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Study of Two Phase Fluid Flow in Water Wet Reservoir Rocks by Using X-Ray In situ Saturation Monitoring

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Abstract
Displacement of oil and water in porous media of reservoir rocks is described by relative permeability curves, which are important input data for reservoir performance simulation and drive mechanism studies. Many core studies, such as multiphase relative permeability, capillary pressure and saturation exponent determination, depend on the volume fractions of multiphase fluids present in the studied rock samples. X-ray scanners are increasingly used for measurement of fluids saturation in the core samples during core studies, mainly due to expanding need of modeling and measuring reservoir condition fluid flow behavior and its being safer issues than other radioactive sources like gamma ray. Incorporating X-Ray in situ saturation measurements into the relative permeability, capillary pressure and intrinsic wettability characterization of reservoir rocks may improve reservoir management and productivity prediction. This paper describes two phase immiscible fluid flow behavior of oil displaced by water through water wet porous media interpreted by X-ray data utility, according to saturation profile shapes incorporated by history matching of oil production and differential pressure history in low oil to water viscosity ratio fluid flow. In situ saturation profiles have been obtained with 1% saturation accuracy. The in situ saturation profiles confirm wettability character of reservoir rock samples and are an indication of the fact that initial water saturation and non-wetting oil phase values are controlled by reservoir rock wettability characteristics. The immovable water saturation increases because of oil snap-off and when light oil enters a water wet porous media, even increasing the oil injection rate cannot overcome van der Waals forces throughout water molecules. The saturation profiles have been shaped rather flat after water breakthrough. These profiles attribute to the recovery of the bulk of oil before breakthrough in low viscosity ratio displacement through water wet rocks. Besides, overlapping of various after bump saturation profiles indicates that there is no significant difference between remaining oil saturation and residual oil saturation in water wet reservoir rocks.

Key words: Relative Permeability, X-Ray In situ Saturation Monitoring, Wettability, Saturation Profiles, Irreducible Water Saturation (IWS), Residual Oil Saturation (ROS), Viscosity Ratio

Introduction
The study of oil and water displacement in porous media of reservoir rocks, which is important to reservoir performance simulation and drive mechanism studies, needs accurately representative core flood experiments and appropriate interpretation of the basic laboratory data. Relative permeability results and curve shapes are composite effects of many parameters such as pore geometry, wettability of reservoir rock, reservoir fluid composition and viscosity, rate and pressure of injection, and fluid distribution. These curves are explicit representations of fluid flow in naturally porous media.

Usually, two methods exist for relative permeability measurement in order to estimate the flow properties for reservoir grid blocks such as small field core samples in the laboratory. The unsteady state displacement method is more popular than steady state method for several reasons. Unsteady state method takes few hours instead of weeks or months for steady state method test. In addition, most of oil reservoirs produce under unsteady state flow regime and results of flow displacement can characterize of regions far away from wellbore.

Petroleum reservoir researchers infer the advantage or disadvantage for unsteady state (USS) and steady state (SS) methods of relative permeability measurements, but in any case, appropriate high quality water oil relative permeability input data is acquired during in situ saturation data interpretation for both methods. Performing the in situ saturation measurements overcomes some of the shortcomings of the USS method as well.

Many core analyses, which provide vital data for hydrocarbon reservoirs simulation and production prediction, depend on the volume fractions of multiphase fluids present in the studied rock samples. These include investigation of relative conductivity of the reservoir rock samples to fluids at specific saturations or multiphase relative permeability determination, capillary pressure measurements of reservoir fluids when different fractions of the fluids have occupied the pore spaces of the reservoir porous media, and so on. Conventionally, the saturation of fluids in the core samples is calculated by measurement of effluent fluids in the graduated vessels at ambient conditions or more accurately in the separators at test conditions, nevertheless, the corrections for dead volumes are necessary.

Measuring in situ saturation changes during core floods by an energy absorption technique such as X-ray or gamma-ray scans is becoming common [1]. X-ray in situ saturation data tends to reduce the sensitivity of some errors in relative permeability calculations. Advantages gained from the core plug X-ray scanning technique, especially at reservoir conditions, are as follows:

1) Corrections for production volumes are not necessary.
2) Saturation measurements at steady conditions from core scans can be obtained at the same time as pressure gradient measurements, requiring no time corrections.
3) In situ core saturation measurements are not affected by fluids form emulsions or slow separation [2]

The mobility ratio, which is defined as $(Krw/\mu w)/(Kro/\mu o)$, is the dominant parameter for frontal stability in oil displacement by water. The mobility ratio is estimated utilizing end point water and oil relative permeabilities. The high mobility ratio eventuates in viscous fingering of water through the displaced oil phase and this evidence is supported by many studies [3], [4], [5], though some researchers have not found any influence of fluid viscosity on relative permeabilities [6], [7].

Due to wettability alteration during core cleaning, laboratory special core analysis studies are necessary to determine water oil relative permeability at typical reservoir conditions. The experiments performed with native state, cleaned and restored state cores show the importance of measuring relative permeability on native state and restored state cores rather than on cleaned ones [8], [9], [10], [11], [12], [13].

Cleaned cores should be used only in such core analyses as porosity and air permeability where the wettability is unimportant. They may also be used in other tests when the reservoir is known to be strongly water wet [14], [15]. In addition, in order to provide better explanation of fluid flow in porous media, namely, water saturation, which also controls the relative permeability results may have to be taken into consideration. Inaccurately established irreducible water saturation, measurement of saturation and fluid production during water flood will jeopardize relative permeability results.

Water flood performance results including oil recovery, residual oil saturation, end point relative permeability to water at Residual Oil Saturation (ROS) and shape of relative permeability curves of oil wet core plugs are different from water wet core plugs. These differences are consequent upon the fluid distribution in porous media of reservoir rocks by different wettability behavior [16], [17], [18], [19], [20], [21].

This work describes interpretation of two phase immiscible fluid flow behavior by low viscosity ratio in water wet rocks by using X-ray in situ local saturation data. These data show the evidence of several physical phenomena: circumstance of IWS (Irreducible Water Saturation) profile in water wet rock by injecting low viscosity oil, displacement of oil by water, oil recovery, ROS and sharp decrease in oil recovery after breakthrough during water flood.

In this study, relative permeability curves determined by using X-ray in situ saturation data, have good agreement with water wet rock characteristics. Local end point saturations have been used for calculation. Water saturation profiles obtained by X-ray in situ saturation data are underpinning to displacement process in water wet rocks.

Phenomena and process of linear X-ray scanning

The principle of linear X-ray scanning is the attenuation of an incident X-ray beam, with initial intensity of I, when it passes through materials. This attenuation depends on the density of materials crossed by the beam. From Beer-Lambert's law we have:

$$\hat{I} = Ie^{-(\sum_{i=1}^{n} \mu_i x_i)} \tag{1}$$

$\hat{I}$: the intensity measured at the detector
μ_i: the linear attenuation coefficient of material i
x_i: the thickness of material i penetrated by X-ray beam
n: number of materials which are crossed by the X-ray beam

A linear attenuation coefficient reflects the probability per unit length for an X-ray to interact as it passes through a material and is a function of the atomic number and the bulk density of that material and the X-ray energy. [22]

From 1980's, linear X-ray scanning was widely used in the study of rock characteristics and nowadays its more advanced technique, namely X-ray Computed Tomography (CT scan), is used in some more technical aspects of core studies. The X-ray scanning is a non-destructive measurement method of characterizing rock properties and fluids saturation in core samples and without this knowledge, core scale artifacts can lead to significant errors when interpreting experimental data.

The advantage of linear X-Ray scanning to the Computed Tomography scanning (CT scan) is its much lower price and maintenance cost, easy application and data analysis, and safer X-Ray generators as they have lower voltage. But this technique has fewer capabilities. Thus, some researchers prefer to use CT scanning for more advanced studies.

Determination of X-ray in situ fluids saturation in Special Core Analysis by an energy absorption technique such as linear X-ray scanning is becoming common. Core Research Department of RIPI is equipped with an advanced two level energy one. In this system, generated X-ray source is collimated to provide a beam of 5 mm diameter. Number of photons received by the detector is the value representing the beam attenuation due to passage through the objects between X-ray generator and detector. This system provides 2 different (dual) X-ray energy levels which are needed for three phase fluids saturation. However, in this investigation, we have only used the high level of energy of the system for two-phase flow relative permeability experiments. The contrast between attenuation coefficients of fluids can be enhanced by adding dopant to one of the fluid phases.

Due to difficulty in measuring the incident beam intensities and applying the basic equation and also existing other materials being penetrated by the X-ray beam rather than the occupying fluids in the core sample, some fluid calibrations are done in order to calculate the in situ fluid saturation. The methodology of two phase fluid saturation measurement by this system in any position of a core plug sample is in the following. It should be noted that the experimental conditions, confining pressure, pore fluids pressure, temperature, and any material other than the fractions of test fluids within the beam path must be constant during every stage of the test and X-ray runs. The position of the core holder and the properties of the fluids in the core sample during the experiment are fixed as well.

$$I_w = Ie^{\sum(-\mu_m x_m) - \mu_w x_t} \tag{2}$$

$$I_O = Ie^{\sum(-\mu_m x_m) - \mu_o x_t} \tag{3}$$

$$I_{wO} = Ie^{\sum(-\mu_m x_m) - \mu_w x_w - \mu_o x_o} \tag{4}$$

I: the incident beam intensity of a level of energy in the X-ray system, which is constant

I_w: the intensity measured at the detector in photon counts/sec of a core plug fully doped water saturated

I_o: the intensity measured at the detector in photon counts/sec of a core plug fully oil saturated

I_{wo}: the intensity measured at the detector in photon counts/sec when the core plug is partly saturated with doped water and partly with oil during the experiment

$\sum(-\mu_m x_m)$: total attenuation of X-ray beam caused by the constant materials containing the core holder, confining oil and rock matrix within the beam path during every stage of the experiment

μ_W and μ_O: the linear attenuation coefficients of water and oil, respectively

x_t, x_W and x_O: total thickness of fluids penetrated by the X-ray beam, water and oil fractions of this thickness, respectively

Total thickness of fluids is total effective pore space at each slice of the plug sample being X-ray scanned and the fraction of each fluid to total void space is its saturation. From equations (2) to (4), one can do the following calculations [14]:

Whereas: $x_t = x_W + x_O$

$$\mathrm{Ln}(I_{WO}/I_O) \Big/ \mathrm{Ln}(I_W/I_O) = (-\mu_w x_w - \mu_o x_o + \mu_o x_t) \Big/ (-\mu_W x_t + \mu_o x_t)$$
$$= (-\mu_w x_w - \mu_o (x_t - x_W) + \mu_o x_t) \Big/ (\mu_o - \mu_W) x_t = x_W \Big/ x_t = S_W \tag{5}$$

In which S_W is in fraction and is obtained at each slice in the core plug sample penetrated by the X-ray beam. Equation (5) shows that we do not need to obtain the attenuation coefficients of the materials any more. Having the bulk porosity of the sample (φ_{Bulk}), the porosity (φ_i) at i[th] position along the sample is calculated from the equations below:

$$\varphi_i = \varphi_{Bulk} Ln(I_O/I_W)/Avg \tag{6}$$

$$Avg = \textstyle\sum_{i=1}^{n} Ln(I_O/I_W)/n \tag{7}$$

There are n positions along the plug sample, which have been X-rayed. In order to obtain the uncertainty of two phase fluid saturation determination, from equation (5) it is known that calculated water saturation is a function of I_W, I_O and I_{WO} [23]:

$$S_W = f\,(I_W, I_O, I_{WO}) \tag{8}$$

By differentiating equation (5) with respect to each of the above variables, one can get the following equation, which is the sum of the squares of the individual errors in S_W:

$$dS_W^2 = [(\partial S_W/\partial I_W)dI_W]^2 + [(\partial S_W/\partial I_O)dI_O]^2 + [(\partial S_W/\partial I_{WO})dI_{WO}]^2 \tag{9}$$

In equation (9), dS_W , dI_W, dI_O and dI_{WO} are absolute errors in S_W, I_W, I_O and I_{WO}, respectively. The absolute errors of the measured intensities at different stages of the experiment can be obtained by statistical analysis of a large number of the intensities measured at a random position of core sample.

Rock samples and fluids characterization

In the experiment performed by unsteady state method 10 cm in length and 3.8 cm in diameter, water wet reservoir rock were selected. The selected core samples belong to an Iranian carbonate reservoir located in the south region. Whereas the experiments showed almost the same characteristics of water wet rocks, the results of only a typical plug sample were selected to be included in the paper. The sample specification and test conditions are extensively characterized in Table1. Cross sectional CT scans and porosity distribution of the selected sample are shown in figures 1 and 2, respectively.

Table1- Sample specification and test condition

Air perm. mD	Helium Porosity, %	Brine Viscosity cP, @ Res.cond	Oil Viscosity cP, @ Res.cond	Confining Pressure, psi	Pore pressure, psi	Tem. ºC	Rate cc/hr	Swi, %PV	Sor, %PV	BT PV inj.
4.876	19.79	0.59	0.4	3000	2000	90	4.2	36.22	32.40	0.30

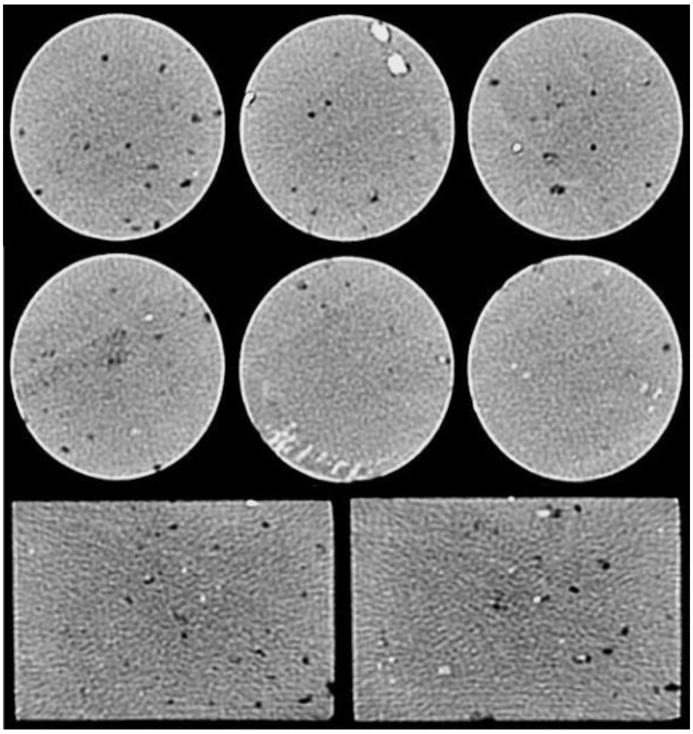

Figure 1- Cross sectional CT scans of the selected sample

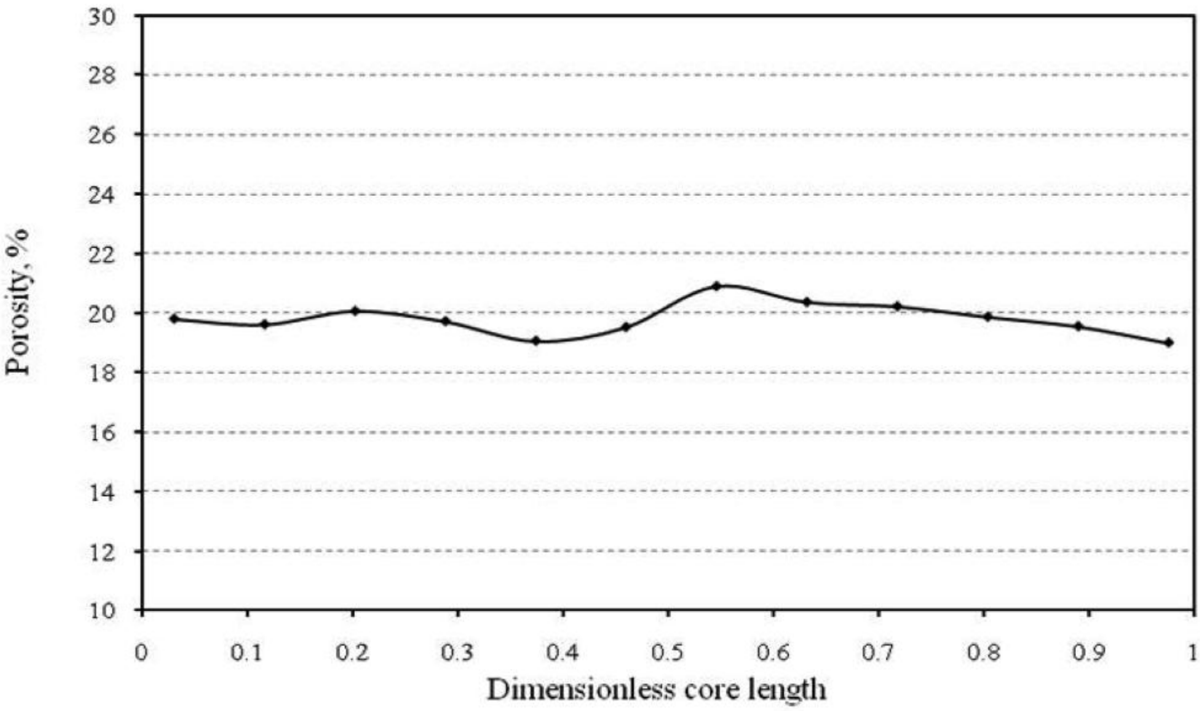

Figure 2- Porosity distribution of the selected sample

The fluid system consists of simulated reservoir brine doped with Potassium Iodide (KI) and light reservoir oil whose viscosity ratio is approximately 0.7 implying predictions about the stability of displacement process. The water was doped by adding 100 gr/Lit of KI to increase contrast between oil and water X-ray absorption characteristics. Selected oil did not contain polar components and wettability alteration was not observed. The fluid viscosity was measured in the laboratory.

The system setup

The key components of the system for our experiment include X-ray table, generator and detector, associated hardware and software, composite carbon core holder, high pressure dual injection pump and computer control and data acquisition system. The X-ray generator and detector traverse the length of the core plug sample with the aid of a stepper motor. The X-ray beams are generated by applying a high voltage. Therefore, the source can be turned off for safety. The X-ray beams are collimated to provide a spot diameter of about 5 mm at the middle of the core plug.

High accuracy differential pressure transducers were used to monitor the differential pressure along the core plug. An aluminum core holder with 1.5 mm thickness, which is over radially wrapped with composite carbon, was used to have minimum of X-ray absorption. The core holder temperature is maintained constant by a recirculation heating system, which uses silicon oil to heat the core by recirculating it to keep temperature constant.

The experimental procedure

The objective of conducted experiments was to distinguish the X-ray in situ saturation data and saturation profile shapes in low viscosity ratio immiscible fluid flow through water wet rocks and as a result, to acquire representative relative permeability curves. In order to improve the accuracy of measurement and also to provide higher quality output data, we used reservoir condition core flood setup accompanied by linear X-ray scanner for in situ saturation measurements.

The core plugs were completely saturated with and immersed in doped water for at least 10 days to attain ionic equilibrium, covered by teflon tube and then by a viton sleeve. The core plug was loaded in the composite carbon core holder and a confining pressure of 3000 psig was applied. The pore pressure was controlled by Back Pressure Regulator (BPR) set to 2000 psig. 2 accumulators, one filled with doped water and the other with oil were used to inject the fluids to the sample with a high pressure dual injection pump.

After reaching the temperature equilibrium of 90°C in the core holder and injection fluids, the absolute water permeability was obtained. At this stage of 100% water saturated core, the water calibration X-ray runs were performed. We performed 5 runs to check the repeatability of the calibration runs.

In our experiments, irreducible water saturation (IWS) was established by injecting non-wetting phase and gradually increasing its rate. After reaching the SWI condition, 5 X-ray runs were performed for further calculation of irreducible water saturation profile. Water flooding experiments were performed with constant and reservoir low rate. At the end, when oil production had ceased and differential pressure stabilized, water flow rate was increased to bump the oil phase with increasing the rate up to at least 5 times the initial rate.

Based on Jones & Roszelle method, [24] the water saturation at effluent end face of the core plug should be calculated or measured. For this purpose, during water flooding stage, we continuously X-rayed the plug sample in order to have overall saturation profiles along the sample and end core face saturation as well, for further relative permeability calculations. Data acquisition and controlling system were done via a laboratory PC and recorded information was interpreted and analyzed in order to accurately obtain raw data for calculating the water and oil relative permeabilities.

At the end of the water flooding and bump rate, the sample was washed according to the standard procedure. The procedure consists of injecting at least 15 pore volumes of firstly distilled water, methanol, and finally hexane or toluene and eventually by testing oil with gradually increasing the flow rate to an allowable rate for the core plug sample. Once the core sample is 100% oil saturated under test conditions, we ran X-ray measurements for oil calibration.

These calibrations were used to calculate average water saturation during oil flood for establishing Swi and the subsequent water flood saturation profiles. With the aid of equation (5), the water saturation at any position along the sample can be calculated. It should be noted that the positions of core plug, which are X-rayed, must be the same in all the X-ray runs. The repeatability of the X-ray data acquisition was checked through water and oil calibrations. It did not show any problematic noise.

Results and discussion

A significant end effect was present in the oil and water phases, which means that the true irreducible water saturation was significantly lower than the mean water saturation. Consequently, experiments without in situ saturation measurements could significantly overestimate the irreducible water saturation in water wet and ROS in mixed wet and oil wet core samples.

In order to obtain more accurate saturation and relative permeability results, X-ray in situ saturation data collection was employed to reduce measurement errors. To calculate relative permeability, we need the production data, pressure gradient history, and time. Since average and core end face water saturations were measured directly from X-ray in situ saturation data, corrections to compensate for upstream and downstream tubing volumes and time lag between the time when fluid exits the core and the time observed were not necessary. In addition, we used constant rate injection and knowing the saturation difference between two measurement times, the drained oil volume and thus the average volumes of produced fluids can be calculated.

The irreducible water saturation by volumetric measurement was approximately 36%, i.e. approach to X-ray IWS, but distinction of X-ray data was to exhibit circumstance of water saturation distribution along the core length (Fig.5) and perception of this data. Although the oil flood rate increased in order to reach true IWS, no or negligible change was observed in shape of saturation profile and value of IWS.

Fig.3 displays variation of differential pressure and Fig.4 shows oil production versus injected brine pore volume. Differential pressure gradually decreased during the experiment and in addition oil recovery increased and eventually became constant. After oil production had stopped, the water injection rate was increased in steps to the bump rate and there was not significant additional oil production with increasing flow rate. 1D overall saturation profiles before breakthrough and after that are presented in Fig.5. Because of various bump rate saturation profiles overlapping, we have just shown the last bumped saturation profile.

The in situ water saturation profiles obtained during water flood, display wettability influence and displacement front position. The plot of relative permeabilities to water and oil versus water saturation is shown in Fig.6. Water saturation was 52% at cross-over point and relative permeability to water at the maximum water saturation was 0.134. Oil recovery at breakthrough was 43% oil in place and this value of oil swept by 0.30PV water injection. After breakthrough, oil recovery increasesd only 6% and this phenomenon is evidence of mainly oil production before breakthrough in water wet rocks.

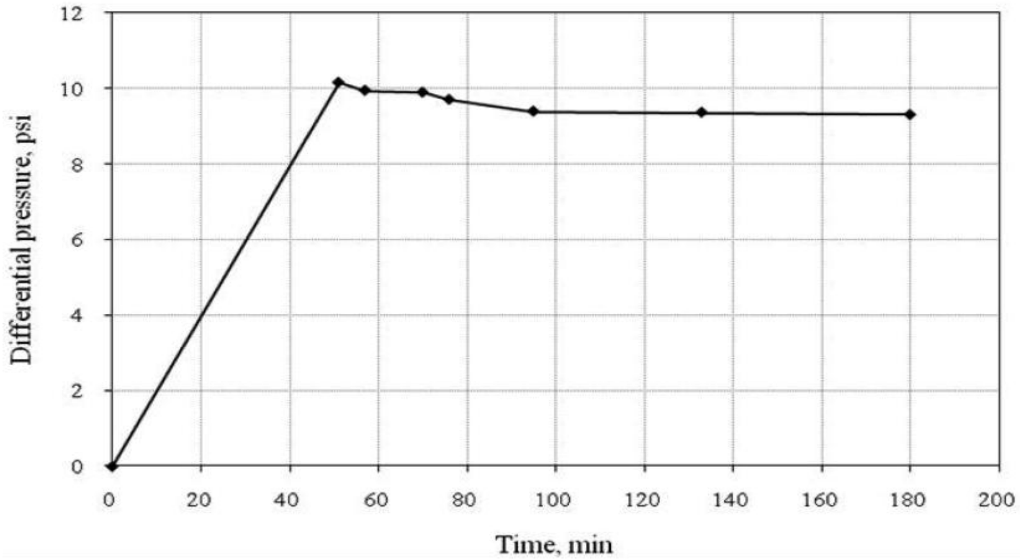

Figure 3- Differential pressure vs. time during low viscosity oil displacement by water in water-wet porous media

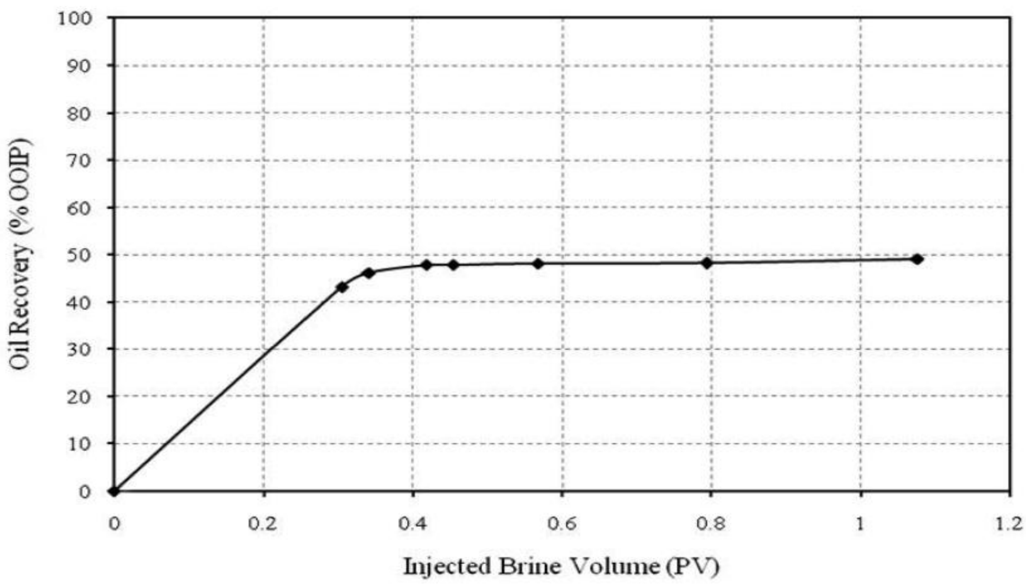

Figure 4- Oil recovery versus injected brine volume

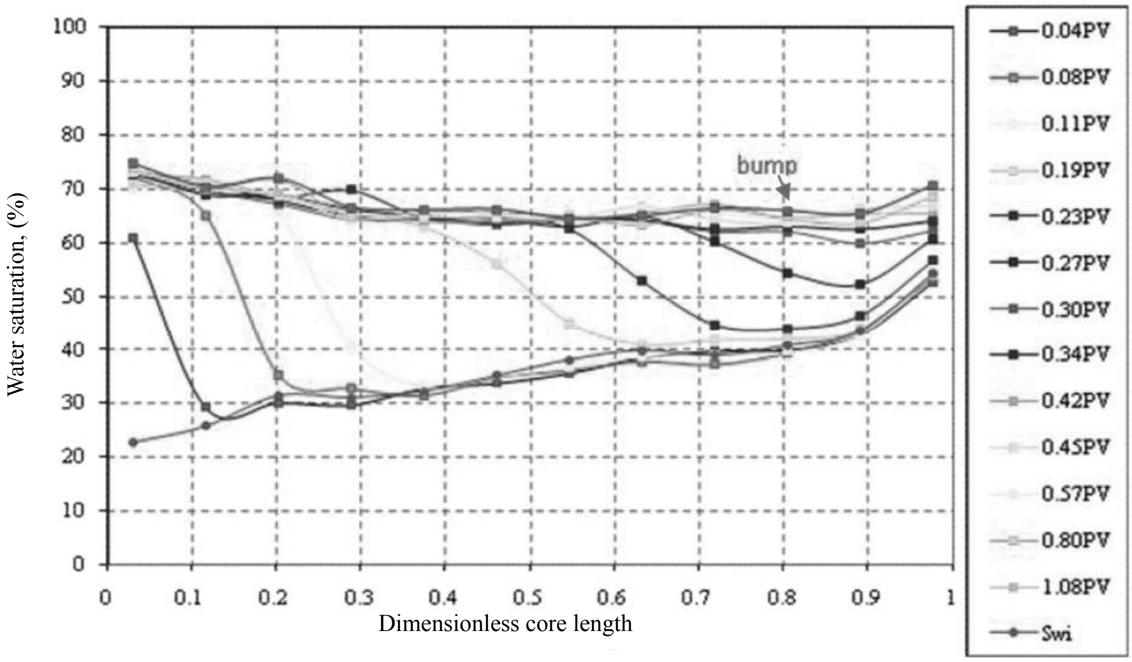

Figure 5- Water saturation profiles in low viscosity oil displacement through naturally water-wet porous media

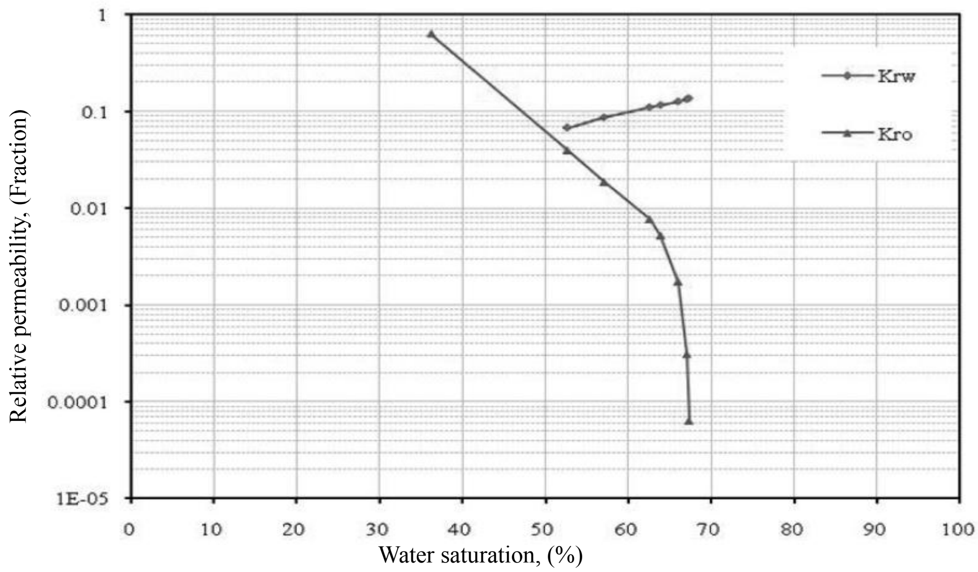

Figure 6- Water and oil relative permeabilities vs. water saturation in low viscosity oil displacement through naturally water wet porous media

The average irreducible water saturation value determined by X-ray in situ saturation data is high as expected in a water wet rock. A major implication of the gradually increasing of irreducible water saturation value along the core during injection of low viscosity oil into completely water saturated porous media is that the saturation value of non-wetting oil phase is controlled by reservoir rock wettability characteristics. When non-wetting phase tries to enter to the wetting phase, due to snap-off, it forms discontinuous globules through the wetting phase and is trapped in the larger pores. Since flow rate is constant during water flood and wetting phase is injected to porous media, injection becomes convenient and pressure is decreased, oil recovery increases and eventually becomes constant. The saturation profile shapes characterize oil production before breakthrough and display displacement front position.

The mobility ratio is the dominant and important parameter for frontal stability in oil displacement by water. As the mobility ratio increases, the Buckley-Leverett shock front becomes unstable. In displacement of light oils by water encroachment, the breakthrough happens when oil saturation is near the residual value and a little oil is produced after breakthrough. In addition, during the water flood in experimented water wet system at low viscosity ratio, a large percent fraction of producible oil in place is recovered before breakthrough. In our experiments, after water breakthrough, saturation profiles have a flat aspect compared with breakthrough. This profile marks that the majority of oil recovery occurs before breakthrough and a small number of pore volumes of water is required to complete a water flood in low viscosity ratio displacement through water wet rock porous media.

Experiments were performed with constant and reservoir low rate and X-ray was periodically employed for data acquisition. Then, the flow rate was increased in steps. Any decrease in the oil remaining in the core with increasing water flood rate can be due to the reduction in capillary effects and it is important to use flow visualization to understand the reasons [25].

The oil recovery is independent of increasing various bump rates and negligible oil production at the end of the experiment are attributed to the absence of capillary end effect and also nature of water wet porous media. This phenomenon is sensible in bump saturation profile shapes by flat and overlapping aspect for remaining and residual oil saturation.

X-ray in situ saturation data correctly determined saturations and in addition contributed to achieve valuable information and concept in water oil displacement through water wet porous media. In our study, in situ saturation profiles obtained by linear X-ray scanner, are underpinning to water oil relative permeability curves. A plot of relative permeability to water and oil versus water saturation was in qualitative agreement with wettability characteristics of water wet reservoir core samples and Craig's rules of thumb.

Conclusions

The present investigation provided the following conclusions:

1. The X-Ray in-situ saturation data is a perceptible device for characterizing the specifications of displacement process through naturally porous media and intrinsic wettability characteristics of reservoir rocks.
2. Saturation value of non-wetting oil phase is controlled by reservoir rock wettability characteristics. The immovable water saturation increases even increases the oil injection rate because of oil snap off when light oil enters a water wet porous media.
3. The calculated accuracy of saturation determination is almost 1%.
4. In displacement of light oils by water encroachment, the breakthrough happens when oil saturation is near residual value and in experimental water wet system, a low viscosity ratio a large fraction of producible oil in place is recovered before breakthrough.
5. A few number of pore volumes of water were required to complete a water flood in low viscosity ratio displacement through water wet rock porous media.
6. Overlapping of various bump rate saturation profiles indicates that there is no significant difference between remaining and residual oil saturation in water wet reservoir rock.

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