Physical Models for Shale Gas Reservoir Considering Dissolved Gas in Kerogens

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Abstract

To figure out the complexity of the fabric and gas flow mechanism within the shale gas reservoirs shapes our preliminary study purpose. The pore structure and composition of shale are much more complicated than that of conventional and tight gas reservoirs. Apart from the classic matrix and fracture media, two new triple porous medium models regarding kerogen as the third medium are proposed in this paper. Furthermore, integrated gas flow mechanisms (containing Darcy flow, slippage flow, transient flow, Knudsen diffusion and Henry Diffusion) within each of the models are illustrated. Overall, four types of gas flow models are presented and related gas flow patterns and flow principles are explicated.

Introduction

Shale gas resources are termed "unconventional" due to its super low permeability (10^{-16} m^2 to 10^{-20} m^2) and severe heterogeneity caused by various scales of connected and unconnected fractures, fissures, micro, macro, and inter-aggregate pores, and organic matters. Moreover, free gas, adsorption gas and dissolved gas are widespread in shale gas reservoirs. All of these reservoir characteristics complicate the gas flow mechanisms which make shale gas extraction more difficult. Thus, to uncover the secrets of gas storage and flow in shale gas reservoir is one of the hottest topics in petroleum engineering.

X-CT technology is one of the most common methods to study the microscopic structure of rocks. While it could not be used to analyze the inner structure of shale due to its ultra-low pore diameters.

Therefore, a more advanced technology named FIB-SEM is used to engage in 3D digital core analyses. By making use of FIB-SEM, Curtis et al. (2010) got 500 pieces of cross-sectional slices each of whose thickness is 10 nm (**Figure 1**). The images from this process formed a 3D dataset which was used to reconstruct a volume of the sectioned shale material (**Figure 2**).

Knudsen (1909) conducted his research on the interaction between gas molecules and pore walls and explicated phenomenon of Knudsen diffusion. He proposed the concept of Knudsen number and used it to differentiate gas flow patterns.

In the aspect of mechanism of non-Darcy gas flow in tight porous media and based on the achievements of Knudt and Warburg (1875), Klinkenberg (1941) applied the theory of gas slippage effects occurring on the surface of solid walls into gas reservoirs and presented the corresponding first order apparent permeability expression. Beskok and Karniadakis (1999) studied the gas flow mechanisms in tight gas reservoir and deduced a generalized apparent permeability formula which contains continuum flow, slippage flow, transition flow and molecular diffusion flow.

Civan (2002) concluded that gas flow in tight porous media was subject to the integrated influence of

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Darcy flow, slippage flow and Knudsen flow. He also proposed a triple porous media model considering fractal characters to model gas flow in tight reservoirs.

Javadpour (2007) found that the gas flow in nanopores of shale can be modeled with a diffusive transport regime with a constant diffusion coefficient and negligible viscous effects. They deduced a new diffusion model and proposed the diffusion coefficient for gas flow in nanopores of shale. The obtained diffusion coefficient is consistent with the Knudsen flow which supports the slip boundary condition at the nanopore surfaces. This model can be used for shale gas development evaluation and production optimization.

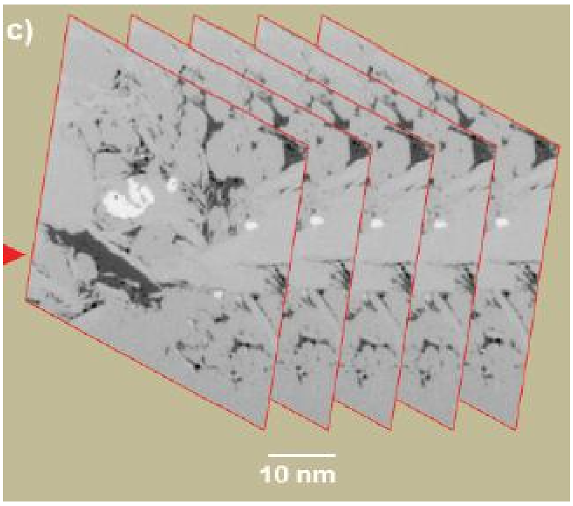


Figure 1—Cross-sectional slices by FIB-SEM.

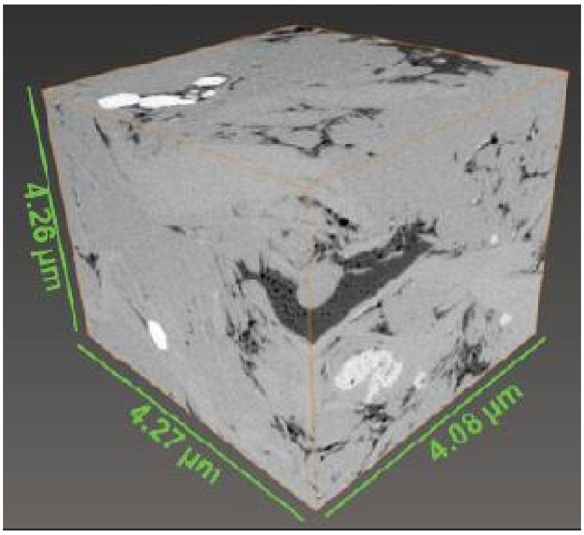


Figure 2—A 3D shale reservoir model reconstructed by FIB-SEM.

A higher-order permeability correlation for gas flow called Knudsen's permeability was deduced by Ziarani and Aguilera (2011). As opposed to Klinkenberg's correlation, which is a first-order equation, Knudsen's correlation is a second-order approximation. They concluded that Knudsen's permeability correlation was more accurate than Klinkenberg's model especially for extremely tight porous media with transitional and free molecular flow regimes. The results from their study indicated that Klinkenberg's model and various extensions developed throughout the past years underestimate the permeability correction especially for the case of fluid flow with the high Knudsen number.

What's more, there are a large amount of gas adsorbed on the surface of pore walls of shale which will highly affect shale gas in place evaluation, apparent permeability calculation and shale gas production prediction.

Ambrose (2012) combined the Langmuir adsorption isotherm with the volumetrics for free gas and formulate a new gas-in-place equation accounting for the pore space taken up by the sorbed phase. The calculation result showed the role of sorbed gas is more important than previous thought and a 10-25% decrease in total gas-storage capacity compared with that using the conventional approach.

Based on scanning electron microscope images and a drainage experiment in shale, Sakhaee-Pour and Bryant (2012) analyze the effects of adsorbed layers of methane and of gas slippage at pore walls on the flow behavior in individual conduits of simple geometry and in networks of such conduits. At large pressures such as typical initial shale-gas-reservoir pressures, the effect of the adsorbed layer dominates the effect of slip on gas-phase permeability. Slip dominates at smaller pressures typical of those after longer periods of production. Consequently, the reservoir matrix permeability is predicted to increase significantly throughout the life of a well, by a factor of 4.5, as production continues and pressure declines. The models predict that the typical conditions for laboratory measurements of permeability cause those values to overestimate field permeability by as much as a factor of four. The model results are captured in simple analytical expressions that allow convenient estimation of these effects.

Huang et al. (2007) established a comprehensive model for multi-scale shale gas flow which considered dissolved gas diffusing in kerogen bulk, desorption gas on the pore walls, Knudsen diffusion and slippage effects in nanopores, and conventional gas flow in fracture network towards the wellbore. It was found that desorption, Knudsen diffusion and slippage flow in nanopores have significant influences on transient flow behavior. The desorption effect could supplement gas to the reservoir, effects of diffusion and slippage could increase the apparent permeability and ease gas flow in nanopores, all of them decrease the rate of pressure depletion in shale gas reservoir.

The purpose of this paper is to figure out the relationship among matrix, natural fractures and kerogen and clarify the gas flow mechanism in these porous media.

Scales for shale gas flow

Javadpour et al. (2007) proposed the concept of transport regime which divided the gas flow in shale porous media into five scales, shown in **Figure 3.**

(a) macroscale, referring to gas flow from shale gas reservoir to wellbore (i.e., methane flow from hydraulic fractures and stimulated reservoir network to wellbore;
(b) mesoscale, referring to gas flow in natural fractures;
(c) microscale, referring to gas flow in nanopores;
(d) nanoscale, referring to desorption of gas from nanopore walls;
(e) molecular scale, referring to diffusion of dissolved gas in kerogens.

Shale reservoir models of triple porous media

The triple porous media model, which includes vuggy pores, matrix and fractures, has already been widely used in carbonate reservoirs. The fluid flow in carbonate reservoir follow the principle of Darcy Law. Different from carbonate reservoirs, gas flow in shale reservoirs contain both Darcy flow and non-Darcy flow (e.g., slippage, desorption, diffusion, et al.).

It is discovered that there are substantial volumes of methane dissolved in organic matters (Ross and Bustin 2009). According to the gas transport regime proposed by Javadpour (2007), flow of dissolved gas in kerogen adheres to Henry diffusion equation (Huang et al. 2007) which belongs to molecular scale.

Here, we regard kerogens as the third porous media. Thus, the triple porous media of shale gas reservoir comprises matrix system, kerogen system and enriched natural fractures. It should be noted that kerogens play the role of both matrix system the micro pores of whom provide storage spaces for sorbed and free gas and the triple porous media system in which substantial dissolved gas enrich.

If there are a lot of organic matters (i.e., kerogens) and natural fractures in the shale gas reservoirs, the natural fractures existing in the form of widespread fracture network could effectively connect the pores within matrix and organic matters.

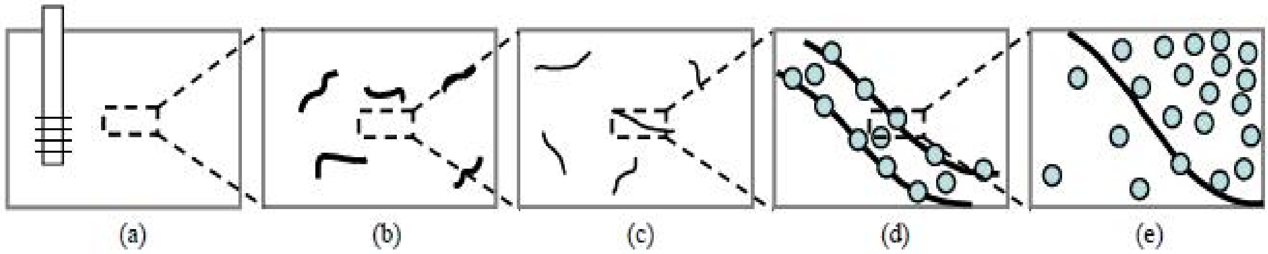


Figure 3—Different length scales for shale gas evolution and production.

We define triple porous media mentioned above as first type of triple porous media (F-TPM). The real and ideal physical models of F-TPM are shown in **Figure 4a** and **4b**, respectively. In the model of F-TPM, natural gas dissolved in the organic matters could either diffuses into fracture system directly or diffuses into matrix system and then flows from matrix system to fracture regime. At last, natural gas will flow from fracture system to the wellbore.

If the content of organic matters and the density of natural fracture in the shale gas reservoir are relative low, the natural fractures exist in the form of a sparse fracture network and play the role of high conductive passageway which connect matrix system with wellbore. Moreover, organic matters are embedded into matrix system and are isolated from fracture system. We definite this kind of triple porous media as the second type of triple porous media (S-TPM). The real and ideal physical models of S-TPM are shown in **Figure 5a** and **5b**, respectively. In this model, natural gas dissolved into organic matters have to diffuse into fracture system first and then flows from fracture system to the wellbore.

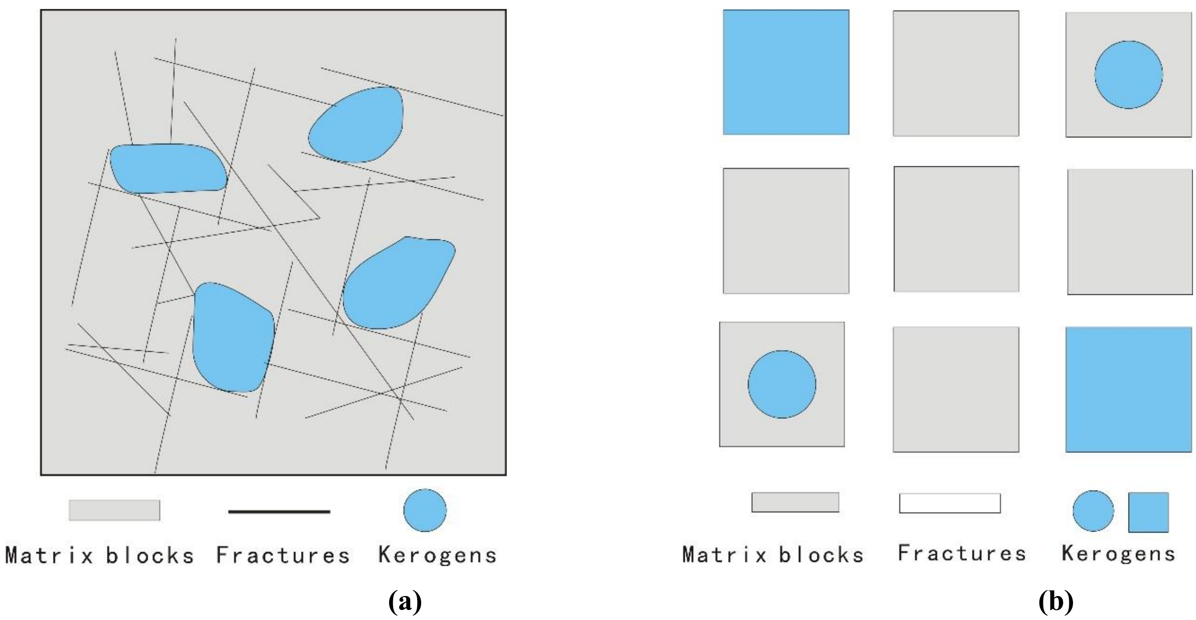
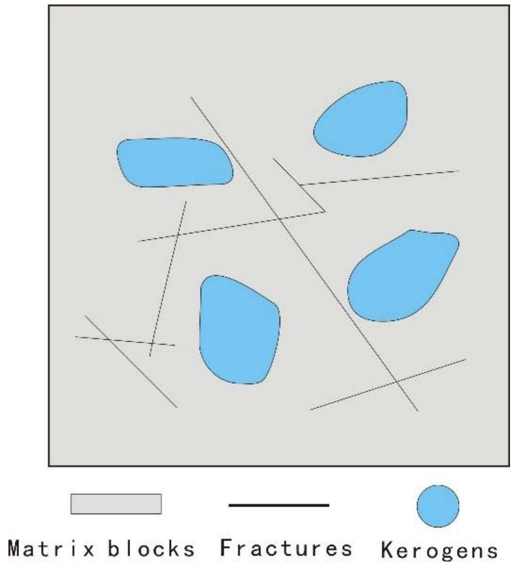
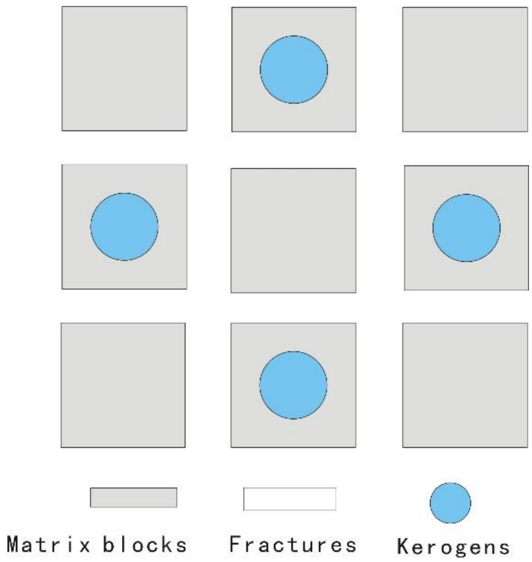


Figure 4—The first type of triple porous media (F-TPM). Real physical model. (b) Ideal physical model.



(a)



(b)

Figure 5—The second type of triple porous media (S-TPM). Real physical model. (b) Ideal physical model.

According to pathways of gas flow from reservoir systems to the wellbore, we divide shale gas reservoir models into two major categories: (1) triple porosity singular permeability model (TPSP), and (2) triple porosity dual permeability model (TPDP). If gas within wellbore is only provided by fracture system, this kind of model is defined as TPSP. If gas within wellbore is not only from fracture system but matrix system, this kind of model is defined as TPDP.

The model of TPSP which is derived from F-TPM is called first type of triple porosity single permeability model (F-TPSP) (**Figure 6a**). Gas flow within F-TPSP mainly experience four steps:

(a) gas flow from fracture system to wellbore, conforming to Darcy flow or slippage flow and belonging to the flow scale of mesoscale;
(b) under the effect of concentration difference, gas diffuse from matrix (conforming to Knudsen diffusion law and belonging to the flow regime of microscale) and organic matters (conforming to Henry diffusion law and belonging to the flow regime of molecular scale) to natural fractures;
(c) abundant adsorbed gas is desorbed from surface of matrix or organic matters to nanopores, conforming to Langmuir desorption law and belonging to the flow regime of nanoscale;
(d) concentration difference will exist between surface and inside of organic matters and gas will diffuse from inside of organic matters to nanoproes within matrix blocks.

The model of TPSP which is derived from S-TPM is called second type of triple porosity single permeability model (S-TPSP) (**Figure 6b**). Gas flow within S-TPSP mainly experience four steps as well:

(a) gas flow from fracture system to wellbore, conforming to Darcy flow or slippage flow and belonging to the flow regime of mesoscale;
(b) under the effects of concentration difference, gas diffuse from matrix to natural fractures, conforming to Knudsen diffusion law and belonging to the flow regime of microscale;
(c) abundant adsorbed gas is desorbed from surface of matrix to nanopores, conforming to Langmuir desorption law and belonging to the flow regime of nanoscale;
(d) concentration difference will exist between surface and inside of organic matters and gas will diffuse from inside of organic matters to nanoproes within matrix system.

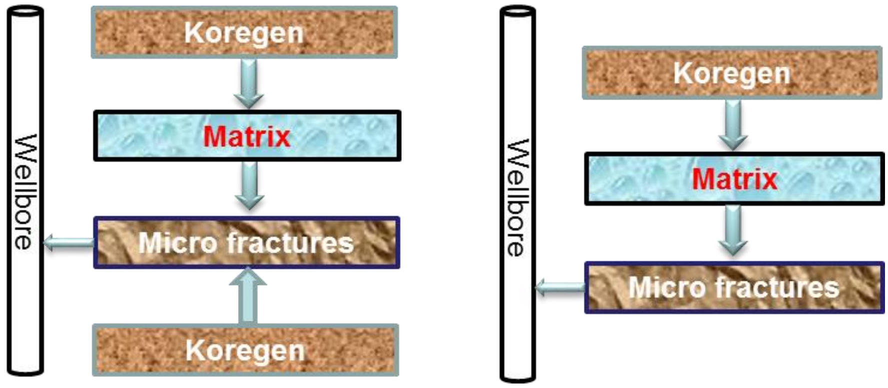
The model of TPDP which is derived from F-TPM is called first type of triple porosity dual permeability model (F-TPDP) (**Figure 7a**). Gas flow within F-TPDP mainly experience four steps:

(a) gas flow from fracture system (conforming to Darcy flow or slippage flow and belonging to the flow regime of mesoscale) or matrix system (conforming to Knudsen diffusion law and belonging to the flow regime of microscale) to wellbore simultaneously;

(b) under the effects of concentration difference, gas diffuse from matrix (conforming to Knudsen diffusion law and belonging to the flow regime of microscale) and organic matters (conforming to Henry diffusion law and belonging to the flow regime of molecular scale) to natural fractures;

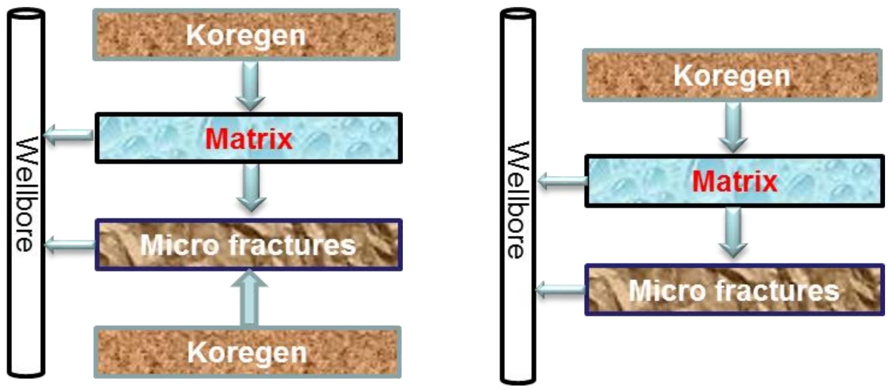
(c) abundant adsorbed gas is desorbed from surface of matrix or organic matters to nanopores, conforming to Langmuir desorption law and belonging to the flow regime of nanoscale;

(d) concentration difference will exist between surface and inside of organic matters and gas will diffuse from inside of organic matters to nanoproes within matrix blocks.



(a) (b)

Figure 6—Schematics for shale gas flow in TPSP. (a) F-TPSP. (b) S-TPSP.



(a) (b)

Figure 7—Schematics for shale gas flow in TPTP. (a) F-TPTP. (b) S-TPTP.

The model of TPDP which is derived from S-TPM is called second type of triple porosity dual permeability model (S-TPDP) (**Figure 7b**). Gas flow within S-TPDP mainly experience four steps as well: (a) gas flow from fracture system (conforming to Darcy flow or slippage flow and belonging to the flow regime of mesoscale) or matrix system (conforming to Knudsen diffusion law and belonging to the flow regime of microscale) to wellbore simultaneously;

(b) under the effects of concentration difference, gas diffuses from matrix to natural fractures, conforming to Knudsen diffusion law and belonging to the flow regime of microscale;

(c) abundant adsorbed gas is desorbed from surface of matrix to nanopores, conforming to Langmuir desorption law and belonging to the flow regime of nanoscale;

(d) concentration difference will exist between surface and inside of organic matters and gas will diffuse from inside of organic matters to nanoproes within matrix blocks.

Conclusions

The following conclusions can be drawn,

1. Natural gas in the shale gas reservoirs restored in the form of free gas in natural fractures and pores within matrix and kerogens, adsorption gas on pore walls and dissolved gas in kerogens. Kerogens in shale gas reservoirs play multiple roles, it could contain not only free and desorption gas but also dissolved gas. The triple porous media model of shale gas is made up of fractures system, matrix system comprising pores within organic and non-organic matters and kerogen blocks containing dissolved gas.
2. Four models for shale gas flow are proposed according to relationships of location of different flow media and permeability mode. Multiple mechanisms of Darcy flow, slippage flow, Knudsen flow, Henry law and Langmuir desorption contribute to gas flow in shale reservoirs and enhance the complexity of shale gas flow.

Conflicts of Interest

The author(s) declare that they have no conflicting interests.

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