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Study on Non-equilibrium Effects during Spontaneous Imbibition

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ABSTRACT: Spontaneous imbibition of water into the matrix blocks because of capillary forces is an important recovery mechanism for oil recovery from naturally fractured reservoirs. In modeling this process, it has been assumed classically that local equilibrium is reached and, therefore, capillary pressure and relative permeability functions are only a function of water saturation, resulting in the appearance of the self-similarity condition. In some works published in the last 2 decades, it has, however, been claimed that local equilibrium is not reached in porous media, and therefore, opposite the classical local-equilibrium/self-similar approach, non-equilibrium effects should be taken into account in modeling multi-phase flow in porous media and, in particular, for the spontaneous imbibition process. Results from laboratory works are still contradictory about the existence of such effects during the spontaneous imbibition process. In the first part of this work, existence of the non-equilibrium effects is investigated by comparing oil recoveries versus time predicted by numerical simulation based on the classical local-equilibrium approach to experimental data from the literature. There is an excellent agreement between the predictions from the numerical simulations and the observed data, indicating sufficiency of the classical method to model oil recovery versus time. In the second part, we use experimental data available in the literature and plot water saturation versus the similarity variable for different times to check the self-similarity condition. Results from this part show that, contrary to the results from part one, non-equilibrium effects exist in all imbibition modes (co-current and counter-current imbibition). The general conclusion from this work indicates that non-equilibrium effects exist during the spontaneous imbibition process but their effect is not significant enough to affect oil recovery versus time, and therefore, the classical local-equilibrium approach seems sufficient to model the spontaneous imbibition process, at least on the small core scale.

1. INTRODUCTION

Spontaneous imbibition (also known as free imbibition or capillary imbibition) of water into the matrix blocks because of capillary forces is an important recovery mechanism for oil recovery from fractured reservoirs, during either water injection or aquifer rise. Two main modes of spontaneous imbibition are recognized: counter-current spontaneous imbibition (COUCSI), in which the displacing wetting fluid flows in the opposite direction from the produced non-wetting fluid, and co-current spontaneous imbibition (COCSI), in which the wetting phase and non-wetting phase are flowing in the same direction.

In most of the research addressing the spontaneous imbibition during the last half century, as a classical approach, it has been assumed that local equilibrium is reached instantaneously, resulting in capillary pressure and relative permeability functions and, consequently, the diffusivity coefficient, dependent upon only the water saturation.[1−5] The assumption of instantaneous local capillary equilibrium allows for the balance flow equations to be cast in the form of a self-similar, diffusion-like problem.[6] The property of self-similarity says that curves of water saturation versus the similarity variable (i.e., the ratio of the distance to the square root of time) for different times all collapse into a single curve upon plotting S_w versus the similarity variable for different times.

There have also been some experimental works investigating self-similarity. In 1958, Gardner and Mayhugh[7] showed that experimental frontal displacements satisfy the diffusion equation with a diffusion coefficient dependent upon saturation. In 2003, Li et al.[8] analyzed data from COUCSI experiments on Berea sandstone core samples and inferred that there was self-similar behavior reflecting the absence of any non-equilibrium effect. Some studies have, however, claimed that significant non-equilibrium effects exist during spontaneous imbibition, implying that this phenomenon is essentially an unsteady-state process.[9−15] The main feature of an unsteady-state process is that relative permeability and capillary pressure are no longer functions of water saturation only and, instead, are time-dependent variables, resulting in breakdown of the self-similarity condition. Numerical works using models based on the new non-equilibrium approach seems to have accurate results.[14,15] In 2006, Guen and Kovscek[6] analyzed oil production data from COCSI and COUCSI experiments on diatomite (a light, friable, siliceous sedimentary rock) samples and observed that non-equilibrium effects existed during the spontaneous imbibition tests, except one case where self-similarity was observed.

In general, the observations of the aforementioned researchers, however, are contradictory about the existence of non-equilibrium effects during multi-phase flow and, in particular, the spontaneous imbibition process. The main aim of this study is

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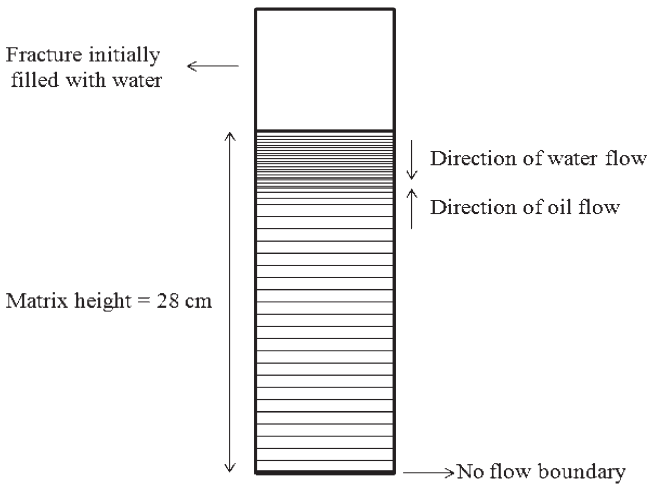

Figure 1. Schematic of the numerical simulation model used in this study, for the GVB-3 case.

therefore to give better insight into the existence and contribution of non-equilibrium effects to multi-phase flow models. The approach has been to first use numerical simulation based on the classical local-equilibrium approach to check its ability to match experimental data. Then, available experimental data from the literature have been replotted to check the self-similarity assumption and, consequently, the existence of non-equilibrium effects. Summary and conclusions are then drawn based on inspection, analysis, and interpretation of the results obtained.

2. NUMERICAL SIMULATION

Numerical simulations based on the classical local-equilibrium approach were performed to check whether they were able to match the observed imbibition experimental data. The two sets of imbibition experimental data reported by Bourbiaux and Kalaydjian[16] were used as a reference. The reason is that they reported a systematic investigation of capillary pressure, relative permeability, and fluid flow characteristics for experiments performed on a sandstone sample. Oil recovery versus time for the experiments referred to as GVB-3 and GVB-4 are used in this work. In the GVB-3 test, the top face of a laterally coated core was put in contact with water, while the bottom face was coated so that oil was produced from the top surface in a pure counter-current flow mode. For the test referred to as GVB-4, both bottom and top faces were in contact with water and oil produced from both bottom and top faces. The flow mode in this test was therefore somewhat mixed because the oil from the top surface was produced both co-currently as well as counter-currently. Of 25.6% of original oil in place (OOIP) produced from this surface, 7.9% OOIP was produced co-currently and 17.7% OOIP was produced counter-currently, respectively.

The numerical simulator used in this study to model the spontaneous imbibition tests was ECLIPSE 100, an industry-widely used reservoir simulator.[17] It is a fully implicit, black-oil simulator. The core sample representative for the two cases GVB-3 and GVB-4 was modeled in Cartesian block-center coordinates, respectively, as shown in Figures 1 and 2, with 44 blocks in the z direction and 1 block in the x and y directions, so that the flow is necessarily one-dimensional. The model comprises three distinct sections. The first section is composed of one block initially filled with water. This block represents the fracture and is referred to as $z = 0$. The second section, initially saturated with oil at connate water saturation, represents the core of length 28 cm. It is divided into 42 blocks with smaller blocks at the inlet(s) to capture accurately the initial advance of water into the matrix. The third and last section only exists in the case GVB-4. This single block represents the fracture initially only filled with water.

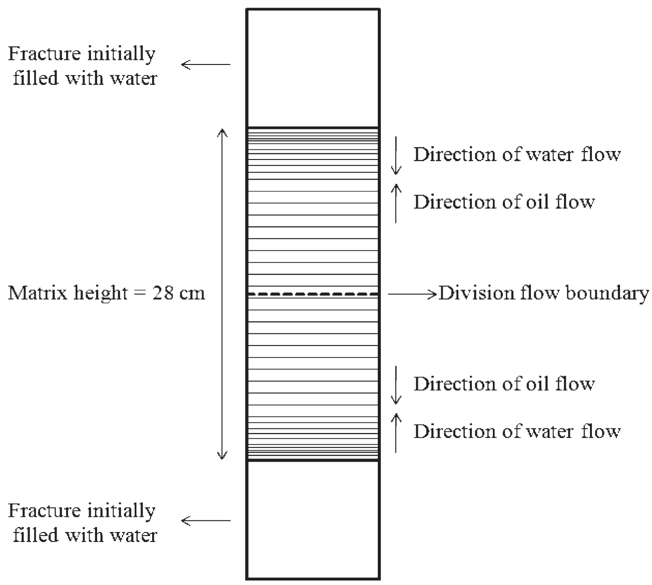

Figure 2. Schematic of the numerical simulation model used in this study, for the GVB-4 case.

Table 1. Rock and Fluid Properties Used in Numerical Simulation[16]

	GVB-3	GVB-4
K (m^2)	124×10^{-15}	118×10^{-15}
Φ (fraction)	0.233	0.233
σ (N/m)	0.035	0.035
L (m)	0.29	0.29
A (m^2)	0.001281	0.001281
S_{wi} (fraction)	0.400	0.411
S_{or} (fraction)	0.422	0.399
K_{rw} (end point)	0.044	0.045
K_{ro} (end point)	0.460	0.490
μ_w (mPa s)	0.0015	0.0015
μ_o (mPa s)	0.0012	0.0012
ρ_w (kg/m^3)	1090	1090
ρ_o (kg/m^3)	760	760

All simulation parameters, which are the same as the rock and fluid properties used by Bourbiaux and Kalaydjian,[16] are summarized in Table 1. The flow functions used when performing the numerical simulations, i.e., the relative permeability and capillary pressure curves, were those provided by Bourbiaux and Kalaydjian.[16] It is, however, important to notice that Bourbiaux and Kalaydjian needed two sets of relative permeability curves referred to as "co-current" and "counter-current" relative permeability curves to match observed oil recovery versus time for the tests performed in co-current (GVB-1 and GVB-5) and counter-current modes (GVB-3), respectively. The relative permeability curves for the co-current case were based on end-points measured at the end of drainage and during tertiary waterflood, respectively. The shape of the curves was furthermore estimated from relative permeability curves measured by the unsteady-state method on other cores from the same porous medium. For the test performed with mixed mode (GVB-4), the "counter-current" relative permeability set was used;

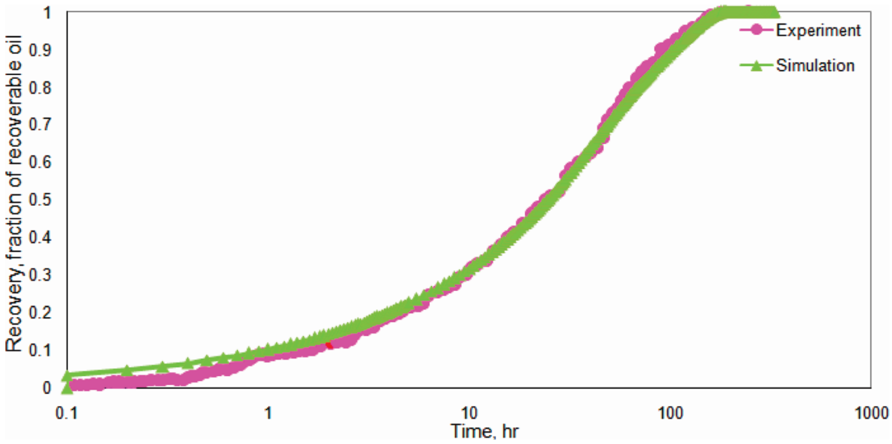

Figure 3. Comparison between oil recovery predicted by numerical simulation and experimental data, for the GVB-3 case.

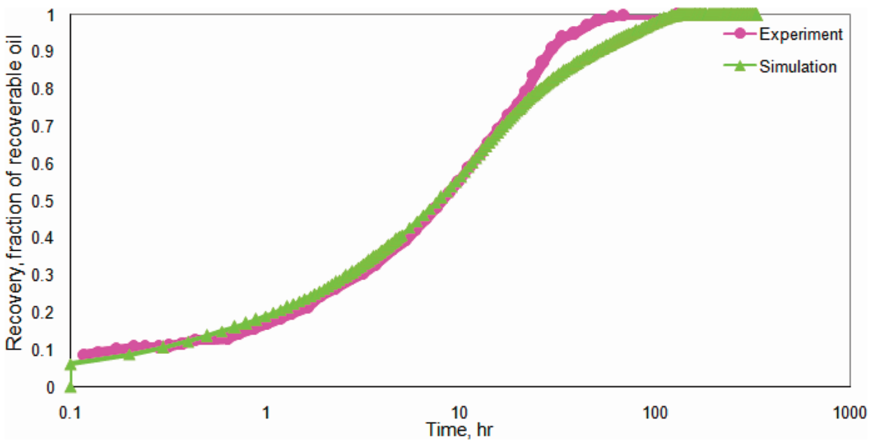

Figure 4. Comparison between oil recovery predicted by numerical simulation and experimental data, for the GVB-4 case.

hence, only the "counter-current" relative permeability set is used in the numerical simulations performed in this work.

3. RESULTS AND DISCUSSION

3.1. Comparing Simulated versus Experimental Spontaneous Imbibition Results. Oil recovery predicted by the numerical simulation procedures described in the previous section is then compared to the experimental data for tests GVB-3 and GVB-4 as reported by Bourbiaux and Kalaydjian.[16] The results of plotting both simulated and observed oil recovery versus time for the GVB-3 and GVB-4 cases are shown in Figures 3 and 4, respectively. As the figures clearly show, there is an excellent match between oil recovery predicted by the numerical simulation and that obtained from the experiments. It is important to notice that only measured input data (relative permeability and capillary pressure) are used in the simulations and no adjustments of these have taken place to improve the match quality.

There are furthermore two essential issues to take into consideration when evaluating the ability of the simulator based on the local-equilibrium assumption to match the experimental data. First is the theory for describing the impact of non-equilibrium on the spontaneous imbibition process developed originally by Barenblatt and co-workers[9−13] and further developed by Silin and Patzek in 2004.[14] They matched the spontaneous imbibition data by introducing an effective water saturation, which in all cases was larger than the actual water saturation given by the local-equilibrium assumption. Introducing the effective water saturation will hence imply that the water relative permeability will be higher than the value given using the corresponding "equilibrium" value. In contrast, the oil relative permeability will always be lower for an effective water saturation always larger than the corresponding "equilibrium" value.

Second, it is crucial to notice that Bourbiaux and Kalaydjian[16] were not able to reproduce the oil recovery profile versus time for the pure counter-current case (GVB-3) using the relative permeability curves used to match the co-current flow experiments. To match the oil recovery versus time profile for the counter-current case, the relative permeability curves from the co-current flow simulations should be modified to either (1) reduce the oil relative permeability by 60% and the water relative permeability by 30% of their co-current values or (2) reduce both the oil and water relative permeabilities by approximately 30% of their co-current values. The latter approach was applied in the paper because of theoretical considerations. The important issue is that both the oil and water relative permeabilities should be reduced to obtain a satisfactory match between the observed and simulated oil recovery response. Taken into account the good match obtained using the local-equilibrium relative permeabilities, it is

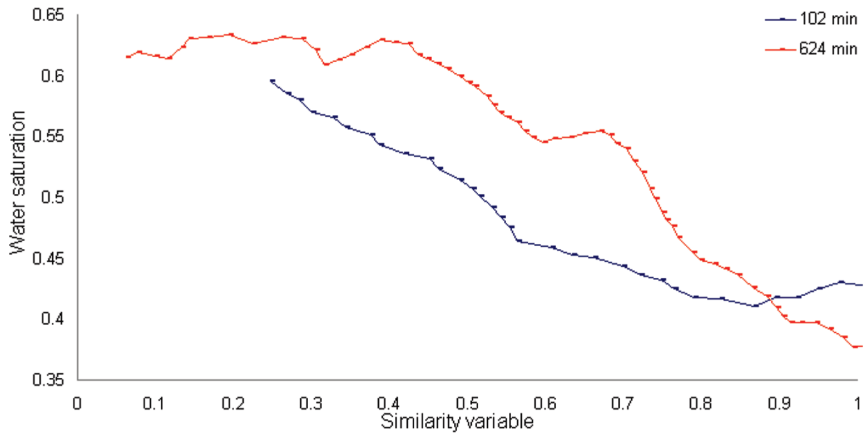

Figure 5. Water saturation versus the similarity variable at different times for experimental data of the COUCSI mode (GVB-3).[16]

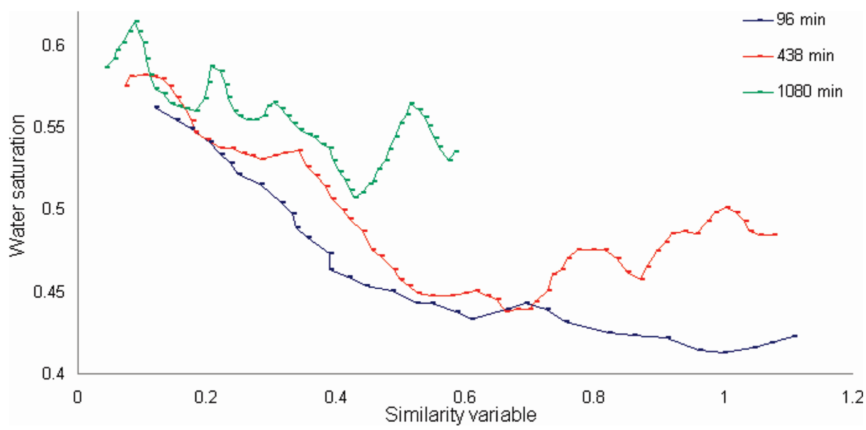

Figure 6. Water saturation versus the similarity variable at different times for experimental data of the COUCSI mode (GVB-4).[16]

not likely that imposing effective water saturation and, hence, simultaneously increasing the water relative permeability and decreasing the oil relative permeability will improve the match. It is therefore a strong reason to believe that the traditional local-equilibrium assumption is able to correctly describe oil recovery versus time for the experiments considered here.

There is, however, a small discrepancy at early times of imbibition for both cases GVB-3 and GVB-4 where the numerical simulation slightly overpredicts the recovery. Besides the measurement errors, the impact of initial spherical flow around the inlet region may be one issue regarding the small discrepancy between the two curves for early times because there are some indications that, before the imbibition front becomes flat and pure, one-dimensional displacement occurs and flow is nearly spherical.[18,19] An additional reason for the aforementioned small discrepancy may be the existence of non-equilibrium effects, as discussed later. In the case of GVB-4, there is also a difference between the experimental and simulated curves for late times. On the basis of the experience with the commercial simulator, such a difference is due to the disability of the simulator used in this study to model the imbibition process when the imbibition front becomes close to the division flow boundary.

The excellent match between the numerical simulation predictions and the experimental spontaneous imbibition data indicates the sufficiency of the classical local-equilibrium approach to model the process.

3.2. Water Saturation Profiles versus the Similarity Variable for Different Times. In this section, four sets of one-dimensional spontaneous imbibition experimental data from the literature[16,18−20] are used to check the self-similarity condition.

In the work performed by Bourbiaux and Kalaydjian,[16] saturation profiles during COCSI and COUCSI tests were monitored using the X-ray computed tomography (CT) scanning method. The configuration of the experimental setup and different fluids involved was discussed for the cases GVB-3 and GVB-4 in the previous section. The saturation profile for the case of pure co-current flow (GVB-1) of oil and water is included in this section as well. In the GVB-1 test, the bottom face of the sample was put in contact with water and the top face remained in contact with oil to allow the oil to be produced from the top face in a co-current flow mode.

In 1998, Schembre et al.[19] also used the X-ray CT scanning method to visualize/quantify saturation during spontaneous imbibition tests. The water-wet diatomite core sample and *n*-decane as the oil phase were used. No initial water saturation was established during the test. The core was sealed with epoxy on the sides parallel to the flow direction to obtain one-dimensional imbibition. The bottom face of the core sample was in contact with water, and oil was allowed to be produced from the top surface in a COCSI mode.

In 1999, Akin and Kovscek[18] monitored the saturation profiles during COCSI imbibition again using the X-ray CT scanning

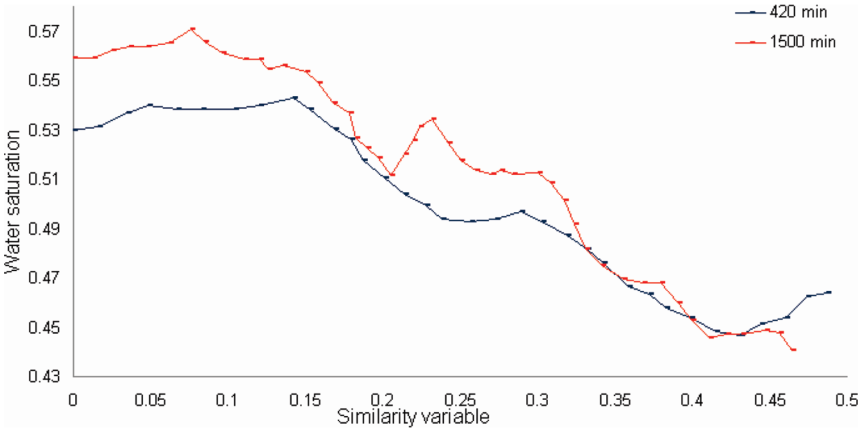

Figure 7. Water saturation versus the similarity variable at different times for experimental data of the COCSI mode (GVB-1).[16]

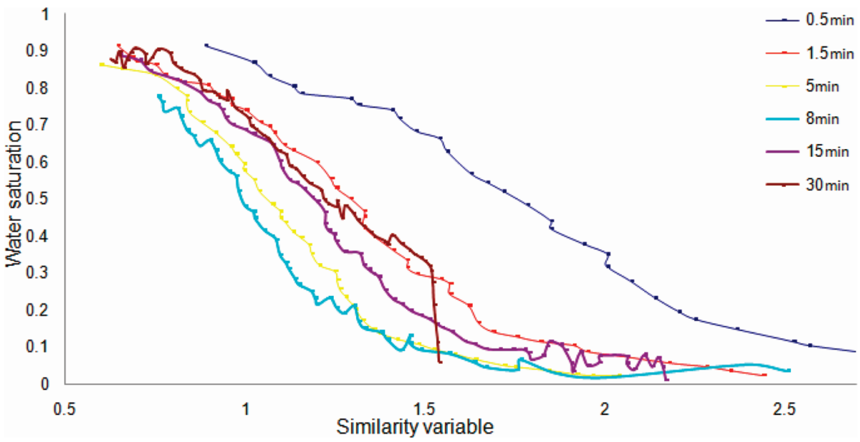

Figure 8. Water saturation versus the similarity variable at different times for the COCSI mode.[19]

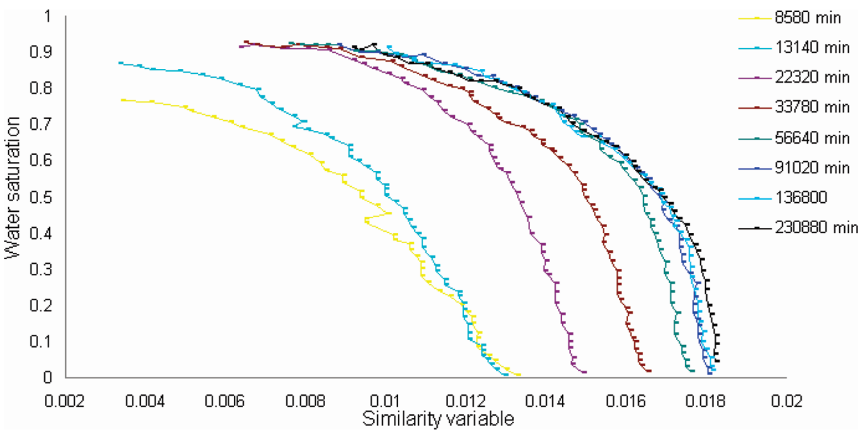

Figure 9. Water saturation versus the similarity variable at different times for the COCSI mode.[18]

method. The images monitored the movement of the imbibition front and the saturation gradient across the front as a function of time. Imbibition tests were performed using water-wet diatomite rock samples together with the fluid pairs water/oil and water/air systems. In this study, only imbibition data for the water/air case (run 4) is used to analyze the similarity condition.

In 2006, Schembre and Kovscek[20] employed a data set comprised of water saturation profile histories collected in their laboratory. These data resulted from two-phase COUCSI of water into water-wet diatomite rock samples. For water/air experiments, zero initial water was established, while for water/decane cases, initial water saturation of 5% was used. Saturation

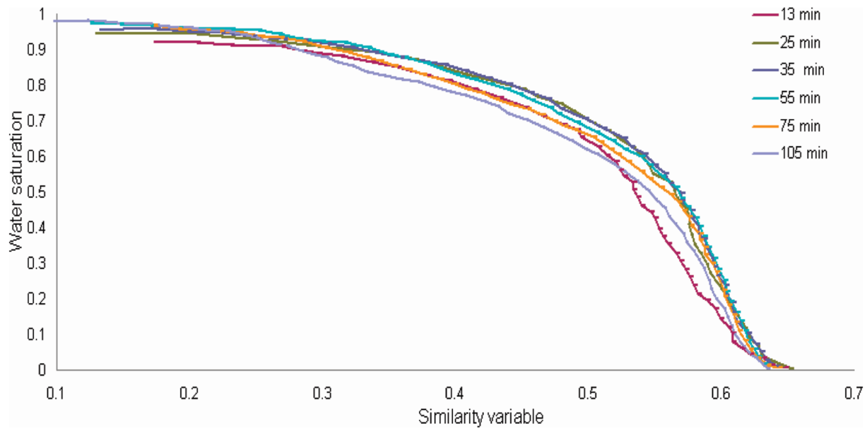

Figure 10. Water saturation versus the similarity variable at different times for the COUCSI mode, for the water/air case.[20]

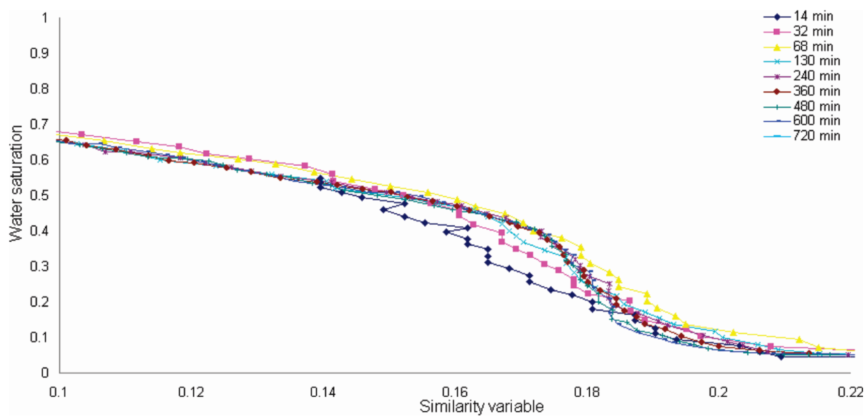

Figure 11. Water saturation versus the similarity variable at different times for the COUCSI mode, for the water/decane case.[20]

profiles as a function of the time were measured using the X-ray CT scanning method.

For each of the imbibition tests, referred to above, the condition of self-similarity could be investigated by plotting water saturation versus the similarity variable, as defined in previous sections, for different times. If self-similarity exists, curves of water saturation versus the similarity variable at different times should collapse into a single curve. It is therefore an indication that non-equilibrium effects are taking place during the imbibition process when the water saturation curves versus the similarity variable does not overlap each other as the process develops in time.

Figures 5−7 show the plot of water saturation versus the similarity variable for different times for the COUCSI (GVB-3 and GVB-4) cases and the COCSI (GVB-1) case reported by Bourbiaux and Kalaydjian.[16] The unit for the self-similarity variable used in all figures is centimeters over the square root of time in minutes. As these figures clearly show, for both modes of flow (either COCSI or COUCSI), curves at different times do not collapse into a single curve, indicating the absence of the self-similarity condition. As time increases (420−1500 min for GVB-3, 96−1080 min for GVB-4, and 102−624 min for GVB-1), the curves shift from left to right on the graph. In contrast, Guen and Kovscek[6] observed that, for the COUCSI case, the curves shifted from right to left in the plot for increasing time and from left to right for the COCSI cases.

It is, however, very important to notice that oil recovery versus time for the tests GVB-3 and GVB-4 could be successfully matched using input parameters basically based on the traditional local-equilibrium assumption without any adjustments or use of any fit parameter. This indicates that oil recovery versus time can effectively be modeled correctly even though the location of the water saturation is not consistent with the similarity variable. Such behavior has also been observed by other researchers.[21,22]

Figure 8 shows the plot of water saturation versus the similarity variable for the COCSI experimental data reported by Schembre et al.[19] As the figure shows, curves at different times from 0.5 to 80 min do not collapse into a single curve, showing the absence of the self-similarity condition. There is generally no distinct trend in the way that the curves are shifted as a function of time because the sequence is more or less randomly distributed.

Figure 9 shows the plot of water saturation versus the similarity variable for the COCSI experimental data by Akin and Kovscek.[18] As the figure shows, curves for the two extreme sampling times of 8580 and 230 880 min do not overlie again, showing the absence of the self-similarity condition. Further, as time increases, curves shift from the left to the right in a similar manner as for the data presented by Guen and Kovscek.[6] In addition, the spacing between the curves of water saturation versus the similarity variable tends to decrease as the imbibition time increases, showing some kind of relaxation of the non-equilibrium state toward a more equilibrium situation for large times. In this case, non-equilibrium effects only seem to exist for early times of imbibition.

Figures 10 and 11 show the plot of water saturation versus the similarity variable for the COUCSI experimental data by Schembre and Kovscek[20] for both water/air and water/decane systems. As Figure 10 shows, curves for the different times fairly overlie, showing existence of the self-similarity condition. If one consider the non-overlying situation, then as time increases, generally curves shift from the right to the left again in a similar manner as for the data presented by Guen and Kovscek.[6] In Figure 11, which belongs to the water/decane case, in some time interval, we can see a right to left shift of curves, while for some other intervals, no distinct trend is observed.

4. CONCLUSION

Contradictory experimental observations regarding the existence of self-similarity/non-equilibrium effects during the spontaneous imbibition process in the literature were the main motivation for this study. To show the ability of the classical local-equilibrium approach to model spontaneous imbibition, the widely used numerical simulation software ECLIPSE 100 was used and its predictions for oil recovery versus time were compared to two sets of experimental imbibition data from the literature. Input data to the numerical simulation were measured data for capillary pressure and relative permeability, and no additional fit parameters were used to improve the fit to the observed oil recovery versus time data. An excellent match in both cases was obtained, showing the adequateness of the classical local-equilibrium method to predict oil recovery versus time.

Then, the existence of the self-similarity condition was investigated using experimental data sets from the literature by plotting the location of the water front divided by the square root of time for an increasing time of imbibition. All cases indicated the existence of non-equilibrium effects during the spontaneous imbibition process because the curves for water saturation versus the similarity variable did not coincide for time development. The general conclusion from this work is therefore that the non-equilibrium effects exist during the spontaneous imbibition process but their effect seems not significant enough to affect oil recovery versus time profiles. The classical local-equilibrium approach seems therefore sufficient to model oil recovery versus time by spontaneous imbibition at least for the small core scale.

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