US) and reverse combustion (mostly used in the Former Soviet Union and Australia).

Figure 2: UCG process

Source: Adapted from DTI: Review of the Feasibility of Underground Coal Gasification in the UK, 2004
The preferences in terms of coal reserves for UCG production are as follows:

### Table 4: Coal reserves for UCG production

<table>
<thead>
<tr>
<th>UCG</th>
<th>Depth</th>
<th>Thickness</th>
<th>Coal type preferred</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth</td>
<td>100 – 1,200m</td>
<td>More than 2m thick</td>
<td>For shallow UCG: lignite, which is more permeable but other coal types can be used. For deep UCG: no particular preference</td>
</tr>
</tbody>
</table>

Source: DTI: Review of the Feasibility of Underground Coal Gasification in the UK, 2004

The syngas is at high temperature and pressure when it emerges from the ground. This excess pressure may be harnessed by and converted into electricity and this is thought to be an important advantage of applying UCG in deep coal seams.

Following extraction, syngas is cleaned to remove minor contaminants and acid gases. Depending on specific UCG process conditions, the resultant dry gas is a low to medium calorific value gas. With air used as the oxidant, the gas has energy content between 3 to 5 MJ/m³; with pure oxygen at high pressure used as the oxidant, energy content can be as high as 13 MJ/m³. The composition of the medium calorific value gas is about 27% H₂, 24% methane, 18% CO and 31% CO₂.

After cleaning, the dry gas can be combusted directly for electricity generation or heating, or transformed into synthetic fuels by Fischer-Tropsch synthesis. Note that CCGT power plants need to be modified for syngas operation. The H₂ and CO₂ can also be extracted for industrial use (e.g. in fuel cells).

### 4.2. Brief history

The gasification of coal underground was first proposed by Sir William Siemens who in 1868 conceived the idea of gasifying slack and waste coal in mines. The concept of UCG as we understand today (i.e. with injection and production wells to remove the coal gasified through the direction and control of underground fires) was first suggested in 1888 by Dmitri Mendeleev, a Russian chemist who also devised the periodic table.

The first patent for UCG was awarded to Ansen Betts in Britain in 1909. Sir William Ramsey promoted the idea of UCG and planned to carry out the first UCG experiment. His plans never materialised, but his advocacy attracted the interest of Lenin who saw the benefits of the technology in the elimination of hard mining labour. Later in the UK, UCG experiments were undertaken in the 1920s and trials in the 1950s succeeded in the gasification of significant quantities of coal. The programme, however, was abandoned in the late 1950s on economic grounds given that oil was cheap and readily available.

In the Former Soviet Union, however, UCG was embraced more readily. A national programme which began in 1928 and continued for nearly 50 years resulted in the development of large scale UCG operations in several locations. The Soviet effort probably exceeded the combined efforts of all other nations. However, as was the case in the UK, interest in the technology began to wane after the discovery of huge oil and gas resources in Siberia in the 1950s. Despite the large scale of the Soviet projects, UCG is not considered to have ever operated on a commercial basis since the country’s economy was not based on market principles.

In the US, the energy crises in the 1970s ignited interest in all forms of alternative energy and the DOE invested billions of dollars in the development of efficient coal gasification technologies for power generation. Over 30 UCG pilot tests were run across the country. Groundwater contamination occurred at two sites raising environmental concerns. The subsequent availability of low-cost natural gas in 1980s led to the abandonment of the government programme.
4.3. Commercialisation status

Underground coal gasification has been researched and trialled since the beginning of the 20th century but has generally failed to achieve commercialisation.

Up to the 1990s, UCG trials were only performed at relatively shallow depths of up to 200m. It was suggested that deeper operations would reduce environmental risks and allow access to larger coal deposits. From 1993 to 1998, the European Union financed a trial of UCG for coal deposits at depths of 550m at ‘El Tremadal’ in Spain. It was demonstrated that UCG was technically feasible in deeper coal seams using the latest drilling and injection control technology. UCG at high pressure (more than 50 bar) was found to favour the formation of methane, which improved the calorific value of the product gas. There was also evidence that wider cavities are produced in the coal seam at greater depths. The success of this trial spurred other studies across the world.

One of these was a feasibility study by the UK DTI in 2004. It concluded that UCG, in conjunction with carbon capture and storage, was a promising technology, although commercial viability remained to be confirmed and concerns over the environmental impact had still to be overcome.

There has been renewed interest in UCG across the world. In China, 12 UCG pilot trials have been undertaken. In Queensland, Australia, the Chinchilla UCG trial was conducted from 1997 to 2003. The Chinchilla pilot is probably the closest a UCG project has come to commercialisation in the Western world. However, it operates at a shallow depth using simple vertical borehole technology. In contrast, deeper coal seam gasification increasingly relies on deviated and in-seam drilling. Other test sites are being developed in the US, Canada, South Africa, New Zealand, India, and Europe.27

4.4. Technical issues

UCG is a technology still under development. The main issues being addressed to bring UCG to the commercialisation stage are: enhancing the connection between the injection and production wells, controlling the underground partial combustion process, and scaling up to commercial-sized operations. Soviet UCG projects have already proven simpler air-blown gasification technologies at a large scale (sufficient to support 200MW capacity power plants) and this provides confidence that it will be possible to scale up newer technologies as well.

For various reasons, environmental costs and benefits are increasingly being factored into decision-making. The commercial feasibility of UCG is also being considered with integrated carbon sequestration. Although the technologies for CO₂ capture are advancing rapidly, integrated carbon sequestration is still an untested concept.

4.5. Environmental issues

Environmental concerns surrounding UCG operations relate to:

- Groundwater contamination – UCG at shallow depths is a risk to groundwater in adjacent strata and thus UCG should not be undertaken at less than 100m of vertical separation from major aquifers. In trials of UCG at greater depths, no groundwater contamination was detected. Some water, which is produced during partial combustion and brought to the surface with the syngas, was found to be contaminated in deep UCG trials. Concern in this case revolves around water disposal.

- The UCG process requires water although much of this is usually provided by groundwater.

- Subsidence management – As with underground mining, the gasification of coal during the UCG process leaves a cavity that is susceptible to subsidence, especially when the overburden is weak. Hence, UCG requires proper characterisation of overlying strata and simulations may be useful. Generally, the risk of subsidence decreases from UCG at depths greater than 200m.

These can be managed in many respects as with coal mining. Satisfaction of the environmental issues has been a major hurdle as part of UCG’s commercialisation process.

The lifecycle emissions from a power plant using UCG with carbon capture is approximately 710 kgCO₂-e/MWhₑ. However without carbon capture this would be higher and would rival IGCC and conventional coal plants in lifecycle emissions. To provide a comparison with the lifecycle economics for carbon capture with natural gas the emissions for this are 430 kgCO₂-e/MWhₑ.16

27 Statement at Underground Coal Gasification conference, 16-17 July 2008
A UCG project entails high exploration costs to understand the structure of the coal seam and surrounding strata. This is a pre-requisite for the design and construction of injection and production wells, and for ensuring groundwater contamination and ground subsidence risks are minimised. Exploration involves drilling boreholes, conducting (preferably 3D) seismic surveys and performing simulations with gathered data. These are especially critical if inseam drilling will be used. Exploration is not particularly difficult, but there is a risk that the ground structure will be found unsuitable as exploration progresses.

Following satisfactory ground characterisation, a UCG plant can be constructed. This will typically consist of facilities to prepare, compress and inject the oxidants, the injection and production wells, gas clean up units, purge gas storage units, and a power generation plant. Facilities for H₂ production, liquefaction or CO₂ capture may also be included.

Studies have shown that CCGT power generation following UCG produces lower CO₂ emissions than other coal power generation technologies, which is favourable to the overall economics of UCG where mechanisms are in place to account for carbon cost. Further, because UCG syngas emerges at pressure, this should reduce the subsequent energy requirements in the UCG plant above ground.

UCG has typically been considered as an energy source for local power generation. Thus, the economics of UCG has generally been considered in the context of power generation and UCG is considered relative to other (especially fossil-fuelled) power generation options. Various independent cost studies by the IEA, CSIRO in Australia, and the DTI in the UK have shown UCG to be competitive in high energy price environments, and that CO₂ capture is more cost effective with UCG than surface gasification. A summary of electricity cost from the competing technologies is shown below.
The estimated cost required for UCG power plants is as follows:

Table 5: Illustrative – Estimated cost required for UCG power plants

<table>
<thead>
<tr>
<th>UCG plant size</th>
<th>50MW</th>
<th>Per MW</th>
<th>300MW</th>
<th>Per MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total development cost (2002 prices)</td>
<td>$92.7m</td>
<td>$1.9m</td>
<td>$337m</td>
<td>$1.1m</td>
</tr>
<tr>
<td>Total electricity generation</td>
<td>350GWh</td>
<td>7GWh</td>
<td>2,100GWh</td>
<td>7GWh</td>
</tr>
<tr>
<td>Number of coal panels (500m x 500m) required for 20 years’ operation</td>
<td>6.6</td>
<td>0.1</td>
<td>24</td>
<td>0.1</td>
</tr>
<tr>
<td>Equivalent coal tonnage required for 20 years’ operation</td>
<td>5.4Mt28</td>
<td>0.1</td>
<td>19.5Mt</td>
<td>0.1</td>
</tr>
<tr>
<td>Maximum daily oxygen requirements</td>
<td>416t/d29</td>
<td>8t/d</td>
<td>1,792t/d</td>
<td>6t/d</td>
</tr>
</tbody>
</table>

Source: DTI: Review of the Feasibility of Underground Coal Gasification in the UK, 2004; PwC analysis
Note: Converted from £ to $ using an average exchange rate in 2002 of 1.51

It is worth noting that UCG uses all the coal resource and any associated trapped gas.

4.6.1. Energy performance

As with IGCC, the syngas produced from UCG has a low heating value compared to natural gas – see section 3.6.1 above.

4.6.2. Market

As described above in section 3.6.2, Syngas has several possible routes to market, the first of which is the most common:

- Combusted directly for electricity generation or heating
- Transformed into synthetic fuels by Fischer-Tropsch synthesis
- Fertilisers and other chemicals
- Extraction of H₂ and CO₂ for industrial use and for carbon sequestration respectively

28 Mt = Million tonnes
29 t/d = tonnes per day
5. Technologies – Coal Bed Methane (CBM)

5.1. Description of technology

Within coal deposits underground, methane exists in three forms: as a free gas, as gas dissolved in water, but mostly as gas “adsorbed” to coal surfaces.

During the “coalification” process (the conversion of plant matter into coal), coal is heavily fractured. These fractures, called cleats, give coal a large internal surface area for methane adsorption. Consequently, as early research found, CBM reservoirs may contain six to seven times as much methane as similarly sized conventional gas reservoirs.

The principle of CBM extraction is fairly straightforward. The methane in coal is held in place by water pressure. CBM extraction thus involves pumping water to the surface to reduce the water pressure and allow the methane to desorb at a rate that is related to the coal’s permeability. Methane can then flow through the cleats into the well bore, and follows water out of the well.

There are two general drilling methods:

- Conventional drilling, which involves drilling a vertical well down to the coal seam similar to those used for recovery from conventional gas reservoirs
- Horizontal drilling, which involves drilling down to a coal seam, then along and into the coal seam, with lateral extent of up to 1,000m

Figure 4: Conventional and horizontal drilling

![Figure 4: Conventional and horizontal drilling](source)

Source: Adapted from Kentucky Geological Survey: Fact Sheet No. 62 (Coalbed Methane)

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30 US Geological Survey: Fact Sheet FS-123-00 (Coal-Bed Methane: Potential and Concerns)
The majority of wells are vertical wells. As each well has an effective radius for CBM drainage, a CBM project will have many wells. With horizontal drilling, fewer wells would be required, but it is technically more difficult and more costly.

The cleat system determines coal permeability and hence the stimulation required. In high permeability systems, no flow enhancement may be required. In others, the permeability of coal may be improved by:

- Hydraulic fracturing, which involves pumping “frac fluids” at high pressure into the coal creating fractures, or
- Cavitation stimulations, which involves repeatedly building up the pressure in the well by injecting gas and water and then rapidly releasing the pressure. This causes sudden expansion of CBM which breaks up the coal

The coal reserves required for CBM are described in the table below:

<table>
<thead>
<tr>
<th>CBM</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Depth</strong></td>
<td>200-1,200m, but typically under 1,000m</td>
</tr>
<tr>
<td><strong>Thickness</strong></td>
<td>At least 0.4m. More gas is contained in thicker seams</td>
</tr>
<tr>
<td><strong>Coal Type preferred</strong></td>
<td>Sub-bituminous and bituminous coal, extraction of CBM from anthracite possible</td>
</tr>
<tr>
<td><strong>Gas Content</strong></td>
<td>Generally methane concentrations greater than 7m$^3$/tonne. CBM is either biogenic (low rank coal, shallow) or thermogenic (higher rank coal, deeper). Figure 5 shows the volume of gas contained in coal across ranks</td>
</tr>
<tr>
<td><strong>Permeability</strong></td>
<td>30mD$^{31}$ to 50mD is typical</td>
</tr>
</tbody>
</table>

Source: British Geological Survey: Mining Planning Factsheet (Coal and coalbed methane), 2006; US DOE: Coal Bed Methane Primer, 2004

The CBM extracted from virgin coal-beds is generally of high quality, with methane concentrations possibly exceeding 95%.

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| Source: Adapted from Oilfield Review, Autumn 2003 |

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31 millidarcy (mD)
Enhanced CBM is a recent development that has been trialled and allows more methane to be recovered from coal seams. This involves injection of CO\textsubscript{2} and/or N\textsubscript{2} gas. CO\textsubscript{2} molecules displace methane molecules from adsorption sites at a ratio of approximately 2:1. Two parts of methane are produced for each part of N\textsubscript{2} injected. This increases CBM production compared to lowering of water pressure alone. N\textsubscript{2} is financially more attractive than CO\textsubscript{2} in enhanced CBM recovery as it can be recovered and recycled. However, the use of CO\textsubscript{2} also allows for carbon sequestration or CCS.

5.2. Brief history

CBM refers to the naturally occurring methane-rich gas found in coal deposits. CBM is predominantly methane, but may also contain ethane and propane, CO\textsubscript{2} and N\textsubscript{2}. These gases are released during the coalification process along with water.

CBM is also known as coalbed gas (CBG) or natural gas in coal (NGC) in Canada, or coal seam methane (CSM) in Australia. CBM can be recovered before, during or when mining has been abandoned, and from deposits deemed “unmineable” for reasons such as being too thin or deep, or being of poor or inconsistent quality. To distinguish between the various sources, CBM is sometimes defined more narrowly as methane extracted from unmined coal-beds (also termed virgin CBM), as distinct from:

- Coal mine methane (CMM), which is methane extracted from operational mines. CMM methane recovery by methane drainage can be between 35% and 75%; but much less in ventilation air (1-5%)
- Abandoned mine methane (AMM), which is methane extracted from no longer operational mines. AMM recovery has variable concentrations from 35% to 90%

As methane permeates most coal deposits, the existence of CBM has been known for centuries within the coal mining industry. CBM is a safety hazard to miners and various methods had been employed to drain it from mining shafts.

Modern CBM production has its roots in the US. Following a severe mine explosion in Farmington, West Virginia, in 1968, the Bureau of Mines was tasked to conduct research into coal degasification. The experimental project which the Bureau of Mines embarked on in 1975 in conjunction with US Steel Corporation in Alabama is credited as being a landmark in CBM research and development. This was then expanded on by the Bureau of Mines and later by the DOE.

Testing and analysis by the Gas Research Institute in the 1980s further contributed to the understanding of the mechanisms governing storage, release, and efficient production of CBM.

5.3. Commercialisation status

The earliest reports of CBM production wells were in the US, but US CBM production remained limited up to 1986. Since then however CBM has been produced commercially on a global basis.

The US currently has 17 basins with CBM production, the largest of which are the San Juan Basin across Colorado and New Mexico, the Powder River Basin spanning Wyoming and Montana, and the Black Warrior Basin in Montana. US annual CBM production is approximately 50 billion m\textsuperscript{3}, some 10% of total natural gas production. Proven CBM reserves stand at about 550 billion m\textsuperscript{3}.

Outside the US, the CBM industry is probably most developed in Australia where commercial operations to extract methane from coal commenced in 1996 with the first commercial CMM operation and the first commercial CBM operation in Queensland. Today, Australian CBM and CMM operations are concentrated in the Bowen and Surat Basins of Queensland and the Sydney Basin in New South Wales.

More recently, commercial CBM production has begun in other countries with significant CBM reserves. Canada’s first commercial CBM project was developed in Alberta in 2002. Currently, the provinces of Alberta, British Columbia and Nova Scotia contribute to Canadian CBM production. China’s first commercial CBM production started with the launch of the Panhe CBM project in Shanxi Province in 2005. China reports to have 37 trillion m\textsuperscript{3} of CBM reserves, the third largest in the world, and has plans to increase annual CBM output to 10 billion m\textsuperscript{3} by 2010.

CBM production in China is overwhelmingly sourced from working mines (i.e. CMM). In the US, Australia and Canada, virgin CBM production from coal deposits that are unlikely to be mined dominates. Europe leads the world in AMM operations. Over half of the world’s coal-bearing countries have now investigated some form of CBM development.
5.4. Technical issues

The technology for CBM recovery is relatively developed and this has allowed rising levels of CBM production globally. Overall technical risk is considered low. There is, however, ongoing research to develop enhanced CBM using CO\textsubscript{2} along with carbon sequestration, as an integrated operation. Other research is directed at increasing CBM recovery. Research in biotechnology for instance has suggested the possibility that methanogens (methane producing bacterium) could be used to increase gas content and to microbially improve coal permeability.

5.5 Environmental issues

On the environmental front, there is uncertainty over of the effect of CBM operations, particularly their effects on local aquifers.

- Drawing out substantial quantities of water and surface disposal bring about changes to land, surface and ground-water systems. There is at least concern over the possible depletion of aquifers. Other environmental effects and effects on long-term sustainability are not yet fully known but are being monitored by research groups.

- There is also concern that CBM well drilling and extraction contribute to methane migration and contamination of ground water. Early reports suggest that some methane migration occurs naturally, but as its nature is not understood fully, this is an area that is being studied.

- Frac fluids which are injected for enhanced CBM may also contaminate water and soil. Although a study by the US Environmental Protection Agency in 2002 did not find evidence that drinking water had been contaminated by frac fluids, this remains a controversial area.

CBM operations face similar environmental issues as other resource extraction activity. These include the removal of vegetation, damage to natural habitats and air pollution (from dust, exhaust and noise). The environmental risks of CBM are well understood and the risks capable of effective management.

The lifecycle emissions from a power plant using natural gas, without carbon capture is approximately 610 kgCO\textsubscript{2}-e/MWh. However with carbon capture this would be approximately 430 kgCO\textsubscript{2}-e/MWh.\textsuperscript{16}

5.6. Illustrative economic analysis\textsuperscript{18}

Figure 6 CBM monetisation

<table>
<thead>
<tr>
<th>Start up</th>
<th>Drilling/Operations</th>
<th>Market</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Licensing costs</td>
<td>• Gas processing/compression costs</td>
<td>• Revenues from gas/power</td>
</tr>
<tr>
<td>• Exploration costs</td>
<td>• Gas transportation costs</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Capex (ongoing for well development)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Opex (including water management)</td>
<td></td>
</tr>
</tbody>
</table>

Source: PwC analysis

\textsuperscript{18} Coal seam

\textsuperscript{16} CO\textsubscript{2}/N\textsubscript{2} (For Enhanced CBM)
Virgin CBM is indistinguishable from natural gas (which has energy content of 38.4MJ/m$^3$) and is thus a substitute, and may be transported to markets via natural gas pipelines, or liquefied and traded as LNG. CMM and AMM are used for power generation often by mining operations and by industrial customers.

Water management is a major issue in CBM operations. The composition of the water removed from each well varies from well to well but is commonly saline and can be acidic and contaminated with sulphates and metals if from mined areas. The amount of water that must be drawn from a given well varies over the life of the well. Typically, more water must be removed initially, and this declines over time as shown in Figure 7. In Australia, possible uses for water from CBM wells are being considered.

Table 7: Illustrative – Some characteristics and indicative costs of CBM wells$^{18}$

<table>
<thead>
<tr>
<th>Characteristic</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well life</td>
<td>5 to 15 years, mostly under 10 years, but some up to 20 years</td>
</tr>
<tr>
<td>Spacing</td>
<td>300,000m$^2$ to 1,300,000m$^2$</td>
</tr>
<tr>
<td>Footprint</td>
<td>Well site: 3,500m$^2$ during development, 1,500m$^2$ during operations.</td>
</tr>
<tr>
<td></td>
<td>Additional 25,000m$^2$ to 50,000m$^2$ during development</td>
</tr>
<tr>
<td>Costs</td>
<td>For US basins:</td>
</tr>
<tr>
<td></td>
<td>• Capital costs: $75,000 to $375,000</td>
</tr>
<tr>
<td></td>
<td>• Operating costs: $50,000 per year, declining over time to $20,000 per year (corresponding to ~$40/million m$^3$ for well and lease expenses; $0.04 to $0.31 per barrel for water management)</td>
</tr>
<tr>
<td>Gas production</td>
<td>5,000m$^3$ - 23,000m$^3$ per day. High yield wells may produce 150,000m$^3$ per day</td>
</tr>
</tbody>
</table>

Source: US DOE: Coal Bed Methane Primer, 2004; PwC analysis

Figure 7: Typical water and gas production profiles

CBM projects have fairly low exploration cost and are cost effective to drill compared to conventional gas projects. Exploration in a CBM project usually revolves around assessing whether coal deposits are suitable for CBM development.

If production is deemed to be economic, a full project can range from 25 to 500 wells. These are usually drilled in stages, 15 to 50 wells at a time. This staged development process allows the project to generate some revenue from production prior to capital expenditure in the next stage and helps to manage the project risk. Energy content of gas is not generally more than 2% of total energy content of host coal.

Less gas is produced from a CBM well than from a conventional gas well. Gas production varies over the life of the well as shown in Virgin CBM is indistinguishable from natural gas (which has energy content of 38.4MJ/m$^3$) and is thus a substitute, and may be transported to markets via natural gas pipelines, or liquefied and traded as LNG. CMM and AMM are used for power generation often by mining operations and by industrial customers.

The extracted gas must be dehydrated to remove water vapour. As a field matures, CO$_2$ removal is required as well as more CO$_2$ is present in the gas. This gas can then be compressed for transport to end users.

5.6.1. Market

CBM competes directly with conventional natural gas and has the same routes to market. These routes to market include:

- Pipeline
- Power generation
- LNG, which is proposed in Queensland
6. Conclusion

The paper aims to consider the three technologies that monetise coal assets via the production of gaseous product as alternatives to conventional coal mining.

In terms of a resource that is ready to be commercially exploited on a large scale here and now, CBM has the advantage over SCG and UCG. Both UCG and SCG technologies have yet to be proven on a commercial scale. This is mainly due to the high capital expenditure required for SCG/UCG projects and unresolved operational and environmental risks. This is especially true of deep UCG, which has not been proven on a large scale and would require additional capital expenditure, but would also provide access to currently unrecoverable reserves.

In terms of UCG versus SCG, the product, syngas, is similar and UCG can already offer a viable commercial process to compete with SCG since in certain situations it appears feasible that it can be carried out at lower cost and can also use coal seams that are not recoverable via traditional mining methods.

CBM on the other hand is currently commercially proven and CBM production is occurring on a commercial scale globally. The capital costs are staggered over the lifetime of the CBM field and this helps the project payback and reduces the project economic risk. However CBM only releases the gas that is trapped in coal seams and does not utilise the coal itself. It may preserve the coal for future use.

It can be seen that whilst SCG retains the requirement for coal mining and the costs and limitations of the coal mining process, UCG does not require mining since the coal is gasified in situ, and therefore does not have the same limitations that coal mining has – particularly in terms of depth. UCG has the potential to increase recoverable coal reserves greatly since a large portion are unrecoverable via traditional mining techniques.

CBM production does not preclude coal mining (and hence SCG). CBM production prior to coal mining is advantageous since methane is both a safety hazard of mining and a greenhouse gas and hence CBM reduces the impact of coal mining on the environment through the exploitation of methane that would otherwise be emitted into the atmosphere. CBM may also not preclude UCG although the reverse is not true since UCG would preclude CBM.

A report presented by Energy & Environment Directorate, Lawrence Livermore National Laboratory at the Potential for Underground Coal Gasification Meeting in Washington in June 2007, claimed synergies between CBM and UCG. They claimed that the detailed characterisation of the seams and the depths of production of the two are often similar. In addition there is the possibility to use existing wells as both injection and syngas production wells and land-use, management and regulatory issues are convergent.

Both SCG and UCG technology (especially deep UCG) are thought to be more attractive if it can be developed in conjunction with carbon capture and storage such that it has value as a clean coal technology. However, as with the SCG and UCG technologies, carbon capture and storage has also not been commercially proven. SCG and UCG both have similar environmental issues to traditional mining e.g. groundwater contamination and subsidence. CBM has less of an environmental impact.

The gas that is produced from CBM is, of course methane, which is a higher quality gas relative to syngas and can thus be sold for a higher price.

Both syngas and CBM can be liquefied. CBM can immediately be used to supply the LNG market which is currently an attractive one and opens up markets for gas globally. A future advantage to CBM is with enhanced CBM, where the coal remains underground and the methane gas that was attached to the coal is replaced by carbon dioxide and hence this is used as a site for carbon storage. It seems unlikely that UCG can follow enhanced CBM where carbon dioxide was employed to displace methane, since carbon dioxide would make it difficult to ignite the coal for gasification.

Further developments and improvements are expected for all three technologies as being alternatives to using coal for conventional power generation in a carbon constrained environment. As such, it is expected that the relative commercial viability may change in particular for capital expenditure and the inclusion of the cost of carbon in project economics.
Appendix
I. Appendix: Comparison of techniques

We present below both a qualitative and quantitative comparison between the technologies, in terms of the differences in coal type, depth and thickness, products and routes to market, infrastructure requirements including any synergies, and current technical issues.

<table>
<thead>
<tr>
<th></th>
<th>Open cast coal mining followed by surface gasification</th>
<th>Underground coal mining followed by surface gasification</th>
<th>Coal Bed Methane</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Qualitative</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Constraints</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>1. The resource</strong></td>
<td>Depth: &lt; 150m, Seam thickness: &gt;5m, Type: Main bituminous</td>
<td>Depth: &gt; 100m, Seam thickness: &gt;2m, Type: Main bituminous</td>
<td>Depth: &lt;1,200m, Seam thickness: Relatively thin seams possible, Type: Main sub-bituminous and bituminous, anthracite possible. Good permeability of coal</td>
</tr>
<tr>
<td><strong>2. The main product(s)</strong></td>
<td>Syngas: Must be cleaned and processed before it can be utilised</td>
<td>Syngas: Must be cleaned and processed before it can be utilised</td>
<td>Gas equivalent to natural gas (for virgin CBM), gas with lower methane concentrations obtained for others. Some cleaning and processing</td>
</tr>
<tr>
<td><strong>3. The by product(s)</strong></td>
<td>SGC process also often removes ash, sulphur compounds, ammonia, mercury, and other metals. SGC process can be combined with CCS</td>
<td>SGC process also often removes ash, sulphur compounds, ammonia, mercury, and other metals. SGC process can be combined with CCS</td>
<td>Water production, typically saline</td>
</tr>
<tr>
<td><strong>Routes to market/Uses</strong></td>
<td>Power: Syngas produced in same process as electricity generation. Can be used to produce synthetic liquid fuels or can be marketed in liquefied form</td>
<td>Power: Syngas produced in same process as electricity generation. Can be used to produce synthetic liquid fuels or can be marketed in liquefied form</td>
<td>Gas pipeline to local customers or national grid; local power generation; liquefaction (LNG, GTL)</td>
</tr>
<tr>
<td><strong>Infrastructure requirements</strong></td>
<td>High level of capital investment required for IGCC (~60% of energy cost)</td>
<td>High level of capital investment required for IGCC (~60% of energy cost)</td>
<td>Capital expenditure is required at intervals over the life of the CBM well</td>
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<tr>
<td><strong>Other requirements</strong></td>
<td>Coal/syngas can be transported overground/water</td>
<td>Coal/syngas can be transported overground/water</td>
<td>Can be transported by pipeline – can use extant pipelines where available</td>
</tr>
<tr>
<td><strong>Synergies</strong></td>
<td>SCG with CCS being considered</td>
<td>SCG with CCS being considered</td>
<td>Enhanced CBM in conjunction with CCS being researched</td>
</tr>
<tr>
<td><strong>Technology / Process issues</strong></td>
<td>Mining limitations and limitation of CCS technology apply. Plant must handle toxic gas</td>
<td>Mining limitations and limitation of CCS technology apply. Plant must handle toxic gas</td>
<td>Large volumes of saline water often produced Enhanced CBM being considered but limitations of technology to date</td>
</tr>
<tr>
<td><strong>Externality</strong></td>
<td>Utilises all coal resource</td>
<td>Utilises all coal resource</td>
<td>Coal deposit mineable afterward (less so if enhanced CBM used.) UCG might be possible afterwards</td>
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<tr>
<td><strong>Quantitative</strong></td>
<td></td>
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<tr>
<td><strong>Risks</strong></td>
<td>Medium: SCG technology commercially proven</td>
<td></td>
<td>Low: A commercially proven technology and market is good</td>
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<tr>
<td>Technology / requirements</td>
<td>Other requirements</td>
<td>Infrastructure requirements</td>
<td>Market/Uses</td>
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<tr>
<td><strong>Qualitative</strong></td>
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<td>1. The resource</td>
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<td>3. The by surface gasification</td>
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<tr>
<td>Externality</td>
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</tbody>
</table>

**Coal/syngas**

- Coal/syngas can be transported by pipeline – can be transported overground/water.
- Can be transported by pipeline – can also be marketed in liquefied form.
- Can be used to produce synthetic liquid fuels or can be marketed in liquefied form.
- Syngas is usually best used for onsite electricity generation.
- Can be used to produce synthetic liquid fuels or can be marketed in liquefied form.
- Syngas produced in same process as power: ICGT (peakload); GTL, petrochemicals.
- Syngas is usually best used for onsite electricity generation.
- Can be used to produce synthetic liquid fuels or can be marketed in liquefied form.

**SCG process**

- Scg process also often removes ash, sulphur compounds, ammonia, mercury, and other metals. UGC process can be combined with CCS.
- Hydrogen comes as a by-product of UCG which is used e.g. in fuel cells.
- SGC process also often removes ash, sulphur compounds, ammonia, mercury, and other metals. UGC process can be combined with CCS.
- Hydrogen comes as a by-product of UCG which is used e.g. in fuel cells.

**Power**

- ICGT (peakload); GTL, petrochemicals.
- Syngas is usually best used for onsite electricity generation.
- Can be used to produce synthetic liquid fuels or can be marketed in liquefied form.

**Infrastructure**

- Deep UCG has high level of capital investment required and also requires significant expenditures on exploration studies prior to construction. There are no major technical problems which cannot be tackled with modern technology, however whether a large scale operation can be commercially viable remains the key question (esp. for deep UCG with no large scales pilots to date).
- Close to power market since in situ gas development and onsite generation due to high cost however syngas only can be transported overground/water.
- UCG with CCS makes UCG more attractive.
- Theoretically easier and more efficient to remove CO₂ from syngas prior to combustion i.e. UCG can be environmentally friendly. However, no large scale CCS projects so far or UCG-CCS trials.
- The plant will need to handle large quantities of toxic substances and must have proper safeguards and environmental controls.
- Potential contamination of ground water – mainly applies to shallow UCG. Can be overcome by extensive exploration and site selection as well as by using the technology of maintaining “a negative pressure” in the cavity.

**Underground coal gasification**

- Utilises all coal resource including any gas in the coal seams.

- High:
  - Not commercially proven on a large scale. Great benefits foreseen for deep UCG since it increases the recoverable reserves, CCS is an attractive addition that is not yet commercially proven.