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Original article

Characterizing hydraulic fractures in shale gas reservoirs using transient pressure tests

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ABSTRACT

Hydraulic fracturing combined with horizontal drilling has been the technology that makes it possible to economically produce natural gas from unconventional shale gas or tight gas reservoirs. Hydraulic fracturing operations, in particular, multistage fracturing treatments along with horizontal wells in unconventional formations create complex fracture geometries or networks, which are difficult to characterize. The traditional analysis using a single vertical or horizontal fracture concept may be no longer applicable. Knowledge of these created fracture properties, such as their spatial distribution, extension and fracture areas, is essential information to evaluate stimulation results. However, there are currently few effective approaches available for quantifying hydraulic fractures in unconventional reservoirs.

This work presents an unconventional gas reservoir simulator and its application to quantify hydraulic fractures in shale gas reservoirs using transient pressure data. The numerical model incorporates most known physical processes for gas production from unconventional reservoirs, including two-phase flow of liquid and gas, Klinkenberg effect, non-Darcy flow, and nonlinear adsorption. In addition, the model is able to handle various types and scales of fractures or heterogeneity using continuum, discrete or hybrid modeling approaches under different well production conditions of varying rate or pressure. Our modeling studies indicate that the most sensitive parameter of hydraulic fractures to early transient gas flow through extremely low permeability rock is actually the fracture-matrix contacting area, generated by fracturing stimulation. Based on this observation, it is possible to use transient pressure testing data to estimate the area of fractures generated from fracturing operations. We will conduct a series of modeling studies and present a methodology using typical transient pressure responses, simulated by the numerical model, to estimate fracture areas created or to quantity hydraulic fractures with traditional well testing technology. The type curves of pressure transients from this study can be used to quantify hydraulic fractures in field application.

1. Introduction

For the unconventional gas reservoirs, hydraulic fractures characterization is important in assuring the maximum stimulation efficiency [1–3]. A lot of researches have been carried out on the flow behavior analysis of vertical wells with finite-conductivity or infinite-conductivity hydraulic fractures. Cinco-Ley and Samaniego summarized fluids flow in a hydraulic fractured well could be divided into four periods: fracture linear flow, bilinear flow, formation linear flow and pseudo-radial flow [4]. Nobakht and Clarkson pointed out that the dominant flow regime observed in most fractured tight/shale

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gas wells is the third one, formation linear flow, which may continue for several years [5]. Transient pressure analysis of this linear flow behavior is able to provide plenty of useful information, especially, the total contact area between hydraulic fractures and tight matrix.

Pseudo-pressure, a mathematical pressure function that accounts for the variable compressibility and viscosity of gas with respect to pressure, is widely used for the transient pressure analysis in conventional gas reservoirs [6]. Compared with conventional reservoirs, gas flow in ultra-low permeability unconventional reservoirs is subject to more nonlinear, coupled processes, including nonlinear adsorption/desorption, non-Darcy flow (at both high flow rate and low flow rate), strong rock–fluid interaction, and rock deformation within nano-pores or micro-fractures, coexisting with complex flow geometry and multi-scaled heterogeneity. Therefore, quantifying flow in unconventional gas reservoirs has been a significant challenge and traditional REV-based Darcy law, for example, may not be generally applicable. For gas flow in these unconventional reservoirs, our previous work indicates that gas-slippage effect and adsorption/desorption play an important role to describe the subsurface flow mechanisms, which cannot be neglected [7]. To the authors' knowledge, these two factors were not considered in the previous pseudo-pressure derivation. In this paper, a new derivation of pseudo-pressure is provided.

This paper presents our continual efforts in developing numerical models and tools for quantitative studies of unconventional gas reservoirs [8,9]. Specifically, we explore the possibility of performing well testing analysis using the developed simulator. The numerical model is able to simulate realistic processes of single-phase or two phase flow in unconventional reservoirs, which considers the Klinkenberg effects and gas adsorption/desorption. We use the numerical model to verify our new derived pseudo-pressure formulation. We also apply it to generate type-curves of transient gas flow in unconventional reservoirs with horizontal well and multistage hydraulic fractures. The type curves of pressure transients from this study can be utilized to quantify hydraulic fractures in field application.

2. Derivation of new pseudo pressure

In 1965, Al-Hussainy and Ramer derived the pseudo pressure which has been successfully used to analyze the flow of real gas in the gas reservoirs.

$$m(P) = 2\int_{P_0}^{P} \frac{P'}{\mu Z} \mathrm{d}P' \tag{1}$$

where P_0 is the reference pressure; P is gas pressure; μ is the gas viscosity and Z is gas pressure Z factor.

The concept of the real gas pseudo-pressure promises a considerable simplification. It brings improvement in all phases of gas well aWnalysis and gas reservoir calculations. These analysis and calculations in terms of pseudo-pressure work very well for the conventional reservoirs but meet some problems when it is directly applied in the unconventional reservoirs analysis. This is mainly because gas flow in ultra-low permeability unconventional reservoirs, different from the gas flow in conventional reservoirs, is subject to more nonlinear, coupled processes, including nonlinear adsorption/desorption, non-Darcy flow, and strong rock–fluid interaction, and rock deformation within nanopores or micro-fractures, coexisting with complex flow geometry and multi-scaled heterogeneity.

Considering the Klinkenberg effects and gas adsorption, the principle of conversation of mass for isothermal gas flow through a porous media is expressed by the expression:

$$\nabla \cdot \left[\rho \frac{k(P)}{\mu(P)} \nabla P\right] = \frac{\partial}{\partial t}\left[\phi\rho + \frac{m_{\mathrm{g}}(V)}{V}\right] \tag{2}$$

The pressure-dependent permeability for gas is expressed by Klinkenberg as:

$$k_{\mathrm{g}} = k_{\infty}\left(1 + \frac{b}{P_{\mathrm{g}}}\right) \tag{3}$$

where k_∞ is constant, absolute gas-phase permeability in high pressure (where the Klinkenberg effect is minimized); and b is the Klinkenberg b-factor, accounting for gas-slippage effect.

The mass of adsorbed gas in formation volume, V, is described by Refs. [10,11,7]:

$$m_{\mathrm{g}}(V) = \rho_K \rho_{\mathrm{g}} f(P) V \tag{4}$$

where $m_{\mathrm{g}}(V)$ is absorbed gas mass in a volume V, ρ_K is rock bulk density; ρ_{g} is gas density at standard condition; $f(P)$ is the adsorption isotherm function. If the adsorbed gas terms can be represented by the Langmuir isotherm (Langmuir, 1916), the dependency of adsorbed gas volume on pressure at constant temperature is given below,

$$f(P) = V_{\mathrm{L}} \frac{P}{P + P_{\mathrm{L}}} \tag{5}$$

where V_{L} is the gas content or Langmuir's volume in scf/ton (or standard volume adsorbed per unit rock mass); P is reservoir gas pressure; and P_{L} is Langmuir's pressure, the pressure at which 50% of the gas is desorbed.

For real gas,

$$\rho = \frac{M}{RT}\left[\frac{P}{Z(P)}\right] \tag{6}$$

Substitute Equations (3)–(6) into Equation (2),

$$\nabla \cdot \left[\frac{P\left(1 + \frac{b}{P}\right)}{\mu(P) Z(P)} \nabla P\right] = \frac{\phi}{k_\infty} \frac{\partial}{\partial t}\left[\frac{P}{z(P)} + \frac{RT\rho_K \rho_{\mathrm{g}} V_{\mathrm{L}} P}{\phi M (P + P_{\mathrm{L}})}\right] \tag{7}$$

From the definition of the isothermal compressibility of gas:

$$c_{\mathrm{g}}(P) = \frac{Z(P)}{P} \frac{\mathrm{d}}{\mathrm{d}P}\left[\frac{P}{Z(P)}\right] \tag{8}$$

We also define the "compressibility" from the adsorption:

$$c_{\mathrm{a}}(P) = \frac{Z(P)}{P} \frac{\mathrm{d}}{\mathrm{d}P}\left[\frac{RT\rho_K \rho_{\mathrm{g}} V_{\mathrm{L}} P}{\phi M (P + P_{\mathrm{L}})}\right] = \frac{Z(P)}{P} \frac{RT\rho_K \rho_{\mathrm{g}} V_{\mathrm{L}} P_{\mathrm{L}}}{\phi M (P + P_{\mathrm{L}})^2} \tag{9}$$

Let the total compressibility:

$$c_{\mathrm{t}}(P) = c_{\mathrm{a}}(P) + c_{\mathrm{g}}(P) \tag{10}$$