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Review of Underground Coal Gasification with Reference to Alberta's Potential

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Contents

Figures

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Abstract

Alberta contains vast coal resources at shallow depths that facilitate economical mine-mouth power generation; however there are greater resources at depth that are currently not economic to mine. They represent a potential energy source for the province.

Many countries used surficial coal gasification to produce fuels and chemicals during the last century. The coal-conversion processes involve reacting coal in a large reactor vessel at high temperature and pressure with steam and a limited amount of oxygen to prevent combustion. The chemical bonds in the coal are broken, producing synthetic gas (syngas) with fuel properties and ash residue remaining from the mineral matter in the coal.

An alternative to the surface gasification process is underground coal gasification (UCG). This process differs from surficial gasification in that the coal is not mined; rather, the underground coal seams serve as the reactor vessel.

A UCG operation consists of a series of injection and production wells drilled into a coal seam. The coal is ignited and air and/or oxygen injected. Chemical reactions convert the coal to syngas by pyrolysis, combustion and gasification reactions in a manner similar to those processes in a surface gasifier. The produced syngas is a mixture of mainly carbon monoxide and hydrogen, which can be used as fuel for power generation and feedstock for various chemical products (i.e., hydrogen and ammonia). The main UCG by-products are in situ deposits (roof-rock fragments and ash-rubble in the void space underground where the coal was consumed) and flue gases and fly-ash, both entrained in the syngas stream, which are subsequently captured and managed as a part of the power or chemical plant system. Emissions from syngas combustion are generally cleaner and may produce less greenhouse gas emissions than coal-fired facilities.

The UCG process is less costly than conventional surficial coal gasification because no coal mining, processing and transport are involved, and no ash/slag removal or disposal is necessary. The environmental impact of UCG is relatively low compared to surficial gasification, as major disturbances in landscape and surface disposal of ash and coal tailings are not required. A properly designed site will recognize and address potential groundwater and subsidence issues. Underground coal gasification may compete with other in situ coal applications, including mining, coalbed methane exploration and development, as well as CO_2 storage.

Coal studies in Alberta suggest that the Ardley, Horseshoe Canyon and upper Mannville coal zones in the central part of the province may be suited for UCG. These coal zones are also the main coalbed methane targets in Alberta. Having similar properties to the coal already being subjected to UCG applications elsewhere in the world, the coals of central Alberta range in rank from sub-bituminous to the initial stage of bituminous (vitrinite reflectance between 0.5% and 0.6% R_0); are thicker than 0.5 m, generally flat-lying and extensively continuous; and occur from surface to a depth of <1400 m. Many central Alberta coals occur in multiple-seam packages with calorific values and coal reactivity parameters conducive to the gasification process.

1 Introduction

Fossil fuels are variably distributed around the globe, and all geopolitical regions satisfy their energy demands mainly with one significant component, such as oil, natural gas or coal (Figure 1A). Fossil fuels account for 87% of global energy supply, according to the World Coal Institute (2007a). Superimposed on the strong and enduring demand for fossil fuels is political pressure to lower the amount of carbon dioxide released into the atmosphere by industrialized and industrializing countries. Technological alternatives are also growing (British Nuclear Fuels PLC, 2005; E.ON UK, 2006; Jackson, 2006) and include such innovations as enhanced oil and gas recovery, nonconventional gas reservoirs (coalbed methane, gas shale deposits, tight reservoirs, gas in high-pressure aquifers and deepwater, and gas-hydrate reservoirs), and renewable energy (wind-power, geothermal and hydroelectric systems, photovoltaic and solar receivers, organic waste, and biomass processes). Coal-conversion processes, such as coal gasification and liquefaction, are alternative technologies for generating clean energy.

The purpose of this report is to provide an overview of the underground coal gasification process (UCG) that is being tested and applied with commercial results in different parts of the world, and an initial look at Alberta's coal endowment. The UCG process is considered an important component in addressing the world-wide controversy over the decline of natural reserves versus the increase in energy demand (Friedmann, 2007). The concept of UCG technology is to convert in situ nonmineable coal into synthetic fuel. The in situ coal gasification process is a promising supplement for Alberta's energy demand, considering the huge underground coal resources in the province that are currently not accessible by conventional mining techniques.

Coal, a carbon-rich rock formed by organic maturation of vegetal matter accumulations, is the most abundant type of fossil fuel. It has been used since the early stages of human history, due to its combustible properties, for generating heat and light. Since the 1960s, coal has had competition as an energy source from the other fossil fuels, crude oil and natural gas. The current statistics show estimated world coal reserves of more than 1000 billion tonnes distributed among 70 countries (World Coal Institute, 2007b; Figure 1B). Canada has close to 10 billion tonnes of coal reserves, representing a larger energy source than all of its oil, natural gas and oil sands reserves combined (Coal Association of Canada, 2009a). Canada is a net coal exporter, one of the largest in the world, most of it coming from the western provinces.

Globally, coal remains an important fuel because it is the largest source of energy used for electricity generation (~65%) and helps produce more than 70% of the world's steel. Over the years, with the advance of technology, there have been important changes in the processing and uses of coal. These changes have positioned it as a high-value, conventional energy source for power generation, as an unconventional source of gas (coalbed methane), for coal gasification and liquefaction (synthetic fuels), and as a potential rock for carbon dioxide storage (Coal Association of Canada, 2009b).

Alberta has the largest coal resources in Canada (Figure 2), distributed mainly in the foreland basin. In this area, the coal resources at a depth greater than 150 m (including coal seams thicker than 1 m) are estimated at 4 trillion tonnes (Beaton et al., 2002; Beaton, 2003). An important amount of coal also occurs in the Cordilleran foothills. Mined coal as feedstock for coal-fired power plants represents the dominant source of energy in the province (Figure 2). Lately, coalbed methane (CBM) exploration and production have represented an increasingly important activity in particular areas of central and northwestern Alberta, and in the foothills.

Maximizing the use of coal in Alberta has the potential to position the province as a leader in adapting and integrating new technologies that achieve near-zero emissions and reduced environmental impacts on
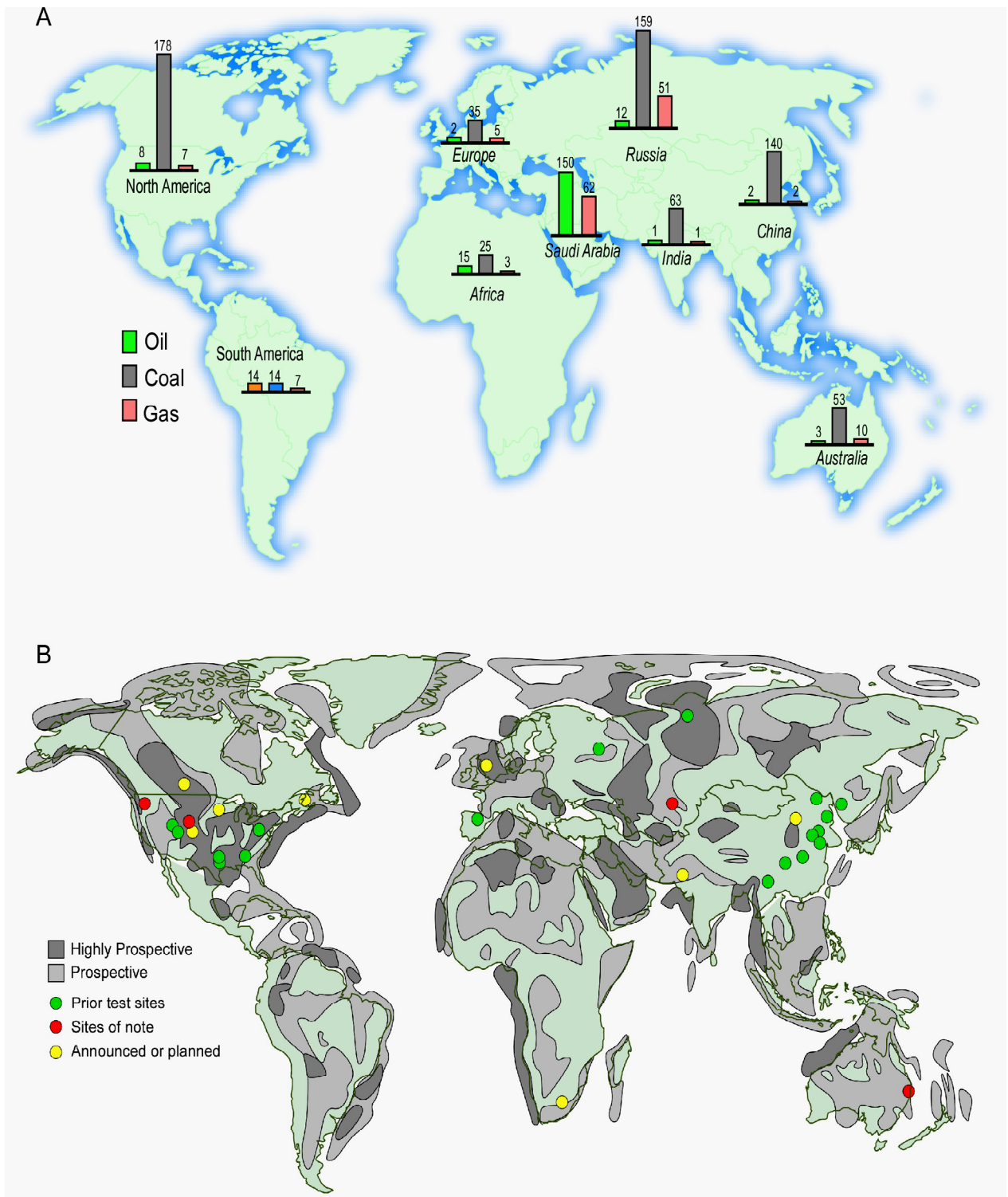
Figure 1. Global distribution of A) fossil fuels (in gigatonnes of oil equivalent; Energy Information Administration, 2008); B) coal resources and stages of the underground coal gasification activity (Friedmann, 2007a).
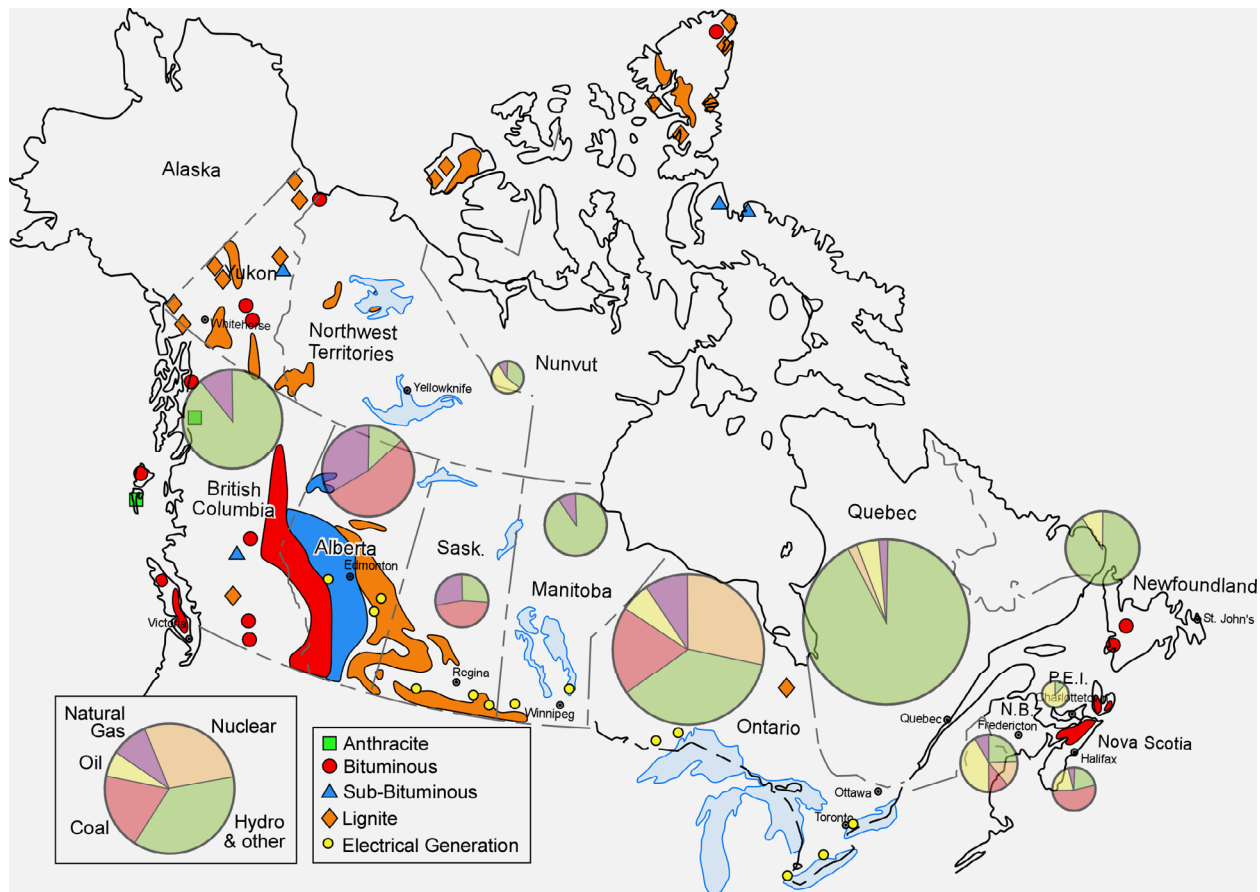
Figure 2. Distribution of coal resources and contribution of coal to power generation in Canada (*after* Coal Association of Canada, 2009b; National Energy Board, 2008).

land, air and water (Alberta Energy Research Institute, 2006).

2 Factors Controlling Quality and Technological Behaviour of Coal

Coal is a combustible, carbon-rich rock formed from in situ or allochthonous accumulations of plant remains. The vegetal matter, concentrating a part of atmospheric carbon, was preserved from oxidation and biodegradation by burial and then underwent elevated temperature and pressure over geological time. The characteristics of coal accumulations differ throughout the world due to the original association of species of plants (coal type), degree of metamorphism or coalification (coal rank) and range of included impurities (grade of coal). Economic occurrences of coal are concentrated in relatively thin but extensive strata that generally lie underground. Where coal is at the surface or at economically viable depth, it is extracted by open-pit or underground mining operations.

The main coal characteristics are the result of its chemical components, degree of thermal maturation, variability of anisotropic characteristics and postsedimentary structural features. Rank and chemical composition are the most important factors in determining the industrial properties of coal.

Coal represents a hydrocarbon source (mainly methane) and reservoir rock because of its dual properties of generating and maintaining hydrocarbons within the carbon matrix. The content of hydrocarbons (volatile matter) changes, as the rank increases, up to a critical level corresponding to the early stages of bituminous rank, and then decreases as the maturation process continues. However, some coal properties,

such as mineral matter content or coal grade, show little or no variation with rank. Nevertheless, comparison of the behaviour and properties of coals of the same rank formed in different coal basins, or even within the same coal basin, can be difficult because of the variability in vegetal diversity during geological time, paleoenvironmental factors and coalification conditions. Depending on the economic use of the coal, certain of these characteristics are considered more important than others.

2.1 Chemical Components

Coal is a chemically and physically heterogeneous substance consisting of both organic and inorganic material. Elemental analysis gives empirical formulas such as $C_{137}H_{97}O_9NS$ for bituminous coal and $C_{240}H_{90}O_4NS$ for high-grade anthracite (Anthracite & Bituminous Coal Forum, 2006). Organically, coal is composed primarily of carbon, hydrogen and oxygen with smaller amounts of sulphur and nitrogen (Figure 3, left). Inorganically, coal consists of a diverse range of ash-forming compounds distributed throughout the rock. The inorganic constituents can vary in concentration from several per cent down to parts per billion (Diessel, 1992).
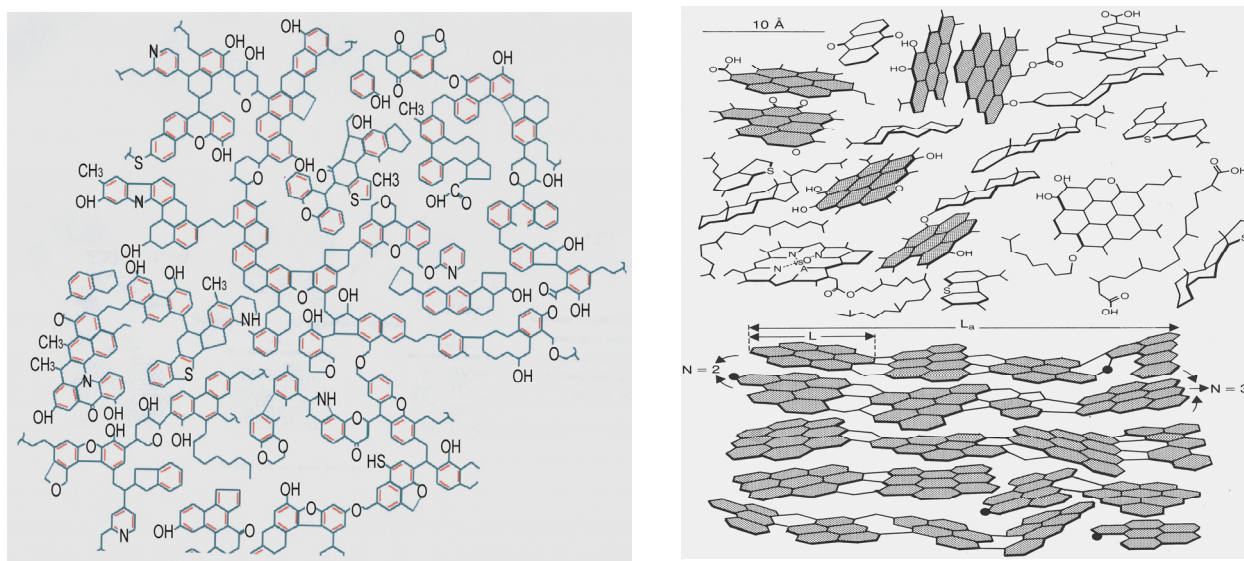
Figure 3. (Left) Model of bituminous coal structure showing the nitrogen and sulphur bonds (*after* Shinn, 1984). (Right) Comparative structural molecular model of low-rank coal (top) and high-rank coal (bottom), with typical arrangement of the aromatic units (grey). Abbreviations: N, number of layers; L, diameter of aromatic units; La, diameter of layer of aromatic units (Oberlin et al., 1980).

For economic purposes, the chemical composition of coal is defined by 'proximate analyses' (moisture [water content], volatile matter [hydrocarbon content], ash and fixed carbon) and by 'ultimate analyses' (quantitative determination of carbon, hydrogen, nitrogen, sulphur and oxygen chemical elements).

2.2 Structural Chemistry of Coal

Coal is a heterogeneous assemblage on both macroscopic and microscopic levels, and many models of coal structure have been developed without regard for such heterogeneity. The construction of molecular models of coal has remained an important ongoing feature of coal science (Davison, 2004). The generic models are useful for a broad statistical view that is applied mainly in underground coal gasification modelling.

High-resolution transmission electron microscopy (TEM) is one of the methods used to identify the ultrafine structure of coal (Taylor et al., 1998). Comparison of structural molecular models of coal of

different ranks, defined through TEM, indicates the trend of structural development during coalification (Oberlin et al., 1980). For instance, the TEM method shows that the structural characteristic of low-rank coals is the wide interlayer spacing. Low-rank coals have structural units comprising stacks of two to three aromatic layers that are randomly oriented and dispersed (Figure 3, top right). The stacks are linked by non-aromatic groups that inhibit the development of consistently close interlayer spacing and dense packing of stacks. Between low-rank coals (low-volatile bituminous) and high-rank coals (semi-anthracite with vitrinite reflectance of <2.0%), a molecular orientation results in aggregates of clusters of aromatic stacks displaying a tighter parallel arrangement in layers (Figure 3, bottom right).

Study of carbon aromaticity of coal using oxidative degradation shows that single-ring aromatics dominate for most of the low to intermediate coal ranks with carbon content of about 80%. Studies of aliphatic structures in coal using Fourier-transformation infrared spectroscopy or ruthenium oxide oxidation indicate a general increase in the percentage of aliphatic hydrogen in methyl groups attached to aromatic rings, in the higher coal ranks (Shinn, 1984).

The mobile phase or molecular/macromolecular model has also been under discussion. There is evidence for material such as methane, carbon dioxide and nitrogen being trapped in coal in variable proportions. The interpretation based on the nuclear magnetic resonance method (NMR) indicates that derived proportions of the mobile phase are concurrent with the proportions of macromolecular network.

Coal scientists recognize that the structural diversity of coal is so great that no conventional structural representation satisfies the demand for structural completeness of each stage in the traditional sense. However, the generic structural representations serve to guide the statistical modelling used in industrial applications. Information on the microscopic chemistry of coal and its relationship to the material's physical structure and reactivity is an essential component in the successful development of the next generation of coal-conversion technologies, such as coal gasification and liquefaction.

2.3   Coalification Process and Level of Thermal Maturation (Coal Rank)

The process of chemical and physical transformation of the original vegetal matter, termed 'coalification,' comprises a series of stages referred to as 'ranks' (Figure 4). Coal rank is an indication of the extent of metamorphism that the vegetal material has progressively undergone during geological time, and can be correlated with the degree of organic maturation of other organic source rocks (Taylor et. al., 1998).

Rank is also a measure of carbon content, since the percentage of fixed carbon increases with the degree of metamorphism. Each phase of the coalification process is the result of temperature and pressure application over millions of years generating considerable macroscopic and microscopic changes in the coal rock. The maximum temperature attained and the way in which the temperature varied over geological time influence the coalification/maturation of the vegetal matter. Pressure retards the chemical reactions that occur during coalification but promotes certain physical changes. The chemical, physical and petrographic changes that characterize the various coal ranks are presented in Figure 5.

During coalification, the main chemical processes are condensation to larger molecules, polymerization and aromatization. The carbon content increases but not linearly. The changes in physical characteristics result in reduced porosity and increased density and hardness due to the tighter alignment of coal intrastructural units. In terms of petrographic properties, translucency of macerals (which depends on their refractive and absorptive indices) decreases with increasing rank, resulting in a characteristic increase in both reflectance and bireflectance (anisotropy) of vitrinites and liptinites (Levine, 1993).
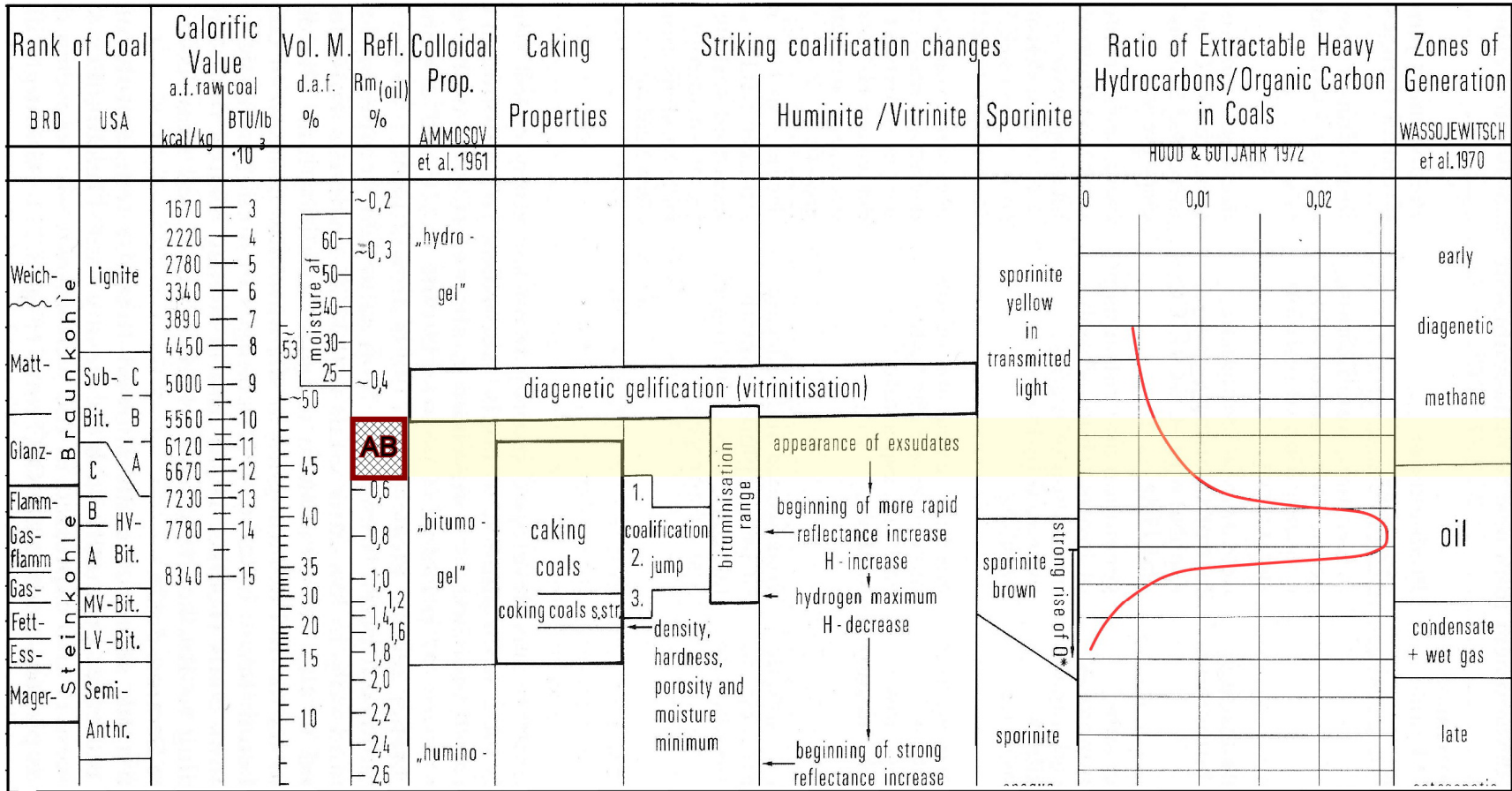
Figure 4. Scale of coal ranks, showing the bituminization range in relation to various characteristics (diagenetic gelification, caking properties, yields of extracts) compared with oil generation in source rocks (*after* Teichmüller, 1987). The red square shows the typical range of coal rank in central Alberta (Beaton et al., 2002, Beaton, 2003; Goodarzi, 2005).

Coalification stage	Approximate ASTM rank range	Predominant processes	Predominant physico-chemical changes
1. peatification	peat	maceration, humification, gelification, fermentation, concentration of resistant substances	formation of humic substances, increased aromaticity
2. dehydration	lignite through sub-bituminous	dehydration, compaction, loss of O-bearing groups, expulsion of -COOH, CO_2 and H_2O	decreased moisture contents and O/C ratio, increased heating value, cleat growth
3. bituminization	upper sub-bituminous A through high volatile A bituminous	generation and entrapment of hydrocarbons, depolymerization of matrix, increased hydrogen bonding	increased vitrinite R_O, increased fluorescence, increased extract yields, decrease in density and sorbate accessibility, increased strength
4. debituminization	uppermost high volatile A through low volatile bituminous	cracking, expulsion of low molecular weight hydrocarbons, especially methane	decreased fluorescence, decreased molecular weight of extract, decreased H/C ratio, decreased strength, cleat growth
5. graphitization	semi-anthracite to anthracite to meta-anthracite	coalescence and ordering of pre-graphitic aromatic lamellae, loss of hydrogen, loss of nitrogen	decrease in H/C ratio, stronger XRD peaks, increased sorbate accessibility, anisotropy, strength, ring condensation and cleat healing

Figure 5. Major chemical and physical changes in coal from peat to meta-anthracite (*after* Levine, 1993).

The main natural by-products of the coalification process are methane, carbon dioxide and water. Water is lost in the early stages of coalification and the ratio of methane to carbon dioxide progressively increases with rank up to a critical point (high-volatile bituminous stage), increasing the coal calorific value. With progressive coalification, there is an associated loss in volume as the result of compaction and expulsion of volatiles and water.

2.4 Coal Type

Coal type relates to the content of microscopic constituents called 'macerals.' Macerals are the equivalent of minerals in other rocks.

The natural maceral association visible on the macro scale, referred to as 'coal lithotypes,' and their vertical succession generates the banded or striped appearance characteristic of coals. There are four generic groups of lithotypes in use (Bustin et al., 1983):

- *vitrain*, consisting of bright coal to banded-bright coal with 10%–40% dull coal

- *clarain*, including the range between banded coal to banded-dull coal with 40%–60% dull coal

- *durain* or 'dull coal,' including less than 10% bright component

- *fusain* or fibrous coal.

In some cases, the constituents can be traced back to specific components of the plant debris from which the coal formed.

At the microscopic level, there are three main groups of macerals characterized by petrographic aspect, chemical composition and optical properties that are relevant in the industrial use of coal: vitrinite, exinite

(sometimes referred to as liptinite) and inertinite, which can be subdivided into finer classifications. Each coal seam consists of a specific proportion of maceral groups that result from the dominant source of vegetal matter within the original ecosystem. According to Stach et al. (1982), vitrinite is the most common maceral group in most coals, varying between 34% and 88%; liptinite/exinite content varies between 5% and 35%; and inertinite can reach up to 50% in special conditions. However, the proportion of the three main groups of macerals can vary even within the same coal seam, making the estimation of coal reactivity more difficult (Teichmüller and Teichmüller, 1982).

The vitrinite group of macerals, derived from humification of woody tissues (chemical transformation into simpler organic acids), occasionally preserves remnant cell structures in coals of lower rank. Vitrinite contains more oxygen than other macerals at any given rank, and intermediate hydrogen and volatile content (at appropriate rank). It is the principal reactive constituent in the industrial coal-conversion process and is susceptible to the liquefaction process (Bustin et al., 1983; Taylor et al., 1998).

The exinite/liptinite group of macerals is derived from plant resins, spore exines, cuticles and algal remains that are fairly resistant to bacterial and fungal decay. This group exhibits higher hydrogen content than other macerals, especially at low rank (lignite to sub-bituminous coals) and higher content of volatiles with dominant aliphatic structure. The exinite/liptinite group is reactive during carbonization and susceptible to liquefaction (Bustin et al., 1983; Taylor et al., 1998).

The inertinite group of macerals represents the degradation products of woody tissue or fungal sclerotia and hyphae caused by in situ combustion or syndepositional biochemical oxidation of peat. The group has high inherent carbon content but lower amounts of hydrogen and volatiles (with dominant aromatic structure). The inertinites present a low response to carbonization and are resistant to liquefaction (Bustin et al., 1983; Taylor et al., 1998).

The vitrinite/inertinite ratio is used as an alternative indicator of coal reactivity (Teichmüller and Teichmüller, 1982).

Petrographic analysis (in transmitted or incident light) is used mainly to characterize coal type and to define the degree of coalification/maturation. For industrial purposes, coal petrography provides insights into the coal's mechanical strength, thermoplastic properties and reactivity to combustion and dry distillation.

2.5   Grade of Coal (Indicator of Inorganic Mineral Content)

The 'grade' of coal relates to the amount of mineral matter finely disseminated or distributed in partings and layers in a coal seam, and represents an overall measure of coal quality. A major reason for studying inorganic matter in coal is combustion performance and environmental protection in the burning of coal. The low-mineral-matter coals correspond to high concentrations organic matter and are of interest for industrial use. A generic classification enables the distinction between relatively 'clean' coals, characterized by 60% to >80% organic-matter content and including the bright, banded, dull and fibrous (macro) lithotypes, and coals with a higher content of mineral matter, such as shaly coal and coaly shale (containing <60% down to 20% organic matter). A 'carbonaceous rock,' such as shale or mudstone, can have as little as 20% organic matter of vegetal origin.

Although inorganic matter is commonly a minor component, it can limit coal's use for industrial purposes due to thermal effects during combustion. The presence of inorganic matter lowers the coal's calorific value. In addition, the type of inorganic matter determines the coal-ash-fusion temperature and the performance of the blast (Suarez-Ruiz and Crelling, 2008).

Mineral layers can be visible in the coal face or be of microscopic dimensions. However, coals that contain no macroscopically visible mineral matter typically contain inorganic components ranging

between 5% and 15%. The acceptable level of mineral matter depends on the intended use of the coal. Lower content of inorganic matter implies a wider spectrum of industrial applications.

Optical microscopy is used for characterizing much of the mineral matter in terms of grain size, shape and association with particular macerals or microlithotypes. It allows general mineral identification, such as the recognition of carbonate and clay group minerals. For detailed characterization, x-ray diffraction, wavelength-dispersive x-ray spectrometry, electron microscopy and electron microprobe techniques provide qualitative or quantitative information on the chemical composition of coal mineral matter (Bustin et al., 1983; Taylor et al., 1998).

Another way to characterize the inorganic matter is to analyze the ash remaining after the organic part of coal has been burned off. The original minerals are altered during combustion and some elements may be lost through volatilization, so the analysis of ash corresponds in part to the original composition of the inorganic matter in the coal. Even low-temperature ashing (<150°C) shows that clay minerals are partially dehydrated and some of the trace elements are lost (Miller, 2005).

One of the attempts to classify the inorganic components contained in coal is based on their genesis (Taylor et al., 1998) and results in the following categories:

- **Syngenetic inorganic matter type A** consists of the plant nutrients group. Calcium, potassium, nitrogen and phosphorus are essential nutrient elements in plant synthesis. Associated elements known or assumed to be physiologically essential in the biosphere (Trudinger and Swaine, 1979) are Al, B, Ba(?), Br(?), Cl, Co, Cr, Cu, F(?), Fe, H, I, Mg, Mn, Mo, Na, O, Rb(?), S, Se, Si, Sr(?), V and Zn, and they usually occur as trace elements.

- **Syngenetic inorganic matter type B** represents the group of inorganic complexes and minerals introduced syndepositionally into the peat environment by wind and/or water. They are of allochthonous origin. In coal seams, they are found as lenses, layers or agglomerates of mudstone, siltstone, sandstone, tonstein and bentonite. In many cases, minerals introduced at the time of deposition are laterally extensive.

- **Epigenetic minerals** represent the later stages in the formation of coal. They are formed by crystallization in cracks, fissures or cavities from ascending or descending solutions. Epigenetic minerals occur as vein-like accumulations with possible extensions into the roof or floor of the seam. In some instances, secondary mineralization may represent only a local attribute of a coal seam. Generally, the infilling minerals do not alter the coal microstructure.

A distribution chart (Figure 6A) of the more common minerals found in coal shows that syngenetic type B minerals, are generally more frequent, followed by the epigenetic group (Taylor et al., 1998). Syngenetic type A minerals, which originated in plant nutrients and paleosols, are commonly recorded as trace elements if their concentration is up to 1000 ppm.

Clay minerals are the most common mineral group present in coal deposits (Figure 6A). In some instances, they account for up to 60%–80% of the total mineral matter associated with coal (Diessel, 1992). The presence of clay minerals in coal seams is mainly the result of syndeposition of allochthonous material. Some aspects of the clay mineral behaviour are important in the industrial applications of coal. For instance, some clay minerals swell in the presence of water. This swelling property is strongly developed in minerals of the montmorillonite group, but there is also swelling in mixed-layer silicates (illite-smectite-illite). Swelling is always accompanied by a substantial reduction of strength, and it can lead to the complete disintegration of a rock package. In coal combustion, swelling clays lead to the formation of an undesirably high proportion of slimes (Suarez-Ruiz and Crelling, 2008).
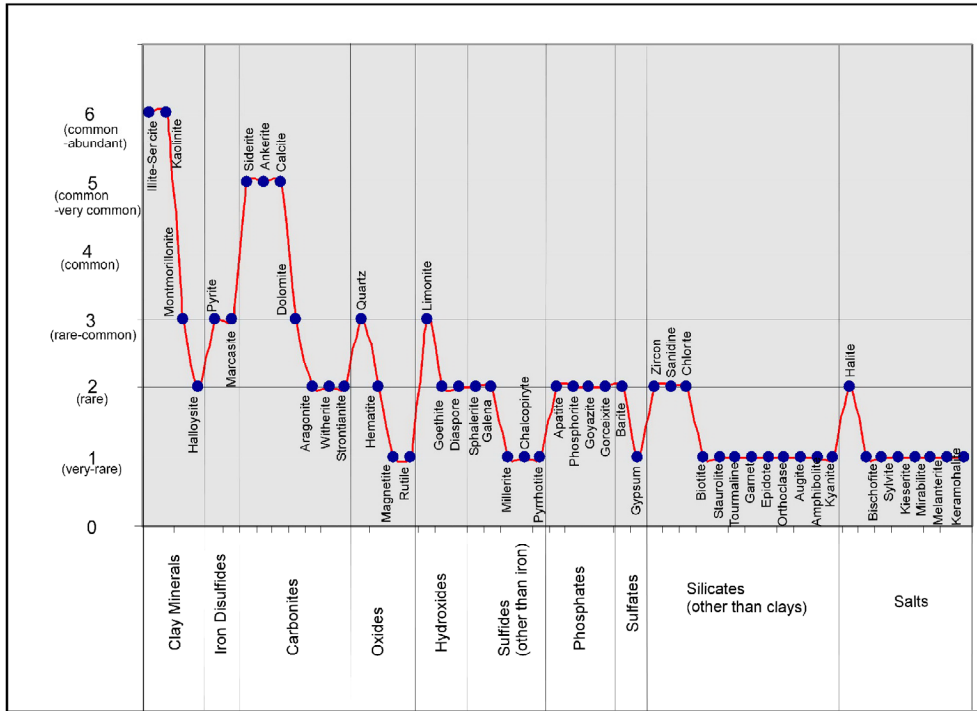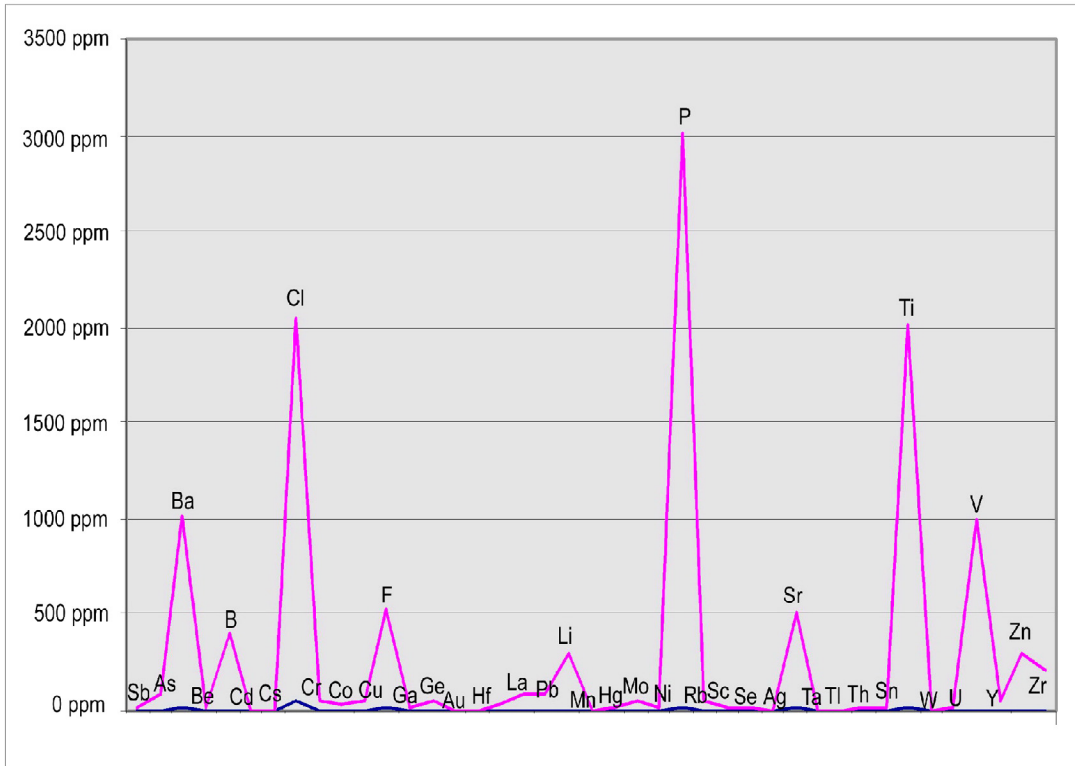
Figure 6. A) Common minerals identified in coal (data *from* Taylor et. al., 1998, Table 4.11). B) Most common trace elements found in coal (estimated maximum value in magenta; data *from* Taylor et. al., 1998, Table 4.12).

Carbonate minerals in coal are commonly calcite ($CaCO_3$), ankerite ($Ca(Fe, Mg, Mn)(CO_3)$) and dolomite ($CaMg(CO_3)_2$; Figure 6A). These minerals can form both during deposition and in the course of coalification (Diessel, 1992). The syngenetic carbonate minerals may indicate a marine-influenced depositional environment and can lead to the prediction of other associated minerals important for coal combustion performance. Some of calcite and ankerite deposited in coal cracks and fissures is the result of epigenetic processes. Dolomite ($CaMg(CO_3)_2$) occurs rarely and as a result of syngenetic conditions, either in the form of idiomorphic crystals or as 'coal balls' impregnating plant material.

When a considerable proportion of carbonate minerals is present, the ash-fusion temperature is significantly lower than when clay and quartz account for most of the mineral matter. At combustion temperature, carbonates break down to form oxides, which then combine with siliceous minerals to form silicates with a comparatively low softening point (Suarez-Ruiz and Crelling, 2008).

Among those elements present in coal, greater than trace amounts, sulphur is of particular interest because it can lead to problematic concentrations in the flue gases. During combustion, additional reactions between sulphur and the alkaline earth elements (Be, Mg, Ca, Sr, Ba) lead to the undesired formation of complex sulphates that contribute to the corrosion of heated surfaces.

Sulphur occurs in coal in both inorganic (generally post-coalification process) and organic forms (bonded to the coal chemical structure; Figure 3A). The most important chemical combinations of inorganic sulphur are the sulphide minerals (Speight, 2005), including pyrite, marcasite, chalcopyrite, galena and sphalerite. In coal seams, they are generally of epigenetic origin. The most common sulphide minerals in coal are pyrite and marcasite, both with the chemical formula FeS_2 (Figure 6A). Pyrite, formed under higher temperature conditions, is the more stable form of iron sulphide and may contain Ni, Co, As, Cu, Zn, Hg, Ag, Au, Tl, Se and V as common impurities. However, the stability of pyrite varies greatly in subsurface or outcrop, sometimes between the time a sample is taken and the time it is analyzed.

Marcasite is frequently found in coal seams and surrounding sedimentary rocks as a replacement mineral. Also, it can be a shallow-depth neoformation mineral formed by precipitation at low temperature from acid solutions. In general, coals deposited in paralic basins are richer in pyrite. Among the paralic coal deposits, the coal seams overlain by marine shale are characterized by higher content of pyrite and sometimes of organic sulphur, especially in the upper part of the seam (Speight, 2005).

The most important silicate mineral in coal is quartz (SiO_2) which generally occurs in small amounts and under specific conditions (Figure 6A; Speight, 2005; Suarez-Ruiz and Crelling, 2008). Granular quartz is detrital. Some coal seams can be remarkably rich in detrital quartz. In some cases, quartz has replaced organic matter, preserving biological structure in detail (petrification). Finely crystalline quartz (rarely chalcedony) formed from solutions during coalification. Much of dissolved silica is the result of the weathering of feldspar and mica; thus, it normally appears associated with other finely dispersed minerals in kaolin-coal tonstein.

Gypsum (Figure 6A) occurs occasionally in coal seams exposed to arid conditions because of crystallization from groundwater and/or through oxidation of pyrite. Gypsum is an indicator of weathered coals (Miller, 2005).

Small amounts of heavy minerals, such as zircon and tourmaline, can be associated with coal (Figure 6A). The rocks above and below the coal seams generally contain greater concentrations of these minerals (i.e., tonstein).

Of particular interest from an environmental standpoint is the occurrence of trace elements in coal seams (Figure 6B). Trace elements are generally defined as those elements that occur at concentrations of <1000 ppm, although they can occasionally be present at higher concentrations (up to 50 000 ppm). With

tighter environmental controls on emissions from coal combustion, trace-element content has become quite important (Miller, 2005).

During the combustion of coal, trace elements are redistributed into 1) bottom ash; 2) removed fly ash by particle attenuation (electrostatic precipitations, fabric filters); 3) fine fly ash (<5 μm in diameter); 4) the vapour phase; or 5) leachate originating from residual waters that are often acidic due to the oxidation of pyrite (Goodarzi, 2005).

Trace elements originate from soils and the plants that grow on them (Figure 7). The trace elements occurring most commonly in coal are Ca, K, Mg, Al, Na, V, Fe, Cu, Zn, Mo, Co, Se, As, Hg, Th and U.
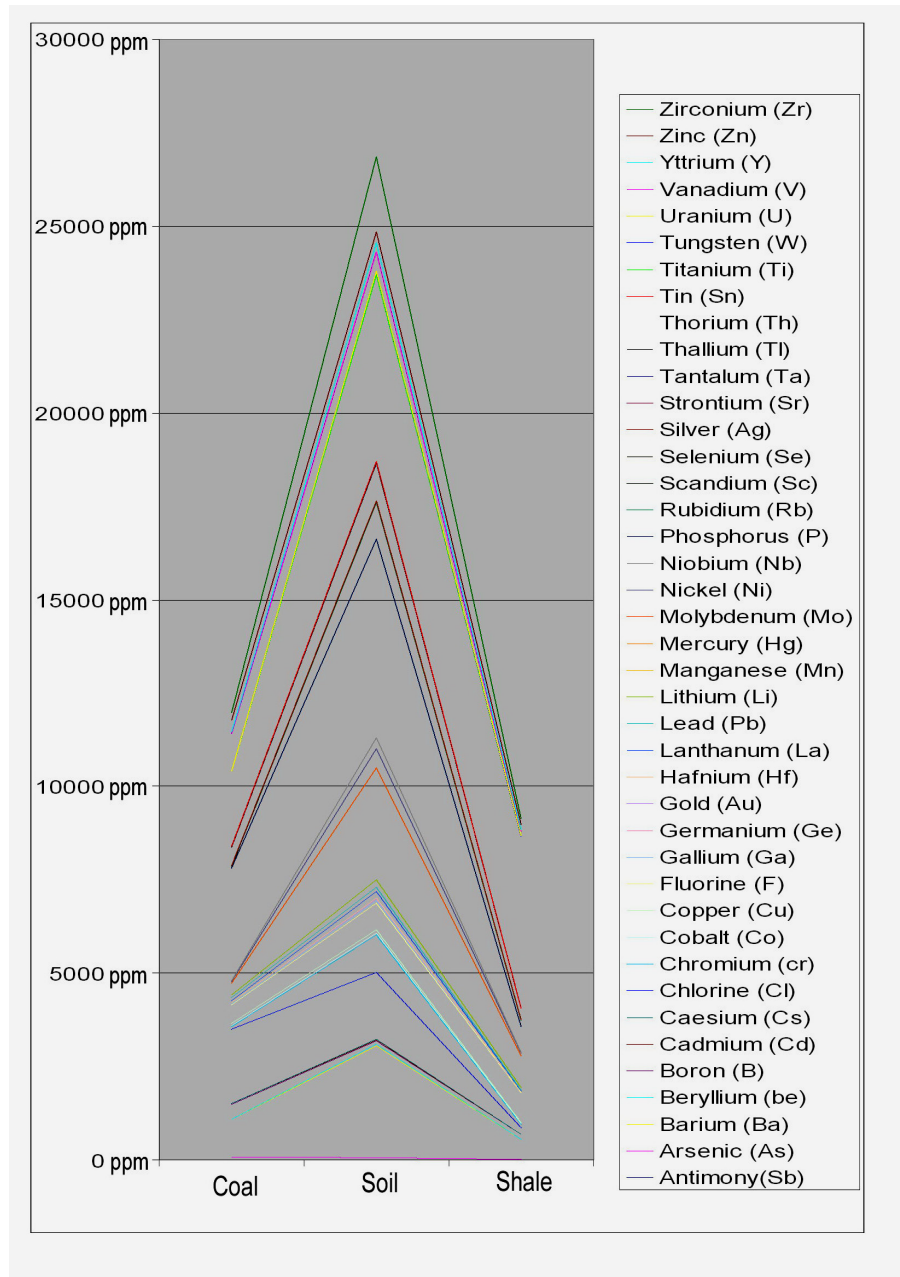
Figure 7. Relative concentrations of the most common trace elements (high values) occurring in coal, soil and shale (data *from* Taylor et. al., 1998, Table 4.12).

Trace-element content of minerals cannot be routinely determined petrographically (Bustin et al., 1983). One of the methods used is scanning electron microscopy with an energy-dispersive detector (SEM-EDS). The results of this analytical technique show that many trace elements (Pb, Zn, Cu, Cd, Zr, Hf, Th, U) occur in micrometre-size accessory mineral grains scattered throughout the macerals. Another group, including As and Hg, is detected in pyrite lattices. The elements Ti, Se, Br and U may be bound in the organic structure of the coal (Bustin et. al, 1983; Miller, 2005).

Certain authigenic minerals occurring in different proportions are the result of specific physical and chemical conditions, and their association is an indication of the environment in which the coal formed, so a paleoenvironmental reconstruction would suggest the extent of similar coal chemical content.

The amount of impurity, or grade of coal, is important to industrial users. All mineral matter present influences the suitability of a coal for combustion in terms of ash-fusion temperature, remnant mineral content and subsequent product-gas cleaning.

3 Clean Coal Technology

The coal industry uses the expression 'clean coal technologies' to describe processes and techniques designed to enhance both the efficiency and the environmental acceptability of coal extraction and processing, with reduced emissions of carbon dioxide. These efforts include chemically washing minerals and impurities from the coal during direct power generation, conventional coal gasification and coal direct or indirect liquefaction processes; and treating the gaseous combustion products (flue gases) to remove sulphur dioxide (SO_2) and capture carbon dioxide (CO_2).

According to the United Nations Intergovernmental Panel on Climate Change (Watson et al., 1992) and the European Climate Forum (Jaeger, 2004), the burning of coal for power generation has been proven to be one of the principal causes of anthropogenic climate change and global warming.

Industry is making progress in finding environmentally acceptable options, such as advanced gasification technologies (polygeneration and cogasification; Suarez-Ruiz and Crelling, 2008). It has been estimated that, before 2020–2025, commercial-scale clean-coal power stations (coal-burning power stations with carbon capture and sequestration) will be commercially viable and widely adopted. Some by-products of coal combustion might be hazardous to the environment if not properly contained. This is seen to be technology's largest challenge, from both the practical and public perception perspectives. It is possible to remove most of the sulphur oxides (SO_x), nitrogen oxides (NO_x) and particulate (PM) emissions during the coal-burning process, and there are options for carbon dioxide emissions (CO_2) to be captured and managed. Technologies do exist to capture and store CO_2, but they have not been made available on a large-scale commercial basis due to the high economic costs and government regulatory frameworks for storage/sequestration that are still in development and specific to various geopolitical zones.

Coal and other hydrocarbons have been gasified for the production of chemicals, fertilizers and synthetic fuels for more than half a century. However, it is only in the last 20 years that gasification has been used for the production of electricity using the integrated gasification combined cycle (IGCC) process. Clean-coal technologies are generally considered synonymous with coal gasification (i.e., IGCC). However, since 2005, they appear to include a number of higher stage conversion technologies such as 'advanced supercritical boilers' and 'fluidized beds' associated with a number of CO_2 capture technologies (i.e., postcombustion solvent absorption, oxy-fuel firing and precombustion). It is now widely anticipated that the new generation of power plants will have to be capture ready. Alongside capture-ready plants, a number of carbon storage/sequestration projects (often referred to as demonstration projects) are envisaged. Sequestration and storage refer, respectively, to the long-term and short-term disposal of carbon dioxide, once captured, into particular geological strata (Suarez-Ruiz and Crelling, 2008).

Pulverized coal combustion, integrated gasification combined cycle (IGCC) and combined-cycle power plant (CCPP) are considered the next generation of clean coal technologies. For instance, the synthesis gas generated by an IGCC is directed to a system for removal of impurities. This results in very low flue emissions, particulates and mercury, and improves the overall efficiency of the synthesis gas compared to conventional coal-fired power stations.

Both conventional coal gasification and underground coal gasification (UCG) use similar technological concepts (i.e., IGCC), the difference being that the syngas is obtained in surface gasifiers as part of conventional coal gasification and in in situ reactor chambers in UCG. However, the UCG process implies reduced relative cost, which makes it a potentially viable technological alternative.

Natural Resources Canada (CanmetENERGY, 2009) has presented the strategic advantage of Canada's large endowment of coal, and the challenges and expectations that industry will face as it works through the various options available toward the achievement of 'clean coal technologies. To achieve these objectives, industry and government commitment is considered essential for the vision of clean coal to become a reality in Canada.

4   Conventional Coal-Conversion Technology

Conventional coal-conversion technology consists of coal gasification and liquefaction processes that have been developed in surface chemical plants using mined coal as feedstock. The main end markets of both these conventional technologies are efficient electric power generation or synthetic fuels as feedstock for other chemical processes.

4.1   Direct and Indirect Coal Liquefaction

Coal can be liquefied by either a direct or an indirect process.

Direct coal liquefaction was invented in the 1920s in Germany by Friedrich Bergius and developed as a commercial process during World War II. The eleven commercial plants produced about 90% of the aviation fuel for the German war effort. Most of the direct processes developed later in the 1980s were modifications or extensions of Bergius's original concept (Suarez-Ruiz and Crelling, 2008). The coal is ground so that it can then be mixed into a coal-derived recycle solvent to form a coal-oil slurry feed. The slurry, containing 30%–50% coal, is then heated to about 450°C in a hydrogen atmosphere at a pressure of 13 900–20 000 kPa for about an hour. A variety of catalysts is used to improve the rates of conversion to liquid products. One tonne of coal yields about one-half tonne of liquids. Processes have been developed to use coals ranging in rank from lignite to high-volatile bituminous. Higher rank coals are less reactive and anthracites are essentially nonreactive. The produced liquids have molecular structures similar to aromatic compounds and need further upgrading to produce specific fuels, such as gasoline and fuel oil.

An indirect coal-liquefaction process was developed to produce a mixture of alcohols, aldehydes, fatty acids and hydrocarbons, known as synthol, from a synthesis gas consisting of hydrogen and carbon monoxide. This process was also invented in Germany in the 1920s by Franz Fischer and Hans Tropsch, and has been known generically since then as the Fischer-Tropsch (F-T) process (Suarez-Ruiz and Crelling, 2008). The Fischer-Tropsch coal-liquefaction technology is considered indirect because it is a two-step process consisting of

1) gasification of coal using oxygen and steam as reactants, as a result of which the coal structure is completely broken down into CO and H_2 as major components of the synthesis gas; and

2) reaction of the synthesis gas over an F-T catalyst to form predominantly liquid, paraffinic hydrocarbons of widely ranging molecular weights.

This method was also used to produce motor fuel during WWII, and since the 1960s in South Africa.

4.2   Direct Coal Gasification

Coal gasification is a process that converts carbonaceous matter into mainly carbon monoxide and hydrogen by reaction of the raw material at high temperatures (>700°C) with a controlled amount of oxygen and steam (Kharchenko, 1997). The gas mixture is called synthesis gas or syngas, and it is by itself a combustible fuel. Gasification is generally a very efficient method for extracting energy from many different types of organic materials, such as coal, bitumen and plastic waste.

4.2.1   Fundamental Chemical Reactions in Coal Gasification

In a conventional gasifier, the ground coal undergoes several different processes (Kharchenko, 1997):

3) **Pyrolysis** (or devolatization) occurs as coal heats up in the absence of oxygen. The volatiles H_2, CH_4 and possibly N_2, as well as tar, are released and a solid residue known as char results from this oxygen-free reaction. During volatile release and char forming, approximately 70% of the weight of the original carbonaceous matter is lost. The process depends upon the properties of the coal, which also determine the structure and composition of the char that will then undergo gasification reactions.

4) **Combustion** occurs as the residual volatile products and some of the char react with O_2 introduced into the system to form mainly CO, H_2 and subordinate CO_2. The quantity of CO_2 is controlled by the amount of O_2 made available. This process is exothermic and provides an internal energy resource as heat for the subsequent gasification reactions.

   $2C\,(s) + O_2\,(g) \rightarrow 2CO\,(g)$ (exothermic and self-sustaining reaction)

5) **Gasification** occurs as the char reacts with steam to produce CO and H_2, via the main reaction:

   $C(s) + H_2O(g) \rightarrow H_2(g) + CO\,(g)$ (endothermic reaction)

   An additional reaction may take place:

   $C(s) + 2H_2O\,(g) \rightarrow CO_2\,(g) + 2H_2\,(g)$ (secondary endothermic reaction)
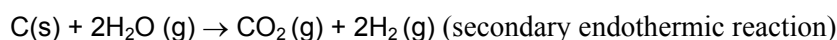
   Introducing steam into the input oxygen or air of a gas producer would increase the calorific value (CV) of the fuel gas by enriching it with carbon monoxide and hydrogen.

6) **Water-gas shift** is a chemical reaction in which CO reacts with H_2O to form CO_2 and H_2. In the gasifier, this reversible gas-phase reaction reaches equilibrium very quickly at the system temperature:

   $CO(g) + H_2O(g) \rightarrow CO_2(g) + H_2(g)$ (slightly exothermic reaction)
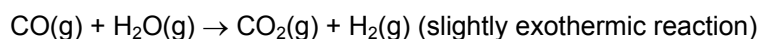
The process is reversible and it can be reversed by means of infinitesimal changes in some properties of the system. The water-gas shift reaction is sensitive to temperature, with a tendency to shift towards the reactants as temperature increases, due to Le Chatelier's principle (Kharchenko, 1997). In rich hydrocarbon combustion processes, the water-gas reaction at equilibrium state is often employed as a means of providing estimates for molar concentration of burned gas constituents. This balances the concentration of carbon monoxide, steam, carbon dioxide and hydrogen. In essence, a limited amount of oxygen or air is introduced into the reactor to allow some of the organic material to be combusted to produce carbon monoxide and energy, which drives a second reaction that converts further organic material to hydrogen and additional carbon dioxide.

4.2.2 Industrial Use of Direct Coal Gasification

The advantage of coal gasification is that the syngas product is a more efficient fuel than the direct combustion of coal (Penner, 1987). Syngas can be burned directly in internal combustion engines or used to produce methanol and hydrogen, or as feedstock for the Fisher-Tropsch conversion process to be further converted into other synthetic fuels as described above. Conventional gasification of coal is currently used at industrial scale to generate electricity.

The production of electricity using syngas can be achieved by IGCC, with the possibility of producing additional methane and hydrogen for fuel cells (Penner, 1987). The IGCC is also a more efficient method of CO_2 capture as compared to conventional power generation technology. Integrated gasification combined cycle demonstration plants have been operating since the early 1970s and some of the plants constructed in the 1990s are now entering commercial service.

An IGCC power plant uses synthesis gas (syngas) as feedstock (Suarez- Ruiz and Crelling, 2008). This gas is used to power a gas-turbine generator whose waste heat is passed to a steam-turbine system or combined-cycle gas turbine. The plant is called 'integrated' because the syngas is produced in a gasification unit, which has been optimized for the plant's combined cycle. The gasification process produces heat, which is reclaimed by steam waste-heat boilers. Steam turbines use this steam to generate power. In a combined cycle power plant (CCPP) or combined cycle gas turbine (CCGT) plant (Siemens AG, 2007), a gas-turbine generator produces electricity and the waste heat is used to generate additional electricity via a steam turbine; this last step enhances the efficiency of electricity generation. Most new gas power plants in North America and Europe are of this type. In a thermal power plant, high-temperature heat produced by burning syngas is converted into electricity as one of the outputs and low-temperature heat as another output. To achieve high efficiency, the temperature difference between the input and output heat levels should be as high as possible (Imatran Voima Oy et al., 1990). This is achieved by combining the Rankine (steam) and Bryton (gas) thermodynamic cycles. Such an arrangement is called a combined gas (turbine) and steam (turbine) system (COGAS). Combining the results of two or more 'cycles,' such as the Bryton and Rankine cycles (Kharchenko, 1997), will improve overall process efficiency.

As of 2007, only two IGCC plants were generating power in the United States; however, several new IGCC plants are expected to come online between 2012 and 2020. General Electric is currently designing an IGCC model plant that should introduce greater reliability. General Electric's model features advanced turbines optimized for the coal syngas. The gasification process can produce syngas from high-sulphur coal, heavy petroleum residues and biomass (GE Energy, 2009).

In central Alberta, six conventional coal-fired power plants are using mined coal as feedstock. Industry interest in the move to conventional coal gasification power plants led in 1988 to a pilot project in which the Alberta Research Council (ARC) carried out an initial assessment of the suitability of Jurassic, Upper Cretaceous and Tertiary coals for the integrated gasification combined cycle (IGCC), mainly for producing electricity (Kovacik and Chambers, 1988). The IGCC was considered at that time a technology of choice for the next generation of coal-fired plants. The objective of the ARC study was to characterize the suitability of the coal for various IGCC processes, such as coal-water slurry feed (Texaco); dry, pulverized feed (Shell); and dry, crushed feed (British Gas–Lurghi). The implementation of IGCC technology was suspended. However, two IGCC power-generation projects will come on stream in Alberta: a coal gasification facility at Genesee near Edmonton (The Electricity Forum, 2009) in 2015, and a large natural-gas–fed facility near Calgary (ENMAX Energy Corporation, 2009). The EPCOR-Siemens Genesee power plant is designed to capture 85% of the CO_2 generated during the conventional coal gasification process. The ENMAX project has been reviewed to integrate alternatively coal-derived syngas from conventional and unconventional combustion; the project proposal is in progress. In 2001,

TransAlta Utilities Corporation (TransAlta Utilities Corporation, 2008; The Energy Blog, 2008) evaluated the IGCC option as a better technology in the Keephills coal-fired power plant modernization project.

5 Unconventional Coal-Conversion Technology: Underground Coal Gasification

Underground coal gasification (UCG) represents an unconventional type of coal-conversion process. Both conventional and unconventional technologies use the same concept of coal gasification and the product of both technologies is the gaseous mixture known as 'syngas.'

The UCG process has been applied in the former Soviet Union since 1933 and began to expand world-wide in the late 1970s, in many cases with commercial results.

Underground coal gasification uses a technological concept similar to conventional coal gasification (i.e., IGCC; Figure 8A), including the terminal infrastructure unit, such as a power or chemical plant (Figure 8B). The main difference is that the reactor in the UCG technology is a subsurface cavity (reactor chamber) within the target coal seam. The UCG concept also has similarities to the in-situ combustion process applied in heavy-oil recovery; some of the operational parameters, such as roof/floor stability, coal seam continuity and groundwater influx, are similar to those encountered in underground mining (Friedmann, 2007).

Underground coal gasification is based on a system of injection-production wells that makes possible the in situ conversion of coal into syngas by a physicochemical process. In UCG technology, the in situ coal is not subjected to cleaning or preparation stages as in the conventional gasification process, so a good understanding of the in situ coal properties and coal calorific value is required.

5.1 Coal Combustion Properties

Coal combustion consists of three relatively distinct phases (Suarez-Ruiz and Crelling, 2008), which are similar in both conventional and unconventional (in situ) coal-gasification processes:

- **Preheating phase:** When the coal fuel is heated to its flash point and then fire point, flammable gases start being evolved in a process similar to dry distillation.

- **Distillation phase or gaseous phase:** When the mixture of evolved flammable gases and oxygen is ignited, energy is produced in the form of heat and light. Heat transfer from the combustion area maintains the generation of flammable vapours.

- **Charcoal phase or solid phase:** This represents the stage when the output of flammable gases from the material is too low for persistent presence of flame and the charring/charred fuel no longer burns rapidly but just glows and later only smoulders.

Susceptibility of coal to in situ combustion is inferred by the dominant petrographic components vitrinite and liptinite versus inertinite, moisture, and amount and type of inorganic matter. In addition, the volatile content of in situ coal has an important role in the combustion process.

In complete combustion, coal will burn in oxygen, producing a limited number of products, such as carbon dioxide and water. When any fuel including coal burns in air, the combustion products will also include nitrogen. When elements such as carbon, nitrogen, sulphur and iron are burned, they will yield the most common oxides. Carbon will yield carbon dioxide, nitrogen will yield nitrogen oxides, sulphur will yield sulphur oxides and iron will yield iron (Fe^{+3} or ferric) oxide. When actual combustion reactions come to equilibrium, a wide variety of major and minor chemical species will be present. In incomplete combustion, there is insufficient oxygen to allow the coal fuel to react completely to produce carbon dioxide and water. Incomplete combustion may occur when the combustion front is quenched by a heat sink such as a solid surface or flame trap. A flame trap occurs as the self-extinguishing result of too rich

Coal-Gasification Power Generation Concept (i. e., IGCC)

A

Steam Turbine

Steam Generation → Power Generator →

UCG Syngas Fuel

Syngas Combustion Turbine → Power Generator →

Coal-Fired Power Generation Concept

Coal Fuel →

Combustion-Boiler System

Steam →

Steam Turbine → Power Generator →

Synthesis of Ammonia from UCG Syngas

B

Reformer

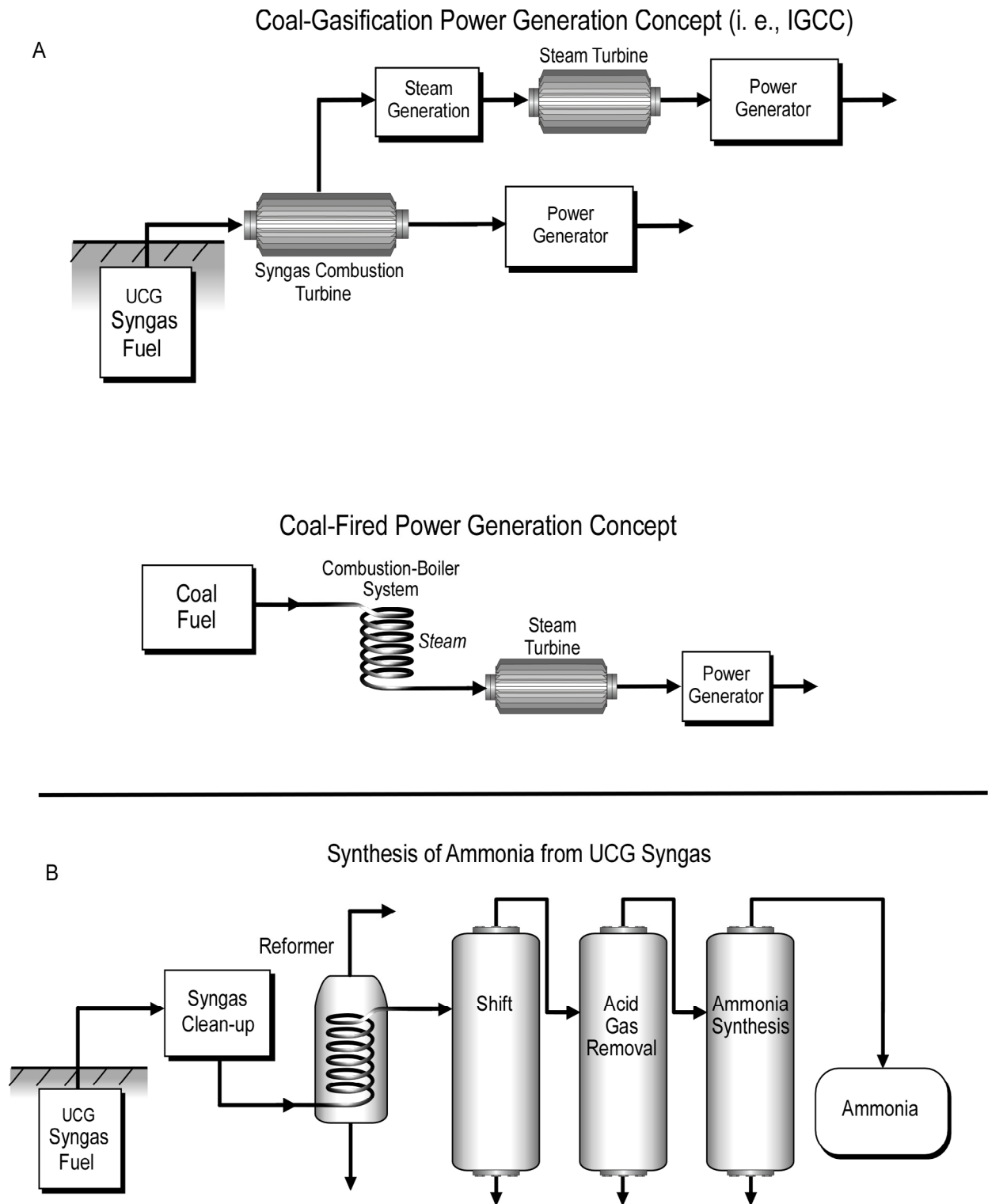UCG Syngas Fuel → Syngas Clean-up → Shift → Acid Gas Removal → Ammonia Synthesis → Ammonia

Figure 8. A) Simplified versions of the coal-gasification power-generation concept using underground coal gasification (UCG) syngas as feedstock (above) and coal-fired power-generation concept (below). B) Simplified version of ammonia-synthesis process using UCG syngas as raw material (B. Gollpudi and B. Radulovic, pers. comm., 2009).

or lean a mixture of flammable components and air/oxygen to support combustion. The products of incomplete combustion are carbon monoxide, hydrogen, water, carbon dioxide, pure carbon (soot or ash) and various other compounds (e.g., nitrogen oxides).

5.1.1 Coal Chemical Analysis

Information on coal behaviour used in the marketing of coals is provided by coal chemical analyses and calorific determination. Additional analyses refer to ash chemistry and ash-fusion temperature.

Chemical analyses of coal include proximate and ultimate analysis. The proximate analysis gives the relative amounts of moisture, volatile matter, ash (i.e., inorganic material left after all the combustible matter has been burned off) and, indirectly, the fixed carbon content of the coal. The moisture and mineral matter (or ash) are extraneous to the coal substance. Analytical data can be expressed on several different bases to reflect the composition of as-received, air-dried, fully water-saturated coal or the composition of dry, ash-free (daf) or dry, mineral-matter–free (dmmf) coal. Ultimate analyses give the concentrations of carbon, hydrogen, nitrogen, sulphur and oxygen in the coal. Oxygen is typically determined by subtracting the analytically determined percentages of carbon, hydrogen, nitrogen and sulphur from 100. This indirect method is used due to the complexity of determining oxygen directly. However, this technique accumulates into the calculated value for oxygen all the errors that occur when determining the other elements (Miller, 2005; Speight, 2005).

Each type of coal has a certain set of calorific parameters that are mostly controlled by moisture, volatile content (in terms of aliphatic and aromatic hydrocarbons) and fixed carbon content.

5.1.1.1 Moisture

Moisture is an important property of coal, especially at low to intermediate ranks. Groundwater and extraneous moisture are known as adventitious moisture (not inherent or innate), which is readily evaporated. Moisture held within the coal itself is analyzed and is known as inherent moisture.

Moisture can occur in four possible forms within coal (Miller, 2005):

- **surface moisture:** water held on the surface of coal particles

- **hygroscopic moisture:** water held by capillary action within the microfractures of the coal

- **decomposition moisture:** water held in decomposed organic matter within the coal

- **mineral moisture:** water incorporated in the crystal structure of hydrous silicates

The moisture content is analyzed according to American Society for Testing and Materials (ASTM) standards.

5.1.1.2 Volatile Matter

Volatile matter in coal represents the components of coal, which are liberated at high temperature in the absence of air (noncombustion). The components are usually in a mixture of short- and long-chain hydrocarbons, aromatic hydrocarbons and some sulphur. The volatile matter of coal is determined under rigidly controlled standards. British-Australian and American laboratories use similar standard laboratory procedures that essentially involve heating the coal at high temperatures (>900°C) in special crucibles (silica or platinum). The two methods give different results, so the method used must be stated.

5.1.1.3 Fixed Carbon

The fixed carbon content of the coal is the carbon found in the material left after volatiles have been driven off. This differs from the ultimate carbon content of the coal because some carbon is lost with the hydrocarbon volatiles. Fixed carbon is used as an estimate of the amount of char that will be generated

from a sample of coal. The amount of fixed carbon is determined by subtracting the mass of volatiles determined using the volatility test from the original mass of the coal sample.

5.1.1.4 Additional Chemical Analysis

Ash content is the noncombustible residue left after the coal is burned. It represents the bulk mineral matter after carbon, oxygen, hydrogen, nitrogen, sulphur and water have been driven off during combustion. After the coal has been thoroughly burned, the remaining ash material is expressed as a percentage of the original weight. Ash residue includes the majority of primary and secondary mineral matter, and any trace elements associated with the coal.

5.1.2 Coal Calorific Value

Coal calorific value, also known as heating value, is the most important coal characteristic for the gasification process. Calorific value is a measure of the amount of energy that a given quantity of coal will produce when completely oxidized (burned). Since combustion processes are never perfect or complete in real environments, both unburned carbon (soot) and carbon compounds (CO and others) will be present in flue gases resulting from combustion of coal. When air is the source of the oxygen, nitrogen is part of the resultant flue gas.

Calorific value is measured in units of energy per unit of the substance (usually mass), such as Kcal/kg, kJ/kg, J/mol or Btu/lb.

Coal calorific value (Q) is a complex function of the elemental composition of coal and can be determined experimentally using a calorimeter. When the oxygen content is less than 10%, the formula used is:

$$Q = 337C + 1442(H–O/8) + 93S$$

where C is the mass percentage of carbon, H is the mass percentage of hydrogen, O is the mass percentage of oxygen and S is the mass percentage of sulphur in the coal. With these constants, Q is expressed in kilojoules per kilogram (Dulong-Petit law concept).

When air is the oxidant in the UCG process, nitrogen will be oxidized to various nitrogen oxides (NO_x). This is one of the reasons that the product gases resulting from *air injection* have lower calorific values, in the range 4.0–5.5 MJ/m^3 (United Kingdom Department for Business Innovation and Skills (2004); approximately twice the calorific value can be achieved with *oxygen injection,* depending on specific site conditions.

The coal heating value increases with increasing rank but begins to decrease in higher rank coals such as semi-anthracite. This decrease in heating value is due to the significant decrease in volatile matter (Figure 4).

In the combustion process, energy in the coal fuel is needed to change water from liquid to vapour. The amount of energy required depends on the moisture content (MC)—the higher the moisture content, the more energy is required. The amount of energy absorbed by water when changing from liquid to vapour at its normal boiling point is called the heat of vapourization.

5.1.2.1 Combustion Temperature

In the case of a fossil fuel burned in air, the combustion temperature depends on all of the following: heating value, stoichiometric air:fuel ratio (λ), specific heat capacity of fuel and air, and the air and fuel inlet temperatures. The degree of combustion efficiency can be measured and analyzed with test equipment.

Coal generally ignites in air at atmospheric pressure between 400° and 500°C, and glows at temperatures higher than 1300°C temperature (Miller, 2005). The temperature regime applied in UCG operation is commonly >1000°C (i.e., 1200°C) at slightly higher than ambient pressure. Coal undergoes a great number of pyrolysis reactions, which are endothermic and therefore require constant energy input from the combustion reactions. A lack of oxygen or other poorly designed conditions result in the emission of undesired pyrolysis products as thick black smoke.

There is a close interaction of coal organic and inorganic mineralogy, ash chemistry, ash melting with slagging properties, and ash-fusion temperature. For instance, low- to medium-rank coals with higher amounts of volatile matter require lower ignition temperatures and tend to have greater amounts of fouling and slagging. The optimum ash-fusion temperature is higher than the ignition temperature because slag products reduce heat transfer and may decrease the operational efficiency. Generally, clay minerals that contain significant amounts of iron, calcium, sodium or potassium cause low ash-melting temperatures. Specifically high CaO content induces a low fusion temperature. Interaction of pyrite, clay minerals and alkalis with aluminosilicate minerals forms low-temperature viscosity melts. Most fouling problems are caused by calcium sulphate deposits (Suarez-Ruiz and Crelling, 2008).

5.2 Underground Coal Gasification Process (UCG)

5.2.1 Technological Concept

The simplified version of the underground coal gasification process involves the drilling of two boreholes into a particular coal seam at depth, creating an injection-receiving (production) system. Typically, lignite and sub-bituminous coals are considered suitable for the process due to their volatile matter and moisture content (Beath and Davis, 2006). The complete system consists of surface infrastructure modules, such as input-output units (i.e., gasification and injection equipment, and gas cooler and cleaning components), and an underground drilling-linking subsystem. Operation of the input-output infrastructure (i.e., steam injection and clean-up system) requires a certain amount of energy.

The injection wellbore allows a pressurised oxidant, such as air or oxygen-rich gaseous blends, to be introduced into the coal seam. The coal is heated to ignition and the adjacent gasification process is maintained by oxidant flow, with product gas being recovered from the second borehole (Figure 9A).

As the underground reaction proceeds, a void is created that extends laterally and up to the roof of the coal seam; simultaneously, the coal dissociation process migrates progressively toward the production well, where the product gas is captured and directed to the output module, which is similar to the surface infrastructure for conventional surface coal gasification. The product gas still has a temperature (about 300°C) and pressure that are higher than atmospheric values.

The underground cavity, equivalent to the conventional surface gasifier, is confined by the surrounding rocks of the coal seam. Cavity growth is by 'spalling,' where material falls off the roof and walls. At the base of the cavity, the in situ by-products consist of ash rubble made up of coal mineral matter overlain by rock rubble and char rubble (Figure 9B). The geometry of the cavity is continuously monitored by adjusting the injection pressure to the in situ pressure (Figure 10). Groundwater influx into the gasifier creates an effective 'steam jacket' around the reactor chamber, making the in situ heat loss tolerably small. Optimal pressure in the underground gasifier promotes controlled groundwater flow into the cavity, confining the chemical process to the desired gasifier space and thus preventing leakage or contamination beyond the operational area (Blinderman and Jones, 2002; Beath and Mallett., 2006).

Large-scale production facilities consist of multiple injection-production modules. For instance, a UCG exploration block in production can operate through several injection-production well pairs distributed in line (Figure 11A). The incremental distance can be in order of 200–300 m, based on international experience. All injection wells and production wells are connected to major injection and production
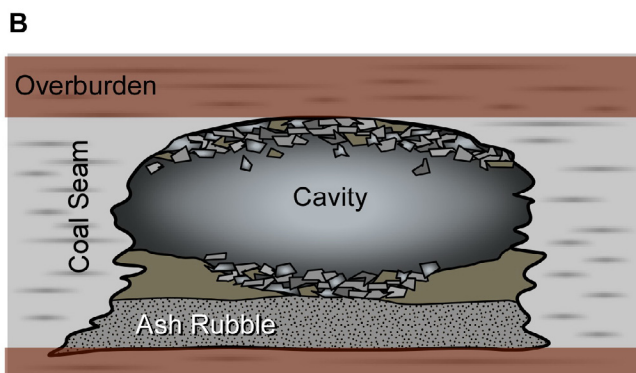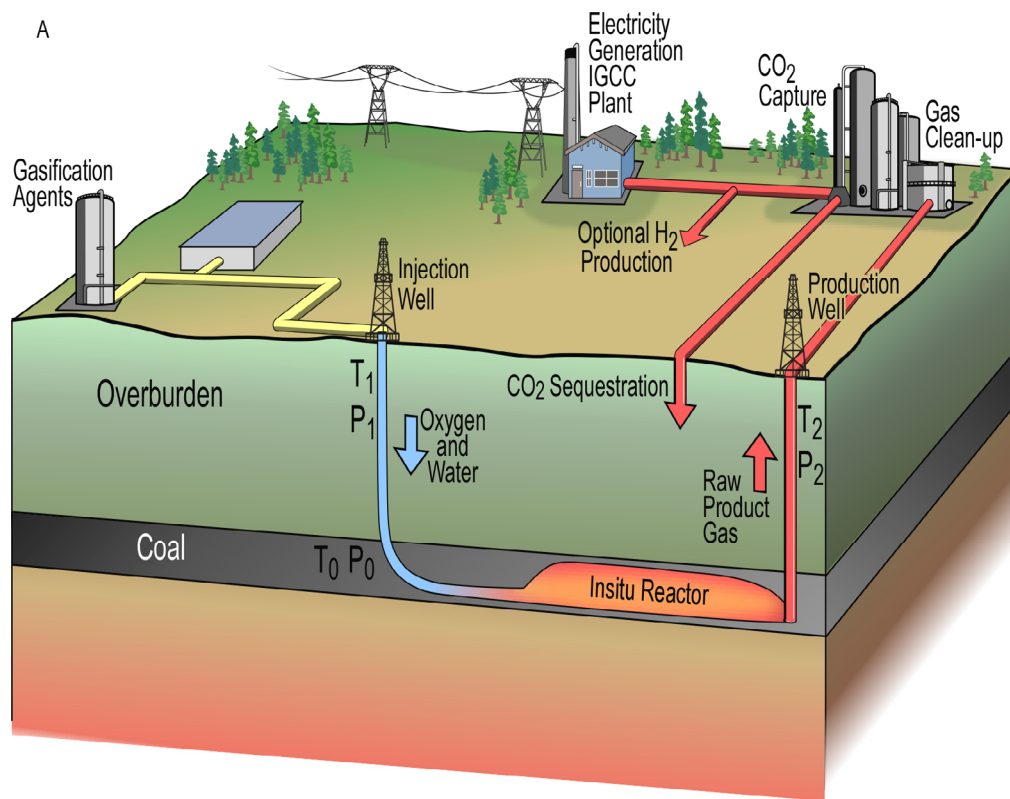
Figure 9. A) Underground coal gasification system and the input-output surface-operation modules, continuous retraction injection point (CRIP) drilling design; T_0P_0 = in situ temperature and pressure; T_1P_1 = temperature and pressure of the input oxidants; T_2P_2 = temperature and pressure of output gas (*after* UCG Engineering Ltd., 2006). B) Underground cavity residue (*after* Beath and Mallett, 2006).
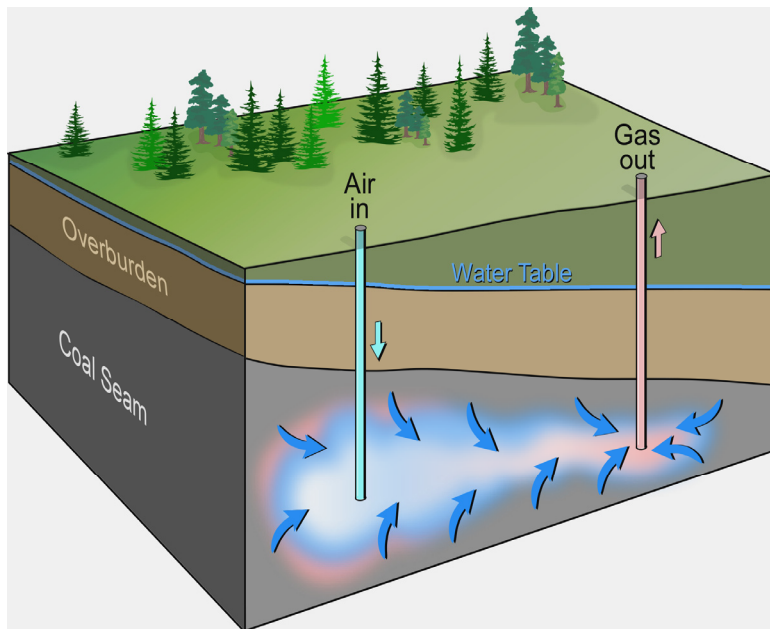
Figure 10. Underground pressure during combustion. The pressure in the gasifier is lower than the pressure in the coal seam and surrounding strata. No flow from the gasifier into the surroundings is allowed, thus preventing loss of product and escape of contaminants. The resulting pressurized gases are confined within the seam by overlying impermeable rocks and pore water, and are brought to the surface through the second borehole (*after* Blinderman and Jones, 2002).
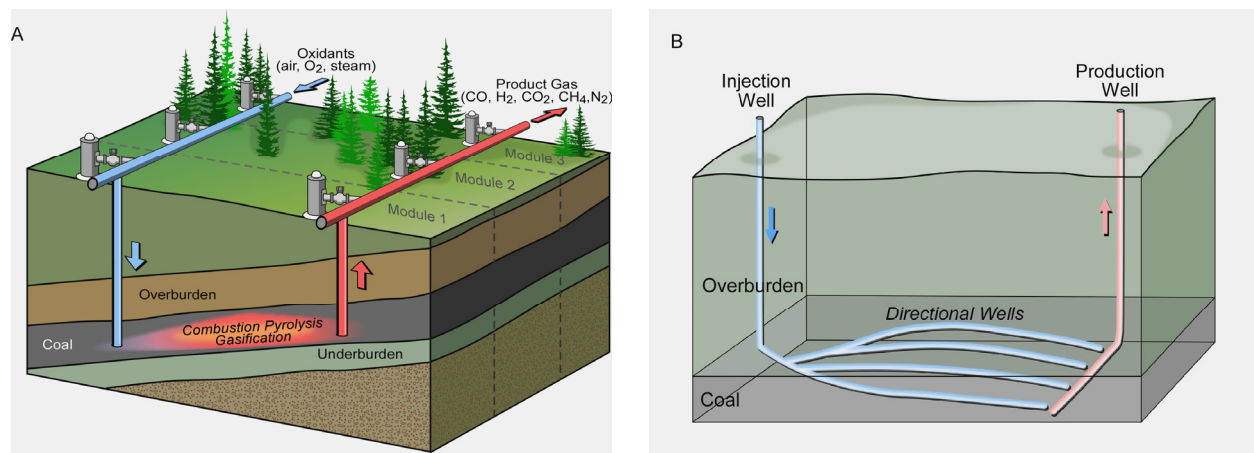
Figure 11. Underground coal gasification operation in an exploitation block using A) in-line distribution system of vertical wells (*after* Sawhney, 2006a); and B) variable well distribution using a multidirectional injection well connected to one directional production well (*after* Bharat Heavy Electricals Limited, 2006).

pipelines, respectively (A. Turta, pers. comm., 2009). The high-pressure production gas streams from different reactors are mixed to ensure a gas product of consistent quality. If required, the gas product captured at surface is directed to chemical plants for removal of contaminants.

More complex conventional coal-gasification power plants can be adjusted to receive syngas generated in conventional and unconventional gasification processes. Syngas is not a compatible feedstock for conventional coal-fired power plants. Coal-fired plants have a completely different technological concept, designed to process only mined coal in a combustion-boiler system (Figure 8; B. Gollpudi, pers. comm., 2009).

5.2.2 Fundamental UCG Chemical Reactions

'Gasification' is a general term used for various reactions, besides combustion, that result primarily in a gaseous mixture of CO, H_2 and CH_4. In both conventional and underground gasification processes, the chemical and physical changes are similar; however, the in situ coal naturally has higher methane and moisture contents than does the coal feedstock for conventional coal gasification, which has been ground and exposed to atmospheric conditions previously to the process. The volatiles and moisture generated from the in situ coal will undergo conversion under specific conditions (Kharchenko, 1997) and according to the following reactions:

1) **Oxidation (a), partial oxidation (b) and Boudouard reaction (c):**

   a) $C(s) + O_2(g) \rightarrow CO_2(g)$ (or combustion reaction), $\Delta H = -406.0$ kJ/mol

   b) $C(s) + \frac{1}{2}O_2(g) \rightarrow CO(g)$ (or partial combustion reaction), $\Delta H = -123.1$ kJ/mol
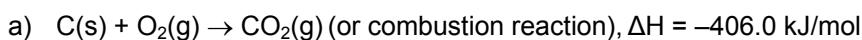
   Both the oxidation and the partial oxidation reactions provide energy as heat ($-\Delta H$) distally to the water-gas shift reaction (3).

   The concentration of CO_2 can be decreased by reacting CO_2 with coal at high temperatures to form CO (Boudouard reaction), involving an input of energy (heat):

   c) $C(s) + CO_2(g) \rightarrow 2CO(g)$, $\Delta H = +172.5$ kJ/mol

2) **Shift conversion (a) and methanation–hydrogenic gasification (b and c):**

   a) $CO(g) + H_2O(g) \rightarrow CO_2(g) + H_2(g)$ (or shift reaction), $\Delta H = -42.3$ kJ/mol

   b) $CO(g) + 3H_2(g) \rightarrow CH_4(g) + H_2O(g)$ (or reformation reaction), $\Delta H = -206.0$ kJ/mol

   c) $C(s) + 2H_2(g) \rightarrow CH_4(g)$ (or hydrogasification reaction), $\Delta H = -87.5$ kJ/mol
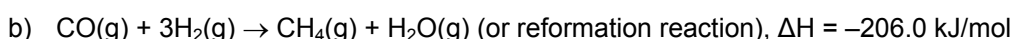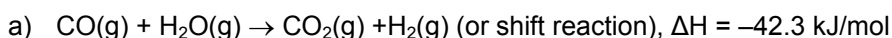
3) **Heterogeneous water-gas shift reaction:**

   $C(s) + H_2O(g) \rightarrow H_2(g) + CO(g)$ (or water-gas reaction), $\Delta H = +118.5$ kJ/mol

The water-gas reaction is the most important for generating the gas fuel mixture of mainly H_2 and CO, known also as 'water-gas' product. Note that the enthalpy of reaction is positive, which means that this reaction is endothermic. As a result, the preparation of the water-gas reaction typically involves alternating blasts of steam and either oxygen or air through a heated coal seam. The exothermic reactions between coal and oxygen to produce CO and CO_2 provide enough energy to drive the reaction between steam and coal. Additional steam in the injection blast generally lowers the temperature of the reaction zones and thus improves the efficiency of the gasification. Too much steam, however, slows the gasification due to further lowering of temperature in the reaction zone.

Product gas is itself considered a fuel because it oxidizes further to CO_2 and H_2O, releasing roughly 11.2 kJ/L of gas consumed. The product gas also contains CO_2 and other contaminants in a relative proportion. The product gas from which the CO_2 has been removed is called 'clean-up gas' and can be used as a feedstock for a variety of organic and inorganic components.

5.2.3 Operation Infrastructure Modules

The UCG system consists of three modules:

1) **upstream equipment**, comprising compressors for oxidants (air, oxygen), high-pressure water pumps, drilling rigs, structures for injection-production wells and the piping system;

2) **gasification equipment**, including mixing vessels for air, oxygen and/or steam, and igniters; and

3) **downstream equipment**, comprising gas-product pipelines from all production wells to the gas clean-up system, a flaring system of dust cyclones (in case of high ash content in the fuel gas), gas coolers, scrubbers, electro de-tarring equipment, and carbon dioxide (CO_2), sulphur oxide (SO_x: SO_2 and SO_3) and nitrogen oxide (NO_x: NO and NO_2) handling and storage devices (Burton et al., 2006).

5.2.4 Key Components of UCG Technology

A UCG operation is a complex process and represents a multidisciplinary effort that includes geology, geochemistry, hydrogeology, geomechanics, drilling, pipelines, and chemical, mechanical and process engineering (Burton et al., 2006).

There are three key components of UCG operations that can lead to commercial success:

1) good geological exploration,

2) adequate well-completion design, and

3) an advanced process-modelling system.

5.3 Geological Exploration for UCG

Coal-seam characteristics are important in modelling the process and monitoring the operation by predicting variability of the target coal. In addition, a successful UCG operation must include very good control of the characteristics of the adjacent rocks in terms of continuity, permeability and thermal properties.

Geological exploration for a suitable UCG site consists of several steps:

1) **Geological mapping** of individual coal seams, overburden and floor rocks, and intervening shale units

2) **Coring** of the complete coal interval, including the roof and floor rock, accompanied by detailed descriptions

3) **Laboratory analysis**, including petrography, volatile content, qualitative and quantitative determination of the inorganic components, calorific value, porosity, permeability, compressibility, gasification reactivity of the target coal and, eventually, distribution maps of the analytical data to give a complete depiction of coal and roof/floor rock characteristics

4) **Structural features** associated with the target interval, such as frequency, continuity and degree of infilling of joint systems, and other structural aspects, such as folds and faults

5) **3-D modelling** of the coal seam objective that combines the information available from laboratory analysis, paleoenvironmental reconstruction and structures with log analysis from oil and gas exploration wells to predict the variability in the coal and roof/floor rocks

6) **3D seismic survey**

7) **Aquifer pressure and hydrogeological modelling**

Summarizing the available international examples, optimum coal characteristics for the UCG process are

- coal seam thickness greater than 0.5 m, depth between 30 and 800 m, maximum inclination of 70° and predictable continuity;

- coal seams preferably in saturated conditions and not in the groundwater protection zone; however, undersaturated coals can be considered in special circumstances;

- coal seams with inherent permeability, although there are technological processes, such as reservoir fracture, to increase the permeability;

- preferably low rank (lignite and sub-bituminous) due to the content of volatile matter;

- higher reactivity, characterized by significant amounts of exinite (liptinite), vitrinite reflectance <0.8%, average amount of vitrinite + exinite (liptinite) >60%, volatile matter >35% and H/C atomic ratio >0.75%;

- relatively high calorific values (i.e., later stages of lignite and sub-bituminous); and

- as little mineral matter as possible and ash-fusion temperature as high as possible (lower Ca, Mg and Fe content).

Based on research at the University of California and Lawrence Livermore National laboratory (Burton et. al, 2006), the United States Department of Energy considers geology the key to the success and environmental safety of a UCG operation. They suggest as an operational target deep and geologically isolated coal seams with proven structural integrity. The adjacent deep aquifers should consist of saline (nonpotable) water and have stratigraphic seals. Deeper seams are less likely to be linked with potable aquifers, thus avoiding contamination of drinkable water and subsidiary problems.

Comparison of UCG operations in coal seams of varying thickness shows that thicker seams need fewer wells; however, the overall thickness of the coal seam should be greater than 2 m. Heat loss is considerably higher in thin seams, leading to low process efficiency and lower product quality. The dominant experience of the former Soviet Union, the United States and Australia is in relatively thick (2–18 m) and shallow (<500 m) coal seams. In contrast, European operations have targeted thinner (~2 m) and deeper seams (>700 m; Figure 12).

Other important geological factors are porosity and permeability of the coal seams. The deeper seams require guided drilling technology so the well can be deviated to intercept and follow the coal seam and to establish a link between injection and production wells (Burton et al., 2006). In this approach, there are techniques, such as forward and reverse combustion linking (FCL and RCL), to create the required level of permeability and other techniques to maintain permeability for optimum product-gas flow (Blinderman et al., 2008). The Indiana Center for Coal Technology Research (Bowen and Irwin, 2008) considers that the more permeable coal seams make it easier to link the injection and production wells, and increase the rate of gasification due to the easier reactant transport. However, some situations require particular attention, such as excessively high porosity and permeability that may cause a higher influx of water into the underground cavity and consequent loss of product gas.

The main characteristic of a UCG geological exploration project is the long-term operational plan. To ensure a convenient flux of UCG syngas supply to the power or chemical plant, a long-term project should include exploration for and development of other blocks in the surrounding area.
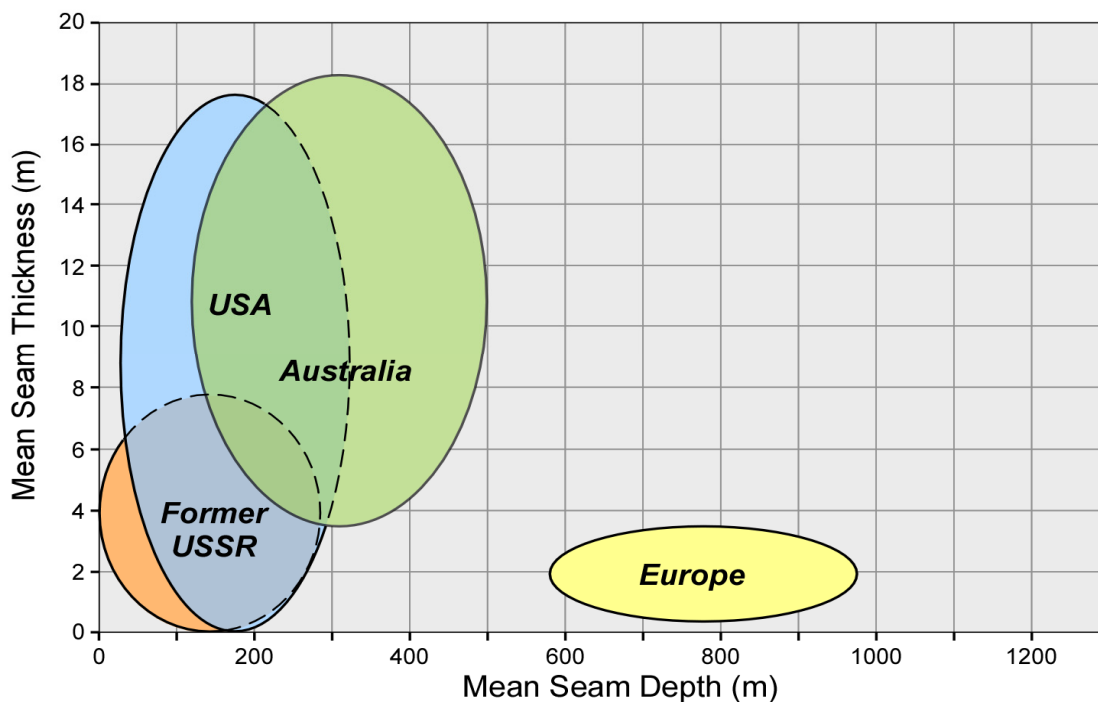
Figure 12. Coal seam depth and thickness of international underground coal gasification operations (*after* Burton et al., 2006).

5.4   Well Design for UCG

The following details are required on injection and production wells: well design and completion, type and size of casing, size and type of tubing, and cementation that is highly resistant to the injection temperature of >1000°C. Furthermore, the distance between injection and production wells should be based on coal-seam thickness and roof/floor geomechanical characteristics.

The following additional controls and instrumentation are beneficial: devices for sensing coal boundaries from down-hole drilling assemblies (upper and lower coal contact with adjacent lithological components), and a telemetry system to surface and other devices to control the connection of wells within the coal seams.

The UCG technology uses a variety of modern drilling methods, including high-precision directional drillholes, conventional vertical and inclined drillholes, various methods of well-linking, and a variety of designs for underground gasifiers. The UCG drilling models can be applied to coal in a wide range of geological conditions. The chosen design should balance the efficiency of coal exploitation with the operational cost (Burton et al., 2006).

There are three available UCG operational systems (Bharat Heavy Electricals Limited, 2006):

- Vertical wells generally coupled with air pressurization to open an internal pathway in the coal seam (former Soviet Union method; Figure 13A)

- In-seam control retraction injection point (CRIP), which uses wellbore technology adapted from heavy-oil recovery that can move the injection point during the process. The injection-production system consists of a directional well for injection and a vertical well for production; the opened interval moves backward from the production well, where the reservoir is ignited, to the injection well

(Figure 13B). When the combustion zone reaches the injection well, the injection of air will initiate a forward combustion (reverse combustion mode). The need for high reservoir permeability with the use of reverse combustion is stressed. It is also necessary to consider mechanical aspects of reverse combustion, air requirement, peak temperatures, velocity of the combustion front, mathematical models, field tests, and the evaluation of advantages and limitations of the process (Blinderman et al., 2008). This technology has been tested in Europe and successfully applied in Australia and the United States.

- Abandoned coal-mining galleries used as gasification channels and additional boreholes for product-gas capture (Chinese method; Figure 13C).

The wells can be arranged inline using multiple injection-production systems of vertical wells or directional wells with control retraction injection point (CRIP). If required, the arrangement of wells can be irregular to optimize the coal-seam potential. For instance, two to three injection wells can be connected to one production well (Figure 11B).

Where the target consists of multiple-seam packages, the UCG operational approach is from the uppermost target coal seam progressively downward through the section.

Within a particular UCG exploration area, it is possible to simultaneously pursue multiple activities, such as conventional and unconventional oil and gas production, open-pit or underground mining, and CO_2 storage. The exploration activities and CO_2 management can be applied independently at different target depths under rigorous planning.

5.5   Process Modelling for UCG

After the coal potential is evaluated for gasification and the suitable end market (power generation, chemical feedstock or synthetic pipeline gas) is defined, the UCG process goes through two major stages. The first stage establishes the operational parameters framework, including determination of injection pressure and temperature, type of ignition and oxidants, and process flow. The second phase consists of monitoring the ongoing operation (Burton et al., 2006).

5.5.1   Operational Parameters

Process parameters, such as operating pressure, inlet-outlet temperature and flow of product gas, are governed by highly variable coal characteristics and roof/floor rock properties. As the gasification front progresses, process conditions need to be continuously monitored. The monitoring system receives updated information as the underground gasifier develops. Process parameters must be adjusted to accommodate ever-varying gasification conditions. Simulation and modelling expertise are mandatory (Bowen and Irwin, 2008).

5.5.1.1   Operating Pressure

Generally, pressure increases with the depth of the coal seam. Higher pressure in the UCG working zone ensures no groundwater seep onto the gasifier cavity, but excessive pressure will increase the loss of product gas. An impermeable overburden helps provide a reasonable balance between pressure and gas loss.

5.5.1.2   Inlet Temperature

Ideal UCG temperatures of >1000°C (1832°F) are similar to those of conventional surface coal gasification. Achieving the ideal UCG temperature depends on careful control of the water influx and gas flow. Gasification temperature is normally estimated before the beginning of the operation by considering the input of certain oxidants, and it is monitored continuously during the operation.

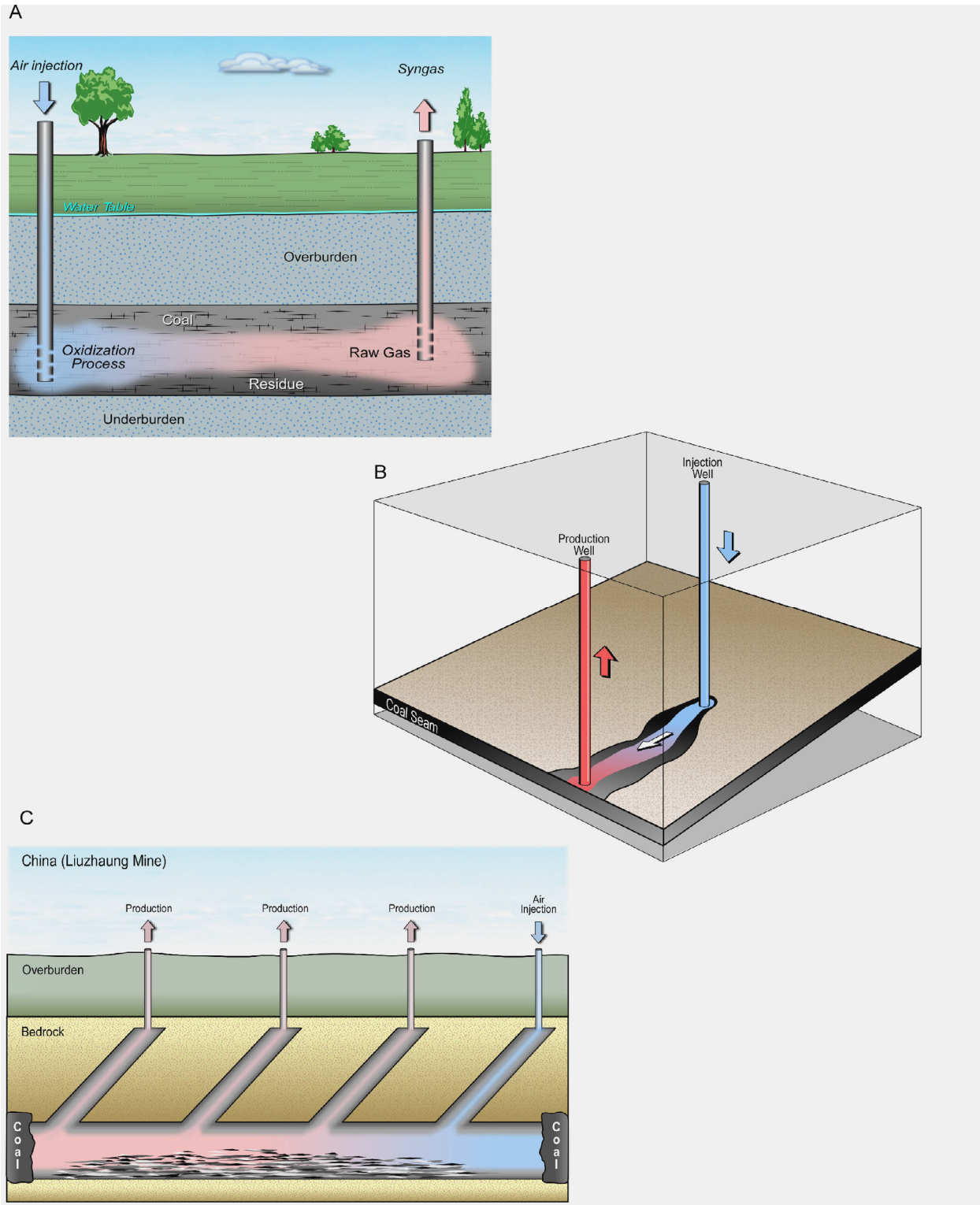**Figure 13. Models of drilling design for UCG operation: A) former Soviet Union model of vertical wells opening a horizontal coal seam; B) western European model (Spain) in deep and inclined coal seam with continuous retraction injection point (CRIP); and C) Chinese model using a combination of abandoned underground coal-mine galleries (reactors) and vertical wells for gas production (*after* Bharat Heavy Electricals Limited, 2006).**

5.5.1.3   Flow of Product Gas

Flow of fuel gas is an essential element of the UCG process. Several process components should be previously modelled and continuously monitored during the operation to ensure an optimal flow of fuel gas. These include

- studies on the effect of injection pressure, quality of oxidants (air/oxygen) and water seepage on the quality of product gas (composition and calorific value);

- gas flow and coal-to-char reactions, water flow and evaporation, and heat transfer (conductivity, convection and radiation);

- cavity performance (quality and volume) related to coal/char structural behaviour, and rock/coal breakage to prevent overburden collapse by resizing matrix with growth;

- computational studies on fluid dynamics; and

- mathematical modelling of the UCG process.

Most published models are limited to analyzing only part of the UCG process, but UCG research involves analysis of a complex system of interacting factors, such as geological elements, gasification process parameters and groundwater impacts. So far, all of the models require simplifying assumptions to permit solutions. Sharing of international experience in this area is of prime importance.

5.6   End Markets for UCG

The UCG process is designed for one major end market, such as power generation, chemical feedstock or a replacement for the traditional natural gas. Each of these requires a different technological approach.

A simplified scheme resulting from international experience (Sawhney, 2006b) shows two major process avenues for UCG: one involving air injection and the other involving oxygen and steam injection (Figure 14). In the air-injection process, the product gas will contain nitrogen as nitrogen oxides, higher amounts of carbon dioxide and consequently a lower calorific value. However, the air-injection process has been applied with good results at several commercial sites for power generation. In the oxygen- and steam-injection process, which has a higher operational cost, the product gas will be almost free of nitrogen and will contain smaller amounts of carbon dioxide, thus substantially increasing the calorific value. If the product gas is put through a cleaning-up process, in which all the contaminants including carbon dioxide are removed, the resulting 'clean-up gas' represents the feedstock for further chemical processes (i.e., production of pure H_2). Another option is to put the product gas resulting from oxygen and steam injection through an intense methanation process to obtain a methane-enriched gaseous mixture with high calorific value, essentially the highest calorific value that can achieved using the UCG process (Figures 14, 15). The methane-enriched gaseous mixture represents a replacement of natural gas with synthetic pipeline gas.

5.6.1   UCG Products

The important economic product of underground coal gasification (UCG) is syngas. The generic name 'syngas' is derived from the term '**syn**thesis **gas**.' The composition and production rate of the product gas is a direct function of 1) coal characteristics; 2) geological conditions; 3) pressure, flow rate and composition of the input oxidant; and 4) local conditions created during linkage and gasification (Penner, 1987).

Syngas may have less than half the energy value of natural gas and is readily combustible. It is often used as a fuel to produce electricity by combustion in a gas-turbine system, heat generation or as feedstock for the production of other chemicals. Another use is in the production of diesel-like synthetic fuel via the
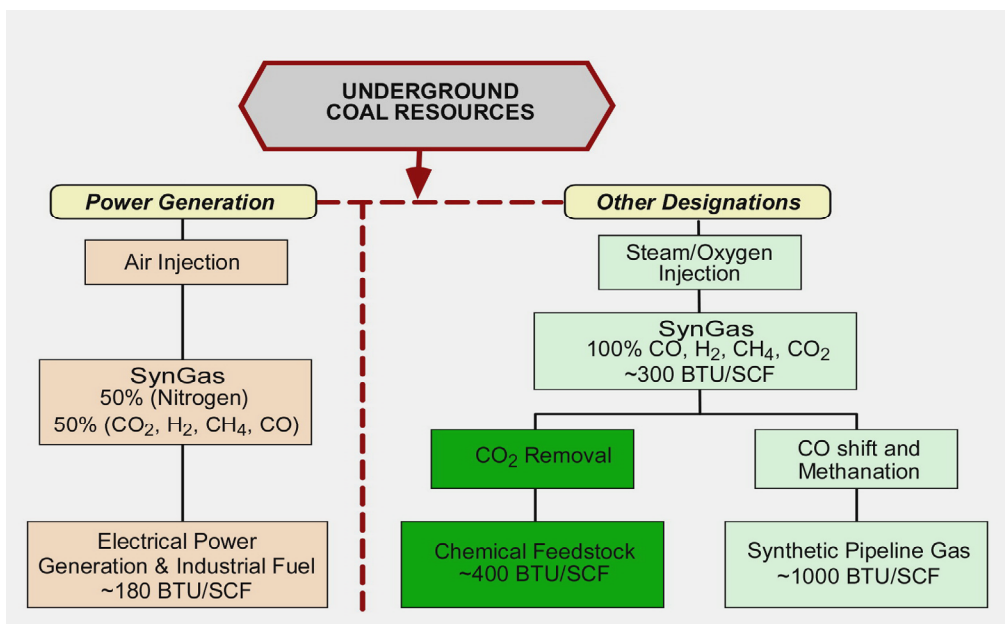
Figure 14. Schematic diagram of UCG end markets based on the types of oxidants injected (lignite from India); note the change of calorific value as a function of process applied (*after* Sawhney, 2006b).

Fischer-Tropsch catalytic synthesis process, or in the Mobil methanol-to-gasoline process to produce synthetic fuel or lubricant.

For thermal applications, syngas burns cleanly into water vapour and carbon dioxide:

$$2CO(g) + H_2(g) + 2O_2 \rightarrow 2CO_2(g) + 2H_2O(g) \text{ (exothermic)}$$

Alternatively, syngas can be converted efficiently to methane via the Sebatier reaction or the reaction of hydrogen with carbon dioxide at elevated temperature and pressure in the presence of nickel catalyst to produce methane and water:

$$CO_2(g) + 4H_2-(g) \rightarrow {}^{(catalyst: Ni)} \rightarrow CH_4(g) + 2H_2O(g)$$
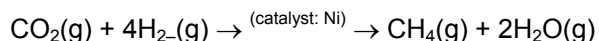
Another route for producing methane or synthetic pipeline gas (SPG) is:

$$CO(g) + 3H_2(g) \rightarrow CH_4(g) + H_2O(g)$$

$$2CO(g) + 2H_2(g) \rightarrow CH_4(g) + CO_2(g)$$
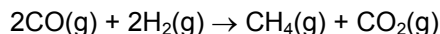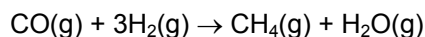
Syngas is a valued source of pure H_2, considered the cleanest and most efficient unconventional fuel (Pimentel et al., 1994). The combustion of hydrogen with oxygen to give pure water and energy is used in rocket engines:

$$2H_2(g) + O_2(g) \rightarrow 2H_2O(g) + \text{energy (heat)}$$
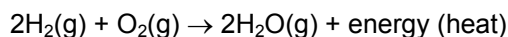
Syngas can be used in the synthesis of ammonia:

$$N_2(g) + 3H_2(g) \rightarrow NH_3(g)$$
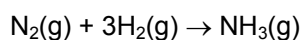
It can also be used to produce methyl alcohol or methanol:

$$CO(g) + H_2(g) \rightarrow CH_3OH(l)$$
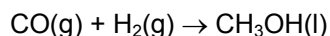
Methanol then can be used as a starting material for the synthesis of alkenes, aromatic compounds, acetic acid, formaldehyde and ethyl alcohol (ethanol).

Geological, technical and environmental considerations will govern the product stream and overall suitability of a site UCG for development. Commercial factors, such as the volume and characteristics of the coal resource, by-products and disposal solutions, and the market for the product gas, are also critical in the development of a UCG project of any size.
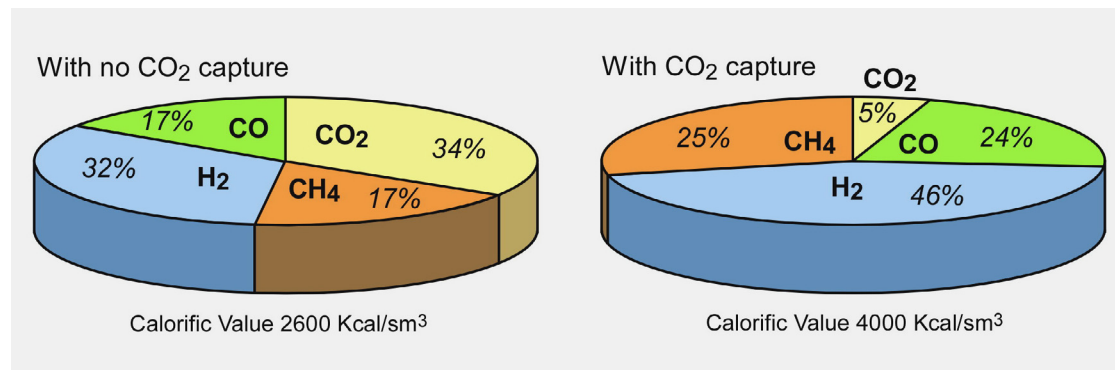
Figure 15. Example of increase in calorific value of syngas by capturing CO₂ (sub-bituminous coal from Australia; *after* Blinderman and Jones, 2002).

5.6.2 UCG By-Products

The secondary or incidental products deriving from the UCG process are considered by-products. Some of these UCG by-products are useful and marketable in small amounts, whereas most have negative environmental impact. According to clean coal technology constraints, modern UCG engineering designs include the intermediate products of the process and integrate them into other beneficial technological processes or discard them in an environmentally safe manner.

There are two major categories of by-products from the UCG process:

- **Cavity deposits** consist of roof-rock fragments, ash rubble (represented by coal mineral matter) and char rubble. The ash rubble is similar to the bottom ash in conventional coal-fired power plants. Bottom ash within the reactor cavity results from the decomposition and alteration of coal mineral matter and unburned carbon. The mineralogical composition of coal is known to have a significant influence on the amount and speciation of elements during or as a result of combustion (Goodarzi et al., 2002; Helle et al., 2003). When the UCG operation is closed, this type of deposit remains in situ and can be the subject of later groundwater contamination if not appropriately deactivated or cleaned up. The contamination relates mainly to the potential concentration of trace minerals.

- **Released residues** are fine-size particles and gases that have escaped from the reactor cavity. These by-products are discarded by the system as fly ash and flue gases at the surface, and they require special attention to prevent air contamination. Most fly ash consists of silicates and a fraction of unburned carbon (Hower et al., 2000; Goodarzi et al., 2002). The unburned carbon content in fly ash can be as high as 60% (Curtis, 1994), and approximately 99.8% of the fly-ash content is removed by the electrostatic precipitator (ESP). It was observed that fine fly-ash particles have a higher concentration of mercury (Hg) than the coarser fraction with higher carbon content (Sakulpitakphon et al., 2004).

The content and type of coal combustion by-products depend mainly on the rank and petrographic components of the coal, the type and quantity of oxidants, and operational parameters. As previously

discussed, coal petrographic components, or macerals, behave differently during combustion. Reactive macerals burn rapidly, whereas nonreactive macerals form slow-burning chars. Small particles escape and are captured by an electrostatic precipitator or fabric-filter pollutant control. Liptinite and vitrinite groups and some of inertinite types (e.g., semifusinite) are reactive to combustion. Liptinite that is derived from hydrogen-rich waxes, spores, pollens and resins is readily volatilized during combustion and produces essentially no char (unburned carbon). Vitrinite contributes in a minor way to the char in fly ash (Hower et al., 2000). The nonreactive group consists mostly of inertinite components, particularly inertodetrinite. Inertinite-rich coal burns about three to four times longer than vitrinite-rich coal (Wall et al., 1992). The inertinites that formed at high temperatures in forest fires and peat fires (temperature up to 600°–700°C), or by in situ weathering and oxidation of vegetal matter, escape the in situ combustion system and are carried away by flue gases to the electrostatic precipitator.

The amount of unburned carbon in fly ash depends also on the rank of the coal (Bailey, 1992). According to Jones et al. (1985), char porosity reaches a peak for parent coals between sub-bituminous and high-volatile bituminous rank. As well, chemical reactivity or burning rate is at a maximum between these ranks due to a combination of poor molecular ordering and high porosity, which permits maximum intraparticle diffusion of the reactant.

Another type of released residue is flue gases: carbon dioxide (CO_2), sulphur oxides (SO_x) and nitrogen oxides (NO_x). These emissions are harmful to environment if not appropriately captured (Suarez-Ruiz and Crelling, 2008).

The most significant flue by-product is carbon dioxide (CO_2). The UCG process accompanied by carbon capture and disposal (CCD) has been the central theme of the Underground Gasification Partnership Conference (Underground Coal Gasification Partnership, 2008), providing evidence of international effort to implement near-zero emission technology. However, in contrast to the harmful aspects of CO_2 emissions, there are some technological uses for the CO_2. The United States, Europe, Japan, and Australia are looking at the potential of CO_2 in catalysis, chemical synthesis, and polymers. Research is underway on liquid and supercritical CO_2 stages for potential industrial processes and applications. When CO_2 is compressed to a liquid or, above its critical point, to a supercritical fluid, it can be used in chemical processes that are less harmful to the environment than their predecessors (i.e., hazardous solvents replacement). Frequent uses of CO_2 include refrigeration (dry ice), fire fighting, fire extinguishers and carbonated beverages.

When CO_2 is a technological by-product emitted in quantities exceeding any potential industrial use, there is reason to capture and store it in repository such as lithogeological units and/or terrestrial ecosystems (Rogner et al., 2007). Each of these options has opportunities, challenges and operational costs involved. Lithogeological units include depleted oil and gas reservoirs, nonmineable coal seams, deep saline formations, oil- and gas-rich shales, and basalt units (Figure 16). As a value-added, CO_2 injected into a mature oil reservoir enables incremental oil to be recovered. For instance, a CO_2 flood enables recovery of an additional 10–15% of the original oil-in-place. Injection of CO_2 into coal seams can lead to enhanced CBM production, and a similar process can be applied to gas-rich shale deposits. Terrestrial ecosystems refer to the enhancement of carbon storage in soils as an opportunity for low-cost CO_2 storage.

Another group of UCG flue by-products is the sulphur oxides. Sulphur oxides consist mainly of sulphur dioxide (SO_2) and smaller amounts of sulphur trioxide (SO_3). Both gases are toxic in higher concentrations to living organisms. In coal, sulphur may be present in small quantities in its native form (pure element), in inorganic compounds (sulphide and sulphate minerals) and bonded in organic combinations. During coal combustion, sulphur combines with oxygen to form sulphur dioxide (SO_2). When the oxygen level exceeds the amount required to produce SO_2, sulphur trioxide (SO_3) is formed. The natural reaction of SO_2 and/or SO_3 with water, usually in the presence of NO_2 catalyst, forms

sulphuric acid (H_2SO_4), the principal cause of acid rain. Acid rain is a significant environmental concern associated with the use of coal in not-yet-modernized conventional power plants. However, flue-gas desulphurization is a technology that enables sulphur dioxide to be chemically bound to calcium oxide (lime) to form calcium sulphite:

$$CaO + SO_2(g) \rightarrow CaSO_3$$
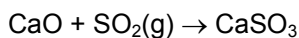
Aerobic oxidation converts $CaSO_3$ into $CaSO_4$. Most gypsum ($CaSO_4 \cdot 2H_2O$) manufactured in Europe comes from flue-gas desulphurization.
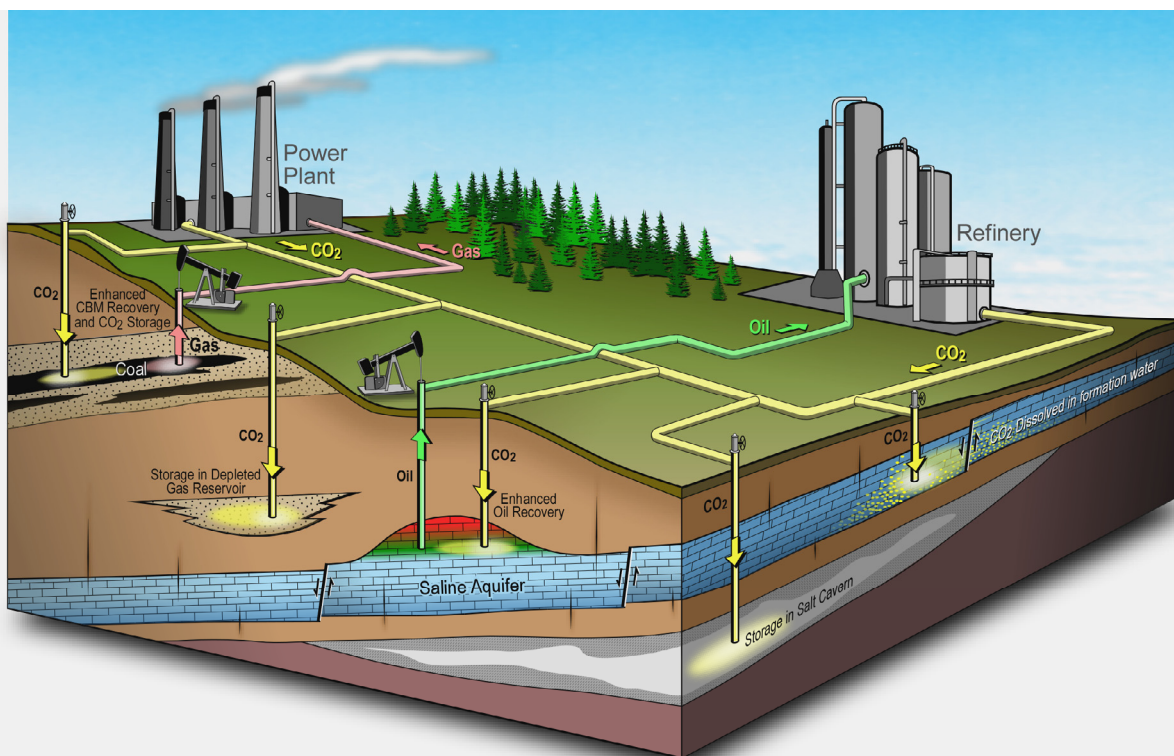
Figure 16. Options for CO$_2$ storage in depleted oil and gas reservoirs, coal seams and salt caverns (Alberta Geological Survey, 2009a).

Sulphur dioxide itself is used in small quantities as a food preservative and a refrigerant. It is a versatile inert solvent for dissolving highly oxidizing salts and is used occasionally as a source of the sulphonyl group in organic synthesis. In urban wastewater treatment, sulphur dioxide is used to treat chlorinated wastewaters.

Another use of the flue-gas mixture of SO_2 and SO_3 is the manufacture of sulphuric acid, considered one of the most important industrial chemicals. The method of converting sulphur di- and tri-oxide to sulphuric acid is called the contact process, and it consists of two steps that generate sulphurous and sulphuric acid:

$$SO_2(g) + H_2O(g) \rightarrow H_2SO_3(g) \quad \text{and} \quad SO_3(g) + H_2O(g) \rightarrow H_2SO_4(g) \ (-88 \text{ kJ/mol})$$
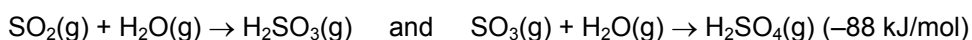
Sulphur trioxide (SO_3) represents the anhydrous form of sulphuric acid (H_2SO_4). The reaction with water occurs both rapidly and exothermically. At 340°C, sulphuric acid, sulphur trioxide and water coexist in significant equilibrium concentrations.

More than 50% of the sulphuric acid produced each year is used to make fertilizers. The rest is used to make paper, synthetic fibres and textiles, insecticides, detergents, feed additives, dyes, drugs, antifreeze, paints and enamels, linoleum, synthetic rubber, printing inks, cellophane, photographic film, explosives and automobile batteries. It is also used in the production of steel and such metals as magnesium, aluminum and iron.

The third UCG flue by-product is the nitrogen oxides (NO_x). In addition to NO and NO_2, the nitrogen oxides may also include a mixture of other binary compounds of oxygen and nitrogen in small proportions: nitrous oxide (N_2O), dinitrogen trioxide (N_2O_3), dinitrogen tetroxide (N_2O_4) and dinitrogen pentoxide (N_2O_5). The Kyoto Protocol classifies only nitrous oxide (N_2O) as a greenhouse gas due to its impact on the formation of tropospheric ozone, and calls for substantial world-wide reductions in its emission. However, the nitrogen oxides NO and NO_2, even in minimum concentrations of 40–100 μg/m^3 in air, are considered extremely toxic to living organisms. In the atmosphere, the nitric oxides eventually form nitric acid, which contributes to acid rain.

In coal, nitrogen originates in plant nutrients and occurs in minor quantities bonded to organic groups. In the UCG combustion process, particularly during combustion with air injection, the temperature is high enough to drive endothermic reactions between atmospheric nitrogen and oxygen, yielding various oxides of nitrogen. The two gases do not react under atmospheric conditions but, at combustion temperatures above 1000°C, molecular nitrogen (N_2) and oxygen (O_2) dissociate into their atomic states and participate in a series of reactions. The product gas from the combustion process with air injection will contain significantly higher amounts of nitrogen oxides than the product gas from oxygen and steam injection. Limiting the production of nitrogen oxides requires precise control of the amount of air used in combustion. An excess of air relative to that required for complete combustion of the coal introduces more nitrogen into the system, which can generate even nitrous oxides (N_xO_y) in the product gas.

It is possible to chemically revert the nitrogen oxides (NO_x) back into nitrogen and water using either a selective catalytic reduction unit (SCR) or a selective noncatalytic reduction procedure (SNCR). In coal-fired power plants, SNCR is the conventional method applied to reduce nitrogen oxide emissions. The process involves injection of ammonia or urea into the boiler, where the flue gas is between 870°C and 1150°C (1600°F and 2100°F), to react with the nitrogen oxides formed during the combustion process. The resulting products are elemental nitrogen (N_2), carbon dioxide (CO_2) and water (H_2O). Technologies such as flameless oxidation (FLOX) and steam injection have been developed to reduce the formation of nitrogen oxides. Flameless oxidation works by suppressing the peak flame temperature. Steam injection technology introduces water into the combustion chamber to reduce the formation of nitrogen oxides, thereby increasing the overall efficiency in the combustion process.

Nitrogen dioxide (NO_2) is an intermediate product in the industrial synthesis of nitric acid, with millions of tonnes being produced each year.

5.7 Worldwide Development and Application of UCG Technology

The UCG process has been known since the beginning of the 20th century; however, its development at the international level has been slow and inconsistent for various reasons. National research programs on UCG have been undertaken during the past 80 years in the former Soviet Union and since the 1980s by Western Europe, the United States, China, India and Australia (Figure 1B). A recent favourable combination of factors has provided the opportunity for the process to become commercially viable by optimizing the technological parameters and reducing the impact on the environment (Burton et al., 2006). These factors include competition in the power industry, such as the demand for lower greenhouse-gas emissions from coal-fired power generation, a shift toward gas as a preferred fuel and a reviving interest in the production of synthetic fuels.

5.7.1 Former Soviet Union

The former Soviet Union (FSU) initiated a national program of UCG research and development in 1928, with underground operations beginning in 1933. Soviet UCG technology was confronted with numerous geological problems that resulted in a variety of operational designs. By the 1950s, the FSU had developed a successful UCG system, which was applied in the flat-lying beds of the coal fields near Moscow and in steeply dipping beds in Siberia and the Donets coal basin. The experience of the FSU has demonstrated that UCG can operate successfully in a variety of geological settings and under complex conditions created by cavity subsidence and collapse. So far, industrial-scale UCG applications in the FSU have gasified more than 17 million tonnes of underground coal.

5.7.2 Europe

Belgium developed the method of linking wells by continuous retraction injection point or reverse combustion (CRIP) for deep coal seams. The experiments (1982–1984) were successful and now CRIP is one of the technologies in widespread use. France (1983–1984) conducted experiments to develop a better understanding of coal reactivity and the hydraulic properties of linking wells using reverse combustion. Spain (1992–1999) tested the use of directional in-seam drilling to construct the well configuration and to evaluate the feasibility of gasification using the CRIP process at depths greater than 500 m.

5.7.3 Australia

The Chinchilla project, 350 km west of Brisbane in Queensland, started in 1999 and is the largest underground coal gasification project outside the former Soviet Union. The project ran for more than 30 months, with 35 000 tonnes of coal gasified. The technique achieved 95% economic upturn of the coal resources, with 75% total energy recovery. The operators (Ergo Exergy Technologies Inc., 2005; Linc Energy Ltd., 2008) plan to expand the current Chinchilla project (World Coal Institute, 2007a). The long-term goals of the Chinchilla project are power generation and liquid fuels production using gas-to-liquid Fischer-Tropsch synthesis technology. During the tests, nine wells were drilled, producing syngas from a 10 m thick coal seam at a depth of about 140 m, at a rate of 80 000 Nm^3/h, equivalent to 70 MW. The gasified coal generated more than 80 000 000 Nm^3 of syngas produced with low heating value (LHV) of 5.0 MJ/Nm^3, pressure of 10 bars (145 psi) and temperature of 300°C. The project is currently being expanded to include a gas-turbine and gas-cleanup plant.

5.7.4 United States

A number of UCG pilot tests were undertaken through the joint efforts of industry, research institutes and government agencies to study the economic viability and environmental acceptability of the UCG process. The most recent field experiment was a joint industry–Department of Energy UCG test conducted in Wyoming in 1987–1988, known as Rocky Mountain 1. Based on the results of this pilot demonstration, the cost of the UCG gas produced via directionally drilled wells was US$2.20/mmBtu, and the operation met environmental requirements.

5.7.5 China

China has emerged as a UCG technology leader and has invested in extensive research programs. China has huge reserves of coal, estimated at 114 trillion tonnes of variable rank and grade and ranging from high to low ash content, generally with high sulphur content. Since late 1991, 16 pilot programs have either been completed or are currently operating. In addition to the common UCG process applied elsewhere, some of the experiments in China have explored another type of UCG technology in which abandoned small coal mines are used as gasifiers. Presently, UCG provides syngas as feedstock for commercial fertilizer and chemical plants. It appears that Chinese companies and government entities are accelerating the development of commercial UCG, supporting the notion that UCG economics are favourable.

5.7.6 India

The Indian economy is growing steadily, limited only by the availability of energy and infrastructure. More than half of the power produced in India is from coal. India has huge reserves of coal, estimated at 467 billion tonnes of mainly sub-bituminous and bituminous with 35%–50% ash content. Sixty-six per cent of the estimated reserve is considered a potential candidate for UCG technology. The syngas will be produced through UCG operations and is intended for power generation.

5.7.7 Japan

Japan, which has substantial coal interests outside of its borders, has included UCG in its future plans for coal exploitation. For many years, Japan has maintained a low-level research program on UCG technology. However, Japan is currently showing interest in trial sponsorship overseas as the result of recent economic and technical studies. Japanese coal companies are also interested in the UCG technology as a possible export opportunity.

5.7.8 Canada (Alberta)

The first attempt to test the suitability of Alberta coal for the UCG process, led by the Alberta Research Council in 1974, targeted the Drumheller coal seams (287 m drilling program) at Halkirk, southeast of the Battle River Power Station (Vogwill, 1976). The suitability of the coal seams for the UCG process was studied by testing the horizontal permeability distribution and the direction and magnitude of higher permeability, both of which have been considered to control the direction of the coal-burning front during gasification testing. The next stage of the pilot testing was suspended. The first complete study of UCG in Alberta, conducted by the Alberta Research Council in 1976 (Roehl et al., 1976), used air injection. The test site was located south of Forestburg, close to the Paintearth-Vesta coal mines, and targeted a 3.6 m sub-bituminous coal seam of the Horseshoe Canyon Formation at a depth of approximately 20 m. The test involved the study of ignition and linking between wells, additional post-burning hydrogeological tests (formation water analyses), in situ residue analyses and environmental impacts during and after the test was performed (e.g., surface subsidence). The results of the pilot test were positive in terms of operational flux with no surface subsidence recorded.

Since the summer of 2008, two pilot projects have been proposed to test the UCG process, one targeting the Ardley coals west of Edmonton and the second the upper Mannville coals in the Swan Hills area (Figure 17). The Mannville target involves a new technological challenge testing coal seams deeper than 800 m. The results of both pilot tests will be of the utmost interest for scientific and industrial purposes.

5.8 Assessment of the UCG Technology

5.8.1 UCG Potential

There are at least three major criteria to be considered when evaluating the UCG technology as an important option in the present-day economic and environmental context: 1) accessibility to an otherwise uneconomic coal resource, 2) process efficiency (power generation and chemical feedstock) versus operational cost, and 3) control of the environmental impact (Burton et al., 2006).

The UCG process offers accessibility to uneconomic coal resources. It can be applied to multiple layered seams, thereby saving part of the operational cost. In a large exploration area, it is possible to have concurrent activities, such as oil and gas exploration, coal mining and UCG, at different target depths.

Process efficiency versus operational cost favours UCG because no coal mining, manipulation or transport is involved. No ash/slag removal or handling is necessary, since the inert material remains predominantly in the underground cavities. Underground coal gasification can be connected to existing chemical plants. Syngas can be used to generate electricity with a power efficiency as high as 55% and

the overall efficiency of UCG-IGCC process reaching 43%. For instance, the energy potential of about 1000 MW of power can be generated from a small block of coal measuring 25 km² in area by about 10 m thick. The efficiency of the process also means very low rates of greenhouse emissions per unit of net power generated and half the quantity of water required compared to conventional coal-fired power plants. The syngas is produced under pressure and at moderately high temperature (~300°C), and easily lends itself to CO_2 removal by a range of standard methods, with low energy penalty and at relatively low cost.

The environmental effect of UCG is considered less than surficial gasification or coal-fired power generation due to reduced emissions, no appreciable change in the landscape and no surface disposal of ash and coal tailings. Some of the potential UCG sites are also potential CO_2 sequestration sites. Captured CO_2 can be stored in the underground cavities created by coal removal during UCG operations. The energy penalty and relative cost of CO_2 compression and injection are comparatively low. As well, the CO_2 can be stored in deep saline aquifers and deeper coal seams, or used for oil, natural gas and CBM enhanced recovery (Figure 15).
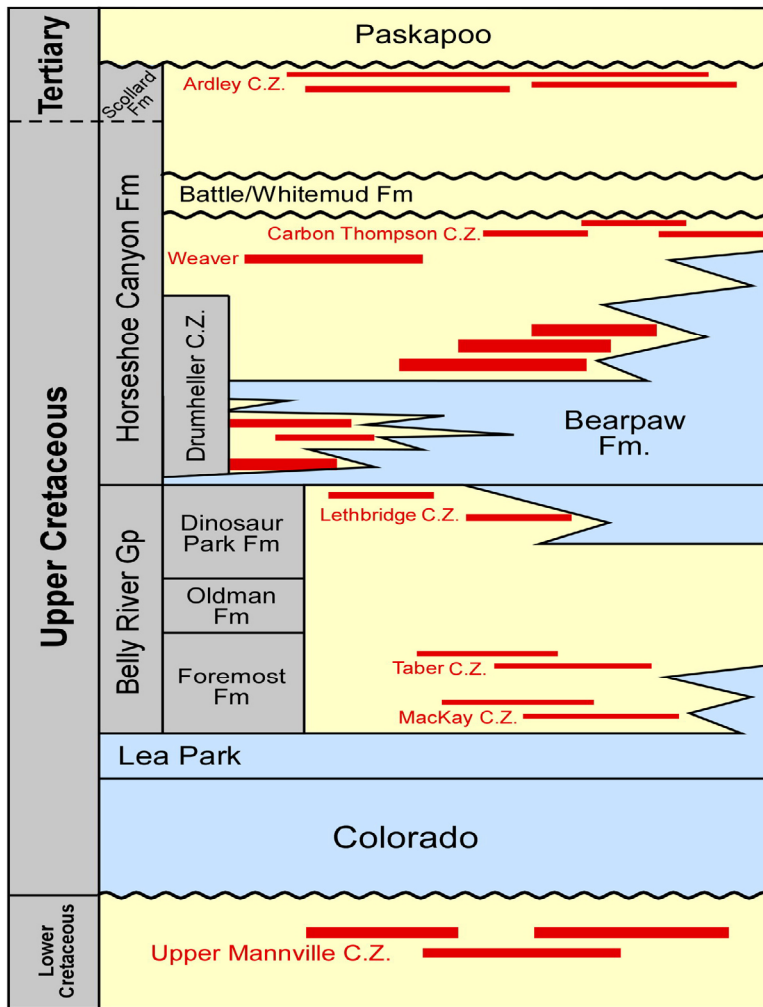

Figure 17. Stratigraphy and coal zones of central Alberta.

5.8.2 UCG Risk Factors

The risk factors associated with the UCG process are related to technological, economic and environmental issues (Burton et al., 2006).

Underground coal gasification, like any other unconventional process, depends on the rate of technological advancement. Any technological advance in this or a related field is sooner or later reflected in enhanced syngas production with reduced emissions relative to conventional coal combustion and at lower overall cost. The greater the economic interest, the more accelerated will be the UCG technological progress.

The UCG technological and environmental risk factors can be summarized as cavity collapse or roof subsidence, and groundwater contamination. The performance of the UCG operation depends on a number of factors and can be improved by more comprehensive combustion/gasification simulation models and monitoring processes:

- The injection pressure needs to be established in advance and monitored cautiously throughout the operation to maintain a balance between the pressure in the reactor and hostrock water flow, minimizing coal swelling by creating large-dimension channel cavities.

- The cavity space should be modelled in advance by considering the roof-rock geomechanics and structural context, to prevent cavity collapse; this collapse can be manifested as subsidence or seismic activity, during or after operation.

- The burning front during the operation should be continuously monitored. Depending on the intrinsic geomechanical properties of the coal and roof/floor rock type, the UCG operations variably alter the initial characteristics of the coal and roof/floor successions through the thermal and geomechanical stress fields.

- Well construction materials need to withstand elevated temperatures and corrosion caused by injected and produced fluids.

- Avoiding selection of prospect intervals that are not well understood geologically (i.e., low coal seam continuity, discontinuous seal, sandy overlying units) could mitigate the risk of leakage.

- Liquid accumulation at the bottom of the coal seam should be under rigorous control to avoid gas flow circulation restricted to the top of the cavity and the flame front getting too close to the roof rock.

- Appropriate closure and abandonment of the in situ cavity to prevent subsequent groundwater contamination is mandatory; the closure process usually includes washing the cavity after the operation is shut down.

- Removal of contaminants from released residue (fly ash and flue gases) is also mandatory and is normally incorporated in the design of the existing power or chemical plant.

6 Alberta Potential for the UCG Process

Alberta has approximately 40% of Canada's coal resources (Figure 3). The major coal accumulations in Alberta occur in specific stratigraphic intervals of the Cretaceous–Tertiary clastic succession (Figure 17). The succession consists of the following lithological components: sandstone, siltstone, mudstone, shale, bentonite, tonstein and coal. The proportion and regional distribution of the lithological components vary slightly over geological time, but sandstone, siltstone and mudstone are generally dominant. The coal-peat accumulated in the Cordilleran foreland in association with fluvial and marginal-marine–complex deposits. The Laramide orogeny (Late Cretaceous–Tertiary) generated a displacement of the western part of the foreland basin and, as a result, part of the coal deposits is now incorporated into the foothills

structure; furthermore, the Cordilleran tectonism implied basin-wide structural rearrangements leading to the present-day asymmetry of the foreland deposits that deepen and thicken westerly. During the eastward advancement of the Cretaceous–Tertiary fold-and-thrust belt, younger deposits were preserved closer to the deformation belt, whereas substantial erosion took place in the eastern part of the foreland, leading to the exposure of coal deposits in older strata. Close to the erosional edge, active open-pit mines are extracting Tertiary coals at Whitewood, Highvale and Genesee, west of Edmonton. The mined coal supplies the Keephills, Wabamun and Sundance coal-fired power plants. Two other mines south of Edmonton, Paintearth and Sheerness, provide feedstock from the uppermost Cretaceous coal deposits to the Battle River and Sheerness power plants (Figure 18).

According to ERCB/AGS, the underground coal resources of Alberta are concentrated in the foreland area and estimated at 4 trillion tonnes (Beaton et al., 2002; Beaton, 2003). The coal deposits are regionally extensive and may consist of single or multiple coal seams. The UCG process can be applied in a variety of locations, and essentially any of the coal zones can be a potential candidate for UCG. Each of the locations has opportunities and challenges.

Considering the international criteria for UCG, it appears that the Cretaceous–Tertiary clastic succession of the Alberta foreland basin contains two categories of coal zone: one with primary potential that meets most of the criteria, and another that satisfies only some of the criteria and is therefore considered of secondary suitability.

The secondary category includes predominantly single-coal-seam deposits such as the Taber and McKay coal zones of the Belly River Group, and the Weaver and Carbon-Thompson coal zones of the Horseshoe Canyon Formation (Figure 17). These four coal zones are the result of fluvial depositional conditions and consist generally of thin and discontinuous coal seams with higher ash content. The lower level of predictability of coal seam continuity and high ash content may cause difficulties in modelling the UCG operation. The overall coal seam thickness of less than 2 m can also lead to higher heat loss during the UCG process. However, this generally unfavourable characterization does not rule out the possibility of identifying—through detailed subsurface geological mapping—locations with good potential for UCG within any of this group of coal zones.

The coal zones with primary potential for extensive UCG operations are characterized by multiple–coal-seam packages in which at least one of the seams is thicker than 2 m. This category includes the Ardley coal zone in the Scollard Formation (Paleocene), the Drumheller coal zone in the lower part of the Horseshoe Canyon Formation (Maastrichtian) and the Mannville coal zones (Aptian–Albian; Figure 18). These same coal zones are in-production CBM targets and tests sites for CO_2 storage. The most intense CBM exploration activity targets the Horseshoe Canyon lower coals, which consist of numerous and relatively thin coal seams opened and producing simultaneously.

For this report, three areas have been selected to show specific characteristics of Alberta's coal zones. These are schematically illustrated in Figures 19–21.

Analysis of the coal geometry and depth in the selected areas indicates that the Horseshoe Canyon Formation south of Edmonton (Twp. 36–45, Rge. 20–23, W 4th Mer.) has the shallower coal deposits, at about 150 m depth. The lower part of the succession has a remarkable number of coal seams that are sometimes separated by relatively thin intervals (5–15 m). Also, coal seams 3–4 m thick may occur within the succession. Silty mudstone and silty shale are the dominant lithological components in the succession. Coarsening-upward sandstone units are observed less frequently (Figure 19).

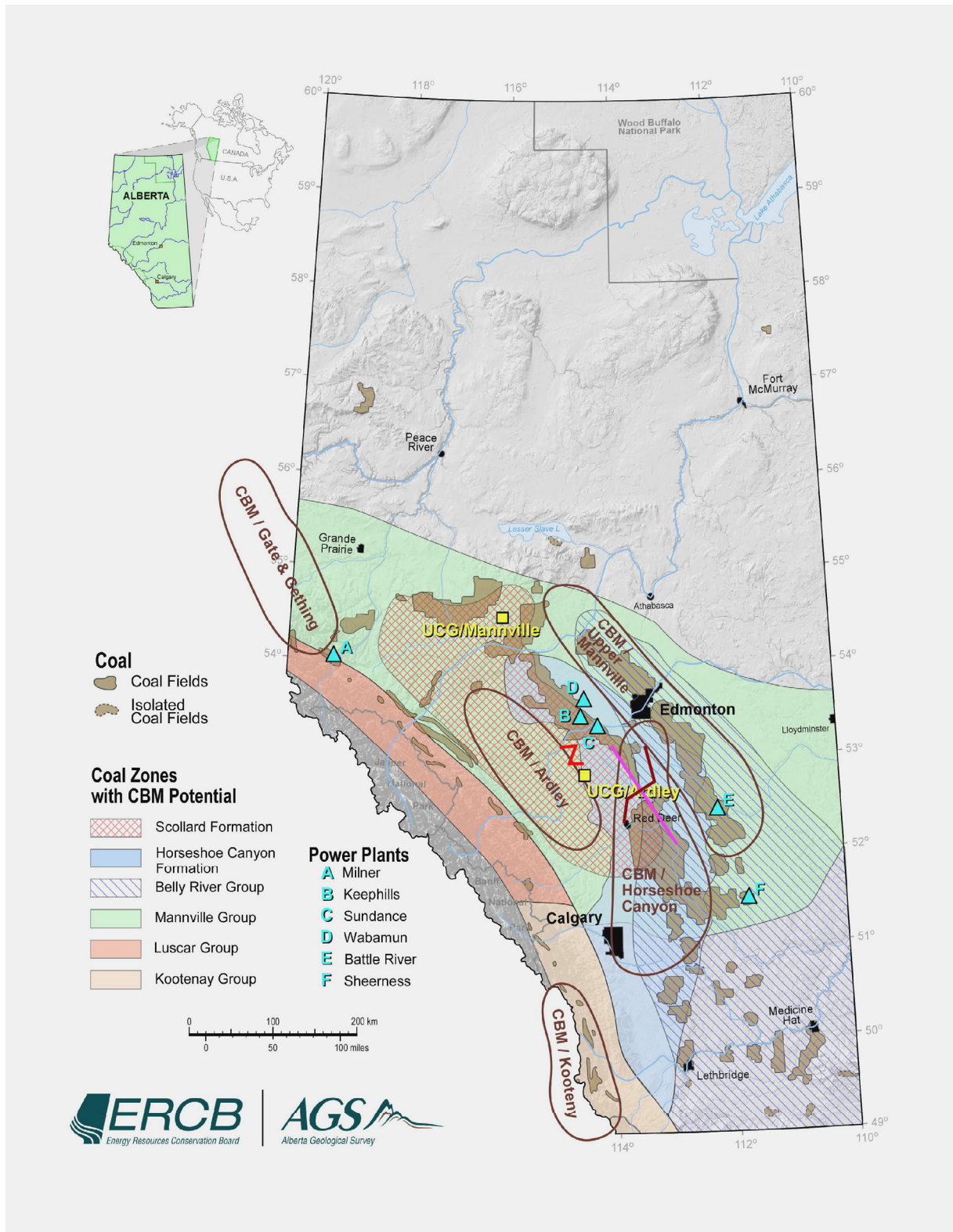**Figure 18. Distribution of coal resources and coal outcrop areas, and areas of CBM exploration and UCG potential (*after* Alberta Geological Survey, 2009b]). Symbols: red line, Ardley coal zone cross-section, (Twp. 45–46, Rge. 6–7, W 5th Mer.); brown line, Horseshoe Canyon cross-section (Twp. 36–45, Rge. 20–23, W 4th Mer.); magenta line, upper Mannville Group cross-section (Twp. 39–45, Rge. 20–28, W 4th Mer.).**
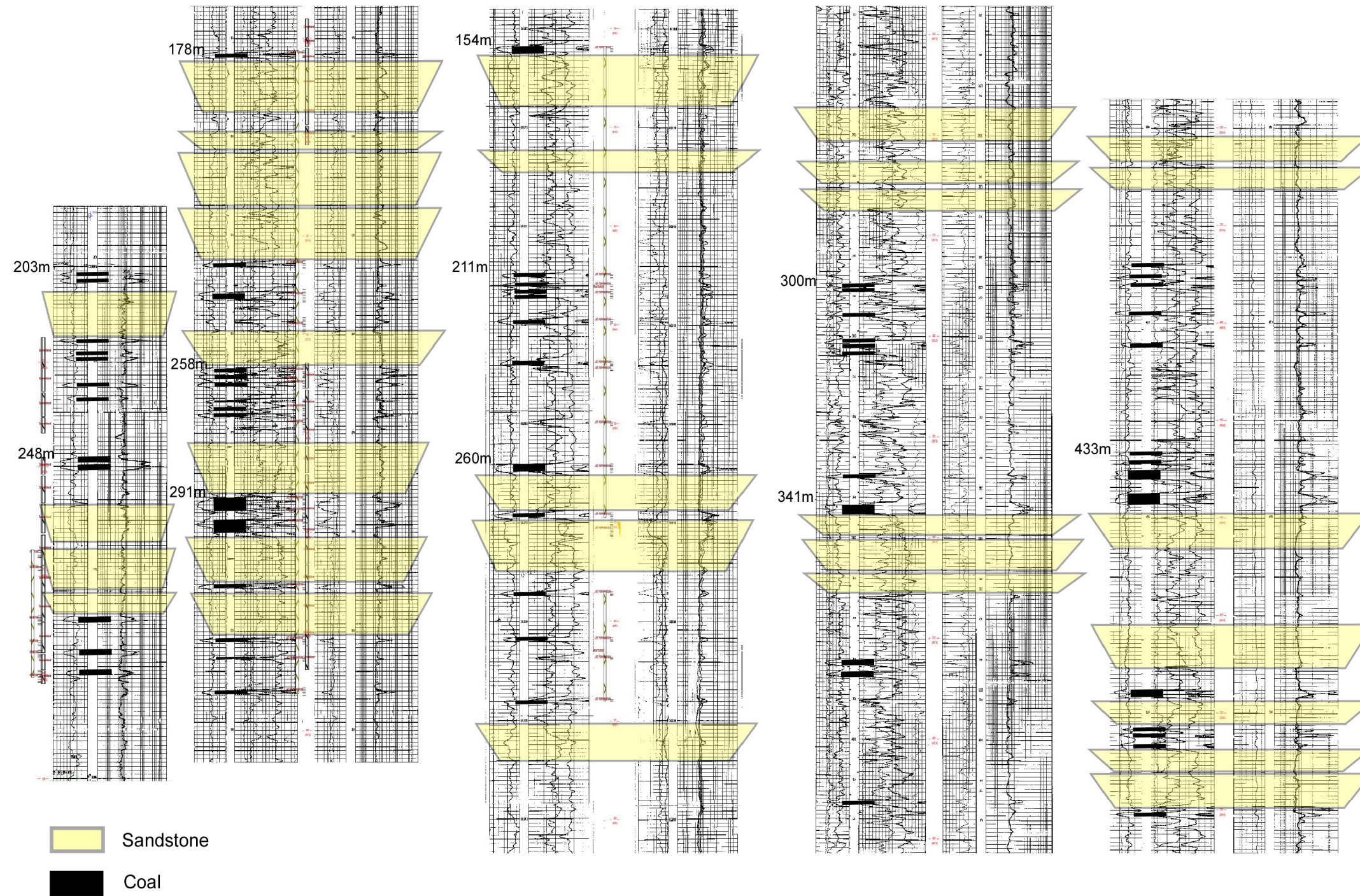
Figure 19. Horseshoe Canyon coal seams (C. Pana, unpublished data, 2008.
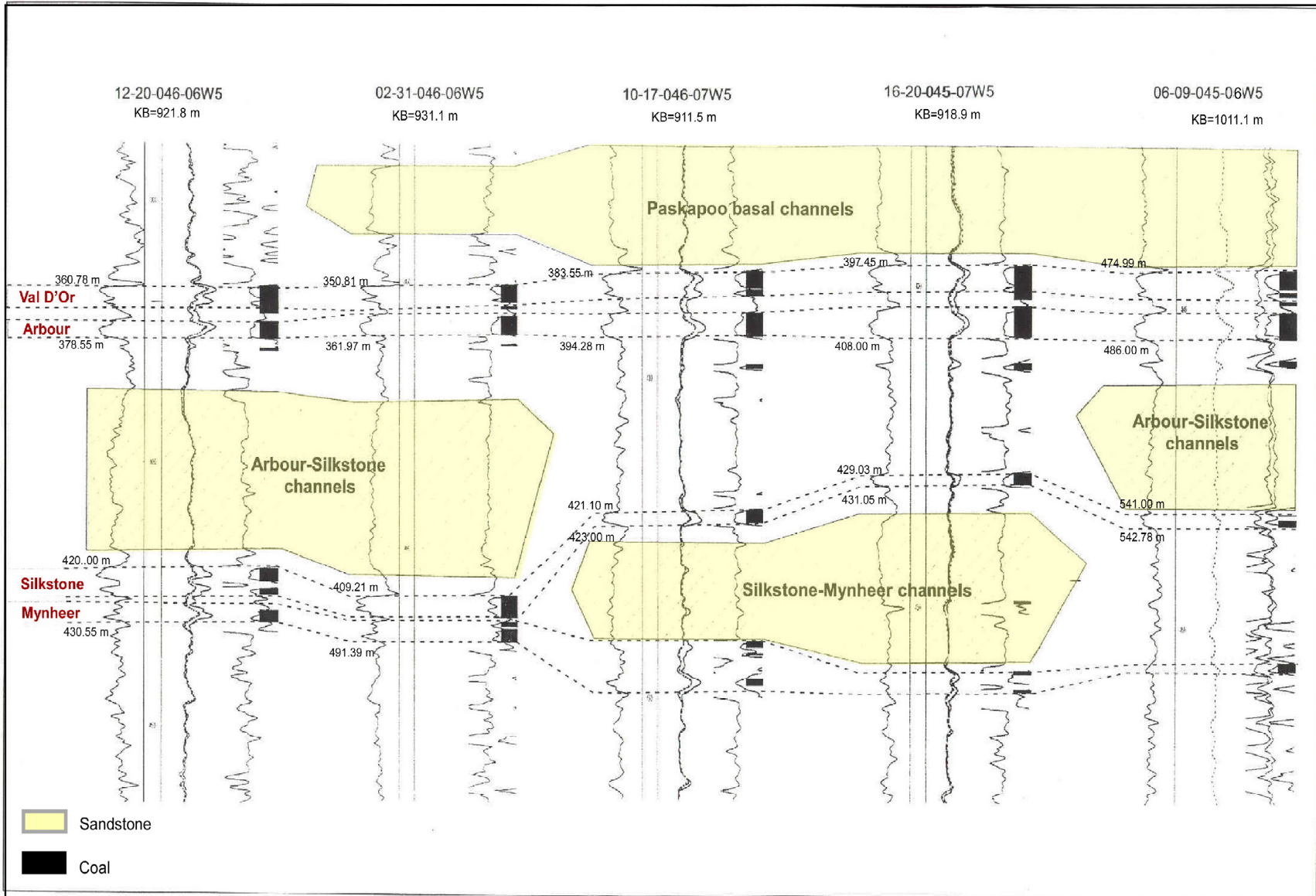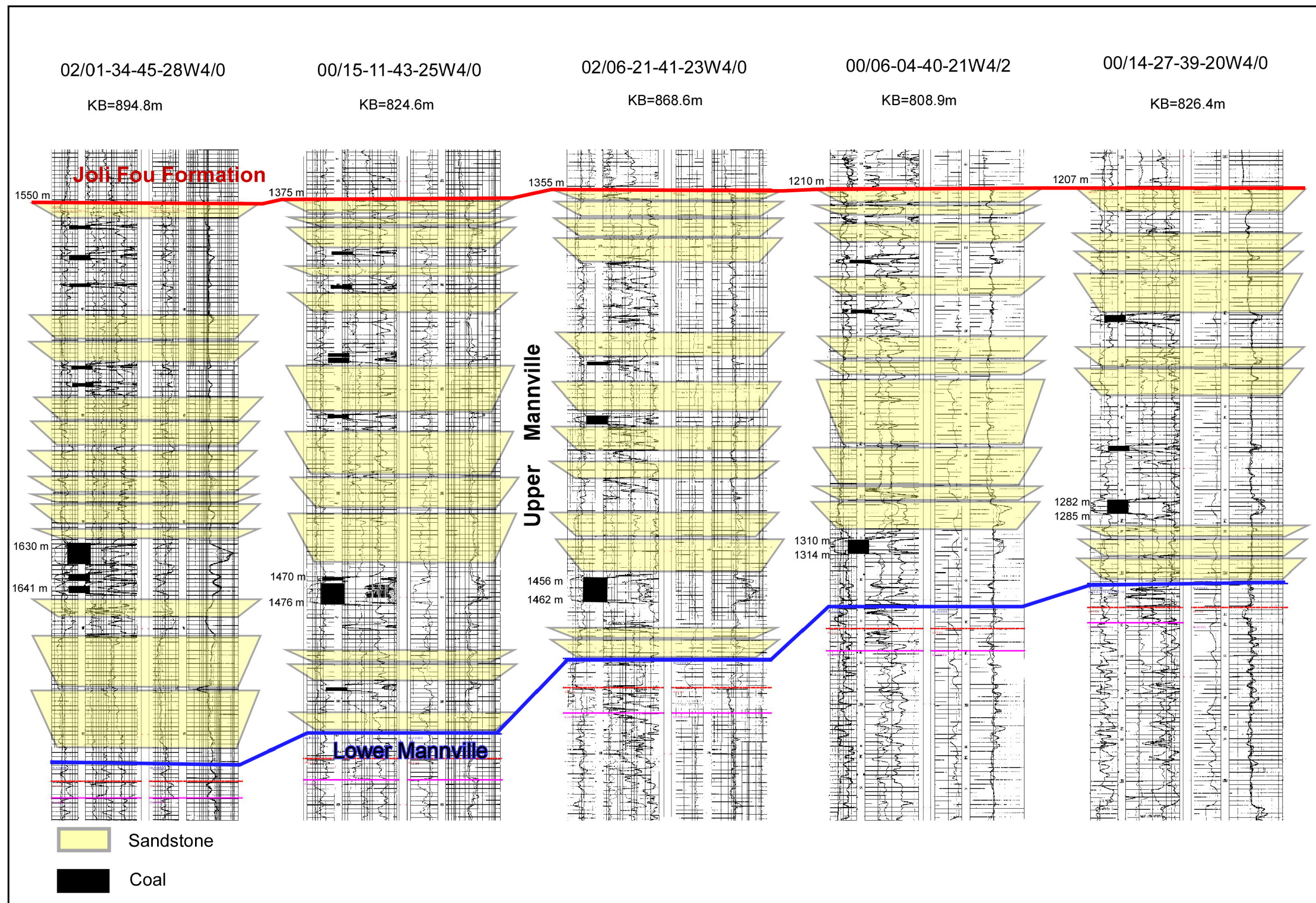
Figure 20. Ardley coal seams (Pana, 2007).

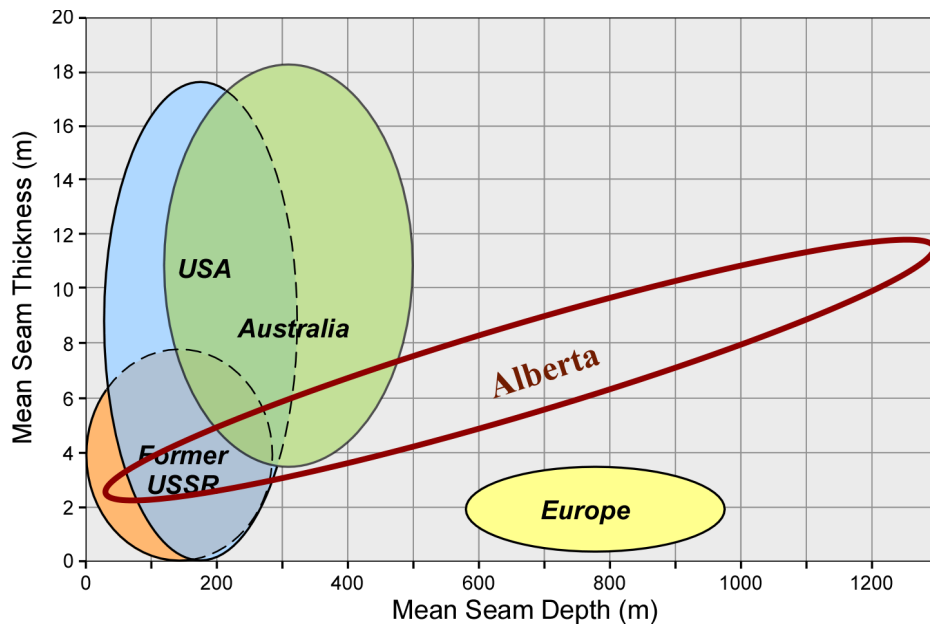Figure 21. Upper Mannville coal seams (C. Pana, unpublished data, 2008).

Figure 22. Comparison (in terms of coal seam depth versus thickness) of the potential UCG targets in Alberta with international targets.

The second example is a selected two-by-two township area within the Ardley coal zone (Twp. 45–46, Rge. 6–7, W 5th Mer.) south of Pigeon Lake, characterized by a remarkable coal cumulative thickness of 8–10 m and continuity of the upper coal deposits. The depth is greater than 350 m. The top seal consists of a continuous thin layer of tonstein overlain by either silty mudstone or sandstone. The lower coal seams merge toward the northeast, resulting in a cumulative thickness of 7 m (Figure 20).

The third example is a potential UCG area in the upper Mannville coal-bearing deposits (Twp. 39–45, Rge. 20–28, W 4th Mer.) that shows a significant continuity and thickness of the basal coal seam (6–8 m). The depth is greater than 1200 m. The succession consists of silty sandstone, sandstone and silty mudstone. In some locations, the basal coal seam overlies or is overlain by sandstone with variable porosity, as shown by the selected logs (Figure 21). Detailed studies will consider all geological aspects for UCG suitability.

A recent AGS study (Energy Resources Conservation Board, 2007) indicated that the Ardley coal zone of the Scollard Formation and all the coal zones of the Horseshoe Canyon Formation are within the groundwater protection interval defined by the maximum concentration of total dissolved solids of 4 g/L. The Mannville succession is located below the groundwater protection interval and considered a confined aquifer (Michael, 2002). Previous interpretations of the hydrogeological data demonstrated that both the Ardley and Horseshoe Canyon coal zones range from a saturated to a slightly undersaturated regime. The salinity data for the upper Mannville Group show relatively higher salinities (<15 g/L total dissolved solids) than the Ardley–Horseshoe Canyon interval (<4 g/L total dissolved solids).

For the purpose of this report, the grade of coal (mineral matter content) has been interpreted from well-log records. The complementary gamma ray–density logs are responsive to major fluctuations of mineral matter content in coal seams. Vertical changes in the characteristics of coal seams are recorded by the geophysical logs and interpreted as alternating low-ash and high-ash content. The procedure allowed the separation into layers thicker than 33 cm of clean coal (60%–80% organic matter), which includes bright, banded, dull and fibrous coal macrolithotypes. Lower content of organic matter (coaly shale and shaly

coal) is estimated between 60% and 40% and occurs occasionally within the coal seams. In most locations, the coal seams contain approximately 60%–80% organic matter.

In terms of coal petrographic and chemical characteristics, few new data are available in the public domain; the previously published data reflect a degree of inconsistency in sampling and analysis. However, in central Alberta, the vitrinite reflectance of all three zones discussed above is in the range 0.5%–0.6% R_o, indicating sub-bituminous to lower bituminous rank (Beaton et al., 2002; Beaton, 2003; Goodarzi, 2005). Nurkowski (1985) considered that the coals range in rank from sub-bituminous C to high-volatile bituminous C in the Alberta Plains region and are characterized by variable ash content and low sulphur content. The relationships between calorific value (dry basis, kJ/kg, CV[D]) and ash (dry basis, %, Ash[Dl]), and calorific value (moist mineral matter free, kJ/kg, CV[MMMF]) and equilibrium moisture (%, MEQ) were determined to be (Nurkowski, 1985):

$$CV[D] = 29262 – 286(Ash[Dl])$$

$$CV[MMMF] = 31816 – 442(MEQ).$$

The Ardley and Horseshoe Canyon coal maceral components and coal behaviour during conventional combustion were discussed in detail by Goodarzi (2005). The analyzed samples represent the uppermost Cretaceous and Tertiary mined-coal feedstock for the six central Alberta power plants (Figure 17). Mannville coals are too deep to meet the mining requirements and were therefore not part of Goodarzi's assessment.

Chemical and petrographic analyses show low liptinite and mineral matter content in both the Ardley and Horseshoe Canyon coal zones, higher vitrinite and inertinite content in the Ardley coals (Figures 23, 24B) and high boron content in the Horseshoe Canyon samples (Figure 24A). The explanation of the dissimilar boron contents relates to different coal-peat depositional environments: the higher boron content of the Horseshoe Canyon coals (217–266 mg/kg) is the result of marine waters always having higher concentrations of this element, compared to the freshwater environments in which the Ardley coals (49–75 mg/kg) were formed. The vitrinite-inertinite proportion indicates the coal's reactivity to combustion and some of the combustion by-products: the higher content of inertinite (35%–44%) in the Ardley coals can be explained by more exposure to peat fire events or in situ oxidation of organic matter in fresh-water peat deposits, compared to the marginal marine environments characteristic of Horseshoe Canyon coals (14%–14.2%). In addition, a more detailed petrographic examination of the Ardley samples shows that the inertinite group of macerals includes thermally altered inertinite macerals (inertodetrinite) (Figure 24C), which formed at high temperatures and are therefore particularly resistant to the combustion process. This type of maceral represents the main source of char particles in fly ash (0.52%–2.72%; Goodarzi, 2005). Overall, Horseshoe Canyon coals are more efficient during combustion (Figure 23A, B) and would release fewer char particles in fly ash than the Ardley coals.

The selected areas in the Ardley, Horseshoe Canyon and upper Mannville coal zones meet some of the UCG criteria regarding coal rank, thickness and continuity, and estimated organic matter content. The stratigraphic position of the Ardley coals (at depths greater than 350 m) and Horseshoe Canyon coals (at depths greater than 150 m) within the groundwater protection interval may present technical difficulties for UCG development. However, an adequate UCG modelling program would indicate the optimum operational parameters (injection pressure versus in situ pressure) to reduce the risk of groundwater contamination. In addition, the shallower depth of the Horseshoe Canyon coals may generate cavity collapse or surface subsidence if not prevented through adequate modelling of cavity volume progress and optimum drilling design.

The Indiana Center for Coal Technology Research (Bowen and Irwin, 2008) suggests reducing cavity volume progressively from the deeper targets to the shallower. The depth of the selected area in the upper

Mannville is greater than the maximum of 800 m suggested by the international UCG experiments (Figure 12) and may therefore cause difficulties during the channel opening part of the operation due to low to very low permeability. This implies the need for additional technology to improve coal permeability. One of the advantages of deeper coal deposits is that fewer injection-production well systems are required per block to complete the UCG operation by increasing the cavity volume with no risk of cavity collapse. Another advantage of the upper Mannville coal seams is that they are part of the confined brine aquifer and therefore present no risk of contamination of the groundwater protection zone.
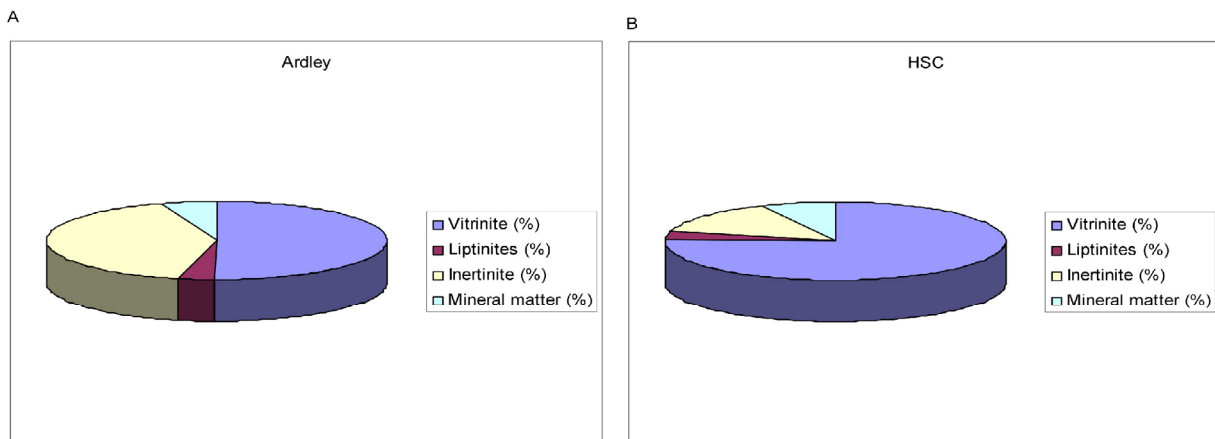

Figure 23. Characteristic maceral components of A) Ardley coals, and B) Horseshoe Canyon coals (data *from* Goodarzi, 2005, Table 1).

A comparison of the three selected areas for UCG exploration indicates the upper Mannville coal zone could be the most favourable target in terms of groundwater protection and undesirable overburden subsidence because of its depth and status as a confined aquifer. It is followed by the Ardley coal zone, where there is a concern regarding groundwater contamination. The Horseshoe Canyon coals are the shallowest and mostly within the groundwater protection zone, so the risk of groundwater contamination and cavity subsidence might be the highest if not appropriately modelled. In addition, Horseshoe Canyon coals are under intense CBM exploration, which could mean a delay of the UCG application until the current level of unconventional gas exploration declines.

7 Conclusions

The underground coal gasification (UCG) process has been internationally demonstrated as a realistic alternative source of energy for several decades, making available resources that are not economically accessible through conventional mining. The technology uses in situ coal physical and chemical processes such as pyrolysis, combustion and gasification, sustained by the injection of oxidants, into a coal seam using an injection-production drilling system.

The product gas (syngas) can be used as fuel for direct power generation, feedstock for chemical products and synthetic pipeline gas. The main UCG by-products are in situ deposits (roof rock fragments and ash rubble) and released residue (flue gases and fly ash), which are captured, managed or discarded.

The composition and production rate of the product gas are a direct function of

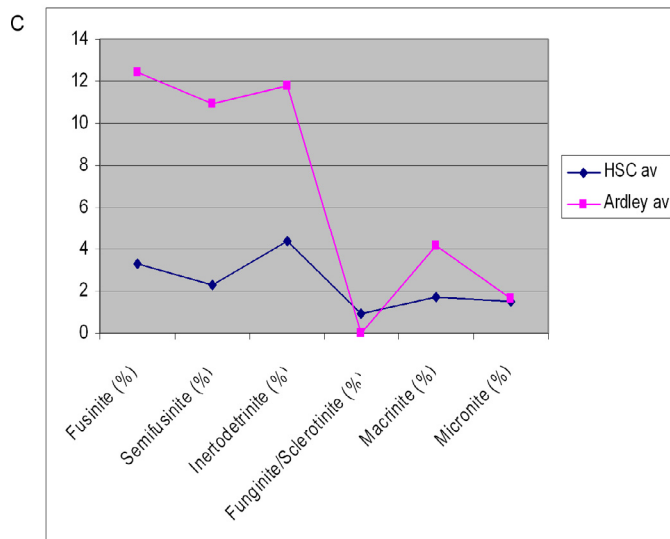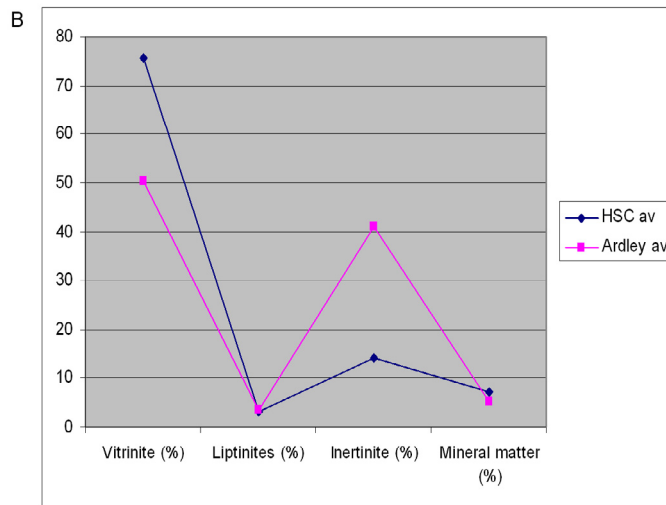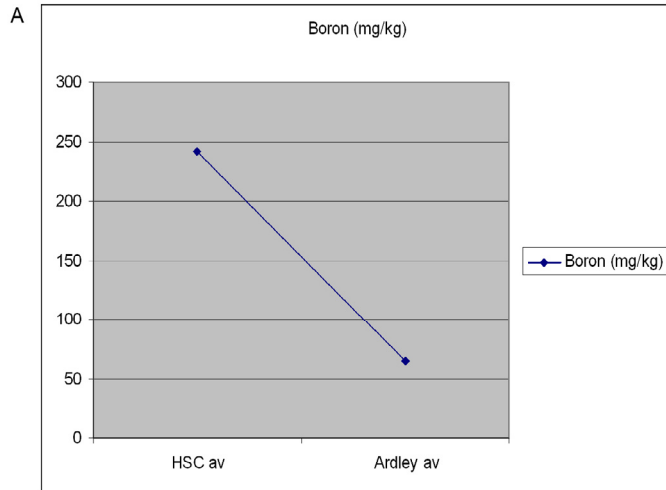* coal characteristics;
* geological conditions;

Figure 24. Comparison of average Ardley and Horseshoe Canyon (HSC) coal analyses (data *from* Goodarzi, 2005; Table 1): A) boron content (average mg/kg), B) maceral content (average %), C) components of inertinite group (average %).

- pressure, flow rate and composition of the input oxidants; and
- local conditions created during underground linkage and gasification.

The main issues with the UCG process are the prevention of cavity collapse and groundwater contamination during or after operation. These can be monitored and controlled through improved modelling of the cavity volume and balancing the injection pressure of the oxidants with the in situ pressure.

Alberta's foreland underground coal resources can be considered suitable for UCG operations. Generally, UCG candidates can be found in each individual coal seam deeper in the subsurface (i.e., European experience) or shallower using abandoned coal mines (i.e., Chinese experience). Preferable targets are packages of multiple coal seams with interseam intervals of less than 50 m, such as in the Ardley, lower Horseshoe Canyon and upper Mannville coal zones. This report identifies three major coal deposits (the Ardley, Horseshoe Canyon and upper Mannville coal zones) as potential targets for UCG exploration. Since the summer of 2008, proposals have been made to test the UCG process for in situ gasification in two locations: southwest of Edmonton, targeting the Ardley coal zone; and northwest of Edmonton, targeting the upper Mannville coal zone. These UCG exploration areas are optimally situated at a convenient distance from the proposed integrated gasification combined cycle (IGCC) power plants.

Primary UCG targets in the Alberta foreland basin (Ardley, Horseshoe Canyon and upper Mannville coal zones) have coal characteristics similar to those of existing UCG operations worldwide:

- coal thickness greater than 0.5 m at depths varying from <30 to >800 m; multiple coal seams, with minimum inclination and predictable continuity
- coal reactivity (indicated by average amount of vitrinite + exinite [liptinite]) >60%, vitrinite reflectance between 0.5 and 0.6 R_o (sub-bituminous rank), volatile matter >35%, and overall high calorific value

Each of the coal zones has been exemplified by one area with UCG potential: south of Pigeon Lake for the Ardley coal zone, east of the Edmonton–Red Deer area for the lower Horseshoe Canyon coal zone, and east of the Edmonton-Stettler area for the upper Mannville coal zone.

Comparison of the UCG potential of the three selected areas indicates that each area has opportunities and challenges:

- The Ardley coal zone presents the easiest access (depth >350 m) to a thick coal seam (8–10 m), similar to the Australian commercial experience. The impediment is its location within the groundwater protection interval, thus requiring a vigilant simulation and monitoring process during the operation. The UCG target area is also currently a coalbed methane (CBM) exploration target.

- The Horseshoe Canyon succession also has several shallow coal seams (depth >200 m), averaging 1 m thick and occasionally including a thicker coal seam. It is located within the groundwater protection interval and the site of intense CBM exploration activity, which can be an impediment in the UCG application.

- The upper Mannville coal seams are situated deeper (at more than 1200 m) than the previous European experience, which could imply such technical challenges as reduced permeability; however, the basal coal is 6–8 m thick and shows a clear 'clean coal' signature on well logs. The entire Mannville succession is considered a confined aquifer with salinities around 15 g/L, below the groundwater protection interval. Coalbed methane exploration is in progress.

Since the target coal is exhausted at the end of the UCG operation, its exploitation should be planned in conjunction with such related activities as CBM exploration and production. For instance, if the same coal is targeted by UCG and CBM exploration in the same area, then UCG should be considered after CBM

production has declined. Simultaneous UCG and CBM operations can be applied in different areas or in the same area but targeting different coal seams.

There are, however, knowledge gaps in the evaluation of Alberta coal deposits that require careful consideration to assess the efficiency of the UCG process and eliminate risks. It will be necessary to

- establish optimal methodology for generating new and consistent data on coal zone characteristics;

- improve (and validate) scale-up measures for applicability of the UCG process and determine limiting capacities of individual coal zones or areas within coal zones;

- develop chemical and physical understanding of the in situ coal-conversion processes and its relationships to 1) cavity char formation, 2) ash formation, 3) condensable products chemistry, and 4) catalytic effects;

- develop a greatly expanded environmental database for potential emissions of, and health hazards related to, remnant or emitted trace constituents related to the UCG process;

- define the suitability of each coal zone for both UCG and CBM, including the potential risk factors associated with each process, based on regional characterization of the coal zones (foreland area) that should include petrography, chemical analysis and determination of calorific value;

- understand and model the hydrogeological regime of the potential UCG targets;

- develop comprehensive (numerical) models for coal gasification characteristics based on our best scientific knowledge of chemical and physical phenomena, and validate and improve these models by performing appropriate laboratory and field analyses; and

- characterize the properties of the in situ gasification residues (including ash chemical analyses), to predict the leachability for cleaning or, alternatively, procedures of solid residue inactivation.

The UCG process represents a lower emission, efficient alternative source of energy in Alberta, unlocking coal resources for the production of electricity, chemical products and synthetic pipeline gas. The UCG process is linked to development of integrated gasification combined cycle (IGCC) power plants, which are considered the next generation of coal-fed power plants. The successful technologies that have been developed for conventional and unconventional coal gasification have opened up alternatives for multiple coal end-market uses.

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