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Laboratory measurements of slippage and inertial factors in carbonate porous media: A case study

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ABSTRACT

Two important issues for accurate modeling of gas reservoir performance are the gas slippage and the inertia flow within porous media. Depending on the flow condition, these factors can make the gas permeability differ from the true (liquid) permeability. Nevertheless, since the gas flow tests are cheaper and less time consuming than the liquid flow tests, a reservoir engineer may choose to estimate the true (liquid) absolute permeability from the results of a single gas permeability test utilizing a valid empirical correlation. Although many such correlations exist in the literature, most of them have been developed for unconsolidated porous media or sandstone core samples. Therefore, using them for a specific formation will result in erroneous predictions.

This paper is presented in three parts. In the first part, an empirical equation is developed to estimate the gas slippage factor using the results of laboratory measurements on 49 samples of Iranian carbonate reservoirs of Kangan and Dalan. In the second part, a correlation is developed to estimate the inertia factor for the samples. In the last part of the paper, an equation is derived to estimate maximum allowable pressure drop per length to maintain the laminar (Darcy) flow regime in the samples.

The developed models in the first and the second parts of the current paper match the experimental data more accurately than the popular existing correlations. The derived equation in the last part is applicable in proper design of gas flow tests, where a laminar flow must be maintained in porous media.

1. Introduction

Fluid flow through porous media is an important issue in different areas of science and engineering. In reservoir engineering, accurate modeling of fluid flow is essential to predict production behavior of hydrocarbon reservoirs. Based on equation (1), the pressure gradient within the porous media is linearly proportional to the apparent fluid velocity (Darcy (1856),):

$$-\frac{dP}{dx} = \frac{\mu}{cK} v \tag{1}$$

Where P, x, μ, K, c, and ν denote pressure, fluid flow direction, fluid viscosity, permeability, unit conversion constant ($c = 6.328$), and fluid velocity, respectively.

The steady state gas permeability measurement procedure has long been in use due to its simplicity, speed and cost efficiency. If the Dracy equation is written for gas flow in porous media, while expressing the flow rate at atmospheric pressure, one can get

$$Q_{atm} = c\frac{KA}{\mu L}\frac{\left(P_1^2 - P_2^2\right)}{2 \times P_{atm}} \tag{2}$$

Where A is the cross sectional area, P_{atm} is the atmospheric pressure, P_1 is the upstream pressure, P_2 is the downstream pressure and Q_{atm} is the gas flow rate measured at atmospheric pressure (Torsæter and Abtahi, 2003).

One of the complications of measuring gas absolute permeability is the slippage phenomenon. Gas slippage occurs when gas flows in porous medium or capillary tubes meaning, gas velocity in the vicinity of the solid wall is not zero. Therefore, in similar conditions, gas flows faster through porous media than liquids.

Klinkenberg (1941) used Poiseuille law and slippage phenomena to relate gas permeability and liquid permeability of an ideal porous media as:

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$$K_g = K_L\left(1 + \frac{b}{P_m}\right) \tag{3}$$

Where K_g, K_L, P_m and b represent apparent gas permeability, equivalent liquid permeability (A.K.A true or Klinkenberg permeability), mean pressure and slippage factor, respectively. The slippage factor depends on mean free path of particular gas and mean pore radius; which means it would be larger in pathes with smaller radius. As a result, in tight gas reservoirs, the gas slippage effect is significant.

Base on equation (3), if the measured gas permabilities are plotted against the reciprocal of the mean pressure, a line could be regressed; Extrapolating this line to infinite mean pressure (i.e. zero reciprocal mean pressure), gives the slippage factor and the liquid permeability. At least four measurements should be performed to obtain these parameters. However, to determine the absolute permeability of core plugs quickly, it is common to measure gas permeability only by one test called the single point gas permeability test, then the equivalent liquid permeability is obtained using an empirical correlation for the slippage factor.

Heid et al. (Heid et al., 1950) measured the gas slippage factor and the (extrapolated) liquid permeability of 11 synthetic and 164 natural core samples of representative sands from different oil fields of the United States. They developed a relationship between the gas slippage factor (b) and the corresponding equivalent liquid permeability (K_L) as

$$b = 11.419(K_L)^{-0.39} \tag{4}$$

Where K_L is in miliDarcies and b is in psi.

Jones and Owens (1980), measured gas permeability of tight rock samples with permeabilities ranging from 0.0001 to 1 md. Based on their experimental data, an empirical correlation was developed between the slippage factor and the liquid permeability as

$$b = 12.639(K_L)^{-0.33} \tag{5}$$

Where K_L is in miliDarcies and b is in psi.

Using only ten core samples, Sampath and Keighin (1982) published a formula, relating the gas slippage factor to the ratio of permeability and porosity as

$$b = 13.851\left[\frac{K_L}{\varphi}\right]^{-0.53} \tag{6}$$

Where K_L is in miliDarcies and b is in psi.

The Darcy equation is valid for laminar flow only; as a result, in permeability measurements, the velocities must be low enough to establish the laminar flow through rock sample. Another deviation from the Darcy law can occur under the influence of inertia flow in porous media. Although in bulk of the reservoir, this law predicts the flow behavior, in some cases, like the areas near the high rate gas wells or in propped fractured wells, pressure drop is higher than what is predicted by Darcy equation.

Various terms such as non-Darcy flow, turbulent flow, inertial flow, and high velocity flow have been used by different researchers to describe this deviation (Firoozabadi and Katz, 1979). The additional pressure drop is associated with dissipation of inertial energy as fluid particles accelerate and decelerate.

Non-Darcy flow has a significant adverse effect on well performance and could seriously harness production on hydraulically fractured gas wells (Guppy et al., 1982; Holditch and Morse, 1976; Martins et al., 1990).

Many attempts have been made to model non-Darcy flow. Forchheimer (1901) discovered that Darcy underestimates the pressure drop in high velocity gas flow in porous media. He proposed an additional pressure drop term, proportional to square of flow velocity (Whitaker, 1996):

$$-\frac{dP}{dx} = \frac{\mu}{cK}\vec{v} + \rho \times \beta \times \vec{v}|v| \tag{7}$$

Where ρ is the fluid density and β denotes the inertial factor. The first term in equation (7) is the Darcy term and the second term is referred to as the non-Darcy term. If β is zero, the Forchheimer equation reduces to Darcy Law. In the oil and gas industry, non-Darcy flow has been mostly described by the Forchheimer equation. Equation (7) can be re-written for gas flow as:

$$\frac{cT_{sc}A\left(P_1^2 - P_2^2\right)}{2zTL\mu P_{sc}q_{sc}} = \frac{1}{K} + \frac{\beta}{\mu}\left(\frac{P_{sc}MW}{T_{sc}RA}\right) \times q_{sc} \tag{8}$$

where MW, A, z, R, T, μ, L, q_{sc}, T_{sc}, and P_{sc} stand for the molecular weight of the gas, the cross-sectional area of the sample, the gas compressibility factor, the universal gas constant, flow temperature, gas viscosity, sample length, gas flow rate at standard condition, the temperature and pressure at standard conditions, respectively (Temeng, 1988).

The non-Darcy coefficient in wells is commonly calculated by analysis of multi-rate test results, but such data are not always available. There are few correlations in the literature which could be utilized instead.

Reynolds and Forchheimer numbers have been used by researchers to determine the onset of non-Dracy flow. Reynolds number is represented as:

$$\mathrm{Re} = c'\frac{\rho v x}{\mu} \tag{9}$$

Where ρ stands for fluid density, ν denotes fluid velocity, x is a characteristic length and c'denotes unit conversion constant. The definition of characteristics length is not the same in different researchers' works. In addition, it cannot be easily found for reservoir rock samples, due to the complexity of their pore spaces. Therefore, the Reynolds number has only been traditionally used for unconsolidated porous medium. The critical Reynolds number corresponds to the boundary between laminar and turbulent flow regimes, which is in the range of 0.10–1000. As shown in Table 1, the value of critical Reynolds number depends on porous media type. Therefore, it is not a suitable term for predicting the flow regime within the porous media (Bear, 2013; Hassanizadeh and Gray, 1987; Plessis and Masliyah, 1988).

Forchhimeier number is another criterion for flow regime determination, originally defined by Green and Duwez (1951) as:

$$Fo = \frac{K\rho\beta v}{\mu} \tag{10}$$

This dimensionless number has the advantages of clear definition and easy applicability. All involved parameters through equation (10) can be determined experimentally or empirically.

The β factor has been named different in the literature, like turbulence factor, coefficient of inertial resistance, velocity coefficient, and beta factor (Li and Engler, 2001). In the current paper, we will refer to it as "Inertial Factor". The main parameter for modeling non-Darcy behavior is the inertial factor. Inertial factor can be estimated using multi rate tests. Since the well must be shut in for these tests, they are expensive and usually, not easily available, it is a common practice to use empirical correlations to compute this parameter.

Various correlations have been developed to predict inertial factor through theoretical analysis or by regressing experimental data. For the sake of simplicity and applicability, most available correlations for inertial factor use permeability and porosity as the correlating parameters.