3D pore scale imaging and modeling as a tool to understand multiphase flow in porous media

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SCAL Objectives (special core analysis)

•Measuring and predicting the detailed behaviour of multiphase flow in porous media

•Give information on the geometry and topology as well as the fluid distribution at the laboratory scale

•Modelling of fluid displacement mechanisms including fluid/fluid and fluid/solid interface at the plug scale

Field application

- ✓ hydrocarbon formation, migration and production,
- ✓ water resources and management
- ✓ management,
- ✓ soil remediation
- ✓ CO_2 sequestration

New tools to address SCAL problems

- ***In-Situ Micro-CT Lab***
- ***Petrophysics Digital Lab***

Context of oil recovery

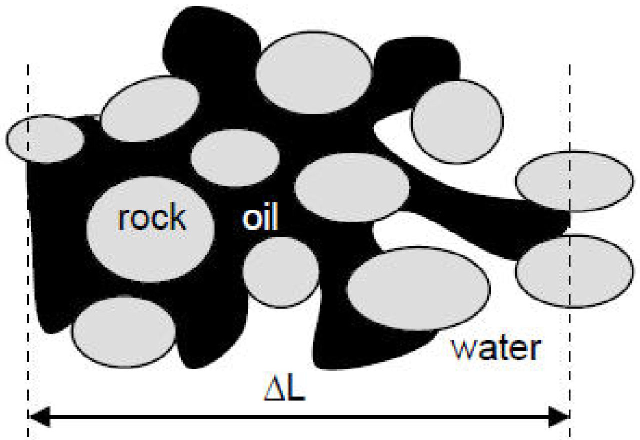
➢After the secondary recovery (water flood), The major part of the remaining oil (45-90%) is trapped as disconnected phase under capillary forces.

➢These forces are strongly related to:

✓the geometry of pore network,

✓the fluid-fluid properties (interfacial tension)

✓ fluid-rock properties (wettability)



Trapped oil at pore scale.

Chemical EOR methods' objective is to decrease residual oil by changing trapping conditions such as rock wettability or fluid-fluid interfacial tension.

Rising questions:

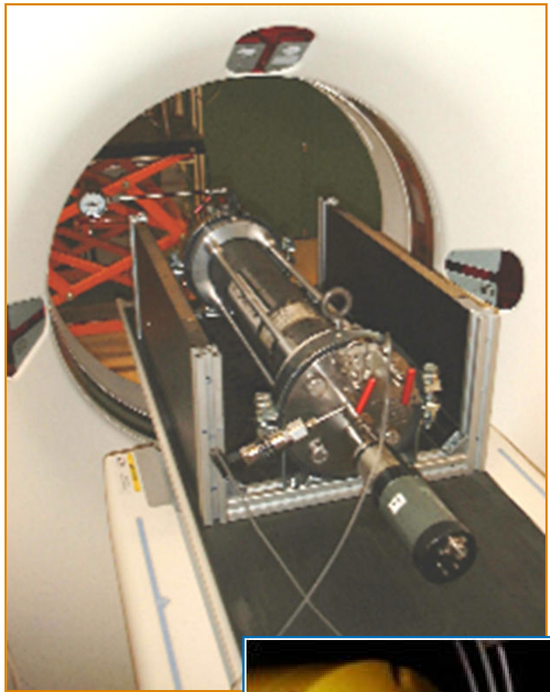
- ✓ *Is there specific properties to mobilize the residual oil?*
- ✓ *How is the oil distribution at residual oil saturation?*
- ✓ *What are the conditions required to mobilize the trapped oil?*
- ✓ *How the geometry and topology of the rock impact the fluid distribution?*
- ✓ *How to upscale from the local mechanisms to the core scale?*

Investigation tools and technics

3D Imaging techniques

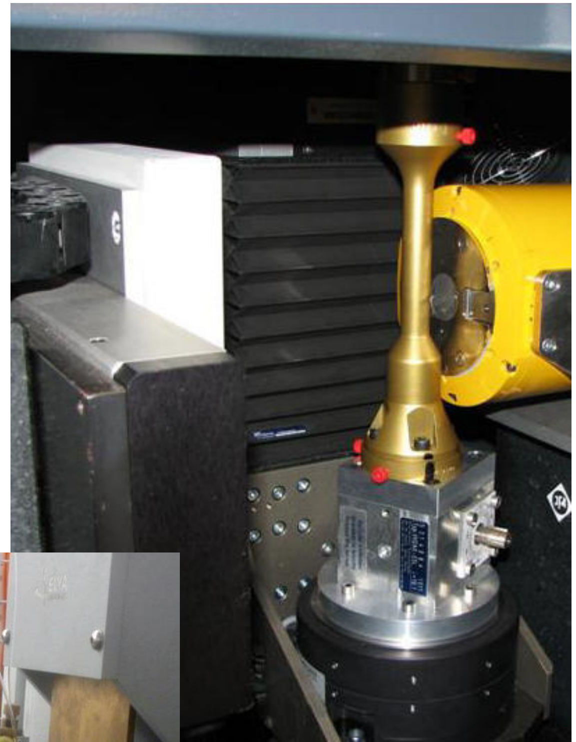
	Medical CT	Lab µCT	Synchrotron CT
Spatial Resolution	100 µm	1 µm	0.3 µm
Time Resolution	1 s	7200 s	0.5 s
Detector size	512x512	2304x2304	2024x2024
Sample diameter	60-20 mm	10-4 mm	10-4 mm
In-situ coreflood	Dynamic (P,T)	Steady-state (P)	Dynamic (P)

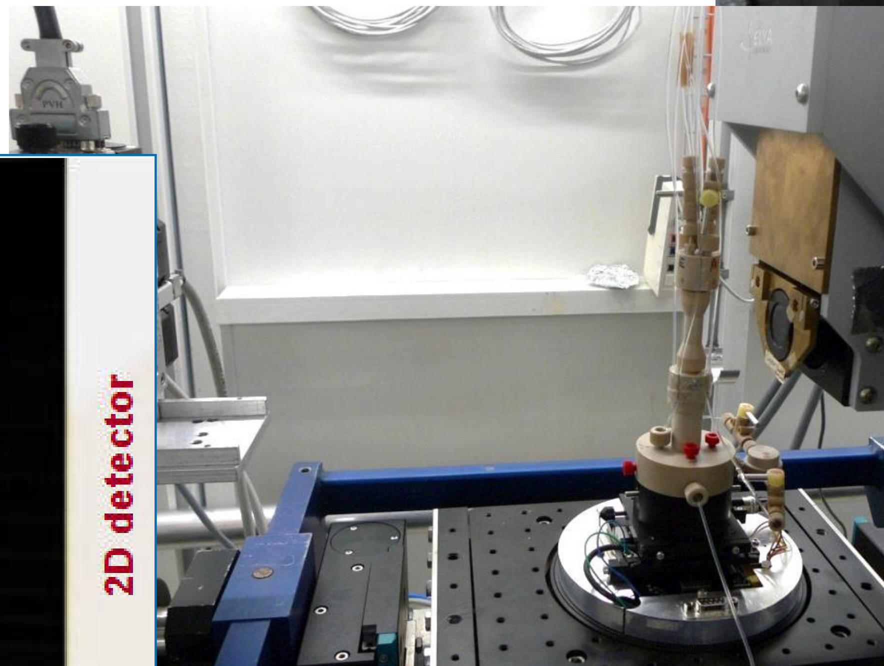
In-Situ µCT Lab

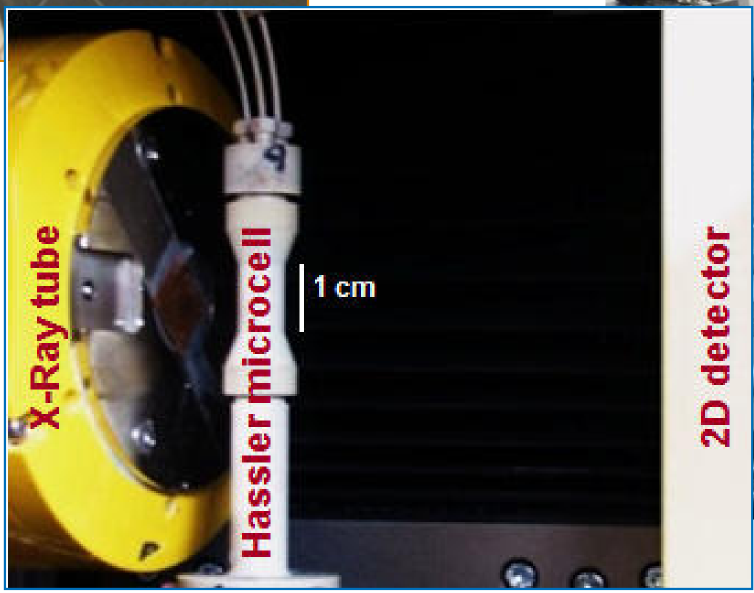


Coreholder (Hassler type cell):

- ✓ 3D image acquisition
- ✓ X-ray transparent
- ✓ in-situ monitoring of the flow rate
- ✓ P,T conditions
- ✓ Injection of up to 5 fluids
- ✓ Tri-axial cell

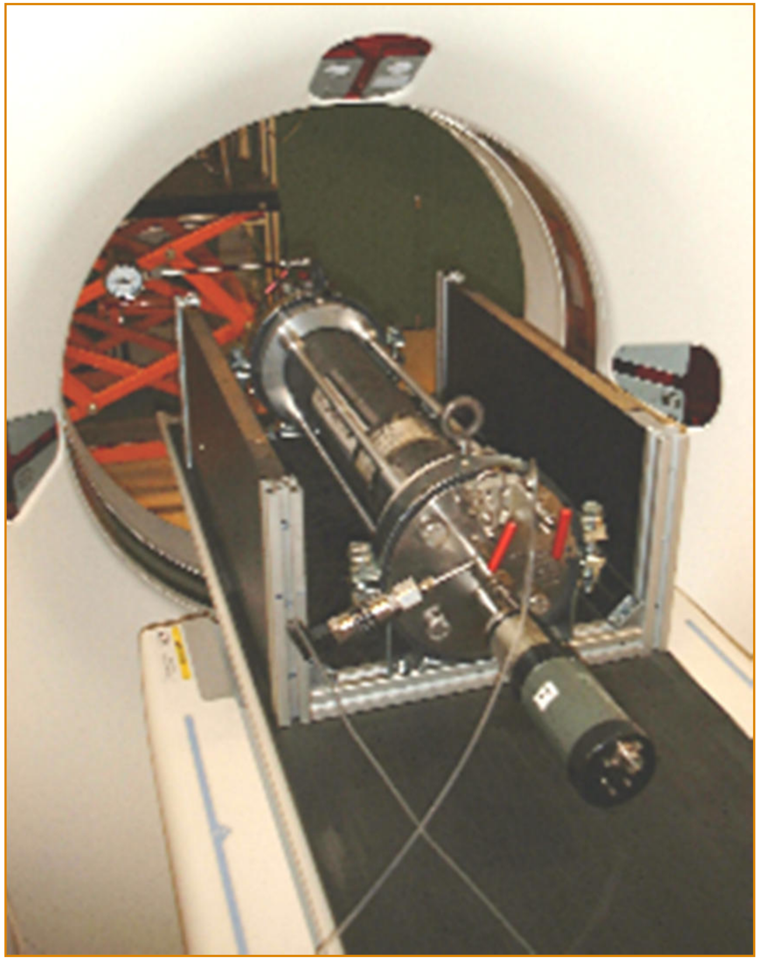






Monitoring and imaging by CT scan a surfactant flooding test

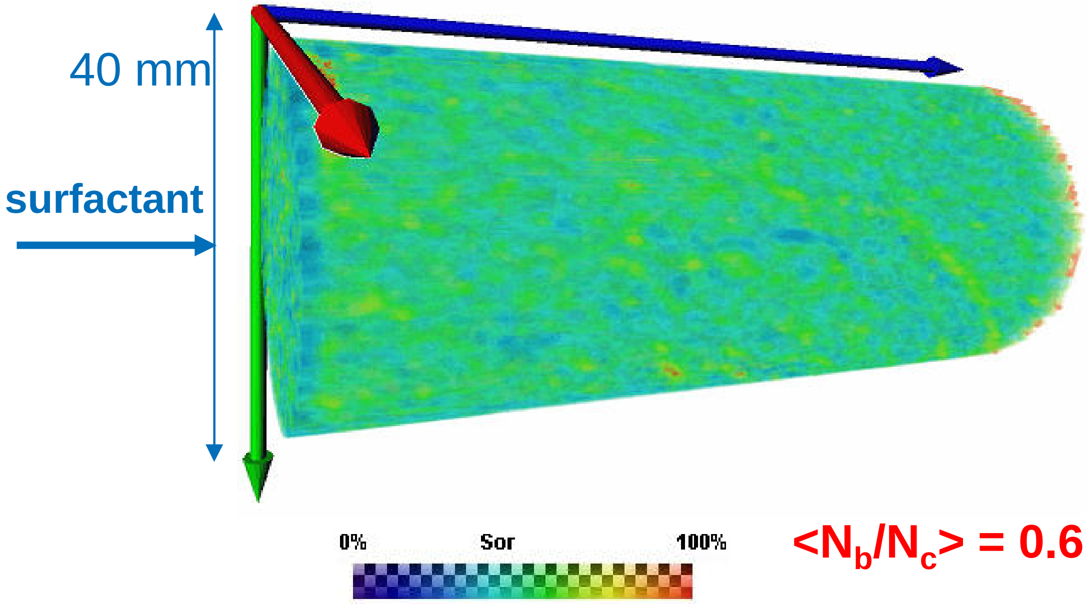
X-ray transparent cell



Initial saturation Sor 51% IFT 5 10-^{2} dyne/cm

- **3D representation of Sor**

Clashach "CL1", S_{or1} = 51.7 %



$<N_b/N_c>$ = 0.6

How to characterize the efficiency of an EOR process?

The total trapping number (Nt) was introduced to combine capillary and Bond effect:

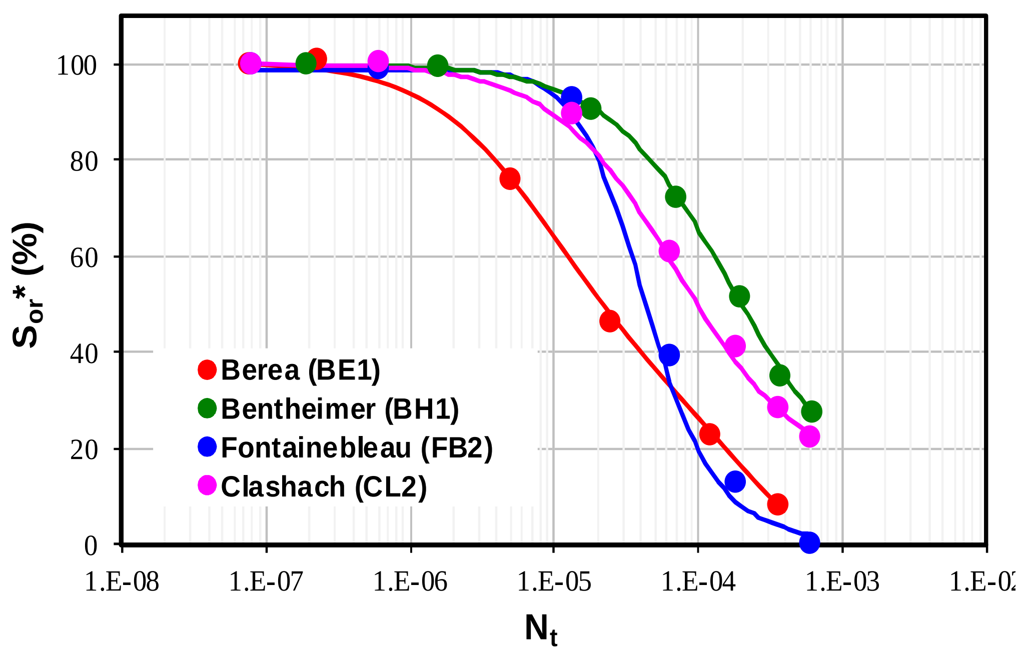
$$N_t = N_c + N_b$$

Capillary Number:

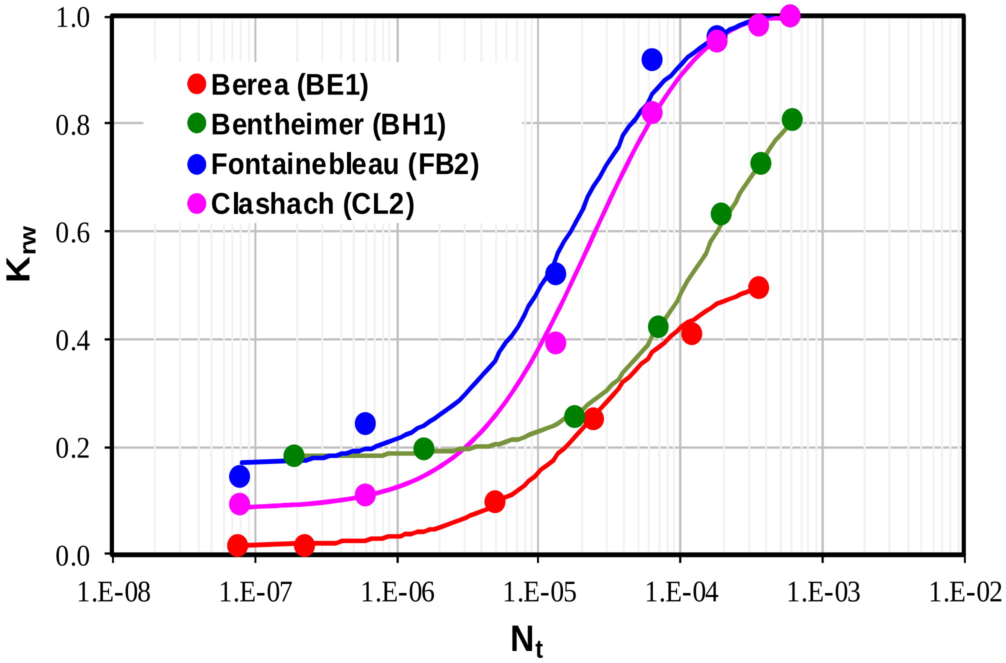
$$N_c = \frac{V \mu}{\sigma \cos\theta}$$

Bond Number:

$$N_b = \frac{\Delta\rho \, g \, K_a K_{rw}}{\sigma \cos\theta}$$



CDC

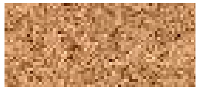


K_{rw}

What's happened at the pore scale?

How is the oil distribution at residual oil saturation (Sor) ?

Experimental sequence :



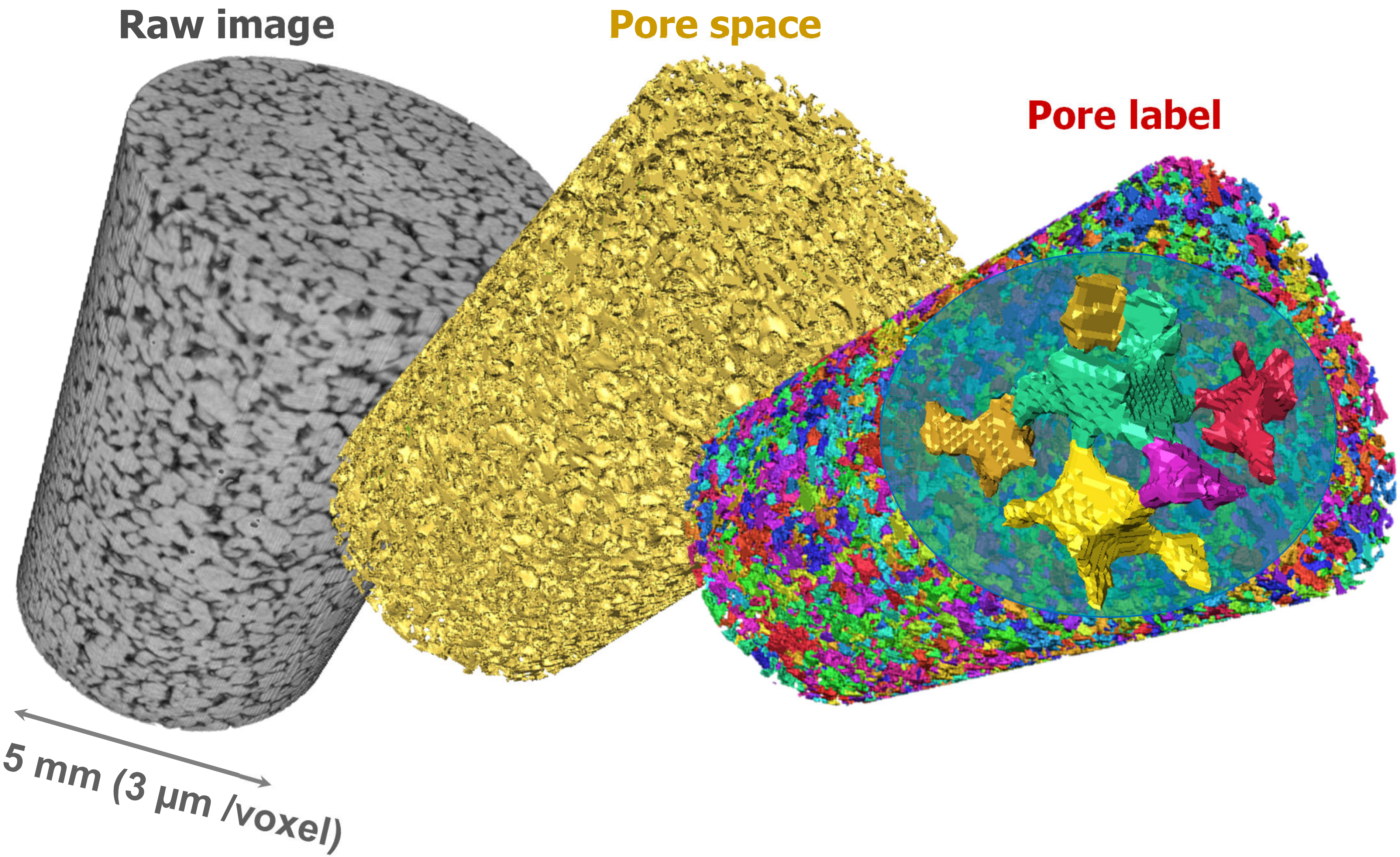
100% Brine – Oil drainage – Water imbibition

3D visualization with Lab µCT at a resolution of 3µm

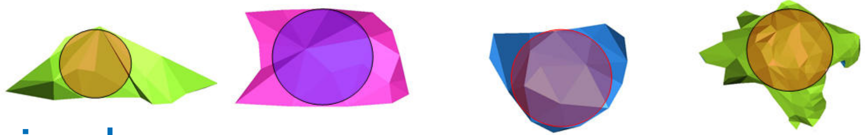
4 Water-wet sandstones

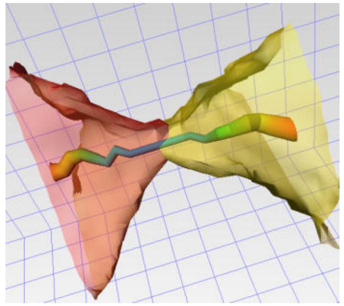
Core type	K_0 (mD)	Porosity ϕ (%)
Berea "BE1"	208	19.4
Bentheimer "BH1"	2676	22.1
Fontainebleau "FB2"	304	11.9
Clashach "CL2"	426	14.1

Pore network extraction workflow:



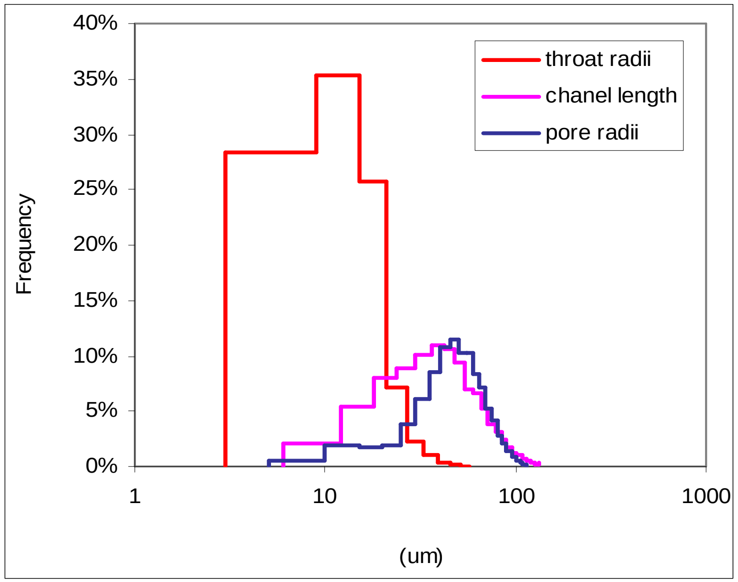
Pore scale statistics

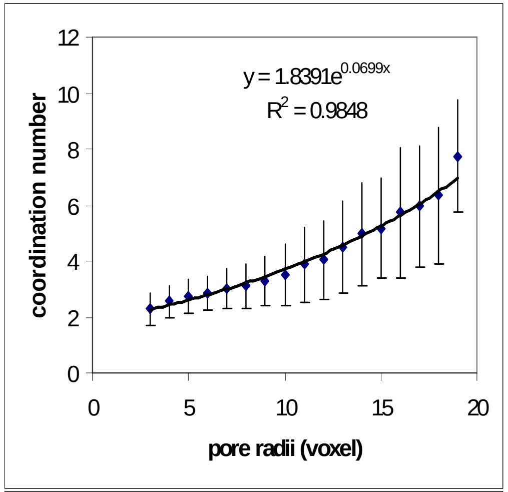


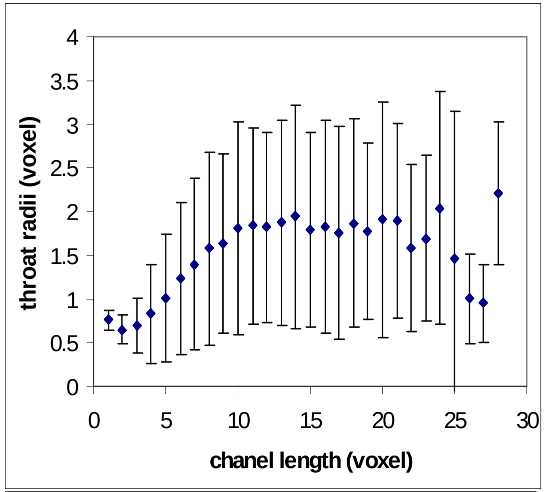


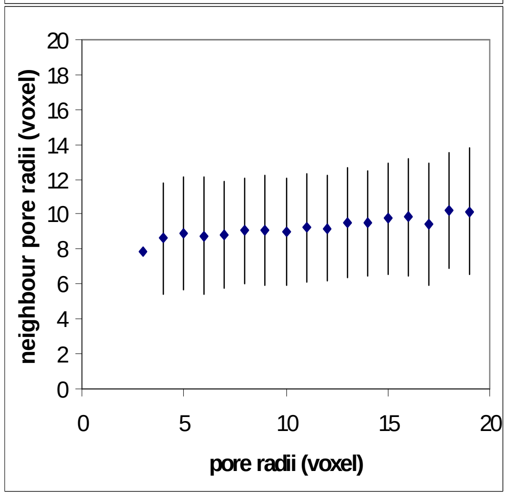
Pore data: label, volume, maximal embeded sphere radius, spatial coordinate, coordination number.

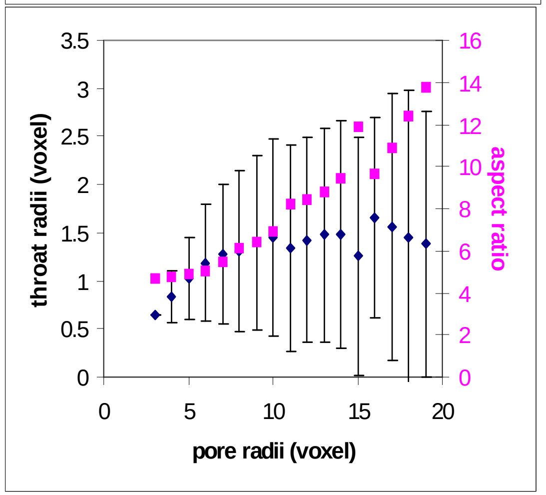
Chanel data: min radius, neighbouring pore labels, equivalent length







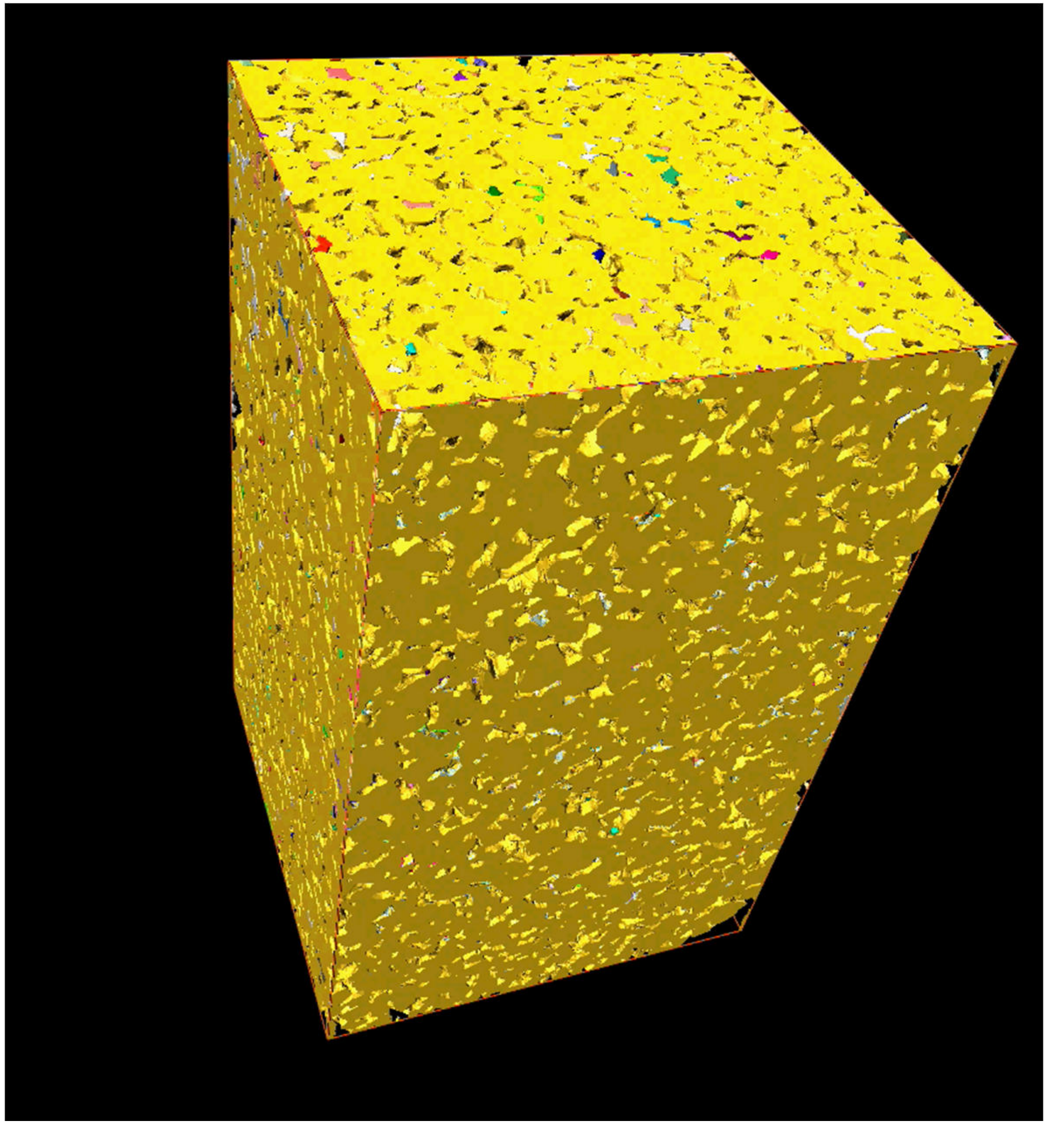




How is the oil distribution at residual oil saturation (Sor) ?

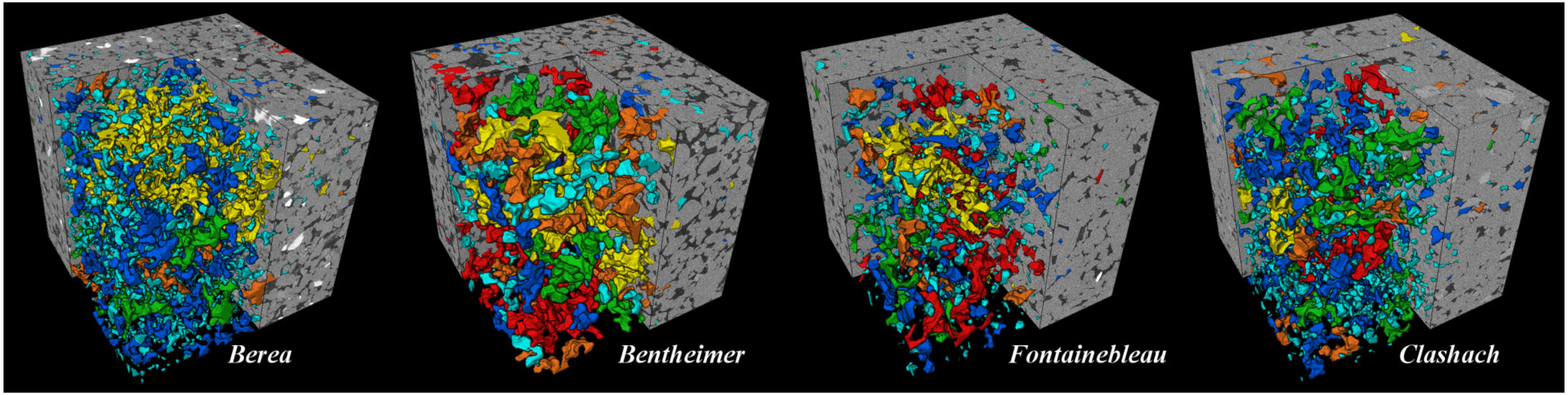
U = 30cm/day
U = 3.10^{-6} m/s
γ = 50mN/m
η = 10^{-3} Pa.s

Nc =7 10^{-8}



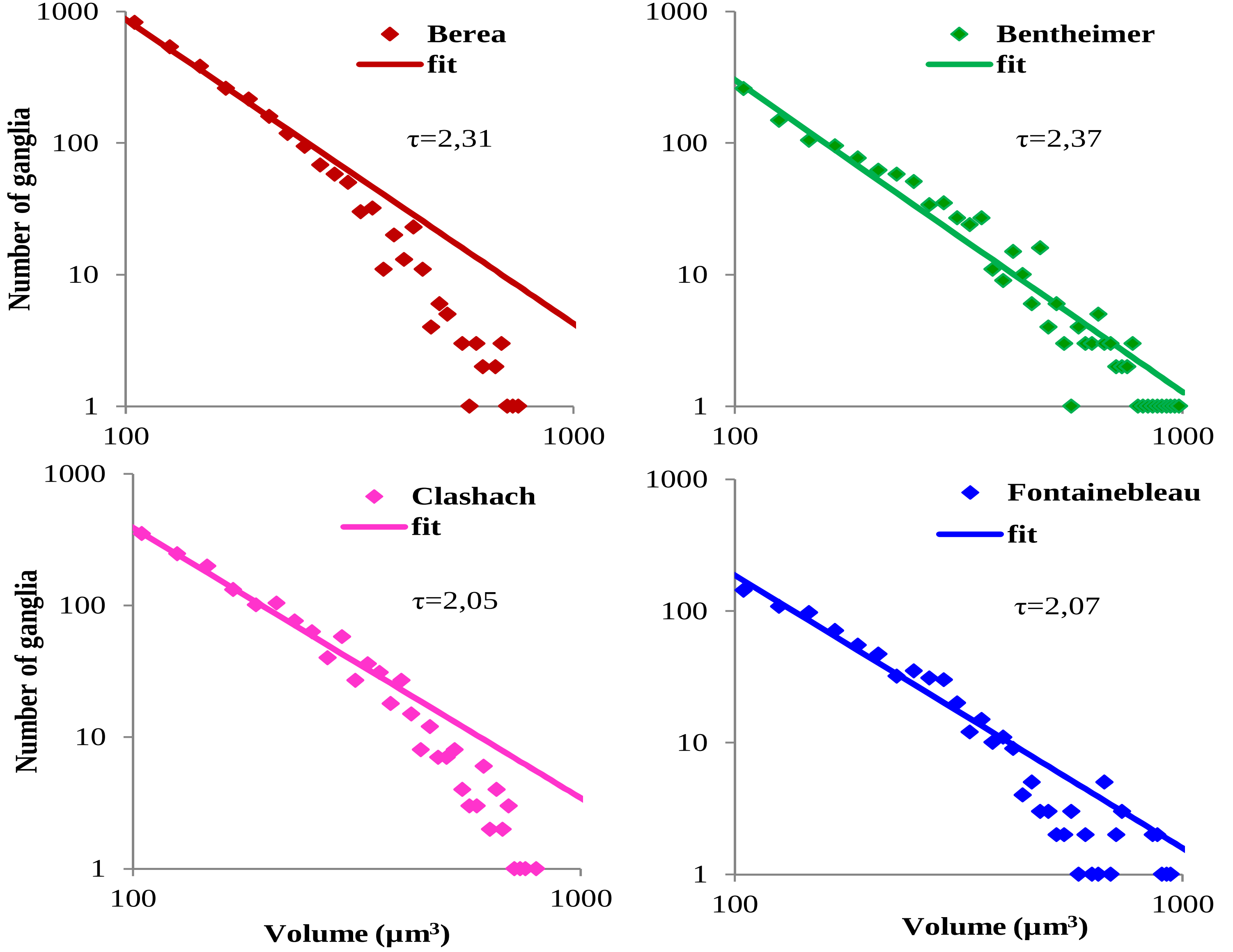
The oil phase is disconnected !

How is the oil distribution at residual oil saturation (Sor) ?



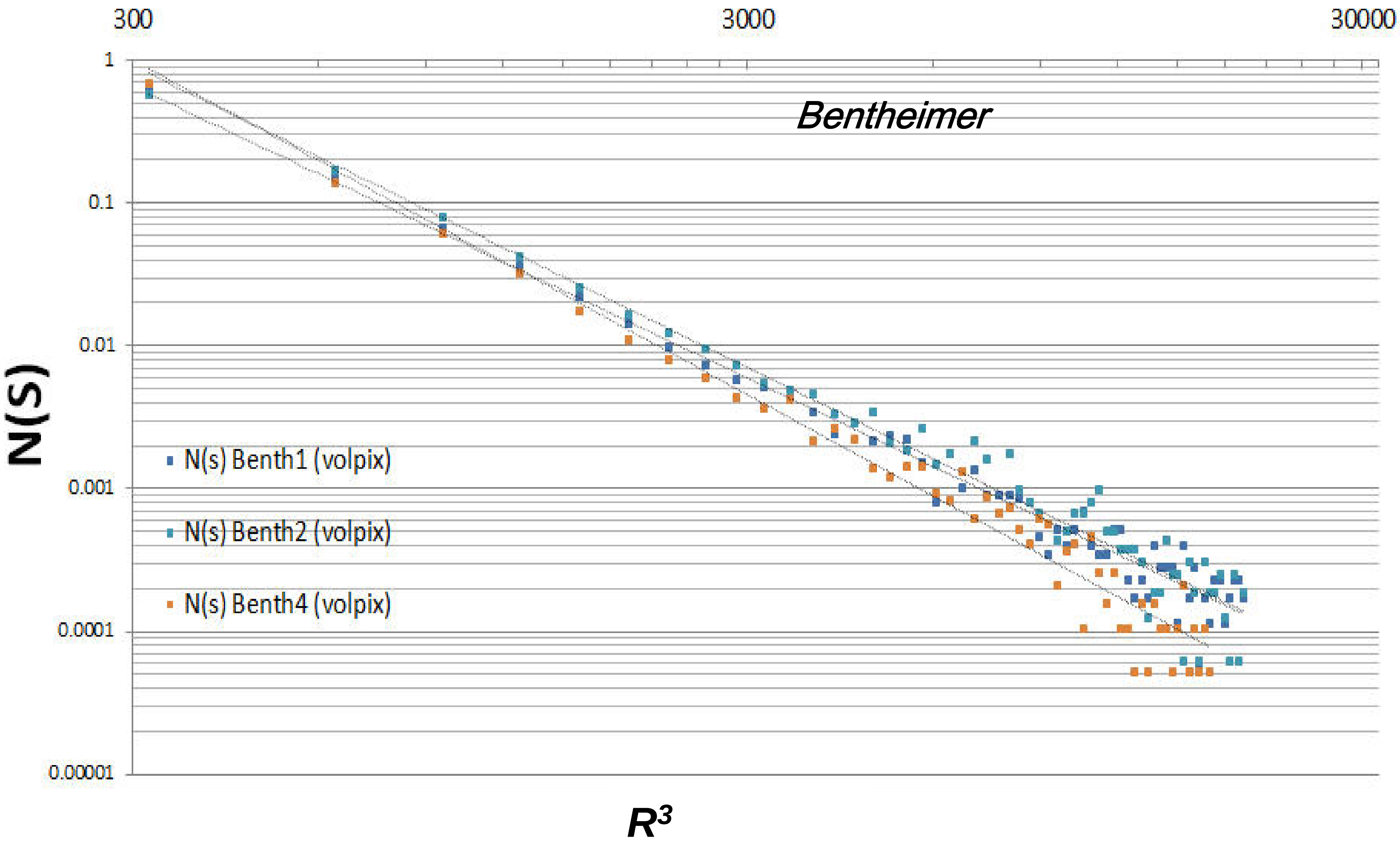
Core type	ϕ_{img} (%)	Sor_{img} (%)	R (µm)	r (µm)	R_b (µm)
Berea	17.6	45.2	28.6	10.5	31.5
Bentheimer	23.1	45.2	36.9	14.8	40.1
Fontainebleau	12.0	37.2	41.4	13.0	38.6
Clashach	10.5	58.2	38.7	12.7	37.2

Oil ganglia size distribution



Power law distribution

Oil ganglia size distribution



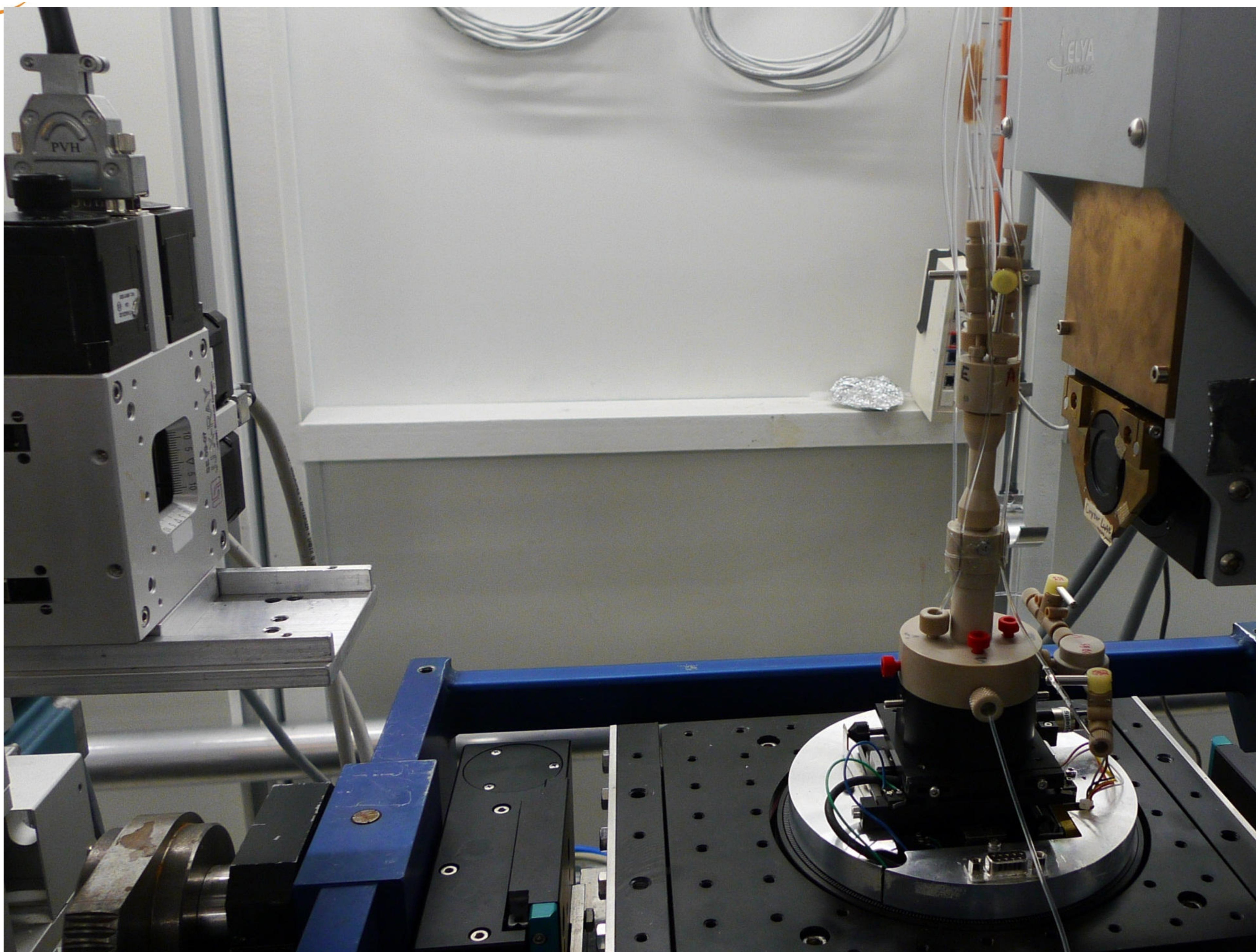
The ganglia size distribution has a universal character

How these ganglia are mobilized?

Real-time 3D imaging of fluid flow

Synchrotron facilities (SLS) at the PSI

Experimental setup



EOR process: Acquisition and sample

- Filtered white beam (peak energy around 25 keV)
- 500 projections over 180° with an exposure time of 2 ms
- Oscillatory rotation
- Field of view 1008x1008 pixels
- Resolution 5 µm
- Phase contrast reconstruction

→ **50 images at a rate of one 3D image each 3 sec**

- Bentheimer sandstone
- Porosity of 22%
- A diameter of 5.8 mm and a length of 8 mm
- Surfactant solution : Brine 40 g/l KI + 0.025%wt SDBS
- Oil : n-Decan
- Interfacial tension: Oil/Brine 40 mN/m, Oil/Surfactant 0.3 mN/m

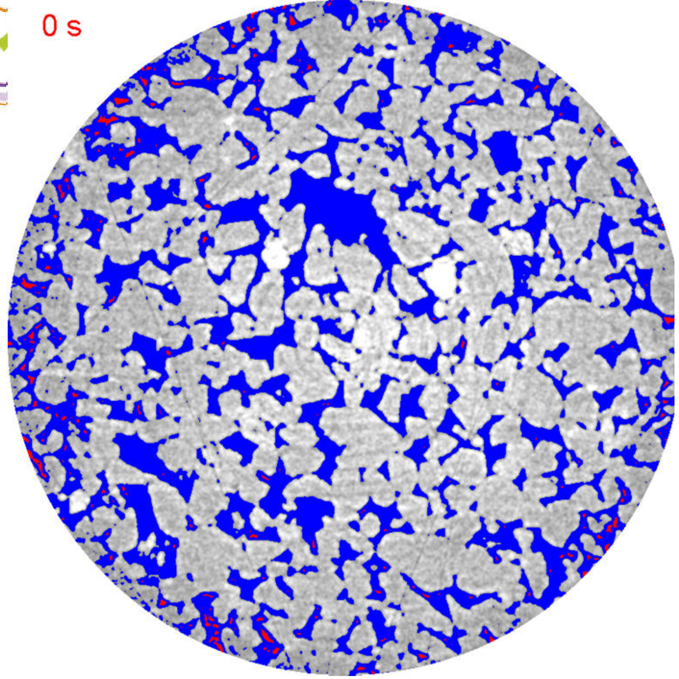
EOR process oil/brine pressurized experiment (pore pressure 4 bars):

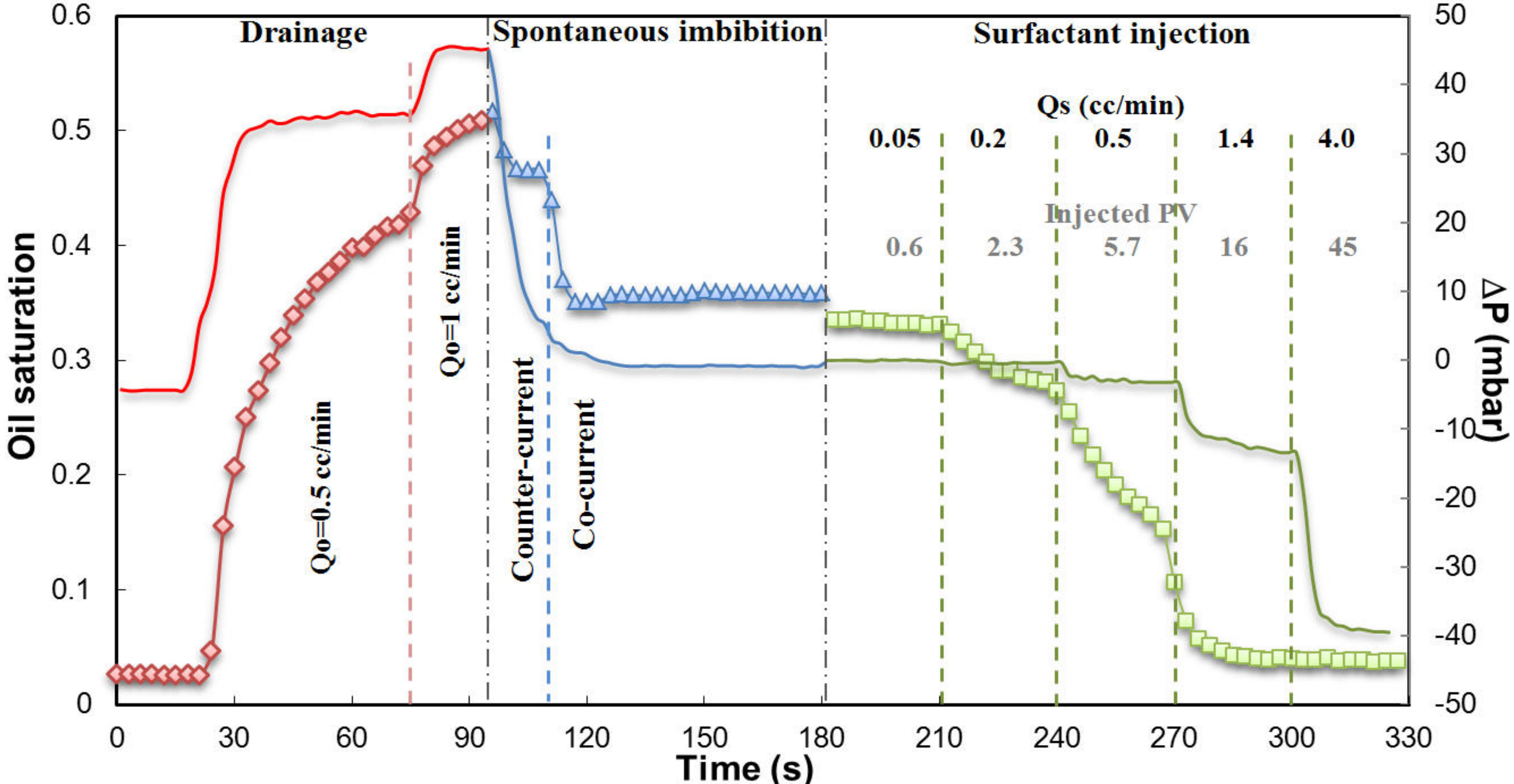
Three acquisition cycles are conducted during the flooding experiments:

Drainage with n-Decan,

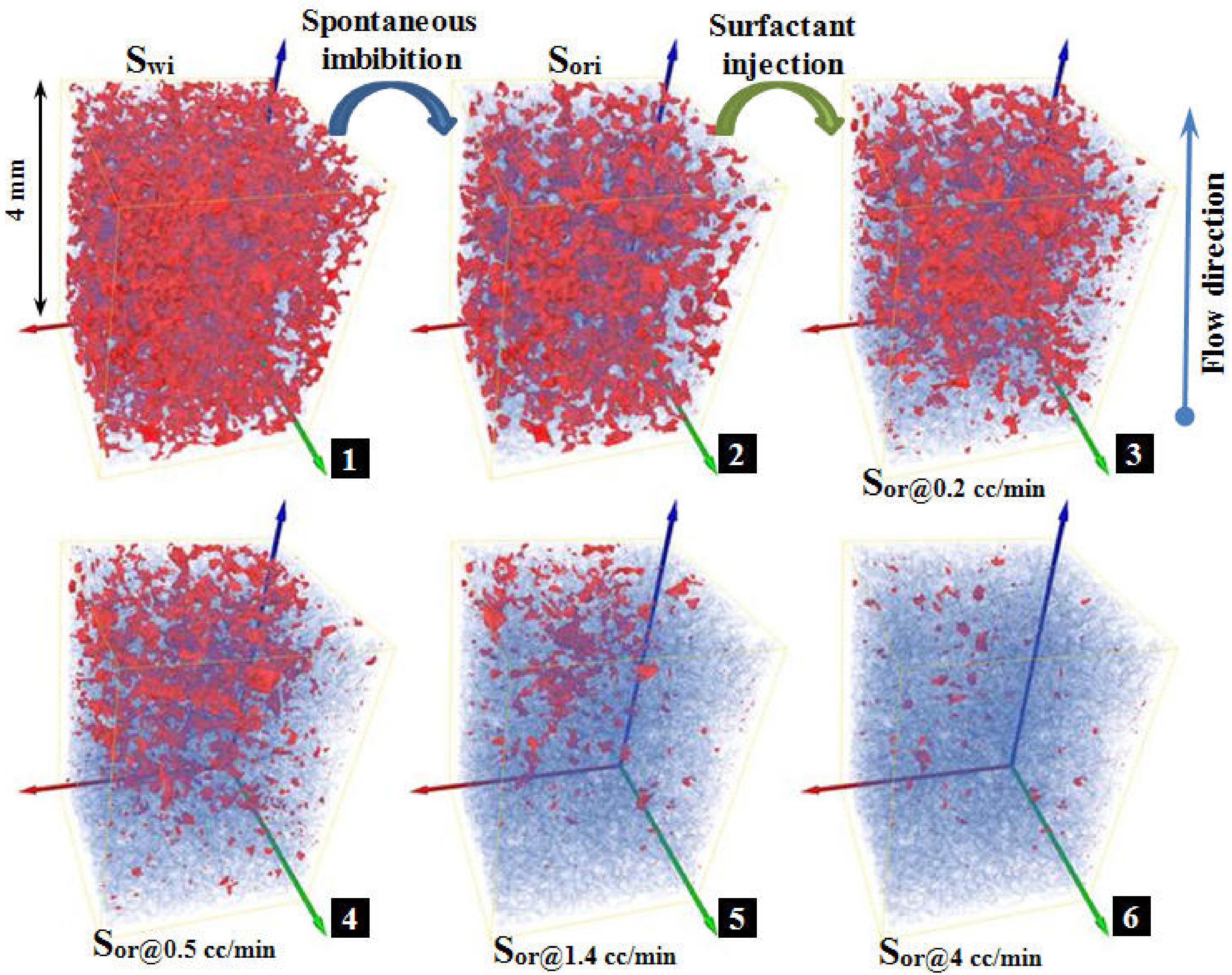
Imbibition with brine,

Surfactant injection at different flow rate



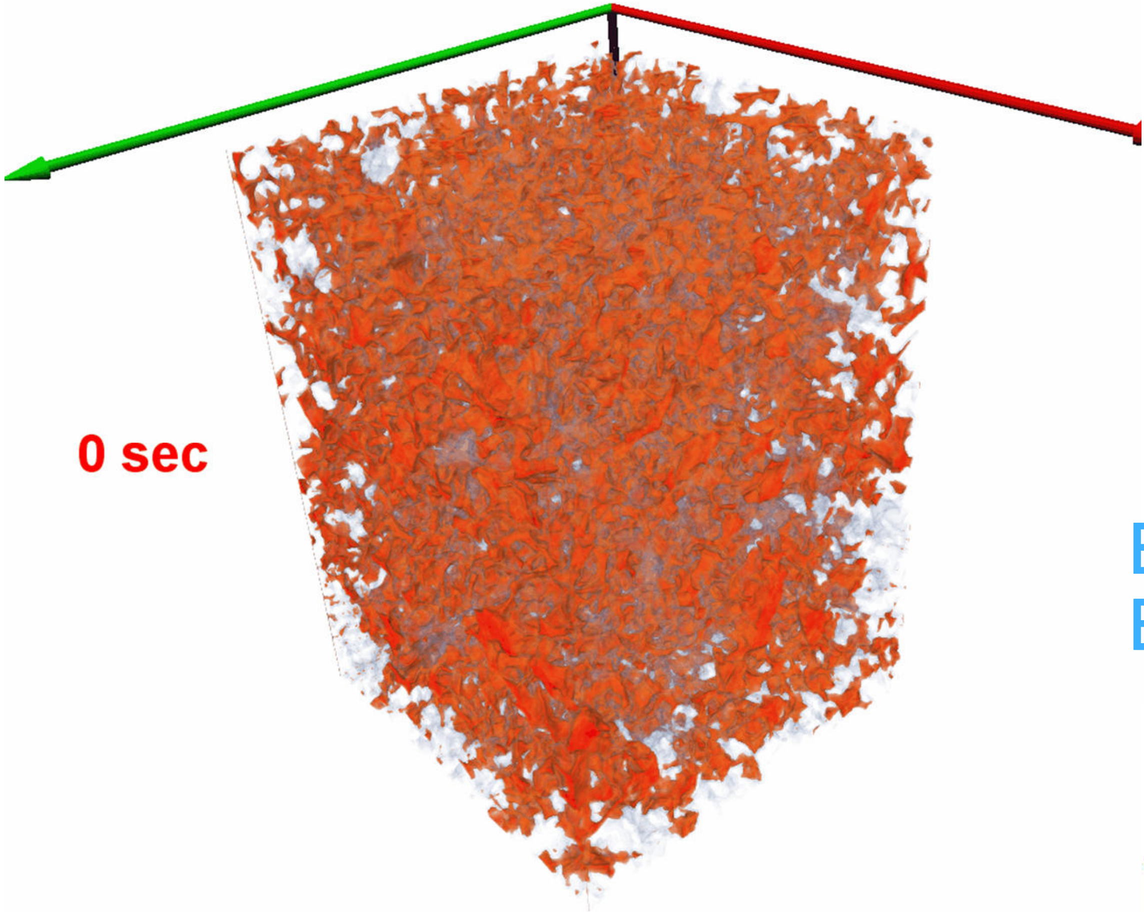


Qualitative observations

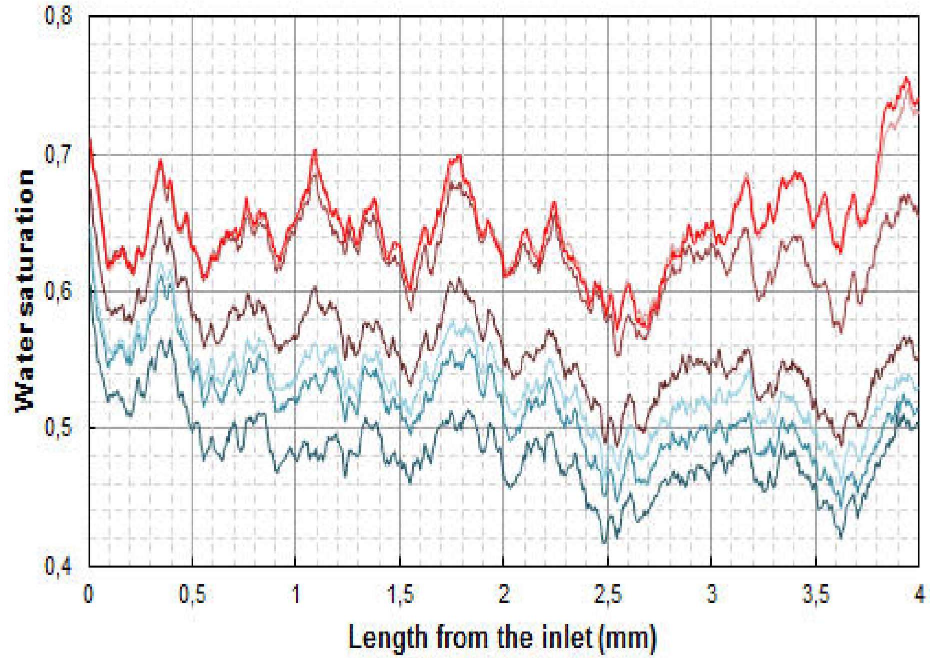


3D image sequence of the imbibition and surfactant injection process

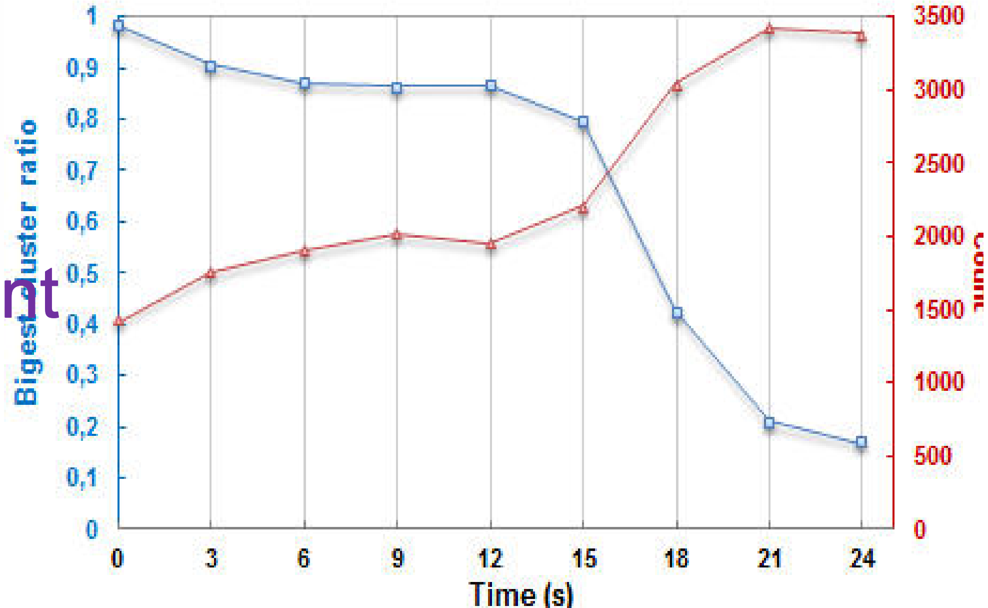
Spontaneous imbibition



0 sec

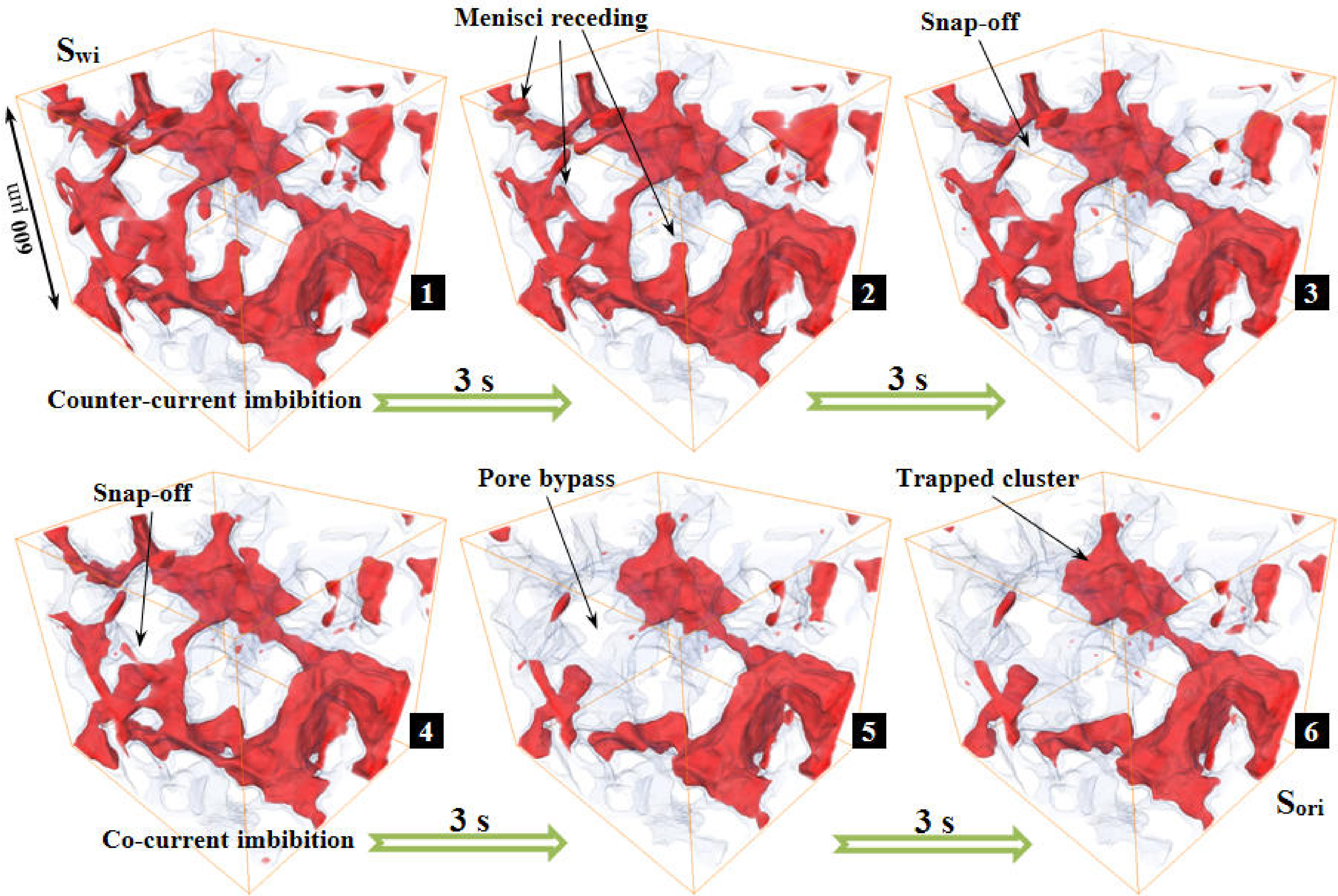


End of drainage Swi= 52%
End of imbibition Sori= 35%



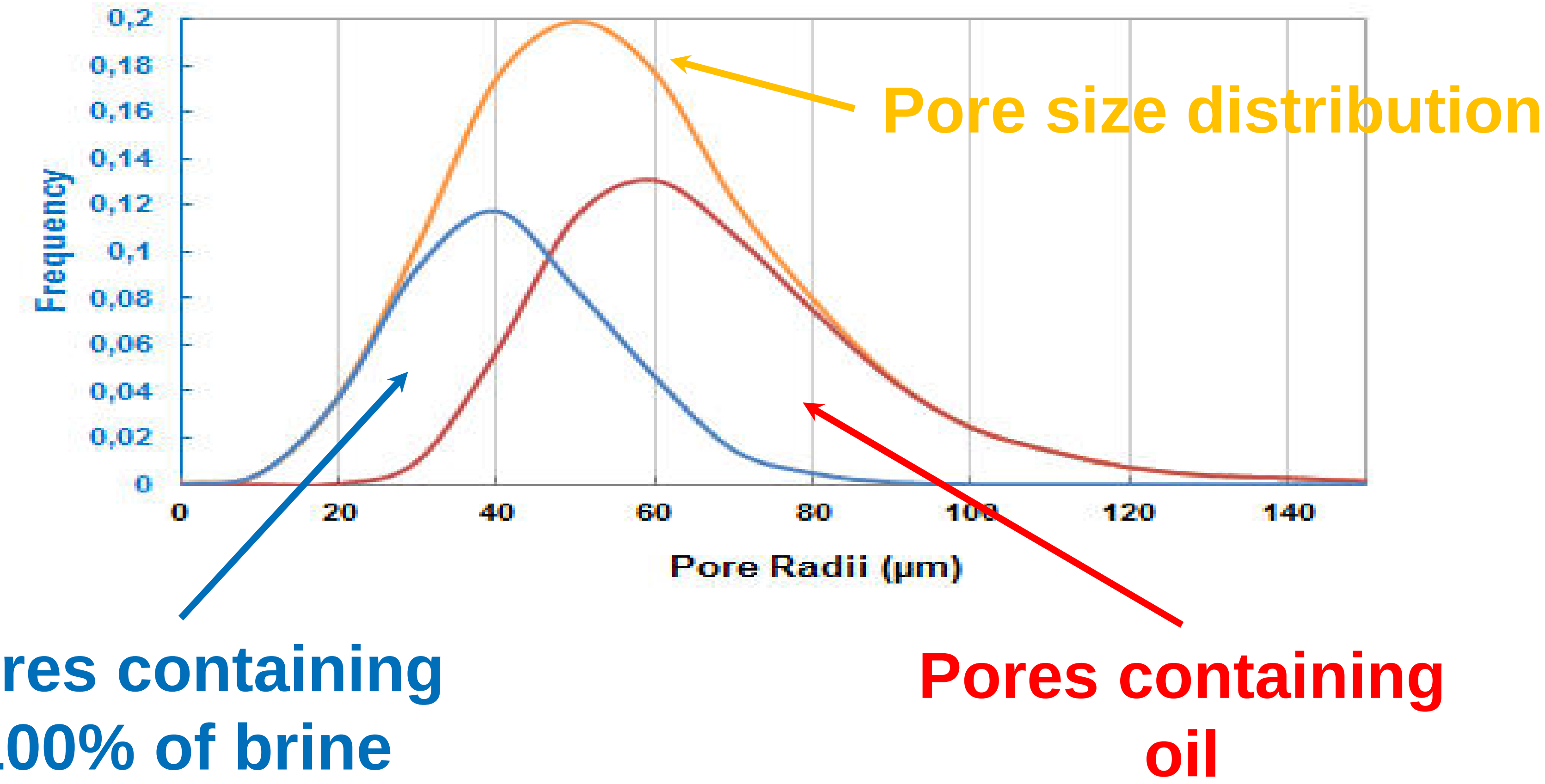
A two step imbibition: counter-current (12 s) and co-current (12 s)
Sori is reached after 24 sec

Trapping mechanisms



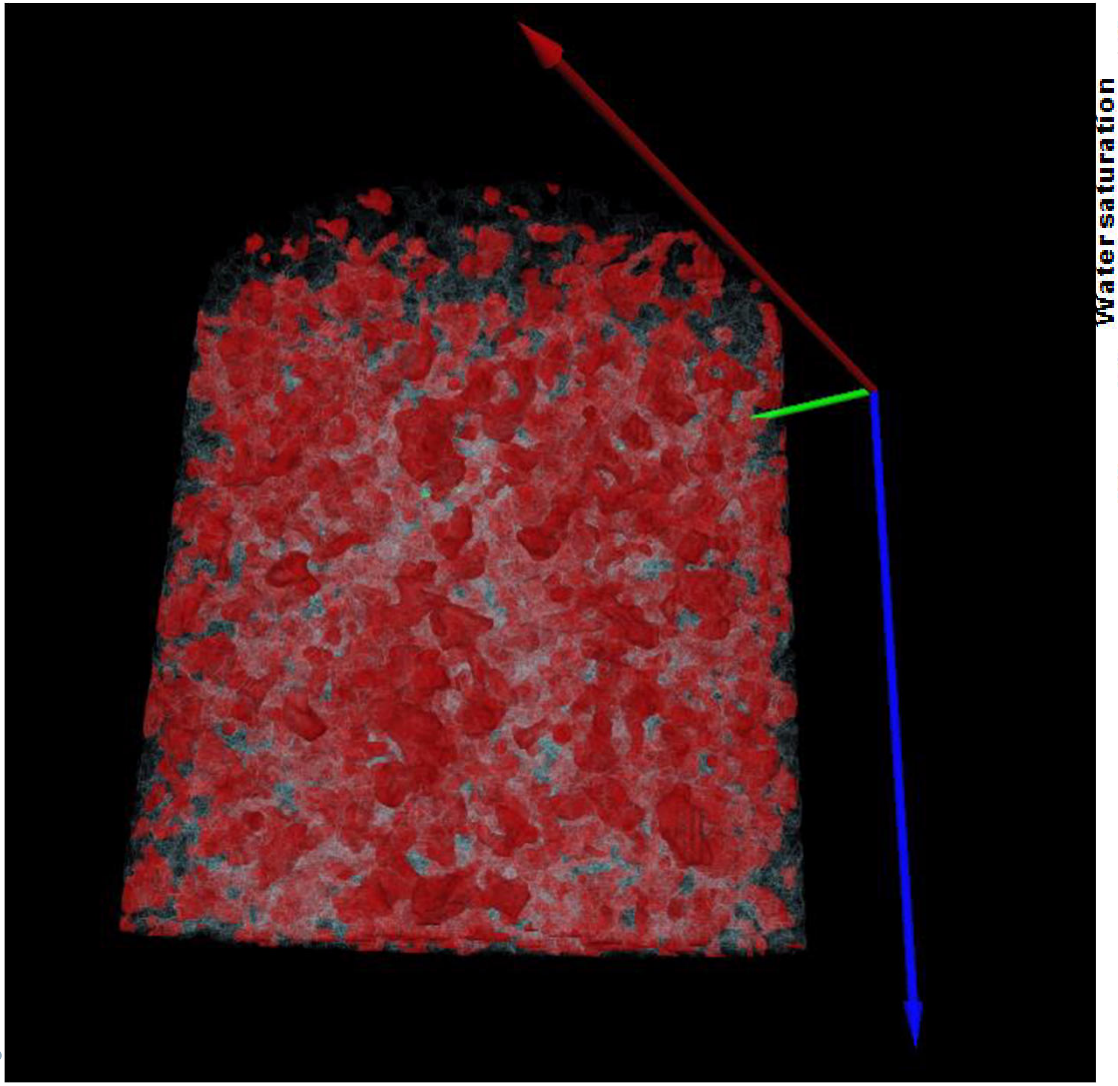
Spontaneous imbibition

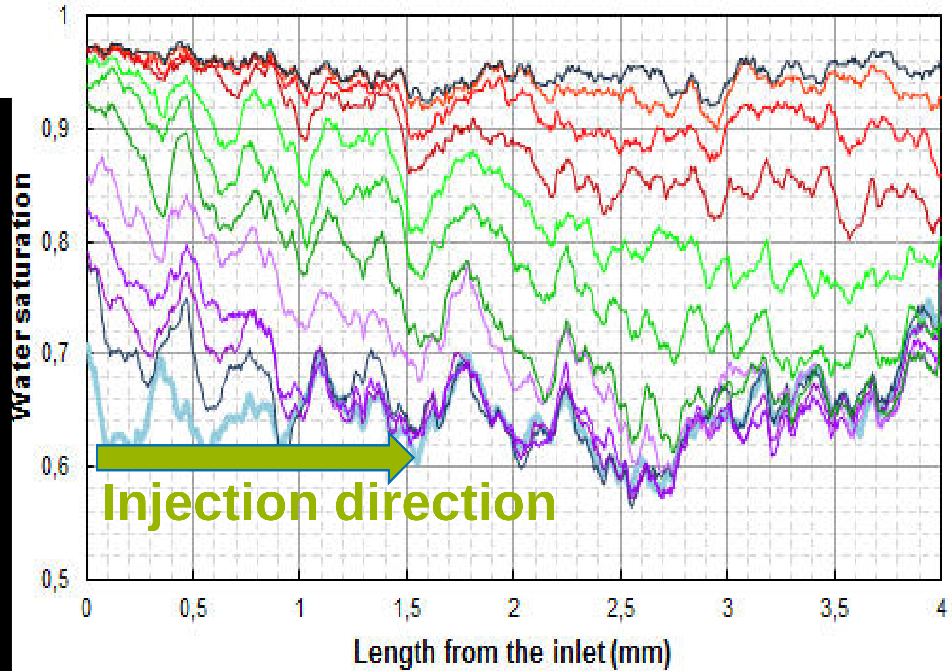
Pore scale statistics

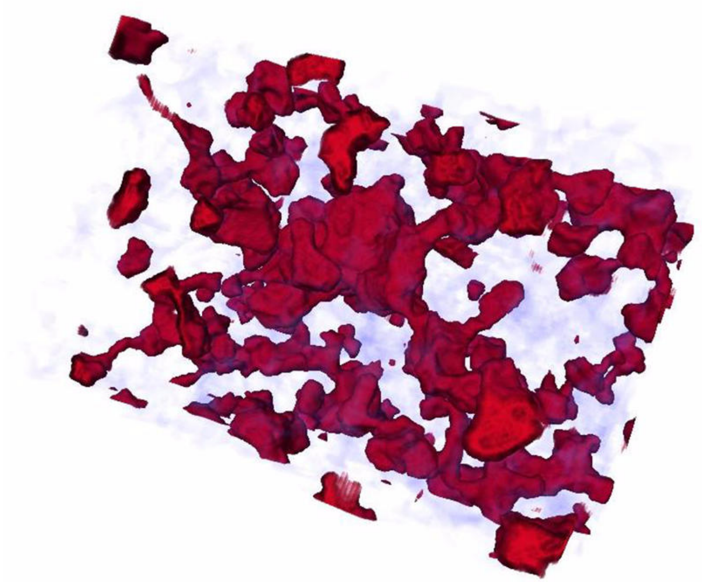


- The mean radius of the pore invaded by brine is 36.5 µm.
- The mean radius of the pore containing oil is 62.2 µm.
- This confirms the fact that oil is trapped in the largest pores (mean pore radius in the sample is 52.2 µm).

Multi- step surfactant injection



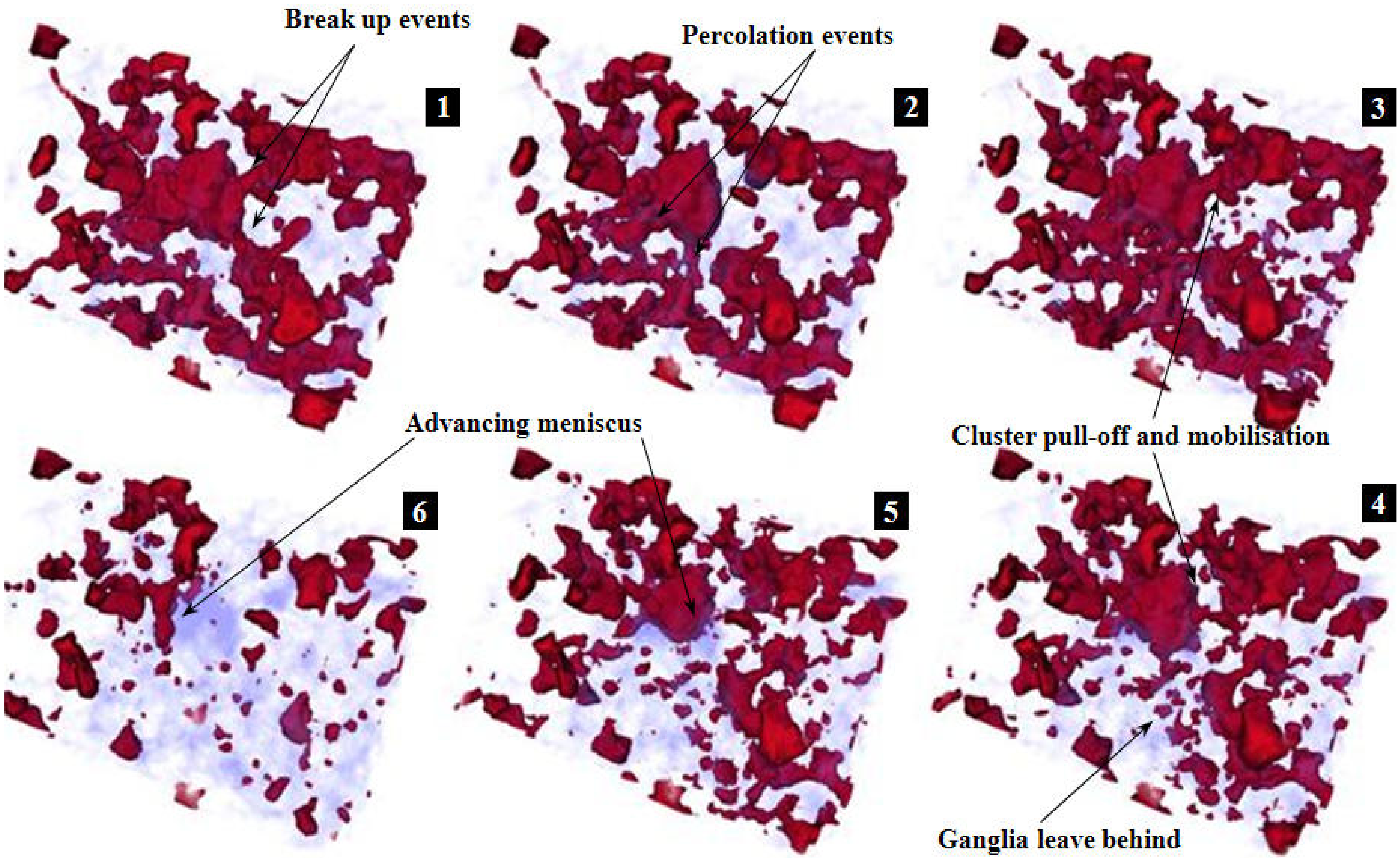




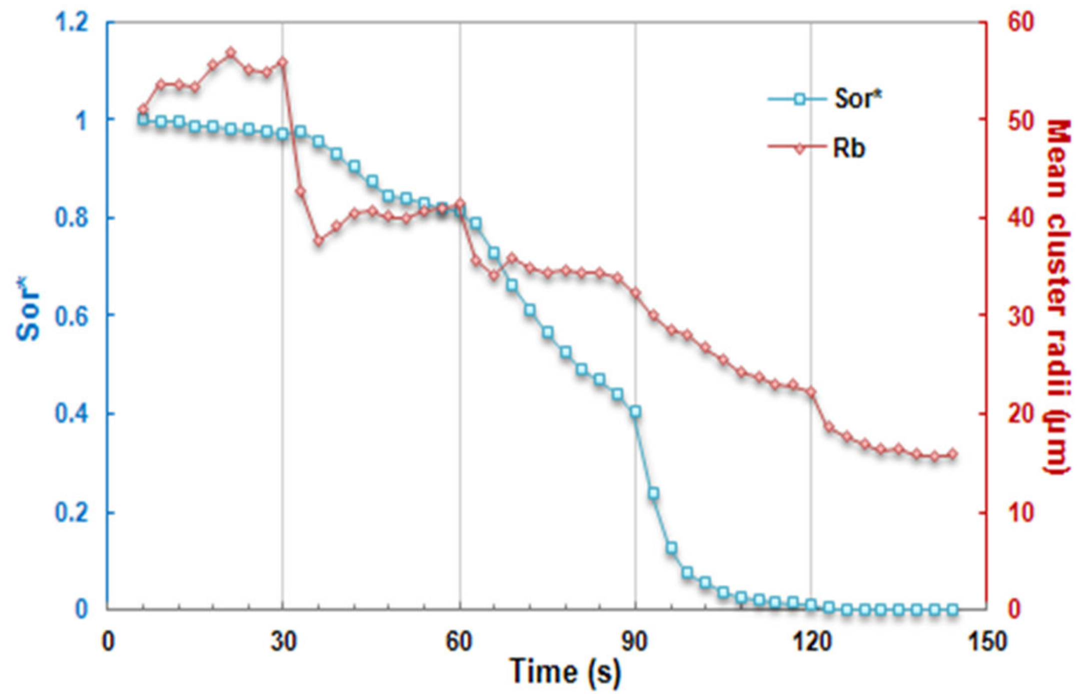
Surfactant Injection

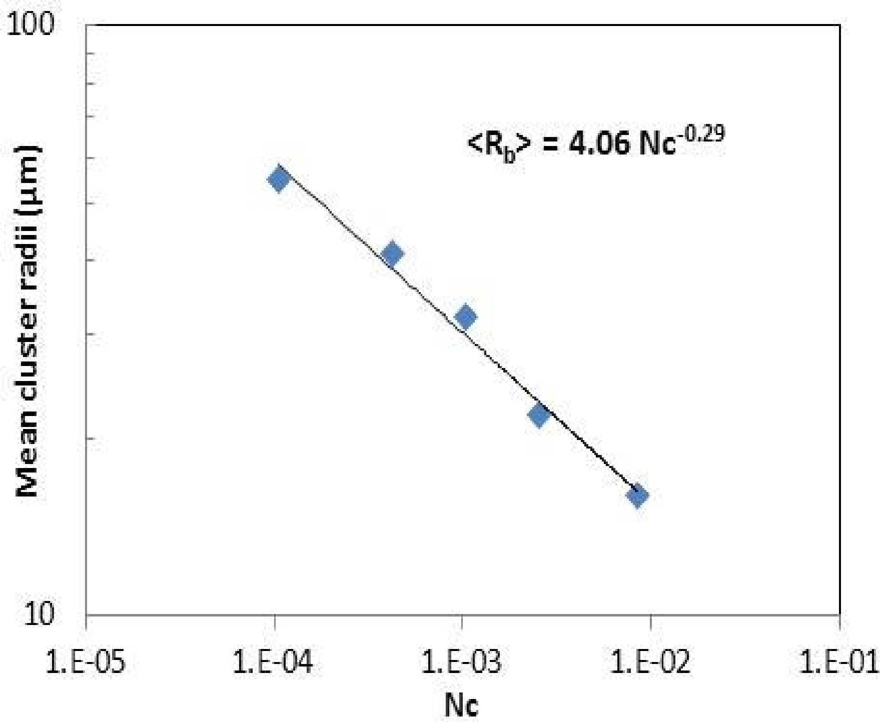
Oil ganglia dynamics

Oil ganglia dynamics



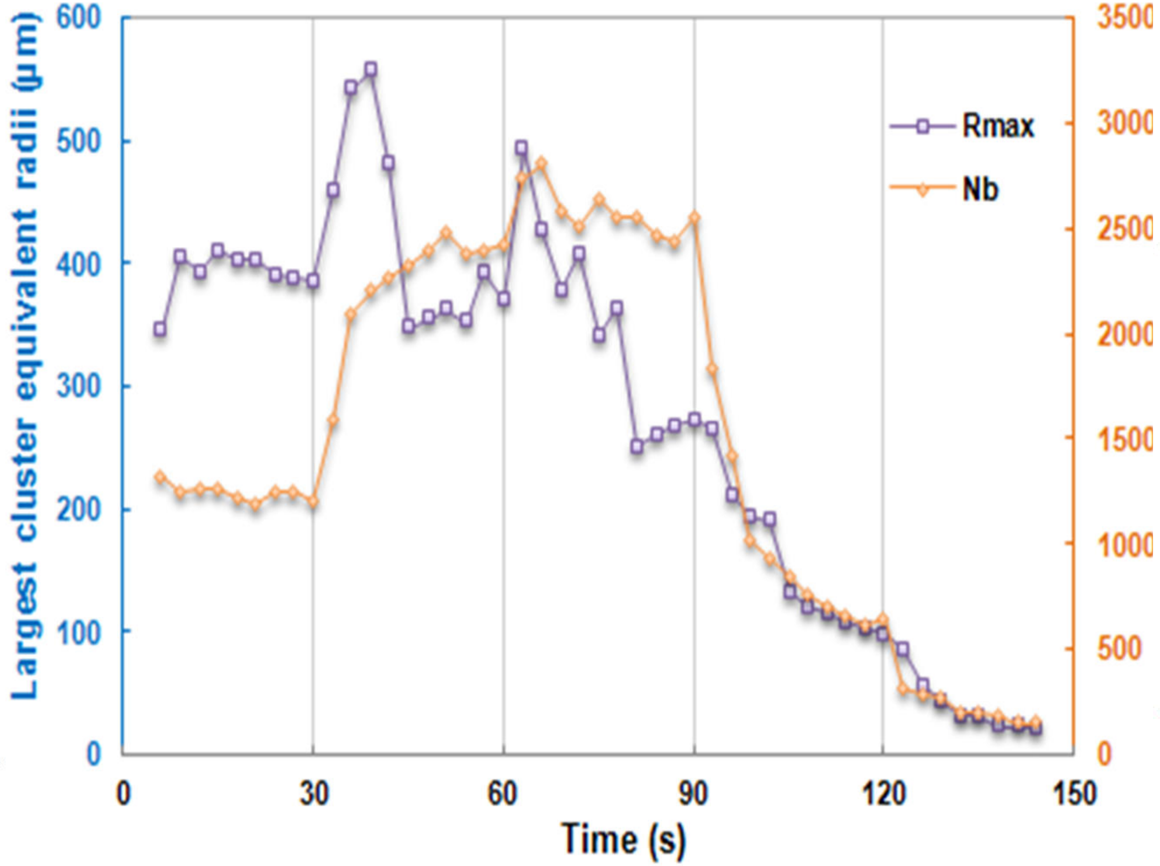
Oil ganglia population statistics

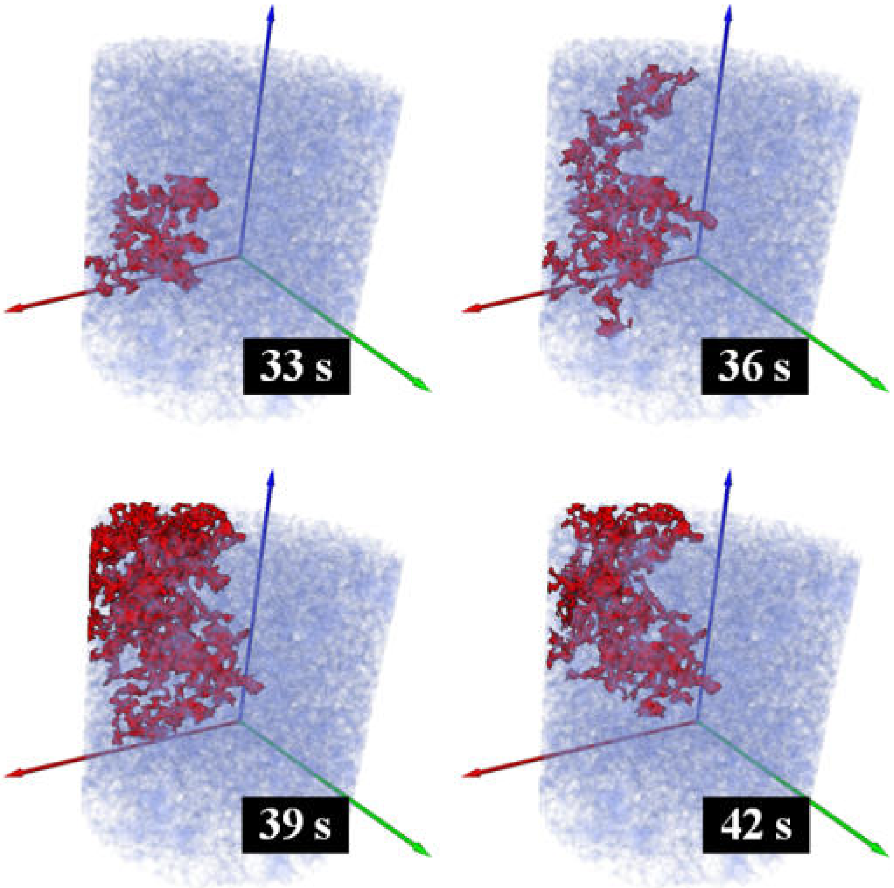




- The mean cluster size decreases at each injection stage corresponding to an increase in the capillary number.
- Steady-state mean cluster radius exhibits power low of the capillary number.

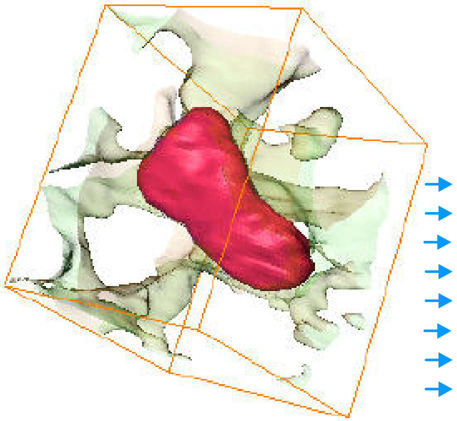
Oil bank formation



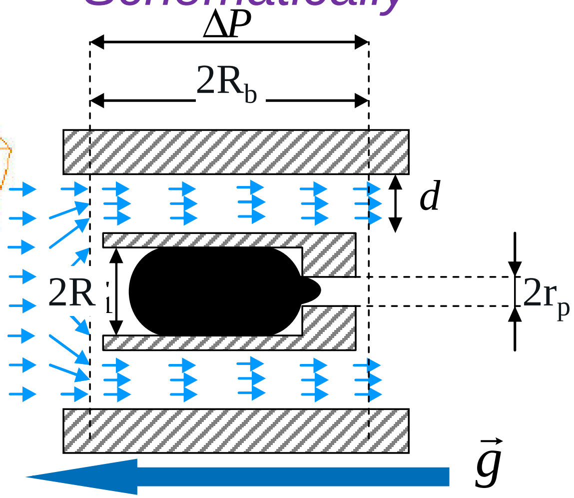


The largest cluster at different time steps

Local force balance on an oil ganglia



Schematically



The minimum pressure drop (ΔP_{min}) required to mobilize the oil blob is equal to the capillary pressure given by:

$$\Delta P_{min} = P_{w1} - P_{w2} - \rho_o g(2R_b) = 2\sigma\cos\theta\left(\frac{1}{r_p} - \frac{1}{R}\right)$$

Darcy's law is expressed by:

$$V = -\frac{K_a K_{rw}}{\mu L}\left(P_{w2} - P_{w1} + \rho_w g\,(2R_b)\right)$$

$$\frac{V\mu}{\sigma\cos\theta} + \frac{(\rho_w - \rho_o) g K_a K_{rw}}{\sigma\cos\theta} = \frac{K_a K_{rw}}{R_b}\left(\frac{1}{r_p} - \frac{1}{R}\right)$$

→

$$N_t = \frac{K_a K_{rw}}{R_b}\left(\frac{1}{r_p} - \frac{1}{R}\right)$$

As a consequence and considering $1/r_p >> 1/R$ an oil blob can be mobilized if the following inequality is respected:

$$N_t \geq \frac{K_a K_{rw}}{r_p R_b}$$

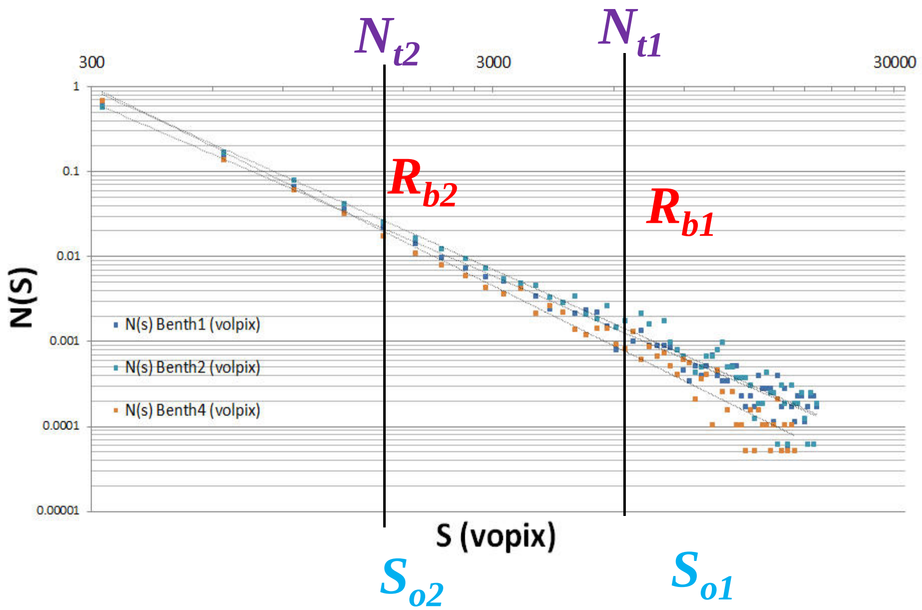
Building the Capillary Desaturation curves

$$N_t^* = \frac{N_t \langle r \rangle^2}{K_a K_{rw}} \geq \frac{\alpha \langle r \rangle^2}{R_b^2}$$

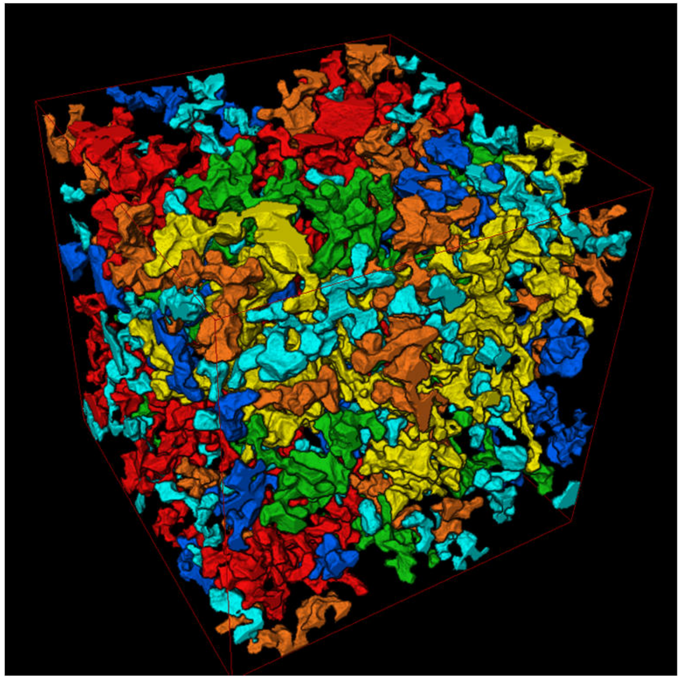
At a given reduced trapping number N_t^* corresponding to a given R_b all the ganglia with a size greater then R_b are removed.

At the micro-scale $S_{or}^*(N_t^*)$ in the mini plug can be predicted by:

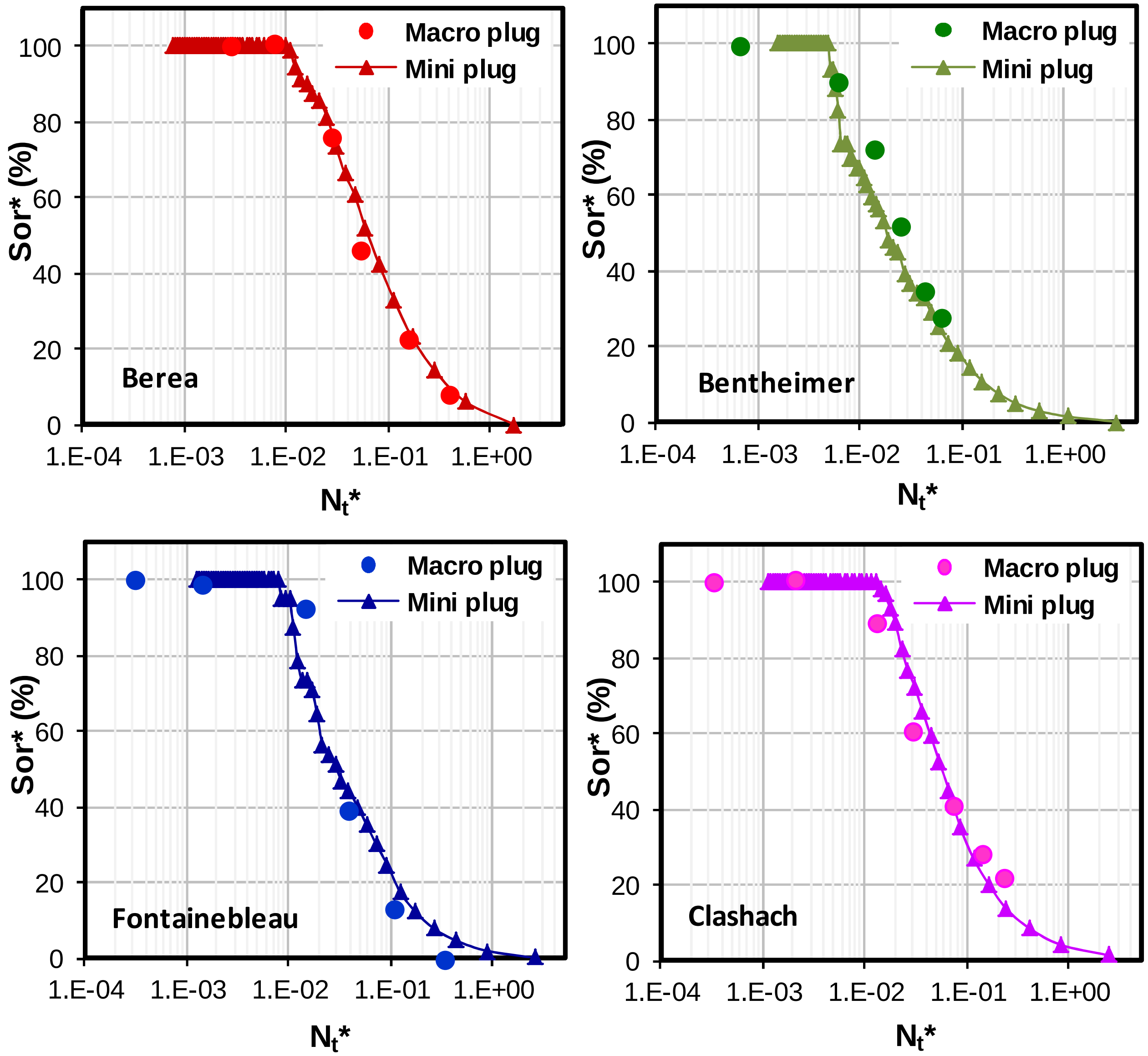
$$S_{or}^*(N_t^*) = \frac{4\pi}{3V_{ori}} \sum_{R_{bi} \leq R_b} R_{bi}^3 \, f(R_b = R_{bi})$$



Oil ganglia zise distribution at Sor



Comparison of the predicted CDC using the microscopic model and the CDC measured on the macro plug and the



- CDC can be estimated using structural parameter
- Ganglion size distribution is a first order parameters.

Summary

- ✓ The advance of 3D imaging techniques in combination with simulation model open a new way to investigate porous media structure and properties and gives new insights into the complexity of multiphase fluid flow mechanisms at the plug and pore scale.
- ✓ Digital and in-situ lab can be considered as complementary technique that can be fully integrated to routine SCAL techniques.
- ✓ Some critical aspects still has to be addressed, among which: the representativeness digital samples, the compromise between sample size and image resolution and more generally the upscaling from digital image scale to reservoir scale.

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