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Unified relative permeability model and waterflooding type curves under different levels of water cut

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ABSTRACT

Understanding the relative permeability of multiphase flow in porous media is crucial for the efficient development of waterflooding reservoirs. The semi-log linear relationship between oil-water relative permeability ratio (k_{ro}/k_{rw}) and water saturation (S_w) has been commonly used to derive waterflooding type curve—an empirical and practical tool for the forecast of production performance. However, recent experiments suggest that owing to the highly dispersed oil in water phase, the k_{ro}/k_{rw} vs S_w correlation deviates from a straight line in a semi-log plot at high water-cut stage (> 90%). Considering the linear model of $\ln(k_{ro}/k_{rw})$ vs S_w fails to describe the multiphase flow behavior for average water saturation greater than ~65%, we present a unified mathematical model to account for different water saturations and develop two type curves to predict the waterflooding performance. Data from previous literatures, numerical simulations, and actual oilfields are employed to examine the capability of the proposed method. In comparison with traditional Type-A and -B curves, in which the correlation of $\ln(k_{ro}/k_{rw})$ vs S_w is linear, the proposed model provides remarkably accurate results. Although the nonlinear relationship occurs only at high water saturations, neglecting this feature of the relative permeability curve can cause a significant error in the prediction. This work provides a comprehensive model of $\ln(k_{ro}/k_{rw})$ vs S_w and new Type-A and -B curves for reservoirs at high water-cut stage, which are beneficial for accurate performance forecasts for the entire duration of waterfloods.

1. Introduction

As a fundamentally important parameter to study multiphase flow in porous media, relative permeability, i.e., the ratio of effective permeability of a particular fluid phase to its absolute permeability, can characterize the relative transport capability of each fluid (Aggelopoulos and Tsakiroglou, 2008; Akhlaghinia et al., 2013; Shojaei et al., 2015). In the context of reservoir engineering, relative permeability plays an essential role in these commonly used tools for performance prediction, e.g., numerical simulation, waterflooding type curves, etc. (Al-Abri et al., 2012; Ren et al., 2014; Sivasankar and Kumar, 2014; Wang et al., 2015; Yu et al., 2015; Yu, 2000; Zhang et al., 2016).

It has been confirmed that relative permeabilities are multidimensional functions that rely on a large number of parameters, e.g., pore geometry, fluid properties, wettability, saturation history, etc. (Karabakal and Bagci, 2004; Mo et al., 2015; Nguyen et al., 2006; Ren et al., 2017; Solbakken et al., 2014). Traditionally instantaneous equilibrium of the local state is assumed and hence, classical relations describing multiphase flow in porous media are always believed to be only dependent on local saturation. However, recent studies demonstrate that if the density and/or viscosity contrasts between the injected and displaced fluids are very high, prominent instabilities can be observed, thus leading to the mismatch of experimental observations using the classical theory (Cinar et al., 2007; Ren et al., 2017). Therefore, nonequilibrium/dynamic models have been proposed to remedy the problem, such as the work reported by Hassanizadeh and Gray (1993), Barenblatt et al. (2003), and Aryana and Kovscek (2013). Ren et al. (2017) examined the performance of these models by using a Bayesian model selection framework.

Because the classical constitutive theory is established on the basis of instantaneous local phase-equilibrium, relative permeability function is defined by assuming steady-state conditions and then employed to describe flow dynamics in porous media. Thus, all techniques for the

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Nomenclature

N_p	cumulative oil production, [10^4 t]
W_p	cumulative water production, [10^4 t]
A	oil-bearing area, [km^2]
h	average effective thickness, [m]
ϕ	average porosity, [fraction]
ρ_o	average oil surface density, [t/m^3]
S_{av}	average water saturation, [fraction]
S_{oi}	initial oil saturation, [fraction]
S_{we}	water saturation at the outlet, [fraction]
S_{wi}	initial water saturation, [fraction]
B_{oi}	initial oil volume factor, [fraction]
N_o	the geological reserves, [10^4 t]
μ	oil viscosity, [mPa s]
γ_o	relative density, [fraction]
Q	production rate, [10^4 t/d]
$Ei(x)$	exponential integral function
WOR	water-oil ratio [fraction]
f_w	water-cut [fraction]
$m, n, a, b, c, A, B, C, D, A1, B1, C1, D1, A2, B2, C2, D2$	fitting coefficients

Subscripts

o	oil phase
w	water phase

measurement of relative permeability, regardless of steady-state or unsteady-state methods, rely on the steady-state assumption (Aryana and Kovscek, 2013; Barenblatt et al., 2003; Hassanizadeh et al., 2002). However, both of these experimental techniques show some drawbacks: the former is time-consuming while the application of the latter method is restrained by the data interpretation. Also note that owing to the subtle requirements for the instruments, relative permeability under reservoir condition is not readily to be determined (Civan and Donaldson, 1989; Jahanbakhshi et al., 2015; Toth et al., 2002). Therefore, based on experimental data and/or certain assumptions, many empirical and theoretical models have been proposed to predict relative permeability, which provides valuable information for reservoir simulations and production analyses when the experimental data is not sufficient or available. Prucell (1949) suggested that relative permeability depends on capillary force and built a mathematical model for this correlation. Corey (1954) reported that oil-gas relative permeability can be expressed by an approximation correlation between capillary pressure and saturation, i.e., the relative permeability was a power function of dimensionless saturation. Then Brooks and Corey (1966) improved this model by incorporating the effect of pore size distribution and extended it to water-oil relative permeability. On the basis of existing experimental results, Guler et al. (2003) utilized artificial neural networks (ANN) to predict relative permeability.

Although a few quantitative models have been proposed to estimate relative permeability, the one developed by Craft et al. (1959) attracts more attention. Through large amounts of experiments, Craft et al. (1959) observed that the oil-water relative permeability ratio k_{ro}/k_{rw} is linearly dependent on water saturation S_w in a semi-log plot (Fig. 1(a)). This linear model lays a foundation for the derivation of waterflooding type curves, which is widely applied to forecast the development performance and recoverable reserves of waterflooding reservoirs because of its simplicity and practicability (Ling, 1990; Timmerman, 1971; Tong, 1978; Yu, 1998). Moreover, this model is also employed in reservoir simulations and well testing (Chen, 2003; Jiang et al., 2006).

On the basis of the linear correlation of $\ln(k_{ro}/k_{rw})$ vs S_w (Fig. 1(a)), Ershaghi and Omoregie (1978), Ershaghi and Abdassah (1984) proposed a model for oil recovery vs water-cut. Yang (2009) obtained an analytical solution of oil fractional flow and developed a diagnostic analysis tool. Chen (1993) derived different kinds of waterflooding type curves by incorporating Craft et al.'s model and the average water saturation estimated from Buckley-Leverett (1942) and Welge (1952) equations. Waterflooding type curves are always categorized into three kinds, among which the most commonly used are Type-A and -B. Type-A describes the relationship between cumulative water production (W_P) and cumulative oil production (N_p), whereas Type-B curve is for water-oil ratio (WOR) and N_p. Both of them are straight lines in a semi-log coordinate system and the schematics are presented in Fig. 1(b) and (c). A large number of oilfield practices have proved that the Type-A and -B are efficient tools for the forecast of waterflooding performance (Chen, 1985, 1993, 2003; Jiang et al., 2006; Yu, 2000). Currently these type curves are frequently employed in waterflooding reservoirs and even recognized as the industry standard.

However, recent core flooding experiments and field production data demonstrate that when the water-cut exceeds ~90%, the variation of oil-water relative permeability ratio k_{ro}/k_{rw} as a function of water saturation S_w would deviate from the straight line in a semi-log plot (Bondar and Blasingame, 2002; Can and Kabir, 2014; Cui et al., 2015; Hou and Wang, 2013; Ji et al., 2012; Song et al., 2013; Wang et al.,

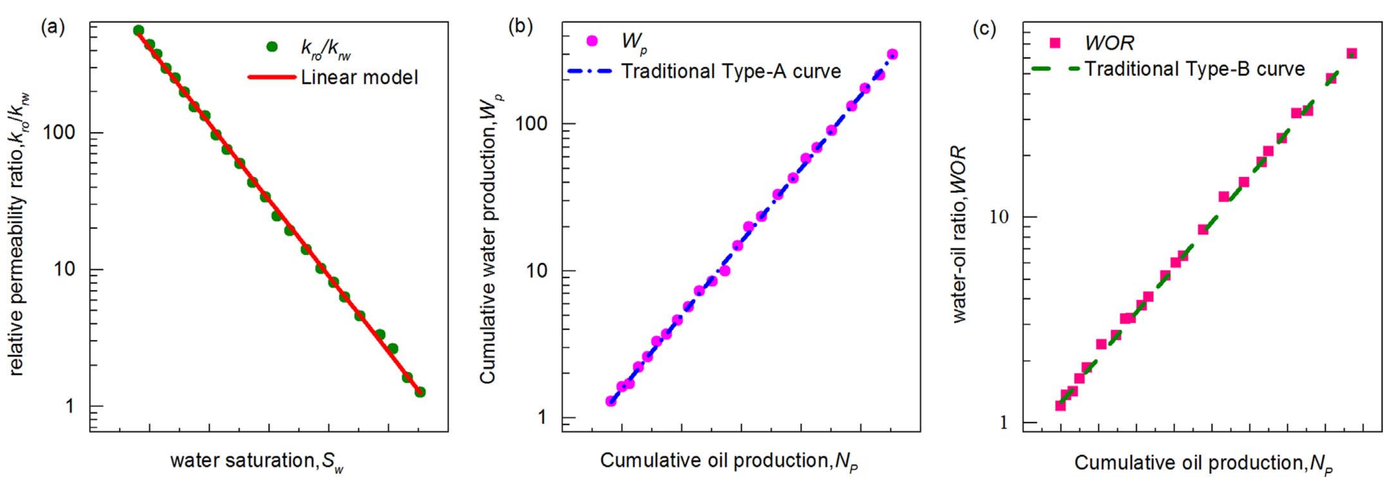

Fig. 1. Schematic showing (a) oil-water relative permeability ratio k_{ro}/k_{rw} as a function of water saturation S_w and traditional Type-A (b) and Type-B (c) curves for waterflooding reservoirs.