Modified Version of Aronovsky Model for Predicting the Performance of Naturally Fractured Oil Reservoirs

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ABSTRACT

In this work the mathematical model developed by Aronovsky et. al. for predicting rates of free-water imbibition in naturally fractured oil reservoirs has been modified. The proposed model allows prediction of fractional oil recovery by spontaneous water imbibition in core samples with high accuracy.

The proposed modification involves development of an empirical correlation for the reservoir rock/fluid system-dependent parameter (λ) used in Aronofsky model and defined as rate of convergence. The key reservoir rock and fluid physical properties considered in this work include absolute permeability of the rock, porosity, initial water saturation, interfacial tension between oil and water (IFT), viscosity of oil, viscosity of water, and length of core sample.

The accuracy of the modified model is evaluated using the results of laboratory imbibition tests on nine limestone core samples. All imbibition tests were conducted at 90 ° C. The absolute per cent error based on laboratory versus calculated values of (λ) is found to range between 0.334 and 3.88.

The proposed model may also be applied for predicting fractured reservoir performance on field scale by simply replacing the core length by matrix block length when the block is totally immersed in water. Additional experimental work and/or field observations would be necessary to verify the reliability of the proposed modification.

Key Words: imbibition, fractured reservoirs, rate of convergence, Aronovsky model, and empirical correlations.

Introduction

In any natural or artificial water drive reservoir the oil recovery mechanism is controlled by (1) the external imposed pressure differential, and (2) the pressure difference due to capillarity. In highly fractured oil reservoirs the flow of oil is mainly through the fracture networks with little pressure gradient across the matrix blocks. Consequently, the capillary pressure gradient dominates the oil displacement process in the matrix block.

In oil/water, water-wet system, water has a natural tendency to penetrate (imbibe) the matrix and gravity forces reinforces capillary imbibitions. The expelled oil then is displaced by oncoming water through the fracture network to the producing well (Al-Lawati and Saleh, 1996). The capillary forces oppose the penetration of water into the matrix and the displacement is only possible if the driving force (gravity)

overcomes the resistance defined in terms of "threshold capillary pressure". This is only possible for matrix of elements of a certain size (large blocks). It follows that oil cannot be expelled by water from an intensely fractured oil-wet reservoir. Such reservoirs have gained emphasis as a result of the failure of a number of water floods carried out on limestone; it would appear that the presence of small quantities of organic matter (such as coal) dispersed in the matrix can induce a wettability to oil which results in poor reservoir performance under water injection. Additional methods, other than water flooding, such as injection of chemical solution which involves the use of surfactants capable of altering matrix wettability, should be considered to increase the effectiveness of the capillary imbibition (Babadagli, 2001; Adibhatla and Mohanty, 2008). Also low-salinity or smart waters may be considered in this connection [Al-Attar, et. al., 2013 and Abubacker, et. al. (2017).

Several laboratory studies, mostly on sandstone cores, synthetic sandstone cores, and sand packs, were published using different fluid systems and different methods of imbibition. Some early laboratory work by Manon and Chilingar (1972) was performed on both linear and counter-current flow at both constant and variable rates. The first real work on imbibition that describes the process was made by Mattax and Kyte (1972). They reported results of experiments performed with fixed interfacial tension (IFT) showing that the dimensionless imbibition time (t_D) depends on the matrix geometry and physical properties of the fluids. They stated that, if imbibition oil recovery is plotted against the dimensionless scaling parameter t $(k/\phi)^{1/2}(\sigma/\mu_w L^2)$, the same recovery curve will be obtained for the model and for all matrix blocks of the same rock type and geometry. This means that imbibition tests on a small reservoir sample can scale imbibition behavior for all reservoir matrix blocks of the same shape and rock type. Where, t is imbibition time, ϕ is porosity, k is permeability, σ is IFT between the wetting and non-wetting phases, μ_w is water viscosity, and L is characteristic length of matrix block or sample. Zhang et al. (1996) reported that most experimental work on imbibition behavior is concentrated on the scaling aspect of the process in order to estimate oil recovery from reservoir matrix blocks that have shapes and sizes different from those of the laboratory core samples. Ma et al. (1999) generalized the shape factor which was proposed by Kazemi et al. (1992) to account for the effects of viscosity ratio, sample shape, and boundary conditions. The dimensionless time proposed by Ma et al. (1999) is defined as follows:

$$t_D = (k/\phi)^{1/2}(\sigma/\mu_m L_a^2)\, t \qquad\qquad\qquad (1)$$

Where μ_m is geometric mean of the viscosities of the two phases, $(\mu_o\mu_w)^{1/2}$, and L_a is characteristic length. Li and Horne (2002) developed a general approach to scale the spontaneous imbibition data for gas-liquid-rock and oil-water-rock systems in both co-current and counter-current cases. Their definition of dimensionless time considers almost all the parameters physically involved, and takes the following expression,

$$t_D = c^2(kk^*_{re}/\phi)(P^*_c/\mu_e)((S_{wf} - S_{wi})/L_a^2)\, t \qquad\qquad\qquad (2)$$

Where $kk^*_{re}/\mu_e (= M^*_e)$ is effective mobility of the two phases at the average water saturation behind the imbibition front (S_{wf}), P^*_c is capillary pressure at S_{wf}, S_{wi} is initial water saturation, and c is ratio of gravity force to capillary force.

Fischer and Morrow (2005) addressed oil recovery from cylindrical sandstone cores by spontaneous imbibition at very strongly water-wet conditions for viscosity ratios of unity. In all, 25 imbibition data sets

reported in their study for various boundary conditions were satisfactorily correlated by the Mattax and Kyte (1972) scaling group. They concluded that final oil recoveries for radially dominated imbibition were independent of viscosity whereas recoveries for linear imbibition were consistently lower and decreased by up to 2.5% PV with increase in viscosity.

Al-Attar (2010) investigated the response of oil-wet chalky limestone cores to free imbibition by alkali aqueous solution and surfactant solution. He concluded that addition of nonionic surfactant to the aqueous solution could change the surface wettability properties of the core matrix towards the water-wet regime. He also concluded that ultimate oil recovery by spontaneous imbibition and rates of imbibition are largely related to the IFT between oil and the imbibing fluid and to the permeability of the core sample.

The objective of this work is develop an empirical correlation for the rate of convergence of oil recovery to ultimate oil recovery by free imbibition from water-wet limestone core samples. The proposed correlation includes key rock and fluid properties which control the imbibition process. Such a correlation would be very useful in simulating laboratory imbibition test data and predicting oil recovery in fractured oil reservoirs on large scales.

Development of proposed modification

Imbibition is the spontaneous displacement of a non-wetting phase by a wetting phase under zero external pressure gradient. The rate of free imbibition is controlled by the physical properties of the rock/fluid system including rock wettability. Aronovsky et. al., (1958) proposed a simple mathematical model to describe the imbibition process and as follows.

$$r(t) = R\left(1 - e^{-\lambda t}\right) \tag{3}$$

Where:

$r(t)$: volume of oil in place recovered at time t, cc

R: volume of oil in place recovered at end of the imbibition test, cc

λ: rate of convergence, hr^{-1}

t: imbibition time, hr.

Equation (1) may be written as follows:

$$1 - [r(t)/R] = e^{-\lambda t}$$

$$ln\{1 - [r(t)/R]\} = -\lambda t$$

$$log\{1 - [r(t)/R]\} = -\lambda t /2.303 \tag{4}$$

A plot of $log\{1 - [r(t)/R]\}$ versus t would yield a straight line with slope $(m^*) = -\lambda/2.303$ and thus $\lambda = -2.303\ (m^*)$. The results of the free-imbibition tests presented in the following section were used to prepare the above plots and to determine their corresponding values of λ.

The next step was to correlate λ with rock/fluid system physical properties. For this purpose the various dimensionless scaling parameters developed by Mattax and Kyte (1972), Ma et. al. (1999), and Li-Horn (2002), and the conclusions made by Al-Attar (2010) were considered. By similarity with these scaling parameters and after attempting various combinations of grouping of variables, the following laboratory data-based empirical correlation has been found to accurately predict values of λ.

$$\lambda = 1.1309519\ (k/\phi)^{0.5}\ (\sigma_{wo})\ (S_{wi})^{3.49} / [(\mu_o - \mu_w)\ (L^2)] \tag{5}$$

Where:

k is the absolute permeability of the rock, md

ϕ is the porosity, fraction

σ_{wo} is the IFT between water and oil, dynes/cm

S_{wi} is the initial water saturation, fraction

μ_o is the oil viscosity, cp

μ_w is the water viscosity, fraction, and

L is the length of core sample, cm, and

1.1309519 is units' conversion factor.

Equation (5) is similar in form to the aforementioned scaling parameters and it shows that λ is largely sensitive to initial water saturation and length of core sample, and to a lesser extent to the viscosity difference between non-wetting and wetting phases, IFT, absolute permeability and porosity.

Results of experimental work

In this work the oil-saturated core sample were totally immersed in water and standard imbibition tests were conducted at 90 °C. The physical properties of the rock/fluid system used in these tests are listed in Table 1. The results of selected imbibition tests in terms of $[r(t)/R]$ versus time are presented in Table 2 and in terms of $\log\{1 - [r(t)/R]\}$ versus time are illustrated in Figs. 1 through 4. These results clearly show the exponential nature of oil recovery by the free imbibition process.

Table 1 Physical properties of the rock/fluid systems used in the experimental work.

Core No.	Imbibing Water	Air Permeability k, md	Porosity, ϕ, fraction	Initial Water Saturation, S_{wi}, fraction	Core Length, L, cm	IFT, σ_{wo}, dynes/cm
1	Sea Water (SW)	7.2	0.21	0.331	8.330	9.0
2	Sea Water (SW)	9.3	0.15	0.334	8.650	9.0
3	Sea Water (SW)	3.0	0.11	0.291	6.640	9.0
4	Sea Water Diluted 50 times (SWx50)	13.0	0.27	0.170	5.180	13.9
5	Sea Water Diluted 10 times (SWx10)	11.0	0.27	0.192	5.116	11.7
6	Formation Water (FW)	12.0	0.29	0.210	5.210	13.0
7	SW	12.0	0.29	0.195	5.210	9.5
8	SW	17.0	0.25	0.185	5.188	9.5
9	SW	17.0	0.25	0.180	5.188	10.8

Table 2 Results of imbibition tests of selected core samples; [$r(t)/R$] versus time.

Time, hrs.	Core #4	Core #5	Core #6	Core #7
0	0	0	0	0
24	0.15	0.17	0.38	0.22
48	0.46	0.50	0.75	0.33
72	0.69	0.67	0.75	0.44
96	0.69	0.75	0.88	0.67
120	0.77	0.83	1.00	0.78
144	0.77	0.92	1.00	0.89
168	0.85	1.00	1.00	1.00
192	1.00	1.00	1.00	1.00
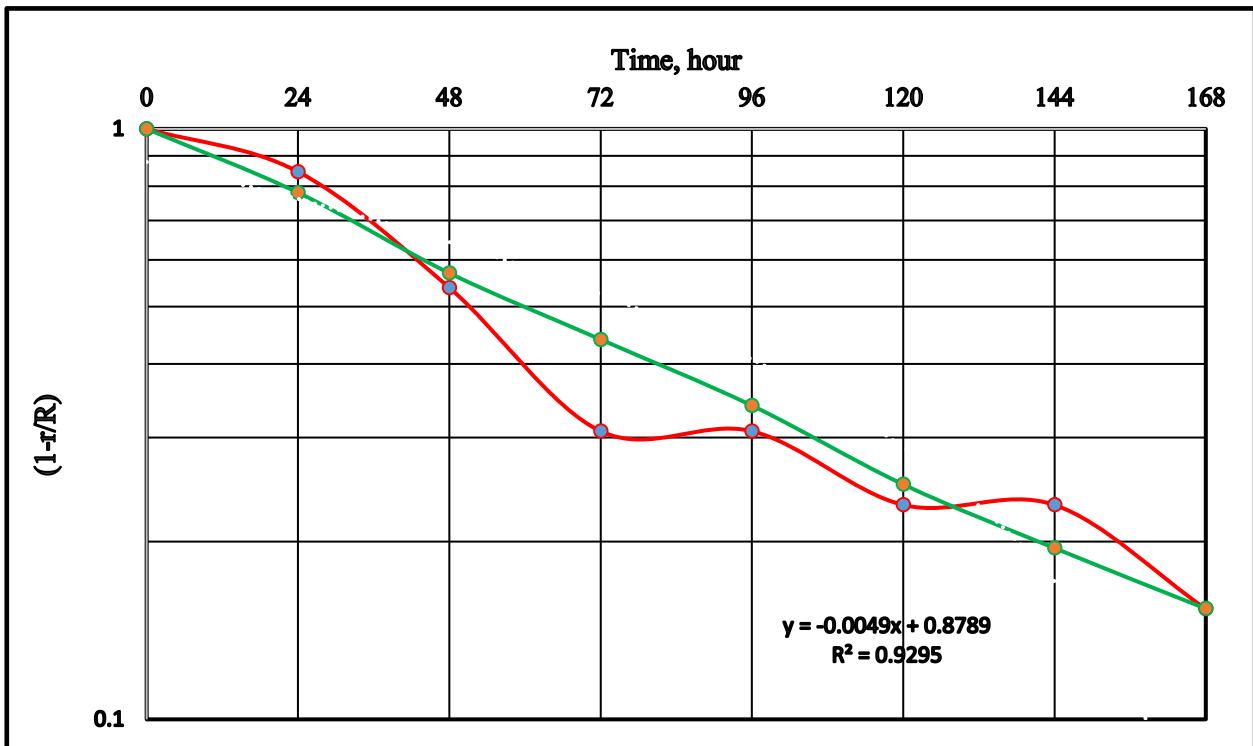
Fig. 1. Plot of Eqn. (4) using imbibition test results of core no. 4 with SWx50.
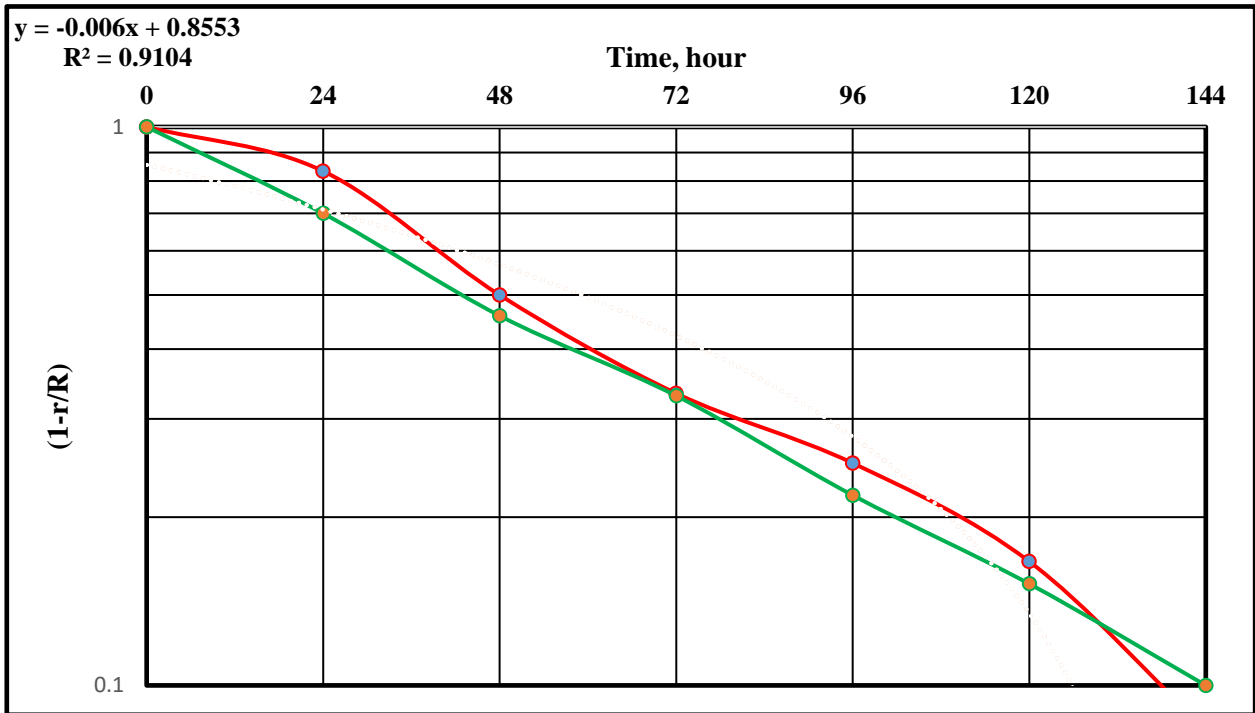
Fig. 2. Plot of Eqn. (4) using imbibition test results of core no. 5 with SWx10
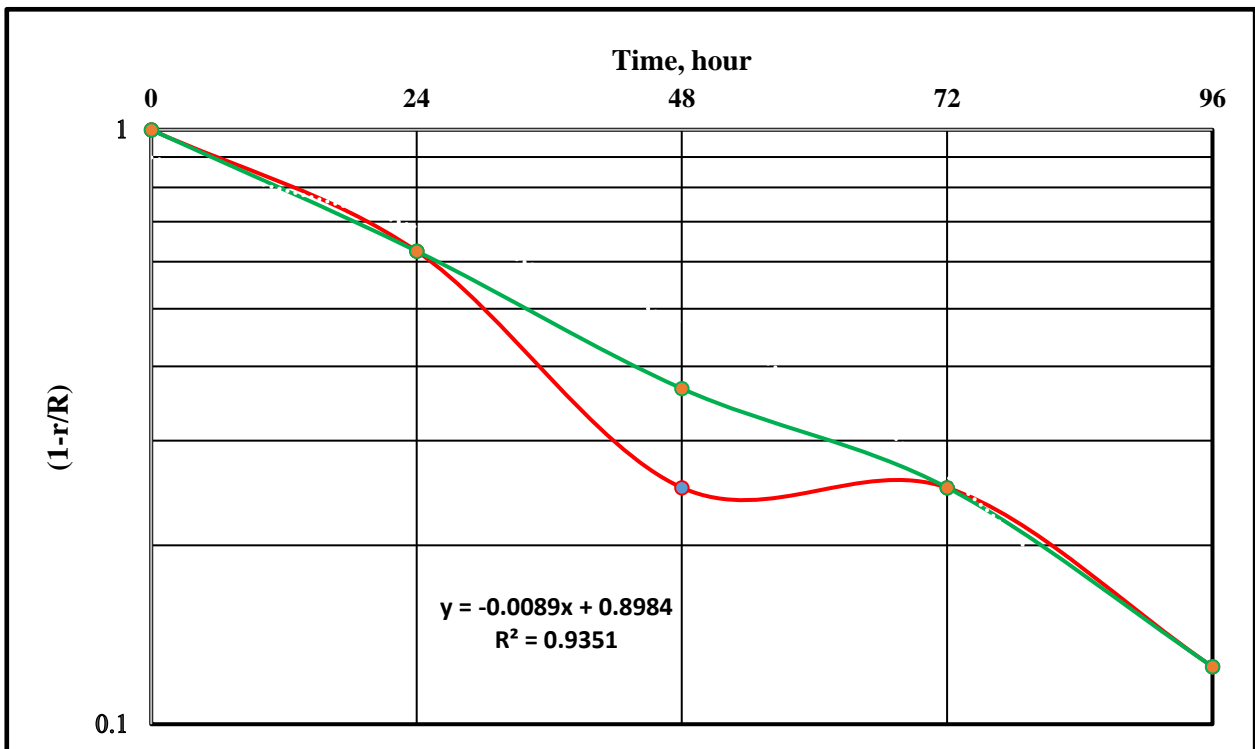

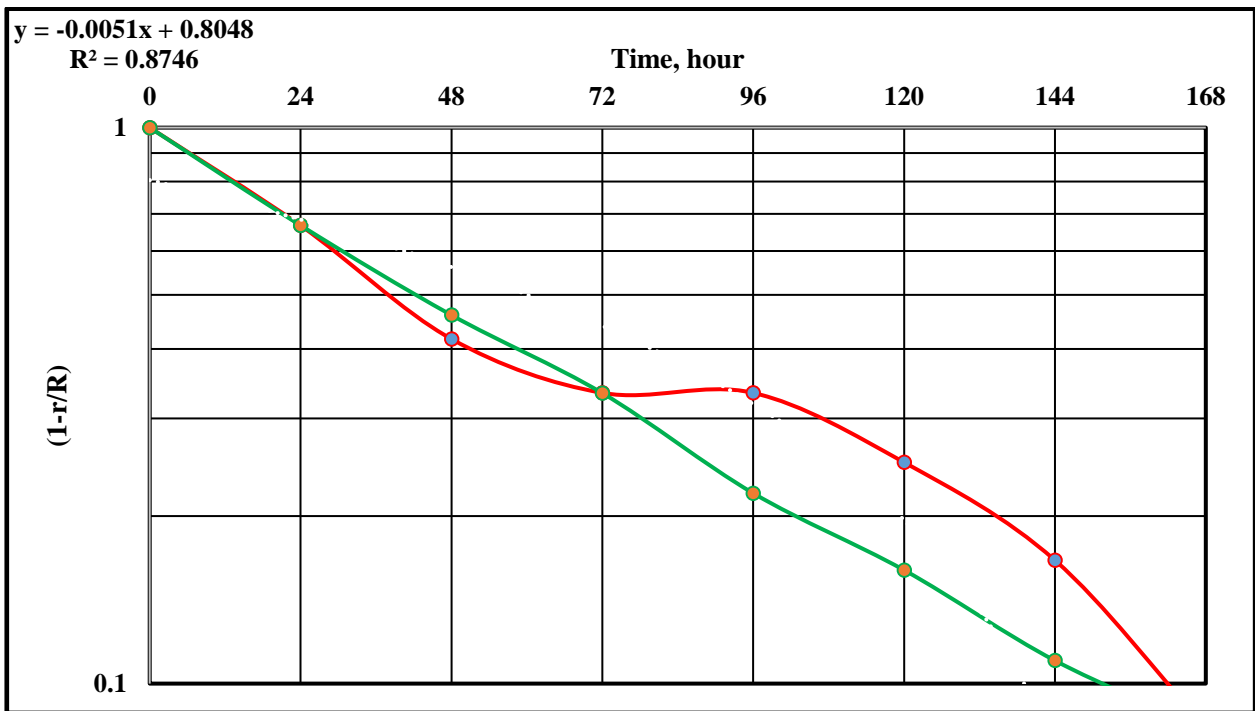**Fig. 3. Plot of Eqn. (4) using imbibition test results of core no. 6 with FW.**

Fig. 4. Plot of Eqn. (4) using imbibition test results of core no. 7 with SW.

Results of proposed modification

Table 3 presents the results of calculations of λ by Eqn. (5) and the results of λ deduced from the slopes of plots of Eqn. (4). The last column of Table 3 shows the results of calculations of absolute per cent error of the two values of λ for each core. The range of this error ranges from as low as 0.334% up to 3.88% which gives confidence in the application of the proposed modification to predict the rate of convergence. A comparison between laboratory deduced- and calculated values of λ is also illustrated in Fig. 5 showing almost a perfect match on the 45 degree line.

Table 3 Evaluation of accuracy of predicted λ by the proposed model.

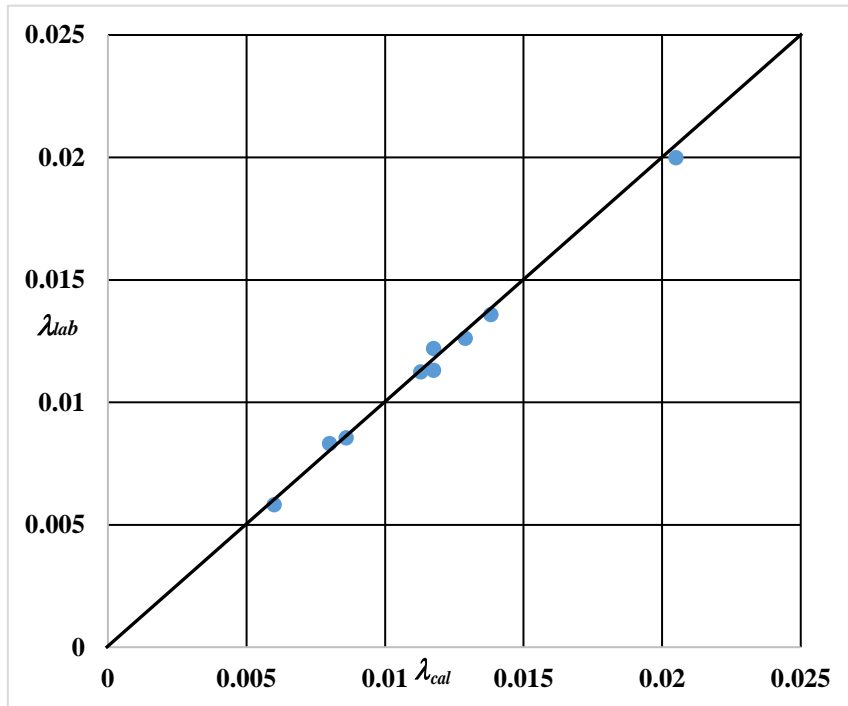| Core No.	Laboratory λ, hr $^{-1}$	Predicted λ Eqn. (5), hr $^{-1}$	Absolute % Error
1	0.008600	0.0085450	0.640
2	0.008000	0.0083102	3.880
3	0.006000	0.0058141	3.100
4	0.011285	0.0112473	0.334
5	0.013818	0.0135860	1.681
6	0.020497	0.0199834	2.500
7	0.011745	0.0113090	3.715
8	0.011745	0.0121920	3.800
9	0.012897	0.0126100	2.220

Fig. 5. Comparison between laboratory deduced and predicted values of λ.

Discussion of results

The Aronovsky et. al. (1958) mathematical model was developed to simulate the imbibition process in naturally fractured oil reservoirs. This model may only be used to predict reservoir performance when enough field production data were available. The technique presented in this work provides a simpler approach for predicting the performance of naturally fractured reservoirs using some basic physical properties of the reservoir rock/fluid system. These basic properties include porosity, absolute permeability, IFT and viscosity of the imbibing and imbibed phases, and the length of matrix block (core length), all of which can be easily measured in the laboratory.

The first step of development of the proposed modification involved plotting laboratory data of imbibition tests as log $\{1 - [r(t)/R]\}$ versus time as shown in Figs. 1 through 4. The best trend line was then constructed through the plotted data points and rate of convergence (λ) calculated. These trend lines seem to closely match the actual trends of the experimental data which is to be expected considering the exponential trend of the imbibition process depicted by Arononvsky et. al. model.

The validity of the proposed modification presented in Eqn. (5) was tested using laboratory imbibition data of nine limestone core samples. The imbibing fluids include sea water (SW), formation water (FW), sea water diluted 10 times (SWx10), and sea water diluted 50 times (SWx50). In all tests, the values of rate of convergence (λ) deduced from imbibition plots almost perfectly matched those calculated by the Eqn. (5). Further attempts are necessary to develop a correlation for the ultimate oil recovery (R) by spontaneous imbibition process using laboratory and field data.

Conclusions

The following conclusions may be drawn from this work:

1. The Aronovsky et. al. mathematical model which describes the free imbibition process has been modified using laboratory imbibition tests on nine limestone core samples.

2. The accuracy of the modified version of Arononvsky et. al. model has been evaluated using the experimental data and the absolute per cent error is found to range between 0.334 and 3.88.

3. The proposed empirical correlation of the rate of convergence is found to be largely sensitive to the initial water saturation and length of the core sample. The same correlation may be applied to predict the performance of naturally fractured oil reservoirs using the physical properties of the reservoir rock/fluid system including the length of the matrix block.

4. No attempt was made to develop a correlation for the ultimate oil recovery, *R*, from the imbibition process.

5. Additional laboratory and/or field data are required to verify the reliability of the proposed modification.

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