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A new rate-decline analysis of shale gas reservoirs: Coupling the self-diffusion and surface diffusion characteristics

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ABSTRACT

Forecasting production in shale reservoirs accurately has been of growing interest in the industry in recent years. Until now, various techniques to interpolate production have been developed. Among them, decline curve analysis models have been widely recognized as the most efficient and easiest approach to apply. Unfortunately, each decline curve model has its own limitations and will not allow us to forecast production in shale gas reservoirs with confidence. In this paper, based on the similar characteristics between shale gas production and self-diffusion of dense gas/surface diffusion of adsorbed gas, a new early-late decline model with two fitting parameters were developed by employing general equations of this two behaviors respectively. These flow characteristics cannot be addressed by traditional decline curve models. In addition, a detailed forecasting procedure applying this novel decline model in the whole life of shale gas production was proposed, which is reliable and easy to utilize. Furthermore, this proposed model was validated by numerically simulated cases and field observations. Good matches between forecast rates calculated using this novel method and numerically simulated rates/field rates were obtained. The comparison between this proposed method and traditional methods were further conducted, which indicated that this novel approach leads to more confident forecasts than commonly utilized approaches. This work will provide a theoretical basis for analysts in evaluating hydrocarbon production rapidly and efficiently in shale gas reservoirs.

1. Introduction

In the past two decades, especially in North America, unconventional gas exploration and development has been a huge success, and it has become an inevitable trend that unconventional energy occupies an increasingly important position (Wright et al., 2015; Aydemir, 2011). Horizontal wells with multiple fractures are the most popular choice for exploiting shale gas reservoirs (Chen et al., 2015; Zhao et al., 2013; Figueiredo et al., 2017; Yu et al., 2014; Li et al., 2017), which will encounter multiple flow regimes during the life of wells (Amir and Sun, 2017; Sobhaniaragh et al., 2016; Zhang et al., 2016; Fan and Ettehadtavakkol, 2017; Wang et al., 2016a,b,c). Accordingly, it is challenging to forecast production accurately in shale gas reservoirs.

The methodologies of forecasting production and estimating reserves include volumetric calculations, material balance, analogy, decline curve analysis (DCA), history matching, type curves and numerical simulation (Burch and Cluff, 1997; Hodgin and Harrell, 2006; Sidle and Lee, 2010; Spivey, 2006; Freeman et al., 2009; Fetkovich et al., 1987; Agarwal et al., 1999; Palacio and Blasingame, 1993). Among them, decline curve analysis is the most widely used approach to analyze production in the industry. When we face to forecast in conventional reservoirs, the Arps decline model (Arps, 1945) is reliable and effective. However, there are various complications while utilizing this approach in unconventional reservoirs (Lee and Sidle, 2010; Sharma and Lee, 2016). Recently, a number of new empirical methods have been introduced to the petroleum industry to conduct the production prediction of shale reservoirs.

Ilk et al. (2008) presented a new “power law loss-ratio” rate relation for reserve evaluation, which employs a different functional form for the decline rate. However, Johnson et al. (2009) indicated that this parameter is difficult to determine without ambiguity and that the procedure benefits from multiple analysis methods. Valko (2009) proposed the Stretched Exponential Production Decline Model (SEPD). There are two

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Nomenclature

A_c	cross-sectional area of cavity or channel (m^2)
$\mathscr{A}^{(m)}$	some certain determinant
D	self-diffusion coefficient of a simple gas (m^2/s)
D_s	surface diffusion coefficient (m^2/s)
D_s^0	surface diffusion coefficient when gas coverage is "0" (m^2/s)
E_t	relative translational energy (J)
K	Boltzmann constant (J/K)
k_a	rate constant of activation
k_b	rate constant of blockage
k_m	rate constant of forward migration
m_r	particle mass (kg)
M	rate of migration
n	number density (m^{-3})
q	gas production (m^3/d)
r	intermolecular separation (m)
T	Temperature (K)
V_c	volume of cavity or unit volume of channel (m^3)
w_j	related to the Lennard–Jones potential

Greeks

α^*	scattering coefficient for a soft-sphere model
α_j	model parameters determined from the transport property data
σ	molecular diameter (m)
σ_T	total collision cross-section (m^2)
ε	molecular potential well depth (J)
$\Gamma(\ldots)$	gamma function
H(1-κ)	Heaviside function
ξ_{ms}	correction factor for surface diffusion of adsorbed gas in nanopores
Θ	fractional surface coverage
Δ	length per cavity or unit length of channel (m)

advantages of this model over the Arps model: the EUR is bounded and it is designed to model the transient flow rather than boundary dominated flow (BDF). Unfortunately, Yu and Miocevic (2013) pointed out that Valko's SEPD method will extremely underestimate EURs of wells with reservoir permeability greater than 0.001mD. Duong (2011) presented a novel decline method assuming long-duration linear flow to evaluate the performance of shale gas wells. However, Joshi and Lee (2013) pointed out that using a non-zero q_∞ can lead to unrealistic results for both field and simulated cases, especially when only 6-12 months of historical production data are available. Patzek et al. (2013) developed the scaling method which provides a surprisingly accurate description of gas extraction, and then (Male et al. 2014, 2016) applied this method for Haynesville and Marcellus shale, which illustrated that it is a more time consuming method than the conventional methods.

Accordingly, each traditional approach has its own limitations and may produce unreasonable reserve estimations. In addition, in shale gas reservoirs, various flow regimes and complex matrix/fracture systems will bring similar characteristics caused by the self-diffusion of dense gas and surface diffusion of adsorbed gas during the early and late period of well production respectively (Masoumeh and Davood, 2017; Rajat and Khanna, 2007; Octavio et al., 2007; Wu et al., 2015, 2016), which has never been well described by currently published models.

Self-diffusion is the diffusion of tagged particles of compound A in a fluid where all particles are chemically identical, i.e., where only compound A particles are present (2006). This phenomenon is characterized by self-diffusion coefficient. Currently, many equations have been proposed to describe self-diffusion of dense gas. Ruckenstein and Liu (1997) proposed a model for self-diffusion coefficient in a hard-sphere fluid based on molecular dynamics simulations. That expression, extended to the Lennard-Jones (LJ) fluids through the effective hard-sphere diameter method, represents accurately self-diffusion coefficients obtained in the literature by molecular dynamics simulations, as well as those determined experimentally for argon, methane, and carbon dioxide. Silva et al. (1998) constructed a new four-parameter model for the description of self-diffusion coefficients of polar, nonspherical and even hydrogen-bonding substances. It gives accurate results over wide ranges of temperature and pressure. Yu and Gao (1999) described the real compounds as freely tangent Lennard-Jones chain (LJC). A new equation for self-diffusion coefficient of hard-sphere chain fluid is proposed and an expression for self-diffusion coefficient for the LJC fluid is obtained.

Transport of bulk gas (free gas) in nanopores and surface diffusion of adsorbed gas coexist in shale gas reservoirs (Akkutlu and Fathi, 2012). A concentration gradient is the driving force of surface diffusion. Adsorbed gas on organic pore walls has a large concentration gradient with a great specific surface area (Yi et al., 2009; Clarkson et al., 2013). Many researches have been working on the surface diffusion of adsorbed gas and proposed the equations of fluid surface diffusion in porous media. For examples, Hwang and Kammermeyer (1966) derived an analytic model of surface diffusion in a low pressure condition, which was validated by experiments. Guo et al. (2008) fitted an empirical expression of a surface diffusion coefficient in a methane-activated carbon system based on experimental data and a previous analytic model, but the influence of pressure was not considered and cannot be applied for surface diffusion calculations of adsorbed gas under a high pressure condition. Chen and Yang (1991) developed a surface diffusion model with consideration of adsorbed gas coverage under a high pressure condition based on hoping models, and it can be directly applied to surface diffusion in shale gas reservoirs.

Therefore, in this study, for the early flow period of shale reservoirs, based on same characteristics between the shale gas production and the self-diffusion of dense gas, the new decline model with self-diffusion characteristics was first proposed by employing the common equation of the self-diffusion coefficient of dense gas. Next, for the late flow period of shale gas, depending on similar characteristics between the shale gas production and the surface diffusion of adsorbed gas, it was switched to construct the novel decline model by utilizing the general equation of the surface diffusion coefficient of adsorbed gas. In addition, forecasting procedure applying this novel decline model to estimate the whole life of shale gas production was addressed, which is reliable and easy to apply. Furthermore, this early-late decline model was validated by both test cases constructed by numerical simulation and field cases in Barnett. In order to present advantages of this proposed model, the classical Arps model and most advanced Duong model were adopted to compare with this new approach. The comparison results illustrated that this novel decline model will produce more reliable production forecasting than traditional models, which should provide a critical guidance for analysts in determining reasonable shale gas targets.

2. Methodology

2.1. A new decline curve development

When the mean free path of molecules is comparable to the characteristic length of a system in rarefied gas flows, the continuum assumption breaks down and the gas must be described by the Boltzmann equation (Gad-el-Hak, 1999). The direct simulation Monte Carlo (DSMC) method is a particle-based numerical scheme for solving the nonlinear Boltzmann equation for the high Knudsen number gas flow (Bird, 1976,