Fuel 163 (2016) 196–204

Contents lists available at ScienceDirect

Fuel

journal homepage: www.elsevier.com/locate/fuel

Predicting heavy oil/water relative permeability using modified Corey-based correlations

Farshid Torabi [a,*], Nader Mosavat [a,b], Ostap Zarivnyy [a]

[a] Petroleum Systems Engineering, Faculty of Engineering and Applied Science, University of Regina, Regina, Saskatchewan, Canada
[b] Mechanical and Industrial Engineering, University of Toronto, Toronto, ON, Canada

HIGHLIGHTS

- Relative permeability to water and heavy oil is systematically examined.
- Effects of flow rate, pressure, temperature, and oil viscosity is introduced.
- Relative permeability values are greatly reliant on temperature and oil viscosity.
- Corey's correlations are adjusted to consider the oil viscosity.
- New correlations are in better agreement with literature data.

ARTICLE INFO

Article history:
Received 27 February 2015
Received in revised form 4 September 2015
Accepted 15 September 2015
Available online 25 September 2015

Keywords:
Heavy oil
Relative permeability
Unsteady state flooding
JBN method
Correlation

ABSTRACT

In this study, the effect of various parameters such as operating temperature, crude oil viscosity, injection flow rate, and operating pressure on heavy oil/water relative permeability were investigated followed by proposing new correlations for calculating heavy oil/water relative permeability. The experimental results obtained in this study showed that both water and oil relative permeabilities are significantly temperature dependent and they increase when temperature increases. It was also found that relative permeability to oil and water increase with decrease in oil viscosity. Additionally, tests results indicated that increase in injection flow rate results in higher oil relative permeability and lower water relative permeability. Unsteady state core flooding experiments carried out at various operating pressures showed that the relative permeability to oil in heavy oil/water system is independent of operating pressure. The heavy oil/water relative permeability data obtained in this study was used to develop new heavy oil/water relative permeability correlations by modifying the original Corey's correlations. The comparative evaluation of the new correlations with the original Corey's correlations indicated significant improvement in both heavy oil and water relative permeability estimation. Statistical analysis of the results showed that the new correlations facilitate reliable calculation of heavy oil/water relative permeability values by decreasing the root mean square magnitude from 0.167 and 0.178 to 0.004 and 0.061 for water and oil relative permeability, respectively. In addition, the accuracy of newly developed correlations was tested against five sets of experimental data obtained from literature. Results of this comparison also showed that heavy oil/water relative permeability predicted by new correlations is in better agreement with experimental data compared to those predicted by Corey's model.

1. Introduction

Oil/water relative permeability data plays an important role in characterizing the simultaneous flow of fluids in porous media and predicting the performance of waterflooding as a means of an immiscible displacement processes in oil reservoirs. Previous studies showed that oil/water relative permeability can be affected by many parameters including saturation states, saturation history, interfacial tension, fluids viscosity, overburden pressure, temperature, flow rate, wettability, and capillary end effect [1].

Leverett presented an investigation of the effect of viscosity variation of an oil–water mixture on relative permeability [2]. He found no systematic variation in relative permeability when the

* Corresponding author at: SPE-South Saskatchewan Section, Petroleum Systems Engineering, Faculty of Engineering and Applied Science, University of Regina, Regina, Saskatchewan S4S 0A2, Canada. Tel.: +1 (306)585 5667; fax: +1 (306)585 4673.

E-mail address: farshid.torabi@uregina.ca (F. Torabi).

http://dx.doi.org/10.1016/j.fuel.2015.09.035
0016-2361/

Nomenclature

k_{rw}	relative permeability to water
k_{ro}	relative permeability to oil
S_w^*	normalized water saturation
S_w	water saturation
S_{wi}	irreducible water saturation
P_{exp}	experiment pressure (Psia)
μ_{oil}	crude oil viscosity (cP)
q_{exp}	experiment flow rate (ml/min)
P_{std}	standard atmospheric pressure (14.7 Psia)
μ_{std}	standard brine viscosity (1 cP)
q_{std}	standard fluid flow rate (0.1 ml/min)
P_D	dimensionless pressure
μ_D	dimensionless viscosity
q_D	dimensionless flow rate

Unit conversion

*1D $9.868 \cdot 10^{-13}$ m^2 = $0.987 \cdot 10^{-12}$ m^2

oil viscosity was varied from 0.31 cP to 76.5 cP. Richardson also showed that the water–oil relative permeability ratio is independent of fluid viscosity where the oil viscosity range is from 1.8 to 151 cP [3]. Based on some experimental studies conducted by Yuster, it was shown that relative permeability depends on variation of viscosity ratio and increases when viscosity ratio $\left(\frac{\mu_{nw}}{\mu_w}\right)$ increases [4]. The results obtained by Odeh showed that nonwetting phase relative permeability increases when viscosity ratio is increased, while the wetting-phase relative permeability is not affected by variations in viscosity ratio [5]. Considering different experimental studies conducted to investigate the influence of fluids' viscosity on relative permeability, it is recommended that experimental relative permeability measurements to be conducted with fluids which do not differ greatly in viscosity from the reservoir fluids [6].

For the past two decades, thermal methods such as cyclic steam injection, Steam Assisted Gravity Drainage (SAGD), and steam flooding are among major production techniques applied to heavy oil fields. Thermal energy delivered to the reservoir during these processes reduces oil viscosity and as a result, affect relative permeabilities in two- and three-phase flow regions. Although several studies have been conducted to determine the effect of temperature on relative permeability, there are still discrepancies exist in the literature on the effect of temperature on relative permeability and end point saturations. Some studies indicated that irreducible water saturation increases with increasing temperature while residual oil saturation decreases with increasing temperature, which affects relative permeability [7–9]. However, laboratory tests conducted by Miller and Ramey and Akin et al. showed that the relative permeability is independent of temperature [10–12]. Aforementioned studies also showed some increase in oil relative permeability at irreducible water saturation when temperature increased.

One of the major problems during measurement of relative permeability is the capillary end effect. This phenomenon is caused by the saturation discontinuity existing at the outlet face of the porous medium (core sample) when mounted for a flow test. The most convenient way to minimize this effect is to adjust the capillary forces by increasing the displacement flow rate. However, higher flow rates increase fluid dispersion. It is believed that such mixing might affect relative permeability. Many studies have examined the effect of flow rate, however contradictory results were observed. Henderson and Yuster found that relative permeability is rate dependent in all gas–liquid systems [13]. Wyckoff and Boste also reported that the gas–liquid relative permeabilities were rate-dependent [14]. Based on a study in water-wet sandstone and oil-wet carbonate cores, Labastie et al. concluded that relative permeabilities were independent of flow rate except near residual oil saturation [15].

Since obtaining relative permeability data from laboratory experiments is rather delicate, time consuming, and costly, a series of empirical models has been developed by other researchers to estimate relative permeability in the absence of experimental data from core samples. The empirical correlations are also employed to reproduce experimentally determined relative permeability curves as a means of verification. These methods were based on experimental data and mathematical derivations or heuristic concepts to predict relative permeability values. The most common and well-known correlations used for prediction of two-phase oil/water relative permeability are summarized in the study published by Siddiqui et al. [16]. An often used approximation of relative permeability is the correlations developed by Corey which are power-law function of water saturation [17]. Corey proposed a set of correlations for relative permeability in oil–water system. Corey's model assumes the water and oil phase relative permeabilities to be independent of the saturation of the other phase and relative permeability equations for water and oil phases. Corey's correlations are given as:

$$k_{rw} = \left(S_w^*\right)^4 \tag{1}$$

$$k_{ro} = \left(1 - S_w^{*2}\right)\left(1 - S_w^*\right)^2 \tag{2}$$

where

$$S_w^* = \left(\frac{S_w - S_{wi}}{1 - S_{wi}}\right) \tag{3}$$

where S_w and S_{wi} are water and irreducible water saturations, respectively.

Review of literature indicated extensive experimental studies on two-phase oil/water relative permeability for light oil systems. However, such studies on the effect of various crude oil characteristics and operational factors on oil/water relative permeability in heavy oil systems are limited. Hence, previously developed correlations, such as Corey's equations which are developed based on experimental data obtained in light oil systems, provide unsatisfactory results when applied to heavy oil systems. The purpose of this study is to determine the effect of various parameters including viscosity, pressure, temperature, and flow rate on relative permeability values in heavy oil/water systems. In addition, new empirical equations are developed to predict imbibition heavy oil/water relative permeability characteristics using experimentally obtained data from sandstone Berea core samples. Least-square regression techniques were applied on the newly proposed models utilizing the characteristics of porous media, fluid saturation, and operational condition. The new empirical equations are evaluated against Corey empirical equations using the data utilized in the development and validated using published relative permeability data.