Advances in Geo-Energy Research

Vol. 4, No. 1, p. 99-106, 2020

Original article

A new scaling equation for imbibition process in naturally fractured gas reservoirs

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Keywords:
Naturally fractured gas reservoir
imbibition
inspectional analysis
scaling

Cited as:
Ghasemi, F., Ghaedi, M., Escrochi, M. A new scaling equation for imbibition process in naturally fractured gas reservoirs. *Advances in Geo-Energy Research*, 2020, 4(1): 99-106, doi: 10.26804/ager.2020.01.09.

Abstract:
Spontaneous imbibition is an important mechanism in naturally fractured reservoirs. Efforts were made to study matrix-fracture interaction where matrix blocks are surrounded by water-filled fractures by developing the scaling groups. Despite previous studies about the scaling groups introduced to characterize the imbibition process in oil reservoirs, gas reservoirs have been less considered. In this paper, the effects of various factors on the spontaneous imbibition in the gas reservoirs were investigated and by inspectional analysis, a modified scaling equation was introduced. The proposed scaling equation includes a variety of fluid and rock parameters. Furthermore, the efficiency of the presented scaling equation was tested in several cases with considerable different fluid and rock properties. The imbibition process in these cases were simulated by means of a realistic procedure. A comparison of the performance results of the new scaling equation for the defined cases showed much better accuracy for the imbibition scaling in the gas reservoirs by means of the presented scaling group in this work.

1. Introduction

A considerable portion of oil and gas resources exists in naturally fractured reservoirs (Nelson, 2001). In naturally fractured reservoirs, two very different media, i.e., matrix and fracture interact. Due to the heterogeneous nature of these reservoirs, it is difficult to investigate the production performance of them (Abbasi et al., 2016, 2017). For the naturally fractured reservoirs with active water drive or water injection process, the spontaneous imbibition of water from surrounding fractures to oil or gas saturated matrix blocks is one of the most important production mechanisms (Pow et al., 1997; Morrow and Mason, 2001; Morrow and Xie, 2001; Zhou et al., 2002). In these types of reservoirs, because of the high conductivity of the fracture system, water flows through fractures faster than matrix blocks. As a result of this fact, matrix blocks with high oil or gas saturation remain surrounded by water-saturated fractures (Ghaedi and Riazi, 2016). Afterward, oil or gas production can occur through the imbibition process, which is generally a slow mechanism. In this process depending on boundary conditions, gravity and viscous forces work either through co-current or counter-current phenomenon (Mason and Morrow, 2013; Meng et al., 2017). Investigation of the spontaneous imbibition is essential to understanding the production performance of fractured reservoirs (Pow et al., 1997; Babadagli, 2005; Abd and Alyafei, 2018).

A considerable amount of literature has been published on scaling of the spontaneous imbibition process (Mattax and Kyte, 1962; Reis and Cil, 1993; Zhou et al., 2002; Li and Horne, 2006; Schmid et al., 2012; Mirzaei-Paiaman, 2015; Torsu and Aryana, 2016). The spontaneous imbibition is controlled by many parameters including pressure, block dimensions, relative permeability, rock and fluid properties (Cai and Yu, 2011; Cai et al., 2014). Using an appropriate scaling group that considers the effects of almost all of these parameters can lead to an accurate characterization of the spontaneous imbibition performance.

Scaling of the imbibition process has been studied in oil

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Received February 27, 2020; revised March 8, 2020; accepted March 8, 2020; available online March 13, 2020.

Ausasia Science and Technology Press

systems extensively. Previous researches mainly focused on the investigations of the impacts of different parameters on the imbibition process. Efforts also were made for appropriate experimental and numerical simulations and developing new scaling equation for better characterizations of imbibition process (Mattax and Kyte, 1962; Rapoport, 1955; Ma et al., 1997; Morrow and Mason, 2001; Ghaedi and Riazi, 2016). In contrast, much less attention has been paid to the study of the imbibition process in naturally fractured gas reservoirs.

Working with dimensionless numbers is a very efficient way to characterize different processes. Two methods have been utilized to develop a dimensionless scaling equation using the main governing equation including inspectional analysis and applying the approximate analytical solution. In the inspectional analysis approach the main governing equation is utilized and by using the similarity between the equations of model and prototype, dimensionless groups are developed (Mattax and Kyte, 1962; Mirzaei-Paiaman, 2015; Ghaedi and Riazi, 2016). In applying the approximate analytical solution method, a solution to the recovery process is derived by considering important factors. Then dimensionless numbers are determined (Reis and Cil, 1993; Li and Horne, 2002).

Based on the work of Rapoport (1955), Mattax and Kyte (1962) proposed a scaling equation where impacts of different properties such as permeability, porosity, and size were considered. Ma et al. (1997) later empirically modified that scaling equation. They considered the effect of oil and water viscosities.

$$t_{D,Ma} = t\sqrt{\frac{k_m}{\phi_m}}\frac{\sigma}{\sqrt{\mu_w\mu_o}}F_s \tag{1}$$

where $t_{D,Ma}$ is dimensionless time; t is imbibition time; k_m is matrix permeability; ϕ_m represents matrix porosity; μ_w and μ_o are water and oil viscosities, respectively; σ is interfacial tension between oil and water, and F_s is shape factor defined by Kazemi et al. (1992) as follows:

$$F_s = \frac{1}{V_m}\sum_{i=1}^{n}\frac{A_{mi}}{d_{mi}} \tag{2}$$

where V_m is defined as the bulk volume of matrix block; A_{mi} is the area of surface i exposed to flow in the i^{th} flow direction; d_{mi} is the space between A_{mi} to the no-flow boundary and n is the number of all exposed surfaces of matrix block to flow.

Gas production from naturally fractured gas reservoirs was investigated by Pow et al. (1997). They performed two imbibition tests to predict the imbibition rate and ultimate recovery. In their work also, the coefficients of the scaling equation proposed by Ma et al. (1997) for oil systems, were modified for gas reservoirs.

Li and Horne (2002) proposed a scaling equation for gas systems. They assumed the Darcy equation for gas and water flow, piston-like flow for water and infinite gas mobility to develop the equation:

$$t_{D,Li\&Horne} = c^2\frac{k_w}{\phi_m}\frac{P_c}{\mu_w}\frac{\left(s_{wf}-s_{wi}\right)}{L_a^2}t \tag{3}$$

where c is the ratio of gravitational to capillary forces, and is defined by parameters "b" and "a"; s_{wf} and s_{wi} are frontal and initial water saturations; k_w is effective permeability of water at the saturation of s_{wf}; P_c is capillary pressure at the saturation of s_{wf}; L_a is equal to the core length and t is imbibition time. Constant b is defined as:

$$b = \frac{Ak_w\Delta\rho g}{\mu_w} \tag{4}$$

where A is the cross-sectional area of the core, and $\Delta\rho$ is the density difference between water and gas. Constant a is expressed as follows:

$$a = \frac{Ak_w\left(s_{wf}-s_{wi}\right)}{\mu_w L}P_c \tag{5}$$

where L is the length of the core.

$$c = \frac{b}{a} \tag{6}$$

With the increasing demand for natural gas, the industry's attention to fractured gas reservoirs has been increased. Despite all efforts made to characterize the imbibition process in oil reservoirs, this process in gas reservoirs has been less studied. Presenting a new scaling equation that covers a wide range of effective parameters in the imbibition process in naturally fractured gas reservoirs is needed. It should also be mentioned that most of the scaling equations developed for oil-water systems are based on the equal velocity of phases during the displacement process. Due to the high compressibility of the gas phase, this assumption is not valid in the gas reservoir during the gas-water movement. Thus, the available oil-water scaling equations are not very suitable for gas reservoirs.

In this work, a realistic procedure is suggested to mimic the imbibition process in naturally fractured gas reservoirs. Then, by performing inspectional analysis a new dimensionless time for scaling is presented. The new scaling equation considers the effects of different parameters including rock and fluid properties and gas compressibility.

This work is organized as follows. The spontaneous imbibition simulation steps are discussed in the simulation of the imbibition process section. Following this section, the procedure of determining the new scaling group using inspectional analysis is described. In the simulation of the test cases section, the spontaneous imbibition process in designed test cases with desired properties is simulated and recovery curves are plotted. Finally, in the result and discussion section, the scaling capability of the proposed scaling group is demonstrated.

2. Simulation of imbibition process

The imbibition process can be investigated by performing numerical simulations and experiments. A realistic numerical simulation can be an effective method for characterizing the production behavior of naturally fractured reservoirs. For this propose, in some steps, the matrix block model surrounded by water-filled fracture is constructed and the mass transfer process between this matrix block and surrounded fractures is simulated. These steps include gridding, allocating matrix and fracture properties, proper initialization, simulation and calculation of recovery curves.

2.1 Gridding

The numerical model contains a total of 1000 blocks in Cartesian coordinates (10 × 10 × 10 in x, y, z directions respectively). These number of grids was determined by performing sensitivity analysis on the number of the grid blocks and these grid size showed good enough accuracy and simulation run-time. The outermost grid blocks represent the fracture domain. In order to mimic the imbibition cell, the core sample is surrounded by 100% water-saturated fractures.

2.2 Allocating matrix and fracture properties

At this step, values of matrix and fracture domain properties are assigned. These properties include: Matrix porosity (ϕ_m), fracture porosity (ϕ_f), matrix permeability (k_m), fracture permeability (k_f), matrix dimensions in x, y and z-directions, matrix initial water saturation, relative permeability and capillary pressure curves.

2.3 Properties initialization

According to the initial condition of the spontaneous imbibition process, surrounded fractures are completely saturated with water and matrix blocks are saturated with gas and initial water saturation. Considering the reference pressure at a datum depth, the pressure in the center of each block is calculated in proportion to the existing fluid, density. Fig. 1 shows a view of the initial water in a quarter of representative built model. Also, Fig. 2 demonstrates the corresponding initial pressure distribution.

2.4 Simulation and calculation of recovery curves

The commercial simulator, ECLIPSE 100 (GeoQuest, 2005), is utilized as a simulation engine of the imbibition process. Previous researchers also, used ECLIPSE 100 simulator for the imbibition process (Behbahani et al., 2006; Schembre and Kovscek, 2006; Andersen et al., 2014; Ghaedi and Riazi, 2016).

Using simulation results of each model, the recovery factor at time t, $R(t)$ is calculated by the following equation:

$$R(t) = \frac{S_{gmi} - S_{gm}(t)}{S_{gmi}} \tag{7}$$

where $S_{gm}(t)$ and S_{gmi} are the average and initial gas saturation of the matrix at time t, respectively.

3. New scaling group

It should be mentioned again that gas has much higher compressibility than water. Therefore, the assumption of equal phases velocities during imbibition might not be true for the spontaneous imbibition process in gas reservoir systems. This

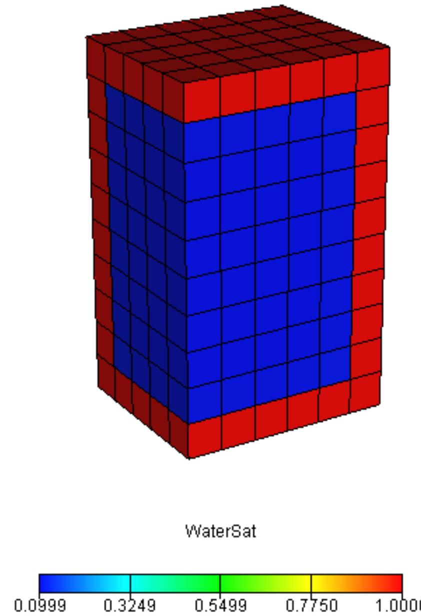


Fig. 1. Representation of allocated s_{wi} in matrix and fracture domains.

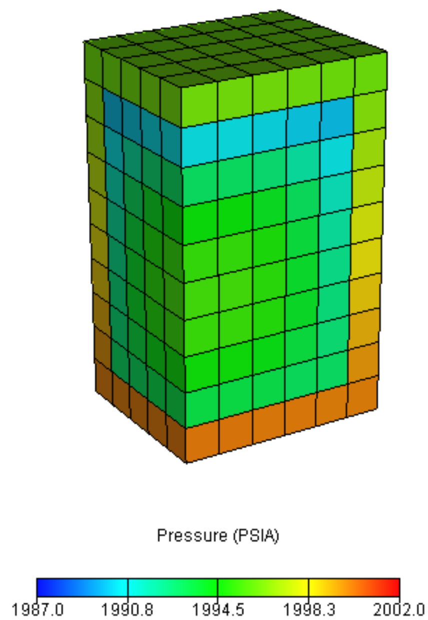


Fig. 2. Representation of initial pressure distribution in matrix and fracture domains.

fact has to be considered in developing the new scaling group. In this work effect of gas compressibility on the scaling equation using inspectional analysis based on the work of Mirzaei-Paiaman (2015) and Ghaedi and Riazi (2016) has been investigated.

Considering the effect of gas compressibility, the main governing equation of flow is as follows:

$$\phi \frac{\partial s_w}{\partial t} + \frac{k_m}{\mu_g} \frac{\partial}{\partial z} \left[a k_{rg} f(s_w) \left(\frac{\partial P_c}{\partial z} - \Delta \rho g \right) \right] = 0 \tag{8}$$

where k_{rg} is gas relative permeability; $f(S_w)$ and a, are the fractional flow of water and compressibility factor respectively and are defined as:

$$f(s_w) = \frac{\frac{k_{rw}}{\mu_w}}{\frac{k_{rg}}{\mu_g} + \frac{k_{rw}}{\mu_w}} \tag{9}$$

$$a = [zc_g(\rho_g g s_g + \rho_w g s_w)(1-\phi s_g) + 1] \tag{10}$$

Similarly, for prototype next equation can be developed:

$$\phi' \frac{\partial s_w}{\partial t'} + \frac{k'_m}{\mu'_g} \frac{\partial}{\partial z'} \left[a' k'_{rg} f'(s_w) \left(\frac{\partial P'_c}{\partial z'} - \Delta\rho' g \right) \right] = 0 \tag{11}$$

where the superscript ($'$) differentiate between the parameters used for the model and prototype.

Based on the experimental observations Akin and Kovscek (1999) and Li and Horne (2001), one can assume that water imbibes into gas saturated rocks in a piston-like manner. At this condition the following equation can be written:

$$\frac{\partial P_c}{\partial z} = \frac{p_c}{z} \tag{12}$$

The β parameter was defined by Ghaedi and Riazi (2016) as follows:

$$\beta = \frac{\frac{k^*_{rg}}{\mu_g} \frac{k^*_{rw}}{\mu_w}}{\frac{k^*_{rg}}{\mu_g} + \frac{k^*_{rw}}{\mu_w}} \tag{13}$$

By calculating the relative permeability of gas and water at the endpoint values and using the β parameter definition, Eq. (8) for the model can be rewritten as:

$$\phi \frac{\partial s_w}{\partial t} + k_m \beta \frac{\partial}{\partial z} \left[a \left(\frac{P_c}{z} - \Delta\rho g \right) \right] = 0 \tag{14}$$

In the same way for the prototype it can be written as:

$$\phi' \frac{\partial s_w}{\partial t'} + k'_m \beta' \frac{\partial}{\partial z'} \left[a' \left(\frac{P'_c}{z'} - \Delta\rho' g \right) \right] = 0 \tag{15}$$

The ratio of model to prototype parameters were defined as, $\phi/\phi' = C$, $k/k' = D$, $P_c/P'_c = G$, $q_w/q'_w = B$, $(\Delta\rho g)/(\Delta\rho' g) = T$, $z/z' = N$, $W/W' = P$. In these ratios, q_w is volumetric flow rate and W is cross-section width of matrix block normal to direction of flow. Furthermore, the relation between apparent or Darcy velocity (u_w) to actual velocity (v_w) can be written as:

$$u_w = v_w \phi = \frac{z}{t}\phi \tag{16}$$

Putting the described ratios into Eq. (14), the next governing equation for the model is as follow:

$$\phi' \frac{\partial s_w}{\partial t'} + \frac{P^2 DGH}{BFN} a' k'_m \beta' \frac{\partial}{\partial z'} \left[\left(\frac{P'_c}{z'} \right) - \frac{TD^2 PH}{BF} (\Delta\rho' g) \right] = 0 \tag{17}$$

Equating Eqs. (15) and (17) results in:

$$\frac{P^2 DGH}{BFN} = 1 \tag{18}$$

$$\frac{TD^2 PH}{BF} = 1 \tag{19}$$

By using resulted ratios defined in Eqs. (18) and (19) and previous equations, it can be concluded that:

$$t_{D,new,c} = \frac{\sqrt{a \frac{k}{\phi} F_s P_c \beta t}}{\sqrt{a' \frac{k'}{\phi'} F'_s P_c{}' \beta' t'}} = \frac{\frac{z}{L_c}}{\frac{z'}{L'_c}} \tag{20}$$

$$t_{D,new,gr} = \frac{\frac{a\Delta\rho g K_m}{\phi_m H} \beta t}{\frac{a' \Delta\rho' g K'_m}{\phi'_m H'} \beta' t'} = \frac{\frac{z}{H}}{\frac{z'}{H'}} \tag{21}$$

where L_c is defined as characteristic length; $t_{D,new,c}$ and $t_{D,new,gr}$ are scaling relations for capillary and gravity dominated displacements, respectively.

Finally, the newly developed dimensionless time for gas systems can be obtained by summing up $t_{D,new,c}$ and $t_{D,new,gr}$.

$$\begin{aligned} t_{D,new} &= t_{D,new,c} + t_{D,new,gr} \\ &= \sqrt{a \frac{k}{\phi} F_s P_c \beta t} + \frac{a\Delta\rho g K_m}{\phi_m H} \beta t \end{aligned} \tag{22}$$

4. Simulation of test cases

For the purpose of considering the different effective parameters, the optimum condition of numerical simulation tests was designed using Minitab 17 statistics software. K_m, a_m, P, D_z, and S_{wi} are varying parameters between designed cases. In order to evaluate the capability of the proposed scaling group 3 values of mentioned parameters in high, medium and low levels were considered. Moreover, 3 fluid and rock types were utilized in designed cases. The defined cases with their properties are shown in Table 1 and Table 2 illustrates the μ_g, μ_w, ρ_g and ρ_w at a pressure of 200, 3500 and 5000 psi for the fluid types 1, 2 and 3, respectively. According to values of ρ_g, gas type 1 is the lightest and the gas type 3 is the heaviest.

Figs. 3 and 4 show the relative permeability and capillary pressure for the different rock types.

The inverse Bond number presented by Schechter et al. (1994) was utilized to calculate the comparative strength of gravity and capillary forces.

$$NB^{-1} = C \frac{\sigma \sqrt{\frac{\phi_m}{k_m}}}{\Delta\rho g H} \tag{23}$$

where C is equal to 0.4. In capillary dominated flow the value of NB^{-1} is greater than 5 and in the gravity dominated flow NB^{-1} tends to zero. The calculated NB^{-1} for all cases is shown in Table 1. This table shows that, almost in all cases gravity force is considerable.

Table 1. The properties of defined cases used for simulating of spontaneous imbibition process.

Case name	Rock type	Fluid type	K_m (mD)	ϕ_m [-]	S_{wi} [-]	P (psi)	F_s (ft^{-2})	a [-]	NB^{-1} [-]
SMB 1	1	1	1	0.1	0.1	2000	0.12	1.000	0.22
SMB 2	2	2	1	0.1	0.1	2000	0.12	1.000	0.22
SMB 3	3	3	1	0.1	0.1	2000	0.12	1.001	0.25
SMB 4	1	1	10	0.2	0.15	3500	0.12	1.000	0.23
SMB 5	2	2	10	0.2	0.15	3500	0.12	1.000	0.24
SMB 6	3	3	10	0.2	0.15	3500	0.12	1.000	0.31
SMB 7	1	1	100	0.3	0.2	5000	0.12	1.000	0.25
SMB 8	2	2	100	0.3	0.2	5000	0.12	1.000	0.26
SMB 9	3	3	100	0.3	0.2	5000	0.12	1.000	0.33
SMB 10	1	2	1	0.1	0.15	5000	0.0048	1.001	0.05
SMB 11	2	3	1	0.1	0.15	5000	0.0048	1.001	0.07
SMB 12	3	1	1	0.1	0.15	5000	0.0048	1.001	0.05
SMB 13	1	2	10	0.2	0.2	2000	0.0048	1.003	0.04
SMB 14	2	3	10	0.2	0.2	2000	0.0048	1.003	0.05
SMB 15	3	1	10	0.2	0.2	2000	0.0048	1.003	0.04
SMB 16	1	2	100	0.3	0.1	3500	0.0048	1.001	0.05
SMB 17	2	3	100	0.3	0.1	3500	0.0048	1.002	0.06
SMB 18	3	1	100	0.3	0.1	3500	0.0048	1.001	0.05
SMB 19	1	3	1	0.1	0.2	3500	0.0012	1.005	0.03
SMB 20	2	1	1	0.1	0.2	3500	0.0012	1.003	0.02
SMB 21	3	2	1	0.1	0.2	3500	0.0012	1.004	0.02
SMB 22	1	3	10	0.2	0.1	5000	0.0012	1.001	0.03
SMB 23	2	1	10	0.2	0.1	5000	0.0012	1.001	0.02
SMB 24	3	2	10	0.2	0.1	5000	0.0012	1.001	0.03
SMB 25	1	3	100	0.3	0.15	2000	0.0012	1.005	0.02
SMB 26	2	1	100	0.3	0.15	2000	0.0012	1.004	0.02
SMB 27	3	2	100	0.3	0.15	2000	0.0012	1.004	0.02

5. Results and discussions

The spontaneous imbibition process simulation results of the 27 defined cases in form of recovery curves, are shown in Fig. 5. Data distribution in the 27 defined cases is in a way that all of the possible models with varying effective parameters have been considered. Thus, different reservoir conditions exist in the cases. According to Fig. 6, the proposed scaling equation could successfully match the recovery curves. This fact shows that this scaling group has a good ability for the characterization of the spontaneous imbibition process. Also, the results of the previous scaling group ($t_{D,Li\&Horne}$) are plotted in Fig. 7. Based on Figs. 6 and 7, the proposed equation has better results especially in matching cases with different dimensions in the reservoir scale.

Normalized area factor (A_{norm}) proposed by Ghaedi and Riazi (2016), was used to evaluate the capability of the defined scaling group. The A_{norm} is the area between two normalized recoveries versus normalized dimensionless time curves that have the maximum distance. The A_{norm} values change between zero and one. When the A_{norm} value approaches zero it shows the better capability of a scaling group and in contrast, the capability is worst when A_{norm} approaches one. Calculated A_{norm} values for cases 1-10, 11-20 and 21-27 are shown in Fig. 8. Small values of this factor confirm the good capability

Table 2. Gas and water properties of fluid types in different pressures.

Fluid type	P (psi)	μ_g (cP)	μ_w (cP)	ρ_g (lbm/ft^3)	ρ_w (lbm/ft^3)
1	2000	0.0167	0.219	5.54	62.4
1	3500	0.0211	0.222	9.40	62.4
1	5000	0.0259	0.224	12.58	62.4
2	2000	0.0174	0.219	6.82	62.4
2	3500	0.0235	0.222	11.49	62.4
2	5000	0.0296	0.224	14.95	62.4
3	2000	0.0238	0.219	13.35	62.4
3	3500	0.0360	0.222	19.16	62.4
3	5000	0.0447	0.224	22.12	62.4

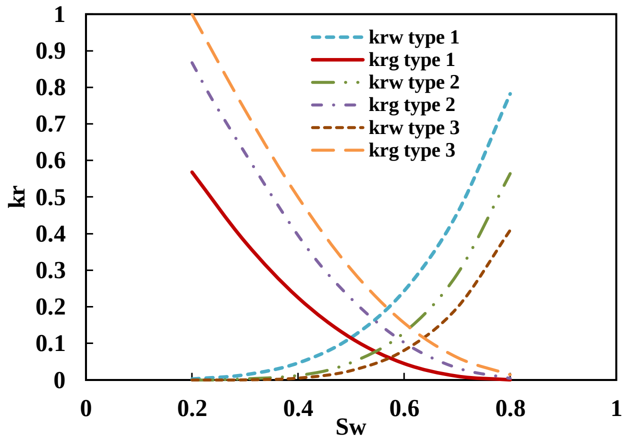


Fig. 3. Gas and water relative permeability curves for types 1, 2 and 3.

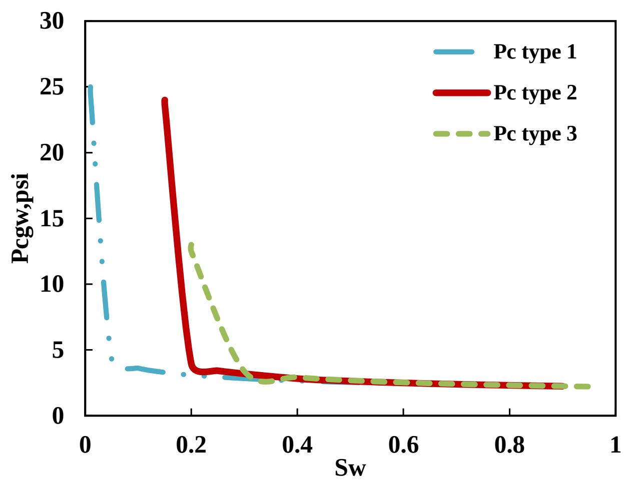


Fig. 4. Gas and water capillary pressure curves for types 1, 2 and 3.

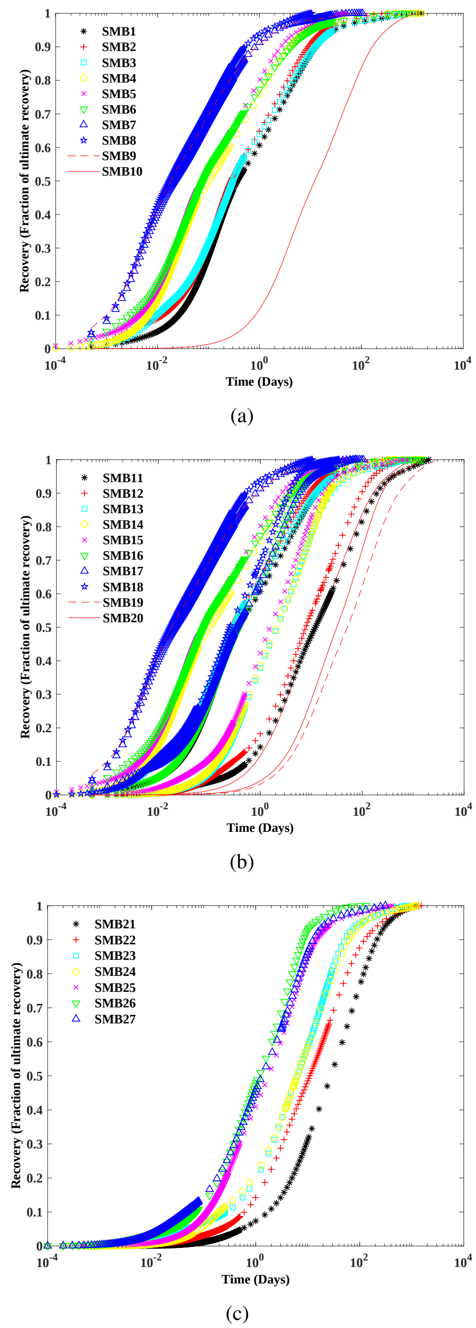


Fig. 5. Gas recovery normalized by R_∞ versus imbibition time for cases 1-10 (a), cases 11-20 (b) and cases 21-27 (c).

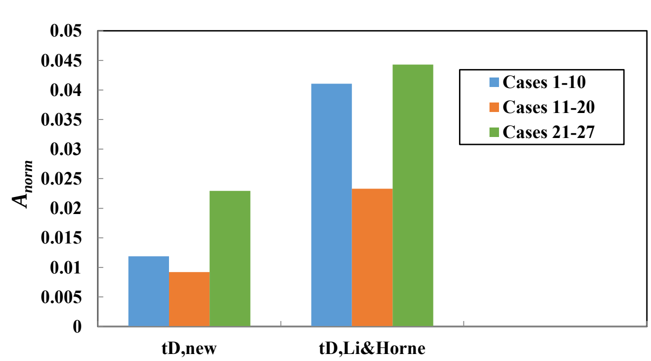


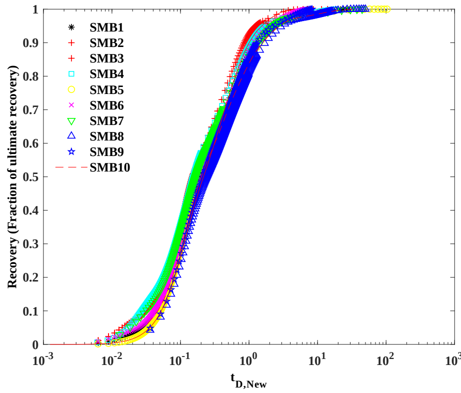
Fig. 8. Evaluating scaling capability for cases 1-10, 11-20 and 21-27.

of the scaling group in different conditions. Fig. 8 shows the better ability of the new equation for the scaling of imbibition data at different reservoir conditions.

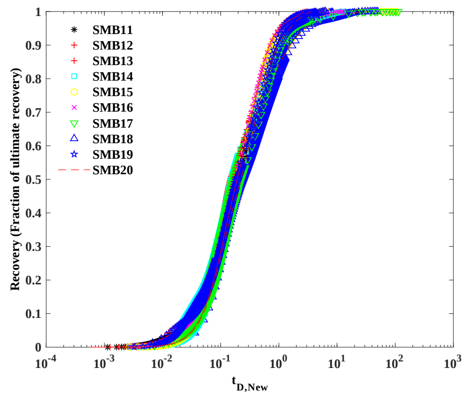
It should be highlighted that the proposed scaling equation considers the effects of almost all effective parameters on spontaneous imbibition process, including porosity, permeability, initial water saturation, capillary pressure and relative permeability curves and matrix dimensions. In this work, the effect of gas compressibility has been also investigated. Moreover, the gravity force has been taken into account. It should be noted that in gas systems because of considerable density differences between gas and water, the effect of gravity force on the spontaneous imbibition process is more significant. Another feature is that this scaling model was derived according to the fluid flow mechanism in porous media instead of through empirical analysis.

6. Conclusions

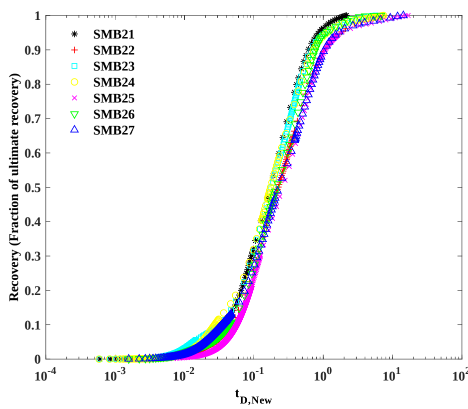
In this study, a new scaling group was proposed that covers a wide range of effective parameters in the imbibition process in naturally fractured gas reservoirs including porosity, perme-



(a)

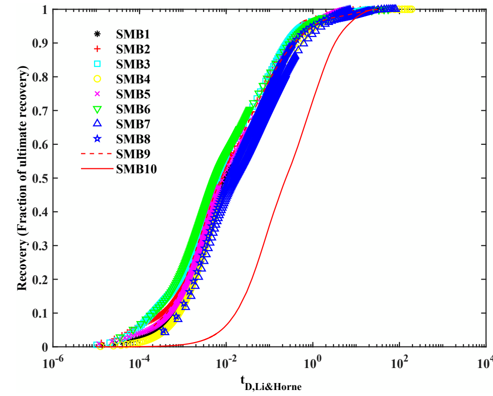


(b)

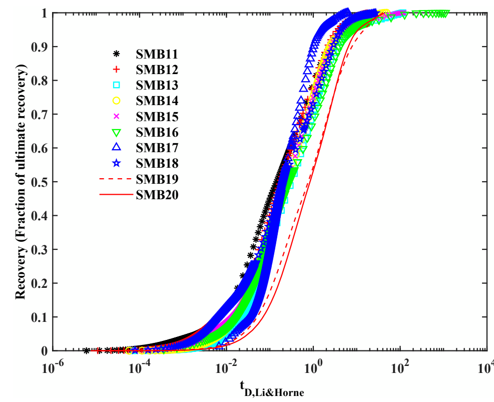


(c)

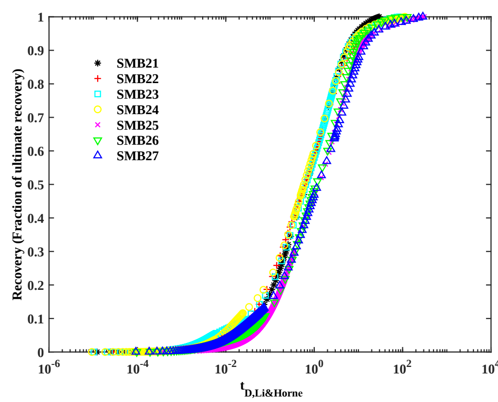
Fig. 6. Gas recovery normalized by R_∞ versus $t_{D,new}$ for cases 1-10 (a), cases 11-20 (b) and cases 21-27 (c).



(a)



(b)



(c)

Fig. 7. Gas recovery normalized by R_∞ versus $t_{D,Li\&Horne}$ for cases 1-10 (a), cases 11-20 (b) and cases 21-27 (c).

ability, initial water saturation, capillary pressure and relative permeability curves, matrix dimensions and gas compressibility. With the purpose of evaluating the scaling group, different cases were designed with noticeable differences in rock and fluid properties. The scaling results of recovery curves show the high capability of the proposed scaling group to the characterization of the spontaneous imbibition process in the naturally fractured gas reservoirs.

Acknowledgement

We would like to offer our special thanks to the Editor (Prof. Jianchao Cai, China University of Geosciences, Wuhan) and the anonymous referees for their valuable comments that greatly improved the manuscript.

Conflict of interest

The authors declare no competing interest.

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