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A quadruple-porosity model for shale gas reservoirs with multiple migration mechanisms

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ABSTRACT

This paper presents a quadruple-porosity model for multi-stage fractured horizontal well (MFHW) with finite conductive hydraulic fractures in shale gas reservoirs. In this model, free gas, adsorbed gas and dissolved gas co-exist and gas migration in shale incorporates diffusion in kerogen bulk, desorption from the surface of organics and clays, slippage flow in porous kerogen and inorganic matrix, and Darcy flow in natural fractures. Bi-Langmuir theory was introduced to describe gas desorption from the surface of clays and organics. Continuous line source function, Laplace transform and numerical discrete method were employed to solve this new model. Gauss-Jordan elimination method and Stehfest numerical inversion algorithm were applied to calculate the pressure and production responses. Type curves were plotted and flow regimes were identified. Sensitivity analysis of solubility coefficient, diffusion coefficient, inter-porosity coefficient, TOC, clays content, hydraulic fracture conductivity and permeability correction coefficient was performed. Finally, the proposed model was validated by fitting actual production data of a field case and comparing with other models. The matching results showed that quadruple porosity model considering dissolved gas was closer to the actual situation than trilinear-flow model and dual-porosity radial-flow model. To sum up, this presented model considering some key mechanisms further expands the transient pressure models for MFHW in shale gas reservoirs and it can be utilized to analyze well performance in the production life of gas wells.

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1. Introduction

Shale gas has become an important component of the U.S. natural gas consumption, and about 30% of United State natural gas supply comes from shale gas by the end of 2013 (Oyekunle, 2013). It can be expected that this proportion will be further expanded in the future. Due to its high specific surface area and organic-rich characteristics (Javadpour et al., 2007, 2009), the storage and migration mechanisms of natural gas in shale are obviously different from conventional gas reservoirs and tight sand gas reservoirs.

Gas shale is composed of porous kerogen, inorganic matrix and natural fractures (Kang et al., 2010; Akkutlu and Fathi, 2011; Hudson et al., 2012; Sun et al., 2014), and shale gas can be stored at different forms in gas shale, which contains dissolved gas in organics or bitumen (Javadpour et al., 2007, 2009; Ross and Bustin, 2007), adsorbed gas on the wall of kerogen bulk and clay minerals (Lu et al., 1995), and compressed gas in pores and natural fractures. Gas migration in shale can be seen as a combination of several mechanisms (Zhao et al., 2013; Wang et al., 2014), such as diffusion, desorption, slip flow and viscous flow.

The total organic-carbon content (TOC) can reach up to 40% in some shale gas reservoirs (Passey et al., 2010). Due to its high porosity and specific surface area characteristics (Dmitriy et al., 2011), porous kerogen plays a significant role in providing storage space and migration path for gas. However, the capacity of kerogen bulk to dissolve shale gas (Javadpour et al., 2007, 2009; Ross and Bustin, 2009) is usually neglected in most physical and mathematical models for shale gas reservoir. In fact, the solubility coefficient can arrive at 1.43×10^{-6} $m^3/Pa/m^3$ (Vivek and Settari, 2012) which demonstrates that the content of dissolved gas in organic matters is quite considerable. Moreover, the diffusion coefficient of dissolved gas in kerogen bulk can reach up to the order of 10^{-20} m^2/s and dissolved gas in organic matters can contribute about 22% of total gas-in-place (Reza Etminan et al., 2014). Therefore, dissolved gas in shale gas reservoir cannot be ignored in pressure and

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Nomenclature

C,C_i	Gas concentration in organics (at initial formation condition), m^3/m^3
C_{wD}	Dimensionless wellbore storage factor
C_t	Total compressibility, Pa^{-1}
D_o	Diffusion coefficient of organics, m^2/s
f_c,f_k	Volumetric content of clay/kerogen
h	Thickness of formation, m
H	Solubility coefficient, m^3/(Pa m^3)
k_h	Permeability of hydraulic fractures, m^2
k_{fa},$k_{f\infty}$	Permeability of natural fracture, m^2
k_{ka},$k_{k\infty}$	Apparent/absolute permeability of nano-pore in porous kerogen, m^2
k_{ma},$k_{m\infty}$	Apparent/absolute permeability of matrix, m^2
K_n	Knudsen number
l_{ref}	Reference length, m
m_F	Number of hydraulic fractures
M_g	Average molecular weight, kg/mol
p_i	Initial pressure of formation, Pa
$p_{k,m,f,h}$	Pressure of porous kerogen/matrix/natural fracture/ hydraulic fracture, Pa
p_L	Langmuir pressure, Pa
p_{sc}	Reference length, m
q_{sc}	Pressure at standard condition, Pa
q_{fR},q_{fL}	Production of right/left wing of hydraulic fracture, m^3/s
$\tilde{q}$	Linear source strength, m^3/s
$r_{o,k,m,f}$	Radius of organic particle/kerogen sphere/matrix sphere/natural facture, m
$R_{o,k,m}$	Radius of organic particle/kerogen sphere/matrix sphere, m
r_e	Radius of formation boundary, m
R_g	Universal gas constant, 8.314 Pa m/(mol K)
s	Laplace variable
S_k	Skin factor
t	Time, s
T	Formation temperature, K
T_{sc}	Temperature of standard condition, K
V_{Lk},V_{Lc}	Langmuir volume of kerogen/clay, m^3/m^3
$v_{k,m,f}$	Flow rate of porous kerogen/matrix/natural fracture, m/s
w_f	Width of hydraulic fracture, m
$x_{mi,j}, y_{mi,j}$	The middle point coordinate of j-th segment in i-th fracture, m
$x_{ei,j}, y_{ei,j}$	The end point coordinate of j-th segment in i-th fracture, m
y_{wi}	The cross point coordinate of i-th fracture and horizontal well, m
α	Permeability correction coefficient
ϕ	Porosity, f
μ	Gas viscosity, Pa.s
ξ_{fRi},ξ_{fLi}	Length of right/left wing of i-th hydraulic fracture. m
ρ	Gas density, kg/m^3
θ	Angles between wellbore and hydraulic fracture
$\psi_{k,m,f,h}$	Pseudo pressure of porous kerogen/matrix/natural fracture/hydraulic facture, Pa^2/(Pa s)
ψ_{wD}	Dimensionless pseudo pressure of wellbore without considering well storage and skin effect
ψ_{wDH}	Dimensionless pseudo pressure of well bottom hole considering well storage and skin effect
Subscript	
c	Clay minerals
D	Dimensionless
h	Hydraulic fracture
k	Porous kerogen
m	Matrix system
o	Organics in porous kerogen
sc	Standard condition
Superscript	
—	Laplace transform

production analysis.

Adsorbed gas in shale can contribute to the 20%–85% of gas reserve in five productive shale formations in Unite State (Hill and Nelson, 2000; Montgomery et al., 2005). The adsorbents in shale are mainly divided into two categories: clays and organics (Zhang et al., 2012; Ji et al., 2012; Liu et al., 2013). An obvious difference of the adsorption properties between clays and organics is confirmed by laboratory experiments (Lu et al., 1995; Zhang et al., 2012; Liu et al., 2013). Due to the assumption that all adsorption sites are energetically equivalent which is suitable for homogeneous adsorbent (Langmuir et al., 1918), Langmuir model may not fit adsorption data very well where an obvious difference in adsorption properties between clays and organics. In view of this, Bi-Langmuir method (Lu et al., 1995) is proposed to describe the adsorption and desorption characteristics in shale gas reservoir.

In addition, the shale porosity ranges from 2 to 15% (Curtis, 2002). The storage space for free gas in shale consists of four types of pores: organic pores, inorganic pores, natural fractures and hydraulic fractures (Wang et al., 2009). Usually, abundant nanopores can be observed in shale by scanning electron microscope (Ambrose et al., 2010; Curtis et al., 2010; Hu et al., 2013). However, restricted by the size of focused ion beam SEM cubes (1–5 μm), it is difficult to observe all the various pores in inorganic matters in gas shale (Milner et al., 2010). Based on the scanning images, many researchers neglected the gas stored in inorganic-pores in their mathematical models (Guo et al., 2012; Zhao et al., 2013; Wang et al., 2014; Ren et al., 2015). It can be seen in Table 1 that the porosity of inorganic matters cannot be neglected, especially for Hayneville shale.

Due to the ultra-low permeability, horizontal well drilling and multistage hydraulic fracturing technology have been proven to be effective in the development of shale gas reservoirs (Zhu et al., 2007). The economic feasibility of developing shale gas reservoirs has a strong relationship with the permeability enhancement of the fracture system. In contrast to vertical and horizontal well, MFHW can not only create high-conductivity hydraulic fractures as flow paths, but also activate and connect existing natural fractures so as to develop large fracture network system (Clarkson, 2013). Until now, a large number of mathematical models have been established to analyze the pressure and production performance of MFHW in shale gas reservoir. These mathematical models can be divided into the following categories: (1) Dual-porosity model (Kucuk and Sawyer, 1980; Rasheed and Robert, 2010; Guo et al., 2012), (2) Tri-linear flow model (Ozkan et al., 2010; Brown et al., 1946; Sang et al., 2014), (3) Five-linear flow model (Bello and Wattenbarger, 2010; Stalgorova and Mattar, 2012), (4) Triple porosity model (Zhao et al., 2013; Chen et al., 2015), (5) Composite model (Zhang et al., 2015; Xu et al., 2015).

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