Coalbed Methane Properties

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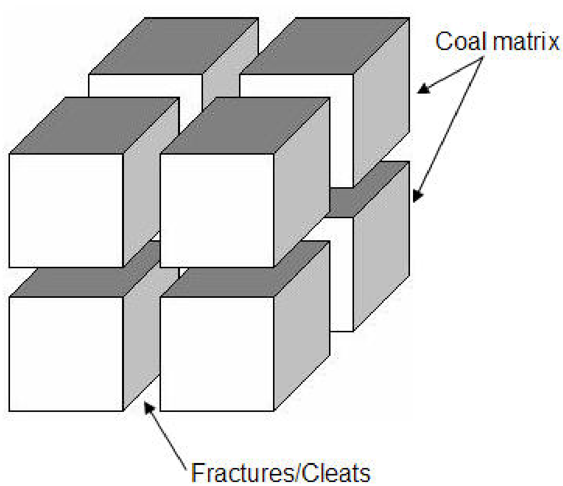
- History Matching Using Gas Permeability (CBM)

Coalbed methane (CBM) is the natural gas contained within coal. Characteristics of CBM reservoirs differ from conventional reservoirs in several areas. Unlike conventional gas reservoirs, coal is both the reservoir rock and the source rock for methane. Coal is a heterogeneous and anisotropic porous media characterized by two distinct porosity systems: macropores or cleats, and micropores or matrix. The cleats constitute the natural fractures ` common to all coal seams. The matrix contains the vast majority of the gas.



The gas storage mechanism is unlike what is found in a conventional reservoir. In a typical gas reservoir, gas is compressed by the pressure in the formation. Expansion of the gas provides the means for the gas to be produced. In a coal reservoir, the gas is stored within the coal matrix by a process known as adsorption (*not a***b***sorption*). In adsorption, gas molecules adhere to the surface of the coal. As the reservoir pressure is reduced, gas is released from the coal surface, diffuses through the coal matrix, and flows through the fracture system of the coal.

The capacity of coal to adsorb gas is described by a pressure relationship called the Langmuir Isotherm.

A comparison of conventional and CBM reservoirs is shown below:

Characteristic	Conventional	CBM
Gas Generation	Gas is generated in the source rock, 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 declines Little or no water GWR decreases with time	Gas rate increases with time then declines Initial production is mostly water GWR increases with time
Mechanical Properties	Young's Modulus ~10^6 Pore Compressibility ~10^{-6} psi^{-1}	Young Modulus ~10^5 Pore Compressibility ~10^{-4} psi^{-1}

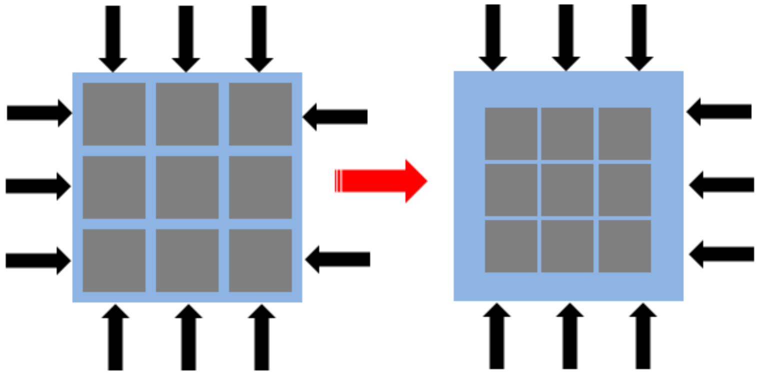
Permeability-Pressure Relationship

The absolute permeability in coal can change due to changes in the pressure of the formation as it is depleted. There are two main components to consider when creating a permeability-pressure relationship:

- Coal compressibility
- Matrix shrinkage

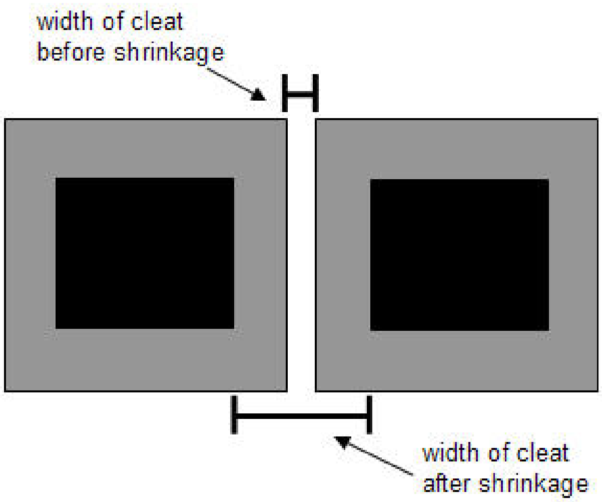
Coal Compressibility

In naturally-fractured reservoirs, the rock compressibility can play a significant role in the deliverability potential of the well. As the pressure decreases, the overburden compresses the cleats thereby reducing the permeability. A schematic of this behaviour is shown in the following picture.



Matrix Shrinkage

Gas is stored within the porous structure of the coal matrix. As gas is desorbed from the coal, the pressure exerted by the gas in these pores decreases. This causes the volume of the coal matrix to reduce in size. A reduction in the matrix size simultaneously acts to widen the cleats thereby increasing permeability.



A more thorough development of matrix shrinkage/swelling has been suggested by a variety of literature sources. Four relations that relate matrix shrinkage to porosity were proposed by the following authors:

Seidle and Huitt

This general model was created from experimental analysis from high volatile C bituminous coal from the San Juan Basin. Seidle and Huitt obtained results for the following relationship of coal swelling due to gas sorption:

$$\frac{\phi}{\phi_i} = 1 + \left(1 + \frac{2}{\phi_i}\right) C_m(10^{-6}) V_L \left(\frac{p_i}{p_L + p_i} - \frac{p}{p_L + p}\right)$$

where:

$$C_m = \frac{\varepsilon_{exp} + C_p\, p}{V_L\left(\frac{p}{p_L + p}\right)}$$

To relate permeability to porosity, the following relation is used:

$$\left(\frac{k}{k_i}\right) = \left(\frac{\phi}{\phi_i}\right)^n$$

The exponent n is typically set to 3, although it could be higher (12 or more), according to experimental evidence.

Palmer and Mansoori

Palmer and Mansoori also created a matrix shrinkage model. This model calculates pore volume compressibility and permeability in coals as a function of effective stress and matrix shrinkage using a single equation. It is appropriate for uniaxial strain conditions, as expected in a reservoir. It accounts for grain compression/expansion, and is suitable for porosity changes less than 30%.

This model uses elastic moduli to describe the effect of changing pressure on the coal volume. The formulation is as follows:

$$\frac{\phi}{\phi_i} = 1 + \frac{c_{ma}}{\phi_i}(p - p_i) + \frac{\varepsilon_l}{\phi_i}\left(\frac{K}{M}\right)\left(\frac{p}{p_L + p} - \frac{p_i}{p_L + p_i}\right)$$

where:

$$c_{ma} = \frac{1}{M} - \left(\frac{K}{M} + f - 1\right)\gamma$$

and

$$\frac{K}{M} = \frac{1}{3}\left(\frac{1+\upsilon}{1-\upsilon}\right)$$

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Shi and Durucan

This newer stress formulation makes a direct link between volumetric matrix strain and the amount of gas desorbed. This model can be extended to account for adsorption-induced matrix swelling as well as matrix shrinkage during enhanced methane recovery involving the injection of an inert gas or gas mixture into the seams.

The Shi and Durucan model uses the same compression term as the Palmer and Mansoori model, but uses a stronger matrix shrinkage term, which generally results in a stronger rebound in permeability in the course of coalbed reservoir depletion. The model is given below:

$$k = k_i \, e^{-3 \, c_f(\sigma - \sigma_i)}$$

Above the critical desorption pressure p_d ($p_i > p > p_d$):

$$\sigma - \sigma_i = -\frac{\upsilon}{1-\upsilon}(p - p_i)$$

At or below the critical desorption pressure p_d ($p_d \geq p > 0$):

$$\sigma - \sigma_i = -\frac{\upsilon}{1-\upsilon}(p - p_i) + \frac{E}{3(1-\upsilon)}\varepsilon_l\left(\frac{p}{p + p_\varepsilon} - \frac{p_d}{p_d + p_\varepsilon}\right)$$

Constant Exponent Permeability Incline

This empirical approach was developed by BP and Fekete based on observation of matrix shrinkage in coal from the San Juan Basin. This correlation is only applicable to this particular geographical location.

In this model, the relationship between permeability and pressure is stated as:

$$I = -\frac{1}{k}\frac{\partial k}{\partial p} \quad [\%/psi]$$

The negative sign is necessary as permeability and pressure change in opposite directions. Integrating this equation and imposing the initial condition of $k = k_i$ when $p = p_i$ will lead to:

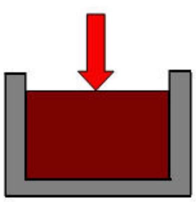
$$\frac{k}{k_i} = e\left(I(p_i - p)\right)$$

Moduli Definitions

Young's Modulus of Elasticity is defined as the ratio between axial stress and strain. It describes the elastic nature of a given substance and can conveniently describe the amount of deformation of a given object when a given stress is applied. Often this is referred to as the "stiffness" of a material. The greater the value of the modulus, the less deformation occurs at a given pressure. Examples of different moduli values include high-strength concrete is (4.5E6 psi) and a more ductile material, such as polystyrene (0.45E6 psi).

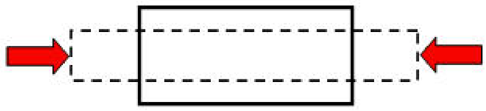
$$E = \frac{\sigma}{\varepsilon}$$

Constrained Axial Modulus is defined as the ratio between axial stress and strain, but strain in only one axis is allowed. The compressed material is bounded on the sides, but not in the direction force is applied, as in the following diagram.



Bulk Modulus is the ratio of the change in pressure to the fractional volume compression of the material. For example, the bulk modulus for steel is $160 * 10^9$ Pa while water is at $2.2 * 10^9$ Pa. Therefore, in an environment where the pressure is $2.2 * 10^7$ Pa, we would expect the fractional change in water to be 1.0%.

Poisson's ratio (υ) relates changes in size of an object along different axes. When compressive force is applied to a particular axis of a material, there is tensile deformation along a different axis than from which the force was applied. Poisson's ratio is the ratio of contraction strain to extension strain. To give the value a direction, positive is said to be when strain occurs in the direction of a stretching force.



Relative Permeability

There are three relative permeability correlations that can be used for CBM:

1. Corey
2. Honarpour
3. Generalized Corey

There is also an option to enter custom-defined relative permeability curves. For more information, see Relative Permeability.

Aquifer

Aquifer support is important with respect to material balance calculations. Including water in the general material balance equation results in:

Produced Gas + Produced Water = (Initial Gas – Remaining Gas) + (Initial Water – Remaining Water + Water Influx)

Aquifer support is represented by the water influx term. There are two models for determining aquifer influx:

1. Schilthuis Steady-State Model
2. Fetkovich Model

Schilthuis Steady-State Model (Infinite-Acting Aquifers)

This model assumes that the pressure of the aquifer remains constant, and is equal to the initial reservoir pressure. The water influx is proportional to the pressure drawdown as defined by the productivity index, J.

The general equation for calculating water influx at any point in time is as follows:

$$W_e\,(t) = J * (p_i - p_{(t)}) * \Delta t$$

Fetkovich Model (Finite Volume Aquifers)

This model assumes the aquifer to be in pseudo-steady state, and therefore depletes according to the material balance equation. It is dependent on the transfer coefficient, and the volume of the aquifer.

The general equation for calculating water influx at any point in time is as follows:

$$W_e(t) = \frac{W_{ei}}{p_i} * \left(p_{(t-1)} - p_{(t)}\right) * (1 - e^{-\frac{J p_i \Delta t}{W_{ei}}})$$

$W_{ei} = c_w p_i V_{aq}$

Deliverability

CBM reservoir calculations are based on the assumption of a radial reservoir in pseudo-steady state flow. Gas production rates can therefore be calculated in terms of the average reservoir pressure according to the following equation:

$$q_g = \frac{k_g h\left[\Psi\left(\bar{P}\right) - \Psi\left(p_{wf}\right)\right]}{1422T\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4} + s\right]}$$

Where:

h = net pay (ft)

k_g = gas effective permeability (md)

Ψ () = gas pseudopressure ($psia^2/cp$)

p = average reservoir pressure (psia)

p_{wf} = bottomhole flowing pressure (psia)

q_q = gas rate (mscfd)

r_e = external radius of the reservoir (ft)

r_w = wellbore radius (ft)

s = skin

T = temperature (°R)

Water rates can be calculated in a similar fashion, according to the following equation:

$$q_w = \frac{k_g h\left[\bar{P} - p_{wf}\right]}{141.2\,\mu_w B_W\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4} + s\right]}$$

Where:

B_w = water formation volume factor (bbl/stb)

h = net pay (ft)

k_w = water effective permeability (md)

$\bar{P}$ = average reservoir pressure (psia)

p_{wf} = bottomhole flowing pressure (psia)

q_w = water rate (bbl/d)

r_e = external radius of the reservoir (ft)

r_w = wellbore radius (ft)

s = skin

μ_w = water viscosity (cp)

Forecasting

In order to create a forecast, the deliverability equation is used in conjunction with the material balance equation.

The procedure is as follows:

1. At any given point in time, the average reservoir pressure is known from the material balance equation and the cumulative production. Using the average reservoir pressure and the specified flowing pressure, the gas and water deliverability equations can be used to calculate q_g and q_w. This rate is assumed to stay constant over the specified time period.

2. The total gas and water produced over the time period is calculated as follows:

   Gas Produced = $q_g\ \Delta t$
   Water Produced = $q_w\ \Delta t$

3. The gas and water produced during the given timestep is added to the cumulative gas and water production, and a new reservoir pressure is determined using the material balance equation.

4. The procedure is repeated until abandonment conditions are met.

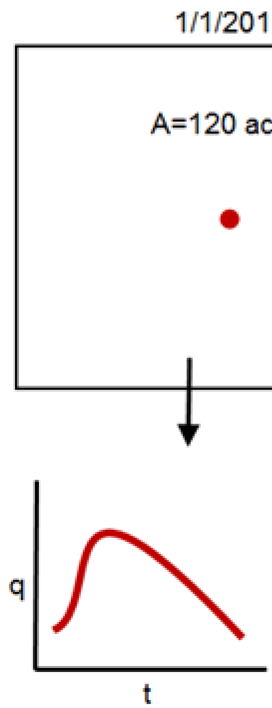
   Note: CBM forecasting uses the King Material Balance method.

Acceleration

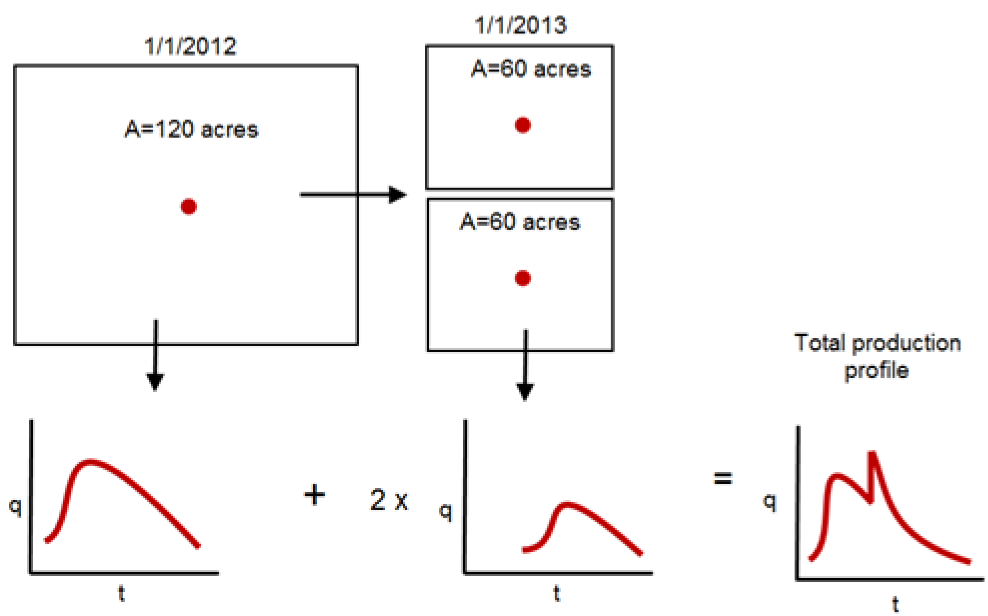
CBM fields generally consist of close well spacing in order to accelerate the dewatering phase of production. The acceleration feature is designed to simulate the production acceleration effects of a higher density of wells within the specified drainage area. This feature functions by dividing the drainage area by the number of wells, and modeling each well as its own tank. All the wells have the same reservoir properties (except area), but can have different start dates.

See the example below:

1. One well begins draining an area of 120 acres on 1/1/2012



2. On 1/1/2013, a second well is put on production. The original area is divided by two. In this case, each well drains an area of 60 acres. The production profile for each of the wells is exactly the same; therefore, the profile from 1/1/2013 onward is two times the production profile of a well draining 60 acres. This causes a spike in production on 1/1/2013.



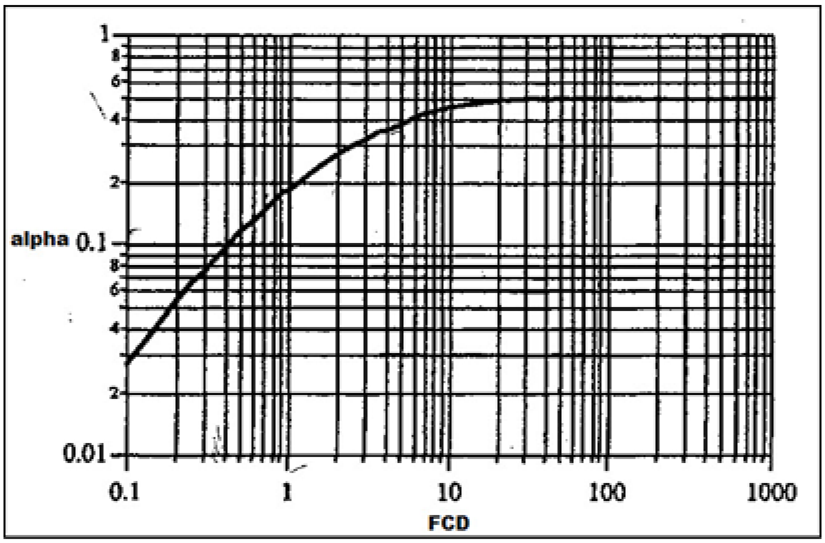
Fracture Equivalent Skin

Forecasting and history matching in the PSS model assume a vertical well with a skin. To model a fractured well, a formula relating fracture half length (x_f) and dimensionless finite conductivity (F_{CD}) can be used to calculate an equivalent skin.

Skin can be calculated from fracture half-length using the following formula:

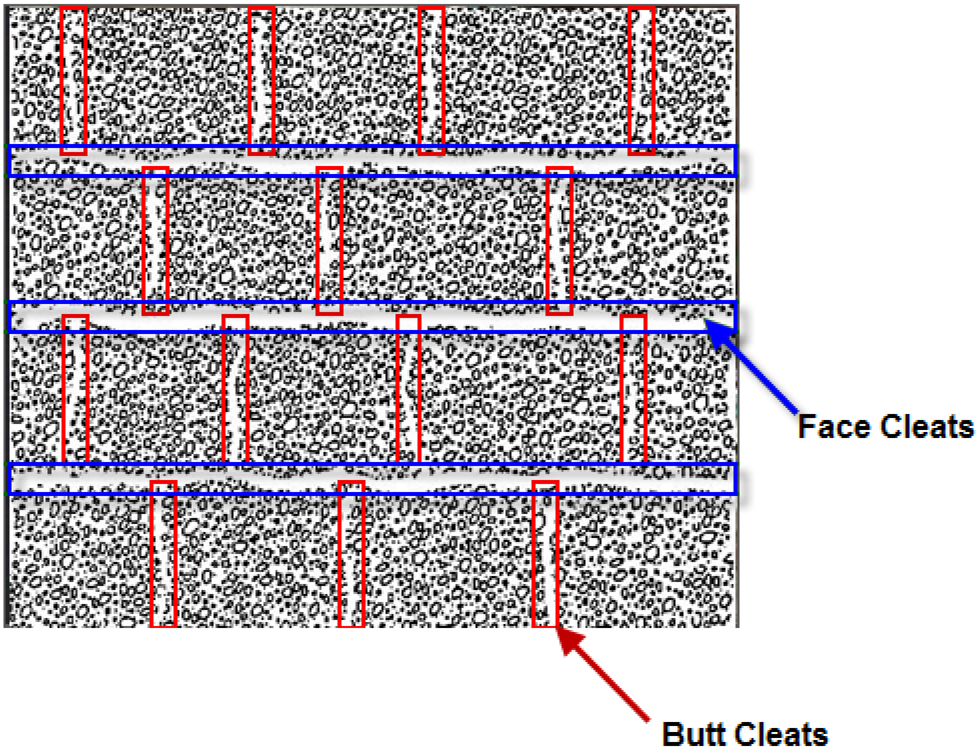
$$s = \frac{-\ln(\propto x_f)}{r_w}$$

α is a function of the fracture dimensionless conductivity (F_{CD}) as illustrated in the figure below.

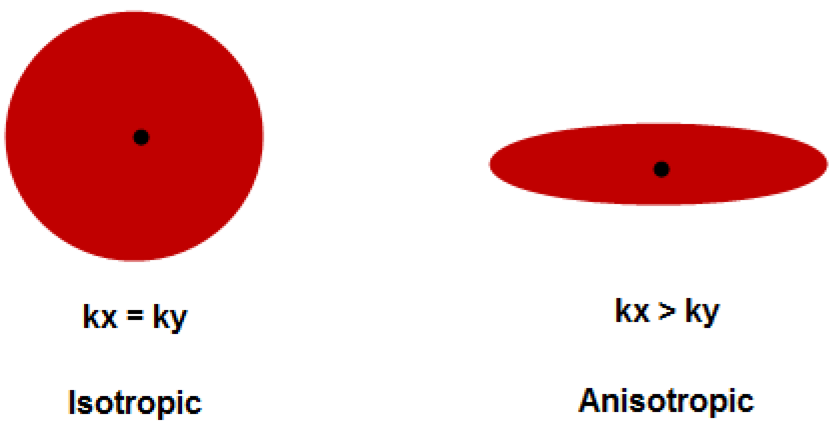


Elliptical Drainage / Permeability Anisotropy

Many CBM reservoirs display permeability anisotropy, meaning the permeability in the x direction is not the same as the permeability in the y direction. Coal is naturally fractured, with closely spaced, regular, planar fractures that are collectively known as cleats. There are two main cleat types: face cleats and butt cleats. Face cleats act as the main channels for flow in coal. Butt cleats typically terminate perpendicularly to a face cleat.



Face cleats are longer and more continuous than butt cleats, and are therefore the main conduits for flow. This causes permeability anisotropy, and therefore elliptical drainage patterns, with flow favouring the direction of the face cleats.



The x and y permeability of an anisotropic system can be converted to an equivalent isotropic permeability as follows:

$$k = \sqrt{k_x * k_y}$$

A circular drainage pattern can be converted to an ellipse by calculating the major and minor axes of the ellipse using the radius of the circle as well as k_x and k_y:

$$r = \sqrt{\frac{A}{\pi}}$$

$$Ellipse\ axis\ x = r * \sqrt[4]{\frac{k_x}{k_y}}$$

$$Ellipse\ axis\ y = r * \sqrt[4]{\frac{k_y}{k_x}}$$

History Matching Using Gas Permeability (CBM)

Harmony includes a feature that allows history matching of gas permeability calculated from production data. This technique is based on SPE 107705 (Clarkson et al., 2007). In this method, gas permeability is calculated from production data by re-arranging the standard gas rate deliverability equation:

$$k_{g\_production} = \frac{1422 q_g T\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4} + s\right]}{h\left[\psi\left(\bar{p}\right) - \psi\left(p_{wf}\right)\right]}$$

In the above equation, gas permeability (k_g) is calculated for each historical data point using the measured gas rate (q_g) and flowing pressure (p_{wf}) at this point. It should be noted that r_e, r_w, s, and h are all user inputs, and $\bar{p}$ is calculated from the model and material balance equations; therefore, the calculated gas permeability is not a true historical value in the same sense as gas rate and flowing pressure.

Synthetic gas permeability is then calculated using the initial absolute permeability (k_i), the specified matrix shrinkage correlation, and the relative permeability curves using the following sequence of calculations:

1. Using the material balance equation and model inputs, calculate the average reservoir pressure and water saturation for each time step.

2. Use the specified matrix shrinkage correlation to determine the permeability ratio at each calculated reservoir pressure. See Matrix Shrinkage for additional information.

3. Multiply the permeability ratio from step 2 by the given k_i value to calculate the absolution permeability (k_{abs}) at each reservoir pressure.

4. Use the water saturation calculated in step 1, and the given relative permeability curves, to determine the gas relative permeability (k_{rg}) at each reservoir pressure.

5. Multiply the k_{abs} from step 3 by the k_{rg} to determine the gas permeability ($k_{g\_synthetic}$) at each reservoir pressure.

The calculated $k_{g\_production}$ and $k_{g\_synthetic}$ are plotted versus reservoir pressure. If the model inputs are correct, $k_{g\_production}$ and $k_{g\_synthetic}$ should plot together. If they do not match, the model inputs can be changed until a satisfactory match is obtained.

In theory, if the k incline matrix shrinkage correlation is selected, the slope of the k_g vs P plot should give the value for the permeability incline rate (I). See Constant Exponent Permeability Incline for additional information.