Coalbed methane (CBM), or coalbed gas, is a form of natural gas extracted from coal beds. The term coalbed methane has been used since the early days of the industry, because during the early years it was assumed that the only type of gas that would be generated from coal would be methane. Subsequent research changed this perspective once it was demonstrated that coalbed methane is comprised of methane, ethane, butane, pentane, and higher hydrocarbons, as well as carbon dioxide and nitrogen, rather than simply methane (Scott, 1994). In some areas, light weight (API 40+ gravity) oils are produced from coal seams. The term coal gas is being used more frequently when addressing the natural gases that occur in coal seams, whereas the term coalbed methane is still used to refer to the industry as a whole.

Coalbed methane represents an important part of the natural gas supply for the United States and will continue to do so in the foreseeable future. Initial coal gas exploration and development was conducted by major oil companies and larger independents, but smaller operators have played a progressively more important role in developing this natural resource.

Coalbed methane production in the United States has increased from 10 bcf in 1985 to more than 1,754 bcf in 2007. It now represents nine percent of total dry gas production and nine percent of proved dry gas reserves (Energy Information Administration, 2008). Coalbed methane resources are estimated to be more than 755 trillion cubic feet (tcf; 126 billion barrels of oil equivalent or BOE) in the contiguous United States, more than 80 percent of which is located in the western United States. Coalbed methane resources in Alaska probably exceed 1,037 tcf (173 billion BOE) (Clough and others, 2001), indicating that the total coalbed methane resources for the entire United States are 1,792 tcf (299 billion BOE).

However, expanded exploration efforts into other parts of the country and better resource assessments will undoubtedly increase these values. Coal gas proved reserves increased significantly over the past three years, primarily from new coalbed methane plays, and is currently estimated to be approximately 21.875 tcf (3.6 billion BOE)(Energy Information Association; 2008). Although over 50 percent of current coal gas production is derived from the San Juan Basin, coal gas production from other western basins continues to increase, particularly from the Powder River Basin, which now represents 23 percent of the total production. The unusually high water production associated with coal beds in the Powder River Basin is unique worldwide; many coal beds have relatively little or, in some cases, essentially zero water production.

Coalbed methane represents an abundant supply of environmentally clean energy and a source of hydrogen. Furthermore, unwanted greenhouse gases such as carbon dioxide also can be sequestered into coal beds. Injection of carbon dioxide into coal beds enhances coalbed methane production while simultaneously reducing greenhouse gas emissions to the atmosphere, thereby reducing global warming potential. Additionally, given the tragic events of September 11th, the probability continued conflicts in the Middle East, and exponential population growth, there is a strong incentive for the United States to develop new environmentally friendly, energy resources in order to reduce our dependence on foreign energy supplies.

The increase in proved coal gas reserves despite the significant increase in production is attributed to the efforts of smaller operators and independents in finding new reserves. Coal gas production and reserves are expected to increase as exploration continues in unexplored areas and as secondary recovery techniques using nitrogen or carbon dioxide are employed.
This chapter summarizes various aspects of how gas is stored on coal seams, including sorption isotherms, and the critical hydrogeologic factors that affect coalbed methane production. Additionally, water disposal methods and coal gas ownership issues are reviewed.

**Coal gas sorption and gas content**

In conventional gas reservoirs, coal gases occupy the voids, which are either pore spaces or fractures, in clastic (sandstone) and carbonate (limestone and dolomite) reservoirs. The gas is not generally physically sorbed (trapped) to the mineral grains, but can be sorbed to organic matter in the rocks. The gases within these conventional reservoirs have been generated by source rocks such as shale and coal, and subsequently migrated to the reservoir. In contrast, coal seams are often the source and the reservoir for the natural gas, although gases generated from other source rocks can migrate to the coal seams and become sorbed by the coal.

Well cuttings are collected during the drilling process and sealed in canisters and then taken to the laboratory for several tests. The amount of gas liberated from the coal is called the **gas content** and is usually given in standard cubic feet per ton of coal (scf/ton). Proximate analysis measures the moisture and ash (inorganic fraction) content of the coal. This is important because the coal gases are sorbed only on the organic fraction of the coal and not the ash. The gas content values are often corrected to a moisture and ash-free basis (dry ash-free or DAF) for comparison. Gas contents (DAF) in the subsurface can range from zero to more than 800 scf/ton, but most operators prefer a minimum of 150 to 250 scf/ton depending on natural gas prices.

More natural gas can be retained or sorbed to the coal surface as the pressure increases and in general, lower rank (less thermally mature) coals have a higher sorption capacity than higher rank (more thermally mature) coal seams. The coal samples are placed into canisters and the amount of gas that is sorbed at various pressures is measured. The laboratory tests are run under reservoir temperature and moisture conditions taking into consideration the types of gases that are sorbed on the coal. From these tests, a sorption isotherm is created. Each coal has a unique sorption isotherm, so it is important to perform enough sorption isotherm tests to characterize the reservoir.

If the measured gas content values at reservoir pressure fall on the laboratory-determined sorption isotherm, the coal is called **saturated** or saturated with respect to methane. If the measured gas content value falls below the isotherm, the coal is called **undersaturated**, and if the gas content value falls above the isotherm at reservoir pressure, the coal is **oversaturated** with respect to methane. For a variety of hydrogeologic reasons, most coal beds are undersaturated with respect to methane, and oversaturated conditions usually indicate errors in the gas content measurements or the laboratory-derived sorption isotherms. Truly oversaturated conditions in coal beds are very rare and cannot be determined from laboratory analyses.

For the operator, finding saturated or nearly saturated coal beds is very important economically, because the coal beds must be depressurized in order for gas production to begin. The coal seams are depressurized by removing water from the fractures (or cleats) in the coal. In undersaturated coal seams, coal gas production will start only when the measured gas content intersects the sorption isotherm at the critical desorption pressure during the dewatering stage. Therefore, coalbed methane production will continually increase during the first few years of production during the dewatering or depressurization stage, reach a maximum production rate, and then follow a normal type of production decline curve similar to conventional oil and gas reservoirs. In some cases, the production decline curve in coalbed methane reservoirs is nearly flat, indicating...
that production may continue for 40 or more years.

**Review of water disposal issues**

Recently, concerns regarding coalbed methane water disposal have been raised, but many of the arguments against coalbed methane development as whole (industry) are based on misconceptions and omission of information. Arguments against future coalbed methane development anywhere in the United States (and internationally) appear to focus primarily on activity in the Powder River Basin and ignore data from other basins worldwide.

Coal seams are heterogeneous arid; therefore, the water and gas production varies significantly among basins and even within coal-bearing basins. In some areas, there is essentially zero water production (e.g., less than one barrel per day), whereas some basins, such as the Powder River Basin, have very high production rates. Note that the high water production rates in the Powder River Basin are the exception and not the rule for coalbed methane. Unfortunately, some opposed to future coalbed methane development appear not to have looked at other coal-bearing basins before reaching their conclusions and passing judgment on the industry as a whole. Using natural gas produced from coal seams is much cleaner than burning coal for electricity generation. Natural gas generates only 117 pounds of carbon dioxide per million Btu's compared to over 205 pounds of carbon dioxide for bituminous coal (Energy Information Administration, 2009). Additionally, it will be natural gas that leads the way into the new "hydrogen economy", because natural gas appears to be the dominant source of hydrogen in the near term.

Coal seam waters can range from being fresh (potable) to highly saline and the water chemistry generally varies across the basin. The freshest coal seam water generally occurs near the outcrop where meteoric recharge occurs, but in highly permeable systems (such as the Powder River Basin), the fresh water can extend tens of miles from the outcrop. Fresh water can be disposed of through surface discharge or vaporization techniques using high pressure jet sprays to enhance evaporation, whereas less fresh water can be placed in evaporation pits. However, saline waters must be re-injected into the subsurface. In some cases, operators have re-injected the produced coalbed methane into oil reservoirs water as part of enhanced oil recovery water floods, thereby reducing the need for water from other sources. The rules for water disposal and the definitions regarding "too saline" vary significantly among the states. Some states insist that any coal seam water (potable or saline) is oilfield waste fluid and must be re-injected into an appropriate formation.

**Review of coal gas ownership issues**

During the initial stages of coalbed methane development, multiple lawsuits developed over who owned the coal gas — coal owners or gas owners. Much of the following information is taken from Lewin et. al., (1993) and documentation taken from the EPA 2003 website.

In 1993, Lewin et al. noted that the courts could apply any of six rules pertaining to ownership: (1) CBM is gas and gas owners have title to CBM, (2) CBM is coal and coal owners have title to CBM, (3) priority of severance, where the purchaser in the severing transaction receives title to CBM, (4) case-by-case, where title to CBM is based upon the documents in the severing transaction, (5) successive ownership where coal owners have title to the gas to CBM within the coal, but gas owners have title to escaped or free gas in the gob zone, and (6) mutual simultaneous rights where gas owners have title to CBM and gob gas in conjunction with mining as an "incidental mining right". The primary focus of ownership issues appears to be the definitions of coal, coal gas, and how the gas is stored on the coal.
Coal is a complex compound consisting of an organic fraction and an inorganic fraction, called ash. The length of time for one foot of coal to form ranges from 65 years along the Mississippi River to 1,250 years in the Arctic. The organic fraction (ash-free coal) consists entirely of organic material deposited in the peat swamp over time. The ash fraction (ash) can be silt or clay that is carried into the peat environment by depositional processes, volcanic ash carried to the peat swamps by wind, and silica within the plant material itself. Coal gases are sorbed (adsorbed and absorbed) to the organic fraction of the coal, whose structure will expand or swell during the sorption process. Therefore, the argument boils down to whether the sorbed gas is actually part of the coal structure or whether the sorbed gas is separate from the coal.

The coal owner will argue that the coalbed methane is an inherent part of the coal and that ownership of the gas contained within the coal. Additionally, the coal owner may argue that (1) coal gases are adsorbed to the coal, (2) the physical bond between the coal and the coal gas is so close that the two cannot be separated, and (3) the coal is the source of and the reservoir for the coal gas (EPA, 1998).

The oil and gas owner may argue that the chemical composition of the coal gas is nearly identical to natural gases derived from other sources and that the gases may have migrated to the coal seams. These arguments provide the gas owner with a significant argument for ownership. The gas owner can further argue that the right to produce coalbed methane from coal is no different than the right to remove gas from other types of subsurface formations. The plain meaning of gas appears to definitely include coalbed methane, whereas in contrast coal commonly refers to a solid mineral, not a gas (EPA, 1998).

The oil and gas owner may further argue that (1) recovery methods parallel that of natural gas, (2) the migratory nature of coalbed methane is the same as natural gas, and (3) the surface owner may also claim interest in the coalbed methane, although this position is clearly the weakest (EPA, 1998). In states where the ownership of the container space reverts to the surface owner once the coal is removed, a surface owner could claim that that since he or she owns the space where the coal was previously situated, he or she could also claim ownership to the coal gases within that space. EPA (1998) states that this would not be a substantial argument since the gas or coal owner could easily counter that as the mineral owner, he or she is entitled to the mineral within the container space. However, where the coal and oil and gas rights have been specifically severed, the surface owner may be able to claim that since coalbed methane was not contemplated (but rather coal gas was considered to be a hazard) at the time of severance, ownership of the non-severed minerals (coal gas), remains with the surface or other mineral owner (EPA, 1998).

The ownership issue for coalbed methane is still being determined in some states, but on June 7, 1999, the United States Supreme Court ruled that coalbed methane (or coal gas) was not a part of the coal in the case of *Amoco Production Co. vs. Southern Ute Indian Tribe*. Therefore, the oil and gas operators were given ownership of coalbed methane. However, it appears that coalmine operators still retain ownership of the gob gas removed for safety purposes during or preceding mining operations. Hopefully, the Supreme Court decision will resolve most of the issues concerning coalbed methane ownership.

**Coalbed exploration model**

Previous coalbed methane exploration strategies are often based only on the location of the greatest net coal thickness and ignore other hydrologic and geologic factors affecting coalbed methane producibility. Coalbed methane producibility is determined...
by the complex interplay among six critical controls: (1) depositional systems and coal distribution, (2) coal rank, (3) gas content, (4) permeability, (5) hydrodynamics, and (6) tectonic/structural setting (Scott, 1999). If one or more of these key hydrogeologic factors is missing, then the potential for higher coalbed methane producibility will be reduced. However, even with a missing key factor, the coalbed methane play may remain economically viable. For example, the Piceance Basin is characterized by exceptionally high gas content values (more than 700 scf/ton), but coalbed methane production has been limited because of low permeability. Conversely, the Powder River Basin remains economically successful with gas contents generally less than 20 scf/ton, because thick (more than 100 ft) coal beds are present at shallow depths.

The following summary of the key hydrogeologic factors affecting coalbed methane is after Scott (2002). It is important to note that coal seams are heterogeneous on many different levels ranging from microscopic (coal macerals or types of organic matter) to regional (basinwide). Therefore, an integrated hydrogeologic approach on a regional scale is critical for delineating coalbed methane sweet spots. Of equal importance, application of the exploration model can allow the operator to avoid areas with marginal coalbed methane potential, thereby allowing company resources to be focused in more profitable ventures.

Depositional setting and coal distribution

Coal beds are the source and reservoir for methane, indicating that their widespread distribution within a basin is critical to establishing a significant coalbed methane resource. Coal distribution is closely tied to the tectonic, structural, and depositional settings, because peat accumulation and preservation as coal require a delicately balanced subsidence rate that maintains optimum water-table levels but excludes disruptive clastic sediment influx. The depositional systems define the substrate upon which peat growth is initiated and within which the peat swamps proliferate. Net coal thickness trends and depositional fabric strongly influence migration pathways and the distribution of gas content. The depositional setting also controls the types of organic matter – macerals - which affect sorption characteristics and the quantity of hydrocarbons produced from the coal. Knowledge of depositional framework enables predication of coalbed thickness, geometry, and continuity and, therefore, which potential coalbed methane resources.

Tectonic and structural setting

The tectonic and structural setting control of a basin control the distribution and geometry of coal beds in the basin during deposition, and therefore, exert a strong control on the lateral variability of maceral. Both the burial history and stress direction control the timing of cleat development in various parts of the basin and the final orientation of face cleats. The basin burial history and variability of regional heat flow control coalification and the types and quantities of thermogenic gases generated from the coals. Additionally, present-day in situ (in its original place) stress directions may significantly affect coalbed methane producibility. Stress directions orthogonal to face cleats will lower permeability, whereas stress directions parallel to face cleat orientation may enhance permeability. Uplift and basinal cooling often result in undersaturation with respect to methane in the coals and possible degassing of coal beds. Finally, the location and geometry of faults may strongly influence the recharge of meteoric water, and therefore, the generation of biogenic gases.

Coal rank and gas generation

Coals must reach a certain threshold of thermal maturity (vitrinite reflectance values between 0.8 and 1.0 percent; high-volatile A bituminous) before large volumes of thermogenic gases are generated. The amount and types of coal gases generated during coalification are a function of burial history, geothermal gradient, maceral composition,
and coal distribution within the thermally mature parts of a basin. Gases in coal beds may also be formed through the process of secondary biogenic gas generation. Secondary biogenic gases are generated through the metabolic activity of bacteria, introduced by meteoric waters moving through permeable coal beds or other organic-rich rocks. Thus, secondary biogenic gases differ from primary biogenic gases because the bacteria are introduced into the coal beds after burial, coalification, and subsequent uplift and erosion of basin margins. Secondary biogenic gases are known to occur in sub-bituminous through low-volatile bituminous and higher-rank coals (Scott, 1993; Scott et al., 1994).

**Gas content**

Gas content is one of the more important controls of coalbed methane producibility, yet often is one of the more difficult parameters to accurately assess. Gas content is not fixed, but changes when equilibrium conditions within the reservoir are disrupted and is strongly dependent upon other hydrogeologic factors and reservoir conditions (Scott, 2002). The distribution of gas content varies laterally within individual coal beds, vertically among coals within a single well, and laterally and vertically within thicker coal beds. In general, gas content increases with depth and coal rank, but is often highly variable due to geological heterogeneities, the type of samples taken, and/or the analytical laboratory. The gas content of coals can be enhanced, either locally or regionally, by generation of secondary biogenic gases or by diffusion and long-distance migration of thermogenic and secondary biogenic gases to no-flow boundaries such as structural hingelines or faults for eventual resorption and conventional trapping. Therefore, determination of migration direction through isotopic and hydrogeologic studies is critical for determining migration direction and the areas of higher gas content.

**Permeability**

Permeability in coal beds is determined by its fracture (cleat) system, which is in turn largely controlled by the tectonic/structural regime as mentioned previously. Cleats are the permeability pathways for migration of gas and water to the producing wellhead, and cleats may either enhance or retard the success of the coalbed methane completion. Permeability will decrease with increasing depth, suggesting that in the absence of structurally enhanced permeability at depth, coalbed methane production may be limited to depths less than 5,000 to 6,000 ft. Permeability is highly variable in coal beds ranging from darcies to microdarcies, but the most highly productive wells have permeability ranging between 0.5 to 100 md. Higher permeability will result in recovery of more sorbed coal gases, because lower reservoir pressures and, therefore, more coal gas desorption will occur in higher permeability reservoirs. However, permeability that is too high results in high water production and may be as detrimental to the economic production of coalbed gas as extremely low permeability.

**Hydrodynamics**

Hydrodynamics strongly affects coalbed methane producibility and includes both the movement of meteoric water basinward as well as the migration of fluids from deeper in the basin. Basinward migration of ground water is intimately related to coal distribution and depositional and tectonic/structural setting because ground water movement through coal beds requires the recharge of laterally continuous permeable coals at the structurally defined basin margins. Coal beds act not only as conduits for gas migration but also are commonly ground-water aquifers having permeabilities that are orders of magnitude larger than associated sandstones. The presence of appreciable secondary biogenic gas indicates an active dynamic flow system with overall permeability sufficient for high productivity. Migration of thermogenic gases may result in abnormally high gas contents in lower rank coals or coals that are saturated or oversaturated with methane. Basin hydrogeology, reservoir heterogeneity, location of permeability barriers (no-flow...
boundaries), and the timing of biogenic gas generation and trap development are critical for exploration and development of unconventional gas resources in organic-rich rocks.

**Conclusions**
Coalbed methane is an important resource that has evolved from a possibility 25 years ago to a significant part of our national energy supply today. Coal gas chemistry is highly variable and is comprised of mostly methane. Therefore, coalbed methane represents an environmentally friendly source of energy; recovery of only a small fraction of the natural gas from coal seams will reduce the nation’s dependence on foreign sources of energy, thus enhancing national security. Concerns regarding excessive water production from the industry as a whole, derived from the exceptionally high water production in the Powder River Basin, appear to be unfounded. Coal gas ownership issues have been resolved in many states, although it is important to verify ownership before securing a land position.
References


Scott, A. R., 1994, Composition of coalbed gases: In Situ, v. 18, no. 2, p. 185-208