A New Model for Shale Gas Matrix Flow Using the Dynamic-Slippage Concept

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Background

For gas flow through some tight gas reservoirs, the mean-free path of gas molecules may be non-negligible compared to the average effective rock pore throat radius causing the gas molecules to "slip" along pore surfaces – this slip-flow creates an additional flux mechanism which may be additive to viscous flow. This additional flux can cause apparent gas permeability (k_a) to be higher than permeability derived from single-phase flow of a liquid through the same porous medium. Historically, the Klinkenberg method has been used to "correct" effective gas permeability to a liquid-equivalent permeability using a "gas-slippage" factor:

$$k_a = k_\infty \left(1 + \frac{b}{\overline{p}}\right) \quad \text{...(1)}$$

The gas-slippage factor is usually derived from core data by plotting apparent gas permeability versus the reciprocal mean pressure ($1/\overline{p}$). This procedure generally assumes that b is constant, although b has been observed to increase with increasing pressure. Klinkenberg (1941) derived the following expression for the slippage factor, which illustrates the effect of mean-free path and pore radius on the magnitude of the slippage factor:

$$\frac{b}{\overline{p}} = \frac{4K_1\overline{\lambda}}{r_c} \quad \text{...(2)}$$

In 1986, Ertekin et al. introduced a novel method to account for dual-mechanism (pressure- and concentration-driven) flow in tight formations. Pressure-driven flow was modeled using Darcy's Law, while concentration-driven flow associated with gas-slippage along the pore wall boundaries was modeled with Fick's Law. An apparent Klinkenberg gas-slippage factor for single- and multi-phase flow was introduced - in this formulation, the gas-slippage factor (b) is not constant, which is commonly assumed for tight gas reservoirs, but is pressure-composition-saturation-dependent. In Ertekin et al.'s work, desorption of gas from organic matter was not accounted for, nor was diffusion of gas through the organic matter microporosity.

Recently, observations of shale gas pore structure have shown that shale organic matter contains nanopores, and a wide distribution of pore sizes may exist in some shale gas reservoirs (ex. Loucks et al., 2009). Adsorption of gases is also known to occur in the organic matter. According to Wang and Reed (2009), four types of porous media may be present in gas shales: organic matter, nonorganic matrix, natural fractures and pore space created by hydraulic fractures. Gas flow through the shale matrix may therefore be expected at several scales and by several mechanisms. Javadpour (2009) suggests that several mechanisms for flow can occur in gas shales including advective, slip-flow and diffusion; he demonstrated the pressure and temperature-, gas composition- and pore size-dependence of apparent gas permeability. A common method for establishing which flow mechanisms may be contributing is through the use of the Knudsen number, defined as:

$$K_n = \frac{\overline{\lambda}}{l_c} \quad \text{...(3)}$$

Where l_c is the characteristic length of the flow geometry. Florence et al. (2007) derived a "microflow" model which relates the k_a to Knudsen number for tight gas reservoirs:

$$k_a = k_\infty \left[1 + \alpha(K_n) K_n \right] \left[1 + \frac{4K_n}{1 + K_n} \right] \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots(4)$$

New Methodology for Modeling Gas Flow through the Shale Matrix

Recognizing that flow through the shale gas matrix may occur through a variety of mechanisms, and that the relative importance of each flow mechanism is dependent on gas pressure/composition and pore size, we have attempted to derive a methodology that captures the essential elements of flow while keeping the methodology simple enough that commercial simulator algorithms will require little to no modification to approximate flow through these complex reservoirs.

In the present work, the shale gas matrix is conceptualized to have a multi-modal pore structure, consistent with recent observations. Flow through the larger (meso/macro) porosity in the inorganic fraction is modeled using a similar approach to Ertekin et al. (1986). A dynamic gas-slippage factor is incorporated into the transport equation. Gas is assumed to be adsorbed in the organic matter, and the model accounts for diffusion of gas through the organic matter (micro) pore structure. In effect, the new model for shale matrix flow is similar to dual porosity (fracture + matrix) models developed for CBM reservoirs, except flow through the inorganic fraction of the shale is assumed to occur by multiple mechanisms and takes the place of fracture flow in CBM simulation. The mathematical model used to describe flow through the matrix is given below:

$$\frac{\partial}{\partial x}\left(\beta_c \frac{A_x k_{\infty x}}{\mu_g B_g K_g} \frac{\partial P}{\partial x} \right)\Delta x + \frac{\partial}{\partial y}\left(\beta_c \frac{A_y k_{\infty y}}{\mu_g B_g K_g} \frac{\partial P}{\partial y} \right)\Delta y + q_{sc} + q_m = \frac{V_b \phi}{\alpha_{c1}} \frac{\partial}{\partial t}\left(\frac{1}{B_g} \right) \dots\dots\dots\dots(5)$$

which describes flow of gas through a 2-D shale matrix (Cartesian coordinates) with an incompressible pore volume. Dynamic-slippage is incorporated into the K_g term as follows:

$$K_g = \left(1 + \frac{b_a}{p} \right)^{-1} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots.(6)$$

Where:

$$b_a = \frac{p c_g \mu_g D}{\alpha_{c2} k_\infty} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots.(7)$$

Note that the pressure-temperature-composition-dependence of b_a occurs through the $p c_g \mu_g$ term. The diffusion coefficient, D, is assumed to be independent of pressure. The source term q_m represents flow from the organic matter (via diffusion) to the inorganic framework. Alternatively, Eq. 5 could represent flow through meso/macroporosity of the organic matter, with q_m representing flow from the organic matter microporosity. In either case, all of gas that flows from microporosity to the larger pores represented by Eq. 5 was originally in the adsorbed state. q_m could be calculated using sophisticated matrix transport models such as the bidisperse diffusion model of Clarkson and Bustin (1999); for the sensitivities described below, we have used the simple single diffusion parameter, pseudo steady-state approach that is commonly used to describe flow from microporosity to the fracture system in CBM simulators. Eq. 5 therefore represents a multi-mechanism flow model through the shale matrix.

Modeling the Gas-Slippage Factor

The pressure-dependence of the dynamic gas-slippage factor was investigated for a range of reservoir/fluid properties using Eq. 7 and the procedure described by Ertekin et al. (1986). The apparent gas-slippage factor and Klinkenberg correction factor $(1+b_a/p)$ for one combination of reservoir/fluid properties is given in **Figure 1**.
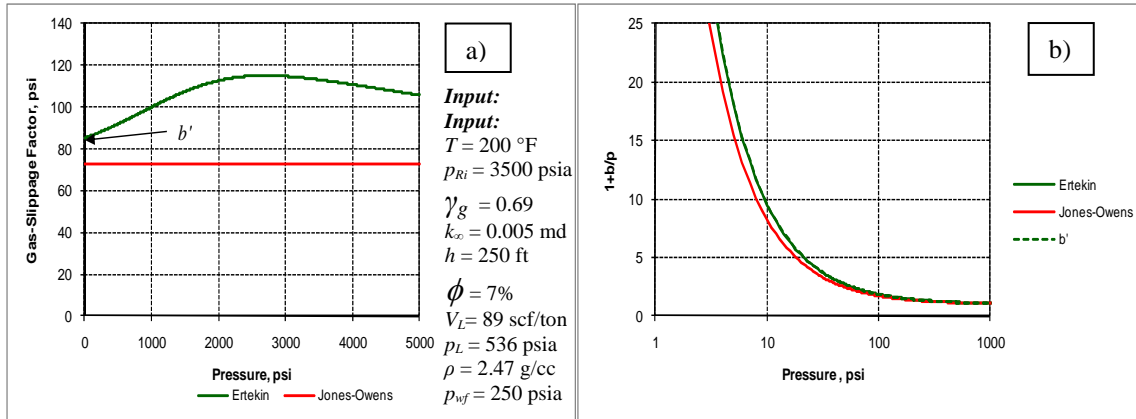
Figure. 1. Plot illustrating (a) pressure-dependence of gas-slippage factor using the Ertekin et al. (1986) approach (green solid line) and (b) associated Klinkenberg correction factor. Also shown is the Jones-Owens calculation for gas-slippage (constant b, red solid line) and associated Klinkenberg correction factor. Although significant deviation in calculated Klinkenberg correction exists using the dynamic- (Ertekin) and static- (Jones-Owens) slippage factor approaches, a reasonable approximation can be achieved using a static-slippage factor equal to the low-pressure limit (b') of the dynamic-slippage factor.

A significant change in b_a occurs with pressure (Figure 1a, green line); the Klinkenberg correction is significant for pressures below 100 psi, translating into differences between apparent gas permeability and equivalent-liquid permeability. The calculated (static) slippage factor using the Jones-Owens (1979) approach (Figure 1a, red line) and associated Klinkenberg correction (Figure 1b) are also shown. There is a difference between the Klinkenberg corrections at low pressure. In this example, we have chosen a relatively large k_∞ for a shale gas reservoir – the difference in the 2 approaches for Klinkenberg correction (dynamic vs. static) will increase with a decrease in permeability/pore size, as shown by Ertekin (1986). However, the dynamic-slippage-derived Klinkenberg correction can be approximated using a static-slippage factor corresponding to the low-pressure limit (b') of the dynamic-slippage calculation (green dashed line in Figure 1b). This result is encouraging because it suggests that commercial simulators that assume a static-slippage factor may be used to approximate the effect of dynamic-slippage if this low-pressure limit is used rather than the Jones-Owens approach.

Impact of Dynamic-Slippage and Sorption on Shale Gas Forecasts

In order to investigate the impact of dynamic gas-slippage and adsorption/diffusion on shale matrix forecasts, a computer model was developed to solve Eq. 5 numerically, assuming pseudo steady-state diffusion from the organic matter to the inorganic matrix. Pore volume of the matrix was assumed to be static so that the effect of gas-slippage alone on apparent permeability change could be investigated. This model was then used to generate several forecasts for a single vertical well (skin -1) completed in a 1570.2 x 1109.7 ft (40 acre) reservoir (**Figure 2**):

- Case 1: assumes no matrix permeability change
- Case 2: assumes permeability change using the Ertekin dynamic-slippage model
- Case 3: assumes permeability change using the Jones-Owens (static) slippage
- Case 4: assumes no matrix permeability change and no gas desorption
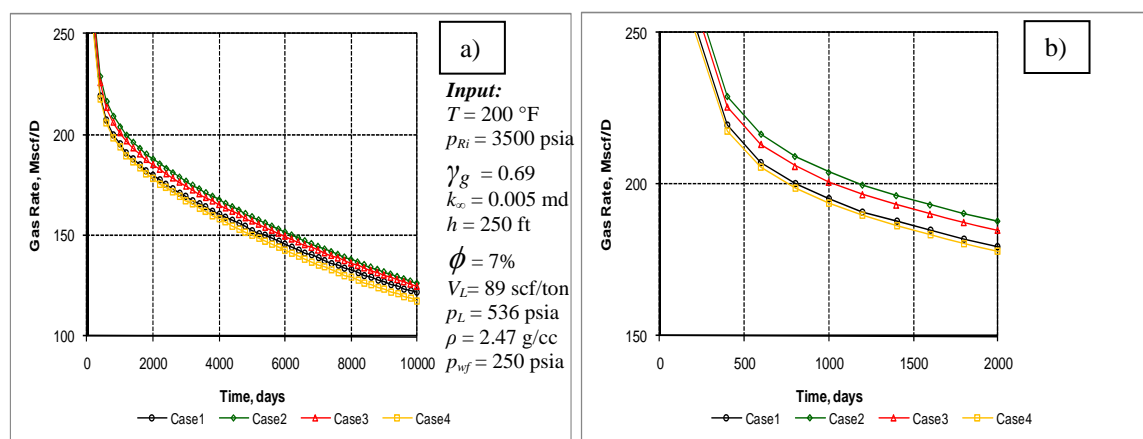
3

Input:
$T = 200\ °F$
$p_{Ri} = 3500$ psia
$\gamma_g = 0.69$
$k_\infty = 0.005$ md
$h = 250$ ft
$\phi = 7\%$
$V_L = 89$ scf/ton
$p_L = 536$ psia
$\rho = 2.47$ g/cc
$p_{wf} = 250$ psia

Figure. 2. Forecasts of using new shale matrix simulator. b) zooms in on the first 2000 days.

Case 2 (dynamic-slippage) yields the highest sustained gas rates over the forecast period (10000 days), whereas the assumption of no permeability change (no gas-slippage) and no desorption (Case 4) yielded the lowest sustained rates. The Jones-Owens calculation (static-slippage) yielded lower rates than dynamic-slippage due to lower predicted permeability growth (Figure 1). If the static-slippage factor is calculated using the low-pressure limit value (*b'*) obtained from the dynamic-slippage plot, the resulting forecasts are close to the forecast using the dynamic-slippage factor. The difference between the forecasts using the dynamic-slippage and static-slippage (calculated with Jones-Owens equation) is expected to increase with a decrease in permeability/pore size/pressure – we have assumed a relatively large k_∞ in this example.

Summary and Future Work

A new methodology for modeling shale gas matrix flow is introduced; multi-mechanism flow (Darcy flow/diffusion) through larger pores in the inorganic (or organic) matrix as well as time-dependent desorption from the organic matter micropore network is assumed. The model is formulated using the dynamic-slippage approach of Ertekin et al. (1986) and therefore should be easily incorporated into commercial simulators. Indeed, the static-slippage approach, which already exists in several commercial simulators, may be used to approximate apparent permeability growth if the low-pressure limit of the dynamic-slippage factor is used.

Future work will include the calculation of dynamic-slippage using other suggested approaches (ex. Javadpour, 2009) and the use of commercial simulators to establish the impact of dynamic-slippage on production forecasts using multi-fractured horizontal wells completed in shale gas plays with variable reservoir properties. Sensitivities to diffusion coefficient magnitude and pressure-dependence will also be performed.

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Nomenclature

A = drainage area, acres

A_x, A_y = gridblock cross-section area, normal to direction given in subscript (Eq. 5), ft^2

b = slippage factor, psi

b_a = apparent slippage factor, psi

B_g = gas formation volume factor, RB/scf

c_g = gas compressibility, psi^{-1}

D = diffusion coefficient, ft^2/D

h = formation thickness, feet

K_1 = proportionality constant

K_n = Knudsen number, dimensionless

k_a = apparent permeability, md

k_∞ = liquid-equivalent permeability, md

l_c = characteristic length of the flow geometry, cm

p = pressure, psi

$\overline{p}$ = mean pressure, psi

p_L = Langmuir pressure constant, psi

p_R = reservoir pressure, psi

p_{wf} = flowing bottomhole pressure, psi

q_{sc} = gas well production/injection rate, scf/D

r_c = capillary radius, cm

t = time, days

T = temperature, °R

V_b = bulk volume of the reservoir, ft^3

V_L = Langmuir volume constant, scf/ton

T = temperature, °R

α = rarefaction coefficient parameter, dimensionless

α_{c1} = unit conversion factor, 5.615

α_{c2} = unit conversion factor, 0.006328

β_c = transmissibility conversion factor, 0.001127

γ_g = gas gravity, air = 1

μ_g = gas viscosity, cp

ϕ = porosity, dimensionless, fraction

$\overline{\lambda}$ = mean free path, cm

ρ = density, g/cm^3