Advances in Water Resources 94 (2016) 1–10

Contents lists available at ScienceDirect

Advances in Water Resources

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

# Direct measurement of relative permeability in rocks from unsteady-state saturation profiles

Amir Kianinejad*, Xiongyu Chen, David A. DiCarlo

*Department of Petroleum and Geosystems Engineering, The University of Texas at Austin, Austin, Texas, USA*

ARTICLE INFO

*Article history:*
Received 6 October 2015
Revised 25 April 2016
Accepted 26 April 2016
Available online 29 April 2016

*Keywords:*
Relative permeability
Gravity drainage
Unsteady-state
Consolidated rock

ABSTRACT

We develop a method to measure liquid relative permeability in rocks directly from transient in situ saturation profiles during gravity drainage experiments. Previously, similar methods have been used for sandpacks; here, this method is extended to rocks by applying a slight overpressure of gas at the inlet. Relative permeabilities are obtained in a 60 cm long vertical Berea sandstone core during gravity drainage, directly from the measured unsteady-state in situ saturations along the core at different times. It is shown that for obtaining relative permeability using this method, if certain criteria are met, the capillary pressure of the rock can be neglected. However, it is essential to use a correct gas pressure gradient along the core. This involves incorporating the pressure drop at the outlet of the core due to capillary discontinuity effects. The method developed in this work obtains relative permeabilities in unsteady-state fashion over a wide range of saturations quickly and accurately.



## 1. Introduction

Along with pressure-saturation measurements, relative permeability of a particular media is a crucial multi-phase property. But relative permeability measurements are difficult, time consuming, and expensive endeavors, especially for three-phase flow (Grader and O'Meara Jr, 1988; Honarpour and Mahmood, 1988; Oak et al., 1990). Moreover, the obtained data are sometimes not representative of the exact processes occurring in the reservoirs due to limitations, interpretations, and assumptions attributed to each measurement method (Geffen et al., 1951; Richardson et al., 1952; Jones and Roszelle, 1978; Oak, 1990; Mohanty and Miller, 1991; Fassihi and Potter, 2009).

The steady-state method was the first method proposed for two- and later three-phase relative permeability measurement (Osoba et al., 1951; Geffen et al., 1951; Richardson et al., 1952; Braun and Blackwell, 1981). However, this method is time consuming, expensive, and only provides a limited number of points on the relative permeability curve. In addition, careful attention must be paid to the design of these experiments to minimize the saturation gradients at the outlet side of the core due to capillary end effects (Osoba et al., 1951; Richardson et al., 1952; Rapoport and Leas, 1953).

As an alternative for faster measurements, unsteady-state methods have been proposed and used (Welge, 1950; Johnson et al., 1959; Sarem, 1966; Saraf et al., 1982; Virnovskii, 1984; Grader and O'Meara Jr, 1988; Siddiqui et al., 1996). These methods allow the phase saturations to change naturally. Consequently, these methods can potentially mimic flow processes occurring in reservoirs better than steady-state methods, since steady-state methods pre-determine the flow rates of fluids. However, the calculation of relative permeability from unsteady-state experiments require assumptions and interpretations of the measured pressure drops and effluent fractional flows, which may not necessarily hold (Mohanty and Miller, 1991). Particularly, the measured fractional flows in the effluent may be altered by capillary end effects, thus the pressure gradient measured across the core may be very different than the local pressure gradients of each phase (Geffen et al., 1951; Osoba et al., 1951; Richardson et al., 1952; Rapoport and Leas, 1953).

It is also possible to calculate relative permeabilities by history matching data; these data can be pressure, production, or saturation data measured during unsteady-state flooding experiments (Maini and Batycky, 1985; Maini and Okazawa, 1987; Vizika and Lombard, 1996). However, the calculated relative permeabilities are susceptible to errors due to local heterogeneity and capillarity. In addition, the resulting relative permeability curves are not unique, which is characteristic of inverse methods (Sigmund and McCaffery, 1979; Kerig and Watson, 1987).

Recently, Sahni et al. (1998) and others (Naylor et al., 1996; DiCarlo et al., 2000a; DiCarlo et al., 2000b; Dehghanpour et al., 2011; Dehghanpour and DiCarlo, 2013a; Kianinejad et al., 2014)

* Corresponding author.
*E-mail address:* kianinejad.amir@utexas.edu (A. Kianinejad).

http://dx.doi.org/10.1016/j.advwatres.2016.04.018
0309-1708/

**Nomenclature**

| | |
|---|---|
| $g$ | gravity, m/s$^2$ |
| $k$ | absolute permeability, m$^2$ |
| $k_{ri}$ | relative permeability to phase $i$, dimensionless |
| $P_c$ | capillary pressure, Pa |
| $P_{c_{entry}}$ | entry capillary pressure, Pa |
| $P_i$ | pressure of phase $i$, Pa |
| $S_i$ | saturation of phase $i$, dimensionless |
| $S_{wr}$ | residual water saturation, dimensionless |
| $u_i$ | flux of phase $i$, m/s |
| $z$ | position along the core, m |
| t | time, s |

*Greek letters*

| | |
|---|---|
| $\lambda$ | Brooks–Corey exponent, dimensionless |
| $\mu_i$ | viscosity of phase $i$, cp |
| $\rho_i$ | density of phase $i$, kg/m$^3$ |
| $\Phi_i$ | potential of phase $i$, Pa |
| $\phi$ | porosity, dimensionless |

*Subscripts*

| | |
|---|---|
| $i$ | phase |
| $g$ | gas |
| $w$ | water |

obtained relative permeabilities from saturation profiles during gravity drainage experiments in vertical sandpacks. They showed that if particular criteria are met, the capillary pressure gradients can be neglected and relative permeabilities can be obtained directly from in situ saturation profiles. Using this method, they obtained many relative permeability data points over a range of saturations; this is opposed to other methods which only provide a limited number of points over the saturation space. However, this method suffered from the following issues:

- It was only applicable to unconsolidated sandpacks with low capillary forces.
- The saturation path of the experiments in three-phase space was chosen by nature, and they did not have any control on the saturation path of their experiments.
- It only obtained relative permeabilities at low saturations ($S < 0.3$), due to fast saturation changes at early times of the experiments.

In reservoirs, there is no practical difference between consolidated rocks and unconsolidated sands as the fluid column height is large enough to create high driving forces solely due to gravity (Hagoort, 1980; Naylor et al., 1996; Zhou and Blunt, 1997; Rezaveisi et al., 2010; Mohsenzadeh et al., 2011). But in the laboratory, rocks require long cores (>1 m) so that the fluid column pressure can exceed the entry capillary pressure of the core, and the fluids inside the core can flow by gravity. It is practically impossible to have long cores in laboratory, and shorter cores show no fluid movement due to insufficient fluid column pressures. This is why only sandpacks have been used in laboratory experiments (Sahni et al., 1998; DiCarlo et al., 2000a; Dehghanpour et al., 2010; Dehghanpour et al., 2011; Kianinejad et al., 2014). Sandpacks have smaller capillary forces, thus fluids can drain by gravity even in shorter columns.

In this work, we extend this gravity drainage method to consolidated rocks by using a small gas pressure gradient to overcome the capillary entry pressure. With this extension, we obtain relative permeabilities in consolidated rocks in unsteady-state gravity driven experiments, directly from the measured in situ saturations along the core samples. We measure two-phase water relative permeability in a 60 cm long Berea sandstone core. Although we inject gas from the top, the drainage process is still a gravity-dominated process; the injected gas is only to allow the in situ fluids (water/oil) to drain by gravity.

## 2. Theory and formulation

The gravity drainage method for obtaining relative permeability has been shown to work well in sandpacks (Sahni et al., 1998; DiCarlo et al., 2000a; DiCarlo et al., 2000b; Dehghanpour and DiCarlo, 2013b; Kianinejad et al., 2015). The basic idea is to fill the column with liquid; open up the bottom and top to let liquid flow out and gas to flow in; and measure the saturation of the liquid phase $i$ as a function of space and time, $S_i(z, t)$. Using these data, the flux of phase $i$ is found using mass conservation. The relative permeability as a function of saturation is then calculated directly from the definition of relative permeability

$$k_{ri} = -u_i\left(\frac{k}{\mu_i}\frac{d\Phi_i}{dz}\right)^{-1} \tag{1}$$

where $u$ ([LT$^{-1}$]) is fluid flux, $k$ is permeability ([L$^2$]), $k_r$ ([−]) is relative permeability, $\mu$ ([ML$^{-1}$T$^{-1}$]) is viscosity, $\Phi$ is fluid potential ([ML$^{-1}$T$^{-2}$]), and $z$ ([L]) is position along the core. Subscript $i$ denotes phase.

Needed in this calculation is the potential gradient. For sandpacks draining under gravity, it has been shown that for the center section of a 1 m long column, this gradient can be estimated to be the gravitational gradient, $\rho_i g$ (Sahni et al., 1998; DiCarlo et al., 2000a; Dehghanpour and DiCarlo, 2013a; Kianinejad et al., 2014). This is the case when one liquid phase (oil or water) drains (being replaced by gas), and also when two liquid phases (oil and water) drain.

Conceptually, this method also works for consolidated rocks. Measuring the saturation as a function of space and time (and calculating the fluxes) is exactly the same for rocks as it is for sandpacks. The difficulty for rocks arises in determining the potential gradient.

In practice, this method fails for the simple reason that if the core is 60 cm of length – which in practice is a long laboratory core – capillary forces hold in the liquid and do not allow gas to penetrate the core. Mathematically, it is equivalent to say that for rocks, the gas entry pressure is greater than the maximum gravitational potential. Or in terms of Eq. (1), the gradient of the total potential ($\Phi_i = P_i + \rho_i g z$) is zero throughout the column, and thus there is no flow. Clearly, if the core remains saturated with liquid, this precludes a relative permeability measurement. If the core was longer, this issue would greatly lessen, but cores longer than 60 cm are hard to handle and must be obtained from outcrops.

Thus the goal in any drainage relative permeability measurement in rocks is to make sure that one can: (a) get gas into the core and allow flow of the liquid(s), and (b) estimate the gradient of the liquid phases accurately.

We accomplish this by injecting gas at the inlet at a pressure greater than the outlet gas pressure. This excess gas pressure is chosen to overcome the gas entry pressure, thus allowing the column to drain. In the following, we show how we can calculate the liquid pressure gradient under this combined gas injection and gravity drainage scenario.

Substituting the definition of capillary pressure ($P_c = P_g - P_i$) into the total modified pressure, and taking the gradient gives

$$\frac{d\Phi_i}{dz}(z,t) = \frac{dP_g(z,t)}{dz} + \rho_i g - \frac{dP_c(z,t)}{dz} \tag{2}$$

where $P_g$ ([ML$^{-1}$T$^{-2}$]) is the gas pressure, $\rho_i$ ([ML$^{-3}$]) is the liquid phase density (which is assumed to be much greater than the gas phase density), and $P_c$ ([ML$^{-1}$T$^{-2}$]) is the capillary pressure, which is dependent on the saturation of phase $i$.