Simulation of Naturally Fractured Reservoirs with SimBestII

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Abstract

Simulation of naturally fractured reservoirs is one of the laborious techniques. This is because there are two different porous media in which fluids exist and flow. These porous media exhibit wide variations in there physical properties. The matrix represents the major storage capacity while the fractures system provides the main paths of the flowing fluids.

Several simulators have been constructed by some of the specialist companies. One of them is the SimBestII, which is the product of Scientific Software-Intercomp. In order to simulate a reservoir perfectly by such simulator, one should have an idea about the equations and the procedure encountered in it.

In the current study, an attempt has been made to understand the general structure of SimBestII. The flow equations that are employed in SimBestII are investigated and some of the calculation procedures are clarified. The exchange term in the flow equations is discussed comprehensively and the factors that could be justified to reduce or magnify the imbibition rate are detected.

Introduction

Warren and Root[1] classified the porosity of reservoirs as

1- Primary porosity, which represents the pores constructed during precipitation of solid grains. Granular rocks, such as sandstone, exhibit this type of porosity.

2- Secondary porosity formed by fractures, solution channels, or vugular voids in porous media. It is attributed to tectonic movements and chemical process. The porosity of carbonate rocks is often secondary porosity.

The volume of fluids, which are reserved in secondary porosity, is often less than that in the primary porosity but the former exhibit less resistance to flow of fluids. Naturally fractured reservoirs can be described as fractured homogenous reservoirs. They often comprise high permeable, low storage volume fractures, and tight, high storage volume matrix blocks. The porosity of the matrix is the primary porosity, whereas secondary porosity is represented by fractures channels. Therefore, naturally fractured reservoirs are termed as dual porosity systems.

Simulation of dual porosity systems is more laborious than conventional reservoirs simulation. In single porosity systems, one equation for each phase can describe the flow of that phase in the system. However, in dual porosity systems, single equation is no longer sufficient unless simplifying assumptions are invoked.

In 1963, Warren and Root[1] introduced the concept of dual porosity model. They presented a comprehensive solution for the problem of single phase flow in naturally fractured reservoir. They idealized naturally fractured reservoirs as a system composed of continuum orthogonal fractures network superimposed by a non continuum, identical, regular parallelepipeds matrix blocks

The fractures network provides the main path for fluids to flow from the reservoir. The fluids in the matrix are produced after they are drained to the fractures by fluid imbibition into the matrix in a counter flow process. Accordingly, the flow of water and oil in fractures with cylindrical coordinate system is governed by(2):

$$\Delta_r (Tw_{rf}^{n+1} \Delta_r Pw_f^{n+1}) + \Delta_z (Tw_{zf}^{n+1} \Delta_z \Phi w_f^{n+1}) - Tw_{\sigma i,k}^{n+1} (\Phi w_f^{n+1} - \Phi w_m^{n+1}) -$$
$$Qw_f^{n+1} = \frac{Vb_{i,k}}{\Delta t} \Delta_t (\varphi_f Sw_f bw_f)_{i,k}^{n+1} \tag{1}$$

$$\Delta_r (To_{rf}^{n+1} \Delta_r Po_f^{n+1}) + \Delta_z (To_{zf}^{n+1} \Delta_z \Phi o_f^{n+1}) - To_{\sigma i,k}^{n+1} (\Phi o_f^{n+1} - \Phi o_m^{n+1}) -$$
$$Qo_f^{n+1} = \frac{Vb_{i,k}}{\Delta t} \Delta_t (\varphi_f So_f bo_f)_{i,k}^{n+1} \tag{2}$$

while the matrix equations are

$$- Tw_{\sigma i,k}^{n+1} (\Phi w_f^{n+1} - \Phi w_m^{n+1}) = \frac{Vb_{i,k}}{\Delta t} \Delta_t (\varphi_m Sw_m bw_m)_{i,k}^{n+1} \tag{3}$$

$$- To_{\sigma i,k}^{n+1} (\Phi o_f^{n+1} - \Phi o_m^{n+1}) = \frac{Vb_{i,k}}{\Delta t} \Delta_t (\varphi_m So_m bo_m)_{i,k}^{n+1} \tag{4}$$

where the subscripts f and m refer to fracture and matrix respectively.

Water and oil transmissibilities which controls fluid transfer between fracture and matrix blocks are defined as

$$Tw_{\sigma i,k} = 0.006328\, Vb_{i,k}\ K_{mi,k}\ \sigma \left(\frac{K_{rw}\ bw}{\mu w} \right) \tag{5}$$

$$To_{\sigma i,k} = 0.006328\, Vb_{i,k}\ K_{mi,k}\ \sigma \left(\frac{K_{ro}\ bo}{\mu o} \right) \tag{6}$$

where σ is a shape factor and it is a property of the system.

The shape factor (σ) plays an important role in the fracture/matrix exchange term. During the last three decades, many attempts had been made to predict exactly the amount of fluid transfer between the fracture and matrix blocks. Therefore, several techniques for handling the shape factor have been presented in the literature. Non of them can be considered as a precise procedure when considering the ambiguity accompanying such process.

In the current study, the approach that has been adopted by SimBestII to simulate naturally fractured reservoir is investigated. One of the practical ways to perform this job is by considering a hypothetical example and solving it by SimBestII and other simulator whose structure is quit recognized. The comparison between the output of the simulators will give a hint about the procedure adopted by SimBestII. Consequently, the simulator presented by Al-Jawad[2] is adopted and the results of the provided example are taken as a base for comparison.

The Flow Terms

Equations 1, 2, 3, and 4 represent the equations that control the flow of water and oil in fracture and matrix systems written in finite difference form. These equations illustrate the concept of dual porosity model, which presumes that no flow takes place between two adjacent matrix blocks. Moreover, the wells are opened to flow only in the fractures blocks. The flow of fluids between the fractures and the matrix is summarized by the exchange term.

Five different terms can be recognized in the fracture equations (eq. 1 and 2). Two of them are similar in nature, which are the flow terms in radial and vertical directions. The sink/source term stands for the production or injection of fluids applied at the block. The exchange term is different in that it represents the transfer of fluids between fractures and matrix block. The right hand side term is the accumulation term that describes the rate of fluid volume change with time. The last two terms are common in fracture and matrix equations.

The flow terms in the fracture equations have the major effect on the fluid movement within the reservoir. Obviously, the fracture permeability is the main factor that controls these terms. In this aspect, two types of fracture permeability are defined in the literature(3). The first one is a measure of the fracture channel conductivity. In this case, only the fracture void area represents the flow cross section. This type is known as the intrinsic fracture permeability and for the single fracture shown in figure 1 it is defined as:

$$K_{ff} = \frac{b^2}{12} \tag{7}$$

The other type of fracture permeability is the conventional fracture permeability, which is based on the classic Darcy's definition(3). Here, the fracture and the associated rock bulk form a hydrodynamic unit. It is defined for a single fracture as:

$$K_f = \frac{b^3}{12\,h} \tag{8}$$

Either one could be used in a flow equation with the suitable cross sectional area. The area corresponds to the intrinsic permeability is:

$$A_f = a\,b \tag{9}$$

While that should be used with the conventional permeability is:

$$A_B = a\,\mathrm{h} \tag{10}$$

All symbols are depicted in figure 1.

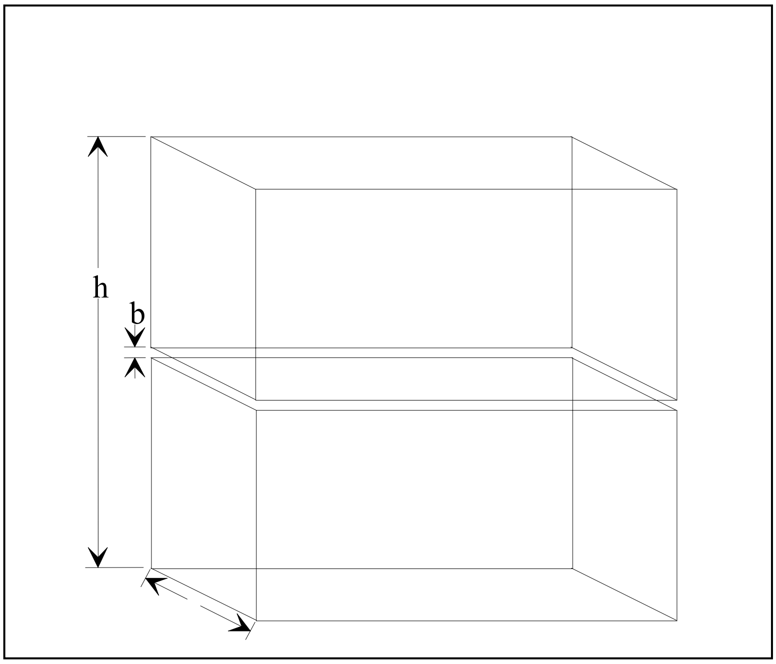

Figure 1- A single fracture in a bulk block

The relationship between the two types of permeability could be defined through fracture porosity. However, fracture porosity is defined as the void volume of the fracture per bulk volume of the block. Accordingly,

$$\varphi_f = \frac{a\,b}{a\,h} = \frac{b}{h} \tag{11}$$

and

$$K_f = \varphi_f K_{ff} \tag{12}$$

As shown in equation 12, the fracture permeability is less than the intrinsic fracture permeability. Naturally fractured reservoirs are usually characterized by small fracture porosity. Keeping this fact in mind, the intrinsic fracture permeability may be several hundreds times greater than the conventional one. Therefore, the utilization of the suitable type of fracture permeability is quite vital.

One of the objects of this study is to realize from the type of permeability that is adopted by SimBestII. However, it is anticipated that SimBestII presumes that the fracture permeability data is the intrinsic fracture permeability. On the other hand, the conventional permeability is adopted in the flow equations since the cross sectional area in these equations is the block area.

The approval of the above hypothesis is accomplished through the following administrations:

1- Run SimBestII in dual porosity mode with conventional fracture permeability.
2- Run SimBestII in dual porosity mode with intrinsic fracture permeability.
3- Run SimBestII in single porosity mode with conventional fracture permeability value assigned to the porous media.
4- Run SimBestII in single porosity mode with permeability equal to the conventional permeability times the fracture porosity.

Other data for these runs are given in table1.

The plot of block pressure for these runs is depicted in figure 2. It is clear from this figure that the results using the intrinsic permeability in fractured medium and conventional permeability in single porosity model are close to each other. In the single porosity model, only one type of permeability is defined and used in the flow equations. This leads to the conclusion that in the dual porosity mode, SimBestII uses the intrinsic permeability in the flow equations after multiplying it by the fracture porosity. In other words, the intrinsic permeability value should be put in the data file and SimBestII will then multiplies it by the fracture porosity, which is also given in the data file, to get the conventional fracture permeability value that would be employed in the flow equations.

The Exchange Term

The exchange of fluids between fractures and matrix has a great effect on the rise of water in the wells. This is attributed to the fact that the water usually rising up in the fractures system due to its high permeability and connectivity. The result is a depleted fractures system and highly oil saturated matrix. The exchange of fluids between fractures and matrix will manage the situation and if there is a higher rate of fluid transfer, the produced water cut will be less. This process is simulated by the exchange term in the flow equations.

Table 1- Example data (after ref. 2)

Basic data	
Total thickness of the reservoir, ft	227.5
Radial extent of the reservoir, ft	2050
Well bore radius, ft	0.25
Thickness of the perforated interval, ft	28.2

Fractures and matrix properties		
	Fractures	Matrix
Permeability, md	1000	5
Porosity	0.008	0.05
Compressibility, psi^{-1}	0.0056	0.00001
Vertical / Horizotal permeability ratio	0.5	1.
Shape factor, ft^{-2}	0.1068	

Fluids properties		
	Water	Oil
Compressibility, psi^{-1}	$5.5x100^{-5}$	$4x10^{-6}$
Stock tank specific gravity	**1.02**	**0.8456**
Viscosity, cp	0.3	15.8
Formation volume factor, RB/STB	**1.0**	**1.053**

Grids Specifications	
Number of radial grids	10
Number of vertical grids	7
Radius to the bounndary of the block, ft	0.25, 2.0, 4.32, 9.33, 20.17, 43.56, 94.11, 203.32, 439.24, 948.92, 2050.0
Thickness of the blocks, ft	28.2, 25.0, 25.6771, 51.2229, 32.4, 30.0, 35.0

Saturation functions							
Fractures system				Matrix system			
S_{wf}	K_{rwf}	K_{rof}	P_{cowf}	S_{wm}	K_{rwm}	K_{rom}	P_{cowm}
0	0.0	1.0	3.869	0.28	0.0	0.94	3.869
0.1	0.052	0.764	1.906	0.324	0.016	0.705	2.773
0.2	0.111	0.592	0.896	0.368	0.034	0.544	2.077
0.3	0.182	0.439	0.54	0.412	0.052	0.431	1.579
0.4	0.271	0.328	0.37	0.456	0.07	0.348	1.195
0.5	0.367	0.239	0.277	0.5	0.092	0.276	0.868
0.6	0.47	0.163	0.205	0.544	0.113	0.207	0.612
0.7	0.586	0.103	0.135	0.588	0.131	0.149	0.384
0.8	0.715	0.057	0.085	0.632	0.154	0.092	0.213
0.9	0.854	0.017	0.043	0.676	0.178	0.034	0.085
1.0	1.0	0.0	0.0	0.72	0.2	0.0	0.0

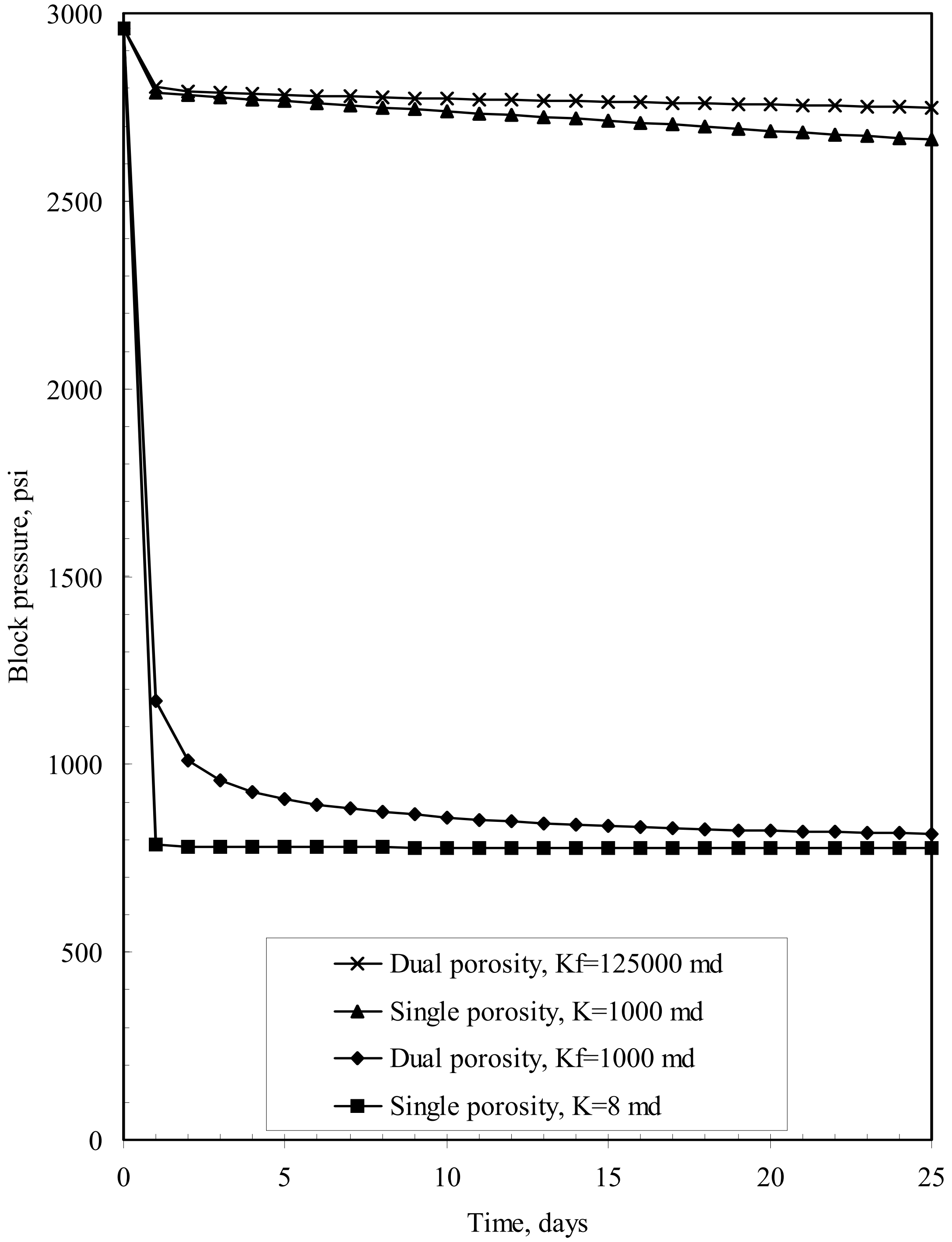

Figure 2- Block pressure history for different runs

Mathematically, the exchange term is simply a source or sink term composed of transmissibility and difference in pressure (or potential) between the matrix and the surrounding fractures. This term appears in the fracture and matrix equations to govern the flow of the considered phases. This means that water will move to the matrix if the water pressure in the fracture is higher than that in the matrix. Similarly, oil will move out of the matrix if its pressure in the matrix is higher. All of the factors in this term are familiar except the shape factor, σ. However, this factor controls the rate of fluid exchange between fracture and matrix. Prediction of the shape factor value is not a simple matter. Kazemi, Merril, and

Zeman[4], have presented a method for estimating the value of σ. SimBestII adopts this method when it calculates the rate of fluid exchange. It can be summarized as follows:

$$\sigma = \frac{4}{L_x^2} \qquad \text{For the flow in one direction} \tag{13}$$

$$\sigma = \frac{4}{L_x^2 + L_z^2} \qquad \text{For the flow in two directions} \tag{14}$$

$$\sigma = \frac{4}{L_x^2 + L_z^2 + L_y^2} \qquad \text{For the flow in three directions} \tag{15}$$

Where L_s (s = x, y, or z) are defined by Kazemi et al. as the dimensions of the matrix block. However, SimBestII manuals[5,6] defined L_s as the distance between the fractures in each of the coordinate directions and if they are identical in magnitude to the grid block dimensions then the model becomes that proposed by Warren and Root[5]. For a highly fractured reservoir, the values of L_s should be substantially less than the matrix grid block dimension[5]. It is obvious that decreasing the values of Ls will increase σ and thus increases the fracture ability to transmit fluid to the matrix or vice versa.

In the current study, the cylindrical coordinates system is adopted which is a special case of the flow in two directions. Thus equation 14 has been used to calculate the value of σ. The example presented by Al-Jawad[2] is employed in SimBestII and the results are compared in order to understand the computation techniques of SimBestII. The data are given in table 1. The initial water saturation in fractures and matrix blocks adjoining the well is compared in figure 3. The movable water saturation for the same grids after 25 days of production is depicted in figure 4. The value of σ in the example is 0.1068 ft^{-2} and according to equation 14, this value corresponds to L_x=L_z=8.65485 ft. Figure 5 demonstrates a comparison between the results of SimBestII and that of reference 2. The compatibility between the curves of figure 5 indicates that similar procedures are used to produce them. Thus, equations 1, 2, 3, and 4 are also the basic equations that implied in SimBestII. This fact is also indicated in reference 5 and 6.

Exact values of L_s are hard to be determined and usually, they assumed equal to the block dimensions and then increased or decreased according to the results of history matching. However, it is believed that value of σ governs the amount of fluid transfer. That is, various values of L_x and L_z could lead to the same value of σ and equal amounts of fluid will transmit from the fracture to the matrix or vice versa. In figure 6 two sets of L_x and L_z are employed in addition to that proposed by the example. For the first one, L_x=30ft, and L_z=6.2514ft. Applying equations 14, the value of σ is 0.1068, which is the same as in the example of reference 2. This value is also duplicated if L_x=10000ft and L_z=6.1199ft. Therefore, the water cut history curves coincide. However, SimBestII should be provided by L_s rather than σ. The values of L_s may be varied regionally or locally. Such variations produce various imbibition rates if and only if the value of σ varies. Consequently, one has to be very cautious when assigning values of L_s, since some different combinations of L_s may not lead to different exchange rate.

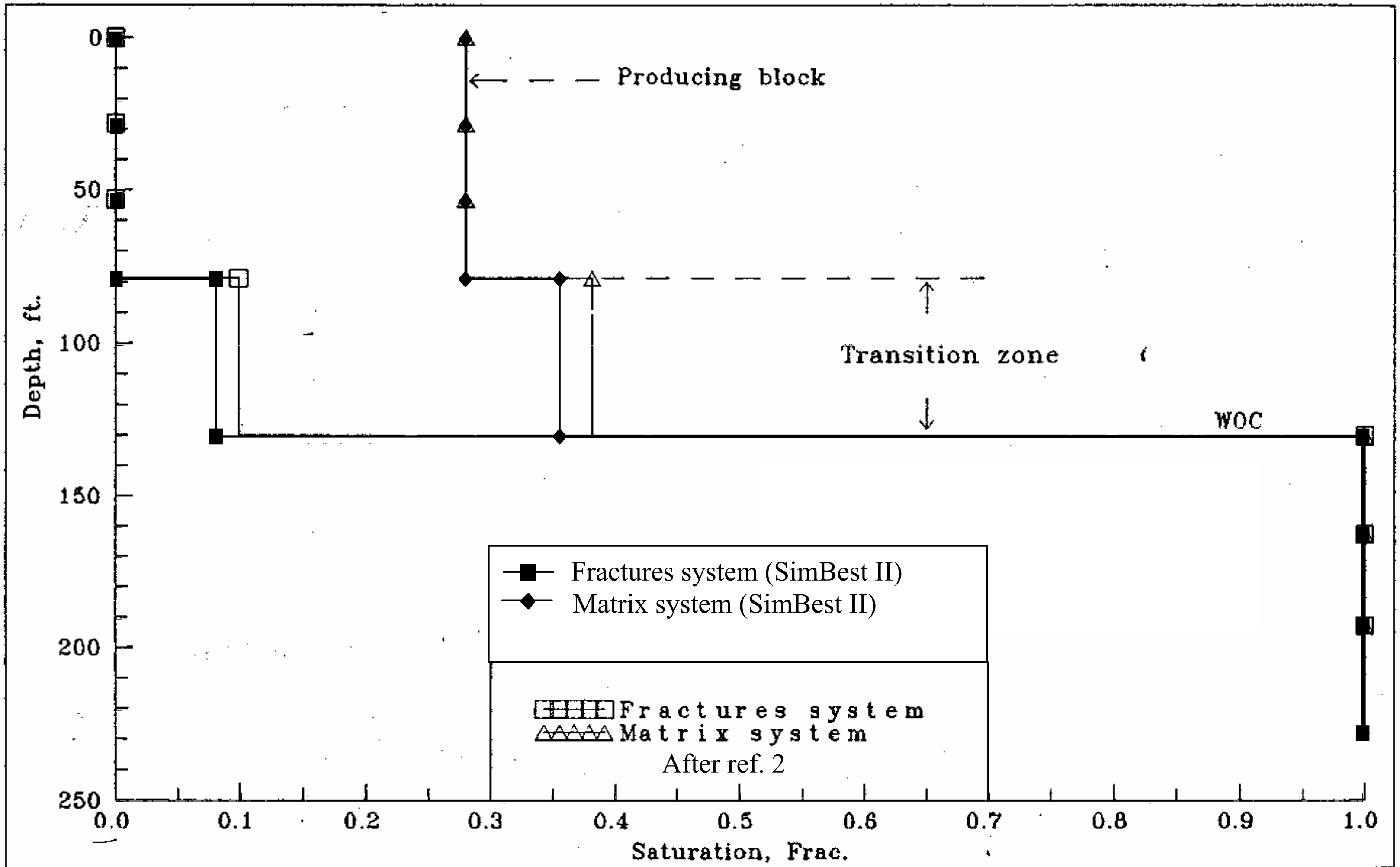

Figure 3- Initial water saturation in fractures and matrix blocks

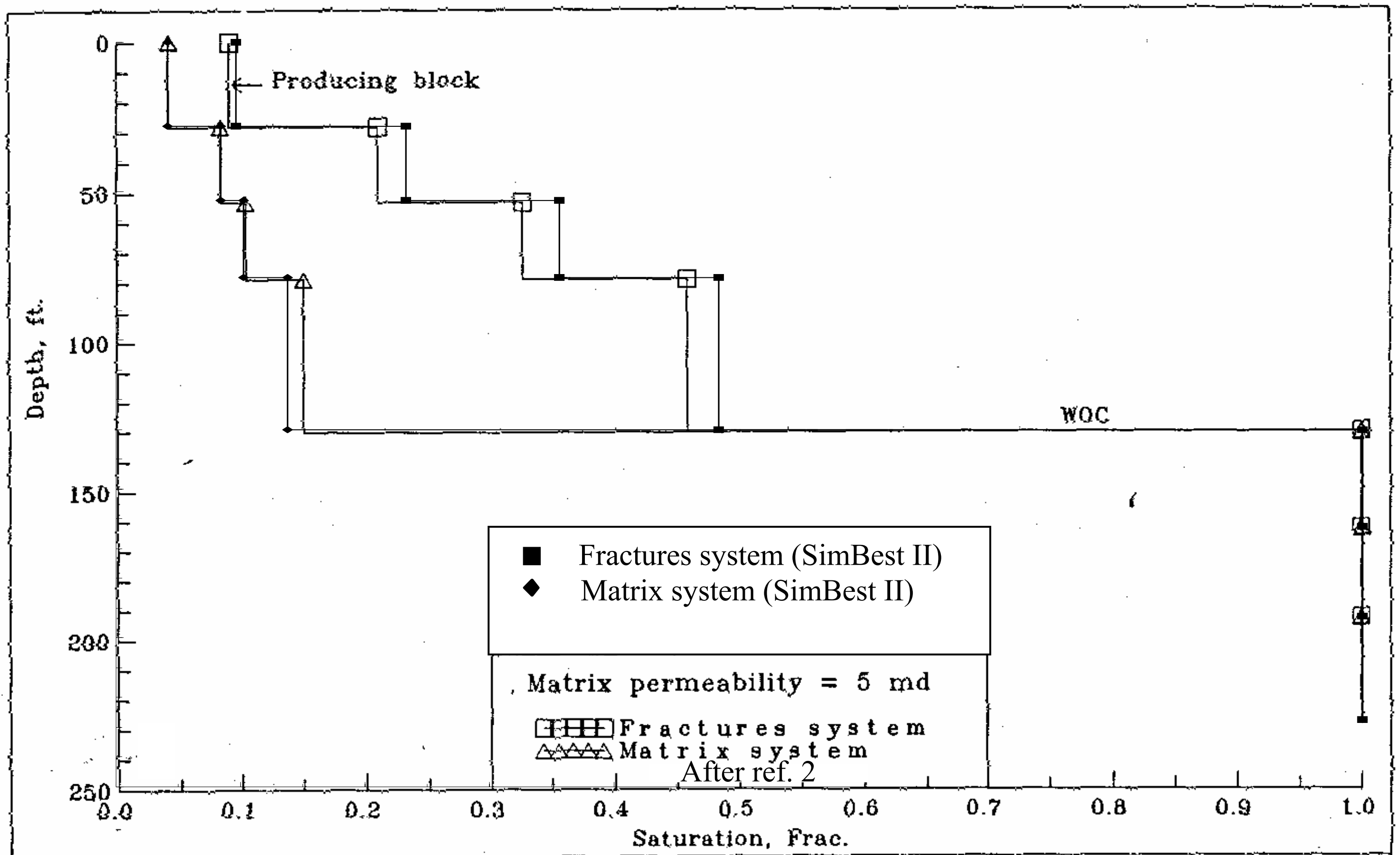

Figure 4- Water saturation in fractures and matrix blocks after 25 days

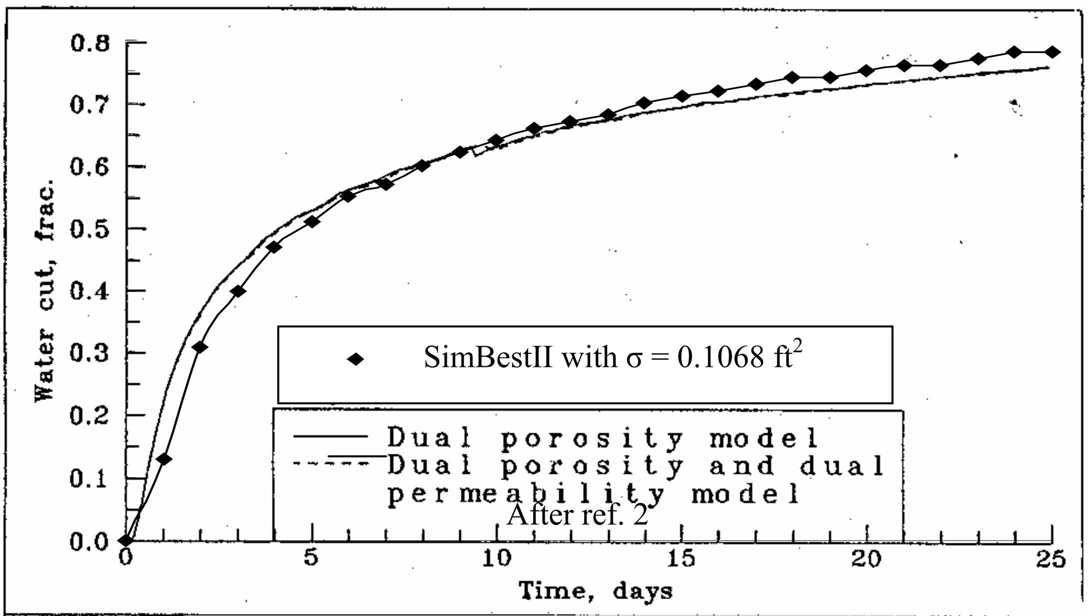

Figure 5– Comparison of water cut history

The final article that will be discussed here is the effect of σ on the imbibition rate. When the value of σ vanishes, the flow of fluids takes place through the fractures system only and no fluid could be produced from the matrix. In this case, the results for fractures system obtained by SimBestII for dual porosity mode will be similar to that of the single porosity mode. On the other hand, as the value of σ increases, to a certain limit, the rate of imbibition also amplifies. Table 2 introduces the values of L_s and the corresponding values of σ as calculated by equation 14. In figure 7, the water cut history is established for the values of σ presented in table 2. As can be seen from the figure, the water cut decreases as the imbibition rate increases. This is true since when the reservoir exhibit higher rate of imbibition the water will be transmitted to the matrix block rather than produced.

Table 2- Values of the shape factor for various values of L_x and L_z	
L_x, L_z, ft	σ, ft^{-2}
0.0008	12500000
0.001	8000000
0.008	125000
0.086548469	1067.999888
0.1730969	267.0000894
0.5409279	27.3408003
1.0818558	6.835200076
2.1637116	1.708800019
4.3274232	0.427200005
8.6548464	0.106800001
17.309693	0.0267
34.619386	0.006675
69.238771	0.00166875

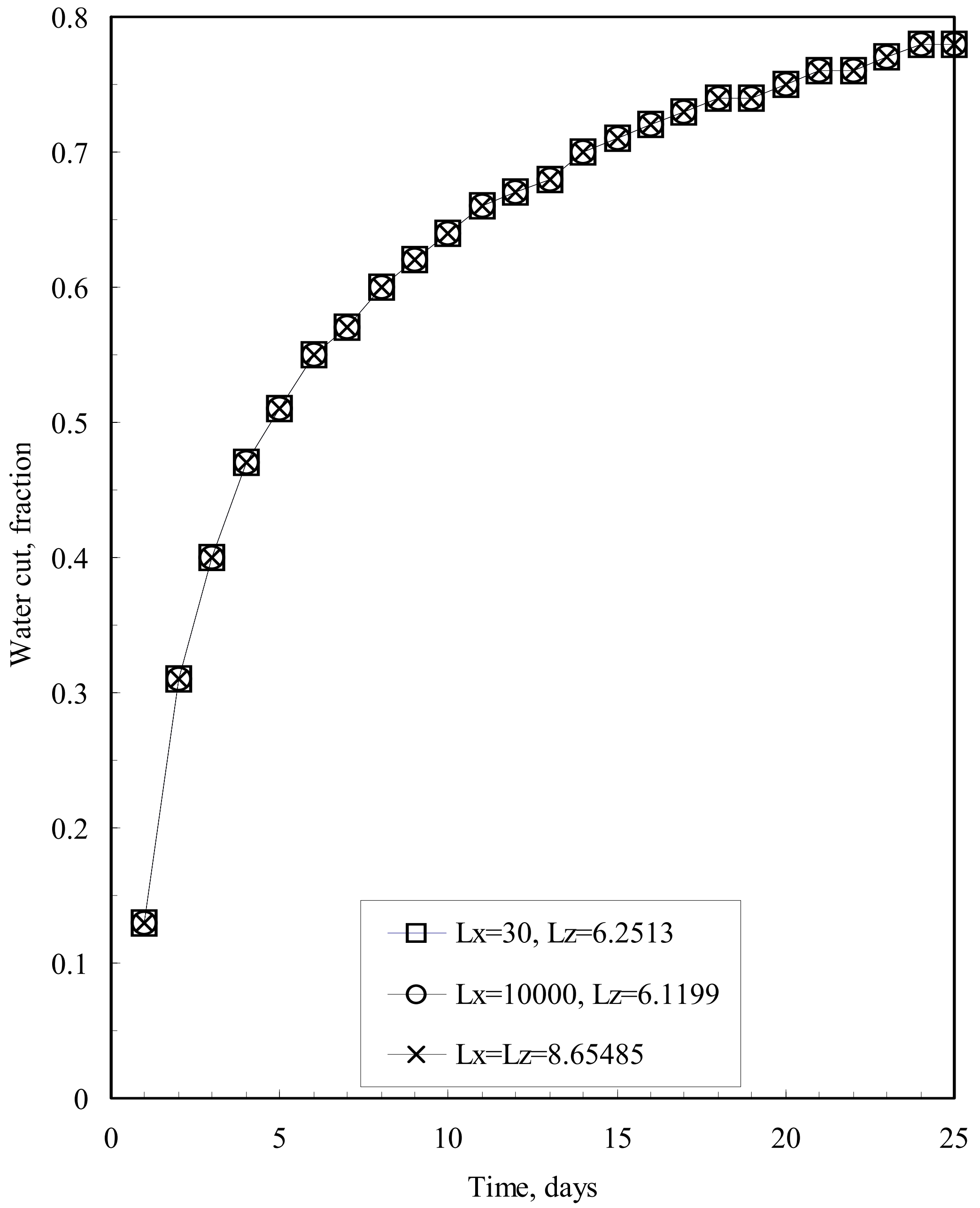

Figure 6- Water cut history for three sete of Lx and Lz

Conclusions

The following conclusions can be drawn from this study:

1- In SimBestII, one should assign the intrinsic fracture permeability value to the fracture permeability in the data file.
2- SimBestII multiplies the given permeability (intrinsic permeability) by the fracture porosity to get the conventional fracture permeability, which would be used in the flow equations.

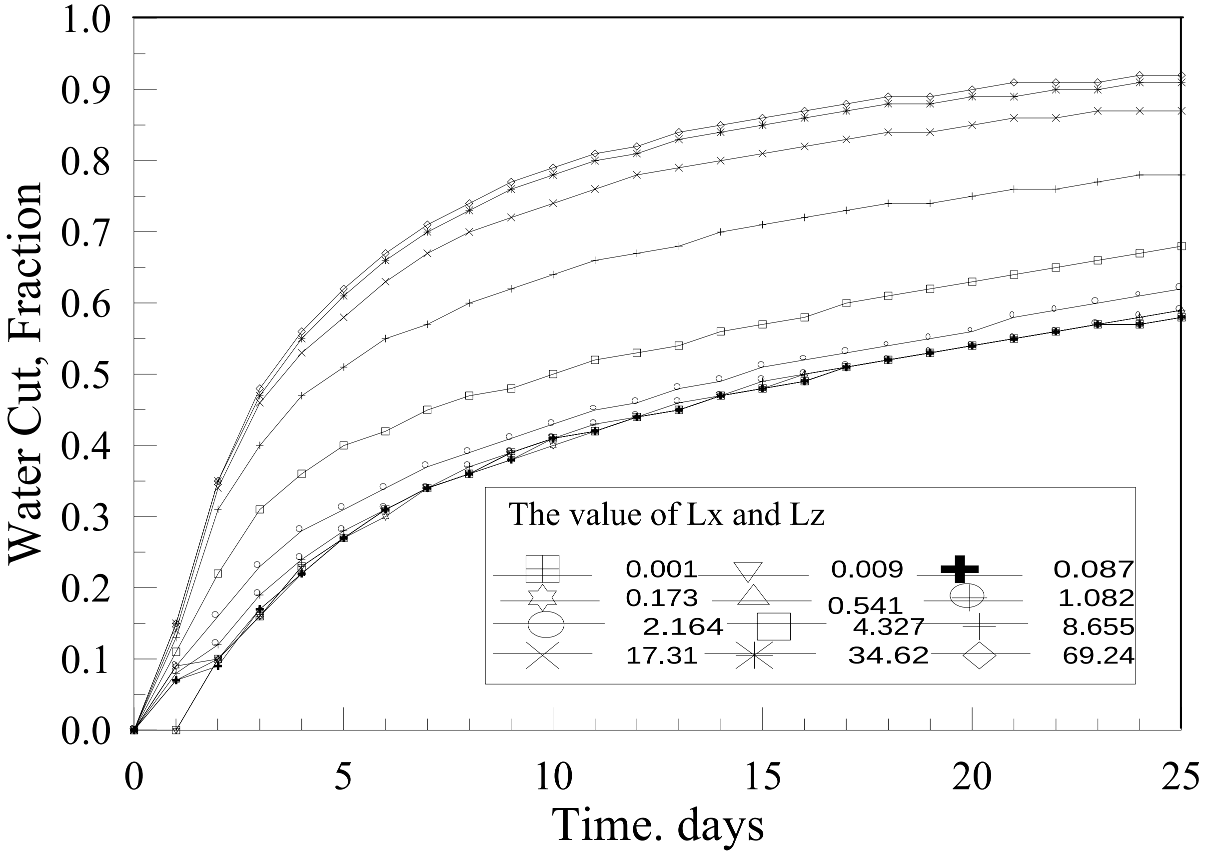

Figure 7- Water cut history for various values of L_S

3- The method presented by Kazemi et al.[(4)] for estimating the shape factor is adopted by SimBestII.

4- The comparison between the results of SimBestII and that of Al-Jawad[(2)] assures the anticipated procedures of SimBestII.

5- The values of L_s have no effect on the imbibition rate unless they change the value of σ.

6- The imbibition rate is directly proportional to the value of the shape factor that is, if σ is doubled, the volume transfer between fractures and matrix will be two times, keeping other factors unchanged. While the variation of L^2_s in some instances may disagree with the imbibition rate. Therefore, the adjustment of σ value is more sensible than the alteration of L_s.

<u>Nomenclature</u>

b= Shrinkage factor, STB/RB

K= Absolute permeability, md

K_r= Relative permeability

L_S= Dimension of the matrix block in s direction, ft

P= Pressure, psi

Pc= Capillary pressure, psi

Q= Flow rate, ft^3/day

S= Saturation, fraction
T= Transmissibility
Vb= Bulk volume, ft^3

Symbols

Δ= Finite difference operator
Φ= Potential, psi
μ= Viscosity, cp
σ= Shape factor, ft^{-2}
φ= Porosity, fraction

Superscripts

n= Time level

Subscripts

i= Grid index in radial direction
k= Grid index in vertical direction
f= Fracture
m= Matrix
o= Oil
r= Radial direction
t= Time index
w= Water
z= Vertical direction

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