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Experimental investigation of temperature effect on three-phase relative permeability isoperms in heavy oil systems

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HIGHLIGHTS

- The Unsteady state technique fails to calculate valid three-phase relative permeability data for heavy oil systems.
- Curvature with oil relative permeability isoperms depends on the oil saturation.
- Temperature has the opposite effect on irreducible water saturation and residual oil saturation.
- Temperature has no considerable effect on the size of the three-phase zone in the ternary diagrams.
- Oil and water relative permeabilities are higher at increased temperatures.

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ABSTRACT

This study reports effect of temperature on the estimated relative permeability isoperms for a fluid system of heavy oil, water, and CO_2. An experimental/numerical technique was utilized to estimate relative permeability isoperms for a three-phase fluid system. Two-phase displacement tests were separately carried out in order to measure residual saturations. Three-phase displacements were conducted in the form of CO_2 injection into a consolidated Berea core saturated with heavy oil and water at temperatures 28, 40, and 52 °C. A three-phase one-dimensional numerical simulator (able to use three-phase relative permeability data in explicit form) was developed to simulate the displacement experiments. The procedure was validated using steady state experiment as well as sensitivity analysis. The results of this study demonstrate that limited three-phase flow zone exists for heavy oil fluid systems due to high values of residual oil saturation. Different curvatures are observed for each of the phases. These curvatures are more complicated for oil and water than in the gas phase. Although temperature is found to change the position of the three-phase flow zone in ternary diagrams, however, no significant change in the size of the three-phase flow zone is observed. The effect of an increase in temperature on the relative permeability isoperms is very different in each phase. This process decreases the relative permeability of oil. In an opposite way, the relative permeability of the gas phase increases at elevated temperatures. When it comes to water, reversal behavior is observed as it increases from 28 °C to 40 °C and, then, decreases as temperature further rises to 52 °C.

1. Introduction

There is a great deal of interest in obtaining reliable three-phase relative permeability data given recent developments in enhanced heavy oil recovery processes mostly associated with multiphase flow in porous media. Three-phase relative permeability data is key parameter in numerical simulation and field performance prediction of Water Alternate Gas injection (WAG) [1–5], Cyclic Steam Stimulation (CSS) [6–8], gas injections [9,10], in situ Combustion [11], Surfactant flooding [12], Steam Assisted Gravity Drainage (SAGD) process [13], Gas Assisted Gravity Drainage (GAGD) process [14], and CO_2 geological sequestrations in depleted reservoirs [15].

Extensive documentation of the various experimental methods used to obtain three-phase relative permeability data can be found in the literature [16–21]. These techniques can be classified into three major categories: steady state experiments, unsteady state or displacement experiments, and empirical predictive models.

In the steady state technique, all fluids (e.g., oil, water, gas) are simultaneously forced into the porous media under a constant rate or pressure constraint. Although steady state technique is considered a reliable and straightforward technique, it is inherently time consuming and laborious to attain equilibrium at each saturation level [22]. The unsteady state method was proposed based on the Buckley and Leverett theory [23] as a fast and convenient

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Nomenclature

A	area (ft^2)
B_g	gas formation volume factor (bbl/scf)
B_o	oil formation volume factor (bbl/STB)
B_w	water formation volume factor (bbl/STB)
k	absolute permeability (darcy)
k_{rg}	three-phase relative permeability to gas (fraction)
k_{ro}	three-phase relative permeability to oil (fraction)
k_{rw}	three-phase relative permeability to water (fraction)
P	pressure (psia)
q_{gsc}	gas flow rate (scf/D)
q_{osc}	oil flow rate (STB/D)
q_{wsc}	water flow rate (STB/D)
S	saturation (fraction)
S_g	gas saturation (fraction)
S_{or}	residual oil saturation (fraction)
S_w	water saturation (fraction)
S_{iw}	irreducible water saturation (fraction)
T	absolute temperature (°R)
t	time (day)
x	length (ft)
Z	compressibility factor (dimensionless)
α_c	volume conversion factor (dimensionless)
β_c	transmissibility conversion factor (dimensionless)
μ	viscosity (cP)
φ	porosity (fraction)

Subscripts

g	gas
o	oil
w	water

Abbreviations

PV	pore volume
FVF	formation volume factor

alternative to the steady state experiments. In this method, fluid is injected at a constant flow rate or pressure into the porous medium with the other two fluid saturations present. Fractional flow and pressure drop are measured against pore volume injected or time. The relative permeability of each phase is then determined using methods introduced by Welge [24], Johnson et al. [25], and Jones and Roszelle [26]. Although there are several advantages to the unsteady state technique, the main limitation is that relative permeability data cannot be determined over the saturation range where the shock front exists. In addition, data analysis of this method is susceptible to measurement error as compared to the steady-state method which results in more uncertainties in the data [27].

As another alternative, several relative permeability models have been developed to predict three-phase relative permeability data [28–32]. These empirical models often utilize two-phase relative permeability data as inputs to predict three-phase relative permeability data. The application of probabilistic models in modern numerical simulators is also in question given that predicted three-phase relative permeability data are routinely manipulated to improve simulation outputs.

Three-phase relative permeability data for heavy oil systems has been rarely investigated and majority of the works focused on three-phase relative permeability measurements in light oil systems. Most of the studies used kerosene, alcohols, condensates, and very light oil as the oil phase in their research [33–36]. In addition, unlike two-phase relative permeabilities, effect of temperature, which is encountered in thermal recovery techniques, has not been investigated for three-phase heavy oil systems [37,38]. It is speculated that such lack of data in the literature is due to the tedious and difficult nature of the experimental procedure of three-phase relative permeability measurements particularly for heavy oil systems. Objectives of this study were to first utilize an inverse problem approach to estimate three-phase relative permeability data in the form of isoperms for a fluid system of heavy oil/water/gas from two- and three-phase displacement experiments. Second, after validation of the procedure, the same approach was used to investigate the effect of temperature on the three-phase relative permeability data.

2. Algorithm

An inverse problem based algorithm was proposed to utilize two- and three-phase unsteady state displacements in order to estimate relative permeability isoperms for a fluid system of heavy oil/water/gas, as depicted in Fig. 1. Using residual oil saturation (S_{or}) and irreducible water saturation (S_{iw}) obtained from two-phase heavy oil/water floods; a three-phase flow zone in a ternary diagram was assigned. On the other hand, three-phase displacement was conducted in the form of gas injection into a consolidated Berea core saturated with heavy oil and water. A three-phase one-dimensional numerical simulator was developed to simulate a three-phase displacement experiment. Appropriate three-phase relative permeability data was selected to correspond to a saturation path drawn across the three-phase flow zone in the ternary diagram (e.g., saturation path 1, 2, and 3 in Fig. 2). This relative permeability data was continuously fine-tuned until differential pressure, heavy oil production, and water production from the numerical simulator match those from the three-phase displacement experiment. Repeating this procedure for different saturation paths provides a set of relative permeability data to plot relative permeability isoperms of each phase in the ternary diagrams using

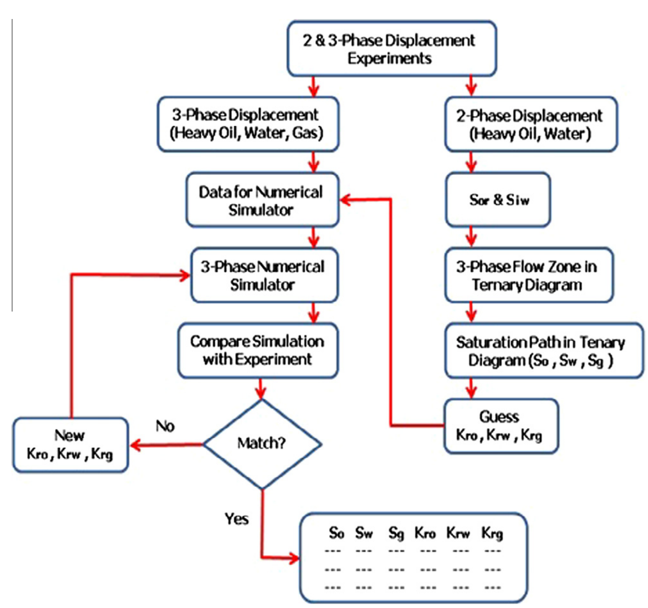

Fig. 1. Inverse problem based algorithm used to estimate three-phase relative permeability data from unsteady state displacement experiments.