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Gas-condensate flow modelling for shale reservoirs

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ABSTRACT

Condensate banking is the most challenging engineering problem in the development of gas-condensate reservoirs where the condensate accumulation can dramatically reduce the gas permeability resulting in impairment of wells productivity. An accurate assessment of condensate banking effect is important to predict well productivity and to diagnose well performance.

Traditionally, Darcy law, combined with relative permeability models, has been used for modelling condensate banking effect in conventional reservoirs. This approach is also widely adopted in reservoir engineering commercial tools. However, for shale gas-condensate reservoirs, the gas flow deviates from Darcy flow to Knudsen flow due to the very small pore size in shale matrix (3–300 nm), compared to conventional reservoirs (10–200 μm). This gas flow is highly dependent on pore size distribution and reservoir pressure.

In this paper, the effect of condensate saturation on Knudsen flow in shale matrix kerogen is investigated using a 3D pore network with a random pore size distribution. The Knudsen flow is incorporated at the pore level and gas permeability is evaluated for the whole network. In addition, the pore distribution effect in terms of log-normal mean and standard deviation is investigated. The concept of relative permeability in Darcy flow is extended to Knudsen flow by defining a new parameter called relative correction factor ξ_{rel} to evaluate the effect of condensate banking on Knudsen flow. This parameter can be employed directly in reservoir engineering tools.

Simulation results showed that the relative correction factor is not only dependent on condensate saturation but also on pressure. This is due to the impact of pressure on the contribution of pore size ranges into the gas flow. In addition, results showed the effect of the pore size distribution where the standard deviation controls mainly the behaviour of Knudsen flow under condensate saturation. Disregarding this effect can lead to an overestimation of Knudsen flow contribution in well production under condensate banking effect.

1. Introduction

In the last decade, shale plays emerged as one of the most important oil and gas resources in the world. In 2014, shale gas accounted for 51% of all US natural gas reserves (EIA, 2015). Shale reservoirs are characterised by very small pore size (from 3 to 300 nm) (Williams, 2012) and a very low matrix permeability, probably on the order of 10 μD or 100 nD. A horizontal well, combined with hydraulic fracturing, is required to make this type of resources commercially valuable.

The gas-condensate flow in hydrocarbon reservoirs has long been recognized as having the most complex fluid flow dynamics in reservoir engineering (Hinchman and Barree, 1985; Barnum et al., 1995; Du et al., 2004). A condensate buildup can rapidly occur around a producing well when the bottom hole flowing pressure falls below dew-point. The condensate accumulation reduces the gas relative permeability resulting in a brisk decline of well productivity and reduction of heavy components fraction at the wellhead. This phenomenon is usually referred to as "*condensate banking*" or "*condensate blockage*". The condensate banking is controlled by three factors: the flow behaviour, the phase behaviour and the development strategy.

In conventional reservoirs, the condensate banking effect can be reduced by pressure maintenance to be able to produce at a bottomhole pressure above dew point. In shale reservoirs, due to very low permeability, wells start to produce under a bottomhole pressure below the dew point in the few first days or months of production. As no method is available to maintain pressure in shale reservoirs, this type of resources continues to produce under condensate banking effect for the most of the well's life.

For conventional reservoirs, the effect of condensate banking on gas flow is interpreted by using relative permeability models. The apparent gas permeability at a condensate saturation is adjusted using the gas relative permeability as a correction factor. However, in shale reservoirs at the nanopore level, the gas flow deviates from conventional Darcy flow to Knudsen flow. Knudsen flow occurs in nanopores due to the interaction between molecules-molecules and molecules-pore walls resulting in an increasing apparent permeability with decreasing pore size and decreasing pore pressure (Javadpour et al., 2007).

Although the dry gas flow under Knudsen conditions in shale gas reservoirs has been the subject of numerous research studies (Javadpour, 2009; Freeman et al., 2012; Mehmani et al. 2013; Civan,

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2010), the effect of multiphase gas-condensate flow is still not well addressed. As Knudsen flow is highly dependent on pore size, the effect of condensate accumulation alters the range of pore sizes that are accessible by gas flow which affects Knudsen flow at the macro-scale level. Therefore, the understanding of how Knudsen flow is affected by condensate banking is essential to evaluate accurately the shale gas-condensate well performance.

Pore-network modelling has become a well-established discipline for petroleum applications for single phase and multiphase flow in porous media. The pore network modelling was first introduced by Fatt (1956). Usually, the void in the porous media is represented by a 2D or 3D network of pores connected by pore throats. The network modelling has been used by researchers to study macroscopic properties of porous media such as permeability and relative permeability by using the pore-level physics of fluid flow and pore space paraments (e.g. pore shapes, wettability and interfacial tension) (Fang et al., 1996; Jamiolahmady et al., 2000; Bustos and Toledo, 2003; Li and Firoozabadi, 2000).

Traditionally, the pores are modelled as spheres or cubes and pore throats are modelled as curved triangular cross-section tubes in conventional reservoirs. A variety of shapes were used in literature, ranging from angular cross-section to grain boundary pores (Blunt, 2001; Joekar-Niasar and Hassanizadeh, 2012). The main challenge of an accurate network modelling is to capture the complexity of the pore space geometry while using simple pore shapes. For multiphase flow, the shapes of pores and pore throats are very important to describe the capillary pressure as a function of wetting phase saturation. When a wetting phase exists in a pore, it occupies the pore corners with high capillary pressure. As saturation increases the capillary pressure decreases until it forms a bridge.

The extension of pore geometry from conventional reservoirs to shale reservoirs should be considered carefully due to the difference of pore space geometry. The shale porosity comprises organic porosity in kerogen and inorganic intergranular porosity. The pore space in organic matter (kerogen) tends to have mainly a round shape which is different from the triangular intergranular shape in conventional sandstone reservoirs (Curtis et al., 2010).

For shale reservoirs, reliable measurement techniques of multiphase permeability are still yet to be developed due to the difficulties related to the control and the measurement of the different phases' saturations in shale matrix samples. Alternatively, pore-network modelling can be used to investigate multiphase flow in shale reservoirs. Mehmani et al. (2013) used single phase gas pore network model to study the effect of Knudsen flow. However, they used an intergranular sandstone pore model. They concluded that the gas apparent permeability is sensible to the fraction of nanopores. Huang et al. (2016) developed a two-phase (gas and water) 3D pore network model including Klinkenberg flow and gas adsorption. Their network is mixed wettability, organic and non-organic, however, they used a square cross section for pore in kerogen which is not in line with experimental observation where nanopores have circular cross section.

In addition, the high capillary pressure in shale matrix affects the phase behaviour of gas-condensate fluids. The phase behaviour deviation of hydrocarbons in shale reservoirs was studied by many researchers (Brusilovsky, 1992; Espósito et al., 2005; Nojabaei et al., 2013; Labed et al., 2015) and they concluded that condensate tends to start forming at higher dew point and to reach higher saturations than in conventional reservoirs. This is mainly due the significant lower condensate pressure (created by high capillary pressure) than gas pressure at the pore level. Labed (2016) used Peng-Robinson EoS (Equation of State) combined with Young-Laplace equation to investigate the phase behaviour deviation of gas-condensate fluids in shale matrix with a log-normal pore size distribution. He concluded that the deviation in terms of condensate saturation is about 10% and less than 5% for rich and lean gas-condensate fluids, respectively; however, these results are still needed to be validated by experimental investigations.

This paper presents an investigation of multiphase flow of gas-condensate fluids in shale matrix using a simple pore network modelling with a focus on the impact of condensate banking on Knudsen flow assuming a limited effect of phase behaviour deviation due to the capillary pressure and gas adsorption. In this research project, the modelling of phase behaviour deviation of gas-condensate in shale matrix and its effect on Knudsen flow have been investigated and results will be presented in a future paper.

2. Gas flow in nanopores

Shale reservoirs are dual porosity/dual permeability systems containing two media: matrix and fractures network (including natural fractures and hydraulically induced fractures). The fluid flows from matrix to the fracture and then to the wellbore. The matrix plays two roles; fluid storage and conductivity to the fractures while fractures serve as connection between matrix and the wellbore. While the fluid flow in fractures in shale reservoirs is similar as in conventional reservoirs, it is commonly believed that the existence of an extensive networks of natural fractures is essential to for a successful hydraulic fracturing (Walton and McLennan, 2013). The main difference of fluid dynamics between shale reservoirs and conventional reservoir resides in shale matrix where Darcy law fails to describe the gas flow in pores at nano and micro-scale.

Three non-Darcy flow regimes: slip flow, transition flow and free-molecular flow can be distinguished using Knudsen number which is defined as a measure of the degree of density rarefaction of gas flow in micro and nano-channels (Karniadakis et al., 2005). It is mathematically expressed as:

$$Kn = \frac{\lambda}{R} \tag{1}$$

where R is the hydraulic radius (m) and λ is the average minimum free path (m), defined as

$$\lambda = \frac{\mu Z}{P}\sqrt{\frac{\pi R_g T}{2M}} \tag{2}$$

where μ is the viscosity (Pa.s), Z is the compressibility factor, P is the absolute gas pressure (Pa), T is the absolute temperature (K), M is the average molecular mass (kg/kmol) and Rg is the universal gas constant.

Table 1 and Fig. 1 illustrate the classification of flow conditions according to the Knudsen number limits in pipes as the continuum, slip, transition and free molecular flow regimes (Karniadakis et al., 2005).

Continuum flow occurs at Kn values under 0.01 where molecule-molecule interaction is the dominant force. Hagen–Poiseuille law describes continuum flow in channels as

$$q = \frac{\pi}{8}\frac{R^4 \Delta P}{\mu L} \tag{3}$$

where q is fluid rate, R is the radius of the channel in m (m^3/s), ΔP is pressure difference (Pascal), μ is the fluid viscosity (cp) and L is the channel length (m).

At $0.01 < Kn < 0.1$ range the molecule-wall effect is more pronounced, but molecule-molecule interaction is still dominant. Slip flow regime dominates when gas molecules near to the channel walls don't exhibit a zero velocity (slip). Navier-Stokes equation is still valid to

Table 1
Classification of flow conditions in pipes according to the Knudsen number limits (Karniadakis et al., 2005).

Knudsen number	$\boldsymbol{Kn} < 0.01$	$0.01 < \boldsymbol{Kn} < 0.1$	$0.1 < \boldsymbol{Kn} < 10$	$\boldsymbol{Kn} > 10$
Flow regime	Continuum	Slip	Transition	Free molecular