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Generalized scaling of spontaneous imbibition data for strongly water-wet systems

Shouxiang Ma [a], Norman R. Morrow [a b,*], Xiaoyun Zhang [b]

[a] *Western Research Institute, University of Wyoming, Box 3295, Laramie, WY 82071-3295, USA*

[b] *Department of Chemical and Petroleum Engineering, University of Wyoming, Box 3295, Laramie, WY 82071-3295, USA*

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Abstract

Mass transfer between fractures and matrix blocks is critical to oil recovery by waterflooding in fractured reservoirs. A scaling equation has been used for rate of oil recovery by spontaneous imbibition and presented their results as oil recovery vs. dimensionless time. Many conditions apply to this scaling equation, including identical core sample shapes and fluid viscosity ratios. Recent investigation by experiment of these two factors has resulted in a more generalized scaling equation for strongly water-wet systems with a general definition of characteristic length and a viscosity ratio term included in the definition of dimensionless time. In this paper, published data on oil recovery by imbibition have been analyzed and correlated through application of the new definition. These data sets were for different porous media, core dimensions, boundary conditions, and oil and water viscosities. All of the systems were strongly water-wet. The generalized correlation was fitted closely by an empirical mass transfer function with the new definition of dimensionless time as the only parameter. © 1997 Elsevier Science B.V.

Keywords: formation evaluation; petroleum engineering; reservoir rocks; time scales; wettability

1. Introduction

Spontaneous imbibition is an important phenomenon in reservoir engineering, especially with respect to oil recovery from fractured reservoirs. The problem of scaling imbibition and two-phase flow phenomena in general is of widespread interest (Rapoport, 1955; Miller and Miller, 1956; Graham and Richardson, 1959; Mattax and Kyte, 1962; Kazemi et al., 1976).

Mattax and Kyte (1962) published a widely applied paper on scaling of oil recovery by imbibition from fractured reservoirs. A scaling group was proposed for systems with different rock and fluid properties. Many conditions were set for the derivation of the scaling equation, including identical core shapes, viscosity ratios, and initial water saturations (S_{wi}). Two sets of imbibition data were used to test the scaling equation (see Tables 1 and 2). One set was for two cylindrical sandstone core samples with all faces open (AFO) to imbibition (Fig. 1a); the oil/water viscosity ratio was about 176. The other set was for four alundum cylindrical cores of different lengths with only one end open (OEO) to imbibi-

* Corresponding author. Tel.: + 1-307-7662838, fax: + 1-307-7666777.

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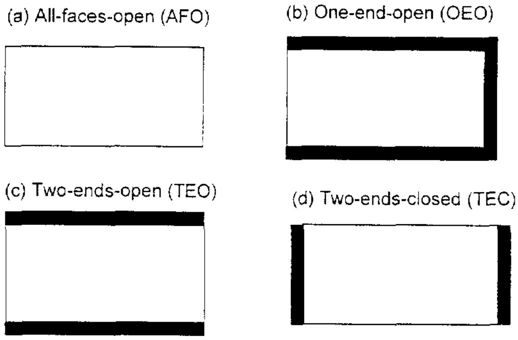

Fig. 1. Boundary conditions used by Mattax and Kyte (1962), Hamon and Vidal (1986) and Zhang et al. (1996).

tion (Fig. 1b): the oil/water viscosity ratio was about 9. In all cases except one, the water viscosity was 0.9 cP. The two sets of data, therefore, provided examples of boundary conditions, oil/water viscosity ratios, and porous media that were all different. Independent correlations were presented for each set of data.

The effect of core length and boundary conditions on imbibition rate was studied later by Hamon and Vidal (1986). The cores were made of aluminum silicate with lengths ranging from about 10 to 85 cm and boundary conditions (as shown in Fig. 1) of all-faces-open (AFO), two-ends-open (TEO) and one-end-open (OEO). The same water and oil phases were used for all of these experiments (Table 3).

In order to develop improved scaling of spontaneous imbibition, an extensive experimental study was performed by Zhang et al. (1996). Twenty Berea cores were prepared with core lengths ranging from 1.17 to 10.24 cm and boundary conditions of AFO, TEO, OEO, and two-ends-closed (TEC). In these experiments, oil viscosity ranged from about 1 to 156 cP.

In this paper, the data of Mattax and Kyte (1962), Hamon and Vidal (1986) and Zhang et al. (1996) are analyzed and compared. All of the systems are con-

Table 1
Boundary conditions covered in this study

Reference	Boundary conditions				Porous media
Mattax and Kyte, 1962	AFO	OEO			alundum and sandstone
Hamon and Vidal, 1986	AFO	OEO	TEO		aluminum silicate
Zhang et al., 1996	AFO	OEO	TEO	TEC	Berea sandstone

AFO = all-faces-open, OEO = one-end-open, TEO = two-ends-open, TEC = two-ends-closed.

Table 2
Experimental parameters from Mattax and Kyte (1962)

	No.					
	1	2	3	4	5	6
Rock	Alundum	Alundum	Alundum	Alundum	Sandstone	Sandstone
B.C.	OEO	OEO	OEO	OEO	AFO	AFO
L (in.)	2	4.35	3.05	4.35	2.06	1.1
D (in.)	1.5	1.5	1.5	1.5	1.97	1
L/D	1.333	2.9	2.033	2.9	1.046	1.1
k_g (darcy)	1.475	1.545	0.075	1.545	0.12	0.12
ϕ	0.291	0.289	0.223	0.289	0.181	0.181
$\sqrt{k_g/\phi}$	2.2514	2.3122	0.5799	2.3122	0.8142	0.8142
μ_o (cP)	8.5	8.5	8.5	116	158	158
μ_w (cP)	0.9	0.9	0.9	12.9	0.9	0.9
$\mu_r = \mu_o/\mu_w$	9.444	9.444	9.444	8.992	175.556	175.556
σ (dyn/cm)	35	35	35	36	35	35
R_{max} (%OOIP)	66	65	64	65	48	47

Table 3
Experimental parameters from Hamon and Vidal (1986)

	No.							
	1	2	3	4	5	6	7	8
B.C.	AFO	TEO	TEO	TEO	OEO	OEO	OEO	OEO
L (cm)	20	19.8	40	85.2	9.8	19.7	40	84.7
k_o (md)	2300	3200	4400	4070	3520	3430	3550	3000
ϕ (%)	45.8	45.6	48	47.6	46.6	45.3	47.8	47.8
$\sqrt{k_o/\phi}$	70.9	83.8	95.7	92.5	86.9	87	86.2	79.2
S_{wi} (%)	13.2	16.4	13.6	18.9	19.8	18.7	17.2	16.4
R_{max} (%OOIP)	83.3	86.5	84.6	87.6	85.2	83.2	85.4	81

Porous media: Aluminum silicate cores of diameter 7.6 cm. Oil: Purified refined oil with viscosity of 11.5 cP and density of 0.835 g/cm^3. Water: Degassed water with viscosity and density assumed to be 1 cP and 1 g/cm^3, respectively, in this study. Interfacial tension was 49 dyn/cm (Vidal, 1986).

sidered to be very strongly water-wet (at, or very close to, spreading of water). The porous media and boundary conditions are listed in Table 1. In all, these data include different porous media, boundary conditions, core sample geometry, permeability, porosity, aqueous phase, and oil viscosities and viscosity ratios. A generalized correlation of all results is presented.

2. The Mattax and Kyte scaling equation

Mattax and Kyte (1962) presented an equation for scaling of imbibition data under the following conditions: (1) the sample shapes and boundary conditions are identical; (2) the oil/water viscosity ratio is duplicated; (3) gravity effects can be neglected; (4) initial fluid distributions are duplicated; (5) the capillary pressure functions are directly proportional; and (6) the relative permeability functions are the same. Their equation is expressed as:

$$t_{D,MK} = Ct\sqrt{\frac{k}{\phi}}\frac{\sigma}{\mu_w}\frac{1}{L^2}, \tag{1}$$

where $t_{D,MK}$ is a dimensionless time. C, a units conversion factor, is equal to 0.018849 if the imbibition time t is in minutes, k the permeability in md, ϕ the fractional porosity, σ the interfacial tension in dyn/cm, μ_w the water viscosity in cP, and L a characteristic length in cm. The characteristic length L was not further defined by Mattax and Kyte (1962).

3. A shape factor

Starting from the work of Warren and Root (1963) and Kazemi et al. (1976), Kazemi et al. (1992) presented a shape factor, F_S, to compensate for the effect of shapes and boundary conditions,

$$F_S = \frac{1}{V_b}\sum_{i=1}^{n}\frac{A_i}{s_{A_i}} \tag{2}$$

where V_b is the bulk volume of the matrix, A_i the area open to imbibition with respect to the ith direction, s_{A_i} the distance from A_i to the center of the matrix, and n is the total number of surfaces open to imbibition. A characteristic length, L_S, that corresponds to this shape factor is defined by

$$L_S = \sqrt{\frac{1}{F_s}} = \sqrt{\frac{V_b}{\sum_{i=1}^{n} A_i/s_{A_i}}} \tag{3}$$

The Mattax and Kyte scaling equation, Eq. (1), can then be modified to

$$t_{DI} = t\sqrt{\frac{k}{\phi}}\frac{\sigma}{\mu_w}\frac{1}{L_S^2}. \tag{4}$$

The shape factor, Eq. (2), was tested using the two sets of data reported by Mattax and Kyte (1962). Recently, using the same sets of data, Gupta and Civan (1994) applied the shape factor in an attempt to characterize wettability by an effective contact angle. Mattax and Kyte's data have also been used to test mathematical models of spontaneous imbibition, such as an empirical imbibition rate model (Torsæter et al., 1987) and theoretical models of imbibition (Reis and Cil, 1993). Because the two sets of data contain errors and a distinct possibility for misinterpretation (Niven, 1974), these data first need to be examined in detail.

4. The Mattax–Kyte experimental results

Details of the two sets of imbibition data reported by Mattax and Kyte (1962) are presented in Table 2. The condition that initial fluid distributions be identi-

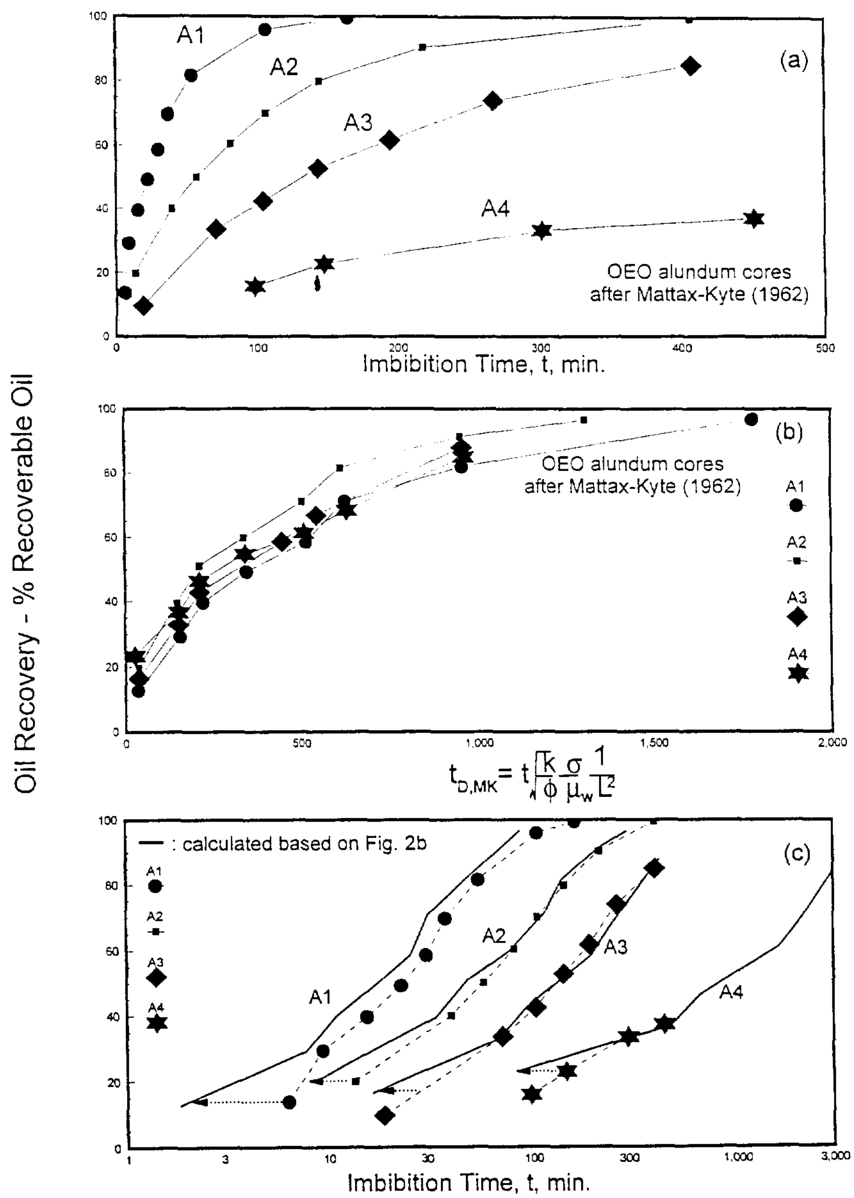

Fig. 2. Oil recovery vs. (a) imbibition time and (b) dimensionless time (after Mattax and Kyte (1962). (c) shows the comparison between the data from (a) and that calculated based on information from (b) and Niven (1974).

cal was satisfied by having all cores initially 100% saturated with oil. The lengths of the OEO alundum cores, L, ranged from 2 to 4.35 in., gas permeability, k_g, from 75 to 1545 md, and porosity from 22.3 to 29.1%. The water viscosity was 0.9 cP, and the oil viscosity was 8.5 cP. In one case, the viscosity of the aqueous phase was raised to 12.9 cP and the oil phase to 116 cP, thus keeping the viscosity ratio, μ_r, almost constant at about 9. The final oil recoveries by imbibition, R_{max}, for the alundum cores were all close to 65%.

The two sandstone cores used to obtain the second data set were geometrically similar within about 5% (see the ratio of L/D in Table 2). Boundary conditions were AFO (see Fig. 1a). The oil/water viscosity ratio was 175.6. Final oil recoveries by imbibition for these two sandstone cores were very close (47% and 48%).

4.1. The first set of data: alundum cores

Imbibition results for the four alundum cylindrical cores (hereafter identified by A1 through A4) are presented, as reported by Mattax and Kyte (1962), in Fig. 2. From Fig. 2a and Table 2, it can be seen that core A1 imbibes the fastest because of its small value of L/D, high permeability, and low oil and water viscosities. Core A4 imbibes the slowest because of the high oil and water viscosities ($\mu_o = 116$ cP and $\mu_w = 12.9$ cP, compared with $\mu_o = 8.5$ cP

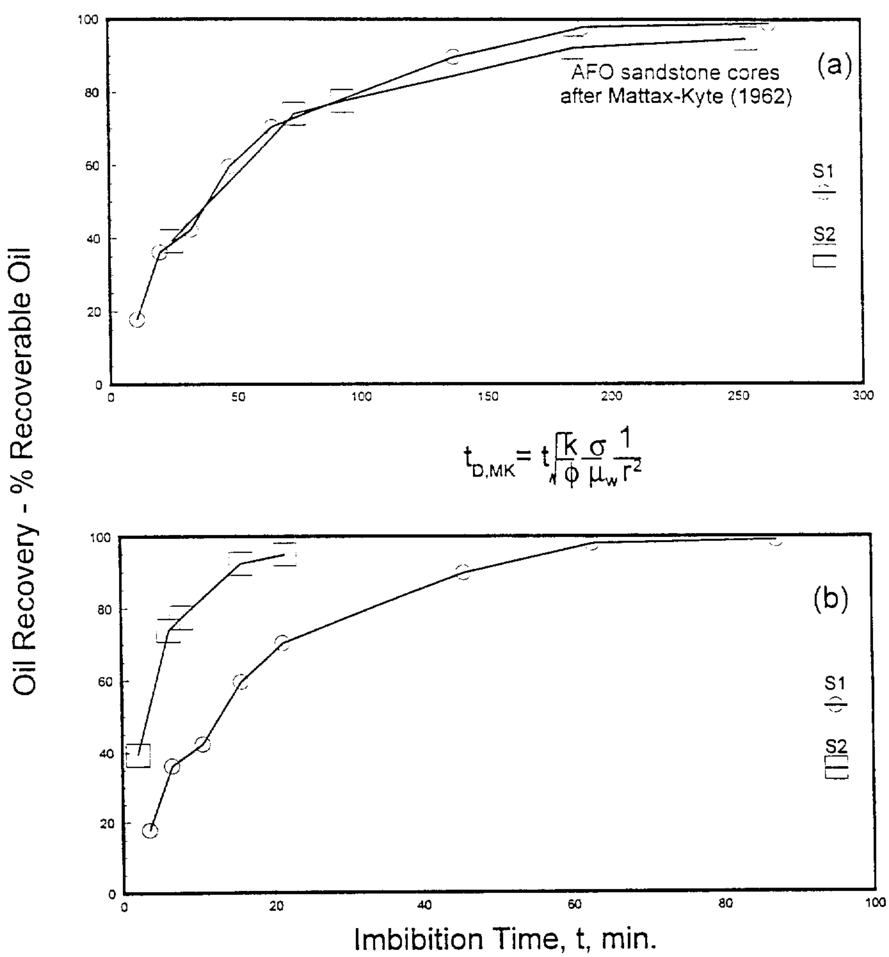

Fig. 3. Oil recovery vs. (a) dimensionless time (after Mattax and Kyte (1962) and (b) the back-calculated data for the two sandstone cores.

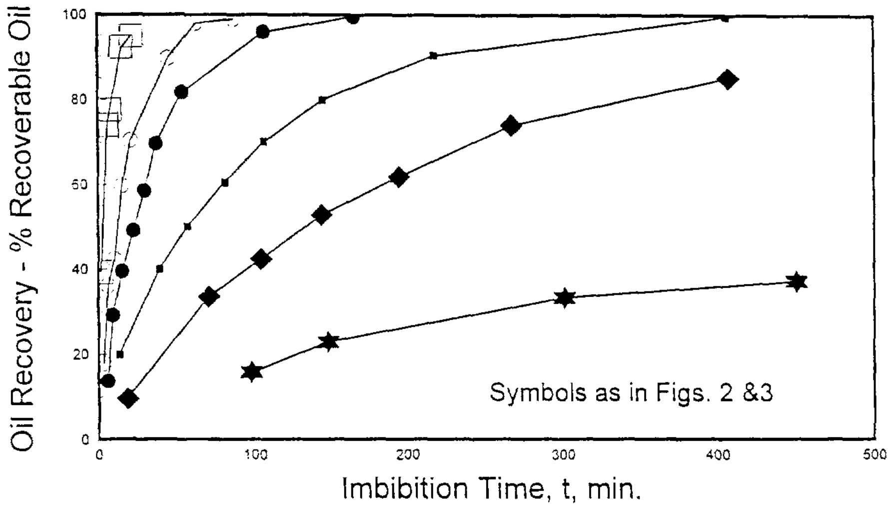

Fig. 4. Relationship between oil recovery and imbibition time for the four alundum cores (Fig. 2a) and the two sandstone cores (Fig. 3b).

and $\mu_w = 0.9$ cP for the other three samples). The permeability of core A3, which was about 1/20th of that for the other three alundum cores (75 md, compared to 1545 md for A2), caused imbibition for core A3 to be slower than for A2.

Mattax and Kyte (1962) used the sample length, L, as the characteristic length for the four alundum cores in obtaining the scaled data shown in Fig. 2b. Even though these cores do not meet the scaling requirement of being geometrically similar, the results can be expected to scale with core length because imbibition is linear and countercurrent. If the diameter of cores with the same boundary condition were varied, correlation of results with L would

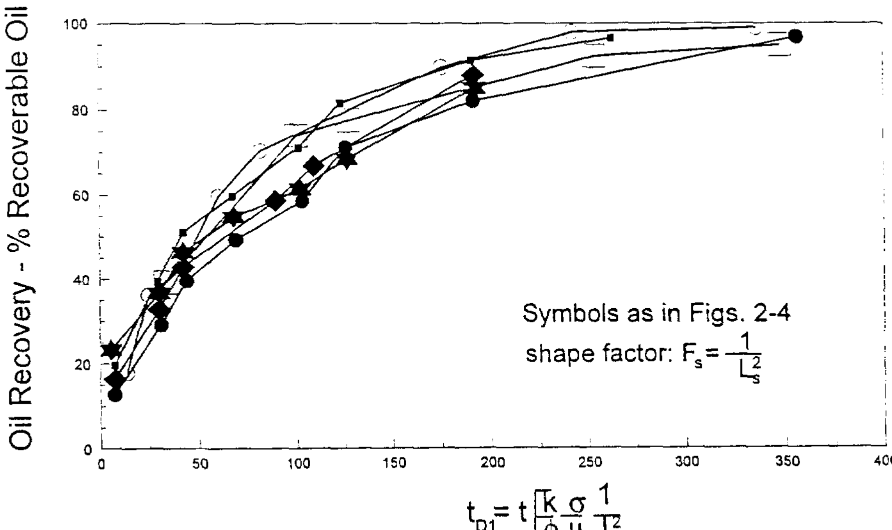

Fig. 5. Oil recovery vs. dimensionless time given by applying the shape factor, F_s, to the data of Mattax and Kyte (1962). In using Mattax and Kyte's data (Fig. 2b and Fig. 3a) to generate this plot, it was assumed that the time scales in both cases were $10\times$ too large and that L is equal to the core length for both data sets.

still be expected; differences in volume of liquid imbibed at any time, t, will be proportional to the area of the core face open to imbibition.

Niven (1974) pointed out that the dimensionless time scale (Fig. 2b) is $10\times$ too large. An error of this size could have resulted from misnumbering the scale or might be related to conversion of the units; the units conversion factor, C, in Eq. (1) will be equal to 0.092389 (i.e. $1/C = 10.824$) if t is in minutes, k in darcy, ϕ fractional porosity, σ in dyn/cm, μ_w in cP, and L in inches as reported by Mattax and Kyte (1962). When the scale was corrected by a factor of 10 as proposed by Niven (1974), the original data (Fig. 2a) and the data back-calculated from the scaled data shown in Fig. 2b are close, but inconsistencies still remain (Fig. 2c).

From Fig. 2c, it can be seen that the back-calculated data points for sample A1, the one that imbibes the fastest, show systematic differences from the original data shown in Fig. 2a. Furthermore, for all four alundum cores, the early time data points of the dimensionless time curves do not match the original data. The magnitudes of the differences are indicated by arrows in Fig. 2c. In further application of the results for alundum cores in this paper, the original data shown in Fig. 2a are used.

4.2. The second set of data: sandstone cores

Results for the two sandstone cylindrical cores were presented by Mattax and Kyte (1962) as oil recovery vs. dimensionless time, as shown in Fig. 3a. Original data were not provided. Thus the correlated data cannot be checked against the original data.

Niven (1974) stated that the scale was correct for this data set, but there was a possibility for misinterpretation. The symbol, L, was used as the characteristic length in the expression for dimensionless time, but the selection of the characteristic length had not been explained. For the alundum cores, L was the core length. However, for the sandstones, Niven (1974) stated that core radius, r, had been used as the characteristic length. With radius as the characteristic length, the imbibition recovery curves were back-calculated and are shown in Fig. 3b. The original and back-calculated imbibition data for both alundum and sandstone cores are presented in Fig. 4.

4.3. Test of the shape factor

Kazemi et al. (1992) showed that the two data sets of Mattax and Kyte (1962) could be correlated as shown in Fig. 5 through use of the Mattax and Kyte scaling equation (Eq. (1)) and the characteristic length defined by Eq. (3), using the scaled data (Figs. 2b and 3a). From comparison with Mattax and Kyte's results, it was implicitly assumed that the dimensionless time scales were $10\times$ too large for both data sets, rather than only for the alundum cores. Furthermore, the core length was taken as the characteristic length for both sets of data. This was the possibility for misinterpretation of the value of L for sandstone cores that had been pointed out by Niven (1974). With these assumptions, a correlation for the two sets of data presented by Mattax and Kyte (1962) was obtained (Fig. 5).

5. Revised definition of characteristic length

Because of the difference in viscosity ratios and the confusion in reporting and interpretation of the data of Mattax and Kyte (1962), results reported by Hamon and Vidal (1986) for different core lengths and boundary conditions, but constant viscosity ratio, were examined (Table 3 and Fig. 6a). These data were used to test the applicability of the characteristic length defined by Eq. (3). It can be seen from Fig. 6b that the AFO and TEO systems correlate well, but the OEO systems form a distinctly separate group.

Consideration of the mechanism of counter-current imbibition and examination of the correlation shown in Fig. 6b led to a modification of the characteristic length, L_C (Ma et al., 1995a),

$$L_C = \sqrt{\frac{V_b}{\sum_{i=1}^{n} A_i / l_{A_i}}} \qquad (5)$$

where l_{A_i} is the distance that the imbibition front travels from the imbibition face to the no-flow boundary. For the boundary conditions shown in Fig. 1a, c and d, the terms in Eqs. (3) and (5) are identical, and hence, $L_C = L_S$. However, for OEO (Fig. 1b), $l_{A_i} = 2 s_{A_i}$ or $L_C = \sqrt{2}\, L_S$.

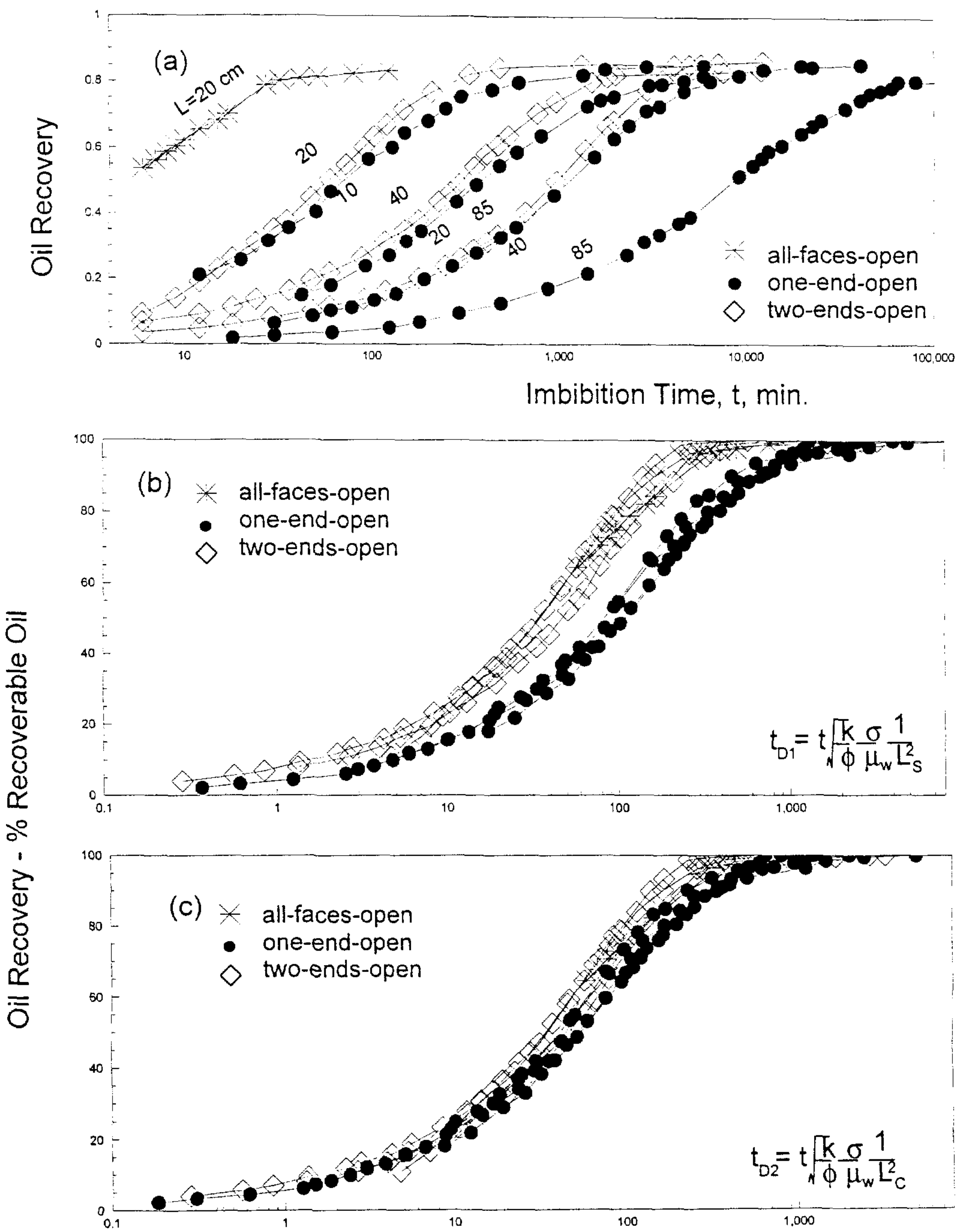

Fig. 6. Oil recovery vs. (a) imbibition time (from Hamon and Vidal, 1986), (b) dimensionless time using the shape factor, and (c) dimensionless time using characteristic length.

With L_C as characteristic length, a dimensionless time, t_{D2}, can be defined as,

$$t_{D2} = Ct\sqrt{\frac{k}{\phi}}\frac{\sigma}{\mu_w}\frac{1}{L_C^2}. \tag{6}$$

Application of this scaling group to the data of Hamon and Vidal (1986) gives a close correlation (see Fig. 6c). (For the OEO cores, the imbibition measurements were performed with the open end facing downward; this may have caused the slightly slower rate of imbibition for these cores.)

From Fig. 6a, it may be noted that the oil recovery curves for the three TEO cores with 20 cm, 40 cm and 85 cm lengths fall very close to those of the three OEO cores with lengths of 10 cm, 20 cm and 40 cm. The OEO cores were about half the length of the TEO cores. These results confirm that the no-flow boundary for the TEO cores is the circular plane through the center of the core. Detailed discussion of the relationship between boundary conditions and no-flow boundaries is given by Zhang et al. (1996).

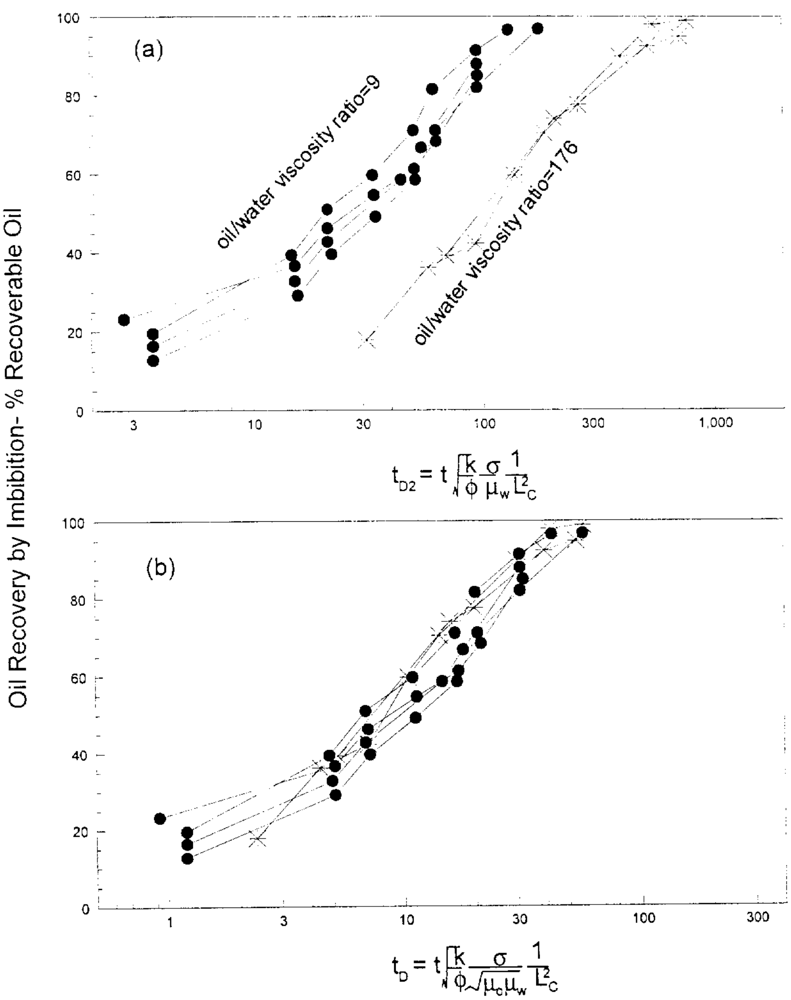

Fig. 7. Relationship between oil recovery and dimensionless time using data from Fig. 4, (a) before and (b) after inclusion of a term which compensates for the effect of viscosity ratio.

6. Generalized scaling equation

If the definition of dimensionless time from Eq. (6) is applied to the two data sets of Mattax and Kyte (1962) as presented in Fig. 4, the results fall into two distinct groups (Fig. 7a). One group, given by the alundum cores, had oil/water viscosity ratios of about 9, whereas for the experiments with sandstone cores, the viscosity ratio was 175.6.

One of the assumptions in deriving Eq. (1) was that viscosity ratios are identical. Experimental study of the effect of oil viscosity on the rate of spontaneous imbibition (Ma et al., 1995b) showed that imbibition time, t, is proportional to the geometric mean of water and oil viscosities. This empirical relationship has also been found to hold for increase in aqueous phase viscosity from 1 to 15 cP, but does not hold if the nonwetting phase is a gas. Thus Eq. (6) can be further modified to include the effect of viscosity ratio,

$$t_D = Ct\sqrt{\frac{k}{\phi}}\,\frac{\sigma}{\sqrt{\mu_w \mu_o}}\,\frac{1}{L_C^2}. \qquad (7)$$

Application of this equation to the two sets of data reported by Mattax and Kyte (1962) gives a satisfactory correlation (Fig. 7b).

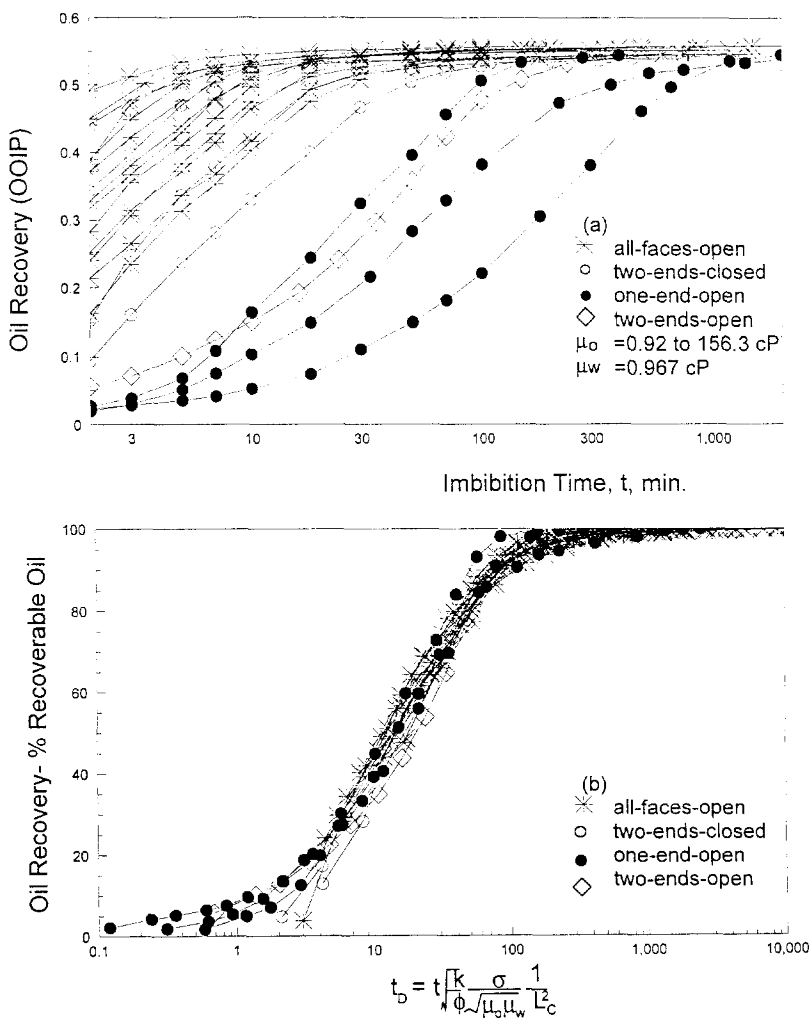

Fig. 8. Oil recovery vs. (a) imbibition time and (b) dimensionless imbibition time (after Zhang et al., 1996).

Results of Zhang et al. (1996) for 20 experiments on Berea sandstone that included different core sample lengths, boundary conditions, and oil viscosities are shown in Fig. 8a. Scaling of the results as a percentage of total oil recovered by imbibition vs. dimensionless time, t_D, defined by Eq. (7), gave close correlation of all results (see Fig. 8b). For these experiments, refined oils identified as Soltrol 130 and Soltrol 220 were cleaned by flow through silica and alumina gel to remove polar components that might exist in the oils. In combination with Berea sandstone, these liquids were considered to give very strongly, if not perfectly, water-wet conditions.

A comparison of the correlated data of Mattax and Kyte (1962), Hamon and Vidal (1986) and Zhang et al. (1996) is presented in Fig. 9. Considering the diversity of the systems, experimental techniques, and conditions, the correlation is remarkably close.

The results of Mattax and Kyte (1962) and those of Zhang et al. (1996) were for zero S_{wi}. This satisfies condition 4 of Eq. (1) that initial fluid distributions be duplicated. It may be noted that the data of Hamon and Vidal (1986) were for S_{wi} ranging from 13.2 to 19.8%. Inspection of the correlation given by this data does not reveal any systematic trend with respect to S_{wi} within this range. However, study of imbibition by Berea sandstone and chalk at strongly water-wet conditions show the effect of S_{wi} on rate of spontaneous imbibition to be surprisingly complicated. Further consideration of this subject is beyond the scope of this paper. For systems which are not very strongly water-wet, such as given by crude oil/brine/rock, imbibition, and hence wettability, also show distinct sensitivity to S_{wi} (Jadhunandan and Morrow, 1995; Morrow et al., 1996).

The fluid mechanics of counter-current spontaneous imbibition in porous media are obviously complex. The generalized correlation (Fig. 9) includes systems with distinctly different porous media: Weiler sandstone and alundum (Mattax and Kyte, 1962), aluminum silicate (Hamon and Vidal, 1986) and Berea sandstone (Zhang et al., 1996). Different ultimate oil recoveries (percent of original oil in place, %OOIP) are observed for different

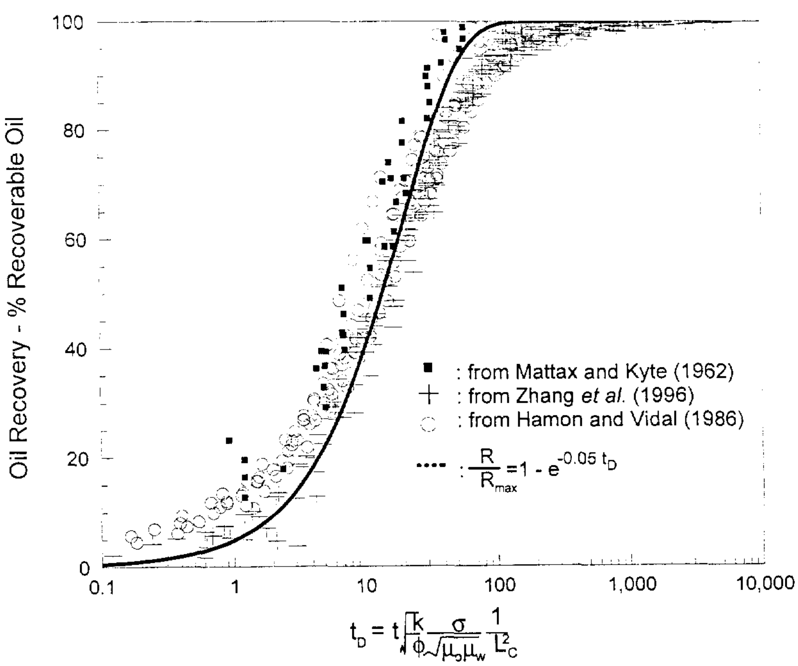

Fig. 9. A generalized correlation of data from Mattax and Kyte (1962), Hamon and Vidal (1986) and Zhang et al. (1996) and a single parameter model fit to all data.

porous media. From Tables 2 and 3 and Fig. 8a, the ultimate oil recoveries were about 65% for Mattax and Kyte's alundum, 48% for Mattax and Kyte's sandstone, about 85% for Hamon and Vidal's aluminum silicate, and about 55% for Zhang et al.'s Berea sandstone. Results of Hamon and Vidal (1986) and Zhang et al. (1996) show that the ultimate oil recovery by imbibition is not affected by core sample size and boundary conditions. This is consistent with the observations of Torsæter and Silseth (1985).

The different media for which the correlation in Fig. 9 was developed can be expected to have differences in relative permeabilities; furthermore, the capillary pressure functions (the relevant imbibition curves) are not likely to be directly proportional. Thus, conditions 5 and 6, under which Eq. (1) was derived, are not satisfied. However, the close correlation of results obtained from use of Eq. (7) indicates that normalizing the produced oil saturation with respect to ultimate recovery and use of the term $\sqrt{k/\phi}$, the microscopic pore radius, compensates reasonably well for differences in pore structure. The correlation needs to be tested further by obtaining results for a wider range of rock types.

7. A mass transfer function

The correlation shown in Fig. 9 was fitted by a single parameter mass transfer function

$$\frac{R}{R_{\max}} = 1 - e^{-\alpha t_D} \tag{8}$$

where R is oil recovery by imbibition, $R_{\max}$ is ultimate oil recovery by imbibition, and α is the oil production decline constant. For the curve shown in Fig. 9, the average value of α is 0.05.

Eq. (8) is of the form proposed by Aronofsky et al. (1958), except that the dimensionless imbibition time is used together with a simplified form of production decline constant. Obviously, a closer overall fit can be obtained by increasing the number of parameters in the mass transfer equation (Shinta and Kazemi, 1993).

8. Application of generalized correlation to characterization of wettability

Many systems that are not strongly water-wet still exhibit spontaneous imbibition. If all other factors are equal, or can be compensated for through Eq. (7), or are of relatively minor importance, the difference in imbibition rate between strongly water-wet porous media and some other wettability state can be used to characterize wettability (Bobek et al., 1958; Ma et al., 1994; Morrow et al., 1996). For oil-reservoir core samples, imbibition-rate measurements can be made on fresh reservoir cores recovered under carefully controlled conditions or on restored state cores (Cuiec et al., 1994). Evaluation of the effect of wettability requires that the imbibition curves for the same cores under very strongly water-wet conditions be known. Measurement of such curves requires that essentially all adsorbed hydrocarbons be removed. Numerous core cleaning procedures involving solvent extraction have been proposed, but there is no method of ensuring removal of all organic material while leaving the rock pore structure essentially intact. Strong solvents, such as pyridine, will displace hydrocarbons through preferential adsorption, but the pyridine will then be more strongly adsorbed than the material it replaced (O'Meara et al., 1988). A further condition for obtaining a rock sample which is completely water-wet is that the rock is free of significant hydrophobic minerals. Thus, in many instances, the correlation shown in Fig. 9 may provide a more reliable estimate of an imbibition curve for very strongly water-wet conditions than is given by measurements obtained after attempting to clean a reservoir core. Alternatively, the correlation can be used to assess the effectiveness of core cleaning processes, because it can be used to estimate an imbibition curve for very strongly water-wet conditions. Comparison of the measured imbibition curve for recovery of clean mineral oil from a cleaned core with the estimated curve will provide a useful test of the effectiveness of core cleaning.

9. Conclusions

(1) Previously reported data on oil recovery from strongly water-wet media by spontaneous imbibition

can be correlated by plotting percent of ultimate oil recovery by imbibition vs. dimensionless time defined by

$$t_D = t\sqrt{\frac{k}{\phi}}\frac{\sigma}{\sqrt{\mu_o \mu_w}}\frac{1}{L_C^2}.$$

(2) The effect of differences in sample size, shape, and boundary conditions are correlated by a generalized characteristic length, L_C. Differences in viscosity ratio are correlated by the geometric mean of the water (aqueous) and oil viscosities.

(3) The general correlation is fitted closely by an equation for exponential decay with dimensionless time, t_D, as the only parameter.

(4) The correlation implies, for the porous media studied to date, that the term $\sqrt{k/\phi}$, a microscopic pore radius, provides a satisfactory correlation for the effects of pore structure and transport properties for two-phase counter-current flow.

(5) For systems which are not very strongly water-wet, wettability can be assessed from the reduction in imbibition rate relative to the predicted result for very strongly water-wet conditions.

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Appendix A

A surface area
C units conversion factor
D diameter
F shape factor
k permeability
L distance from imbibition surface to no-flow boundary
l length or characteristic length of core samples
n number of surfaces available for imbibition
R oil recovery
s distance from a surface to the center of the matrix
t time
V volume

Greek

α modified oil production rate decline constant
μ viscosity
ρ density
σ interfacial tension, IFT
ϕ porosity

Subscripts

A_i ith surface
b bulk
C characteristic
D dimensionless
D1 dimensionless time defined by shape factor
D2 dimensionless time defined by characteristic length without considering the effect of fluid viscosity
g gas
i ith direction
max maximum
MK Mattax–Kyte
o oil
r ratio
S shape
w water
wi initial water

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