Matrix Block Size Determination of Iranian Naturally Fractured Reservoirs

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ABSTRACT

A simple approach for matrix block size evaluation in dual porosity reservoirs using a unified derivative type curve is illustrated with the aid of simulated and field examples under different wellbore conditions.

The effect of wellbore storage on dual porosity characteristics is discussed. The relationship for maximum wellbore storage conditions for obtaining undisturbed values of the dual porosity system parameters (ω and λ) are presented. It is shown that under certain wellbore storage conditions the true values of ω and λ cannot be obtained.

The unified derivative type curve approach is used to evaluate matrix block sizes in two Iranian naturally fracture reservoirs. The results are compared with other available sources of matrix block size for these reservoirs.

INTRODUCTION

A naturally fractured formation is generally represented by a tight matrix rock fragmented by a spatial fracture network as a result of tectonic activities. The matrix store most of the fluid in the reservoir and is often of low porosity and permeability whereas the fractures have a low storage capacity and high permeability.

The fractures vary considerably in pattern, size and geometry. In addition to this complexity, sealed and displaced fractures, deposition of minerals such as calcite and anhydride, dolomitization, dissolution of the matrix and the formation of cavities and vugs introduce considerable difficulties into the description of the internal structure of such reservoirs.

This is why idealized models such as cubical, cylindrical and strata have been used over the past 3 decades in analytical and numerical models to predict the future behavior and to estimate ultimate recoveries. The accuracy of the model in predicting reservoir performance depends on how close the model corresponds to the reservoir.

The analytical models are based on the concept of double porosity systems which was first introduced by Barenblatt et al[1]. The first complete solution for a well of finite radius producing at a constant flow rate was published by Warren and Root[2]. They showed that under pseudosteady state matrix to fracture fluid transfer the pressure behavior at the production well was controlled by two characteristic parameters only, viz. ω and λ. They also showed that the plot of the wellbore pressure versus logarithmic of time reveals two parallel straight lines. The unsteady-state flow from matrix to fractures was first studied by Kazemi[3] in a numerical radial model assuming horizontal slabs separated by fractures. He concluded that Warren and Root's model was valid in reservoirs with uniform fracture distribution and with large contrast between matrix and fracture flow capacities. Later de Swaan[4] presented analytical unsteady state solutions and Najurieta[5] further advanced de Swaan's theory by presenting approximate line source solutions for strata and spherical models. Streltsova[6] and Serra et al.[7] independently, by using de Swaan's model, reached the conclusion that the transition period yielded a straight line with a slope equal to one half the slope of the early and late parallel straight lines for small values of ω. The concept of skin on the surface of matrix was presented by Moench[8] who showed that the interporosity skin provides theoretical justification for the pseudosteady state flow approximation.

The effect of wellbore storage and damage was investigated by Mavor and Cinco[9]. They used Warren and Root's model to prepare type curves similar to the ones published by Agarwal et al.[10] for homogeneous reservoirs. The authors indicated that because four variables, i.e. C_D, S, ω, and λ, were involved, the number of type curves required for log-log analysis would be prohibitive and concluded that the two parallel semilog straight lines were needed for obtaining ω, and λ. Bourdet and Gringarten[11] used Mavor and Cinco's solution and developed type curves for the transition period. Then by superposing Gringarten et al.'s type curve[12] for homogeneous reservoirs, they constructed a new type curve. Bourdet et al.[13] combined Bourdet and Gringarten's type curves[11] with the pressure derivative of the pseudosteady state transitional period and obtained a new set of type curves and Bourdet et al.[14] developed a similar set of type curves for the transient interporosity conditions. Stewart and Ascharsobbi[15] published a new unified derivative type curve for the pseudosteady state model based on a new definition of dimensionless time group. A detailed study of well test analysis in naturally fractured reservoirs may be found in Ref. 16.

This paper discusses the effect of wellbore storage on dual porosity characteristics and presents a simple approach for matrix block size determination. The matrix block sizes in two huge naturally fractured reservoirs located in Southwest of Iran are evaluated. The comparison between the calculated block sizes with other available source are also presented.

FLOW EQUATIONS IN DUAL POROSITY SYSTEMS

The general differential equation for a radial fracture flow in dual porosity systems may be written as:

$$\frac{\partial^2 P_f}{\partial r^2}+\frac{1}{r}\cdot\frac{\partial P_f}{\partial r}=\frac{\phi_{fD} C_f \mu}{K_{fD}}\cdot\frac{\partial P_f}{\partial t}-\frac{\mu}{K_{fD}}\cdot\sigma_{mf} \qquad (1)$$

where σ_{mf} is the only interporosity flow dependent variable. The process of fluid transfer between matrix and fractures is the point at which the various models differ. The differences were found in the transition period and in the duration of the initial fracture flow. By using the dimensionless parameters given in Appendix A, the general solution to Eq. 1 in Laplace space becomes:

$$\overline{P_{fD}} = A I_0 [r_D\sqrt{zf(z)}] + B K_0 [r_D\sqrt{zf(z)}] \qquad (2)$$

where z is Laplace variable and f(z) is given in Appendix A for the pseudosteady state interporosity flow conditions. The bottom hole dimensionless pressure in Laplace domain for a well producing at constant flow rate from infinite reservoir is written as:

$$\overline{P_{fD}} = \frac{K_0[\sqrt{zf(z)}]}{z\sqrt{zf(z)}\,K_1[\sqrt{zf(z)}]} \qquad (3)$$

The inverse of this solution provides the sandface dimensionless pressure. The numerical inversion technique presented by Stehfest[17] may be used to transform the solution from Laplace into real space. The derivative of dimensionless pressure with respect to logarithm of dimensionless time versus block dimensionless time, $t_{Db} = t_D\lambda/4$, is shown in Fig. 1 on a log-log plot[15] for different values of ω and λ. Each curve is characterized by a value of ω. This type curve may be used in the usual manner to calculate permeability , ω and λ.

WELLBORE STORAGE EFFECT

The dimensionless pressure at the wellbore including wellbore storage and damage may be written as:

$$\overline{P_{wD}} = \frac{z\overline{P_{fD}} + S}{z[1 + C_D z(S + z\overline{P_{fD}})]} \qquad (4)$$

The pressure behavior for the pseudosteady-state model under the influence of wellbore storage is shown on a log-log graph in Fig. 2 for different values of dimensionless storage coefficient. It can be seen that as wellbore storage increases the dual porosity behavior will be obscured, as a result the determination of dual porosity parameters become impossible. Fig.3 shows the similar behaviors of homogeneous and dual porosity systems both under the influence of the same amount of wellbore storage. The effect of wellbore storage on ω is depicted in Fig. 4. It can be seen that dual porosity systems with different values of ω exhibit similar behaviours.

Further investigation of wellbore storage effect has shown that in order to obtain undisturbed values ω and λ, the dimensionless wellbore storage, C_D , should be less than $0.001/\lambda$. Further for values of $C_D<.01/\lambda$, the value of λ may be obtained by the derivative type curve.

WELL TEST ANALYSIS

The early work on well test analysis of naturally fractured reservoirs has been reported by Pollard[18] in 1959. In 1961 Pirson and Pirson[19] extended Pollard's method to evaluate matrix and fracture pore volume. Kazemi[3] by using the results of his numerical model reported a considerable error in Pirson's method.

A breakthrough in the pressure transient analysis of naturally fractured reservoirs was provided by Warren and Root[2]. They showed that a standard semi-log plot of pressure versus time exhibits two parallel straight lines with a transition period in between.

Most practical methods for interpretation of pressure drawdown and buildup data are based on the existence of the two parallel semi-log straight lines.

In cases where the two parallel straight lines are fully developed, the calculation of ω is straight forward. The vertical separation between the two straight lines may be used to calculate ω. Many theoretical techniques have been developed to evaluate λ. The procedures for pseudosteady state model are based on the point of inflection[20,21] and the time of intersection of a horizontal line drawn through the middle of the transition curve[22]. For transient interporosity flow model the point of intersection of the second and third lines[23] and the beginning of the third straight line[6,24] have been used to evaluate λ for strata.

The inspection of a large number of pressure buildup tests from many naturally fractured limestone reservoirs in Southwest of Iran reveals that the number of possible behavior types is limited. Wells producing with low productivities, q<5000 STB/D, show wellbore storage. Very few cases exhibited the two parallel straight lines. In most cases the first straight line has not been recorded but the transient period showed the pseudosteady-state behavior. Wells with high productivities (q>20000 STB/D) exhibited homogeneous type behavior.

In cases where wellbore storage is significant the true value of ω cannot be obtained by semi-log or type curve analysis. An estimate of the fracture width may be obtained from correlations between permeability and fracture width for idealized models[25]. In such cases, since the point of inflection and the transition curve are disturbed, there is no simple procedure to calculate λ.

MATRIX BLOCK SIZE DETERMINATION

One of the most important parameters in simulation study of fractured reservoirs which has a major role in reservoir estimation is the matrix block size.

The derivative type curve, Fig. 1, presented by Stewart and Ascharsobbi[15] has been found very useful in the evaluation of λ for the pseudosteady-state interporosity flow model.

This type curve is given as the logarithmic derivative of pressure drawdown versus $t_D.\lambda/4$. Each curve is characterized by a minimum which depends on ω and a unit slope section between the minimum itself and the final period of constant derivative corresponding to the total system straight line on the semi-log graph. If the definition of t_D and λ are substituted in the new time group, yields:

$$\frac{t_D \times \lambda}{4} = \frac{n(n+2)K_{mb}t}{(\phi c_t)_{m+f}\mu h_m^2} \tag{5}$$

The new dimensionless time is called block dimensionless time is denoted by t_{Db}. An interesting feature of the new type curve is that the total system behaviour starts at $t_{Db}=1$ for $\omega<0.1$. This corresponds to the beginning of the second parallel straight line.

This type curve may be used in the usual manner. The logarithmic derivative of test data is plotted verses Δt on a log-log graph of the same size as that of the type curve and matched with one of the curves. This yields a value for ω. The permeability thickness product can be calculated from the pressure match:

$$K_{fb}h = (141.2 q\beta\mu) \times \left[\frac{d(P_D)/d(\ln t_D)}{d(\Delta P)/d(\ln t)}\right]_{match} \tag{6}$$

and λ may be obtained from the time match

$$\lambda = \frac{(15168.75) \times (\phi c_t)_{m+f}\, \mu\, r_w^2}{k_{fb}} \times [\frac{t_{Db}}{t}]_{MATCH} \quad (7)$$

For $t_{Db}=1$, i.e. the beginning of the second parallel straight line, the matrix block size becomes:

$$h_m = A \sqrt{\frac{K_{mb}\, t_{bepsl}}{(\phi c_t)_{m+f}\, \mu}} \quad (8)$$

where t_{bepsl} in hours may be obtained from the time match at $t_{Db}=1$ from the derivative type curve or from semi-log plot. Constant A is equal to 0.02813 for strata, 0.04593 for cylinders and 0.06289 for spheres.

The procedure is illustrated by two generated examples and two field pressure buildup data. The first example is a drawdown test generated by the PSS dual porosity model for $C_D=10^3$, ω= 0.005, K=100 md, and $\lambda=10^{-7}$. The derivative match is shown in Fig.5. From the derivative type curve match the values K= 101.4 md, ω= 0.005 and λ= 0.97×10^{-7} are obtained. It can be seen that wellbore storage has disturbed the early time data but the minimum point of the derivative which corresponds to the inflection point on the semi-log plot is undisturbed. Therefor the matching curve has produced the true value for ω. The second example is a short time buildup test following the drawdown of example 1. The flowing wellbore pressure at the time of shut-in(t_p = 3033.75 hours) was 2721.84 psi. The derivative of the pressure data with respect to the effective time function has been calculated. The derivative match is shown in Fig.6. The matching parameters are K = 98.25 md, ω= 0.005, and $\lambda=0.98 \times 10^{-7}$.

The third example is a buildup test conducted on well 72 in reservoir B. The Horner plot is depicted in Fig. 7. The derivative match is shown in Fig. 8 and finally the comparison between PSS dual-porosity model and the buildup data is shown in Fig. 9. The analysis results are given in table 1. The fourth example is a buildup test obtained from well 76 in the from the same reservoir. The Horner plot for this test is shown in Fig.9. The derivative match and the comparison between PSS dual-porosity model and the buildup data are depicted in Figs. 10 through 12. The analysis results are given in table 2.

FIELD EXAMPLES

The pressure buildup tests from two huge naturally fractured reservoirs, A and B, located in Southwest of Iran have been studied. The derivative type curve has been used to calculate the matrix block sizes in these reservoirs. Table 3 shows the matrix block sizes at 20 locations in reservoir A. For completeness the semi-log analysis is presented in table 4. The distribution of the matrix block size with depth is presented in table 5 and table 6 compares the present matrix block calculations with other available sources. The results from the derivative type curve matching technique for reservoir B are given in table 7. The matrix block size in this reservoir has been estimated to be in the range of 15-45 feet by simulation studies.

CONCLUSIONS

The effect of wellbore storage on dual porosity systems under pseudosteady state interporosity flow is investigated and limiting values of dimensionless wellbore storage for obtaining true values of ω and λ are presented.

A simple procedure for the evaluation of the matrix block size is illustrated by generated and field examples. A correlation for matrix block size calculation using the beginning of the second parallel straight line for the pseudosteady state model is also presented

Two huge naturally fractured reservoirs from Southwest of Iran has been analyzed by the aid of the derivative type curve. Results of analysis as well as comparisons with other available sources are given.

NOMENCLATURE

A = area
bbl = barrel(oil field, 42 U.S.gallons-per barrel)
c = compressibility
c_{ef} = compressibility of fracture
c_m = compressibility of fluid within the matrix
c_t = total compressibility
c_o = oil compressibility
cp = centipoise
C_D = dimensionless wellbore storage coefficient
d = darcy
D = day
h = thickness
h_m = matrix block dimension
hr = hour
K = permeability
K_{fb} = bulk fissure permeability
K_{mb} = bulk matrix permeability
md = milli-darcy
n = number of normal sets of fissure planes
psi = pounds per square inch

P = pressure
P_f = fissure pressure
P_D = dimensionless pressure
P_{fD} = dimensionless fissure pressure
P_i = initial pressure
P_w = bottom-hole pressure
P_{wD} = dimensionless bottom-hole pressure
q = volumetric flow rate
r = radial distance
r_w = wellbore radius
r_D = dimensionless radial distance
z = Laplace transform variable
S = skin factor
t = time
t_D = dimensionless time
t_p = producing time before shut-in
Δt = shut-in time
t_{D*} = $t_D \lambda / 4$
β = oil formation volume factor
Δ = difference ($\Delta P = P_2 - P_1$)
λ = interporosity flow parameter
μ = viscosity
σ_{mf} = matrix to fissure flow rate per unit total bulk volume
σ_{mfD} = dimensionless matrix to fissure transfer rate
ϕ = porosity
ϕ_{mb} = bulk matrix porosity
ϕ_{fb} = bulk fissure porosity
$(\phi c_t)_m$ = matrix total capacity
$(\phi c_t)_f$ = fissure total capacity
$(\phi c_t)_{m+f}$ = matrix total capacity plus fissure total capacity
ω = ratio of fissure storage capacity to total capacity

MATHEMATICAL NOTATIONS

dx = derivative of x
I_o = modified Bessel function of the first kind and of order zero
K_o = modified Bessel function of the second kind and of order zero
K_1 = modified Bessel function of the second kind and of order one
ln = logarithm to the base e
log = logarithm to the base 10
∂x = partial derivative of x

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APPENDIX A

Dimensionless Groups

Dimensionless pressure:

$$p_D=\frac{2\pi K_{fb}h}{q\beta\mu}\Delta p \qquad \text{(A.1}$$

Dimensionless time:

$$t_D=\frac{K_{fb}t}{(\phi C_t)_{m+f}\mu r_w^2} \qquad \text{(A.2)}$$

Dimensionless storage coefficient:

$$C_D=\frac{C}{2\pi(\phi C_t)_{m+f}hr_w^2} \qquad \text{(A.3)}$$

Dimensionless radius:

$$r_D=\frac{r}{r_w} \qquad \text{(A.4)}$$

Dimensionless storativity:

$$\omega=\frac{\phi_{fb}c_f}{\phi_{mb}c_m+\phi_{fb}c_f} \qquad \text{(A.5)}$$

Dimensionless Interflow Parameter:

$$\lambda=\frac{4n(n+2)}{h_m^2}\cdot\frac{K_{mb}}{K_{fb}}\cdot r_w^2 \qquad \text{(A.6)}$$

Dimensionless Matrix Flow rate:

$$\sigma_{mfD}=\frac{2\pi r_w^2h}{q\beta}\cdot\sigma_{mf} \qquad \text{(A.7)}$$

Table 1
Well Test Analysis Results for Well B-72

Analysis	$K_{fb}h$	S	ω	λ
Semilog	26.99	-4.47	-	
Derivative	27.25	-	-	$4x10^{-5}$
Simulator	26.99	-4.47	0.08	$4x10^{-5}$

Table 2
Well Test Analysis Results for Well B-76

Analysis	$K_{fb}h$	S	ω	λ
Semilog	3.77	-3.86	-	-
Derivative	4.2	-	-	$4.8x10^{-4}$
Simulator	3.77	-3.86	0.01	$5x10^{-4}$

Table 3
Matrix Block Size in feet for Reservoir A

WELL No.	SLABS	CYLINDERS	CUBES
A-64	50.18	73.77	101.02
A-83	71.12	112.6	145.52
A-85	37.70	59.68	77.14
A-87	17.45	27.63	35.70
A-88	48.67	77.05	99.60
A-90	83.82	132.7	171.47
A-94	54.23	88.54	121.24
A-99	122.1	193.3	249.80
A-105	32.00	53.10	72.70
A-108	72.66	115.0	148.67
A-110	31.86	50.42	65.18
A-114	53.32	84.40	109.10
A-117	51.40	81.27	105.05
A-123	62.11	98.33	127.09
A-125	87.10	142.2	194.68
A-127	117.5	186.0	240.43
A-128	35.10	57.30	78.43
A-157	59.34	93.93	121.41
A-160	63.19	100.0	129.30
A-161	11.60	18.41	23.80

Table 4
Semi-log Results for Reservoir A

WELL No.	Kh, d-ft.	SKIN FACTOR
A-64	16.8	- 5.26
A-83	74.2	-5.73
A-85	3.02	-
A-87	98.53	-2.39
A-88	48.16	-5.32
A-90	4.6	-5.77
A-94	36.1	-6.62
A-99	0.4	-5.02
A-105	47.38	-
A-108	47.2	-6.29
A-110	51.47	-5.69
A-114	1.3	-4.92
A-117	15.57	-6.55
A-123	6.3	-5.09
A-125	1.27	-5.76
A-127	7.18	-4.32
A-128	2.97	-4.67
A-157	4.86	
A-161	1.58	

Table 5
Distribution of Matrix Block size with Depth, Reservoir A

WELL No.	WELL COMPLETION m, ss	BLOCK SIZE feet
A-161	2190-2255	11.6
A-87	2270-2310	17.47
A-105	2330-2445	32.0
A-88	2520-2565	48.67
A-157	2275-2290	59.34
A-123	2470-2600	62.11
A-83	2420-2515	71.12
A-108	2455-2540	72.66
A-90	2440-2510	83.82
A-125	2280-2345	87.1
A-99	2435-2558	122.1

Table 6
Comparison of Matrix Block Size in feet with other sources for Reservoir A

SECTOR	STRATA	CYLINDERS	CUBES	SOURCE 1*	SOURCE 2*
N1	50-87	74-142	101-195	45	22-56
N2	17-37	28-60	36-77	25	17-33
N4	12-32	18-50	24-65	50	30-70
S1	32-118	53-186	73-240	33	37-73
S2	54-84	89-133	121-171	23-53	22-56
S3-4	49-122	77-193	100-250	26	17-47

* National Iranian Oil Company archive

Table 7
Matrix Block Size for Reservoir B

SECTOR	AVERAGE MATRIX BLOCK SIZE, feet	No. of Wells	No. of Tests
2	13.1	1	1
3	22.5	6	15
4	29.7	5	11
5	15.6	2	6
6	93.5	2	2
7	13.4	4	13
8	25.3	6	15