Relative permeability assessment in a giant carbonate reservoir using Digital Rock Physics

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ABSTRACT

Representative relative permeability data are of great importance for accurate and more importantly valid reservoir simulation models. Relative permeability tests are conventionally performed in specialized laboratories through Special Core Analysis (SCAL) conducted on selected core plugs. The experiments can be time consuming and as such performed on a limited number of reservoir core plugs to represent specific reservoir rock types (RRT), flow units and/or reservoir zones.

A detailed study to investigate the reliability and validity of water-oil relative permeability curves and end points were derived using the new discipline of Digital Rock Physics (DRP). Reservoir core plugs from a giant carbonate reservoir in the Middle East on which imbibition water-oil relative permeability were acquired were chosen for this huge validation study. The cores were selected and tested through a comprehensive SCAL program consisting of careful preserved core acquisition, selection/screening, detailed characterization, testing and QC/QA of laboratory results using numerical simulation and integration with multiple tests such as single-speed centrifuge and water-oil capillary pressure. The DRP based investigations were performed as part of a blind study (relative permeability data unknown to DRP contractor) on 16 different RRT samples, comprising a vast range of lithofacies with core porosities from 11 – 34% and permeabilities from micro-Darcy to several Darcies.

Relative permeabilities are quantified by adopting a multi-resolution integrated pore-scale modeling approach based on X-ray computed tomography images and numerical 3D digital rock models. This technique is able to capture the dominating pore classes present on the core plug scale: vuggy porosity, inter- and intragranular macro-porosity and micritic micro-porosity. Rock curves are generated for each of the pore classes and then used in a steady-state upscaling routine to obtain primary drainage (water saturation decreasing from 100% brine saturation) and imbibition (water saturation increasing) relative permeability curves representing the entire core plug.

The comparisons between relative permeability curves derived from DRP and experimental steady state tests provide an assessment on the validity of the DRP based tests. Comparisons have been performed for each RRT and show an excellent match of laboratory measured relative permeability; typically within 90% of the test results if rock-fluid wettability can be correctly postulated. Wettability variation for different RRT and respective pore geometry can also be quantified, and thus significantly improve the uncertainties in the predicted relative permeabilities.

INTRODUCTION

Conventionally, multiphase flow in porous media is described by means of the concept of relative permeability functions. Accurate characterization of flow and fluid distribution is a key parameter for reservoir management. Relative permeability tests are traditionally performed in Special Core Analysis (SCAL) laboratories and conducted on limited number of selected core plugs.

DRP studies have proven the capability to generate SCAL data at small scale mm to cm (Gomari *et al.*, 2011, Lopez *et al*., 2010, Kalam *et al.,* 2010 and 2011, and Grader *et al*., 2010). In carbonate rocks, pore structure is generally heterogeneous with pore size ranging from sub-micron to several centimeters. Thus, a large scatter of reservoir characterization properties is caused by these variations in pore type, pore geometry and different porosity types. To predict multiphase flow properties of carbonate reservoir rocks, it is necessary to characterize the different types of heterogeneity (i.e. rock types), to recognize which have important effects on fluid flow, and to capture them and the relevant flow physics at different scales by up-scaling.

In this study performed over 9 months, DRP approach was applied on 100+ carbonate core plugs from two giant carbonate reservoirs in the Middle East to numerically predict petrophysical properties and water/oil relative permeability during imbibition from 3D rock models derived from X-ray micro tomography imaging (MCT). Results of 18 selected core plugs comprising 6 different RRT's are presented in this paper. These RRT's have both unimodal and multi-modal pore throat distributions with permeabilities from 1 – 3000 mD and porosities from 15 – 35%.

METHODOLOGY

Laboratory test

Routine Core Analysis (RCA) has been conducted on the selected samples for this study to determine porosity and permeability. Laboratory measurements for water-oil relative permeability during first imbibition were performed on selected core plugs from 6 different RRT's. Data reported in this study were based on the steady state tests on composite cores (minimum of 3 plugs per RRT). The irreducible water saturation (Swi) was determined in each plug using the porous plate method with a maximum capillary pressure of 7 bar. All experiments were conducted at reservoir temperature and reservoir overburden pressure with insitu saturation monitoring using live oil and formation brine. Analytical data were history matched using the commercial software SENDRA.

Digital Rock Physics

Imaging, Modeling and Petrophysical Properties

All the samples investigated in this study were part of 1.5-inch diameter carbonate core plugs. They were imaged with a Nanotom S nanofocus X-ray computed tomography system (MCT) at a resolution of 19µm per voxel. Microplug sub-samples were drilled from the core plug samples at selected locations (rock typing) from end-cuts and scanned with the same scanner or – where appropriate – at the European Synchrotron Radiation Facility in Grenoble, France (ESRF). Microplugs diameter is from 0.5mm to 10mm and resulting 3D images have resolutions between 0.28µm and 5µm per voxel.
Microporous phase is often below the resolution of the CT scans. 3D models of the micorporous phase are then constructed based on analysis of high resolution backscattered scanning electron microscope (BSEM) images. Modeling and calculations of petrophysical properties are described by Lopez *et al.* (SCA 2012), and are not detailed in this paper.

Two-phase Flow Simulations

For microporous phase and intergranular porosity, simulations of multiphase flow are performed on a numerical pore network, which retains the essential features of the 3D rock model's pore space (Øren et al., 1998). The multi-phase flow simulations are based on a quasi-static network model. In the numerical simulations, flow is assumed to be laminar, capillary driven and fluids are immiscible (Øren et al., 1998). The wettability model used for the two-phase flow simulations is discussed in detail in Øren et al. (1998 and 2002). For vuggy porosity identified in core plug CT scans, flow properties are directly computed from CT scans using Lattice-Boltzman calculations (Ramstad *et al.* 2010).

Upscaling

Effective properties of the micro-/core plug samples are determined using steady state scale up methods. The CT scan of the micro-/core plug is gridded according to the observed geometrical distribution of the different rock types or porosity contributors. Each grid cell is then populated with properties calculated on the pore scale images of the individual rock types. The following properties are assigned to each grid cell; porosity, absolute permeability tensor (k_{xx}, k_{yy}, k_{zz}), capillary pressure curve and relative permeability curve.
Single phase up-scaling is done by assuming steady state linear flow across the model. The single phase pressure equations are set up assuming material balance and Darcy's law:

$$\nabla \bullet (k\nabla P) = 0 \text{ with boundary conditions}$$
$$p = P_1 \text{ at } x = 0, p = P_0 \text{ at } x = L$$
$$v \bullet n = 0 \text{ at other faces}$$

The pressure equation is solved using a finite difference formulation. From the solution one can calculate the average velocity and the effective permeability using Darcy's law. By performing the calculations in the three orthogonal directions, we can compute the effective or up-scaled permeability tensor for the core sample.
Effective two-phase properties (i.e. capillary pressure and relative permeability) are calculated using two-phase steady state up-scaling methods. We assume that the fluids inside the sample have come to capillary equilibrium. This is a reasonable assumptions for small samples (<30cm) when the flow rate is slow (<1m/day).

RESULTS AND DISCUSSION

Water/oil steady state flooding experiments were conducted on composite core plugs (CC.) consisting of a minimum of three 1.5-inch core plugs butted together. Each of the core plugs was numerically reconstructed using DRP method. Single and two phase flow properties from DRP were then compared with experimental results. Wettability for all the 2 phase flow simulations was set to strongly oil-wet based on Amott-Harvey tests conducted on samples from same investigated RRT.
In addition, core composite has also been numerically reconstructed based on the 3 DRP core plugs of each RRT to reproduce the real composite cores using during steady state tests.
DRP flooding simulations are conducted down to a forced capillary pressure of -7 bars while experimental steady state flooding tests never reach a differential pressure corresponding to such low negative capillary pressure. High negative capillary pressure is usually obtained in centrifuge or porous plate tests. In order to have comparable end points, the DRP end points at the same differential pressure have been reported in all the result tables.

RRT 6

RRT 6 is characterized by poorly sorted bioclastic floatstones with mud dominated facies and interparticle, intraparticle and vuggy pore types. The measured Helium porosity of this rock type is in the range of 26% and Klinkenberg corrected permeability of 10 to 25mD.

DRP and experimental porosity and permeability are close as shown in Table 1. Relative permeability from DRP and steady state test are presented in Figure 1. Relative permeability from the 3 reconstructed core plugs are quite close and match well the steady state test of RRT 6 as well as for the reconstructed composite core. Swi from DRP are comparable to experimental value defined for the composite core.

Table 1

Sample ID	Lab – CC.RRT6	DRP 1 - RRT6	DRP 2 - RRT6	DRP 3 - RRT6	DRP – CC.RRT6
K(mD)	17.5	13.3	25.8	9.31	23.1
Porosity (frac.)	0.275	0.260	0.270	0.264	0.269
Swi	0.13	0.10	0.06	0.11	0.09
Sorw	0.19	0.18 (0.13*)	0.19 (0.09*)	0.20 (0.13*)	0.20
Krw(Sorw)	0.62	0.74 (0.88*)	0.56 (0.86*)	0.63 (0.82*)	0.70

** Pc=-7bar*

RRT7

Mostly homogeneous moderately sorted bioclastic grainstones / rudstones are represented in RRT7. Porosity occurs dominantly as intraparticle and interparticle. These carbonates are characterized by porosity around 28% and permeabilities of 100-250mD.

Computed and experimental porosity are very similar (~28%) while permeability from DRP is slightly lower but comparable within a reasonable range (Table2). Relative permeability from the 3 reconstructed samples and the synthetic composite core are matching very well steady state flooding test results (Figure 2). Swi from DRP and experiment are the same (9-10%).

Table 2

Sample ID	Lab CC.RRT7	DRP 1 - RRT7	DRP 2 - RRT7	DRP 3 - RRT7	DRP- CC.RRT7
k(mD)	191.6	95.6	108.1	98.0	103.3
Porosity (frac.)	0.278	0.271	0.284	0.287	0.276
Swi	0.09	0.09	0.1	0.1	0.09
Sorw	0.32	0.30 (0.13*)	0.29 (0.13*)	0.32 (0.15*)	0.30
krw(Sorw)	0.75	0.62 (0.82*)	0.67 (0.88*)	0.64 (0.86*)	0.63

** Pc=-7bar*

RRT8a

RRT8a is characterized by a well cemented bioclastic grainstone with mostly vuggy porosity. Observed porosity of this carbonate is about 13% and permeability in the 1-3D range.

Both porosity and permeability are well captured with DRP (Table3). Steady state tests conducted on RRT8a sample show a difficulty to reconcile raw and history match (HM) data. Raw experimental data were then fitted using Corey parameterization on most trustable experimental as shown in Figure 3. Oil relative permeability from DRP, steady state flooding test and Corey fitting on experimental (lab) data are showing very good agreement. While water relative permeability from tests shows a suspicious low value at low water saturation (Sw lower than 40%). These values have been ignored during Corey fitting. DRP and Corey fitted water relative permeability show a very good agreement.

Table 3

Sample ID	Lab – CC.RRT8a	DRP 1 - RRT8a	DRP 2 - RRT8a	DRP 3 - RRT8a	DRP – CC.RRT8a
k(mD)	1672	1326	2533	1490	2097
Porosity (frac.)	0.130	0.135	0.110	0.134	0.131
Swi	0.164	0.13	0.14	0.14	0.13
Sorw	0.28	0.25 (0.11*)	0.24 (0.11*)	0.26 (0.11*)	0.25 (0.11*)
krw(Sorw)	0.79	0.80 (0.87*)	0.80 (0.88*)	0.83 (0.87*)	0.82 (0.88*)

** Pc=-7bar*

RRT8b

Bioclastic grainstones/rudstones with a high degree of recrystallization has been observed in RRT8b. The porosity of these carbonates vary between 27-30% and the dominant pore type are vuggy and intraparticle. Permeabilities range between 200-700mD.

Porosity form the 3 reconstructed core plugs and the composite core plug are within the same range (27-30%) and the permeability of the 3 reconstructed core plugs show a significant spread from 192.4 to 653.4mD (Table 4). The synthetic composite core has a average permeability of 379.6mD and porosity of 29%. Relative permeability of the 3 DRP samples and the synthetic composite core are matching well the steady state test results (Figure 4).

Table 4

Sample ID	Lab - CC.RRT8b	DRP 1 - RRT8b	DRP 2 - RRT8b	DRP 3 - RRT8b	DRP – CC.RRT8b
k(mD)	257.7	302.4	653.6	192.4	379.6
Porosity (frac.)	0.266	0.296	0.278	0.272	0.290
Swi	0.078	0.11	0.07	0.14	0.09
Sorw	0.30	0.25 (0.12*)	0.29 (0.13*)	0.25 (0.15*)	0.29
krw(Sorw)	0.75	0.73 (0.81*)	0.76 (0.82*)	0.74 (0.81*)	0.73

** Pc=-7bar*

RRT11

RRT11 is characterized by bioclastic wackestones to packstones with a high percentage of micritized components. Dominant pore types are intraparticle, interparticle and vuggy. The observed porosities are around 32% and the permeability is in the 10-30mD range.

Porosity from DRP and experiment are close and permeability of the 3 reconstructed samples is ranging from 7.07 to 40.2mD compared to 11.4mD for experimental value (Table 5). The synthetic composite core plug has a permeability of 14.0mD and porosity of 32% very close to the experimental composite core. Swi of the composite core is unexpectedly high at 0.177 (probably due to weighting from 2 additional plugs, not used in DRP tests) compared to individual measured value of each of the DRP core plugs of 0.06 - 0.08, respectively. Therefore, to better compare the data sets, simulated and experimental relative permeability have been reported as a function normalized water saturation with respect to initial water saturations as:

$$S_{wN} = \left(\frac{S_w - S_{wi}}{1 - S_{wi}} \right) \tag{1}$$

Relative permeability from the 3 reconstructed core plugs show a significant spread but capture well the results from the steady state test (Figure 5). Only experimental oil relative permeability close to residual oil saturation is slightly greater to the DRP ones but end point value is very similar (~11%)

Table 5

Sample ID	Lab - CC.RRT11	DRP 1 - RRT11	DRP 2 - RRT11	DRP 3 - RRT11	DRP – CC.RRT11
k(mD)	11.4	17.3	40.2	7.07	14.0
Porosity (frac.)	0.316	0.331	0.347	0.308	0.320
Swi	0.177	0.06	0.08	0.07	0.07
Sorw	0.11	0.16 (0.12*)	0.13 (0.08*)	0.13 (0.11*)	0.17 (0.12*)
krw(Sorw)	0.74	0.81 (0.89*)	0.87 (0.94*)	0.76 (0.88*)	0.85 (0.92*)

** Pc=-7bar*

RRT15

Bioclastic wackestones to packstones are characterizing RRT15. Micritization of the components has been observed. Dominant pore types are vuggy, interparticle and intraparticle. Porosities around 33% and permeabilities of 30-70mD are typical.

The 3 samples from RRT15 exhibit significant variations for both permeability and porosity as shown in Table 6. Porosity of the 3 reconstructed samples varies from 27.1 to 37.2% and the experimental value for the composite core is 31.0%. Permeability is ranging from 27.2 to 52.2mD for an experimental value of 35.6mD. Figure 6 shows the comparison of the 3 DRP relative permeability and the steady state test ones. The 3 DRP relative permeability are significantly different and cannot be compared directly to results from the composite core. Porosity and permeability of the synthetic composite core are well in line with the experimental data. Relative permeability from DRP and steady state test has been compared in Figure 6. Oil relative permeability is matching well the laboratory test. Water relative permeability from DRP is slightly lower than experimental one but within the range of uncertainties for this kind of experiment.

Table 6

Samlple ID	Lab - CC.RRT15	DRP1 - RRT15	DRP2 - RRT15	DRP3 - RRT15	DRP - CC.RRT15
k(mD)	35.6	52.2	42.6	27.2	40.8
Porosity (frac.)	0.310	0.271	0.338	0.372	0.332
Swi	0.11	0.08	0.08	0.08	0.08
Sorw	0.17	0.18 (0.14*)	0.20 (0.15*)	0.16 (0.13*)	0.15
krw(Sorw)	0.70	0.60 (0.66*)	0.63 (0.70*)	0.83 (0.89*)	0.68

** Pc=-7bar*

CONCLUSIONS

The DRP multi-scale approach used in this study yields reliable and consistent SCAL data for heterogeneous carbonate rocks under oil-wet conditions. The study was conducted without any knowledge of experimental results (blind study). Only fluid properties (density, viscosity and interfacial tension) and wettability preferences were provided to the DRP contractor. The comparisons between relative permeability curves derived from DRP and experimental steady state tests have shown an excellent match for the investigated RRT's.

The results presented in this paper show that DRP approach can be used to provide fast, high quality SCAL data at a scale where experiments are commonly conducted in SCAL laboratories. SCAL data from DRP were calculated on both single and composite core plugs.

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Figures

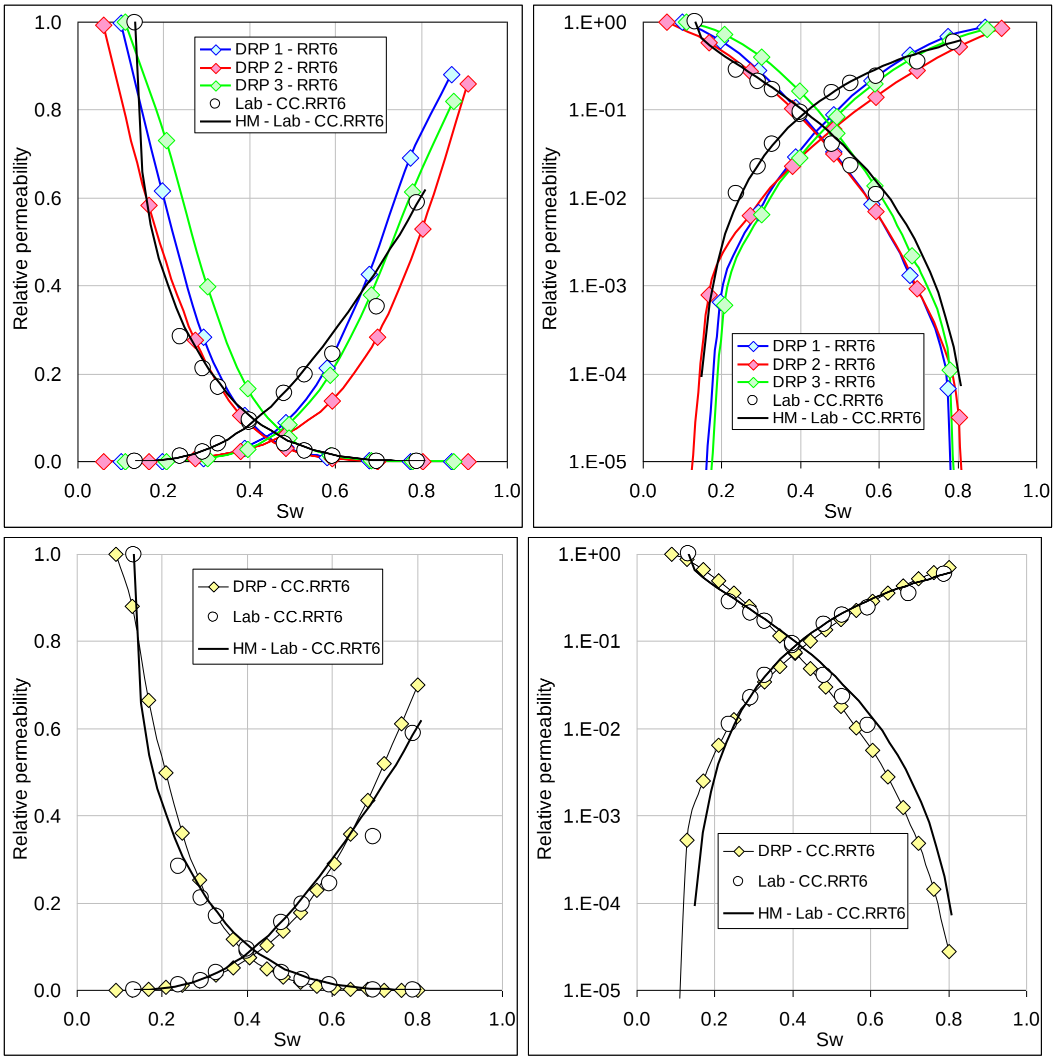


Figure 1: DRP and steady state test Relative permeability for RRT 6

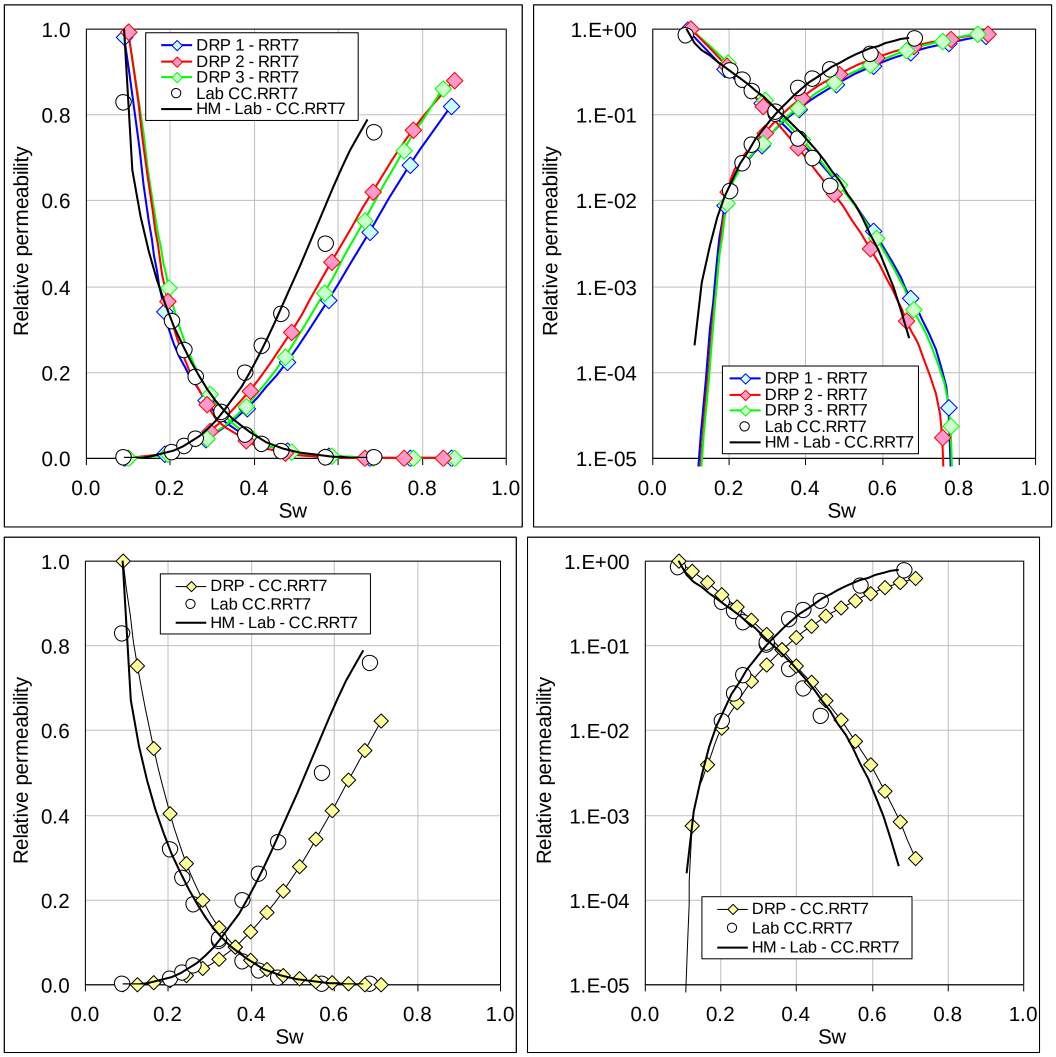
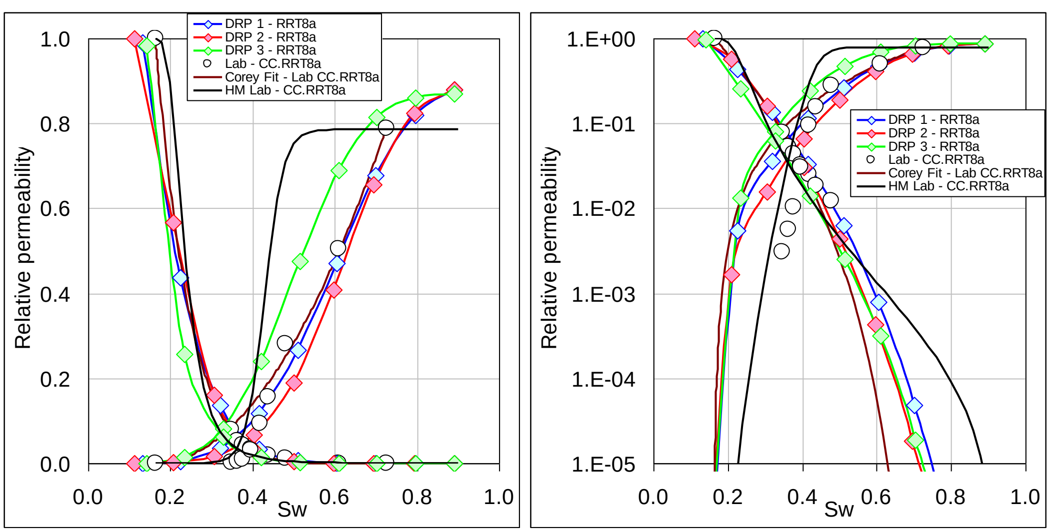


Figure 2: DRP and steady state test Relative permeability for RRT 7



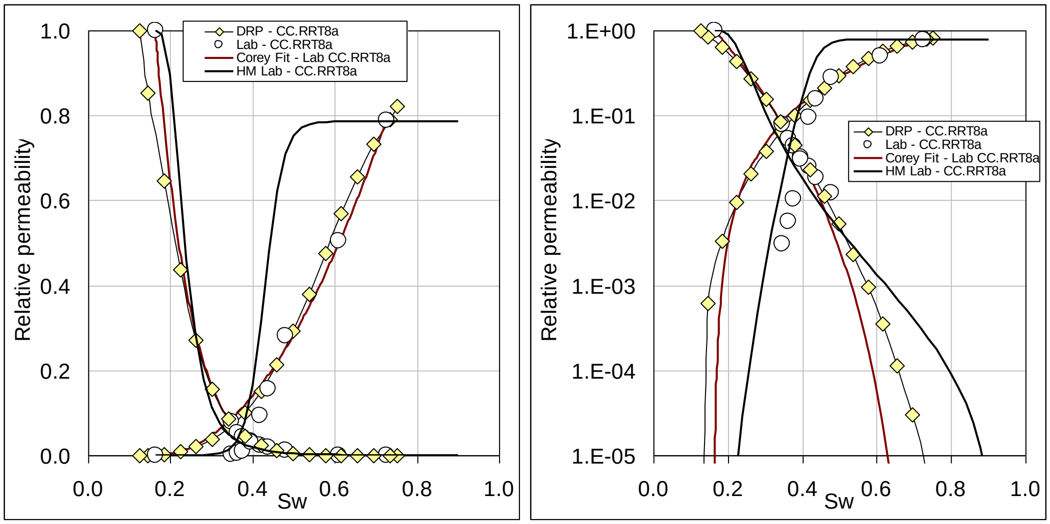


Figure 3: DRP and steady state test Relative permeability for RRT 8a

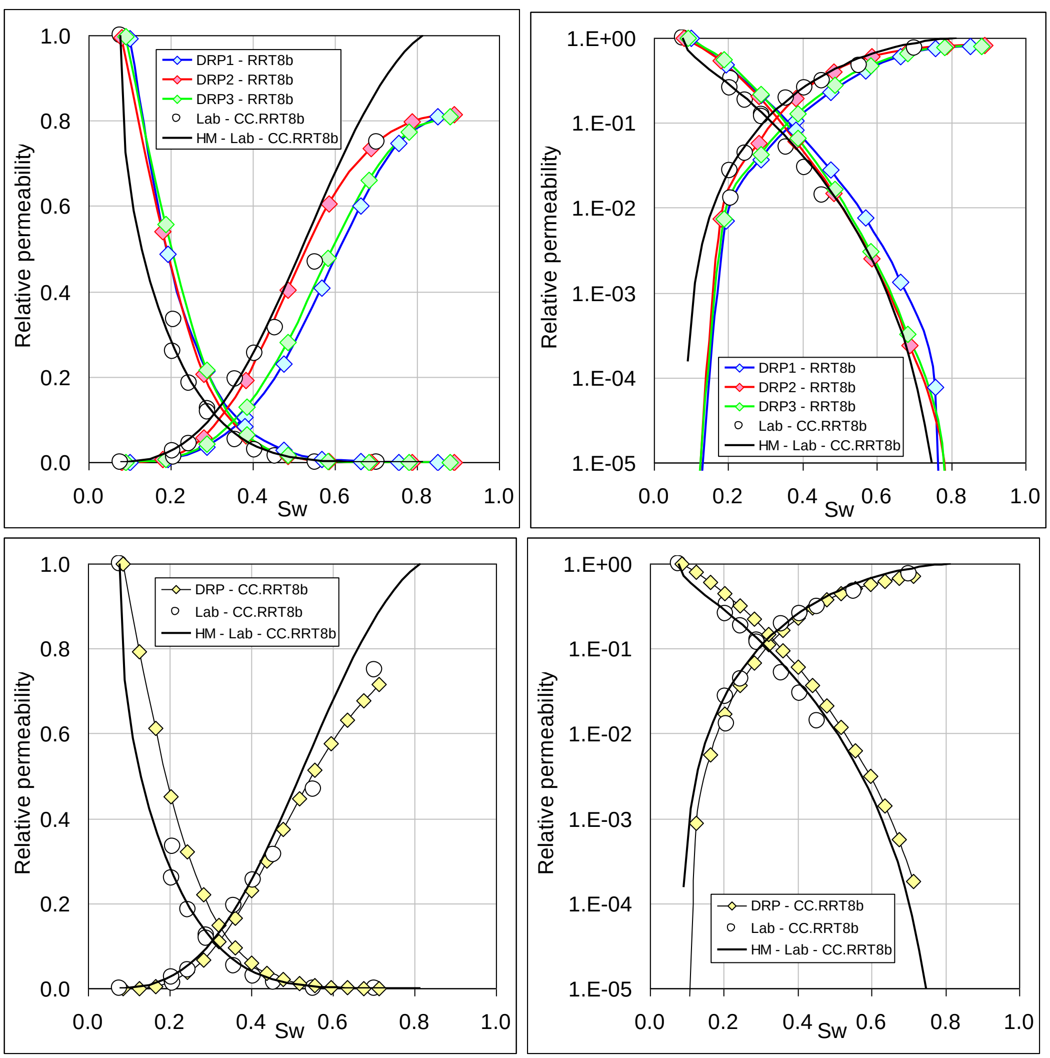


Figure 4: DRP and steady state test Relative permeability for RRT 8b

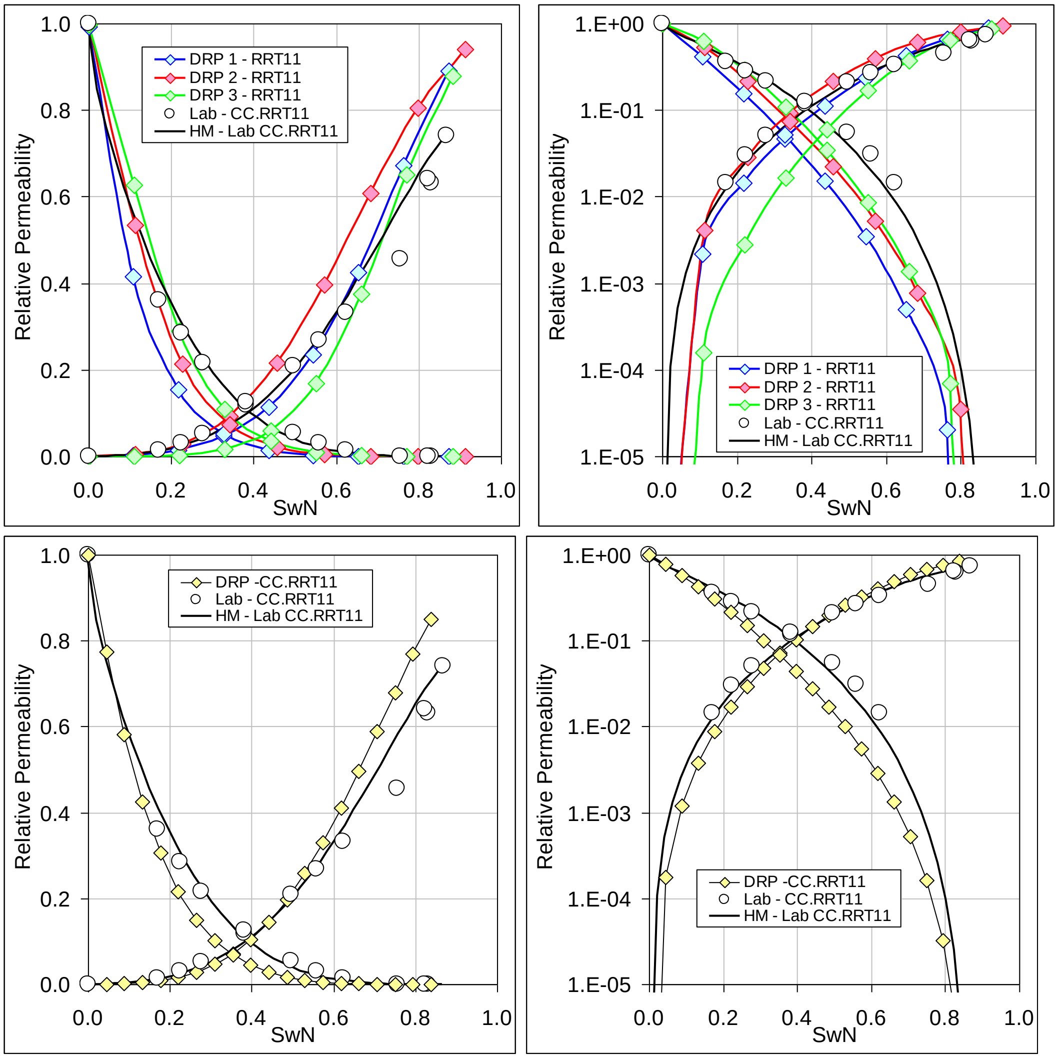


Figure 5: DRP and steady state test Relative permeability for RRT 11

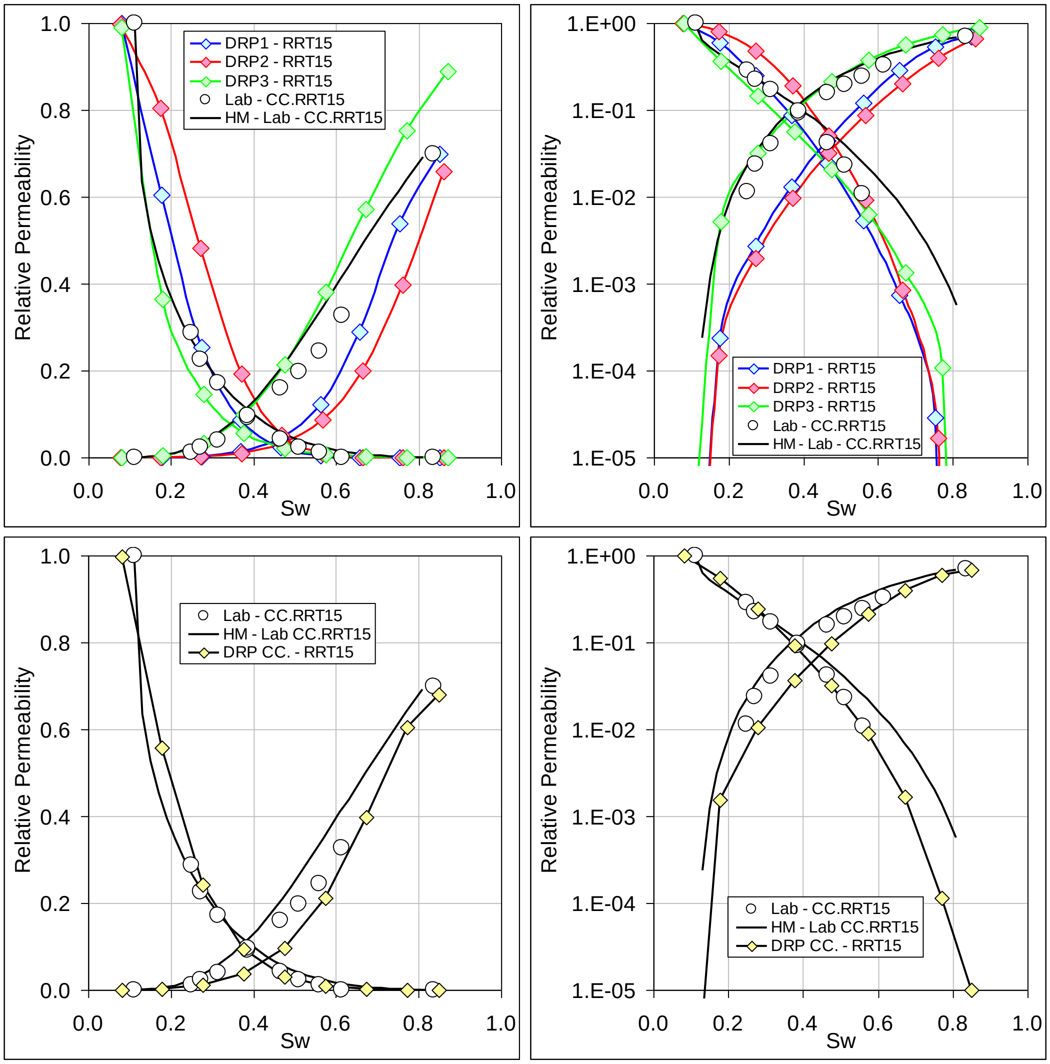


Figure 6: DRP and steady state test Relative permeability for RRT 15