PSMultiphase Flow Properties of Clay Bearing Rocks: Laboratory Measurement of Relative Permeability and Capillary Pressure*

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Abstract

Clay bearing rocks can have a large impact on trapping, reservoir compartmentalization and production oil or gas in a number of ways. Faults are critical for defining the likely sealing or baffling nature of within reservoir systems. The evaluation of new prospects and reservoir production simulations include fault permeabilities based on estimates of fault clay distribution. Fault clay content has been shown to act as a useful proxy for predicting both the sealing capacity of phylosiliclastic faults. There are several clay prediction algorithms (Bouvier et al. 1989, Yielding et al. 1997; Knipe et al. 2004). Far more data has been collected on the single phase permeability and mercury capillary pressure of fault rocks (Fisher and Knipe, 1998, 2001). More recently, one of the first gas relative permeability data for cataclastic rocks has been published (Al-Hinai et Al. 2008). A key problem in production simulation and prospect evaluation is accounting for the relative permeability of clay rich rocks, and for exploration cases their threshold pressure. Therefore in this article we attempt to start filling the knowledge gap of multiphase flow properties of clay rich bearing rocks.

An experimental study was carried out in order to study the feasibility of determining relative permeabilities and capillary pressures with brine, oil or gas. A methodology was developed to create synthetic plugs with controlled amounts of sands and clays that successfully mimic the single phase permeability behaviour of phylosiliclastic fault rocks. This methodology includes various techniques for the determination of steady state oil-brine relative permeabilities, gas relative permeabilities and air-brine capillary pressures. Samples with different clay contents and clay types have been tested. Different measurement techniques provide consistent and comparable results. The gas-brine capillary pressures of the synthetic plugs agree well with mercury results.

The oil or gas relative permeabilities measured show a larger drop within a very small variation in saturation and at relatively small capillary pressure range. The results indicate that attempting to model the impact of faults on fluid flow based on single phase permeability or using general relative permeability curves could significantly overestimate fault transmissibility and their impact on reserves evaluation.

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MULTIPHASE FLOW PROPERTIES OF CLAY BEARING ROCKS: Laboratory measurement relative,permeability and capillary pressure

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Introduction

Clay bearing rocks can have a large impact on trapping, reservoir compartmentalization and production of oil or gas. Faults are critical for defining the likely sealing or baffling nature of within reservoir systems. The evaluation of new prospects and reservoir production simulations include fault permeabilities based on estimates of fault clay distribution. Fault clay content has been shown to act as a useful proxy for predicting the sealing capacity of phylosiliclastic faults. There are several clay prediction algorithms (Yielding *et al.* 1997; Knipe *et al.* 2004). Significant amount of data exists on the single phase permeability and mercury capillary pressure of fault rocks (Fisher and Knipe, 1998, 2001). However, a key issue in production simulation and prospect evaluation of clay rich rocks is accounting for effective permeability, capillary pressure, and for exploration cases their threshold pressure.

We present here an experimental study attempting to fill the knowledge gap on the the multiphase flow properties of clay rich bearing rocks. A methodology was successfully developed, including various techniques for the determination of oil-brine and gas-brine relative permeability and air-brine capillary pressures on a range samples.

Approach and methodology

Three types of core plugs were used in this study:

1- Synthetic plugs made with sand of different grain sizes and Kaolin clay in different proportions,
2- Reconstituted plugs made from reservoir sand, silt and clay separated and mixed in different proportions,
3- Natural and reservoir, clay rich and poorly lithified siltstones

Sample preparation for core plugs type 1 and 2
The desired weight of clay was added to the sand/ silt and mixed to obtain a homogeneous sample. The mix was poured in pre-moulded PTFE sleeves and closed by end caps. These synthetic cores were pre-compacted, then saturated with brine (5% NaCl) before being loaded in a multi-sample holder. The confining stress (hydrostatic pressure) was increased up to 5000 psi in small steps while monitoring each sample for changes in pore volume.The steady state brine permeability was determined at selected stress steps once the pore volume of the samples remained constant
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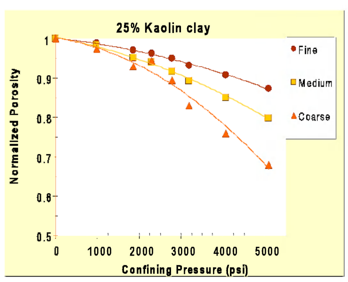
Sample preparation for core plugs type 3
The core plugs were drilled or plunge cored, placed inside a thin metal sleeves with fine metal mesh at the ends and a nominal stress applied to produce a tight fit between sample and the metalic sleeve. Standard cleaning and drying procedures were applied. Gas and brine permeability was measured at increasing confining hydrostatic stress.

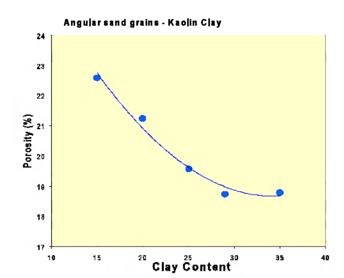
Example of synthetic plugs with different clay content and a reservoir plug

Photograph of the multi-sample core holder with pore volume and resitivity monitoring. The apparatus can be operated upto 10, 000 psi and 150 C

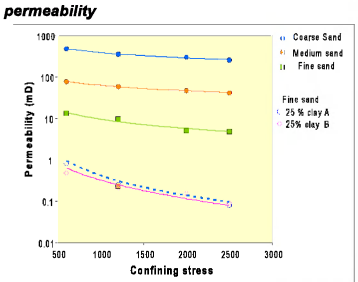
Results

Porosity - In all the samples tested the porosity decreased as the stress increased, an example can be observed in the figures below for mixtures of Kaolin clay and angular sand of a mean grain size of 200 microns.

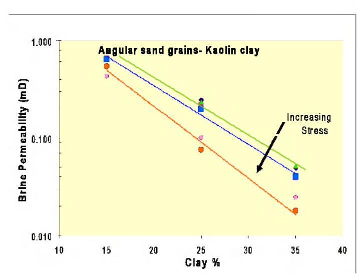




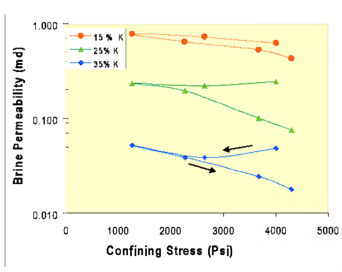
Brine permeability

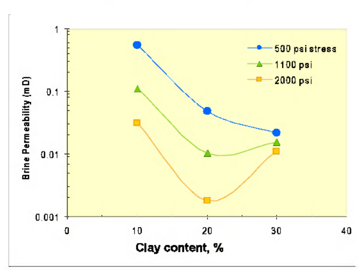


The permeability decreased with grain size and increasing clay content.



The brine permeability also decreased as the stress increased, an example can be observed in the Figure above





The effect of multiple loading cycles was studied in synthetic core plugs. The stress cycle represented cycles of up-llifting and deeper burial. Stress hysteresis was observed in all the samples, which increased with clay content. For some reconstituted samples a minimum on brine permeability was observed at higher confining stress.

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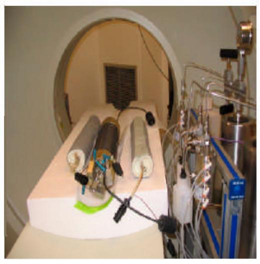
Two Phase Properties

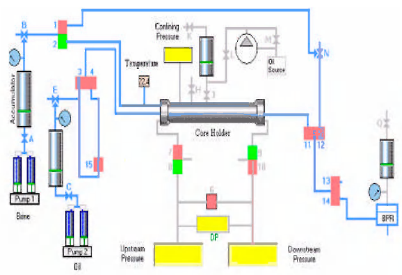
Due to the complexity, difficulty and time consuming characteristics of these experiments only a limited amount of results are currently available. For example one of the first relative permeability data for cataclastic rocks has been recently published (Al-Hinai et Al. 2008).

Oil-Brine Relative Permeability

Inspite of being simple in principle the application of the steady state method is fraught with practical difficulties. The principle is to simultaneously flow oil and water in a predetermined and constant ratio until a steady state is achieved. In our case steady state is defined as constancy in the pressures and saturation, a schematic of the set up is shown below. Once these have been achieved a different oil-water fractional flow is injected while keeping the total flow rate constant. The saturation distributions along the core are determined using a CT scanner.



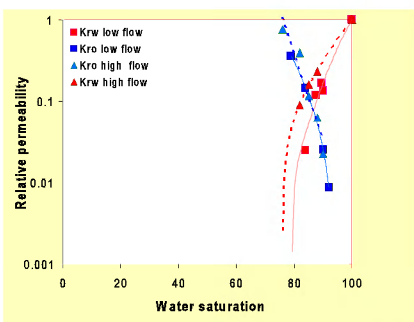
Core-holder within the CTscanner is used to monitor fluid saturation



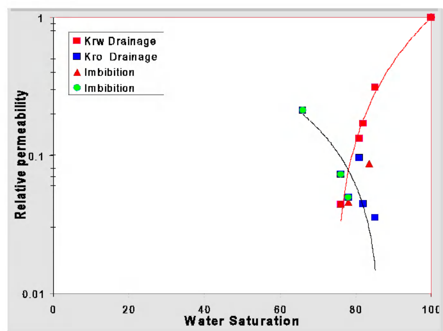
Schematic of the steady state relative permeability setup

Pumps and control unit used for two phase flow system

One of the main objectives of this work was to obtain relative permeabilities for clay rich rocks, which will be used to evaluate their sealing capacity. Therefore, the primary drainage cycle and imbibition was measured in all the cases. Results from two tests on 28% Kaolin sand synthetic plug and a reconstituted plug are shown below.



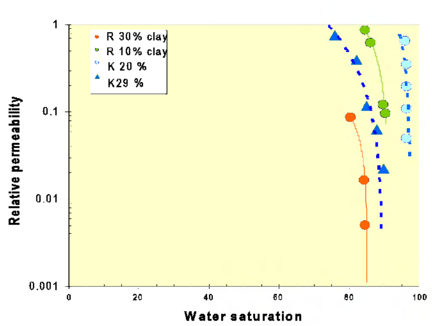
Drainage oil-brine realtive permeability for a synthetic plug 28% Kaolin at two different flow rates

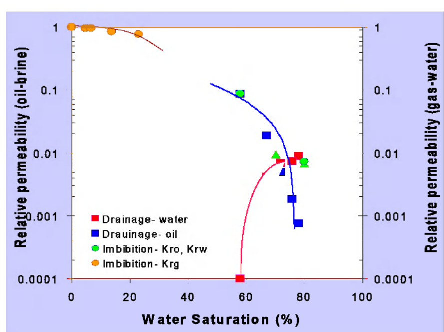


Oil-brine realative permeability for a reconstituted plug with 30 % clay

Gas-brine Relative Permeability

Two different methods have been used to obtain gas relative permeabilities: A- Humidity chambers were used to obtain low water saturations (Al-Hinai *et al.* 2008), and B- A quasi-steady state displacement was used at high water saturations (Grattoni *et al.* 2007).





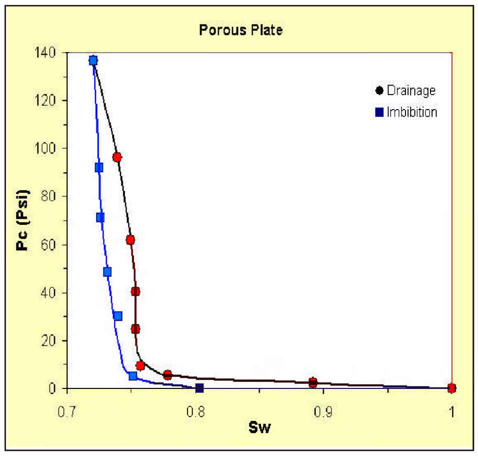
When the air- brine permeability, during drainage at high water saturation, is compared with oil-brine relative permeability for a natural clay rich rock a good agreement between techniques is observed. Also, the low water saturation relative permeability is consistent with the relative permeabilities obtained by other methods.

The gas relative permeabilities during displacement, steady state or quasi steady state, shows a sharp rise of permeability within a small saturation range for clay contents between 10 and 30 %. Additionally, the residual water saturation is extemmely high (60- 90 %). These relative permeabilities are very different to those obtained for clean sandstones and unlithified sands.

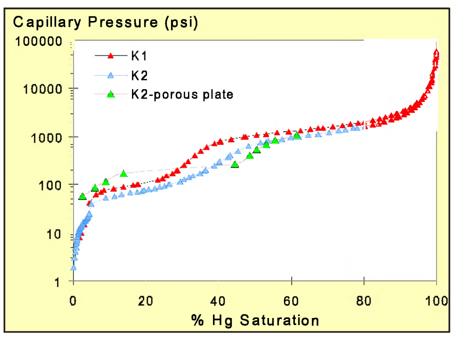
Capillary pressure

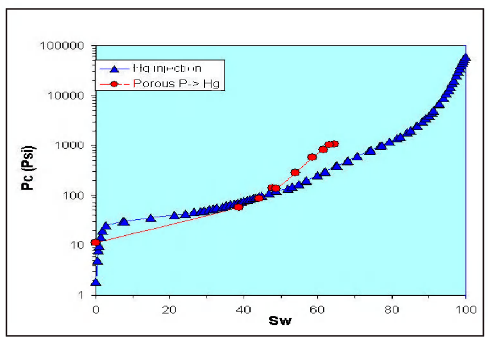
The capillary pressure of several samples were measured using the porous diaphragm method and the traditional mercury injection (MICP) in order to evaluate their sealing capacities.

Photograph of the porous diaphram for gas-brine capillary pressure



Air-brine drainage and imbibition capillary pressure for a synthetic plug





The results from both porous diaphagm and MICP agree very well. Most of the capillary pressure results show a double plateau. The synthetic plugs also presented a double plateau where the start point of the second plateau is displaced at lower mercury saturations as the clay content increases.

Synthesis of Results

* Permeability is a complex function of grain size and shape, clay type and its content, stress and burial history. Although some correlations exist for grain size and clay content, there is a lack of data for the other factors.
* Both the oill and gas relative permeabilities measured show change of several orders of magnitude within a very small saturation range. The residual water saturation at the permeability endpoint is very high 60-90% therefore there is a small capillary range where flow is observed.
* The results presented indicate that attempting to model the impact on fluid flow of clay rich rocks based on single phase permeability or using general relative permeability curves could significantly overestimate fault transmissibility and their impact on reserves evaluation.

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