CXBOX: AN INNOVATIVE TOOL FOR FLUID DYNAMIC QUANTIFICATION DURING COREFLOODS

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ABSTRACT

Corefloods are very useful to understand the oil recovery mechanisms. These corefloods are usually monitored in petrophysical laboratory by using X-rays to visualize fluids in the rock sample. The 2D visualization and quantification of each fluids (water, oil, gas) are very challenging especially for corefloods carried out under reservoir conditions, owing to the attenuation of the environment (coreholder, confinement,..). As a result in this context, the signal-to-noise ratio is very low. Futhermore, it's usually not desirable to change the nature of fluids by adding contrast agents.

This paper presents a new apparatus, which is a cabinet X-ray system, developed to distinguish fluids in porous media in 2D, and to calculate and visualize the quantity of each fluid. This visualization is performed in a dynamic way, under pressure and temperature (up to 650 bars, 155°C), with quite substantial rock sample sizes (up to 100 mm diameter) and all that without having to change the nature of the fluids (by chemical doping for example). The association of all these features makes this equipment innovative.

Instead of trying to increase the signal with a contrast agent, this equipment includes some systems and methods to minimize the noise. By monitoring a coreflood with this system we obtain a picture of the rock sample in grayscale, similar to a medical radiography. The amount of fluids present in the rock is calculated from this radiograph. A false color image is then created that represents at a particular time t the amount in percentage of fluid present in the rock. An image of the rock sample can be produced every second, so we obtain in this way a succession of images (a film) that allows to see changes in fluid saturation in the rock sample at all stages of the core flooding experiment.

INTRODUCTION

Core flood tests are widely used to produce datasets that serve in reservoir simulations (relative permeabilities) and also help test, understand and improve production techniques. During these tests, a rock sample is placed in a Viton sleeve, sometimes wrapped in aluminum, and then placed in a Hassler-type core holder. The sample is maintained under pressure using a confinement fluid in order to ensure injection into the rock. Sensors monitor physical parameters during the experiment (pressure, temperature, density, viscosity, pH, etc.). Since the 1990s, benches are equipped as standard with an X-ray generator that produces a photon beam for measuring saturation *in situ*. The beam passes through the medium and the transmitted photons are counted by a NaI photomultiplier. Based on absorption laws (Beer-Lambert), it is then possible to discriminate and calculate the quantity of fluids crossed at the counting point by working out the difference between the number of photons counted at this particular time t with the counting reference (dry rock). During the experiment, the generator/detector assembly is moved along the length of the core sample to ultimately obtain a series of points and generate a 1D saturation "profile" (see references [1] to [6]). Such a process of obtaining the saturation of each fluid is weak (yet possible) for the following reasons:

The fluid attenuation coefficients are low compared to those of the other materials crossed. Water, for example, has a linear attenuation coefficient of around 0.2 cm^{-1} at 80 kV, whereas that of the rock ranges from 0.4 to 1 cm^{-1}, or higher, depending on the rock. In addition, the fluid length the photon beam passes through (i.e. the volume of fluid to be quantified) is relatively short in relation to the total length. In the case of a rock of 5 cm in diameter with 20% porosity for instance, the photons cross a fluid length of 1 cm (5*0.2) on a total attenuating medium of around 15 cm (rock + coreholder and confinement). As a consequence, when it passes through the medium, the photon beam is mostly attenuated by the rock sample and its environment rather than by the fluids.

Moreover, the differential attenuation between the two fluids to be discriminated is minimal: the attenuation coefficient of water at 80 kV is 0.2 cm^{-1}, that of oil is 0.16 cm^{-1}.

To summarize, the signal-to-noise ratio is low both because fluids to be discriminated and quantified are very close to one another in terms of attenuation, and because they are present in a low quantity in a very attenuating environment.

Even though challenging, this measurement can still be performed in 1D, first by limiting the attenuation of the coreholder using carbon material, but also owing to the very high sensitivity of the NaI detector. However this technique has its limitations: total counting time for a profile is relatively long (30 minutes to 1 hour depending on experimental conditions), the 1D profile cannot always be integrated when it comes to heterogeneous flows, the generator/detector assembly usually emits in the open air thus limiting the intensity of the photon beam for radiation protection purposes.

3D X-ray images during core waterfloods have been available for quite a long time [7],[8]. They are very helpful in so far as heterogeneous samples are concerned, to the extent that these samples do actually represent the reservoir (vuggy facies of carbonate reservoir for example). However, this type of *in situ* saturation monitoring represents today a very small fraction of corefloods, because CT scanning technology is 1) expensive to acquire and maintain 2) has very large footprint 3) suffers from strong limitations when medical technology is used (no vertical scanning).

2D imaging systems have been developed, but mainly for rock slabs [9]. They proved to be very useful for research purposes, but have not been used at reservoir conditions.

In this paper we describe how TOTAL's petrophysical laboratory has developed and designed a new self-protected 2D X-ray bench called the CXBOX, and the associated calculation methods, to apply to reservoir conditions on full size cores.

EXPERIMENTAL SET UP AND METHOD

Description of the way of development

The starting point of this development was the decision to replace the NaI detector with a flat-panel detector in order to obtain a 2D image. However, because this type of detector is far less sensitive than the NaI scintillation detector, the development focused both on how to1) increase the intensity of the signal and 2) reduce the noise.

Several parameters can be thought of to increase the signal. As an example, two of them were discussed but finally given up:

- *Reduction in the experimental pressure and temperature conditions* to obtain a less attenuating environment: this was not acceptable owing to our objectives to continue to propose core flood tests at reservoir conditions.
- *Use of contrast agents (dopants) in one of the phases:* this was rejected due to potential impact on fluid physico-chemical behavior.

After the solutions for enhancing the signal had been reviewed, two were finally selected:

- *Regarding the resolution of the detector:* because our actual need was visualization of fluids and saturations and not of the porous environment, we decided to opt for a sensor with a substantial pixel size (200 µm) contrarily to micro-tomography requirements. This also could help reduce the acquisition time.
- *Regarding the X-ray dose rate:* a self-protected enclosure was designed to house the coreholder in order for the photon beam to be intensified while guaranteeing radiation protection.

A considerable part of the development of the new bench (fig.1) was devoted to reducing and managing noise, and having a signal as stable as possible over the time. A custom-made X-ray generator, able to emit a lasting hyper-stable photon beam, has been purposely developed. The enclosure was also designed such that the operator does not need to stop the generator or to change the configuration inside the enclosure throughout the study (for connecting pumps for example). As a result, the diffuse radiation keeps almost constant over the time and its effect significantly disappears when two images are subtracted. In addition, the technique was also made possible owing to a new type of low-attenuation coreholder made of carbon, without tie bars, able to hold rock samples of up to 100 mm and reach pressures of up to 650 bars and temperatures of 155°C (fig.2).

Setup description

This development resulted in a 2D X-ray bench called the CXBOX (fig.1), that includes:

X-ray source: a few designs with different ranges of power (from 50 to 500W) were developed in order to adapt the generator to a range of applications, especially depending on the size of the reservoir core, which first means to adapt both tension and current (as an example, with a core of 50 mm of diameter, the generator is usually adjusted to 120 kV, 1.8 mA). But most important, these X-ray generators have been designed to be able to emit during a long period without having to be stopped (several weeks) while keeping highly stable. Fluctuations in dose are < 0.5% over at least 24 hours.

Flat panel detector: amorphous Silicon and Gadox scintillator technology, with an active area of 40 cm * 40 cm, and a pixel size of 200 µm.

The coreholder is placed as close as possible to the detector, and at least 50 cm from the X-ray generator.

Development of saturation calculation methods

The flat-panel detector generates grayscale images which are the 2D projection through the entire rock. From these images, two methods were developed and tested for visualizing fluids and calculating saturation.

Calculation method 1: based on image processing

The calculation is carried out in two steps. The first consists in determining, for each fluid phase present, a reference grayscale image representing the rock that is totally saturated with this fluid. Two methods could be used to establish these references.

The simplest method involves physically saturating the rock at 100% with the fluid, then generating a reference image by averaging over several acquired radiographies (generally 10). This method is used to obtain an image of the rock that is 100% dry or 100% saturated with water. However, 100% saturation of the rock with fluid such as reservoir oil is often very complex and time-consuming especially when the sample has a large pore volume. In that case, a second method is used: the image of the rock 100% saturated with oil is simulated from previous acquisitions. First, the image of the dry rock is subtracted from that of the water-saturated rock. Then based on this 'water-only' image, the image of the reservoir oil, distributed throughout the porous medium, is simulated using the ratio of the oil (μ_o) and water (μ_w) attenuation coefficients. Finally, the image of the dry rock is added to this new image to produce a simulated image of the rock 100% saturated with reservoir oil. The equation 1 below, which is the mathematical transcription of these operations, is applied to each pixel :

$$Image\ @So_{100\%} = \left[\left(Image\ @Sw_{100\%} - Image\ Rock_{empty}\right)\times\left(\frac{\mu o}{\mu w}\right)\right] + Image\ Rock_{empty} \quad (1)$$

As the attenuation coefficients of the fluids are needed to produce these simulated images, a technique was developed to calculate them *in situ*. A standard piece in PEEK with an orifice of a known diameter is placed either side of the rock sample (fig.3). During coreflooding, images of these standards are obtained: empty, 100% water, 100% oil, etc. Based on these, the average grayscale value of the pixels in the centre of the standard piece is extracted for each saturation state. The Beer-Lambert law is then applied to this data to obtain the attenuation coefficient of the fluids in experimental conditions. For instance, to obtain the attenuation coefficient of the reservoir oil μ_o, we select a region of interest (ROI) in the centre of the orifice. Then we calculate:
N_{empty} : average gray value of the ROI when the standard piece is empty
N_{oil} : average gray value of the ROI when the standard is 100% filled with reservoir oil
l : path length of the X photons beam through the standard at the selected area location

As we select a narrow area in the centre of the standard, and due to the CXBOX configuration (the standard piece is facing the centre of the emission cone and it is far enough from the generator to be allowed to consider the X photons beam to be parallel in this location), we usually use the diameter of the orifice for the *l* value.

Then, according to the Beer-Lambert law, we calculate μ_o according to equation 2 below.

$$\mu_0 = \ln \frac{\mathrm{N}_{empty}}{\mathrm{N}_{oil}} / l \qquad (2)$$

Once the reference images have been determined, we can then move on to the next step.

During the core flood tests, images of the rock are acquired at regular time steps (e.g. every 10 seconds). For each image, the fluid saturation level in each pixel is calculated based on the gray value by linear regression using the reference images. Equation 3 illustrates the calculation used to establish the water saturation (Sw):

$$Sw = (N_{oil_{ref}} - N_{measured})/(N_{oil_{ref}} - N_{water_{ref}}) \qquad (3)$$

The saturation is then represented by a false color image. By repeating this operation, we obtain a false color film representing the change in saturation in each pixel. This allows us to monitor the changes in a flood front while continuously calculating the quantity of fluid present in the porous medium. IT tools were developed to calculate from these images the fluid saturation in a pre-selected zone and then to extract the data or present them in graphs.

In this application, a linear regression can replace a log linear regression because of the low difference between the attenuation coefficients. This simplification allows us to use a simple imaging software during coreflood and then follow the evolution of saturations in a simple way. After using this calculation method to interpret numerous coreflood tests, we observed that in most cases, we ended up with the same results as those obtained with a material balance. In a small number of cases, however, the results were substantially different from those of the material balance (five saturation units). This usually happens when a study lasts several months: although the system is relatively stable and the fluctuations are corrected (effect of the temperature variations on the flat-panel, temperature variations of the coreholder, etc), these fluctuations cannot be perfectly compensated for. What is negligible over a short period of time is less so over several months, hence the limitation of this method when measurements are compared with references which may have been established several months before. This led us to develop a second calculation method.

Calculation method 2: using the Beer-Lambert law

Compared to method 1, this method is less affected by the fluctuations of the system because the reference used is the last state of saturation. This second method consists in extracting the information from the dose received (N), in grayscale, in a pre-defined zone (a pixel, a pixel line or the entire rock sample). The saturation of the zone is calculated from these doses by applying the Beer-Lambert law. As with method 1, the standard pieces enable to monitor changes in the fluid attenuation coefficients at all times in the injection or production circuit, and thus adapt the interpretation and calculation to changes in the fluid in the case of composition exchanges for example. The saturation of a fluid is calculated by using Beer Lambert law applied to the difference of saturation of this fluid between two states (two images). Equations 4 to 6 illustrate the calculation of oil saturation (So) during a waterflood after reaching irreducible water saturation (Swi); in this case, the Swi image (N_{swi}) is used as a reference ; the attenuation coefficients of the water injected (μ_{water}) and reservoir oil (μ_{oil}) are calculated from the standard. From Beer-Lambert law, we obtain:

$$So = So_{swi} + \frac{\ln\left(N_{current\_image} / N_{swi} \right)}{\emptyset * l * \, (\mu_{oil} - \mu_{water})} \qquad (4)$$

With $\emptyset$ = local porosity.

During the first water saturation, Beer-Lambert law gives :

$$N_{water\_initial} = N_{rock\_empty} * e^{(-\mu_{water\_initial} * \emptyset * l)} \qquad (5)$$

From equations (4) and (5), comes equation (6):

$$So = So_{swi} + \frac{\ln\left(N_{current\_image} / N_{swi} \right)}{\ln\left(N_{rock\_empty} / N_{water\_initial} \right) \times \frac{(\mu_{water} - \mu_{oil})}{\mu_{water\_initial}}} \qquad (6)$$

The calculated saturations can then be averaged and presented in a graph. One advantage of these two calculation methods is that the fluid saturation of the rock can be calculated independently of the material balance. One of the limits of this visualization technique is that it is impossible to calculate local porosity. As described with equation (5), we can calculate the product '$\emptyset * l$'. However, it is not straightforward to find out for each pixel the exact distance crossed by the X-ray photon beam through the rock sample (= l). One reason is that the relative position of the core in relation to the beam and the detector changes from a study to another one, depending on the size of the core. To make up for this shortcoming, another calculation method has been developed which consists in calculating a porosity map based on the reference images, and at least one piece of information from the material balance to calculate the global porosity. This porosity map can easily be defined when the rock is saturated with water. The image of the dry rock is subtracted from that of the water-saturated rock. We obtain an image in grayscale of the water only. From this image, we extract the average of two areas 1) the entire core and 2) the standard. As we know the porosity of each of these two areas, the image in grayscale is converted to a map of local porosity by using a transfer function.

Comment about the use of Beer-Lambert law in this application:
This law generally applies to a given energy, and the attenuation coefficient of a fluid therefore applies to this same energy too. This law has long been used to calculate saturation in porous media on 1D X-ray benches, as the NaI scintillation detector is capable of classifying the images received by energy type: it is therefore possible to obtain quasi-monochromatic information. But the flat-panel detector does not offer this possibility: the information transmitted (the grayscale in ADU) is actually a dose received, i.e. the energy of the photons of the entire emission spectrum. So we had to check first that Beer Lambert law could be used under such circumstances for interpreting the CXBOX data. Based on a great number of situations tested it could be concluded with confidence that this was indeed the case. One reason for that could be related to the high stability of the X-ray generator which implies that the spectrum arriving at the detector is highly stable over the time. Therefore the coefficients thus measured correspond to an attenuation across the entire spectrum and can be used during the entire study period. It is worthy to note that these coefficients are not transposable from a study to another because in the interim, generator and detector have been stopped and restarted, the overall configuration has changed, and consequently the spectrum received changes.

RESULTS

The new 2D bench and the associated calculation methods have since been tested on many samples, both homogeneous and heterogeneous, in standard and in reservoir conditions (up to 650 bar and 155°C). The time needed to acquire an image is 1 to 10 seconds which means that dynamic imaging can be used. Two examples of the monitoring of fluid saturation during coreflood tests, taken from three different studies on rocks of 50 mm in diameter, are presented below. Study A will be used to compare the calculation methods with the material balance, and to illustrate the results generally achieved with the CXBOX. Studies B presents a case in which it is normally difficult to discriminate and visualize the fluids present.

Study A: comparison between the two CXBOX imaging calculation methods and the material balance during coreflooding on a homogeneous sandstone sample (porosity: 21% +/- 0.2 p.u.)

Achieving irreducible water saturation (Swi) by viscous displacement with oil is illustrated in fig.4, showing images from the film obtained, each tagged with the oil saturation value. Fig.5 shows the simultaneous variations of oil and water saturation over time using method 1 and gives a comparison between the two methods of calculation. Table 1 compares the results obtained for Swi by each method of calculation with the result obtained by material balance.

Table 1: achieving Swi - Comparison of the results of the final balance using the calculation methods (methods 1 & 2) with the material balance

	Using MB	Using method 1	Using method 2
Swi (%)	26.6	26.0	25.8
Uncertainty (s.u.)	+/- 1	+/- 3	+/- 2

The subsequent operation of water injection was similarly monitored. Fig.6 provides some images from the film, with the relevant calculated oil saturation (So) values. Fig.7 focuses on the oil and water saturations over time using method 1, and shows the comparison between the two calculation methods. Table 2 summarizes the results obtained for the final water saturation level reached at the end of the coreflood.

Table 2: water injection - Comparison of the results of the final balance using the calculation methods (methods 1 & 2) with the material balance

	Using MB	Using method 1	Using method 2
So (%)	41.6	40.0	39.2
Uncertainty (s.u.)	+/- 1	+/- 3	+/- 2

As we can see in tables 1 and 2, the imaging techniques developed not only make it possible to view flow in the porous medium in 2D but also to calculate consistent saturation values independently of the material balance at all times during the coreflooding. In addition, 2D imaging takes into account the entire sample, unlike 1D techniques where only part of the sample can be investigated. Indeed, when interpreting the experiments conducted on 1D benches, we must assume that the spot measurements taken by the detector are representative of the entire sample. So, the saturation measured at a point at the centre of the sample is considered as homogeneous across the entire width of the sample at this point. This hypothesis is no more valid when the flood front is heterogeneous [9]. 2D visualization is a first step to take heterogeneity into account.

Study B: imaging monitoring of a miscible tracer test performed on a sand sample using two brines with a very small difference in X-ray attenuation (no dopant added)

The sample is 34% (+/- 0.2 p.u.) porosity. The brine concentrations are respectively: 6 g/l for water n1 and 30 g/l for water n2.

Difference in linear attenuation coefficient between the two brines is only 0.06 cm^{-1}.

The series of images taken during the miscible tracer test (fig.8), show that the two fluids can be visualized without adding a dopant, even in conditions that are not favorable in terms of X-ray contrast. In addition, heterogeneous flow (here, preferential path at the edge of the sample) can clearly be seen on this 2D imaging bench. In the present case, this makes it possible to process the information using a dual permeability model, according to the methodology developed by C.Dauba et al [10]. It is also a help for improving sample selection and detecting a technical problem.

CONCLUSION

This new bench and associated methods gives TOTAL a tool to monitor fluid changes in a porous medium, to dynamically calculate fluid saturation (acquisition time of 1 to 10 seconds per image) in conditions not favorable to imaging (pressures up to 650 bars, temperatures up to 155°C, very low X-ray attenuating contrast, samples of up to 100 mm in diameter), without it being necessary to dope the fluids. This tool is very useful for monitoring changes in fluids and characterizing recovery mechanisms in the case of flooding of heterogeneous samples such as carbonates, or in the event of viscous fingering. It is all the more valuable in that it can be used for samples with a large size. Moreover, the fact of being able to perform the core flood tests at high pressure and temperature conditions is an advantage for understanding mechanisms causing composition exchanges. As the images obtained are averaged over the entire rock, this method is currently limited when it comes to the understanding of heterogeneous material but it paves the way to the development of a new 3D bench.

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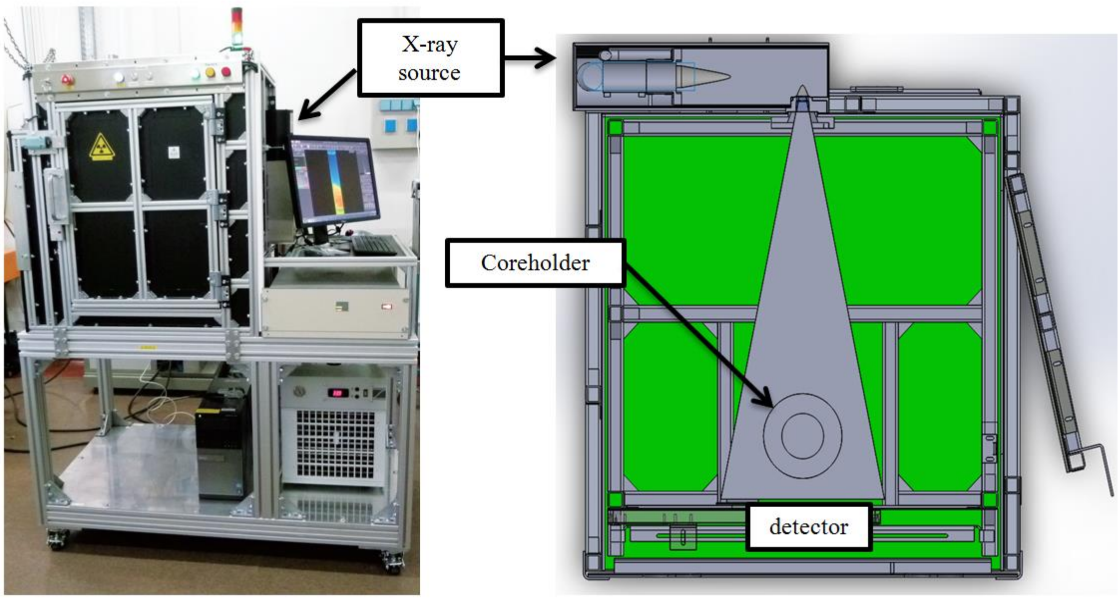


Figure 1: photo and diagram (top view) of the CXBOX1 2D bench after development

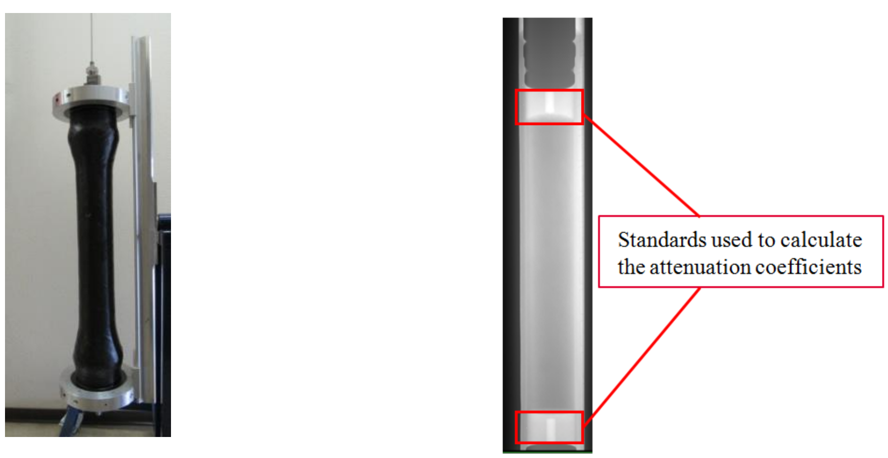


Figure 2 : example of a carbon coreholder used by the petrophysical laboratory - 650 bars, 155°C, for a sample of 50 mm in diameter and with a maximum length of 40 cm

Figure 3 : grayscale image of a sample

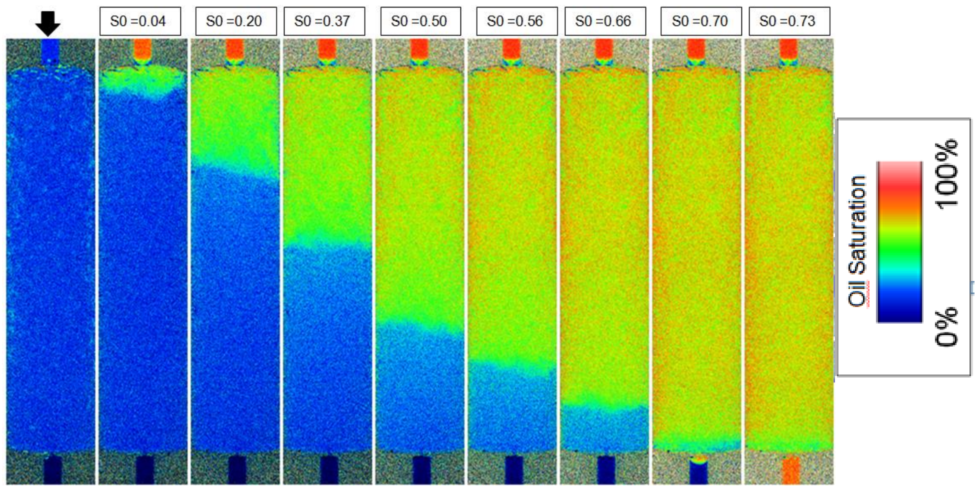


Figure 4: nine images from the film showing saturation states when achieving Swi (oil injection)

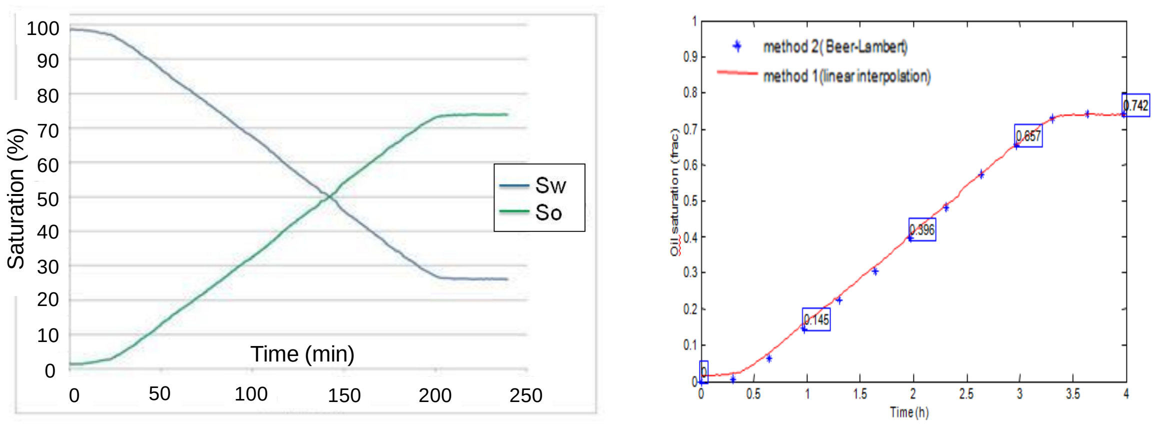


Figure 5 : achieving Swi - Monitoring oil and water saturation over the entire core using method 1 (graph on the left) and the oil saturation of the entire core using method 1 and method 2 (graph on the right)

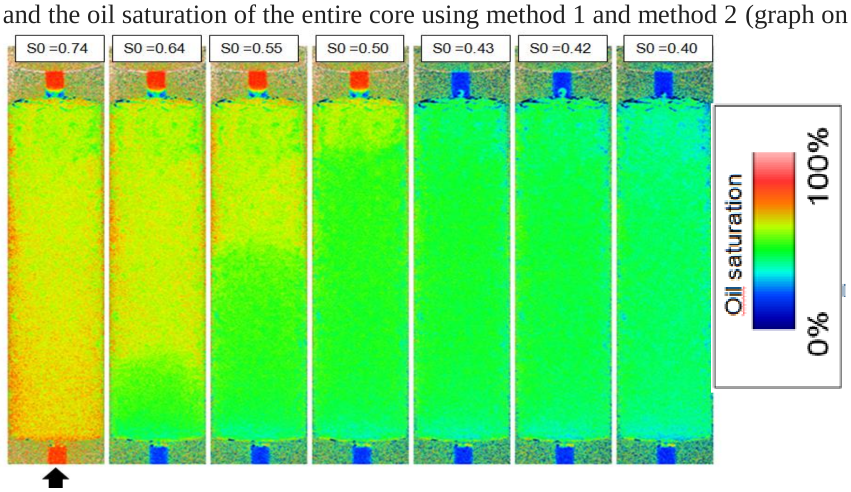
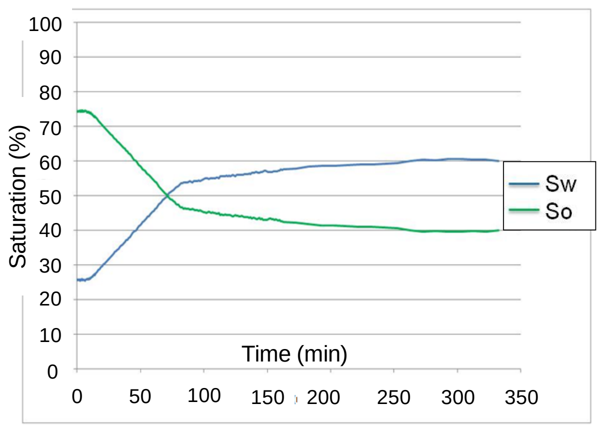


Figure 6 : seven images from the film showing saturation states taken during water injection



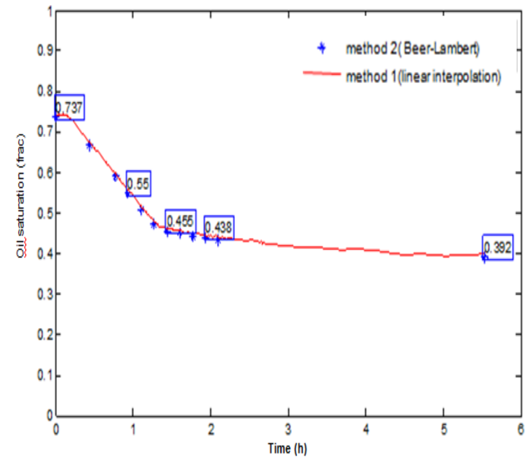


Figure 7: water injection - Monitoring oil and water saturation over the entire core using method 1 (graph on the left) and the oil saturation of the entire core using method 1 and method 2 (graph on the right)

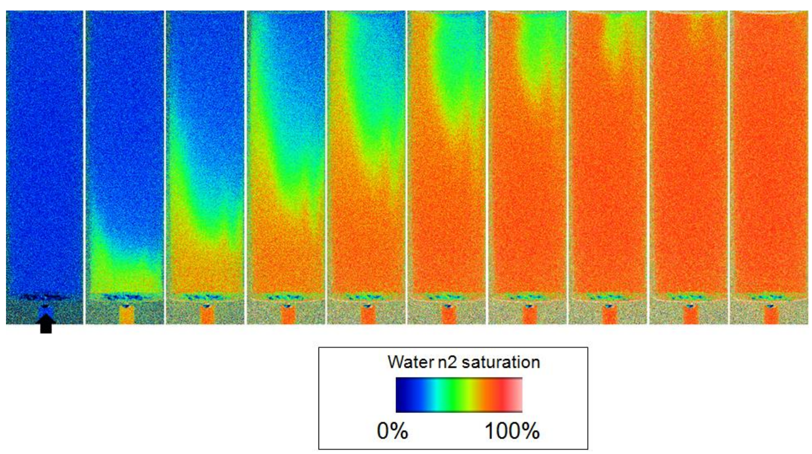


Figure 8: miscible tracer test showing a small difference in salinity between the two brines – Evolution of saturation states during the tracer test