Imbibition Studies of Low-Permeability Porous Media
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Abstract
A systematic investigation of capillary pressure, relative permeability, and fluid flow characteristics within diatomite (a high porosity, low permeability, siliceous rock) is reported. Using an X-ray computerized tomography (CT) scanner, and a specially constructed imbibition cell, we study spontaneous cocurrent water imbibition into diatomite samples at various initial water saturations. Air-water and oil-water systems are used. Despite a marked difference in rock properties between diatomite and sandstone, including permeability and porosity, we find similar trends in saturation profiles and dimensionless weight gain versus time functions. Diatomite is roughly 100 times less permeable than sandstone, yet it imbibes water at rates rivaling sandstone. Importantly, the spontaneous imbibition data when combined with CT-scan images provides a means to determine dynamic relative permeability and capillary pressure functions.

Introduction:
Spontaneous imbibition is perhaps the most important phenomenon in oil recovery from fractured reservoirs. In imbibition, capillary suction draws wetting liquid into the rock matrix. In fractured systems, the rate of mass transfer between the rock matrix and fractures usually determines the oil production \( \frac{1}{2} \). Imbibition is also essential in evaluation of rock wettability \( \frac{3}{2} \). Because of strong capillary forces, the smallest pore bodies next to the fracture are usually invaded first. The rate of imbibition is a function of porous media and fluid properties such as absolute and relative permeability, viscosity, interfacial tension, and wettability\( \frac{4}{2} \). Most experimental work on imbibition behavior has concentrated on the scaling aspects of the process in order to estimate oil recovery from reservoir matrix blocks that have shapes, and sizes different from those of laboratory core samples\( \frac{4}{2}-\frac{6}{2} \).

Two different approaches are used, typically, to model imbibition behavior. The first approach employs a sugar-cube type matrix-fracture system proposed by Warren and Root\( \frac{1}{2} \) where the communication occurs at the matrix-fracture interface\( \frac{2}{2} \). The second approach is based on a representative elemental volume averaged fracture-matrix system\( \frac{6}{2}-\frac{8}{2} \). Both approaches use empirically determined mass transfer functions.

Kazemi et al.\( \frac{2}{2} \) presented numerical and analytical solutions of oil recovery using empirical, exponential transfer functions based on the data given by Aronofsky et al.\( \frac{9}{2} \) and Mattax and Kyte\( \frac{10}{2} \). They proposed a shape factor that included the effect of size, shape, and boundary conditions of the matrix. Later, this shape factor was generalized by Ma et al.\( \frac{11}{2} \) to account for the effect of viscosity ratio, sample shape, and boundary conditions. The following equation was proposed:

\[
\text{t}_D = \frac{t \frac{1}{2}}{k \sigma} \left( \frac{\phi}{\mu_s L^2} \right)^{\frac{1}{2}} \tag{1}
\]

where

\[
\mu_s = \sqrt{\frac{\mu_w \mu_{nw}}{\phi}} \tag{2}
\]

The above scaling equation was used by Zhang et al.\( \frac{4}{2} \) who report that ultimate oil recovery on a pore volume basis by spontaneous imbibition in Berea sandstone cores is approximately constant for systems with differing lengths, viscosity ratios, and boundary conditions.

To date, much of the focus on imbibition has centered on carbonaceous rocks as a result of the importance of the North Sea Chalks\( \frac{12}{2}-\frac{15}{2} \), the West Texas Carbonates, and the Middle Eastern Limestones. An important, yet relatively unstudied, low permeability, reservoir rock for which imbibition is believed to be an important recovery mechanism is diatomite\( \frac{16}{2} \). Imbibition phenomena are also important during steam injection into diatomite because steam condenses upon injection into a cool reservoir, and the hot condensate imbibes into the formation.

Diatomites are high porosity (>50%), low permeability (0.1-10 md)\( \frac{17}{2} \) rocks of a hydrous form of silica or opal composed of the remains of microscopic shells of diatoms, which are single-celled aquatic plankton\( \frac{18}{2} \). Diatomite reservoir rock is assumed to be moderately to strongly water wet\( \frac{16}{2} \).
Estimates of the original oil in place (OOIP) for diatomite reservoirs in California range from 10 to 15 billion barrels\(^1^9\) and primary recovery has been estimated to be about 5% of the OOIP\(^2^0\). Primary recovery is low despite hydraulically fractured wells that improve injectivity and productivity. Because of the high porosity, large initial oil saturation (35 to 70%), and large OOIP, the target for potential production is high.

Multiphase flow in diatomite is assumed to be dominated by capillary forces, but we lack a good understanding of fluid flow and capillary pressure behavior in the rock matrix. Compounding problems, there are only a few reported capillary pressure curves\(^1^6\) and little information on the extent and rate of imbibition\(^2^1\). The mechanisms of oil displacement and trapping are unclear, but assumed to be similar to those in sandstone. However, rock morphology is very different\(^2^2\).

This study presents basic core analysis data and experimental results of spontaneous water imbibition in diatomite and sandstone. A state of the art experimental imbibition cell is employed along with computed tomography (CT) scanning to quantify the saturation distribution along the core. It is found that the imbibition data scales according to the equation proposed by Ma et al.\(^1^1\). The major focus of this article is estimation of relative permeability and capillary pressure from the experimental saturation data using a nonlinear history-matching technique.

**Experimental Details**

**Liquids**

For water-air imbibition experiments, de-aerated water and air were used, whereas for water-oil imbibition, n-decane and de-aerated water were used. Properties of the experimental fluids are given in Table 1.

**Porous Media**

Diatomite cores were cut in a direction parallel to the bedding plane from a block of outcrop diatomite sample (Grefco Quarry, Lompoc, CA). This sample is fairly homogeneous, but there are regions of higher density and correspondingly lower porosity. Figure 1 displays porosity images of the cores used in this study. The procedure to obtain these images will be presented, shortly The average porosity of the samples was slightly greater than 65% and porosity varied by about 2 to 4%. The liquid permeability varied from 6 to 9 md. Table 2 lists exact values for each core. It should be noted that because of the brittle nature of the diatomite, the cores were machined instead of drilled using conventional core bits as described by Schembre et al.\(^2^1\). The lengths (3.45 in. or 8.763 cm) and diameters (0.95 in. or 2.413 cm) of the cores were all close to constant. Cores were potted with epoxy in 1 inch (2.54 cm) Plexiglas tubes. Both ends were left open to enable cocurrent imbibition.

**Experimental Setup**

The experimental setup is designed specifically for CT measurements. It consists of three main parts: (i) a potted diatomite core inside a (ii) water jacket and (iii) a data acquisition system based on a personal computer, as shown in Figure 2. Two end caps hold the imbibition cell in position within the cylindrical water jacket. The end caps are machined with spider-web-shaped fluid distribution grooves where the end cap contacts the core. The entire assembly is placed inside the CT gantry. Fluid is circulated through the jacket to maintain a constant temperature up to 90°C (194°F) using a heating circulator bath. The experiments reported here were conducted at 20 °C (68 °F). The main function of the water jacket is to reduce effects of beam hardening. Beam hardening is the change of overall X-ray attenuation with distance into the object. It occurs when a polychromatic X-ray beam passes through a material that preferentially absorbs lower energy photons. The remaining beam becomes more and more chromatic at higher energy levels and the beam becomes “harder”. The effects of this phenomenon are usually more pronounced at the boundaries where there is a high density contrast (i.e. air and core).

Three polyethylene lines (input, output, and bypass) allow the imbibing fluid to enter the imbibition cell and the produced fluid to exit the cell. The bypass line is used to flush any non-wetting fluid from the lines, thus allowing the imbibing fluid to fill the inlet end plate and easily contact the core face. The amount of water imbibed is found by measuring the weight loss of the water reservoir using an electronic balance connected to a personal computer. The CT-Scanner used in this study is a fourth generation Picker™ 1200-SX scanner with 1200 fixed detectors. It allows rapid scanning on a single vertical volume section in the center of the core as a function of time. The acquisition time of one CT image is 3 seconds, whereas the processing time is around 40 seconds. The total time of measurement is selected such that it is short enough to capture accurately the position of the imbibition front, yet it is large enough to provide necessary X-ray energy. Table 3 gives CT scan parameters used in this study.

**Imbibition Measurements**

For water-air imbibition experiments, the core samples were dried in a vacuum oven at approximately 70°C (158°F) for 24 hours before starting the experiments. After pressure testing for leaks, the imbibition cell is placed into the water jacket either horizontally or vertically and the jacket is filled with water. All experiments reported here are in the horizontal mode. Next, the setup is placed inside the gantry and positioned such that the main scanning plane is at the center of the core sample and there is nothing around the setup (i.e. the patient couch is not in the scanning plane). A reference dry CT image is obtained using the parameters given in Table 3. The image covers the entire length of the core (e.g., Figure 1) rather than conventional circular slices.

Operating in this fashion, rather than conventionally, allows us to track accurately the position of the imbibition front. Additionally, saturation measurement with CT is much cheaper and faster than conventional techniques such as X-ray absorption\(^1^4,2^3\). A final advantage is that continuous two dimensional porosity and saturation maps are generated that can be used to identify heterogeneity and non-uniform displacement. Hence, no three-dimensional reconstruction is necessary.

CT scans are taken during this period at prescribed time intervals. After a day of water imbibition into the initially air-
filled core, several pore volumes of de-aerated water are injected using a positive displacement pump to ensure complete saturation. A reference 100% water saturated CT image is then captured. The core plug is then de-saturated to an irreducible water saturation by pumping n-decane at a rate of 1 ml/min. Another CT image is taken to observe the water saturation distribution at the end of this stage. Water imbibition is initiated and progress of imbibition monitored by CT. Three oil-water diatomite imbibition experiments with nonzero initial water saturations are reported here.

In order to observe the effect of zero initial water saturation, another experiment was conducted. This time the air-filled core is imbibed with oil to 100% oil saturation, and then imbibed with water following the same experimental procedure for at least 14 days.

The porosity, $\phi$, and saturation, $S_w$, distributions in water-air imbibition experiments were calculated using the following set of equations:

$$\phi = \frac{CT_{\text{wet}} - CT_{\text{dry}}}{CT_{\text{water}} - CT_{\text{air}}} \quad (3)$$

$$S_w = \frac{CT_{\text{obj}} - CT_{\text{dry}}}{CT_{\text{wet}} - CT_{\text{dry}}} \quad (4)$$

where $CT$ is the CT number in Hounsfield units. The subscripts dry and wet refer CT numbers for air-filled and water-filled cores, respectively, whereas water and air indicate the CT numbers of pure water and air. The subscript obj describes any CT number during the spontaneous imbibition process.

A slightly different approach is taken for analysis of the water-oil imbibition experiments because it is hard to obtain 100% oil and 100% water saturated images within the same experiment. For experiments with nonzero initial water saturation, the 100% water saturated image is used as the reference image in the following equation:

$$S_o = \frac{CT_{\text{obj}} - CT_{\text{wet}}}{\phi(CT_{\text{oil}} - CT_{\text{water}})} \quad (5)$$

where $\phi$ is the independently measured porosity for a given voxel. However, for experiments with no initial water, the reference image is 100% oil saturated and thus the saturation calculation equation has the following form:

$$S_w = \frac{CT_{\text{obj}} - CT_{\text{oil}}}{\phi(CT_{\text{water}} - CT_{\text{oil}})} \quad (6)$$

These equations are comparable and compatible with Eq. 4 in terms of accuracy, because the images obtained here are flat and exhibit minimum beam hardening and nondetectable positioning effects.

Results and Discussion

Water-Air Imbibition Experiments

A total of four experiments with core properties as reported in Table 2 and the porosity field shown in Fig. 1 were conducted. The permeability varies from 6.2 to 8.6 md., and the porosity, as derived from CT, varies from 67 to 71%. The differences in permeability of the samples, although small, affect the duration of imbibition. Using a 95% water saturation level as a benchmark, an 18 hour difference is observed between completion of the fastest and slowest imbibition experiments.

To confirm that results for diatomite reduce to a single curve when scaled by porosity and permeability, dimensionless weight gain versus dimensionless time, as given by Eq. 1, is plotted in Figure 3. Good agreement is achieved. This demonstrates that water-air imbibition in these diatomite samples can be modeled using a single set of capillary pressure and relative permeability curves. For reference, Fig. 3 also plots the results of imbibition in a roughly 800 md Berea sandstone.

CT derived water saturation images at differing times for each experiment are given in Figure 4. Common to all tests, flow is initially spherical about the inlet region. It was noticed that the duration and the extent of this regime is a function of permeability. That is, if the permeability of the system is small, the spherical flow lasts longer. The most probable reason for the occurrence of this flow regime was the inlet port where a 1/8 inch line was connected to the spider-web-shaped grooved end cap. Water contacted the core from a single point rather than the whole bottom surface of the core plug. We minimized the duration and occurrence of this initial spherical flow regime by placing filter paper between the core and the end cap, but this did not eliminate this problem completely. Localized wettability alteration from epoxy fumes has also been suggested, but this effect, if present, was probably most significant near the sides of the samples.

After the end of the spherical flow period, the front becomes flat and one dimensional displacement occurs. The water saturation gradient across the displacement front is high and the front expands and diffuses somewhat as it advances along the core. There are essentially three regions in the core. In the swept zone, the saturation of the displacing fluid (water) is high, and very close to residual nonwetting phase saturation. The displacement front is a transition zone that separates swept and unswept regions. Downstream of the transition zone, the saturation of the displaced fluid (air) is at its initial value.

Despite slight spreading of the front, the shape of the transition zone changes little throughout the displacement until the front approaches the end of the porous medium. At this point, the transition zone disappears as the end of the core fills with water. The time for arrival of the leading edge of the front at the end of the core corresponds to the change in the slope of the dimensionless weight gain curve as shown in Fig. 4.

Handy proposed that imbibition could be described by the solution of either a diffusion-like equation or a frontal-advance equation. In the former, the diffusion coefficient is
proportional to the partial derivative of capillary pressure with respect to water saturation and computed displacement fronts are significantly diffuse. Whereas in the latter, the velocity of the imbibed phase is proportional to the gradient of capillary pressure with respect to distance, and fronts are assumed to be sharp. The experimental findings as observed in Fig. 4 suggest that the correct idea for imbibition into dry, low permeability porous media that are relatively short is more similar to frontal advance. A relatively sharp front, rather than a diffuse one, is observed in all experiments regardless of the level of heterogeneity present.

Heterogeneity clearly affects the flatness of the front as observed in cores 2 and 5. A sharp front suggests that during spontaneous imbibition, pores of all sizes fill simultaneously. This implies that large pores are well interconnected to small pores. This observation is consistent with the complex, small-diameter pore network of diatomite. Thus, it is hard to fill the very small pores selectively, leaving relatively large pores unfilled.

A comparative imbibition experiment was conducted with a Berea sandstone core to verify development of similar sharp fronts. The sample had a porosity slightly above 22% and the permeability to water was around 800 md. Following the same experimental procedure, weight gain and CT images were recorded throughout the experiment. Relatively sharp fronts similar to those detected in diatomite experiments were observed as shown in Fig. 5. These observations are in agreement with other recent experiments in Berea sandstone where the position and shape of a water imbibition front were tracked. The primary difference between diatomite and sandstone results is that the water saturations are considerably smaller at identical dimensionless time as observed in Fig. 4. The water saturation at the end of the spontaneous imbibition in the sandstone was 65%, compared to about 95% obtained in diatomite experiments. This suggests that the complex structure and low permeability of diatomite actually aid the spontaneous imbibition of water via capillary pressure into a plug filled initially with air.

**Modeling Water-Air Imbibition Experiments**

The CT images and weight gain data from spontaneous imbibition experiments contain much useful information about relative permeability and capillary pressure. We use a nonlinear history-matching technique to model these experiments and extract this information. The following sections describe the methodology used to model diatomite imbibition experiments. These techniques are also applicable to analysis of the oil-water experiments to come.

The nonlinear history-matching performed here is standard. A reservoir simulator (Eclipse, 1995) is coupled with an optimization code. We apply global optimization based on simulated annealing to minimize the following objective function

\[
\sum_{i=1}^{N} \sum_{j=1}^{M} \left( S_{ij}^{\text{experimental}} - S_{ij}^{\text{model}} \right)^2
\]

where \( S_{ij} \) are saturation values along the core. An initial guess of relative permeability and capillary pressure data at specified values of saturation is provided and Eq. (7) is minimized. More detail on the optimization methodology can be found elsewhere.

The grid used for water-air imbibition is one dimensional with circular cross section and consists of 122 blocks in the horizontal direction. Two grid blocks at each end were assigned high porosity and permeability to account for the water reservoir and the spider-web-shaped end plugs. Constant porosity and permeability along with varying porosity and permeability fields were considered.

Figure 6 compares CT derived experimental saturation histories with numerically estimated values for experiment 4 using the average porosity and permeability of each core. Solid lines are experimental data, while dashed lines represent the model data. For consistency with Fig. 3, lines are labeled in units of dimensionless time. It should be noted that capillary pressure and relative permeability curves were estimated simultaneously. It can be observed that the one dimensional numerical model fails to describe experimental results at the inlet and outlet ends of the core. The inlet end mismatch is explained by the aforementioned spherical, nonlinear, flow observed during the early times of the experiments. A close analysis of Fig. 6 reveals that this flow regime is effective for dimensionless distances less than 0.10. After this point, the match between the numerical model and the experimental results gets better, showing that the one dimensional flow assumption is valid.

Figure 7 gives the relative permeability curves obtained using the history-matching procedure. Solid symbols refer to data obtained assuming that porosity and permeability are homogeneous. The computed relative permeability curves feature typical water-wet rock characteristics such as the crossover water saturation is greater than 50% and the end-point water relative permeability is less than end-point gas relative permeability. The estimated capillary pressure curve shown in Fig. 8 is also of the same magnitude, yet somewhat lower, than our limited experimental data. Measured data for the air/water system were obtained with a Ruska porous plate cell (model no. 1081-802) in the imbibition mode of capillary pressure measurement. The maximum capillary pressure measurable with this set up is roughly 480 kPa (4.8 atm).

We attempted to improve the analysis by incorporating heterogeneity during history matching. First, the local porosity obtained from the CT measurements was used rather than average values. Second, the following empirical permeability versus porosity relationship obtained from the average data given in Table 2 is used to estimate the local permeability from porosity:

\[
k = 1.161 \times 10^{1.286\phi}
\]

Using the above equation for each CT voxel, a permeability map is generated from measured porosity information. Porosities and permeabilities are down sized to 1-D by arithmetically averaging the voxel data corresponding to each of the 120 grid blocks. Consequently, the history matching is
repeated. The sum of the squares residual was less than the homogeneous run and the matches improved. Figure 9 compares the model and experimental saturation histories for the heterogeneous case. Again, solid lines are experimental data, while dashed lines represent the model data. A slight improvement in the match apart from the inlet and outlet matches can be observed. The relative permeability and capillary pressure curves shown in Figs. 7 and 8 are more or less the same as the homogeneous case. Values obtained by incorporating heterogeneity are given as open, unfilled symbols.

**Water-Oil Imbibition Experiments**

A total of four experiments were conducted using the same diatomite cores utilized in water-air imbibition experiments. One experiment was conducted without initial water saturation, whereas the others were conducted by starting at an irreducible water saturation. An additional experiment was conducted utilizing core 3 to check the repeatability of the results.

Similar to the water-air experiments, the data collected during the experiments consisted of weight gain measurements and CT scans. In general, the duration of the experiments were much longer compared to water-air imbibition experiments. This is expected because the water-n-decane interfacial tension (51.4 mN/m) is lower than the water-air (72 mN/m) interfacial tension, oil is more viscous than air and much harder to displace, and with initial water saturation the imbibition capillary forces should be less. For the zero initial water saturation, an initial spherical flow period followed by a strong, relatively sharp displacement front similar to the fronts observed in water-air imbibition experiments was noticed, as shown in Fig. 10. A stabilized zone was also present with an extent that is somewhat larger than the zone identified in the water-air imbibition experiments. The displacement was not as effective as the water-air case. Note that the water saturation at dimensionless time equal to 5000 is around 73% compared to an almost 95% water saturation for water-air imbibition.

For experiments with a nonzero initial water saturation, a sharp, clear front is not observed as illustrated in Fig. 11. In this case, water saturation increases almost uniformly throughout the entire core. In this sense, the water-oil imbibition results are diffuse and diffusion-like as compared to the water-air case. The oil saturation reached at the end of spontaneous imbibition experiments varied between 20% to 27% as reported in Table 4. This corresponds to oil recoveries between 18% to 22%. These are in agreement with 8% to 20% oil recovery reported in non-fractured diatomite core plugs by Wendel et al.16. Figure 12 presents dimensionless imbibition performance curves for all oil-water experiments. The shape of curves for runs with initial water saturation are all similar, within experimental error, indicating that a single set of relative permeability and capillary pressure curves can represent spontaneous imbibition for these experiments. Note, that the core without initial water saturation displays significantly better imbibition performance. Figure 12 also shows that 18 to 22% recovery can be obtained within reasonable time frames.

A comparative water-n-decane imbibition experiment was conducted using the same Berea sandstone core as in the water-air imbibition experiment. Again, weight loss and CT images were recorded throughout the experiment. Figure 13 presents n-decane saturation images obtained at various times. Similar to the experiments in diatomite, water imbibes into the core without the development of a front despite different initial water saturation and residual oil saturation values as given in Table 4. The dimensionless weight gain curve for the sandstone is plotted on Fig. 10. It shows that the imbibition performance of the sandstone is somewhat below diatomite because the sandstone curve lies to the right of the diatomite curves.

**Modeling Water-Oil Imbibition Experiments**

The same grid system and procedure used for the water-air case is used to history match the water-oil imbibition experiments. Runs 3 and 4 are the furthest apart of the experiments with initial water saturation, as shown in Fig. 12. Hence, we choose to history match these results to test the sensitivity of our procedure to input data. Figure 14 compares CT derived experimental saturation histories with numerically estimated profiles. Figure 14(a) presents experimental and simulated saturation profiles for run 3 and Fig. 14(b) gives the same information for run 4. Again, capillary and relative permeability curves were estimated simultaneously for each experiment. Heterogeneity was considered by assigning averaged porosity and permeability data to individual grids as described in conjunction with water-air imbibition. Reasonable agreement in timing and saturation values is observed indicating the reproduction of the essential physics of water imbibition into partially water saturated cores.

Figure 15 gives the relative permeability data obtained for each match. Good agreement is seen in shape, endpoint values, and the crossover point for oil and water curves. As in the water-air case, the relative permeability curves have the characteristics of strongly water-wet media.

The capillary pressure curves found for these experiments are given in Fig. 16. As in the case of oil-water relative permeability, good agreement is found between the two curves. Interestingly, the shape of these curves and the magnitude of the capillary pressure differs substantially from that found for the water-air case. In Fig. 8, the history-match, air-water capillary pressure curve increases little as Sw decreases, whereas in the oil-water system shown in Fig. 16, the capillary pressure increases substantially between water saturations of 0.65 and 0.45. Additionally, the magnitude of Pc found at low water saturations in the oil-water system exceeds that of Pp in the air-water system. For example, at Sw equal to 0.5 capillary pressure in the air-water system is roughly 200 kPa while in the oil-water system it is about 1600 kPa. Previously measured curves for oil and water have displayed maximum capillary pressures of roughly 600 kPa. We expected the oil-water values to be lower than air-water values because the surface tension of n-decane is 51 mN/m, while that of water is 72 mN/m.

**Conclusions**

Spontaneous imbibition experiments were performed on core
plugs machined from an outcrop diatomite block. Displacement of gas (air) or oil (n-decane) by water was considered. The experiments were limited to spontaneous co-current imbibition and were monitored with a CT scanner to observe local saturation evolution. For comparison, experiments were conducted using Berea sandstone. It was observed that both water-air and water-oil imbibition results in diatomite can be correlated with a single dimensionless function. Moreover, it was noticed that imbibition fronts in the absence of initial water saturation are sharp suggesting that during spontaneous imbibition pores of all sizes fill simultaneously. In turn, this implies that large pores are interconnected to small pores in the complex network structure of diatomite.

Relative permeability and capillary pressure information is extracted from the experimental data. The evolution of local water saturation was correctly reproduced in all cases. For both water-air and water-oil systems, relative permeability curves display strongly water-wetting tendencies. Capillary pressure curves for the water-air case agree with available experimental data.

Nomenclature

\[ A = \text{cross-sectional area, L}^2 \]

\[ CT_{\text{air}} = \text{CT value of air, Hounsfield} \]

\[ CT_{\text{dry}} = \text{CT value for the dry core, Hounsfield} \]

\[ CT_{\text{obj}} = \text{CT value of the image being processed, Hounsfield} \]

\[ CT_{\text{oil}} = \text{CT value of oil, Hounsfield} \]

\[ CT_{\text{wet}} = \text{CT value for a fully water saturated core, Hounsfield} \]

\[ CT_{\text{water}} = \text{CT value of water, Hounsfield} \]

\[ g = \text{gravitational acceleration, L/t}^2 \]

\[ h = \text{height, L} \]

\[ J = \text{objective function} \]

\[ k = \text{permeability, L}^2 \]

\[ m = \text{mass of water imbibed, M} \]

\[ P_c = \text{capillary pressure, ML}^{-1}T^{-2} \]

\[ S = \text{saturation, dimensionless} \]

\[ t = \text{time, T} \]

\[ x = \text{distance, L} \]

\[ \rho = \text{density, ML}^{-3} \]

\[ \mu = \text{viscosity, ML}^{-1}T^{-1} \]

\[ \Phi = \text{potential, ML}^{-1}T^{-2} \]

\[ \phi = \text{porosity, dimensionless} \]

\[ \sigma = \text{interfacial tension, MT}^{-2} \]

Subscripts:

\[ r = \text{relative} \]

\[ w = \text{wetting} \]

\[ nw = \text{nonwetting} \]

Acknowledgments

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References


19. Ilderton, D.C., T.W. Patzek, J.W. Rector, and H.J. Vinegar:


Table 1: Properties of experimental fluids.

<table>
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<tr>
<th></th>
<th>(\rho) (kg/m(^3))</th>
<th>(\mu) (mPa - s)</th>
<th>(\sigma_{\text{liquid-air}}) (mN/m)</th>
<th>CT # (Hounsfield)</th>
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Table 2: Diatomite permeability and porosity values.

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<th>Average porosity</th>
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Table 3. CT scan operating parameters.

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<th>Voltage, kV</th>
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Table 4. Spontaneous imbibition end-point data, water-oil system.

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<th>(S_w) initial, %</th>
<th>(S_{oi}), %</th>
<th>Recovery, %</th>
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</tbody>
</table>
Fig. 1.—Porosity images of diatomite cores 1 (top) through five (bottom).

Fig. 2.—Schematic of the experimental setup.

Fig. 3.—Dimensionless weight gain versus dimensionless time, water/air imbibition.

Fig. 4.—Water saturation distribution during water imbibition into an initially air-filled core. The top left series of images corresponds to core 2, top right core 3, bottom left core 4, and bottom right core 5. In each series, the images correspond to dimensionless times of 5 (top), 15, 40, 65, 500, and 3000+.
Fig. 5.—Water saturation distribution along Berea sandstone during water imbibition into an air-filled core. Images correspond to dimensionless times of 200 (top), 500, 5000, 12,000+ (bottom).

Fig. 6.—Comparison of experimental and model water saturation profiles at various dimensionless times for water/air imbibition, run 4. Homogeneous porosity and permeability is assumed.

Fig. 7.—Relative permeability functions obtained from history matching water/air imbibition results.

Fig. 8.—Capillary pressure functions obtained from history matching water/air imbibition results compared to measured imbibition capillary pressure.

Fig. 9.—Comparison of experimental and model water saturation profiles at various dimensionless times for water/air imbibition, run 4. Heterogeneous porosity and permeability fields are honored.
Fig. 10.—Water saturation distribution along diatomite during water imbibition into an oil-filled core. Images correspond to dimensionless times of 0 (top), 5, 500, 1000, 5000 (bottom).

Fig. 11.—Oil saturation distribution along diatomite during water imbibition into a partially water saturated core. Images correspond to dimensionless times of 0 (top), 5, 50, 500, 5000 (bottom).

Fig. 12.—Dimensionless weight gain versus dimensionless time, water/oil imbibition.

Fig. 13.—Oil saturation distribution along Berea sandstone during water imbibition into a partially water saturated core. Images correspond to dimensionless times of 5 (top), 50, 500, 5000.
Fig. 14.—Water saturation profiles at various dimensionless times for water/oil imbibition into diatomite cores with initial water saturation (a) results from run 3 and (b) results from run 4.

Fig. 15.—Relative permeability functions obtained from history matching water/oil imbibition results.

Fig. 16.—Capillary pressure functions obtained from history matching water/oil imbibition results compared.