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Numerical study of a stress dependent triple porosity model for shale gas reservoirs accommodating gas diffusion in kerogen

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ABSTRACT

A model accommodating multi-scale pores containing kerogen within an inorganic matrix is used to explore the complex multi-mechanistic transport mechanisms of shale gas reservoirs. These include the complex evolution of pressure, diffusion and flow within both kerogen and inorganic components and their interaction with effective stresses. A general poromechanical model is proposed considering desorption and molecular diffusion in the kerogen, viscous flow in the inorganic matrix and fracture system, and composite deformation of the triple porosity assemblage. The model is verified by history matching against field data for gas production rate. The simulation results indicate that the pattern of gas flow is sequential during gas depletion – pressure first declines in the fracture, followed by the inorganic phase and then in the kerogen. The evolution of permeability is pressure dependent and the evolution of pressure is closely related to the intrinsic gas diffusion coefficient in the kerogen, inorganic matrix intrinsic permeability and fracture intrinsic permeability. A series of sensitivity analyses are completed to define key parameters affecting gas production. The study shows that dominant influence of the fracture network in acting as the main permeable conduit. The intrinsic permeability and porosity of the fracture have a positive correlation with gas production, while fracture spacing has a negative correlation to gas production. Kerogen also plays a critical role in gas production for shale reservoirs with higher total organic carbon. The enhancement of inorganic matrix permeability and gas diffusion coefficient in kerogen could efficiently guarantee a long-term gas production with a higher rate.

1. Introduction

Unconventional gas resources such as shale gas and coalbed methane show significant potential to offset declining conventional natural gas production. Modeling is an important way to reveal gas storage and transport mechanisms in such unconventional reservoirs.

Previous single/dual porosity models (Seidle et al., 1995; Palmer et al., 1996; Shi and Durucan, 2004; Zhang et al., 2008) are either pressure-dependent or strain-dependent, which contribute to reveal how the effective stress and adsorption-induced shrinkage influence coal seam permeability. In these cases, however, the effective stress, is based on the effective stress law for single porosity media, which may not be applicable for shale gas reservoirs since the transport mechanisms may differ between porous matrix and fracture network. Such models may be substituted for more complex models that accommodate the impact of the dual porosity medium on system compliance (Wu et al., 2010). Such models include the roles of deformation for single gas phase (Wu et al., 2010) to describe the evolution of porosity and permeability in the coalbed matrix and fracture system respectively under situ ground stress. In this, the gas flow obeys Darcy's law and the model is applicable to the full range of mechanical boundary conditions, from invariant total stress to restrained displacement. Similar models are available to accommodate nonlinear permeability models (Wu et al., 2011) including P-M models that accommodate gas diffusion and significant impact of Klinkenberg effects (Liu et al., 2015). These dual porosity models (Wu et al., 2010, 2011; Liu et al., 2015) are based on the law of effective stress for dual porosity media (Elsworth and Bai, 1992). However, these still

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may not be applicable to describe the complex gas flow and transport mechanisms in shale gas reservoirs due to the different sorption behavior and flow regimes between kerogen pockets and the inorganic solid medium (Yan et al., 2013a). Furthermore, some triple porosity models (Al-Ahmadi et al., 2011; Dehghanpour et al., 2011; Tivayanonda et al., 2012) consider macro fractures, micro fractures and matrix as a triple porosity medium, with gas flowing from matrix to micro fracture, and then to the macro fractures. Such models take no consideration of molecular diffusion within nanopores within the matrix. Some other triple porosity models are available to accommodate gas diffusion in kerogen within matrix and gas flow through matrix nanopores to fractures (Huang et al., 2015) including the model that accommodates the significance of dividing matrix into kerogen and inorganic matrix (Zhang et al., 2015). The model (Huang et al., 2015) might not be applicable due to the assumption that methane molecules could also be adsorbed on surfaces of inorganic materials.

The existence of nanopores in shale reservoirs has been verified by ultra-high pressure mercury injection (Katsube, 2000; Javadpour et al., 2007), back-scattered scanning electron microscopy (SEM) (Loucks et al., 2009) and atomic force microscopy AFM (Javadpour, 2009). The 2D focused-ion-beam SEM image (Kang et al., 2011; Ambrose et al., 2012; Akkutlu et al., 2012) of Fig. 1(a) shows that the organic matter contains finely dispersed porous kerogen pockets imbedded within inorganic materials (minerals/clay/silica), mainly including the organic micropores (<2 nm) and mesopores (2–50 nm). Pore sizes less than 100 nm are nearly exclusively found in the kerogen matrix, while the majority of pores in the inorganic matrix and fractures have much larger dimensions (Wasaki et al., 2014). Since the flow regime is sensitive to pore sizes (Ziarani and Aguilera, 2012) and their distribution, different types of fluid flow regimes should be conditioned according to the multi-scale pore sizes in shale gas reservoirs as is shown in Fig. 1(b).

In addition, the organic nanopores in kerogen have a relatively large internal surface area covered by a monolayer of methane molecules (approximately 2.8×10^{24} nm^3 for one ton of shale) despite the small dimension of the nanopores (Kang et al., 2011). Thus, the porous kerogen pockets are ideal sites for the storage of shale gas in the adsorbed phase due to the strong affinity (Van de Vaals forces) between hydrocarbon molecules and organic materials associated with the nanopore surface. Conversely, the amount of shale gas adsorbed in the inorganic pores is negligible due to the week affinity between hydrocarbon fluids and inorganic materials. Correspondingly, the relatively larger pores in the inorganic matrix contain a dominantly higher percentage of free gas compared to adsorbed gas (Wasaki et al., 2014).

The different types of gas flow and storage behaviors in the kerogen and the inorganic matrix prompt the conceptual triple porosity model shown in Fig. 2. This accommodates the three different media and their different characteristics, *viz*: the porous kerogen matrix (organic material), the porous inorganic matrix (inorganic material) and the fractured solid system (including both naturally fractured solid media and hydraulically fractured solid media). For the triple porosity model, the composite deformation of the triple porosity assemblage is coupled with gas transport in the three different systems to accommodate desorption and molecular diffusion in the kerogen, and viscous flow in the inorganic matrix and fracture system.

2. Triple porosity model for fractured porous shale

We develop a triple porosity that accommodates transport from a kerogen pocket into pores within an inorganic matrix, and from here into fractures. The mechanical and transport constitutive models are developed for this triple porosity system and combined into conservation equations for momentum and mass to define the field equations.

2.1. Assumptions

There are several assumptions applied to this triple porosity model.

(a) The shale reservoir is a fractured porous medium containing kerogen, inorganic matter and fractures. Each medium is isotropic, homogeneous and linear elastic.
(b) All strains is infinitesimal and the system is isothermal. Gas sorption follows Langmuir isothermal behavior.
(c) A single gas phase is (methane) is considered with assumed constant viscosity.
(d) Gas adsorption occurs only in the kerogen pockets, i.e., the kerogen contains gas in both free phase and adsorbed phase,

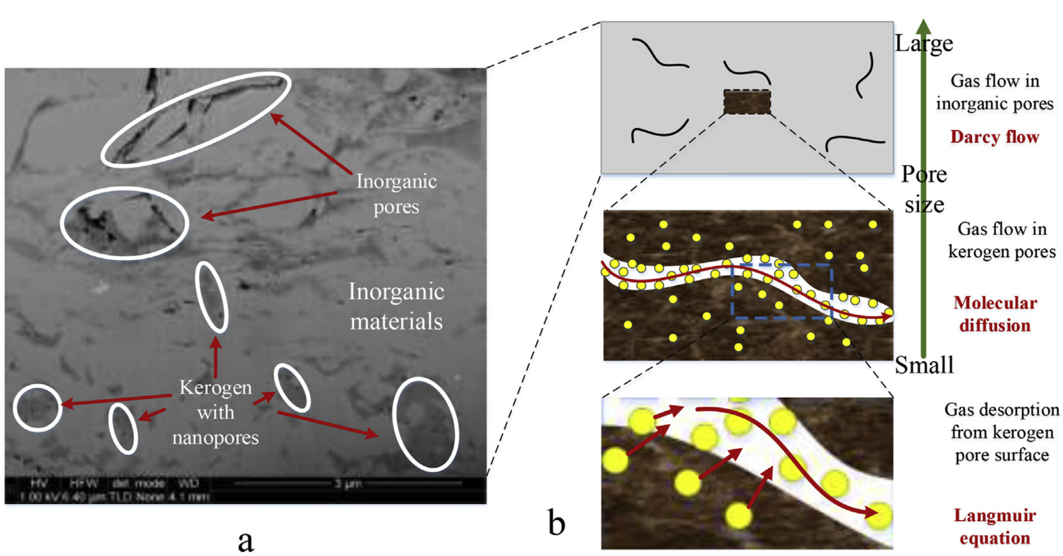

Fig. 1. (a) 2D FIB/SEM image of shale showing finely dispersed kerogen pockets imbedded in inorganic clays (Ambrose et al., 2012). (b) Schematic of gas desorption and flow pattern in kerogen and inorganic pores (modified from Javadpour et al. (2007), Song (2010)).