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Multi-porosity multi-physics compositional simulation for gas storage and transport in highly heterogeneous shales

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ABSTRACT

Shale gas reservoir is comprised of highly heterogeneous porosity systems including hydraulic/secondary fractures, inorganic and organic matrix. Multiple non-Darcy flow mechanisms in the shale matrix further bring challenges for modeling. In this paper, we developed a framework combining a multi-physics compositional simulator with Multi-Porosity Modeling preprocessor for gas storage and transport in shale. A Triple-Porosity Model is used to characterize the three porosity systems in shale gas reservoirs. In the fracture porosity the heterogeneous impact of secondary fractures distribution on matrix-to-fracture fluid transfer is revealed by shape factor distribution. They are upscaled with superior accuracy from a detailed Discrete Fracture Network Model (DFN) sector model, where orthogonal hydraulic fractures are explicitly discretized. With the occurrence of nanopores in shale matrix, the interaction between pore-wall and gas molecules is considered via Knudsen diffusion and gas slippage. Gas adsorption on the pore-wall of organic matrix is modeled by extended Langmuir isotherm. The inter-porosity and intra-porosity connectivities in the Triple-Porosity Model are flexibly controlled by arbitrary connections. Our results show that gas production in the Triple-Porosity Model with shape factor upscaled from DFN exhibits different production performance from models with uniform shape factor distribution. The deviations are caused by the dominance of different regions at different production periods. Connection topology in the shale gas reservoir is also comprehensively assessed. We demonstrate that the intra-porosity connections in the inorganic and organic matrix have negligible impact on the global gas flux, while the inter-porosity connections have different levels of importance for the gas production. Moreover, different combinations of flow and storage mechanisms are investigated. We show that Langmuir desorption maintains reservoir pressure, but gas slippage and Knudsen diffusion accelerate the pressure drop. Both mechanisms contribute to improve the gas production and the consideration of them simultaneously improve gas production most.

1. Introduction

In the recent decades, shale gas development in North America becomes very successful which is mainly attributed to technology advancement of hydraulic fracturing and horizontal well drilling. Shale gas also becomes an active research area since it exhibits much more complexity than conventional natural gas reservoirs. Its production performance is difficult to interpret by traditional analytical and numerical approaches.

The first issue is the reservoir heterogeneity caused by hydraulic fractures and secondary fractures. After hydraulic fracturing, a complex fracture network is generated by the interaction of hydraulic fractures and secondary fractures (McLennan and Potocki, 2013). The reservoir volume associated with the fracture network corresponds to the Stimulated Reservoir Volume (SRV), and beyond this region shale matrix is basically undamaged (Vera and Shadravan, 2015). The micro-seismic fracture mapping data shows that the micro-seismic fracturing events in SRV were mostly located near the center of hydraulic fracture and wellbore (Fisher et al., 2004; Mayerhofer et al., 2010). Suliman et al. (2013) estimated SRV as a collective system of fractures and shattered matrix blocks. They classified the SRV into Flush, Conductive and Hydraulic SRV depending on the micro-seismic density and the connectivity of every grid block in the reservoir model. Therefore, the fracture distribution at the vicinity of horizontal wellbore and perforated stages

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tends to be non-uniform such that the reservoir-scale impact of the fracture network on gas production is not likely to be homogeneous.

In addition, the shale matrix is extremely tight and the influences of non-Darcy flow in the nano-porous media cannot be ignored. In shale matrix, organic part or kerogen distributes in inorganic matrix (Ambrose et al., 2012). Nano-pores are widely developed in kerogen due to the generation of hydrocarbon in geological ages (Wang and Reed, 2009), and those nano-pores have good capacity for absorbed gas and compressed gas storage (Ambrose et al., 2012). Besides, the interaction between gas molecules and nano-pore wall influences the gas flow within the nano-pores. Thus gas slippage and Knudsen diffusion is also important and could be considered using matrix apparent permeability (Civan, 2010). Moreover, organic matrix is usually non-water wet due to its affinity to hydrocarbon molecules (Odusina et al., 2011). On the other hand, inorganic matrix is comprised of different inorganic minerals such as clay, quartz, and pyrite etc. Those mineral pore spaces are mostly hydrophilic and easily blocked by water. Thus the inorganic matrix has much weaker gas adsorption capacity than the organic matrix (Ji et al., 2012; Zhang et al., 2012). The intrinsic difference between the inorganic and the organic matrix makes it necessary to treat them individually. Therefore, it is appropriate to divide shale gas reservoirs into three porosity systems, including fracture porosity (hydraulic/secondary fractures), inorganic matrix and organic matrix.

The complexity of fractured shale gas reservoirs lies in heterogeneity caused by fracture network (Cui et al., 2015, 2016) and shale matrix partition caused by different fluid flow and storage mechanisms. In the past few decades, several approaches have been proposed to simulate fluid flow in fractured reservoirs. They are basically categorized into three types, Discrete Fracture Model (DFM), Dual-Porosity Model, and their combinations. DFM, based on unstructured grid discretization, can explicitly describe the effect of fracture geometric details (Mi et al., 2014; Sun et al., 2012; Sun and Schechter, 2015a, 2015b; Yu et al., 2011), and naturally capture the complex flow phenomena occurring in the vicinities of those sparse fractures. However, it is still not practical for field-scale studies, since unstructured gridding becomes challenging and computationally expensive when a large number of fractures in complex distribution are present (Li et al., 2015). Further, a simplified model of Discrete Fracture Network (DFN) Model was developed, which can decrease the number of grid blocks and computational time (Basquet et al., 2005; Sarda et al., 2001), while still keeping the advantages of the DFM.

On the other hand, Dual-Porosity Model is the most commonly used fractured reservoir modeling approach, and was originally proposed by Barenblatt et al. (1960) and introduced to petroleum industry by Warren and Root (1963). This approach assumes that fracture is a continuous flow system with low pore volume. The matrix with low permeability provides the main fluid storage space and transfer fluid to fracture system as sources. This approach is appropriate and efficient for the modeling of reservoirs with densely distributed fracture networks. However, Dual-Porosity Model can only simulate two continua, insufficient to model fractured shale reservoirs with three porosity systems. Multi-Porosity Models are developed to simulate reservoirs with more than two porosity systems. Extended from Dual-Porosity Model (Hinkley et al., 2013), presented a Multi-Porosity simulation model and applied it in unconventional reservoir modeling through considering different physics in a black-oil type formulation. Yan et al. (2016) developed a general Multi-Porosity Model, allowing porosity subdivision in certain porosity if necessary with arbitrary inter-porosity and intra-porosity connections. Jiang and Younis (2015) coupled MINC (Pruess, 2010) with unstructured DFN (Karimi-Fard et al., 2004) or EDFM (Du et al., 2017; Moinfar et al., 2014) to honor transient flow in matrix and fracture sparsity. In this model the intrinsic characteristics of MINC allow only serial flow mode in the sequence of organics-inorganics-fracture. More recently, EDFM is coupled with Multi-Porosity Model such that different porosity systems and hydraulic fracture sparsity can be characterized (Chai et al., 2016a, 2016b). This approach combines the advantages of EDFM and Multi-Porosity Model such that it is flexible to describe different porosity systems and fracture geometries. Yet in terms of physics only Darcy flow and compressed fluid storage are incorporated in the model. Moreover, in those Multi-Porosity Models discussed above the heterogeneous impact of fracture system on matrix-to-fracture transfer is basically not investigated.

In this work we developed a framework combining an in-house compositional simulator (GURU) with a preprocessor of Multi-Porosity Model (Yan et al., 2016) for gas transport in shale. Multi-Porosity types in shale are fully characterized with no assumption of flow mode since arbitrary connection topology is allowed. Heterogeneous impact of fracture network is upscaled from DFN sector models depending on the fracture intensity in different regions, and it is numerically represented by heterogeneous shape factor distribution. Non-Darcy flow physics is captured in those tight matrix porous media. The reminder of this paper is organized as follows. The next session illustrates the numerical formulation of the model. Then the upscaling of DFN models is presented. Further, the workflow is applied into the evaluation of different shape factor distribution, different connectivity topology, and ultimately different flow mechanisms on shale gas production. Finally the whole work is concluded and summarized.

2. Numerical formulation for shale gas simulator

GURU is implemented based on control-volume finite-difference with two-point flux approximation (TPFA) (Cao, 2002). Our implementation is flexibly in handling neighbor and irregular non-neighbor connections from Multi-Porosity Model or unstructured discretization. The specific compositional formulation is modified from Young and Stephenson (1983). Bulk moles in unit volume for each species (absorbed part not included) and pressure are calculated as primary variables avoiding the necessity to switch primary variables in multi-phase scenario. Water and gas flows are considered for shale gas modeling. Gas matrix apparent permeability multiplier and multicomponent gas adsorption is added for gas flow physics in shale. The water material balance residuals as follows.

$$R_{w,i} = \frac{V_i}{\delta t}\left(N_{w,i}^{n+1} - N_{w,i}^{n}\right) - \sum_{l}\left(T\lambda_w\tilde{\rho}_w\Delta\Phi_w\right)_l - \sum_{p}\left(\tilde{\rho}_w q_w^s\right)_i = 0 \tag{1}$$

$$\lambda_\alpha = \frac{k_{r,\alpha}}{\mu_\alpha},\quad (\alpha = g,\ w) \tag{2}$$

Here only Darcy flow is considered for water phase. The mobility is defined in Equation (2) for gas and water phases. Gas material balance residual is given by

$$R_{i,j} = \frac{V_i}{\delta t}\left(N_{i,j}^{n+1} - N_{i,j}^{n}\right) + \frac{V_i}{\delta t}\left(M_{i,j}^{n+1} - M_{i,j}^{n}\right) - \sum_{l}\left(T\lambda_g\tilde{\rho}_g z_j\Delta\Phi_g\right)_l - \sum_{s}\left(\tilde{\rho}_g z_j q_g^s\right)_i = 0 \tag{3}$$

$$N_{i,j} = \phi_i S_{g,i}\tilde{\rho}_{g,i} z_{i,j} \tag{4}$$

$$M_{i,j} = (1-\phi_i)\rho_{s,i}\tilde{\rho}_g^{sc}\frac{V_{L,\,i,j} z_{i,j}\frac{P_i}{P_{L,i,j}}}{1+\sum_{k=1}^{n_h} z_{i,k}\frac{P_i}{P_{L,i,k}}} \tag{5}$$

The second term of Equation (3) is the gas accumulation term related to adsorption/desorption. The general extended Langmuir model is used in Equation (5) (Cao et al., 2015). Note the amount of gas dissolved in water is neglected since we consider water is an inert phase. Phase behavior calculation for gas is based on Peng-Robinson equation of state (Peng and Robinson, 1976) and gas viscosity is calculated using the Lohrenz-Bray-Clark method (Lohrenz et al., 1964).