Coalbed Methane- Fundamental Concepts

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Introduction

This article is the first in a series of articles that will discuss various aspect of technology for the evaluation and development of coalbed methane (CBM) reservoirs. This article discusses the gas storage and flow mechanism in CBM reservoirs, their differences with conventional gas reservoirs, and their impact on production behavior. In addition, the impact of mechanical properties of coal on CBM reservoirs is discussed.

Historical Perspective

CBM has grown from an unconventional gas play that most operators stayed away from 20 years ago into a commercially important, mainstream natural gas source. Figures 1 and 2 illustrate the increase in CBM production and the contribution of CBM to the total US dry gas production from 1989 to 2003. Figure 3 illustrates the growth in CMB proven reserves over the same period. As figure 3 illustrates, the first wave of development occurred during the early 1990's. Section 29 tax credit played an important role in promoting coalbed methane development during this initial period. The major activities during this period occurred in the San Juan and Black Warrior basins. At the same time, technology advances were instrumental in bringing CBM into the mainstream as a domestic source of natural gas. These advances included an understanding of the coalbed methane production mechanism, development of accurate techniques for isotherm testing and gas content of determination, development of well log interpretation and pressure transient testing techniques to measure reservoir properties, and development of reservoir simulation models. These technological advances, coupled with favorable economic conditions, as reflected by the average gas wellhead price in Figure 4, started the second wave of development in 1997. During this stage, CBM development expanded to new

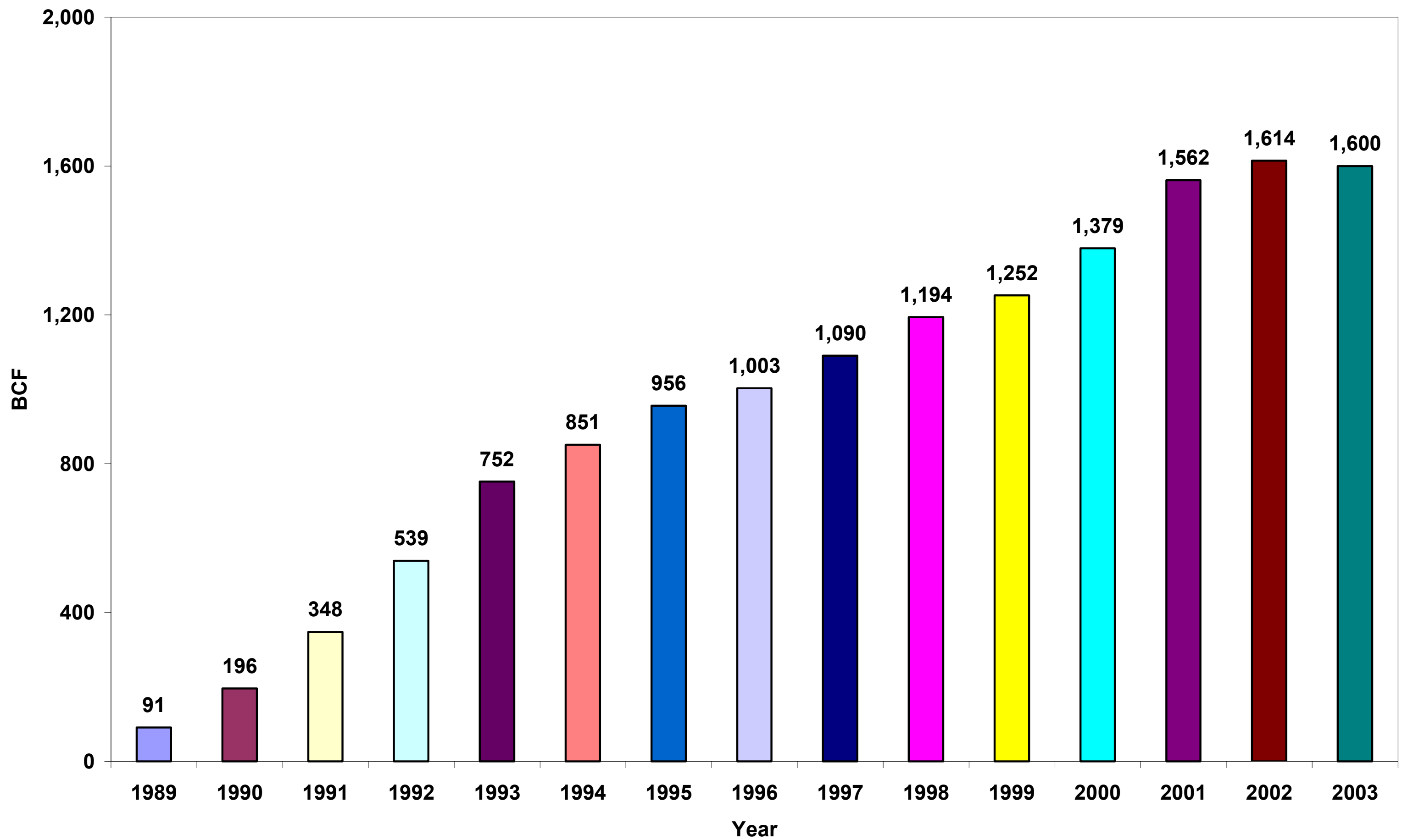

Figure 1. Annual CBM Production in U.S. (Source EIA)

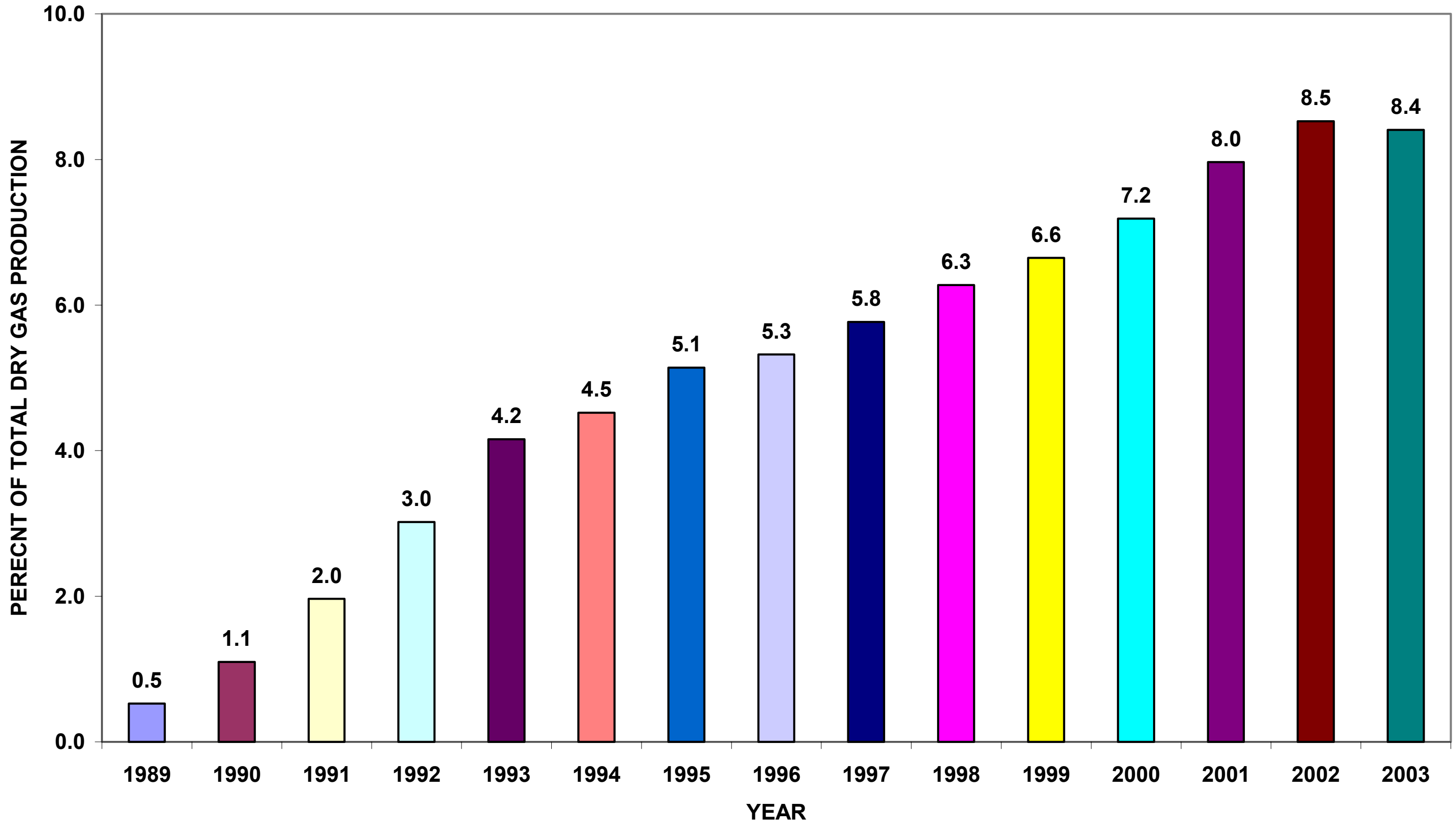

Figure 2. Contribution of CBM to US Dry Gas Production (Source EIA)

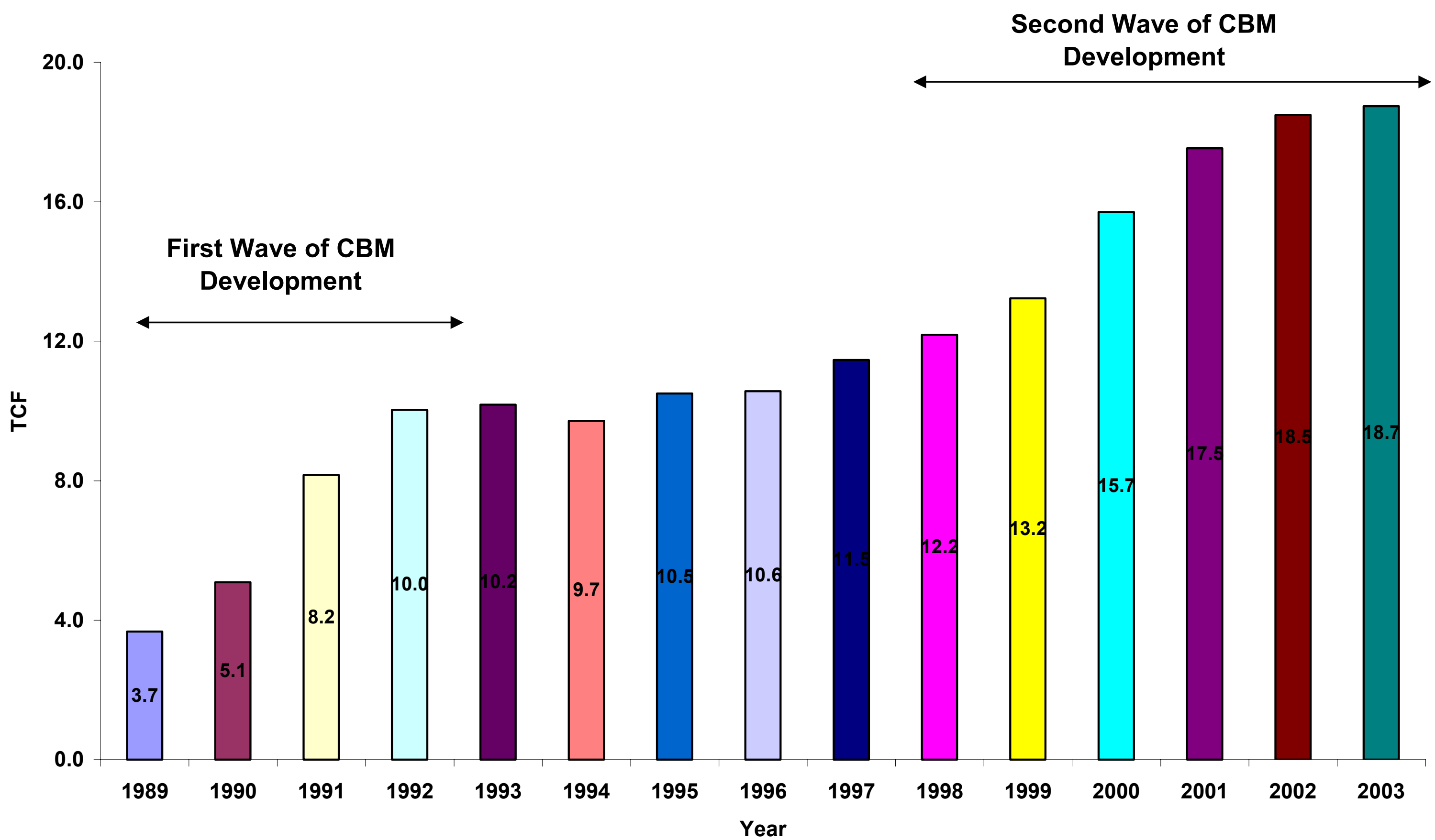

Figure 3. CBM Proven Reserves (Source EIA)

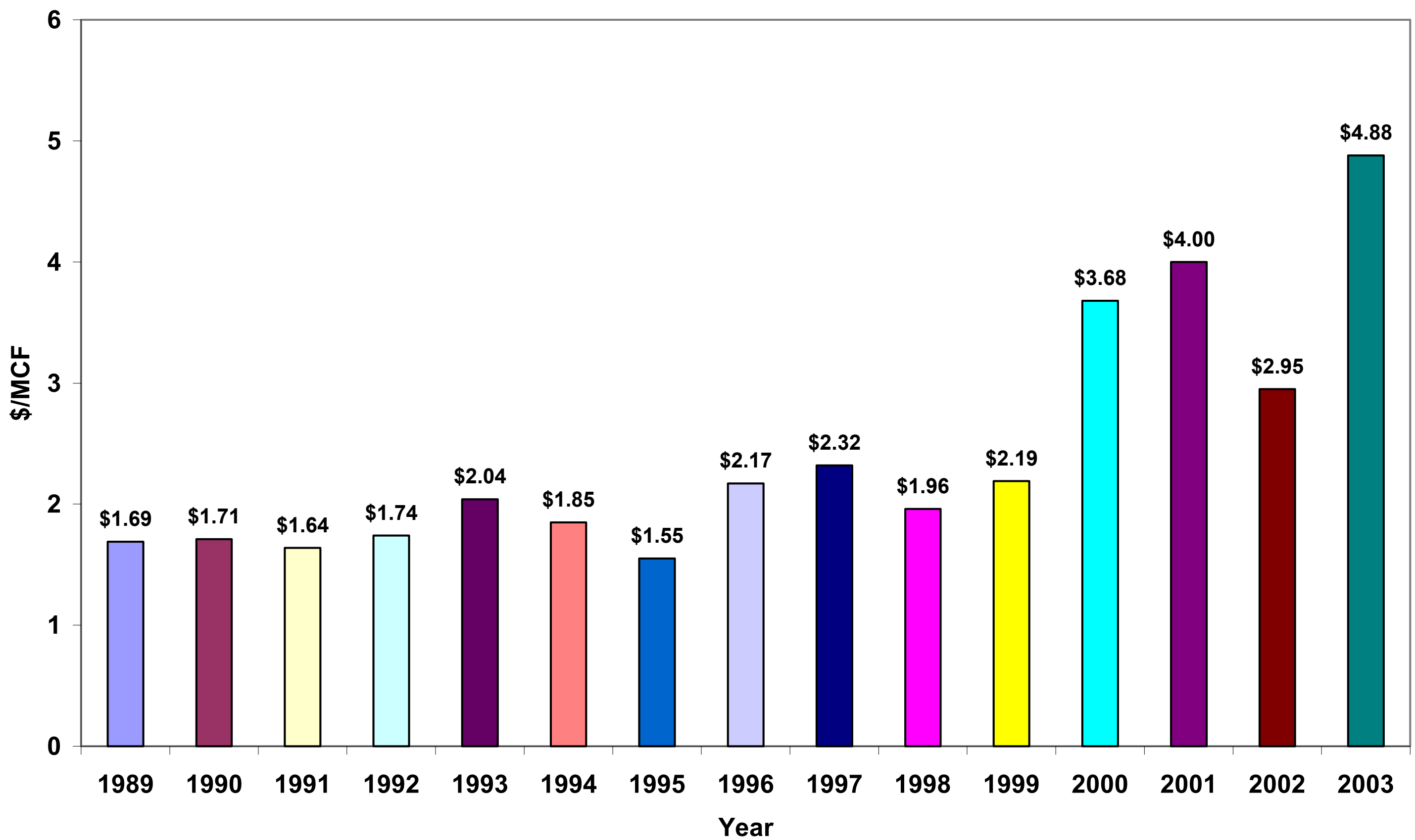

Figure 4. National Average Wellhead Prices (Source EIA)

areas, such as the Powder River, Central Appalachian and Raton basins. CMB proven reserves are expected to increase even further as more resources are discovered and a better understanding of the existing resources is achieved. The contribution of CBM to natural gas production in the US also is expected to increase during the next two decades. However, realistically this projected increase in CBM production in the US cannot be achieved without a substantial increase in CBM production from less developed areas, such as the Northern Appalachian or Illinois basins.

Characteristics of CBM Reservoirs

The characteristics of CBM reservoirs differ from conventional gas reservoirs in several areas (Table 1). Unlike conventional gas reservoirs, coal is both the reservoir rock and the source rock for methane. Coal is a heterogeneous and anisotropic porous media which is characterized by two distinct porosity (dual-porosity) systems: macropores and micropores. The macropores, also known as cleats, constitute the natural fractures common to all coal seams. Micropores, or the matrix, contain the vast majority of the gas. This unique coal characteristic has resulted in classification of CBM as an "unconventional" gas resource. Several key CBM characteristics are discussed in the following sections.

Storage

Gas in the coal can be present as free gas within the macropores or as an adsorbed layer on the internal surfaces of the coal micropore. The micropore of coal has immense capacity for methane storage. Typically, coal can store far more gas in the adsorbed state than conventional reservoirs can hold by compression at pressures below 1000 psia. The porosity of the cleat system is small, and if any free gas is present, it would account for an insignificant portion of the gas stored in the coal. Most of the gas in coals is stored by adsorption in the coal matrix. As a result, pressure-volume relationship is defined by the desorption (adsorption) isotherm and not by real gas law. A sorption isotherm relates the gas storage capacity of a coal to pressure and depends on the rank, temperature, and the moisture content of the coal. The sorption isotherm can be used to predict the volume

Table 1. Comparison of CBM and Conventional Gas Reservoir Characteristics

Characteristic	Conventional	CBM
Gas Generation	Gas is generated in the source rock and then migrates into the reservoir.	Gas is generated and trapped within the coal.
Structure	Randomly-spaced Fractures	Uniformly-spaced Cleats
Gas Storage Mechanism	Compression	Adsorption
Transport Mechanism	Pressure Gradient (Darcy's Law)	Concentration Gradient (Fick's Law) and Pressure Gradient (Darcy's Law)
Production Performance	Gas rate starts high then decline. Little or no water initially. GWR decrease with time.	Gas rate increases with time then declines. Initially the production is mainly water. GWR increases with time.
Mechanical Properties	Young Modules ~ 10^{6} Pore Compressibility ~10^{-6}	Young Modules ~ 10^{5} Pore Compressibility ~10^{-4}

of gas that will be released from the coal as the reservoir pressure is reduced. A typical sorption isotherm illustrated in Figure 5. A common assumption is that the relationship between gas storage capacity and pressure can be described be an equation originally presented by Langmuir:

$$G_S = \frac{V_L\, P}{P_L + P}$$

Where:

G_S = Gas storage capacity, SCF/ton

P = Pressure, psia

V_L = Langmuir volume constant, SCF/ton

P_L = Langmuir pressure constant, psia

The above equation assumes pure coal and for application in the field, the equation is modified to account for ash and moisture contents of the coal:

$$G_S = (1 - f_a - f_m)\frac{V_L\, P}{P_L + P}$$

Where: f_a = Ash content, fraction

f_m = Moisture content, fraction

As Figure 5 shows, the amount of gas sorbed per unit increase in pressure decreases with increasing sorption pressure and the sorbed gas eventually reaches a maximum value which is represented by Langmuir volume constant (V_L). Langmuir pressure constant (P_L) represents the pressure at which gas storage capacity equals one half of the maximum storage capacity (V_L). Figures 6 and 7 illustrate the impact of P_L and V_L on the shape of the isotherm curve. The values of P_L and V_L for a particular coal are determined by laboratory isotherm testing.

It should be noted that most coals are not saturated with gas at initial conditions of the CBM reservoirs. The actual amount of gas in the coal is referred to as the “gas content.” Gas content is the volume of gas at standard conditions per unit weight (i.e., per ton) of coal or rock. The use of this gas volume per weight rather than gas volume per volume of rock is a convention that originated in the mining industry, which sells coal on the

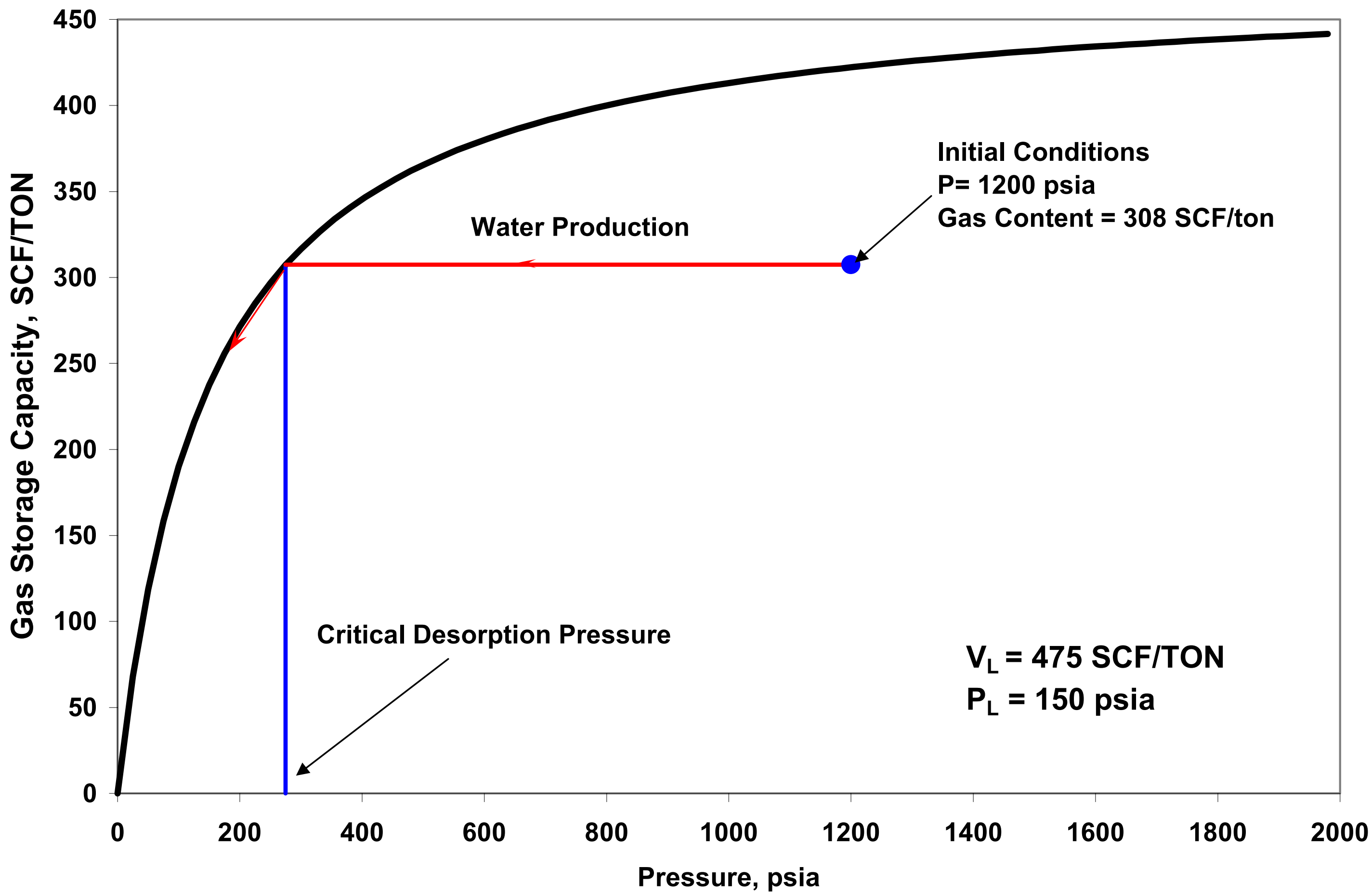

Figure 5. A Typical Langmuir Isotherm

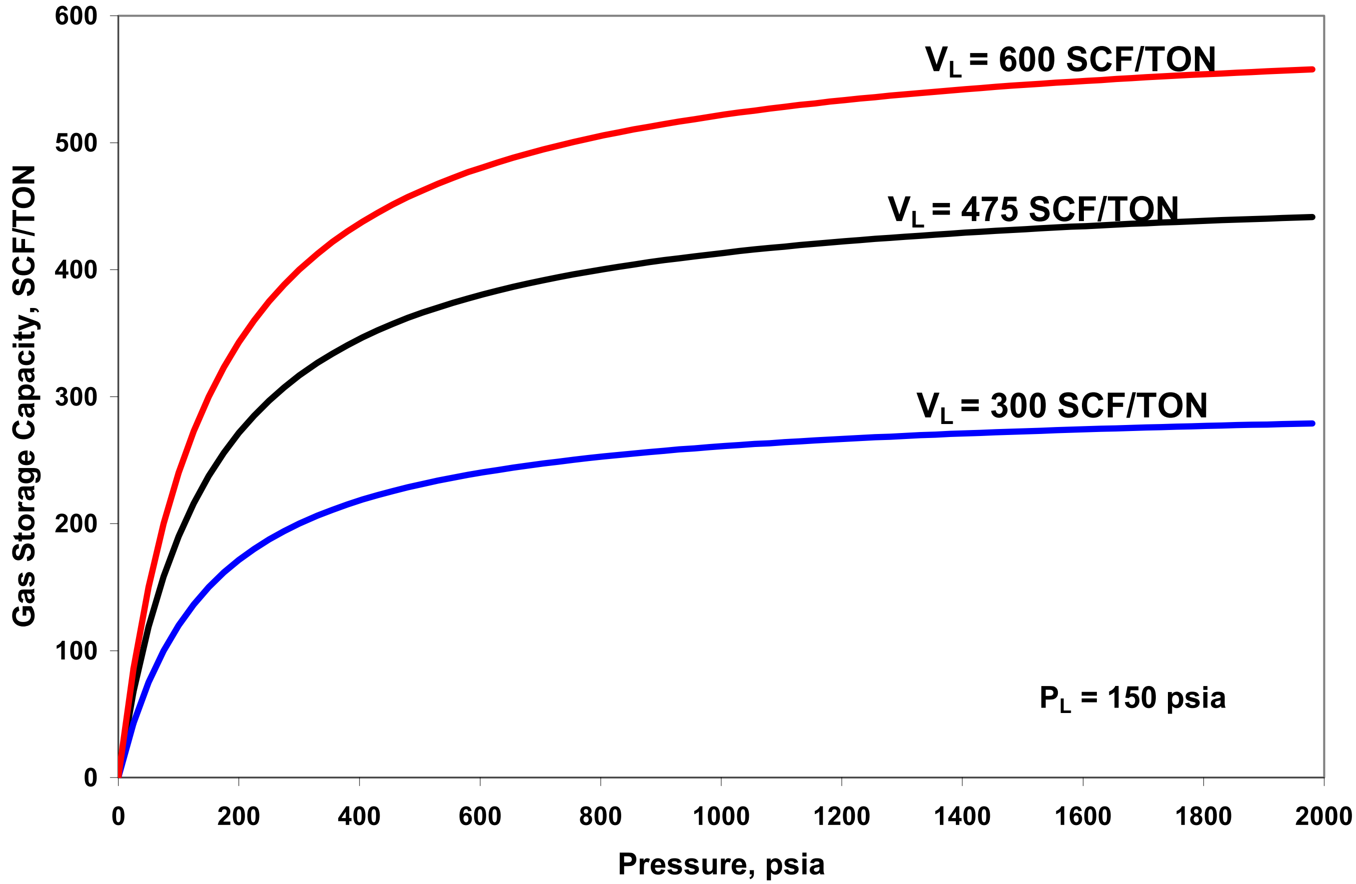

Figure 6. The Impact of Langmuir Volume Constant on the Isotherm

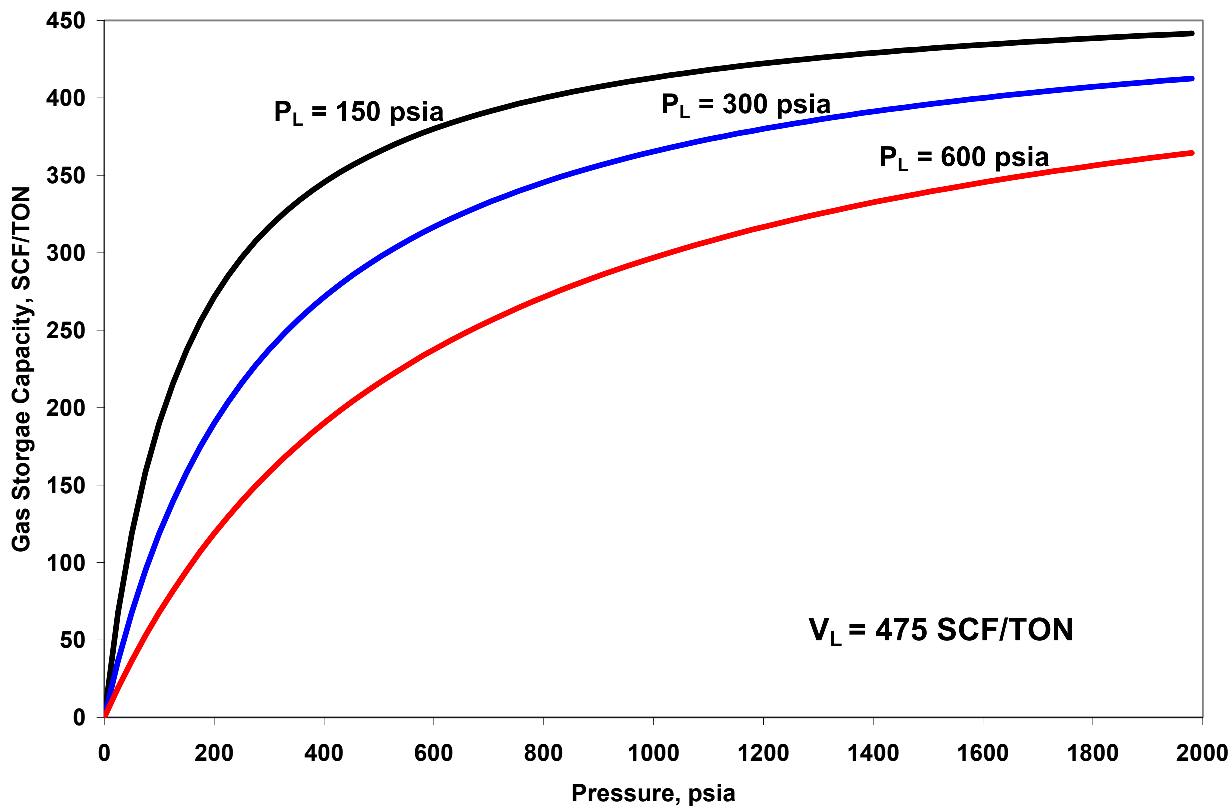

Figure 7. The Impact of Langmuir Pressure Constant on the Isotherm

basis of weight. Gas content of the coal is measured by desorption testing, which involves taking coal core, placing it in a container, and measuring the gas that evolves. If initially the gas content of the coal is below equilibrium with the isotherm, as illustrated in Figure 5, no free gas will be present and the cleats will be filled with water.

Production

Most CBM reservoirs initially produce only water because the cleats are filled with water. Typically, water must be produced continuously from coal seams to reduce reservoir pressure and release the gas. The cost to treat and dispose the produced water can be a critical factor in the economics of a coalbed methane project. Once the pressure in the cleat system is lowered by water production to the "critical desorption pressure," gas will desorb from the matrix. Critical desorption pressure, as illustrated on Figure 5, is the pressure on the sorption isotherm that corresponds to the initial gas content. As the desorption process continues, a free methane gas saturation builds up within the cleat system. Once the gas saturation exceeds the critical gas saturation, the desorbed gas will flow along with water through the cleat system to the production well.

Gas desorption from the matrix surface in turn causes molecular diffusion to occur within the coal matrix. The diffusion through the coal matrix is controlled by the concentration gradient and can be described by Fick's Law:

$$q_{gm} = 2.697 \sigma D \rho_c V_c (\overline{G_c} - G_s)$$

Where:

q_{gm} = Gas production (diffusion) rate, MCF/day

σ = matrix shape factor, dimensionless

D = matrix diffusivity constant, sec^{-1}

V_c = Matrix volume, ft^3

ρ_c = Matrix Density, g/cm^3

$\overline{G_c}$ = Average matrix gas content, SCF/ton

Diffusivity and shape factor are usually combined into one parameter, referred to as sorption time, as follows:

$$\tau = \frac{1}{\sigma D}$$

Sorption time (τ) is the time required to desorb 63.2 percent of the initial gas volume. The Sorption time characterizes the diffusion effects and generally is determined from desorption test results.

Darcy's law can adequately represent the two-phase flow in the cleat system. Cleat system porosity, permeability and relative permeability control fluid flow within the cleat system. As the desorption process continues, gas saturation within the cleat system increases and flow of methane becomes increasingly more dominant. Thus, water production declines rapidly until the gas rate reaches the peak value and water saturation approaches the irreducible water saturation. The typical production behavior of a CBM reservoir is illustrated in Figure 8. After the peak gas rate production is achieved, the behavior of CBM reservoirs becomes similar to conventional gas reservoirs.

Coalbed methane production behavior is complex and difficult to predict or analyze, especially at the early stages of recovery. This is because gas production from CBM reservoirs is governed by the complex interaction of single-phase gas diffusion through the micropore system (matrix) and two-phase gas and water flow through the macropore (cleat) system, that are coupled through the desorption process. Therefore, conventional reservoir engineering techniques cannot be used to predict CBM production behavior. The best tool to predict the performance of CBM reservoirs is a numerical reservoir simulator that incorporates the unique flow and storage characteristics of CBM reservoirs and accounts for various mechanisms that control CBM production. In addition, history matching with a simulator is one of the key tools for determining reservoir parameters that are often difficult to obtain by other techniques.

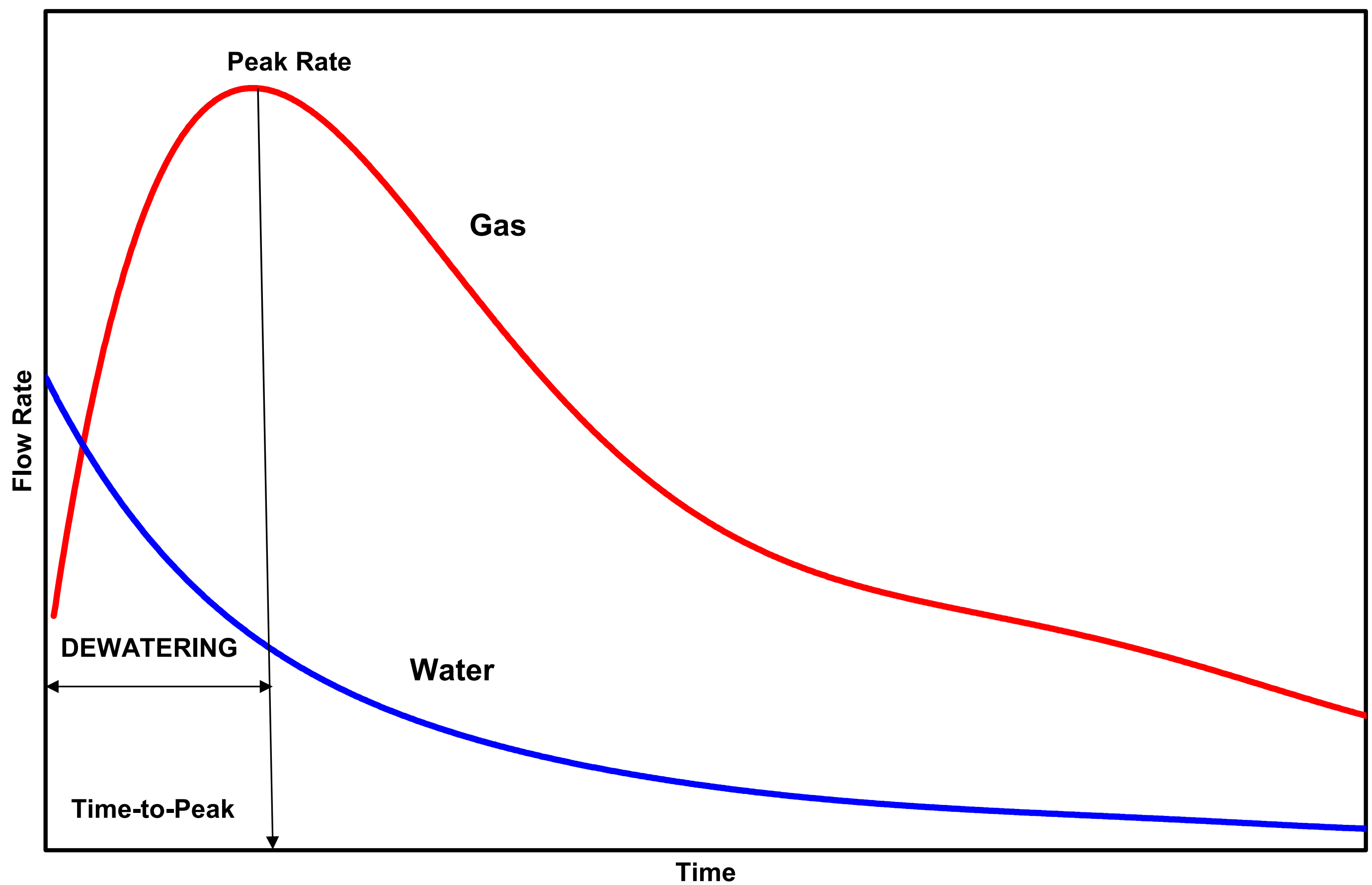

Figure 8. Typical Production History of A CBM Reservoir

Mechanical Properties

Several mechanical properties of coal are significantly different from most reservoir rock, as summarized in Table1. Coal is relatively compressible compared to the rock in many conventional reservoirs. Thus, the permeability of coal is more stress-dependent than most reservoir rocks. The orientation and magnitude of stress can strongly influence coalbed methane recovery. Permeability and porosity are functions of the net stress in the system. Because the vertical stress does not change during reservoir production, changes in pore pressure result in changes in effective stress. In the absence of other factors, porosity and permeability will decrease as pore pressure drops. At the same time, gas desorption is thought to cause a reduction of the bulk volume of the coal matrix. When this occurs, the pore volume of the natural fracture system is hypothesized to increase, resulting in an increased fracture system porosity and permeability.

The friable, cleated nature of coal affects the success of hydraulic fracturing treatments, and in certain cases allows for cavitation techniques to dramatically increase production. Strength of the coal reaches a minimum where cleats are more closely spaced. As a result, obtaining competent core samples from coals with well-developed cleat systems is not possible. Therefore, porosity and permeability, and relative permeability of the fracture system, cannot be accurately determined from core analysis. Properties of the fracture system are usually determined from well testing and/or history matching with a reservoir simulator.