Forecasting Gas Production in Organic Shale with the Combined Numerical Simulation of Gas Diffusion in Kerogen, Langmuir Desorption from Kerogen Surfaces, and Advection in Nanopores

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Abstract

We introduce a new numerical algorithm to forecast gas production in organic shale that simultaneously takes into account gas diffusion in kerogen, slip flow, Knudsen diffusion, and Langmuir desorption. The algorithm incorporates the effects of slip flow and Knudsen diffusion in apparent permeability, and includes Langmuir desorption as a gas source at kerogen surfaces. We use the diffusion equation to model both lateral gas flow in kerogen as well as gas supply from kerogen to surfaces.

Slip flow and Knudsen diffusion account for higher-than-expected permeability in shale-gas formations, while Langmuir desorption maintains pore pressure. Simulations confirm the significance of gas diffusion in kerogen on both gas flow and stored gas. Relative contributions of these flow mechanisms to production are quantified for various cases to rank their importance under practical situations.

Results indicate that apparent permeability increases while reservoir pressure decreases. Gas desorption supplies additional gas to pores, thereby maintaining reservoir pressure. However, the rate of gas desorption decreases with time. Gas diffusion enhances production in two ways: it provides gas molecules to kerogen-pore surfaces, hence it maintains the gas desorption rate while kerogen becomes a flow path for gas molecules. For a shale-gas formation with porosity of 5%, apparent permeability of 59.7 μD, total organic carbon of 29%, effective kerogen porosity of 10%, and gas diffusion coefficient of $10^{-22}$ m²/s, production enhancements compared to those predicted with conventional models are: 9.6% due to slip flow and Knudsen diffusion, an extra 42.6% due to Langmuir desorption, and an additional 61.7% due to gas diffusion after 1 year of production. The method introduced in this paper for modeling gas flow indicates that the behavior of gas production with time in shale-gas formations could differ significantly from production forecasts performed with conventional models.

Introduction

Natural gas is an abundant source of energy which causes less pollution than other available fossil fuels. These features have made natural gas an attractive source of energy for both national security and environmental reasons. However, there exist countless technical challenges associated with the production of natural-gas reservoirs that need to be circumvented to meet the ever increasing demand for energy and replace the decreasing production from current reservoirs (Ground Water Protection Council and ALL Consulting 2009). Gas-bearing shale strata are an abundant source for gas production in North America, but there is no standard and reliable method to forecast gas production in these formations (Passey et al., 2010). Conventional models using Darcy’s equation underestimate actual production (Lu et al., 1995; Gault and Stotts, 2007; Javadvour, 2009; Sondergeld et al., 2010a; Ambrose et al., 2010; Kale et al., 2010; Sondergeld et al., 2010b; Freeman et al., 2010; Shabro et al., 2011a; Swami and Settari, 2012). Forecasting of gas production is necessary for the economical assessment of tight and unconventional gas-bearing formations.

Previously, we developed a pore-scale method to characterize slip and no-slip flow, Knudsen diffusion (Shabro et al., 2009), and Langmuir desorption-adsorption (Shabro et al., 2011a). The combined impact of these flow mechanisms in shale gas is to increase gas production in comparison to that calculated with conventional models. We invoked the permeability enhancement due to slip flow and Knudsen diffusion and quantified the corresponding apparent permeability in a one-
dimensional (1D) radial reservoir model (Shabro et al., 2011b). Reservoir and rock properties such as smoothness of mineral grain surfaces, pressure, temperature, and gas molar mass, in addition to pore-scale morphology, control apparent permeability. Langmuir desorption-adsorption mechanisms were implemented as sources of gas to porous media. In order to model Langmuir desorption-adsorption at non-equilibrium states, we used desorption and adsorption flow equations along with mass conservation balance at the adsorbent surface instead of invoking the Langmuir equilibrium equation (Shabro et al., 2011b). Langmuir desorption depends on chemical potential energy between gas and surfaces, as well as on pressure, and temperature.

In this paper, we implement a modified reservoir model to examine underlying physical transport mechanisms and to forecast gas production in shale-gas formations. Apparent permeability is used instead of constant permeability to capture the effect of slip flow and Knudsen diffusion on permeability. Kerogen surfaces are implemented as sources of gas in the reservoir model. The source term is a combination of desorption and adsorption fluxes. At the initial condition, the equilibrium state dictates that desorption and adsorption fluxes be equal. At the onset of gas production, adsorption flux decreases due to pressure drop, and surfaces effectively desorb gas. We use a previously developed criterion to model gas desorption at the non-equilibrium state where desorption flux surpasses adsorption flux during production (Shabro et al., 2011b). Gas diffusion in kerogen is added to the reservoir model by means of supplying gas from kerogen bodies to surfaces. At equilibrium conditions, gas concentrations at kerogen surface and body are identical. Once gas concentration at the surface decreases due to gas desorption, the resulting gas concentration gradient invokes the gas diffusion mechanism. In turn, gas diffusion in kerogen is a very slow process at the geological framework; nonetheless, a significant gas concentration gradient makes gas diffusion an important part of modeling gas production in shale-gas formations.

The developed model quantifies the impact of each transport mechanism in shale-gas production. It also confirms that the additional physical transport mechanisms give rise to measurable deviations from conventional models used to forecast gas production. The new model relies on fundamental fluid transport mechanisms; therefore, it provides a physical understanding of unconventional gas production performance in shale formations. Limitations include the assumption of single phase flow in a 1D radial reservoir and neglect of the effect of fractures.

Firstly, we invoke a reservoir model (Shabro et al., 2011b) to simultaneously take into account the effects of slip and no-slip flows, Knudsen diffusion, and Langmuir desorption-adsorption. Next, we implement a numerical algorithm to model gas diffusion between kerogen surfaces and bodies. The model is applied to several practical cases to better understand the interplay effects of the various transport mechanisms and to quantify the contribution of each mechanism over time. We conclude by summarizing the importance of each flow mechanism involved in the calculations.

**Reservoir Modeling of Slip Flow, Knudsen Diffusion, and Langmuir Desorption**

We implement a modified 1D radial reservoir model (Shabro et al., 2011b) to take into account the variability of permeability and gas source due to slip flow, Knudsen diffusion, and Langmuir desorption. The modified 1D radial reservoir is described in differential equation form as

$$\phi \frac{\partial}{\partial t} P + \frac{1}{r} \frac{\partial}{\partial r} \left( r \frac{\partial}{\partial r} \left( \frac{k_a P}{\mu} \frac{\partial P}{\partial r} \right) \right) = G,$$  

where $\phi$ is porosity, $t$ is time, $P$ is pressure, $r$ is radial distance, $\mu$ is gas viscosity, $k_a$ is apparent permeability, and $G$ is a generation term due to gas desorption.

We showed that slip flow and Knudsen diffusion are important flow mechanisms in shale-gas formations (Shabro et al., 2009). Apparent permeability is defined to account for these flow mechanisms in a single expression (Javadpour, 2009) and is written as

$$k_a = \frac{\lambda^2}{8} + \frac{8RT}{\pi M} \left( \frac{2}{3} + \frac{\pi}{8} \left( \frac{2}{\alpha} - 1 \right) \right) \mu \lambda,$$  

where $R$ is the universal gas constant, $T$ is temperature, $M$ is gas molar mass, $p_{avg}$ is average pressure, $\rho_{avg}$ is average gas density, $\alpha$ is the tangential momentum accommodation coefficient, and $\lambda$ is an equivalent pore-throat radius to achieve the desired apparent permeability. The first term in Eq. 2 represents the no-slip flow term and is associated with a conventional constant permeability, while the second term in Eq. 2 synthesizes the effect of slip flow and Knudsen diffusion and it varies during production as both average pressure and average gas density vary with time. If the first term exceeds the second term significantly, then the conventional constant permeability is sufficient to describe reservoir behavior. However, the study of different Knudsen regimes in shale-gas formations indicates that slip flow and Knudsen diffusion are leading flow mechanisms in these formations because of the existence of pore-throat sizes in the range of nano-meters (Javadpour, 2009; Shabro et al., 2009).
Gas desorption via interaction of Langmuir desorption and adsorption fluxes lead to the generation term given by

$$G = \chi P \left( K_{\text{des}} \theta - K_{\text{ads}} (1 - \theta) P \right),$$

(3)

where $\chi$ is surface-to-volume ratio, $K_{\text{des}}$ is the desorption coefficient, $K_{\text{ads}}$ is the adsorption coefficient, and $\theta$ is fractional coverage. The surface-to-volume ratio is calculated as total kerogen surface divided by total rock volume and it depends on pore-scale geometry and heterogeneity of the shale-gas formation. Surface-to-volume ratio is estimated from pore-scale images of shale-gas formations (Sondergeld et al., 2010a; Ambrose et al., 2010). Desorption and adsorption coefficients are dependent on the gas and surface chemical potential energies and temperature. These coefficients can be calculated from Langmuir desorption experiments (Lu et al., 1995). Fractional coverage represents the number of filled surface sites for gas molecules divided by the number of total surface sites available for gas molecules to adhere to the surface.

The first term between parentheses in Eq. 3 is desorption volume flux, $J_{\text{des}}$, and the second term is adsorption volume flux, $J_{\text{ads}}$ (Ruthven, 1984). Equation 3 explicitly assumes that the only gas source in a shale-gas formation is due to Langmuir desorption and adsorption; subsequently, we emphasize the importance of gas diffusion in kerogen to replenish fractional coverage. Consequently, gas diffusion in kerogen implicitly supplies gas to the total production. Figure 1 illustrates the interplay of the gas flux in the pore space, $J$, gas desorption and adsorption fluxes between surfaces and the pore space, and gas diffusion flux in kerogen, $J_{\text{diff}}$.

Gas desorption and adsorption are both present continuously and they nullify the effects of one another at the equilibrium state. The generation term is zero at the equilibrium state, whereby the fractional coverage at equilibrium becomes

$$\theta_e = \frac{K_{\text{ads}} P}{K_{\text{des}} + K_{\text{ads}} P}.$$

Equilibrium fractional coverage is controlled by pressure and the chemical potential energy between the surface and gas. When reservoir pressure decreases due to gas production, equilibrium fractional coverage decreases below the initial fractional coverage. Then, fractional coverage decreases to the new equilibrium fractional coverage; as a result, gas molecules desorb from surfaces. It is important to mention that a small deviation from the equilibrium condition is necessary to generate desorbed gas. In other words, the decrease of reservoir pressure causes gas adsorption flux to fall behind gas desorption flux and the consequence is observed as effective desorption of gas molecules from surfaces. Equation 4 defines the initial fractional coverage at initial reservoir pressure.

We invoke a mass balance criterian at the surface to account for the non-equilibrium condition. Mass balance at the surface is implemented as

$$K_{\text{des}} \theta - K_{\text{ads}} (1 - \theta) P = \frac{S_0 M}{\rho N_A} \frac{\partial \theta}{\partial t},$$

(5)

where $S_0$ is the number of total surface sites available for gas adsorption per surface area, $\rho$ is gas density, and $N_A$ is Avogadro’s constant. The scaling term in parentheses converts the dimensionless fractional coverage to gas flux. At the same time, the mass balance condition enforces that effective gas desorption flux (the left hand side of Eq. 5) be consistently justified by the change in fractional coverage (the right hand side of Eq. 5). Fractional coverage is iteratively solved at each time step to satisfy the mass balance condition at surfaces. Figure 2 describes the iterative implementation of surface mass balance along with the modified reservoir model. The iterative algorithm updates the desorption and adsorption coefficients (condition “No. 1” in Fig. 2) if the effective gas desorption flux is greater than the produced gas due to the change in fractional coverage; fractional coverage is updated (condition “No. 2” in Fig. 2) in the reverse condition. After the iterative process satisfies the surface mass balance criterian (condition “Yes” in Fig. 2), the model takes into account the gas diffusion in kerogen. Shabro et al. (2011b) provide additional details about the iterative algorithm implemented to calculate fractional coverage.

**Gas Diffusion in Kerogen**

The migration of hydrocarbon in shale formations is modeled as a diffusion mechanism in typical geological time frames (Thomas and Clouse, 1990). Diffusion of methane molecules in zeolite crystals has shown the ability of methane molecules to diffuse through solid matrices. The methane diffusion coefficient, $D$, in zeolite crystals is approximately $10^{-22}$ m$^2$.s$^{-1}$ at room temperature (Ruthven, 1984). We describe the significance of gas diffusion in kerogen on both gas flow and stored gas during shale-gas production.

Kerogen bodies are located on kerogen surfaces with a uniform thickness ($z_k$). Total organic carbon, TOC, is calculated by

$$TOC = \chi_k z_k,$$

(6)
where \( \chi_k \) is kerogen surface per bulk volume. Figure 1 shows a schematic of kerogen and flow paths due to advection, desorption, adsorption, and diffusion. Gas diffusion flux in kerogen is given by

\[
J_{\text{diff}} = -\phi_k D \nabla C,
\]

where \( \phi_k \) is effective kerogen porosity, and \( C \) is gas concentration in the kerogen body. Gas molecules flow from locations with high concentrations to locations with low concentrations. Conservation of gas molecules at kerogen body enforces the condition

\[
\nabla \cdot J_{\text{diff}} = 0.
\]

We combine Eqs. 7 and 8 to model gas diffusion in kerogen bodies. However, there is no standard method to model gas diffusion from kerogen bodies to kerogen surfaces. We hypothesize that gas diffusion from kerogen bodies to kerogen surfaces is a linear function of the difference between fractional coverage and gas concentration at kerogen body. Accordingly, we modify Eq. 7 to define gas diffusion flux from kerogen bodies to kerogen surfaces as

\[
J_{\text{diff}} = \phi_k D \frac{C - \theta}{\Delta z},
\]

where \( \Delta z \) is the distance between the center of kerogen body and kerogen surface. Mass balance at kerogen surface is enforced by updating fractional coverage as

\[
\theta_{\text{new}} = \theta + \left( \frac{\rho N_A}{S_v M} \right) J_{\text{diff}} \Delta t,
\]

where \( \Delta t \) is the time step. Gas diffusion influx increases fractional coverage at each time step. The fractional coverage enhancement at each time step due to gas diffusion (Eq. 10) increases the generation term (Eq. 3) for the next time step. Consequently, gas diffusion in kerogen implicitly increases the total gas production by supplying gas to kerogen surfaces.

The conventional model only uses Eq. 1 with the generation term equal to zero and a constant permeability (hereafter referred to as “Conventional”). Slip flow and Knudsen diffusion accounted for by implementing Eq. 2 in the “Conventional” case (hereafter referred to as “Add slip flow”). In order to implement Langmuir desorption-adsorption, the generation term is calculated via Eq. 3 and the surface mass balance criterion (Eq. 5) is satisfied via the iterative algorithm described by Shabro et al. (2011b). Henceforth we refer to the reservoir model with slip flow, Knudsen diffusion, and Langmuir desorption-adsorption as “Add desorption”. The comprehensive reservoir model includes gas diffusion in kerogen. Figure 2 is a flowchart of the modified reservoir model introduced in this paper (hereafter referred to as “Add diffusion”). Production curves with respect to time are shown for the four reservoir models involved in Fig. 3a.

Figure 1 describes the numerical grids used for calculations with the modified reservoir model. In order to ensure convergence of results, the time step is increased to twice its value when changes in pressure, fractional coverage, and gas concentration fall below 0.001% in the current time step at all numerical grids. The algorithm decreases \( \Delta t \) to half its value when the largest change in these three parameters is above 0.001% in the current time step.

**Results and Discussion**

We study the effect of slip flow and Knudsen diffusion, gas desorption from surfaces, and gas diffusion in kerogen by comparing production forecasts calculated with the previously defined reservoir models. Figure 3a shows the calculated production velocity in a 1D radial reservoir with 1 m thickness, \( h \), external boundary, \( r_e \), equal to 100 m, and wellbore radius, \( r_w \), equal to 0.3 m after 1 year of production. Table 1 summarizes the assumed modeling parameters. The numerical algorithm uses 10 and 3 numerical grids to define reservoir radial range and kerogen thickness, respectively. Production velocities in all four cases are equal at early times (before 10^7 year) where the prevailing production source is near-wellbore gas stored in the pore space and there is no significant pressure drop. After a short production period, pressure decreases at the near-wellbore region. As a result, the Langmuir equilibrium condition (Eq. 4) is disturbed at surfaces near the wellbore. The corresponding deviation from equilibrium causes the desorption flux to exceed the adsorption flux. Effective desorption acts as a source of gas (Eq. 3), thereby maintaining both reservoir pressure and production velocity. Production velocities for cases “Add desorption” and “Add diffusion” separate from the remaining two cases after 10^7 year.

As shown in Fig 4a, pressure decrease has an additional consequence: apparent permeability increases due to slip flow and Knudsen diffusion (Eq. 2). At initial reservoir pressure (\( P_{\text{initial}} = 17.2 \) MPa), apparent permeability is 59.7 \( \mu D \) from Eq. 2. We assume that laboratory experiments are conducted at initial reservoir pressure and we use 59.7 \( \mu D \) as a constant permeability in the “Conventional” case. However, apparent permeability increases to 68.8 \( \mu D \) as pressure decreases to final reservoir pressure (\( P_{\text{final}} = 8.6 \) MPa). Figure 4b shows apparent permeability at 1 m from the center of the well for the four modeling cases. Apparent permeability increases with time as pressure decreases in the reservoir for the “Add slip flow” case. As a
result, production velocity in the case of “Add slip flow” surpasses that of the “Conventional” case after 10^6 year in Fig. 3a. The enhancement in apparent permeability is smaller in the cases of “Add desorption” and “Add diffusion” because desorption and diffusion mechanisms counteract the pressure decrease by supplying gas to the pore space.

As gas desorption takes place, gas concentration at kerogen surfaces (fractional coverage) decreases and causes a concentration gradient in kerogen. In turn, the concentration gradient gives rise to gas diffusion toward kerogen surfaces (Eq. 9). Gas diffusion acts as a source of gas to maintain gas concentration at kerogen surfaces. The resulting effect is observed in Fig. 3a after 10^5 year when production velocity in the “Add diffusion” case exceeds production velocity in the “Add desorption” case. Figure 3b shows the difference between production velocities for the “Add desorption” and “Add diffusion” cases with respect to time. Gas diffusion to kerogen surfaces acts as an almost constant source of gas after it reaches the maximum difference at 3×10^5 year. We observe that the contribution of gas diffusion to total production is negligible at early times (before 10^5 year).

Quantitative analysis of production curves shown in Fig. 3a indicates that recovery factors are different in all modeling cases. Recovery factor is 37.7% and 41.3% for the “Conventional” and “Add slip flow” cases, respectively. The extra 9.6% gas production in the case of “Add slip flow” is due to apparent permeability enhancement due to slip flow and Knudsen diffusion. Furthermore, the contribution of gas desorption increases the total production by 42.6% while the recovery factor decreases to 17.3%. In this case, the assimilation of adsorbed gas on kerogen surfaces increases total reserves. Gas diffusion from kerogen increases the total production by an extra 61.7% but it decreases the recovery factor to 10.4% due to the corresponding increase of total reserves.

In the next step, we examine the pressure drop in the reservoir for the four modeling cases. Figure 5 shows that reservoir pressure decreases due to gas production; however, the generation term maintains the reservoir pressure for the cases of “Add desorption” and “Add diffusion”. In the cases of “Conventional” and “Add slip flow”, there is no generation term and, consequently, the resulting pressure decrease is similar in the two cases after 0.001 year. The pressure decrease is slightly higher in the case of “Add slip flow” after 1 year because slip flow and Knudsen diffusion raise the apparent permeability when pressure decreases. In the presence of the generation term in the case of “Add desorption”, the reservoir pressure decrease is smaller than the last two cases, whereby it increases production velocity and cumulative production in shale-gas reservoirs. Gas diffusion to kerogen surfaces provides an additional source of gas and maintains fractional coverage. Therefore, the generation term in the “Add diffusion” case is larger than the case of “Add desorption” and the net reservoir pressure decrease is lower than in the presence of gas diffusion in kerogen.

Finally, important modeling parameters are varied to quantify their relative effects on gas production over time. Figure 6 describes production velocities calculated when there is a change in gas diffusion coefficient, kerogen porosity, TOC, and surface-to-volume ratio. When the gas diffusion coefficient decreases to 10^{-22} m^2.s^{-1} (Fig. 6a), gas diffusion to kerogen surfaces becomes negligible before 2×10^3 year. At a higher gas diffusion coefficient, 10^{-20} m^2.s^{-1}, gas diffusion contributes significantly to the production after 2×10^5 year. However, production velocities are similar in both cases after 10^5 year because the higher concentration gradients between kerogen surfaces and bodies compensate the lower gas diffusion coefficient in the former case. Cumulative production decreases only 1.2% for the case with lower gas diffusion coefficient because there is no change in total reserves. Kerogen porosity is doubled in Fig. 6b to increase total reserves by 62%; as a result, the cumulative production increases by 7.7%. Figure 6c describes the case when TOC decreases to half of its original value; total reserves decrease by 31% and the cumulative production decreases by 6.8%. In the latter two cases (Figs. 6b and 6c), changes in cumulative production are smaller than the variation of total reserves. The reason for this behavior is that the additional gas in kerogen needs to be transported through surface and pore space and there is no change neither in desorption nor advection transport mechanisms. We double the surface-to-volume ratio to emphasize gas desorption (Fig. 6d); cumulative production increases by 27% and 17% for the cases of “Add desorption” and “Add diffusion”, respectively. Figure 6 indicates that gas production in the case of “Add diffusion” surpasses that of the “Add desorption” case at early times. Gas diffusion coefficient determines the time when production curves separate in these two cases. Kerogen porosity and TOC control the extent of the separation between the two production curves.

Conclusions

We introduced a new 1D radial reservoir model to quantify production of gas-bearing shales. The numerical algorithm concomitantly considers slip flow, Knudsen diffusion, Langmuir desorption, and gas diffusion in kerogen. Slip flow and Knudsen diffusion increase the apparent permeability; gas desorption from kerogen surfaces acts as a source of gas; and gas diffusion in kerogen replenishes the gas source at surfaces. Four modeling cases were developed to quantify the effect of each transport mechanism. Modeling results suggest that gas desorption from kerogen surfaces and gas diffusion in kerogen maintain reservoir pressure by supplying gas to the pore space thereby becoming the main mechanisms responsible for higher-than-expected production velocities commonly observed in shale-gas reservoirs. Slip flow and Knudsen diffusion marginally enhance the production velocities in gas-bearing shales. Kerogen surface-to-volume ratio is the controlling parameter for gas desorption. Effective kerogen porosity, TOC, and the gas diffusion coefficient in kerogen are important
physical parameters to quantify shale-gas production and reserves. Advection, desorption, and diffusion mechanisms act sequentially in time to influence gas production; therefore, a systematic inclusion of each transport mechanism is necessary to provide reliable forecasts of gas production in shale-gas reservoirs.

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Nomenclature

1D One-dimensional
C Gas concentration in the kerogen body, dimensionless
D Gas diffusion coefficient in kerogen, m².s⁻¹
G Generation term, s⁻¹
h Reservoir thickness, m
J Volume flux, m.s⁻¹
J_{ads} J_{des} Adsorption and desorption volume flux, m.s⁻¹
J_{diff} Gas diffusion flux, m.s⁻¹
k_a Apparent permeability, m² [d = Darcy = 9.869×10⁻¹³ m²]
K_{ads} Adsorption coefficient, m.Pa⁻¹.s⁻¹
K_{des} Desorption coefficient, m.s⁻¹
M Molar mass, kg.kmol⁻¹
N_A Avogadro’s constant, 6.0221415 ×10²³ kmol⁻¹
P Pressure, Pa
P_{final} Final reservoir pressure, Pa
P_{initial} Initial reservoir pressure, Pa
P_{avg} Average pressure, Pa
R Universal gas constant, 8.314 ×10³ Pa.m³.kmol⁻¹.K⁻¹
r Radial distance, m
r_e Reservoir external boundary, m
r_w Wellbore radius, m
S_0 Number of total surface sites available for gas adsorption per surface area, m⁻²
T Temperature, K
TOC Total organic carbon, dimensionless
t Time, s
z Kerogen thickness parameter, m
z_K Kerogen thickness, m
Δt Time step, s
Δz Distance between the center of kerogen body and kerogen surface, m
α Tangential momentum accommodation coefficient, dimensionless
θ Fractional coverage, dimensionless
θ_e Equilibrium fractional coverage, dimensionless
θ_{new} Updated fractional coverage due to gas diffusion in kerogen, dimensionless
λ Equivalent pore-throat radius, m
μ Viscosity, Pa.s
ρ Gas density, kg.m⁻³
ρ_{avg} Average gas density, kg.m⁻³
ϕ Porosity, dimensionless
ϕ_K Kerogen porosity, dimensionless
χ Surface-to-volume ratio, m⁻¹
χ_K Kerogen surface per bulk volume, m⁻¹
References


Table 1. Summary of modeling parameters assumed in the calculations reported in this paper.

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<th>Parameter</th>
<th>Value</th>
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Fig. 1. Schematic of the modified 1D radial reservoir model. Numerical grids at the reservoir scale are identified with light pink rings. Reservoir dimensions are defined by thickness, \( h \), external boundary, \( r_e \), and wellbore radius, \( r_w \). Kerogen bodies (green blocks) are located on kerogen surfaces with pores (white blocks) with a uniform thickness equal to \( z_K \). Orange blocks identify no-flow boundaries. The simulation algorithm calculates pressure, \( P \), in the pore space, fractional coverage, \( \theta \), at kerogen surfaces, and gas concentration, \( C \), in kerogen bodies. Blue arrows describe gas flow paths due to advection, \( J \), desorption, \( J_{des} \), adsorption, \( J_{ads} \), and diffusion, \( J_{diff} \). The effective gas desorption rate is calculated as desorption flux minus adsorption flux. Gas diffusion in kerogen occurs in two directions: (1) parallel to the surface, and (2) toward the surface. Flow of gas toward the surface enriches the gas concentration at the surface (fractional coverage), thereby maintaining the gas desorption rate.
Fig. 2. Flowchart of the modified reservoir model in shale-gas formations advanced in this paper. The simulation algorithm solves Eqs. 1 to 10 at each time step, $\Delta t$, to calculate pressure, $P$, fractional coverage, $\theta$, and gas concentration in the kerogen body, $C$, at each grid. Fractional coverage, desorption coefficient, $K_{\text{des}}$, and adsorption coefficient, $K_{\text{ads}}$, are updated via the iterative algorithm described by Shabro et al., (2011b).

Fig. 3. (a) Production curves of a shale-gas reservoir in 1 year with modeling parameters shown in Table 1. Production curves overlap at early times; however, the contributions of slip flow, Knudsen diffusion, Langmuir desorption, and gas diffusion in kerogen increase the production velocity for each case as time progresses. (b) Difference between production velocity for the “Add desorption” and “Add diffusion” cases with respect to time. The contribution of gas diffusion to total production is negligible at early times. Gas diffusion to kerogen surfaces acts as a constant source of gas after its maximum level at $3 \times 10^{-7}$ year.
Fig. 4. (a) Apparent permeability versus pressure. Apparent permeability increases from 59.7 µD to 68.8 µD due to slip flow and Knudsen diffusion when pressure decreases from 17.2 MPa to 8.6 MPa. (b) Apparent permeability 1 m away from the well center in the four modeling cases described in Fig. 3. Permeability is constant at 59.7 µD in the case of “Conventional”. Apparent permeability increases in the remaining three cases with time as pressure decreases in the reservoir. The highest apparent permeability increase is observed for the case of “Add slip flow” because of the corresponding high pressure decrease in the reservoir. The generation term in the cases of “Add desorption” and “Add diffusion” slows down the pressure decrease, thereby giving rise to a smaller enhancement of apparent permeability.

Fig. 5. Radial profiles of pressure after (a) 0.001 year and (b) 1 years of production from results shown in Fig. 3. Desorption maintains reservoir pressure, whereby it increases production velocity in shale-gas reservoirs. In addition, gas diffusion from kerogen sustains fractional coverage and indirectly maintains reservoir pressure. The drop of reservoir pressure in the “Conventional” case is lower than in the “Add slip flow” case because the enhanced permeability due to slip flow and Knudsen diffusion gives rise to a higher production velocity in the case of “Add slip flow”.

Fig. 6. Dashed curves describe gas production of a shale-gas reservoir with 5% porosity, 16.5 µD permeability, 29% TOC, 10% kerogen porosity, $3.29 \times 10^{10}$ m$^{-1}$ surface-to-volume ratio, and gas diffusion coefficient equal to $10^{-20}$ m$^2$.s$^{-1}$. Table I describes the remaining modeling parameters. Petrophysical properties are changed in each panel with the corresponding results shown in solid curves. When a solid curve overlaps a dashed curve the respective petrophysical property does not affect the production velocity for the overlapping curve. (a) Diffusion coefficient is decreased to $10^{-22}$ m$^2$.s$^{-1}$. (b) Kerogen porosity is doubled in this case. (c) TOC is decreased to half its value. (d) Surface-to-volume ratio increased by 100%.