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Evaluating the accuracy of liquid permeability measurements in shale and tight rocks using transient flow method and comparison with gas permeability

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Highlights

- Provides clarification on the appropriate term of C_t (total compressibility) in the calculation of liquid permeability
- Accurate and consistent term of C_t should be used for the transient flow method.
- Comparison of liquid and gas permeability providesevidence of nonlinear relationship between kgas and 1/P at high pressures.

Abstract

The transient flow method for measuring permeability to liquid is a useful technique for shale and tight rocks; however, it is not as popular as the steady-state method in these rocks. One of the issues is the lack of clarity on a key term of compressibility of the fluid and rock system. Various forms of compressibility have been used in literature, which can lead to inconsistent results of liquid permeability. Using gas for the permeability measurement is more common in shale, and the Klinkenberg corrected permeability is often used to represent liquid permeability; however, how the Klinkenberg permeability is compared to liquid permeability in shale or tight rocks is not adequately addressed. This paper presents a study using the transient flow method for water and oil permeability measurement in three Eagle Ford Shale samples. Gas permeability was also measured for these samples. Different forms of the total compressibility of the fluid-rock system (C_t) are summarized from literature, and a new form of C_t is proposed. The accuracy of the calculations based on different forms of C_t is evaluated through the comparison between water and oil permeabilities and the comparison with gas permeability. The results are also compared with oil permeability obtained from the steady-state method. The new form of C_t provided the most accurate results, whereas the other forms of C_t led to errors. However, for samples with bulk compressibility of less than 1×10^{-7} psi^{-1}, the error using those forms of C_t was negligible. The study also found that the Klinkenberg permeability obtained from the linear extrapolation is larger than the oil permeability for two samples by 12% and 37%, respectively, whereas it is smaller than the oil permeability for the other sample. This comparison suggests that a nonlinear gas slippage effect may exist in the high pressure range (>2000 psi) for shale or tight rock samples.

Keywords

Liquid permeability; Shale; The transient flow method; Compressibility; Comparison with gas permeability

1. Introduction

In theory, permeability is an intrinsic property of porous media that remains constant regardless of the fluid flowing through it. However, in practice, the measured permeability values can vary with different fluids, resulting in differences between gas permeability and liquid permeability. For instance, conventional reservoir rocks or sedimentary rocks can have a Klinkenberg gas permeability that is several times to one order of magnitude greater than liquid permeability (Tanikawa and Shimamoto, 2009; Duan et al., 2020). Jones and Owens (1980) reported equal or an average of 25% smaller oil permeability relative to gas Klinkenberg permeability in tight gas sand samples. Permeability measurement in shale or tight rocks using gas (helium or nitrogen) is common because gas flow is faster, whereas liquid permeability measurement is more time-consuming, expensive, and the data is relatively less. The linear Klinkenberg correction is often applied to gas permeability data, and the Klinkenberg corrected permeability is used to represent the liquid or intrinsic permeability. However, the comparison between Klinkenberg permeability and liquid permeability in shale and other unconventional reservoir rocks has not been adequately addressed in the literature, and this comparison remains unclear.

Two types of methods have been used for liquid permeability measurement in shale or tight rocks, i.e., the steady-state method and the transient flow method. The steady-state method measures pressure gradient between up- and downstream boundaries and the flow rate; permeability is then calculated based on Darcy's law (e.g., Sinha et al., 2013; Bhandari et al., 2019). This method is simple in theory and calculation, but is time-consuming comparing to the transient flow method. It takes days to months for one measurement (Bhandari et al., 2019). In addition, the steady-state method necessitates highly precise equipment to measure flow rates at the level of 0.1–1 μL/min. On the other hand, the transient flow method is relatively faster and only requires measurement of pressures. Despite this, the calculation of permeability in this method is more complex and is accompanied by uncertainties related to rock compressibility. The literature uses various and inconsistent forms of compressibility (Brace et al., 1968; Trimmer, 1981; Oort, 1994; Kwon, 2001; Yang et al., 2021), as will be discussed in more details later, which can result in varying permeability values and lack of clarity on the appropriate term of compressibility to use.

This study addresses the uncertainties regarding the calculation of permeability in the transient flow method by examining the term of total compressibility (C_t). A more accurate mathematical expression of C_t is deduced from the original continuity flow equation. Both water and oil permeability were measured for three Eagle Ford Shale samples. The resulting liquid permeability are compared to the measured gas permeability with the discussion on Klinkenberg correction and gas flow regimes. This topic has not been extensively documented for shale or tight rocks. The oil permeability results are also compared to oil permeability measured by the steady-state method for nearby samples. These comparisons serve to verify the accuracy of the calculations using the proposed C_t.

2. The transient flow method

2.1. Theoretical consideration and permeability calculation

Brace et al. (1968) first introduced the transient flow method for measuring the permeability of granite samples with water permeabilities less than 10^{-18} m^2 (~1.0 μD). Later, Trimmer (1981, 1981), Lin (1982), and Hsieh et al. (1981) employed similar techniques for samples with notable rock compressibility and storage comparing to crystalline rocks, such as shales, with Trimmer (1981) referring to it as the transient pulse technique. Oort (1994) utilized this method, renamed as the pressure transmission method, to examine borehole instability caused by drilling fluid. Since then, the transient method has been used to measure permeability in relatively impermeable (<10^{-18} m^2 or 1.0 μD) rocks (e.g., Kwon, 2001; Yang et al., 2021).

The underlying theory of this method is based on compressible fluid flow in slightly compressible rocks. Starting with one-dimension continuity equation,

$$\frac{\partial}{\partial t}(\rho\emptyset) = -\frac{\partial}{\partial z}(\rho q) \tag{1}$$

where q is the flux and the $q = -\frac{k}{\mu}\frac{\partial P}{\partial z}$ (2) by Darcy's law, P is the pressure of the fluid or pore pressure, ρ is the fluid density, and $\emptyset$ is the porosity.

Assume k, μ, which is permeability and viscosity, respectively, being constant for simplicity, especially under the experimental conditions of constant temperature and small change of fluid pressure, then

$$\frac{\partial}{\partial t}(\rho\emptyset) = \frac{k}{\mu}\frac{\partial}{\partial z}\left(\rho\frac{\partial P}{\partial z}\right) \tag{3}$$

The left side of Eq. (3) is

$$\frac{\partial}{\partial t}(\rho\emptyset) = \emptyset\frac{\partial\rho}{\partial t} + \rho\frac{\partial\emptyset}{\partial t} = \rho\emptyset\left(\frac{1}{\rho}\frac{\partial\rho}{\partial t} + \frac{1}{\emptyset}\frac{\partial\emptyset}{\partial t}\right) = \rho\emptyset\left(\frac{1}{\rho}\frac{\partial\rho}{\partial P} + \frac{1}{\emptyset}\frac{\partial\emptyset}{\partial P}\right)\frac{\partial P}{\partial t} \tag{4}$$

Consider the fluid and porosity compressibility (C_f and $C_\emptyset$, respectively),

$$C_f = \frac{1}{\rho}\frac{\partial\rho}{\partial P} \tag{5}$$

$$C_\emptyset = -\frac{1}{\emptyset}\frac{\partial\emptyset}{\partial P_n} \tag{6}$$

and effective stress (P_n)

$$P_n = P_c - \alpha P \tag{7}$$

where P_c is confining pressure in the context of a laboratory experiment or reservoir stress in field applications, α is Biot coefficient. Let α=1.0, an implicit assumption in most applications, Eq. (6) becomes

$$C_\emptyset = \frac{1}{\emptyset}\frac{\partial\emptyset}{\partial P} \tag{8}$$

Then

$$\frac{\partial}{\partial t}(\rho\emptyset) = \rho\emptyset\left(C_f + C_\emptyset\right)\frac{\partial P}{\partial t} \tag{9}$$

The derivative part in the right side of Eq. (1) is