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Estimation of hydraulic fracture volume utilizing partitioning chemical tracer in shale gas formation

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A B S T R A C T

Hydraulic fracture geometry is of the interest in optimizing stimulation treatment and forecasting production potential. Current diagnostic tools such as tiltmeter and microseismic are insufficient in evaluating fracture geometry. Knowing that gas from the shale reservoir has a much higher mobility than fracking fluid, partitioning chemical tracer is employed so that tracer data can be obtained earlier and more complete. The proposed approach is examined by synthetic numerical simulations. On the semi-log plot, tracer production declined tail clearly divides into two straight-line segments. Applying the moment of methods to the entire tracer production data gives the total volume of hydraulic fracture and the invaded matrix swept by the tracer due to leak-off. Additionally, extrapolating the first segment of tracer decline tail using the exponential law yields a volume that is close to the actual hydraulic fracture volume, especially when fracture permeability is several orders larger than matrix permeability.

1. Introduction

Hydraulic fracturing has been applied in shale gas development to increase the contact area with matrix and create permeable conduits for fluid flow. Knowledge of hydraulic fracture volume is essential in determining the stimulation treatment efficiency. However, the fracture volume diagnosis is very challenging because of the complexities of rock properties and fracturing process. Davis (2009) summarized capabilities and limitations of numerous fracture diagnostic technologies, including tiltmeters, microseismic mapping and radioactive tracers. Among them, only surface tilt mapping is able to determine the hydraulic fracture volume, while its resolution decreases with depth.

Chemical tracer is a powerful technology for reservoir characterization (Tomich et al., 1973; Sheely Jr and Baldwin Jr, 1982; Abbaszadeh-Dehghani and Brigham, 1984; Allison et al., 1991). In recent years, its application has been extended in hydraulic fracturing to evaluate the contribution of each fracture stage to the total hydrocarbon production in a multi-stage horizontal well (Goswick and LaRue, 2014; King and Leonard, 2011; Catlett et al., 2013). Chemical tracer can also help understand interwell communication for fractured wells (Crawford et al., 2014).

Chemical tracer is rarely used to estimate fracture volume. Gardien et al. (1996) revealed that the tracer response was sensitive to an influence ratio, which was the combination of fracture half length, fracture height, formation porosity and injected volume. They noticed that tracer response in fractured reservoir was quite different with a homogeneous reservoir, indicating the possibility of hydraulic fracture diagnosis using the chemical tracer. Nevertheless, it was impossible to determine the fracture volume directly from their work because fracture width was not included in the ratio. Leong et al. (2015) utilized the conservative deuterium tracer to detect the fracture volume based on tracer residence time in a well pair setting. Their target fracture did not have two-phase flow. They also neglected the tracer swept volume in matrix due to leak-off, which could lead to an overestimation of fracture volume eventually. Elahi and Jafarpour (2015) proposed to analyze tracer test data for fracture volume using ensemble Kalman filter. However, this approach is difficult to employ because it required tremendous fracture and matrix information for the data assimilation. As seen from above discussion, none of the work could estimate fracture volume under the condition of multi-phase flow and leak-off.

In this paper, we propose to evaluate fracture volume in shale gas formation using partitioning chemical tracer. The impact of matrix as well as dispersion on tracer production data will be

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Nomenclature

Normal

a	coefficient
b	coefficient
B	formation volume factor, fraction
C	chemical tracer concentration, mole fraction
D	dispersion coefficient, L^2/T
K	partition coefficient, fraction
k	permeability, L^2
L	length, L
h	height, L
t	time, T
V	swept volume, L^3
w	width, L
φ	porosity, fraction

Subscript

BHP	bottom-hole pressure
e	end point
eq	equilibrium
g	gas
i	component i
m	matrix
swept	swept volume
w	water

analyzed, which has never been investigated in previous work. Method of moments (MoM) is applied to compute the swept volume and the tracer production in both phases, vapor and liquid, is accounted for correspondingly. This approach is simple to use without asking for detailed reservoir information. Synthetic numerical simulation is utilized to validate the proposed method.

2. Methodology

2.1. Motivation of using partitioning chemical tracer

For many shale gas formations, more than 60% of fracking fluid is not produced back in the early production stage according to the field observations (Crafton, 2008). Therefore, for the fracking fluid soluble tracers (conservative tracers), their production history would be either too limited, which may lead to incorrect estimations of fracture volume, or the tracer information is too late to yield useful information. Another type of conservative tracer is gas soluble tracers. Given that gas from the shale reservoir has a much higher mobility than the fracking fluid and some reservoirs may even have immediate gas production right after completion (Asadi et al., 2008), we can anticipate these tracers may quickly flow back. However, gas soluble tracers fail to provide sufficient information about the fracking fluid inside the hydraulic fracture, and consequently we cannot evaluate the exact fracture volume.

Upon previous discussions, we propose to use partitioning chemical tracer, which is soluble in both gas and fracking fluid. The partitioning chemical tracer partitions between gas and fracking fluid. The phase preference of such tracer is described by its partition coefficient, K, which is defined as the ratio of tracer mole fraction in gas to its mole fraction in fracking fluid (Eq. (1)). Partitioning chemical tracer production data will reflect information of both phases that it could sense during the test. In addition, it can flow back with gas, suggesting the potential of early interpretation of fracture volume.

$$K = \left(\frac{C_g}{C_w}\right)_{eq} \tag{1}$$

2.2. Swept volume calculation

MoM has been widely used to interpret tracer production data. The first moment gives the tracer swept volume. For the tracer production data within phase i, i.e. produced tracer concentration versus cumulative produced volume, the first moment is calculated as (Oyerinde, 2005):

$$V_{i,swept} = \frac{\int_0^\infty V_i C_i dV_i}{\int_0^\infty C_i dV_i} \tag{2}$$

Gas and fracking fluid could exist in the hydraulic fracture at the same time. Since partitioning chemical tracer also exists in both phases, its swept volumes in both gas and fracking fluid should be taken into account in order to get the total swept volume in hydraulic fracture. Because the produced volume is measured at surface condition, the formation volume factor (FVF) at producing bottom-hole pressure (BHP) is needed to convert volume from surface to subsurface condition (Eq. (3)).

$$V_{swept} = B_{g,BHP} V_{g,swept} + B_{w,\ BHP} V_{w,swept} \tag{3}$$

2.3. Exponential decline

Since the measurement of tracer concentration history is often limited in time, we assume that the tracer concentration declines exponentially with time if the tracer is injected as a slug. In other words, it is possible to obtain the full tracer interpretation earlier by extrapolating the tracer production data when the exponential decline trend occurs (Fig. 1). Mathematically, the tracer exponential decline tail is expressed by (Sharma et al., 2014):

$$C(V) = be^{-aV} \quad \text{for} \quad V > V_e \tag{4}$$

The tracer behavior in a fractured reservoir is different from that in a homogeneous reservoir (Gardien et al., 1996). By plotting the tracer tail in a semi-log plot, we would observe two distinct linear relationships, which help to distinguish the tracer swept volume in matrix and fracture respectively. We will illustrate how to analyze the tracer tail in a hydraulically fractured shale reservoir in the later sections.

3. Model description

To validate the proposed approach, synthetic models are created. This section provides all the critical information and parameters to develop a prototype of hydraulically fractured shale gas reservoir. Adsorption and capillary pressure effects are neglected in the simulations.