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Characterization of two- and three-phase relative permeability of water-wet porous media through X-Ray saturation measurements

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ABSTRACT

We present experimental investigations of multi-phase (two-phase (oil/water, oil/gas) and three-phase (oil/water/gas)) relative permeabilities performed on laboratory scale rock cores. Two- and three-phase relative permeabilities data were obtained on two core samples (a Sand-pack and a Berea sandstone) by way of a Steady-State (SS) technique. Spatial and temporal dynamics of in-situ saturations along core samples were directly measured through an X-Ray absorption technology. The latter rendered detailed distributions of (section-averaged) fluid flow phases through the medium, which can then be employed for the characterization of relative permeabilities. The technique also enabled us to clearly identify the occurrence of end-effects during the experiments and to quantify the reliability of corrective strategies. For the oil/water settings we considered low and high viscosity oil, our findings supporting the observation that relative permeability to oil and water was sensitive to oil viscosity. Three-phase experiments were performed by following an IDI (Imbibition-Drainage-Imbibition) saturation path. The complete experimental data-base is here illustrated and juxtaposed to results obtained by the implementation of simple and commonly employed three-phase relative permeability models. In the three-phase setting, water and gas relative permeabilities display an approximately linear dependence on the logarithm of their own saturation. Consistent with the observation that oil behaves as an intermediate phase in our system, three-phase oil relative permeabilities lie in between those of their two-phase counterparts. Our data-set stands as a reliable reference for further model development and testing, as only a limited quantity of three-phase data are currently available.

1. Introduction

Quantification of multi-phase flow processes taking place in natural porous and fractured rocks has a remarkable relevance to economically sustainable management and viable development of oil- and gas-bearing geologic formations. Characterization of multi-phase flow phenomena is associated with a level of complexity which is considerably higher than that related to the assessment of subsurface systems where single-phase flows take place, because of the need to properly consider the joint (and nonlinear) effects of several factors, including, e.g., interfacial tension, rock wettability and pore size distribution. Attributes of reservoir rocks governing the migration and storage of fluids are key parameters, and their reliable characterization is required for effective reservoir engineering applications. In this context, simultaneous flow of two- and three- fluid phases (i.e., oil, water and gas) in porous media is typically grounded on a continuum- (or Darcy-) scale description which imbues relative permeabilities as key system attributes/parameters to be estimated and linked to state variables, such as fluid saturations. Estimates of the spatial distribution of relative permeabilities are then employed to guide quantification of productivity, injectivity, and ultimate recovery from reservoirs in the context of evaluation and planning of production operations. Relative permeability information can also be used to diagnose the occurrence of formation damage under diverse operational conditions.

Laboratory-scale experiments of two- and three-phase flow are at the core of the characterization of relative permeabilities of diverse rock types, as a function of the flowing fluid types and reservoir conditions. These experiments are generally performed under Steady-State (SS) or Unsteady-State (USS) conditions. While one may expect to obtain similar values of permeabilities for a

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rock-fluid system via either of these techniques, comparative studies have sometimes exhibited some discrepancies amongst the results (Dehghanpour, 2011; Dehghanpour et al., 2011, 2010; Kikuchi et al., 2005; Maini et al., 1990). For instance, unsatisfactory estimates of relative permeabilities have been observed under USS conditions, depending on the data interpretation method employed (Hirasaki et al., 1995; Kerig and Watson 1986; Maini et al., 1990).

In the Steady-State approach, all phases (e.g., water, oil, and gas) are simultaneously injected into a laboratory core of porous medium and a variety of fixed, metered fractional flow rates are considered in a suite of experiments. While SS experiments are more time-consuming and expensive than their USS counterparts, they offer the advantage of simpler data elaboration and more immediate control on the saturation path. Additionally, and depending on the amount of experimental data collected at diverse fluid saturation levels, SS experiments capture the complete dependence of relative permeability on fluid saturation. Otherwise, USS experiments are characterized by a robust control only on the end-points in the saturation space and require the use of a model to estimate the full relative permeability curves.

From an experimental standpoint, the accurate characterization of the spatial distribution of the proportions between volumetric fractions of fluids displacing in a test rock sample is critical, because of the dependence of relative permeability values on fluid saturations. Energy absorption techniques are very often employed to describe qualitatively and quantitatively the real-time evolution of fluid saturations within core plugs during tests (Maloney, 2003; Maloney et al., 1999; Naylor and Puckett, 1994). Amongst the techniques that can be employed, X-Ray scanning is a non-destructive approach for the characterization of pore-scale rock properties and fluid saturation in core samples. Advantages associated with the use of X-Ray scanning technologies for the study of fluid flow within core plugs include: (*a*) the absence of a strict requirement on accurate measurements of fluid volumes during the experiment (i.e., inlet/outlet volumes of fluid injected/produced); (*b*) the absence of influence of fluid emulsion on in-situ saturation measurements (Maloney, 2002); (*c*) the possibility of identifying the effect on fluid saturation of local heterogeneities which are spatially distributed along the test sample (a feature which might be especially relevant in carbonate cores); and (*d*) the possibility of detecting and accurately estimating average core fluid saturations in the presence of end-effects during flooding (Behin and Galiuk, 2011; Maloney, 2003; Spinler and Maloney, 2001).

Accurate and robust experimental data on relative permeability for two-phase flow are less challenging to obtain than three-phase relative permeabilities. Three-phase flow experiments to characterize relationships between relative permeability and fluid saturations and system behavior are very delicate to perform, costly, and time-consuming. Due to a combination of these reasons, documentation and availability of three-phase relative permeability experiments are much scarcer than those associated with two-phase systems (e.g., Alizadeh and Piri, 2014a, 2014b). This is in stark contrast with the observation that three-phase relative permeability (experimental and modeling) studies are becoming increasingly essential in field oriented projects. Several three-phase relative permeability models have been proposed (Baker, 1998; Corey et al., 1956; Delshad et al., 1985; Ebeltoft et al., 1998; Ebeltoft, 2013; Jerauld, 1997; Lomeland et al., 2005; Maini et al., 1989; Skauge and Larsen, 1994; Stone, 1970) and there is a dire need of high quality data for detailed comparative studies on their predictive and interpretive skill.

In this context, our main objectives are (*a*) to illustrate the applicability of X-Ray techniques to obtain in-situ measurements of detailed spatial distributions of fluid saturations along laboratory-scale cores as a function of the viscosity ratio of the displacing fluids under two-phase flow conditions taking place in diverse rock types; and (*b*) to employ the X-Ray technique to document the results of two- and three-phase SS flow experiments which are then used to inform modeling of relative permeability curves as a function of average fluid saturations within the core.

The structure of the work is described in the following. Section 2 describes details of the experimental setup, the rock-fluid system, experimental procedure and the way two- and three-phase saturations are measured and relative permeabilities are modeled. Section 3 illustrates our experimental findings. We start from results of two-phase experiments and highlight the key added value of grounding in-situ saturation measurements on the X-Ray technique, also by considering the effect of employing diverse types of oils, characterized by contrasting viscosities, to characterize oil relative permeabilities in an oil/water system. Three-phase relative permeability data are then illustrated and discussed in light of typically employed simple interpretive models.

2. Materials and methods

2.1. Fluids and core samples

The porous media we considered were a Sand-pack and a Berea sandstone. Both media are typically water-wet. Each core was 30 cm long and was placed inside a rubber sleeve with inner diameter of 3.81 cm. A confining pressure $p_{conf} = 30$ bar was applied to stabilize the packing and prevent flow near the edges.

The fluids used in the displacement experiments were water and Nitrogen (N_2), with isoparaffinic mineral oil (Soltrol-130) and a lubricant oil (*OB*-12), respectively employed as low and high viscose oil in our two-phase experiments. Sodium Bromide (*NaBr*) and Potassium Bromide (*KBr*) were added to the water as X-Ray absorbing chemicals, respectively for the experiments performed on the Sand-pack and on the Berea sandstone samples. This enabled us to (*a*) monitor depth- (i.e., section-) averaged fluid saturation along the core and (*b*) increase the contrast between the X-Ray absorption characteristics of oil and water. The choice of these two different compounds was related to the need of eliminating the possibility of the occurrence of reactions with the host porous matrix, which could damage the core structure. Table 1 lists the properties of the core samples and fluids employed in the experiments.

2.2. Experimental setup and condition

Fig. 1 depicts a sketch of the experimental setup. It consists of Hassler-type core holders (TEMCO FCH-1.5 m) containing the samples and the X-Ray saturation monitoring instrumentation (Core Lab Instruments), embedded in a closed loop system. The experiments were performed through the SS technique. Saturation measurements were performed via X-Ray saturation monitoring.

Table 1.
Physical properties of the tested core samples and fluids.

	Sand-pack	Berea sandstone	
Oil viscosity [cP]	1.74	Soltrol 1.74	*OB*-12 25
Water viscosity [cP]	0.97	1.03	
Gas viscosity [cP]	0.018	–	
Porosity [%]	37	17	
Water absolute permeability [mD]	2900	30	
Permeability of oil at S_{wi} [mD]	2500	25	