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A Gaussian Decomposition Method and its applications to the prediction of shale gas production

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ABSTRACT

History matching is normally used to predict the gas production and guide refracturing. This can be achieved either through a mathematics-based approach such as decline curve fitting or through a physics-based approach such as reservoir simulation. When applied to the case of shale gas, both approaches are not working well. In this study, a Gaussian Decomposition Method (GDM), as an alternative approach, is developed and applied to the investigation of shale gas production. In this approach, an auto-compute program is developed and applied to a spectrum of scales from the core scale to the reservoir scale. Specific steps are as follows: (1) we use the experimental measurements to determine the initial gas content distribution; (2) we use the gas production history to decompose the evolving contributions of different gas components in a shale gas reservoir; and (3) we extend the history matching to predict the production of shale gas under similar extraction conditions. For the core scale, we use the automatically decomposed Gaussian components to illustrate the evolving contributions of different gas components including the free-phase gas in pores, the adsorbed gas and the diffused gas to the overall gas production. In the reservoir study, GDM is applied to the production data history matching and real-time prediction. Firstly, GMD is verified against a commercial software on daily, monthly and annual gas production rates. Then a group of daily and monthly field data are history matched by GDM. Finally, GDM is applied to predict the real-time gas production rate. Application results indicate: (a) the early gas production is mainly from big pores/fractures while the late production is from kerogen/clay components; (b) The period of gas production in the early stage is relatively short while the period in the late stage is long.

1. Introduction

The history matching and the real-time prediction of gas rate are the two indispensable processes for the economic evaluation of a well. The history match and real-time prediction methods of unconventional gas production rates inherit from the conventional gas and are categorized into mathematics-based approach and physics-based approach. The mathematics-based approach, traced back to the 1920s [1], uses the curve fitting to match the field data and gains lots of favor because of its easy use. The most popular Arps curves [2] were classified into three types depending on the decline exponent value (b): harmonic decline ($b = 1$), exponential decline ($b = 0$) and hyperbolic decline ($b > 0$ and $b \neq 0$). The traditional mathematics-based approach could bring huge errors when applied to the shale gas well because of the multi-physics, multi-time and multi-scale flow in shale reservoir [3]. Other mathematical methods, such as Stretched-exponential Decline method [4,5], Power-law Exponential Decline method [6,7] and Duong method [8], are well developed in recent years. However, there are two factors constraining their applications: (1) they have no rigorous theoretical basis which would lead to large uncertainties in prediction; (2) they are not necessarily related to the reservoir property and operating practices; thus, they work better for certain reservoirs but not for all cases [9].

Contrary to the mathematics-based approach, the physics-based approach has strict theoretical explanations establishing a set of Partial Differential Equations (PDEs) to match the bottom hole pressure curve or the gas production data curve. There are two categories of physics-based approach: analytical method and numerical method. For the

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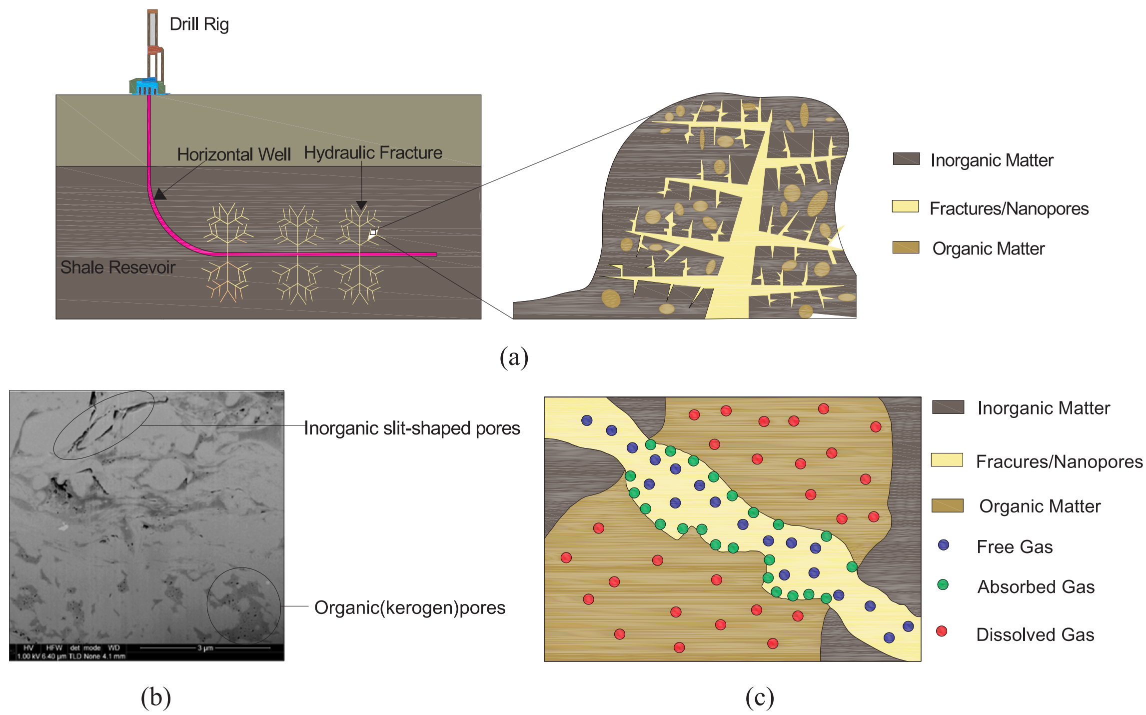

Fig. 1. (a) Schematic illustration of stimulated reservoir volume, (b) SEM image of shale matrix and (c) distribution of gas contents in a controlled volume.

analytical method, the most popular one is the tri-linear flow model. Three linear flow regimes [10,11] are taken into consideration in this method: flow within the fracture, flow within the stimulated region and flow within the un-stimulated region. The analytical method simplifies the reservoir property to search for the analytical solution and the detailed couplings between the gas flow and solid deformation are ignored [12,13]. Moreover, most analytical methods are limited to single-phase flow cases ignoring the impact of water.

The numerical method is popular with the development of computing speed which can be categorized into continuous model and discrete model [14]. For the continuous model, the dual-porosity models and multi-porosity models are widely used [15–18] and in these models the computational notes on the grid can represent different physical meanings. Take as an example, Yan [19] presented an up-scaled triple permeability simulator for fluid flow in shale reservoirs by capturing the sequential flow in three separate porosity systems: organic matter (mainly kerogen), inorganic matter and natural fractures. For the discrete model, the widely used method is Discrete Fracture Network (DFN) where the fractures are directly modeled and the computational notes represent either matrix or fracture [20,21]. A DFN model was developed by Doe [22] to match the production data from the Eagle Ford shale. In Yu's work [23], a similar method was used to match the production data from Barnett Shale and Marcellus Shale. The numerical techniques represent the state-of-the-art in history match and prediction of shale reservoir, but they are usually time and computing resource consuming [16], and require data and information which are not available in all wells [18].

From the review above, it can be concluded that when applied to the case of shale gas production, both approaches are not working well: the mathematical approach has better applicability but would bring huge errors because of lacking the physical background, on the other contrary the physical approach can obtain a good result but cannot be widespread used because of its complexity.

Previous studies have shown that the reservoir properties such as the initial gas distribution have significant impacts on the gas production [18,23–25]. In common, the gas exists as three major forms in shale reservoir: (1) free gas in big pores, fractures and nanopores, (2) absorbed gas on the nanopores surface, (3) dissolved gas in kerogen/clay and water [24,26,27]. Various methods are proposed to calculate initial gas distribution in unconventional gas area. In Ross and Bustin [28] viewpoint, only free gas flows at the early stage until the reservoir pressure is depleted to CDP (critical desorption pressure). Yang and Li [29] incorporated an artificial component subdivision in their numerical simulator to investigate the behavior of the original free gas and the adsorbed gas. Only distinguishing free gas and adsorbed gas is insufficient for shale reservoir due to its high heterogeneous properties. Etminan [30] developed a batch pressure decay (BPD) method to simultaneously measure the shale gas capacity from each source based on the distinctive changing of pressure decline curve slope. Javadpour [31] developed a method to calculate the gas diffusion coefficient in kerogen/clays offering an alternative way to calculate the proportion from each source.

In this study, a Gaussian Decomposition Method (GDM) is developed and applied to the prediction of shale gas production. The gas flow in the shale block is a multi-time, multi-scale and multi-physics process due to the diversity in minerals component and pore structure. GDM is proposed as an alternative approach to history matching and real-time prediction, and applied to decompose the evolving contributions of different gas components (free gas, adsorbed gas and dissolved gas), and applied to a spectrum of scales from laboratory scale to the field scale.

2. Development of a Gaussian Decomposition Method

2.1. Multi-time, multi-scale and multi-physics gas flow

Due to the ultra-low permeability, the horizon well and hydraulic fracture are the two essential processes for shale gas production. In this paper, the shale block defined as the shale matrix in the middle of the hydraulic fractures is investigated, shown in Fig. 1(a). As the SEM image shown (Fig. 1(b) [32]), the shale matrix is a typical porous medium which consists of nanotubes, kerogen and other minerals. The gas stores in the shale as (1) the free gas in nanotube, (2) the adsorbed gas on nanotube surface and (3) the dissolved gas in kerogen [3,57]. A cell tube can be used to characterize the heterogeneity of shale structure and gas storage as illustrated in Fig. 1(c) [26]. The gas flow in the