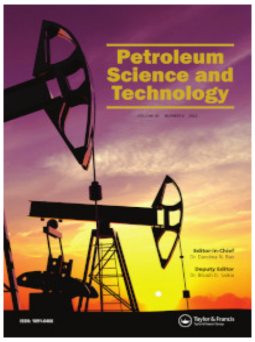


Petroleum Science and Technology

ISSN: (Print) (Online) Journal homepage: https://www.tandfonline.com/loi/lpet20

Applicability of the flowing material balance method to heterogeneous reservoirs

Guofeng Han

PETROLEUM SCIENCE AND TECHNOLOGY
2022, VOL. 40, NO. 6, 641–658
https://doi.org/10.1080/10916466.2021.2006700

Applicability of the flowing material balance method to heterogeneous reservoirs

Guofeng Han

Institute of Mechanics, Chinese Academy of Sciences, Beijing, China

ABSTRACT
The flowing material balance (FMB) method is widely used to evaluate geological reserves because it does not require shut-in wells and uses daily production data. The original FMB method is based on a homogeneous medium model, but the reservoir is often heterogeneous. In this study, FMB equations are derived for radial composite reservoirs and naturally fractured reservoirs, and the effect of reservoir parameters on the estimation of geological reserves is analyzed. The study found that in order to obtain accurate geological reserves, the average formation total compressibility should be used. Inappropriate total compressibility may cause significant errors. Finally, the proposed method is validated by a case study.

KEYWORDS
Dual-porosity medium; flowing material balance method; geological reserve; heterogeneous reservoir; radial composite reservoir

1. Introduction

Geological reserve is one of the most concerned parameters for oil and gas development. Evaluation of geological reserves through production data is the most commonly used method. The original material balance (MB) method requires shut-in wells to determine formation pressure, which will affect oil and gas production. In the past 30 years, since the material balance time was proposed, the rate transient analysis method has been greatly developed (Blasingame and Lee 1988). This type of methods does not require shut-in wells to test formation pressure and can evaluate the reservoir and determine the geological reserves using daily production data. Because it does not require additional testing and does not affect the daily operation of the oilfield, it is widely welcomed (Agarwal et al. 1999; Zhang et al. 2017; Xu et al. 2020). The flowing material balance (FMB) method is the simplest and most convenient method among these methods (Mattar and McNeil 1998; Mattar, Anderson, and Stotts 2006). It is similar to the MB method, which uses straight-line fitting to determine geological reserves, and the analysis results do not have the problem of non-uniqueness. Different from the MB method, it uses flowing bottom-hole pressure instead of formation pressure. The original FMB method is

CONTACT Guofeng Han hanguofeng@imech.ac.cn Institute of Mechanics, Chinese Academy of Sciences, Beijing, China.

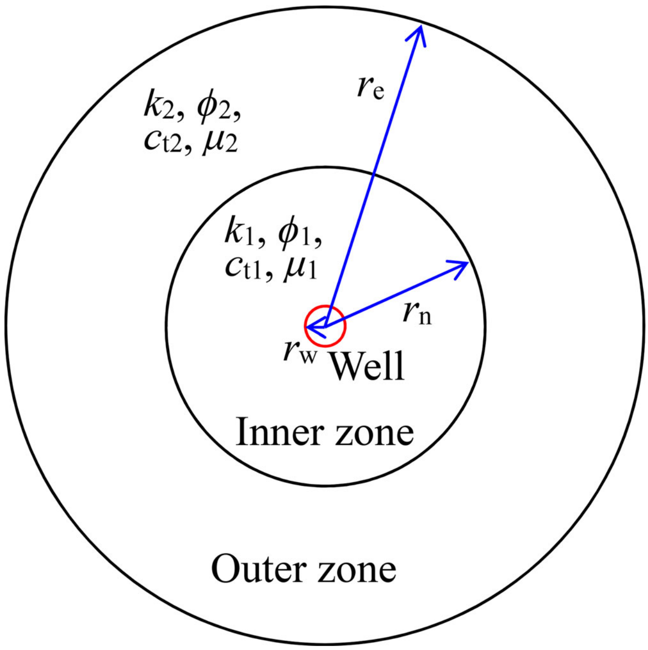


Figure 1. The schematic of the radial composite model.

based on a single-phase homogeneous medium model. In recent years, it has been extended to consider gas adsorption (Clarkson and Salmachi 2017; He et al. 2019; Han, Liu, and Li 2019), multiphase flow (Xu, Adefidipe, and Dehghanpour 2016; Zavaleta, Adrian, and Michel 2018; Zheng et al. 2018; Kazemi and Mojtaba 2020), and multi-well scenarios (Shahamat and Clarkson 2018). However, reservoirs often have strong heterogeneity. Different areas of the reservoir have varying physical properties, or natural fractures are greatly developed. The FBM method cannot identify the heterogeneous characteristics of the reservoir. The geological reserves obtained therefrom must be affected by the heterogeneity of the reservoir. Although some research has been carried out on the FMB method of naturally fractured gas reservoirs (Zhang, Luis, and Ayala 2018), the current research on the effect of heterogeneity on the FMB method is not thorough enough. Since the FMB method itself cannot identify the heterogeneity of the reservoir, in practice, the original FMB method is often used directly for heterogeneous reservoirs, which will inevitably affect the evaluation accuracy of geological reserves. Therefore, it is necessary to study the effect of reservoir heterogeneity on the evaluation results of geological reserves determined by the original FMB method.

This study considers radial composite reservoirs and naturally fractured reservoirs and establishes their FMB equations. Based on these equations, the errors caused by using the original FMB method to evaluate the geological reserves of these two types of reservoirs are analyzed, and the methods to improve the accuracy of geological reserves evaluation are suggested.

2. Flowing material balance method for radial composite oil reservoir

2.1. Derivation of flowing material balance method

The schematic of the radial composite model is shown in Figure 1. The flow governing equations, boundary conditions, and interface conditions of the radial composite closed oil reservoir producing with a constant rate q are as follows.

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial p}{\partial r}\right)=\frac{\mu_1\phi_1 c_{t1}}{k_1}\frac{\partial p}{\partial t}\quad r_w\le r\le r_n \tag{1}$$

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial p}{\partial r}\right)=\frac{\mu_2\phi_2 c_{t2}}{k_2}\frac{\partial p}{\partial t}\quad r_n\le r\le r_e \tag{2}$$

$$\left.\frac{\partial p}{\partial r}\right|_{r=r_e}=0 \tag{3}$$

$$\left.\frac{\partial p}{\partial r}\right|_{r=r_w}=\frac{\mu_1 B_o q}{2\pi k_1 h r_w} \tag{4}$$

$$\left.\frac{k_1}{\mu_1}\frac{\partial p}{\partial r}\right|_{r=r_n^-}=\left.\frac{k_2}{\mu_2}\frac{\partial p}{\partial r}\right|_{r=r_n^+} \tag{5}$$

$$p\big|_{r=r_n^-}=p\big|_{r=r_n^+} \tag{6}$$

where k_1 and k_2 are the permeability of the inner and outer zones respectively (m^2); ϕ_1 and ϕ_2 are the porosities of the inner and outer zones respectively; μ_1 and μ_2 are the oil viscosity of the inner and outer zones respectively (Pa·s); c_{t1} and c_{t2} are the total compressibility of the inner and outer zones, respectively (Pa^{-1}); r_n and r_e are the radius of the inner and outer zones respectively (m); r_w is the radius of the oil well (m); p is the reservoir pressure (Pa); r is the radial coordinate centered on the oil well (m); t is the time (s); B_o is the formation volume factor of the oil (m^3/m^3); h is the thickness of the oil reservoir (m); q is the production rate (m^3/s). When the oil reservoir production is in a pseudo-steady state, the pressure at all parts of the reservoir decreases with the same speed, therefore, the following equation holds.

$$-\left[c_{t1}\phi_1\pi\left(r_n^2-r_w^2\right)h+c_{t2}\phi_2\pi\left(r_e^2-r_n^2\right)h\right]\frac{\partial\bar{p}}{\partial t}=B_o q \tag{7}$$

where $\bar{p}$ is the average formation pressure, Pa. The following parameter is defined.

$$\overline{NC_t}=c_{t1}\phi_1\left(r_n^2-r_w^2\right)+c_{t2}\phi_2\left(r_e^2-r_n^2\right) \tag{8}$$

Then, Eq. (7) can be written as follows.

$$\frac{\partial\bar{p}}{\partial t}=-\frac{B_o q}{\pi h\overline{NC_t}} \tag{9}$$

By using Eq. (9), solving the linear partial differential equation composed of the flow governing equation Eq. (1) in the inner zone and the inner boundary condition Eq. (4), the pressure distribution in the inner zone can be obtained as follows.

$$p(r) = -\frac{B_o q \mu_1 c_{t1}\phi_1}{4k_1 \pi h \overline{NC_t}}\left(r^2 - r_w^2\right) + \frac{\mu_1 B_o q}{2\pi k_1 h}\ln\frac{r}{r_w} + p_{wf} \quad r_w \le r \le r_n \tag{10}$$

where p_{wf} is the bottom-hole pressure (Pa). The relationship $r_{\mathrm{w}} \ll r_{\mathrm{n}}$ is taken into account in the above equation, and the corresponding items are omitted. This relationship and the relationship $r_{\mathrm{w}} \ll r_{\mathrm{e}}$ will also be used in subsequent calculations. For the outer zone, using Eq. (9), outer zone flow governing equation Eq. (2), outer boundary condition Eq. (3) and interface condition Eq. (6), the pressure distribution in the outer zone can be obtained as follows.

$$\begin{aligned} p(r) = &-\frac{MB_o q \mu_1 c_{t1}\phi_1}{4Fk_1 \pi h \overline{NC_t}}\left(r^2 - r_n^2\right) + \frac{MB_o q \mu_1 c_{t1}\phi_1}{2Fk_1 \pi h \overline{NC_t}} r_e^2 \ln\frac{r}{r_n} \\ &-\frac{B_o q \mu_1 c_{t1}\phi_1}{4k_1 \pi h \overline{NC_t}}\left(r_n^2 - r_w^2\right) + \frac{\mu_1 B_o q}{2\pi k_1 h}\ln\frac{r_n}{r_w} + p_{wf} \quad r_n \le r \le r_e \end{aligned} \tag{11}$$

where

$$M = \frac{(k/\mu)_1}{(k/\mu)_2}, F = \frac{(c_t\phi)_1}{(c_t\phi)_2} \tag{12}$$

M is the mobility ratio and F is the storativity ratio. It is easy to check that the above results Eqs. (10) and (11) satisfy the interface condition Eq. (5). Therefore, the average formation pressure is as follows.

$$\begin{aligned} \bar{p} &= \frac{2}{\overline{NC_t}}\int_{r_w}^{r_e} p r c_t \phi dr \\ &= \frac{\mu_1 B_o q}{2\pi K_1 h}\left\{ \ln\frac{r_n}{r_w} - \frac{3}{4} r_n^2 \frac{c_{t1}\phi_1}{\overline{NC_t}} - \frac{c_{t1}\phi_1}{\overline{NC_t}}\frac{c_{t2}\phi_2}{\overline{NC_t}}\left[\frac{M}{F}\left(\frac{3}{4}r_e^4 - r_n^2 r_e^2 + \frac{1}{4}r_n^4 - r_e^4 \ln\frac{r_e}{r_n}\right)\right.\right. \\ &\left.\left. + \frac{1}{4}r_n^2\left(r_e^2 - r_n^2\right)\right]\right\} + p_{wf} \end{aligned} \tag{13}$$

The following parameter is defined.

$$\begin{aligned} b_{c,pss} = \frac{\mu_1 B_o}{2\pi K_1 h}&\left\{ \ln\frac{r_n}{r_w} - \frac{3}{4} r_n^2 \frac{c_{t1}\phi_1}{\overline{NC_t}} - \frac{c_{t1}\phi_1}{\overline{NC_t}}\frac{c_{t2}\phi_2}{\overline{NC_t}}\right. \\ &\left.\left[\frac{M}{F}\left(\frac{3}{4}r_e^4 - r_n^2 r_e^2 + \frac{1}{4}r_n^4 - r_e^4 \ln\frac{r_e}{r_n}\right) + \frac{1}{4}r_n^2\left(r_e^2 - r_n^2\right)\right]\right\} \end{aligned} \tag{14}$$

Then, Eq. (13) can be rewritten as follows.

$$\bar{p} - p_{wf} = q b_{c,pss} \tag{15}$$

The following parameters are defined.

$$\bar{c}_{ct} = \frac{\pi\left(r_n^2 - r_w^2\right)h\phi_1 c_{t1} + \pi\left(r_e^2 - r_n^2\right)h\phi_2 c_{t2}}{\pi\left(r_n^2 - r_w^2\right)h\phi_1 + \pi\left(r_e^2 - r_n^2\right)h\phi_2} = \frac{\left(r_n^2 - r_w^2\right)\phi_1 c_{t1} + \left(r_e^2 - r_n^2\right)\phi_2 c_{t2}}{\left(r_n^2 - r_w^2\right)\phi_1 + \left(r_e^2 - r_n^2\right)\phi_2} \tag{16}$$

$$N_c = \frac{\pi h\left[\phi_1\left(r_n^2 - r_w^2\right) + \phi_2\left(r_e^2 - r_n^2\right)\right]}{B_o} \tag{17}$$

N_c is the geological reserves of the composite reservoir (m^3); $\bar{c}_{ct}$ is the average formation total compressibility (Pa^{-1}). When the oil reservoir is produced with a constant rate q, the following can be obtained from Eq. (7).

$$\frac{qt}{N_c \bar{c}_{ct}} = p_i - \bar{p} \tag{18}$$

where p_i is the initial reservoir pressure (Pa). From Eqs. (17) and (18), the FMB equation of radial composite oil reservoir can be obtained as follows.

$$\frac{t}{N_c \bar{c}_{ct}} + b_{c,pss} = \frac{p_i - p_{wf}}{q} \tag{19}$$

2.2. Adaptability of flowing material balance method

It can be seen from the FMB equation Eq. (19) of the radial composite oil reservoir that it has exactly the same form as the FMB equation of a homogeneous reservoir. The only difference between them is that the constant term has a different expression, and the radial composite oil reservoir uses the average formation total compressibility. However, the geological reserves obtained by straight-line fitting are affected by the total compressibility, not by the constant term. The original FMB method generally uses the total compressibility obtained by wellbore coring. When using it to evaluate the geological reserves of radial composite oil reservoirs, errors will inevitably be brought about.

The following parameters are defined.

$$R_\phi = \frac{\phi_1}{\phi_2}, R_r = \frac{r_n}{r_e} \tag{20}$$

R_ϕ is the porosity ratio, and R_r is the proportion of the inner zone. The ratio of the geological reserves obtained by the original FMB method to the actual geological reserves is as follows.

$$\frac{N_c^h}{N_c} \approx \frac{R_r^2 + \left(1 - R_r^2\right)/F}{R_r^2 + \left(1 - R_r^2\right)/R_\phi} \tag{21}$$

where $N^h{}_c$ is the geological reserve evaluated by the original FMB method

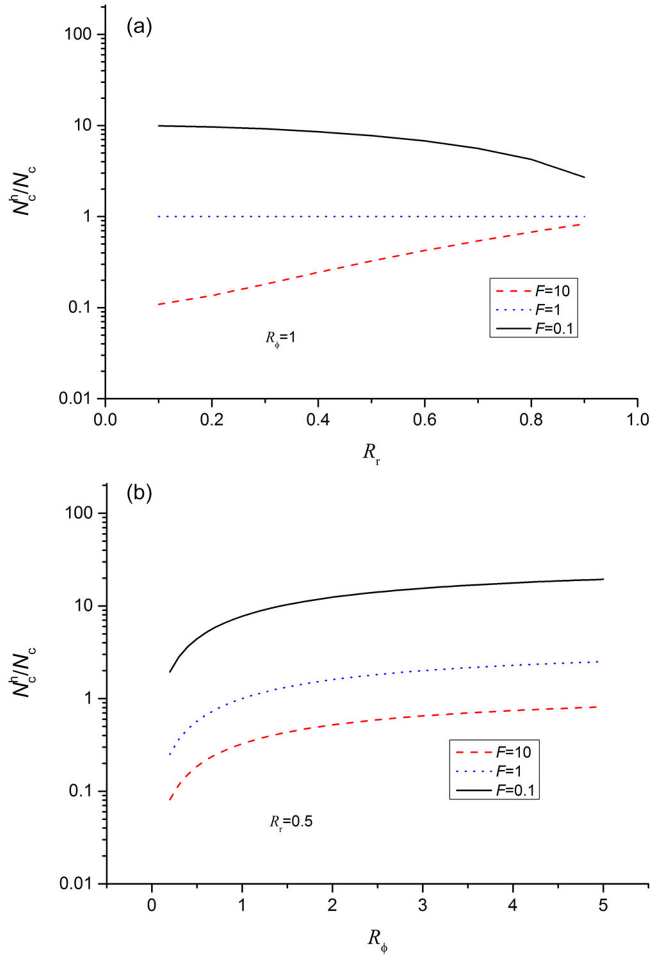


Figure 2. The effect of parameters for radial composite reservoirs on the geological reserves obtained by the original FMB method.

(m^3). The effect of related parameters on the geological reserves obtained by the original FMB method is shown in Figure 2. The FMB method uses the production data of the boundary-dominated flow stage. At this stage, when the well produces at a constant rate, changes in the reservoir state are controlled by the formation fluid and pore compressibility, which is the average total compressibility of the formation. The larger the average total compressibility of the formation, the smaller the geological reserves obtained by the FMB method. For radial composite reservoirs, only the total compressibility at borehole can be obtained. Therefore, the geological reserves evaluated by the original FMB method decrease with the increase of the storativity ratio, and increase with the increase of the porosity ratio, which may lead to an order of magnitude increase. There is no monotonic relationship between the geological reserves evaluated by the original FMB method and the proportion of the inner zone. When the storativity ratio is large, the geological reserves evaluated by the original FMB method increase as the proportion of the inner zone increases. When the storativity is relatively small, the geological reserves evaluated by the original FMB method will decrease as the proportion of the inner zone increases.

3. Flowing material balance method for naturally fractured oil reservoir

3.1. Derivation of flowing material balance method

When the natural fractures are densely developed, the dual-porosity medium model can be used to characterize the naturally fractured oil reservoir. It is assumed that the oil reservoir is a closed circle, the producing well is located at the center of the circle, and the production is carried out at a constant rate q. For the transient dual-porosity medium model with a slab matrix, the flow governing equations, interface conditions and boundary conditions are as follows.

$$\frac{(\phi c_t)_f \mu}{k_f} \frac{\partial p_f}{\partial t} = \frac{1}{r} \frac{\partial}{\partial r}\left(r \frac{\partial p_f}{\partial r}\right) + \frac{\mu}{k_f} q_m \tag{22}$$

$$\frac{(\phi c_t)_m \mu}{k_m} \frac{\partial p_m}{\partial t} = \frac{\partial^2 p_m}{\partial z^2} \tag{23}$$

$$q_m = \frac{2}{h_m} \frac{k_m}{\mu} \frac{\partial p_m}{\partial z}\bigg|_{z=0} \tag{24}$$

$$p_m\big|_{z=0} = p_f \tag{25}$$

$$\frac{\partial p_m}{\partial z}\bigg|_{z=h_m/2} = 0 \tag{26}$$

$$\frac{\partial p_f}{\partial r}\bigg|_{r=r_e} = 0 \tag{27}$$

$$\frac{\partial p_f}{\partial r}\bigg|_{r=r_w} = \frac{\mu B_o q}{2\pi k_f h r_w} \tag{28}$$

where k_{m} and k_{f} are the permeability of the matrix and fracture respectively (m^2); ϕ_{m} and ϕ_{f} are the porosities of the matrix and fracture respectively; c_{tm} and c_{tf} are the total compressibility of the matrix and fracture respectively (Pa^{-1}); z is the coordinate of the slab matrix with the origin at the matrix-fracture interface (m); p_{m} and p_{f} are the pressure of the matrix and fracture respectively (Pa); h_{m} is the thickness of the slab matrix (m); q_{m} is the rate of matrix-fracture interporosity flow (m^3/s).

The MB equation of dual-porosity media is as follows.

$$-c_{tm}\phi_m\pi\left(r_e^2-r_w^2\right)h\frac{\partial\bar{p}_f}{\partial t}-c_{tf}\phi_f\pi\left(r_e^2-r_w^2\right)h\frac{\partial\bar{p}_m}{\partial t}=B_oq \tag{29}$$

When the production reaches the pseudo-steady state, considering $r_w \ll r_e$, the following results can be obtained from Eq. (29).

$$\frac{\partial\bar{p}_f}{\partial t}=\frac{\partial\bar{p}_m}{\partial t}=-\frac{B_oq}{\pi r_e^2h(c_t\phi)_{f+m}} \tag{30}$$

where $\bar{p}_f$ and $\bar{p}_m$ are the average pressure of the fracture system and the matrix system, respectively (Pa). For the matrix flow governing equation Eq. (23), matrix boundary condition Eq. (26) and matrix-fracture interface condition Eq. (25), the following matrix pressure distribution can be obtained.

$$p_m=-\frac{B_oq\mu(1-\omega)}{2\pi r_e^2k_mh}z^2+\frac{B_oq\mu h_m(1-\omega)}{2\pi r_e^2k_mh}z+p_f \tag{31}$$

The storativity ratio is defined as follows.

$$\omega=\frac{(\phi c_t)_f}{(\phi c_t)_{m+f}} \tag{32}$$

Therefore, the average pressure of the matrix system is as follows.

$$\begin{aligned}\bar{p}_m&=\frac{2}{r_e^2-r_w^2}\int_{r_w}^{r_e}r\left(\frac{2}{h_m}\int_0^{\frac{h_m}{2}}p_mdz\right)dr=\frac{B_oq\mu h_m^2(1-\omega)}{12\pi k_mr_e^2h}+\bar{p}_f\\&=\frac{B_oq\mu(1-\omega)}{\alpha\pi k_mr_e^2h}+\bar{p}_f\end{aligned} \tag{33}$$

The shape factor is as follows.

$$\alpha=\frac{12}{h_m^2} \tag{34}$$

From the matrix pressure distribution Eq. (33) and matrix-fracture inter-porosity flow Eq. (24), the following results can be obtained.

$$q_m=\frac{B_oq(1-\omega)}{\pi r_e^2h} \tag{35}$$

Therefore, when the reservoir production is in a pseudo-steady state, from Eq. (35) and fracture flow governing equation Eq. (22), boundary conditions Eqs. (27) and (28), the pressure distribution of the fracture system can be obtained as follows.

$$p_f(r) = -\frac{B_o q\mu}{4\pi k_f r_e^2 h}\left(r^2 - r_w^2\right) + \frac{B_o q\mu}{2\pi k_f h}\ln\frac{r}{r_w} + p_{wf} \tag{36}$$

It is easy to check that Eq. (36) satisfies boundary condition Eq. (27). Therefore, the average pressure of the fracture system is as follows.

$$\begin{aligned}\bar{p}_f &= \frac{2}{r_e^2 - r_w^2}\int_{r_w}^{r_e} p_f r dr \approx \frac{\mu B_o q}{2\pi k_f h}\left(\ln\frac{r_e}{r_w} - \frac{3}{4}\right) + p_{wf} \\ &= \frac{\mu B_o q}{4\pi k_f h}\ln\left(\frac{4A}{C_A e^{\gamma} r_w^2}\right) + p_{wf}\end{aligned} \tag{37}$$

where C_A is the reservoir shape factor; A is the reservoir area (m^2); γ is the Euler constant. If the oil well is produced at a constant rate q, combining with Eq. (33), the following result can be obtained from the MB Eq. (29).

$$\frac{B_o qt}{\pi r_e^2 h(\phi c_t)_{m+f}} = p_i - \bar{p}_f - \frac{B_o q\mu(1-\omega)^2}{\alpha\pi k_m r_e^2 h} \tag{38}$$

From Eqs. (37) and (38), the following equation can be obtained.

$$\frac{B_0 t}{\pi r_e^2 h(\phi c_t)_{m+f}} + (1-\omega)^2\frac{\mu B_o}{\alpha\pi k_m r_e^2 h} + \frac{\mu B_o}{4\pi k_f h}\ln\left(\frac{4A}{C_A e^{\gamma} r_w^2}\right) = \frac{p_i - p_{wf}}{q} \tag{39}$$

The following parameters are defined.

$$N_d = \frac{\pi r_e^2 h\phi_{m+f}}{B_o} \tag{40}$$

$$\bar{c}_{dt} = \frac{(\phi c_t)_{m+f}}{\phi_{m+f}} \tag{41}$$

$$b_{d,pss} = (1-\omega)^2\frac{\mu B_o}{\alpha\pi K_m r_e^2 h} + \frac{\mu B_o}{4\pi K_f h}\ln\left(\frac{4A}{C_A e^{\gamma} r_w^2}\right) \tag{42}$$

N_{d} is the geological reserves of the naturally fractured oil reservoir (m^3); $\bar{c}_{dt}$ is the average formation total compressibility (Pa^{-1}). The FMB equation of the transient dual-porosity medium model can be rewritten as the following form.

$$\frac{t}{N_d\bar{c}_{dt}} + b_{d,pss} = \frac{p_i - p_{wf}}{q} \tag{43}$$

When the matrix is spherical or using a pseudo-steady-state dual-porosity medium model, it is easy to obtain the same FMB equation as Eq. (43).

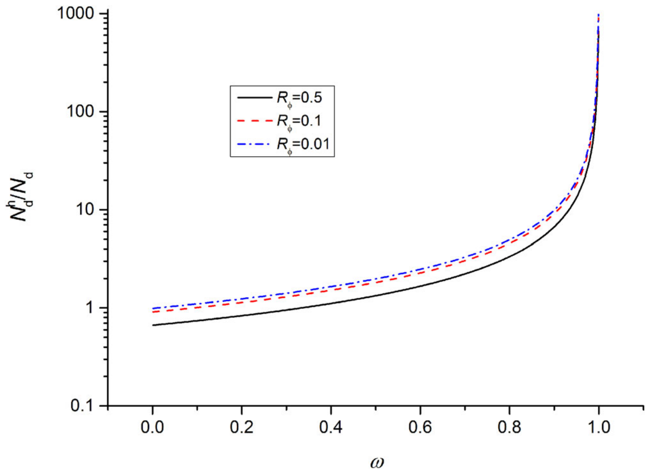


Figure 3. The effect of parameters for naturally fractured reservoirs on the geological reserves obtained by the original FMB method.

3.2. Adaptability of flowing material balance method

Like radial composite oil reservoirs, naturally fractured oil reservoirs also have the same FMB equation as homogeneous reservoirs. Similarly, it has a different expression of the constant term from the original FMB equation, and uses the average formation total compressibility. Therefore, when evaluating the geological reserves of naturally fractured oil reservoirs by the original FMB method, the use of inappropriate total compressibility may cause significant errors.

Equation (20) is replaced with the following definition.

$$R_\phi = \frac{\phi_f}{\phi_m} \tag{44}$$

It is easy to obtain the ratio of the geological reserves of naturally fractured oil reservoirs obtained by the original FMB method to the actual geological reserves as follows.

$$\frac{N_d^h}{N_d} = \frac{1}{(1 + R_\phi)(1 - \omega)} \tag{45}$$

where $N^h{}_d$ is the geological reserves evaluated by the original FMB method (m^3). The effect of related parameters on the geological reserves obtained by the original FMB method is shown in Figure 3. For naturally fractured reservoirs, only the matrix parameters can be obtained from the core sampled from the wellbore. Therefore, the geological reserves evaluated by the original FMB method increase with the increase of the storativity ratio, and decrease with the increase of the porosity ratio. The geological reserves evaluated by the original FMB method increase faster with the increase of

Table 1. Parameters for simulation.

Parameter	Unit	Radial composite	Naturally fractured
Well radius	m	0.1	0.1
Skin factor		0	0
Wellbore storage	m^3/d	0.1	0.1
Initial pressure	MPa	40	40
Reservoir thickness	m	20	20
Formation volume factor	m^3/stm^3		1.026
Viscosity	cp	0.654	0.654
Boundary distance	m	1000	1000
Composite radius	m	500	
Mobility ratio		1	
Storativity ratio		2	0.1
Interporosity flow coefficient			10^{-6}
Inner zone porosity	%	10	
Outer zone porosity	%	2.5	
Fracture porosity	%		1
Matrix porosity	%		18
Inner zone permeability	mD	10	
Fracture permeability	mD		10
Inner zone total compressibility	MPa^{-1}	0.001054	
Fracture total compressibility	MPa^{-1}		0.001054

the storativity ratio. When the storativity ratio is less than 0.8, the geological reserves evaluated by the original FMB method are in the same order of magnitude as the actual geological reserves. For naturally fractured oil reservoirs, the storativity ratio is generally not so large. Therefore, although the geological reserves obtained by the original FMB method may have a significant error, there will be no order of magnitude difference.

4. Case study

We apply the FMB method proposed above to artificially simulated production data, so that we can accurately know the actual geological reserves and the accuracy of the FMB methods can be easily analyzed. The production processes of radial composite reservoirs and naturally fractured reservoirs are simulated respectively. The parameters of the reservoirs are shown in Table 1, and the production process is shown in Figure 4.

Considering the case that the production rate is 0, we rewrite Eq. (19) as follows.

$$\frac{q}{\Delta p} = -\frac{N_p}{b_{c,pss}\Delta p N_c \bar{c}_{ct}} + \frac{1}{b_{c,pss}} \tag{45}$$

where $\Delta p = p_i - p_{wf}$ is pressure difference (Pa); N_p is Cumulative production (m^3). Therefore, the production data can be used to fit the straight line $q/\triangle p - N_p/\triangle p\bar{c}_{ct}$, and the intersection of this straight line and the x-axis is the geological reserves. The FMB Eq. (43) for naturally fractured reservoirs is also rewritten in this way. The results of FMB fitting using different total compressibilities are shown in Figures 5 and 6. For the radial composite

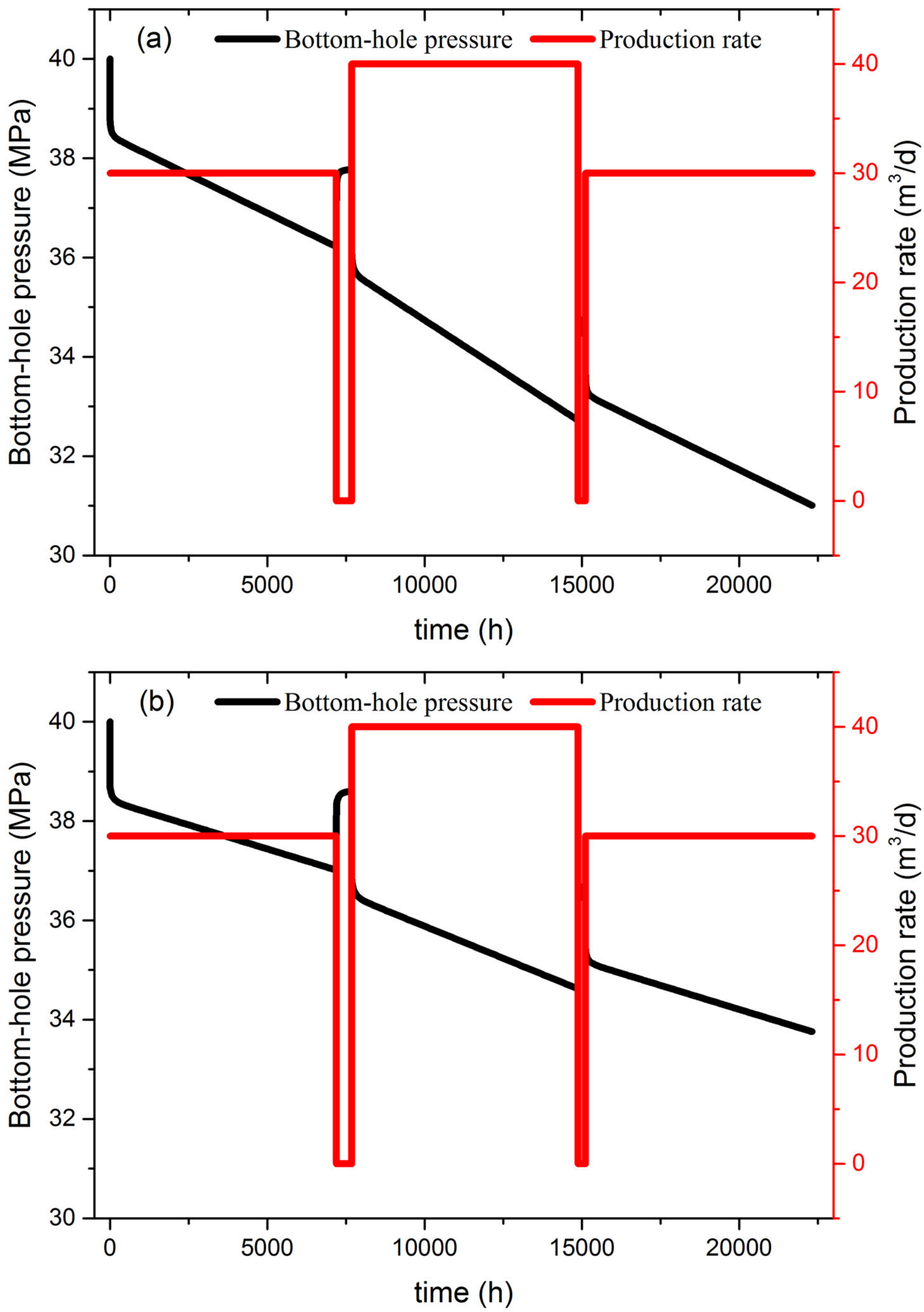


Figure 4. The simulated production (a) radial composite reservoir; (b) naturally fractured reservoir.

reservoir, the actual geological reserve obtained from Eq. (17) is $2.6792 \times 10^6 m^3$; The geological reserve obtained by the original FMB method is $3.8269 \times 10^6 m^3$, with an error of 42.8%; The geological reserve obtained by the FMB method proposed in this study is $2.6789 \times 10^6 m^3$,

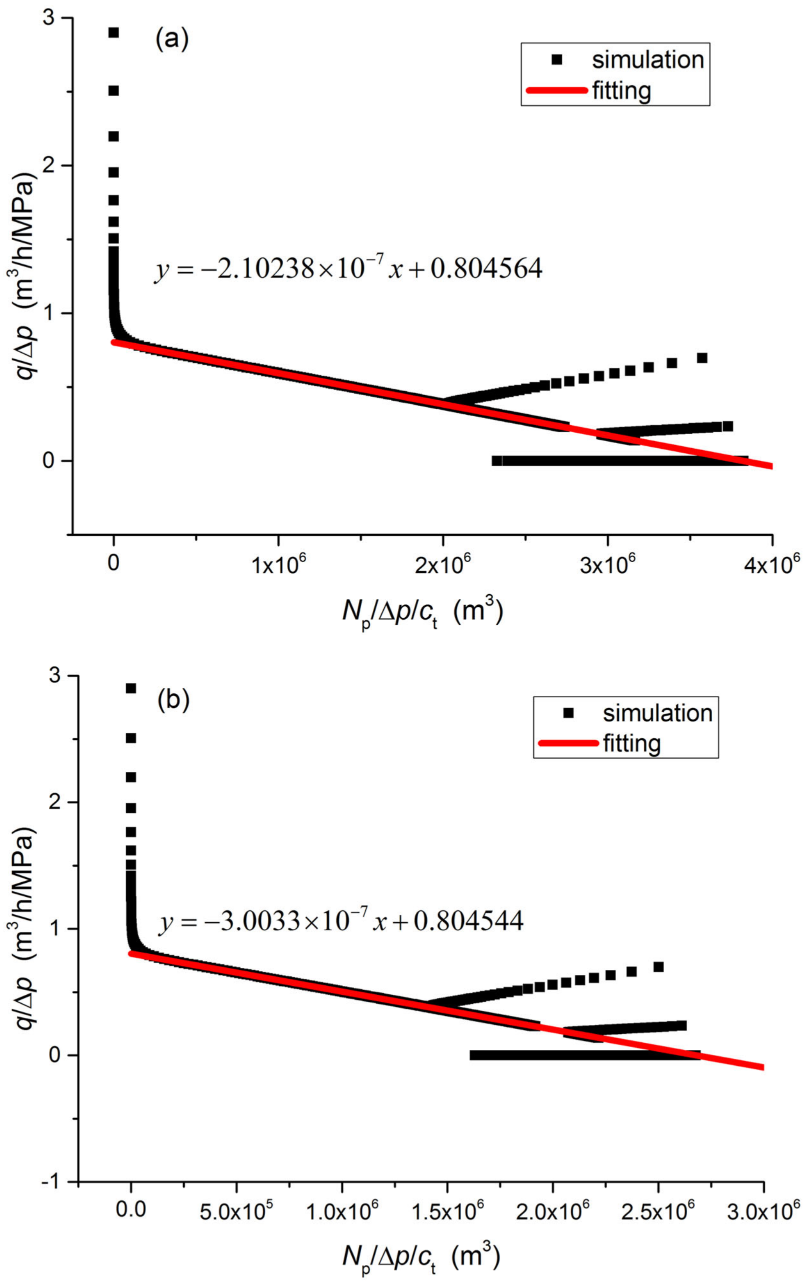
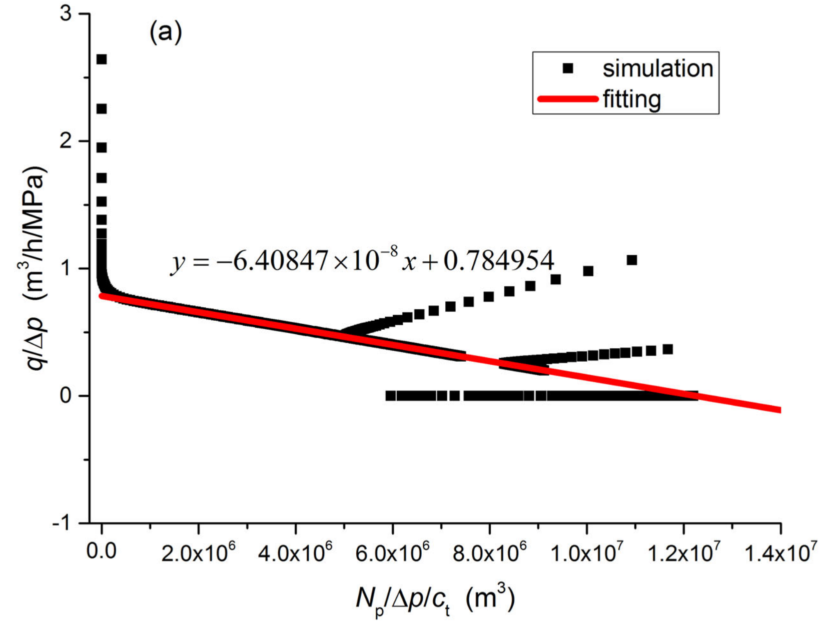


Figure 5. The fitting by FMB method for radial composite reservoir (a) original FMB; (b) FMB proposed in this study.

with an error of 0.01%; It is easy to validate that the geological reserves obtained by these two methods meet the relationship Eq. (21). For the naturally fractured reservoir, the actual geological reserve obtained from Eq. (40) is $1.1636\times10^7 \mathrm{m}^3$; The geological reserve obtained by the original FMB method is 1.2249×10^7 m^3, with an error of 5.3%; The geological



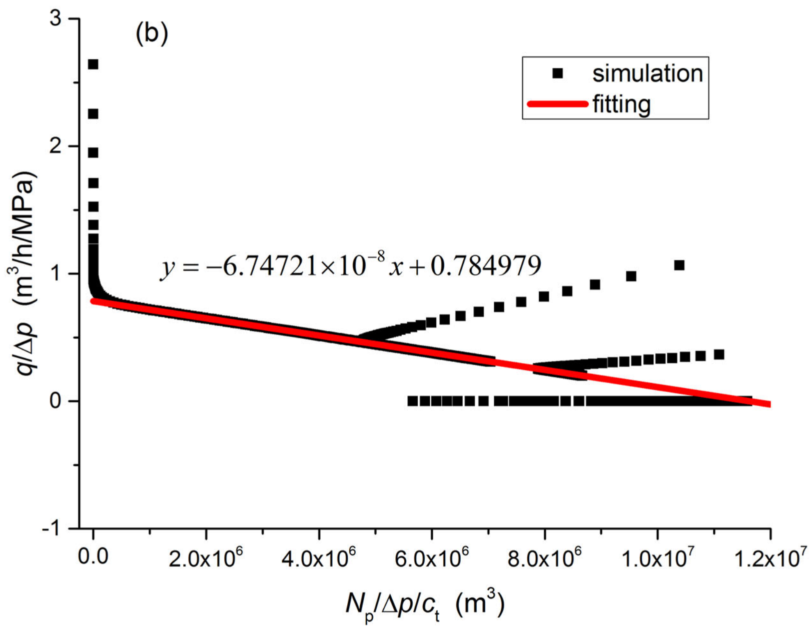


Figure 6. The fitting by FMB method for naturally fractured reservoir (a) original FMB; (b) FMB proposed in this study.

reserve obtained by the FMB method proposed in this study is $1.1634 \times 10^7 \mathrm{m}^3$, with an error of 0.02%; It is easy to validate that the geological reserves obtained by these two methods meet the relationship Eq. (45). Therefore, the method proposed in this study is feasible and more accurate.

5. Discussion

The previous analysis assumes that the reservoir is producing at a constant rate. In the case of variable rate, the actual physical time in the aforementioned method can be replaced by the material balance time. The previous analysis is for water-free oil reservoirs. When the reservoir has immobile water, the effective compressibility considering water saturation can be used instead of the previous total compressibility. For gas reservoirs, pseudo-pressure and pseudo-time can be used to replace the pressure and time in the aforementioned equations. If it is coalbed methane or shale gas reservoirs that need to consider gas adsorption, the total compressibility defined by Han, Liu, and Li (2019) considering the volume of the adsorbed phase can be used instead of the original total compressibility in the previous equations.

In order to reduce the error caused by using the FMB method to determine geological reserves, it is necessary to determine the average formation total compressibility. For composite reservoirs, the parameters obtained by core analysis can only represent the properties of the formation near the oil well, and cannot represent the properties of the distant formation. For naturally fractured reservoirs, the size of the core may not be large enough, and only the properties of the matrix can be obtained, while the properties of larger-scale fractures are lost. Therefore, none of them can get a suitable total compressibility. Han et al. (2019) proposed a method to simultaneously determine the total compressibility of the reservoir scale and the geological reserves. The total compressibility determined by this method is the average value in the drainage area, which is very representative. In addition, although the well test analysis cannot obtain the porosity ratio of different areas of radial composite reservoirs or matrix-fracture porosity ratio, the storativity ratio and inner radius can be obtained, which helps to improve the accuracy of the FMB method.

The FMB method only uses the production data of the boundary-dominated flow stage, and cannot obtain parameters such as the storativity ratio and porosity ratio. Although the method of Han et al. (2019) can obtain the average total compressibility of the formation, these methods require a sufficiently long stable production time, which is often not met in practice. In order to solve this problem, we plan to use machine learning methods in the future to make use of all production data. It is hoped that the storativity ratio and porosity ratio can be obtained through the data of the unsteady flow stage, and the requirement for the duration of stable production time can be reduced.

6. Conclusions

The original FMB method for evaluating geological reserves is based on the homogeneous medium model. However, oil reservoirs are often heterogeneous. We derived the FMB methods for radial composite oil reservoirs and naturally fractured oil reservoirs, and found that they have exactly the same form as the original FMB equations. The difference between them and the original FMB equation is that the constant term expression is different, and the geological reserve is scaled by the average formation total compressibility. The accuracy of the geological reserves obtained by the FMB method is mainly affected by the average formation total compressibility. Generally, the total compressibility is obtained through wellbore coring, which cannot represent the average condition of the reservoir and easily causes errors that cannot be ignored. When the reservoir is a composite formation, there may be orders of magnitude difference in the geological reserves obtained by the FMB method. When it is a naturally fractured reservoir, although there are significant errors, it is usually in the same order of magnitude as the real geological reserves. Case study validates that the method proposed in this study is more accurate. In the future, it will be very important to validate the model proposed in this study with appropriate well test data and production data.

Funding

This work was supported by the National Natural Science Foundation of China under Grant No. 11602276.

ORCID

Guofeng Han http://orcid.org/0000-0002-6536-7378

References

Agarwal, R. G., D. C. Gardner, S. W. Kleinsteiber, and D. D. Fussell. 1999. Analyzing well production data using combined type curve and decline curve concepts. *SPE Reservoir Evaluation & Engineering* 2 (05):478–86. doi:10.2118/57916-PA.

Blasingame, T. A., and W. J. Lee. 1988. The variable-rate reservoir limits testing of gas wells. SPE Gas Technology Symposium, Dallas, Texas, June 13–15. doi:10.2118/17708-MS.

Clarkson, C. R., and A. Salmachi. 2017. Rate-transient analysis of an undersaturated CBM reservoir in Australia: Counting for effective permeability changes above and below desorption pressure. *Journal of Natural Gas Science and Engineering* 40:51–60. doi:10.1016/j.jngse.2017.01.030.

Han, G., M. Liu, and Q. Li. 2019. Flowing material balance method with adsorbed phase volumes for unconventional gas reservoirs. *Energy Exploration & Exploitation* 38 (2):519–32. doi:10.1177/0144598719880293.

Han, G., Y. Liu, L. Sun, M. Liu, D. Gao, and Q. Li. 2019. Determination of pore compressibility and geological reserves using a new form of the flowing material balance method. *Journal of Petroleum Science and Engineering* 172:1025–33. doi:10.1016/j.petrol.2018.09.010.

He, L., H. Mei, X. Hu, M. Dejam, Z. Kou, and M. Zhang. 2019. Advanced flowing material balance to determine original gas in place of shale gas considering adsorption hysteresis. *SPE Reservoir Evaluation & Engineering* 22 (04):1282–11. doi:10.2118/195581-PA.

Kazemi, N., and G. Mojtaba. 2020. Production data analysis of gas reservoirs with edge aquifer drive: A semi-analytical approach. *Journal of Natural Gas Science and Engineering* 80:103382. doi:10.1016/j.jngse.2020.103382.

Mattar, L., D. Anderson, and G. Stotts. 2006. Dynamic material balance oil or gas-in-place without shut-Ins. *Journal of Canadian Petroleum Technology* 45 (11):7–10. doi:10.2118/06-11-TN.

Mattar, L., and R. McNeil. 1998. The flowing gas material balance. *Journal of Canadian Petroleum Technology* 37 (02):52–5. doi:10.2118/98-02-06.

Shahamat, M. S., and C. R. Clarkson. 2018. Multiwall, multiphase flowing material balance. *SPE Reservoir Evaluation & Engineering* 21 (02):445–17. doi:10.2118/185052-PA.

Xu, Y., O. Adefidipe, and H. Dehghanpour. 2016. A flowing material balance equation for two-phase flow back analysis. *Journal of Petroleum Science and Engineering* 142:170–85. doi:10.1016/j.petrol.2016.01.018.

Xu, G., H. Yin, H. Yuan, and C. Xing. 2020. Decline curve analysis for multiple-fractured horizontal wells in tight oil reservoirs. *Advances in Geo-Energy Research* 4 (3):296–304. doi:10.46690/ager.2020.03.07.

Zavaleta, S., P. M. Adrian, and M. Michel. 2018. Estimation of OGIP in a water-drive gas reservoir coupling dynamic material balance and Fetkovich aquifer model. Presented at SPE Trinidad and Tobago Section Energy Resources Conference, Port of Spain, Trinidad and Tobago, June 25–26. doi:10.2118/191224-MS.

Zhang, Z., F. Luis, and H. Ayala. 2018. Analytical dual-porosity gas model for reserve evaluation of naturally fractured gas reservoirs using a density-based approach. *Journal of Natural Gas Science and Engineering* 59:224–36. doi:10.1016/j.jngse.2018.08.022.

Zhang, X., X. Wang, X. Hou, and W. Xu. 2017. Rate decline analysis of vertically fractured wells in shale gas reservoirs. *Energies* 10 (10):1602. doi:10.3390/en10101602.

Zheng, S., J. Shi, T. Zhang, K. Wu, Y. Miao, D. Feng, F. Sun, S. Han, S. Wang, C. Hou, et al. 2018. The modified gas-water two phase version flowing material balance equation for low permeability CBM reservoirs. *Journal of Petroleum Science and Engineering* 165: 726–35.

Nomenclature

k_1, k_2	permeability of the inner and outer zones, respectively (m^2)
k_m, k_f	permeability of the matrix and fracture, respectively (m^2)
ϕ_1, ϕ_2	porosity of the inner and outer zones, respectively
ϕ_m, ϕ_f	porosity of the matrix and fracture, respectively
μ_1, μ_2	oil viscosity of the inner and outer zones, respectively (Pa·s)
$c_{\mathrm{t}1}$, $c_{\mathrm{t}2}$	total compressibility of the inner and outer zones, respectively (Pa^{-1})
c_{tm}, c_{tf}	total compressibility of the matrix and fracture, respectively (Pa^{-1})
$\bar{c}_{ct}$, $\bar{c}_{dt}$	average formation total compressibility for radial composite reservoirs and naturally fractured reservoirs, respectively (Pa^{-1})
r_w, r_n, r_e	radius of the oil well, the inner and outer zones, respectively (m)
r	radial coordinate centered on the oil well (m)
t	the time (s)
B_o	formation volume factor of the oil (m^3/m^3)
h, h_m	thickness of the oil reservoir and the slab matrix, respectively (m)

q, q_{m} production rate and rate of matrix-fracture interporosity flow, respectively (m^3/s)

p, p_{wf}, p_{i} reservoir pressure, bottom-hole pressure and the initial reservoir pressure, respectively (Pa)

p_{m}, p_{f} pressure of the matrix and fracture, respectively (Pa)

p_{f}, p_{m} average pressure of the fracture system and the matrix system, respectively (Pa)

M, F mobility ratio and the storativity ratio for radial composite reservoirs, respectively

R_{ϕ}, R_{r} porosity ratio and the proportion of the inner zone, respectively

z coordinate of the slab matrix with the origin at the matrix-fracture interface (m)

C_{A}, γ reservoir shape factor and the Euler constant, respectively

A reservoir area (m^2)

α, ω shape factor and storativity ratio for naturally fractured reservoirs, respectively

N_{c}, Nh c geological reserves of the composite reservoir evaluated by the presented FMB method and the original FMB method (m^3)

N_{d}, Nh d geological reserves of the naturally fractured oil reservoir evaluated by the presented FMB method and the original FMB method (m^3)

Abbreviations

FMB flowing material balance