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Simultaneous Determination of Capillary Pressure and Relative Permeability Curves from Core-Flooding Experiments with Various Fluid Pairs

Ronny Pini, Ferdinand Hingerl, and Sally Benson
Stanford University, Energy Resources Engineering, Stanford, United States (pini@stanford.edu)

Geological systems are complex and so are the processes that determine the distribution of two (or more) immiscible phases within their porous structure; nevertheless, an empirical relationship between the capillary pressure and saturation, the capillary pressure function, provides the foundation for the theory of multiphase flow in porous media. The simultaneous existence of at least two fluids in a porous rock further implies that the ability of each fluid to flow is reduced by the presence of the other and a so-called relative permeability function has been introduced and defined as the ratio between the effective permeability to the given phase and the absolute permeability of the rock. When coupled to the continuum-scale equations of motion, these two characteristic curves allow for a description of multiphase displacement processes in a variety of natural settings that are related to a wide range of applications, thus including the storage of carbon dioxide into deep saline aquifers.
In this study, capillary pressure and relative permeability drainage curves are measured
on a single Berea Sandstone core by using three different fluid pairs, namely gCO_2/water, gN2/water and $scCO_2$/brine. An important feature of this experimental investigation is
that these two multiphase properties are obtained simultaneously during a core-flooding experiment. The applied technique possesses many of the characteristics of a conventional steady-state relative permeability experiment and consists of injecting the nonwetting fluid at increasingly higher flow rates in a core that is initially saturated with the wetting phase, while observing fluid saturations with a medical x-
ray CT scanner [Pini et al. 2012]. Injection flow rates are varied so as to cover a sufficiently large range of capillary pressures, whereas fluid-pairs and experimental conditions are selected in order to move across a range interfacial tension values (40-65 mN/m), while maintaining a constant viscosity ratio. Moreover, the experiments carried out at moderate pressures (P = 2.4 MPa and T = 50C) can be compared directly with results for gas/liquid pairs reported in the literature and
they set the benchmark for the experiment at a higher pressure (P = 9 MPa and T = 50C), where CO_2 is in the supercritical state. Contrary to prior investigations, from these experiments we find no evidence that the $scCO_2$/brine system behaves differently than any
of these other fluid pairs. At the same time, capillary pressure data show a significant
(but consistent) effect of the different values for the interfacial tension. The fact that the three different fluid pairs yield the same drainage relative permeability curve is consistent with observations in the petroleum literature. Additionally, the observed end-point values for the relative permeability to the nonwetting phase (kr,nw = 0.9) and the corresponding irreducible water saturations (Sw,irr = 0.35) suggest that water-wet conditions are maintained in each experiment. The reliability of the measured relative permeability curves is supported by the very good agreement with data from the literature obtained on Berea Sandstone cores and with various gas/liquid pairs. The Brooks-Corey model is used to describe the capillary pressure data and the parameters derived from
these matches provide a good prediction of the relative permeability curves.

Pini R., S. C. M. Krevor, S. M. Benson, Advances in Water Resources 2012, 38: 48-59.