



Reservoir simulation of free and adsorbed gas production from shale



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ABSTRACT

Shale gas has become a key natural gas resource and has been a great success in the USA and a few other countries. The gas production behaviour from shale is different to that from conventional gas reservoirs or coal seam reservoirs, primarily because of the different gas storage and flow behaviours in shale. Gas is stored in shale mainly as adsorbed gas in the pores of organic matter and clay minerals and as free gas compressed in other pores. Thus to understand how free and adsorbed gas contribute to the total gas production is a key question for shale gas reservoir engineering. One method to answer this question is by using reservoir simulation; however, this will require a reservoir simulator representing the shale gas storage and flow behaviours. In this work, a triple porosity model was applied in the reservoir simulator SIMED II, which was designed for dual porosity coal seam reservoirs, to account for both gas storage mechanisms of adsorption and free gas. A unique aspect of this new development is that the adsorbed gas, matrix free gas and fracture free gas are identified as different gas types but having the same gas properties. Thus the flow and production of gases with different storage mechanisms are directly identified in the simulation and output. The developed simulator was validated through history matching production data of a vertical well from the Barnett Shale. Then a series of parameter sensitivity analyses was carried out to investigate the impact of reservoir properties on adsorbed and free gas production. The results show that the contribution of adsorbed gas on the total gas production is generally low and is dependent on many factors such as the reservoir permeability, porosity and adsorption behaviour, and hydraulic fracturing effect.

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1. Introduction

Shale gas has become an important natural gas resource in recent years. In 2012, shale gas accounted for 39% of the total natural gas production in the USA, 15% in Canada and less than 1% in China (EIA, 2013). Although they are the only three countries with commercial shale gas production, interest in shale gas has spread into many other countries. The production behaviour, especially the long term production behaviour, is of great importance for shale gas exploration and development. This production behaviour is determined by the various gas storage and migration mechanisms within the reservoir.

Gas is stored in shale mainly as adsorbed gas in the organic matter and clay minerals, as free gas in the inorganic pores and fractures and as dissolved gas in the formation fluids (e.g. Curtis, 2002; Zhang et al., 2012). Among these, adsorbed gas may

account for 20–85% of total gas in shale reservoirs (Hill and Nelson, 2000). Thus unlike conventional gas reservoirs, where gas is mainly free gas, or coalbed methane reservoirs, where gas is considered to be mainly adsorbed, both storage mechanisms can play important roles in gas production from shales. To illustrate the impact of gas storage mechanisms on production, Fig. 1 presents the amount of adsorbed, free and total gas content with respect to pressure using the properties of a Silurian Longmaxi shale from China with a Langmuir volume of 3.6 m³/t, Langmuir pressure of 4.0 MPa and total porosity of 5.0% (Yuan et al., 2014). From Fig. 1, the adsorbed and free gas in place is 2.68 and 2.29 m³/t, respectively, assuming that the initial gas pressure is 12 MPa in the reservoir. Thus the adsorbed gas accounts for 54% of the original gas in place. Assuming that the reservoir gas pressure is drawn down to 8 MPa during production, the amount of adsorbed and free gas to be released is 0.3 and 0.8 m³/t, respectively, due to the different relationship of adsorbed gas and free gas with pressure. Hence the contribution of adsorbed gas in the total produced gas is about 27%, which is only half of the ratio of the original adsorbed gas in place. For another example with an initial reservoir gas pressure of 4 MPa, the

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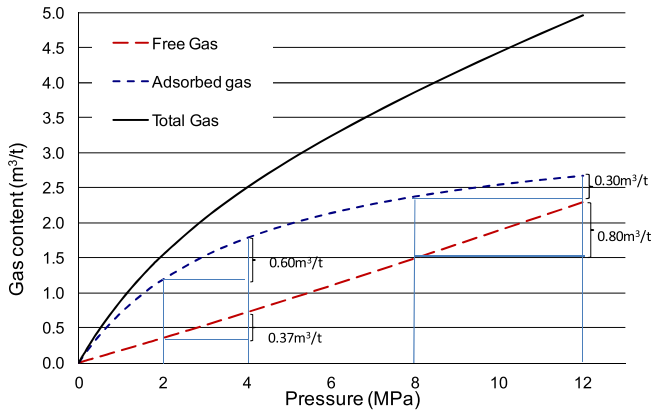


Fig. 1. Illustration of gas storage behaviour with respect to pressure.

adsorbed and free gas in place is 1.78 and 0.72 m³/t, respectively. Thus adsorbed gas represents 71% of the original gas in place. Assuming during production the reservoir gas pressure is drawn down to 2 MPa, the produced adsorbed and free gas are 0.60 and 0.37 m³/t, meaning that adsorbed gas represents 62% of the total gas produced, which is closer to the ratio of the original adsorbed gas in place. These simple analyses demonstrate that the contribution of the adsorbed and free gas to production from shale rely on the initial and final gas pressures. It can be implied from the above analyses that the adsorption parameters and porosity have impact on gas production as well. Moreover, because adsorbed gas may take longer time to transport through the matrix than free gas (e.g. Yuan et al., 2014), the contribution of the adsorbed and free gas may be even more complex thus reservoir simulation tools need to be developed to better understand this issue.

Methods and tools to simulate shale gas production have been developed especially recently (e.g. Cipolla et al., 2010; Ding et al., 2014; Perdomo et al., 2010; Shabro et al., 2011; Alharthy et al., 2012; Fathi and Akkutlu, 2014; Mi et al., 2014). Other work has simulated the effect of hydraulic fractures on gas production (e.g. Freeman et al., 2013; Mohaghegh, 2013; Rubin, 2010). However, most work only considered a dual porosity approach with matrix and fracture systems. Dual-porosity models assume uniform matrix and fracture properties throughout the reservoir, thus they are not able to describe both adsorbed gas and free gas in the shale matrix (Yan et al., 2013). Yan et al. (2013) applied a triple porosity model with both adsorbed and free gas in the matrix that migrated directly to the fracture system. However, this does not accurately represent the shale structure as most of the adsorbed gas has to diffuse through the mineral pores before arriving at fractures.

Since there is no simulator capable of directly simulating adsorbed and free gas production, Cipolla et al. (2010) compared reservoir simulation results between whether adsorbed gas is produced to estimate the contribution of adsorbed gas on overall gas production. This indirect method, though, is not able to accurately represent the production behaviour as the reservoir gas pressure change will be different if the role of adsorbed gas is neglected. Moreover, their model was a single porosity dual permeability model, which is not an accurate representation of shale reservoirs. Thus a direct method to evaluate adsorbed and free gas production from shale would be a valuable contribution.

In this work, a triple porosity model is developed which can represent both adsorbed and free gas storage and flow behaviour within shale gas reservoirs. This model is implemented in SIMED II, a coalbed methane reservoir simulator. More importantly, in order to identify the contribution of adsorbed and free gas to overall production, a method, which differentiates adsorbed from free gas

by describing them as different gas types but with same the gas properties, is applied in the reservoir simulator. Thus the simulator is able to directly calculate both adsorbed and free gas production. The developed simulator is first validated using the field gas production data from Barnett basin. Then a series of reservoir simulation studies was carried out to investigate the sensitivity of parameters on the adsorbed and free gas production to help better understand the overall shale gas production behaviour.

2. Model development

2.1. Gas storage behaviour

Gas shales have been demonstrated to have a wide pore size distribution from nanometer organic pores to micrometer mineral pores and intra and inter particle pores as well as natural fractures (e.g. Chalmers et al., 2012; Clarkson et al., 2013; Kuila and Prasad, 2013; Loucks et al., 2012). According to the mechanisms for gas storage and the typical pore structure of shale, gas is considered to be stored as adsorbed gas, matrix free gas and fracture free gas in this work. In this work, dissolved gas in the formation fluid and/or bitumen phases is not considered, as the quantities of gas stored are often relatively minor compared to storage as free or adsorbed gas.

Gas adsorption in shale can be adequately described by Langmuir (1918) adsorption model despite the heterogeneity of the gas adsorption sites in shale (e.g. Zhang et al., 2012):

$$V_a = \frac{V_L P_a}{P_a + P_L} \quad (1)$$

where V_a (m³/t) is adsorbed amount per unit mass of shale, V_L (m³/t) is the Langmuir volume per unit mass of shale, P_a (MPa) is gas pressure, P_L (MPa) is Langmuir pressure. Matrix free gas can be described by gas density multiplied by the matrix pore volume available for free gas. As helium is often used to characterise the total matrix pore volume under dry conditions, the volume occupied by the formation water and adsorbed gas has to be deducted, which become significant especially when the adsorbed amount is large:

$$V_m = \frac{\rho_{gm}}{\rho_{stp}} \left(V_{pm}(1 - S_{wm}) - \frac{V_a/\rho_{stp}}{\rho_a} \right) \quad (2)$$

where V_m (m³/t) is the amount of matrix free gas per unit mass of shale, ρ_{gm} (t/m³) is gas density in the matrix pores, ρ_{stp} (t/m³) is the gas density at standard temperature and pressure, V_{pm} (m³/t) is the total matrix pore volume per unit mass of shale, S_{wm} (–) is water saturation in the shale matrix, ρ_a is the adsorbed phase density, which is 0.421 (g/ml or t/m³) as often used for methane adsorbed phase density in coal (e.g. Fitzgerald et al., 2005). The free gas in the fracture system can be described by:

$$V_f = \frac{\rho_{gf}}{\rho_{stp}} \left(V_{pf}(1 - S_{wf}) \right) \quad (3)$$

where V_f (m³/t) is the amount of fracture free gas per unit mass of shale, ρ_{gf} (t/m³) is gas density in the fracture, V_{pf} (m³/t) is fracture volume per unit mass of shale, S_{wf} (–) is water saturation in the fracture system. Peng–Robinson Equation of State (PR EOS) (Peng and Robinson, 1976) is used to calculate the methane density in this work.

2.2. Triple porosity model

Triple porosity models have been proposed for reservoirs where

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