SIMULATION OF NATURALLY FRACTURED RESERVOIRS WITH SIMBESTII

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ABSTRACT
Simulation of naturally fractured reservoirs is a laborious techniques, because there are two different porous media in which fluids exist and flow. The porous media exhibit wide variations in their physical properties. The matrix usually represents the major storage capacity while the fractures system provides the main paths of the flowing fluids.
Several simulators have been constructed by specialist companies. One is the SimBestII, which is the product of Scientific Software- Intercomp. In order to simulate a reservoir properly by such simulator, one should have an idea about the equations and the procedures encountered in it.
In the present 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 justifications to reduce or magnify the imbibition rate are explored

الخلاصة
المحاكاة الرياضية لمكمن متشقق هي تقنية معقدة ، وذلك لوجود نوعين مختلفين من الاوساط المسامية والتي يتم جريان الموائع خلالها والوسط المسامي بطبيعته متباين بشكل كبير بصفاته الفزيائية ، الجزء الغير متشقق عادة يمثل الجزء الرئيسي للخزين بينما الجزء المتشقق يعطي المسارات الرئيسية للموائع الجارية .
عدد كبير من برامج المحاكاة الرياضية قد أنجزت بواسطة شركات متخصصة في هذا المجال ، واحدها هو " السمبست 2" والذي هو أحد المنتجات شركة البرامجيات العلمية. ولغرض أجراء عملية المحاكاة الرياضية للمكمن بشكل مقبول بواسطة هذه البرامجيات ، يجب على المستخدم أن يملك معرفة بالمعادلات والطرق الداخلة فيه.
في الدراسة الحالية ، تم أجراء محاولة لدراسة وفهم الشكل العام لبرامج " السمبست 2" معادلات الجريان الداخلية فيه تم دراستها ، كذلك تم توضيح بعض الطرق وأساليب الخاصة بالبرنامج . وتم مناقشة حد التبادل في معادلات الجريان بشكل شامل وتم دراسة التشرب باستخدام هذا البرنامج .

KEYWORDS
Reservoir, Simulation, Fracture, Porous media.

INTRODUCTION

Warren and Root (1963) classified the porosity of reservoirs as

1- Primaryp 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 processes. 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 fracture 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, a single equation is no longer sufficient unless simplifying assumptions are invoked.

THE MODEL

In 1963, Warren and Root 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 superposed by a non continuum, identical, regular parallelepiped 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 (Al-Jawad, 1997)

$$\Delta_r\,(\mathrm{TW}_{\mathrm{rf}}^{n+1}\,\Delta_r\,\mathrm{PW}_{\mathrm{f}}^{n+1}) + \Delta = (\mathrm{TW}_{2\mathrm{f}}^{n+1}\,\Delta = \Phi\,\mathrm{W}_{\mathrm{f}}^{n+1}) - \mathrm{TW}_{\mathrm{cn,k}}^{n+1}\,(\Phi\,\mathrm{W}_{\mathrm{f}}^{n+1} - \Phi W_m^{n+1}) - QW_f^{n+1} = \frac{Vb_{i,k}}{\Delta t}\Delta_t(\varphi_f SW_f\,\mathrm{bW_f})_{i,k}^{n+1} \tag{1}$$

$$\Delta_r\,(\mathrm{To}_{\mathrm{rf}}^{n+1}\Delta_r PO_f^{n+1}) + \Delta_z(To_{zf}^{n+1}\Delta_z\phi O_f^{n+1}) - To_{\alpha i,\mathrm{K}}^{n+1}(\Phi O_f^{n+1} - \Phi O_m^{n+1} - Qo_f^{n+1} = \frac{Vb_{i,k}}{\Delta t}\Delta_t(\varphi_f SO_f bo_f)_{i,k}^{n+1} \tag{2}$$

while the matrix equations are

$$-Tw_{\alpha i,k}^{n+1}(\phi W_f^{n+1} - \phi W_f^{n+1}) = \frac{Vb_{i,k}}{\Delta t}\Delta_t(\varphi_m Sw_m bw_m)_{i,k}^{n+1} \tag{3}$$

$$-To_{\alpha i,k}^{n+1}(\phi\,\mathrm{o}_{\mathrm{f}}^{n+1} - \phi o_m^{n+1}) = \frac{Vb_{i,k}}{\Delta_t}\Delta_t(\varphi_m So_m bo_m)_{i,k}^{n+1} \tag{4}$$

where the subscripts f and m refer to fracture and matrix respectively.
Water and oil transmissibilities which control fluid transfer between fracture and matrix blocks are defined as

$$Tw_{\alpha i,k} = 0.00638 Vb_{i,k} K_{mi,k}\,\sigma\,(\frac{\mathrm{K_{rw}}bw}{\mu \mathrm{w}}) \tag{5}$$

$$To_{\alpha i,k} = 0.0063 Vb_{i,k}\,\mathrm{K_{mi,k}}\,\sigma\,(\frac{\mathrm{K_{ro}}bo}{\mu\,o}) \tag{6}$$

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

The shape factor a plays an important role in the fracture/matrix exchange term. During the last three decades, many attempts have been made to predict exactly the amount of fluid transfer between the fracture and matrix blocks. Several techniques for handling the shape factor have been presented in the literature. Non can be considered as a precise procedure when considering the ambiguity accompanying such process.
In the present study, the approach that has been adopted by SimBestII to simulate naturally fractured reservoir is investigated. One of the practical ways to perform this is by considering a hypothetical example and solving it by SimBestII and simulator whose structure is quite recognized. The comparison between the output of the simulators will provide insight about the procedure adopted by SimBestII. The simulator presented by Al-Jawad, (1997) 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 written in finite difference form represent the equations that control the flow of water and oil in fracture and matrix systems. 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 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 (Van Golf-Racht, 1982). The first is a measure of the fracture channel conductivity. In this case, only the fracture void area represents the flow cross section. This is known as the intrinsic fracture permeability and for the single fracture shown in **Fig (1)** it is defined as:

$$K_{ff} = \frac{b^2}{12} \qquad (7)$$

The other type of fracture permeability is the conventional fracture permeability, which is based on the classic Darcy definition (Van Golf-Racht, 1982). Here, the fracture and the associated rock bulk form a hydrodynamic unit. It is defined for a single fracture as:

$$K_f = \frac{b^3}{12h} \qquad (8)$$

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

$$A_f = ab \qquad (9)$$

While the area that should be used with the conventional permeability is:

$$A_B = a\,h \qquad (1o)$$

All symbols are depicted in **Fig. (1).**

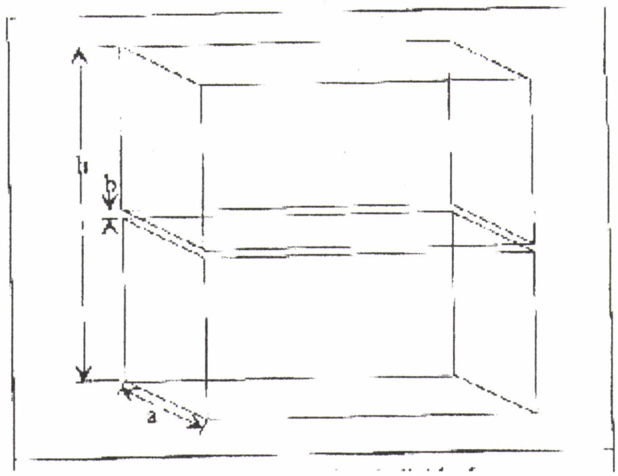

Fig. (1) A single fracture in a bulk block

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

$$\varphi_f = \frac{\mathrm{ab}}{\mathrm{ah}} = \frac{b}{h} \qquad (11)$$

and

$$K_f = \varphi_f K_{ff} \qquad (12)$$

As shown in eq. 12, the fracture permeability is less than the intrinsic fracture permeability. Naturally fractured reservoirs are usually characterized by small fracture porosity. Keeping this 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.

RESYLS AND DISCUSSION

One of the objectives of this study is to realize the type of permeability that is adopted by SimBestII. 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 verification of the above assumption is accomplished through the following steps:

1- Run SimbmitstII 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 **Table (1).**

The plot of block pressure for these runs is depicted in **Fig. (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 multiply 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 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

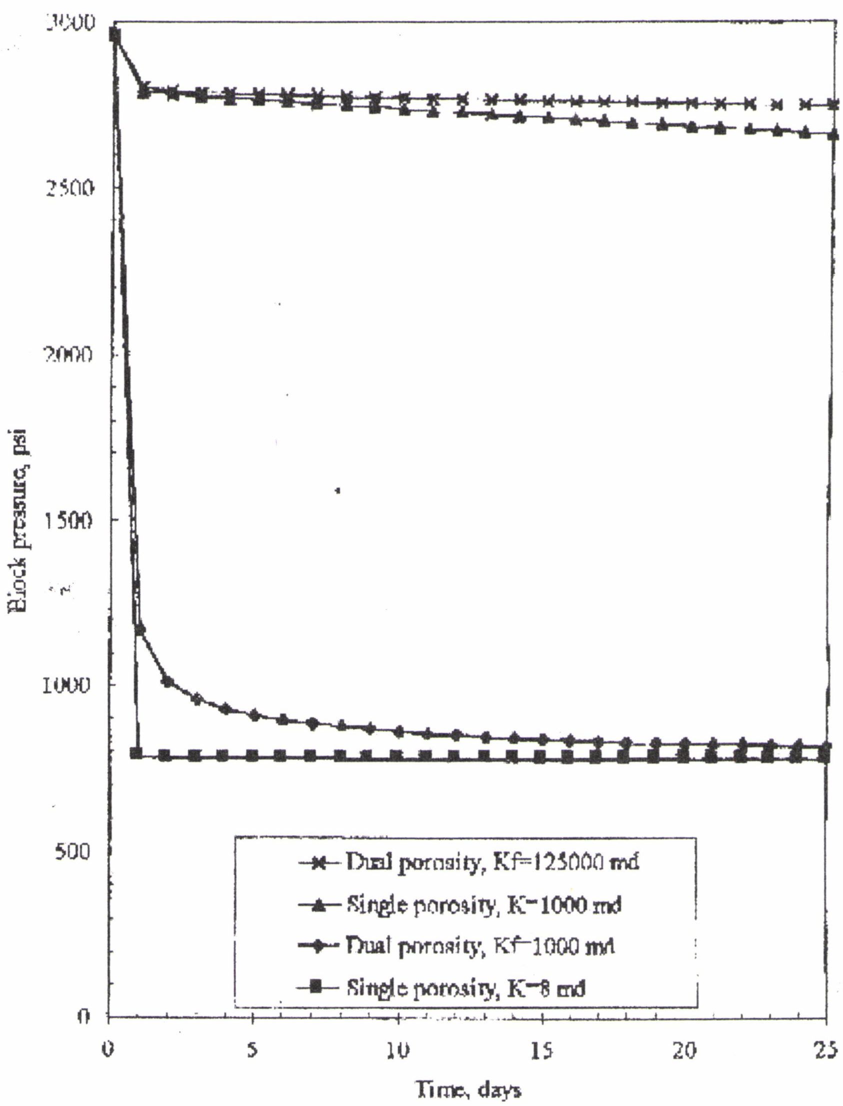

Fig. (2) Block pressure history for different runs

Table 1- Data used in the example,(after Al-Jawad 1997)

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, and	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 l grids	7
Radius to the boundary of the block, ft 0.25, 2.0, 4.32, 9.33, 20.17, 43.56, 94.11, 203.32, 984.92, 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

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, which 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 (Kazemi, 1976), have presented a method for estimating the value of σ. SimBesII adopts this method when it calculates the rate of fluid exchange. It can be summarized as follows:
4

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

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

X

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

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) define 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 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 L_S will increase σ and thus increases the fracture ability to transmit fluid to the matrix or vice versa.
In the present study, the cylindrical coordinates system is adopted which. Thus equation 14 has been used to calculate the value of. σ . The example presented by (Al-Jawad, 1997) 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 **Fig. (3).** The movable water saturation for the same grids after 25 days of production is depicted in **Fig. (4).** The value of a in the example is 0.1068 11-2 and according to equation 14, this value corresponds to L_X=L_Z 8.65485 ft. **Fig. (5)** shows a comparison between the results of SimBestII and that of (Al- Jawad, 1997). The compatibility between the curves of **Fig. (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 is also indicated in reference 5 and 6.
Exact values of L_S are hard to be determined and usually, they are 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_S and Lz 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 **Fig. (6)** two sets of L_S and L_Z are employed in addition to that proposed by the example. For the first one, L_S=3011, and Lz=6.2514ft. Applying equations 14, the value of a is 0.1068, which is the same as in the example of reference (Al- Jawad, 1997). This value is also duplicated if L_Z=1000011 and L_z 6.1199ft Therefore, the water cut history curves coincide. However, SimBestII should be provided by L_S rather than a. 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 Ls, since some different combinations of Ls may not lead to different exchange rate.

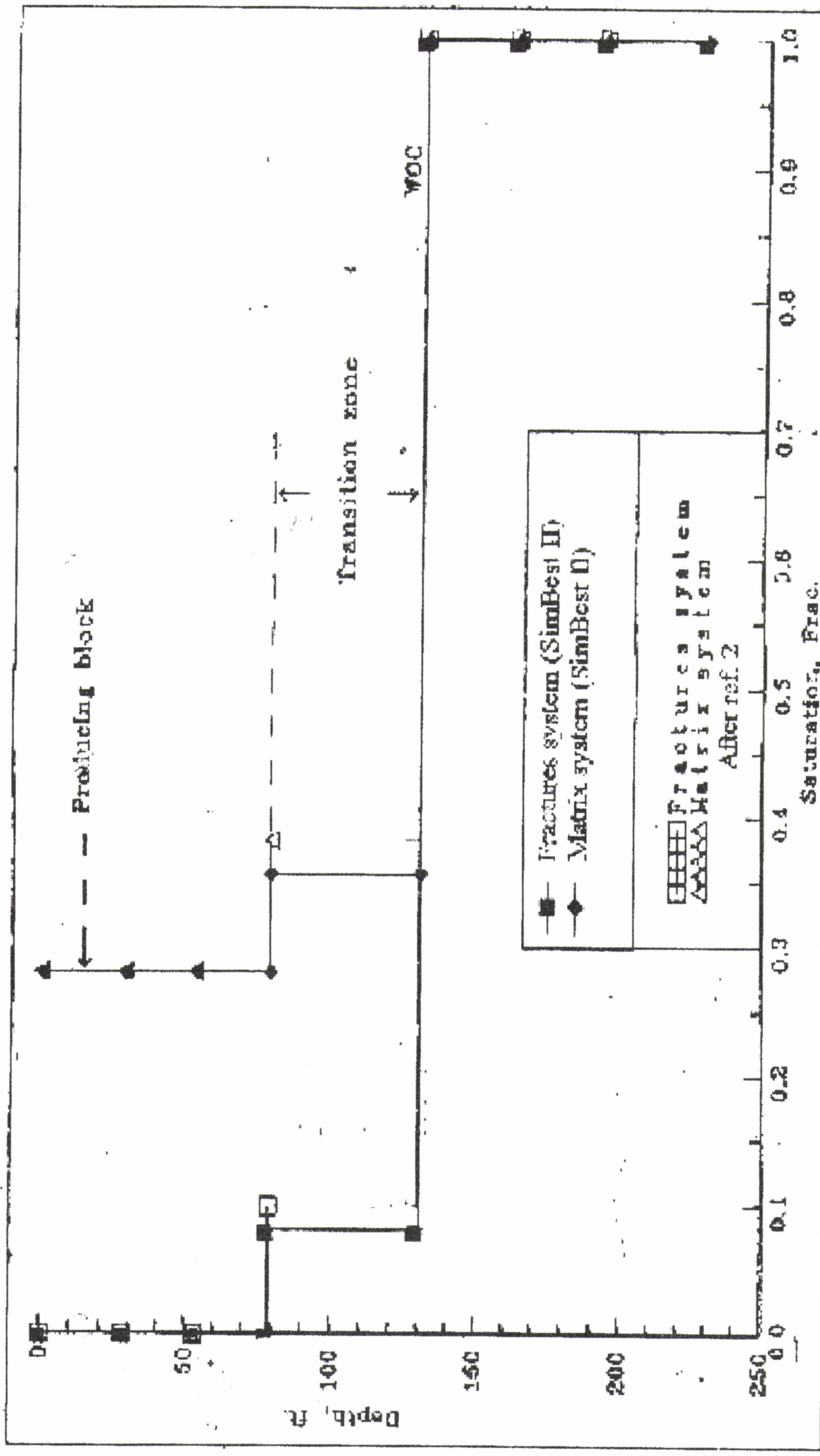

Figure 3- Initial water saturation in fractures and matrix blocks

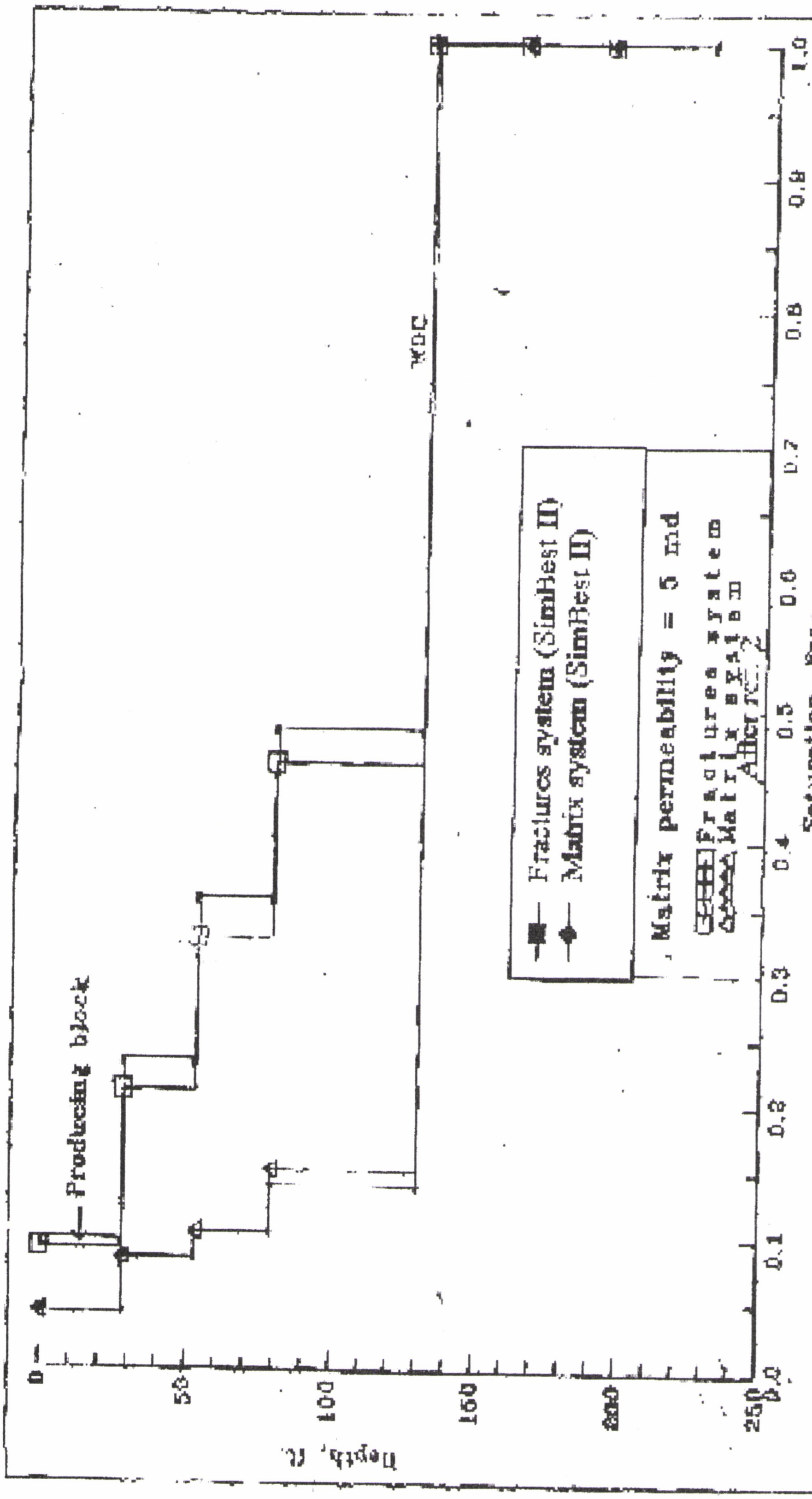

Figure 4- Water saturation in fractures and matrix blocks after 25 days

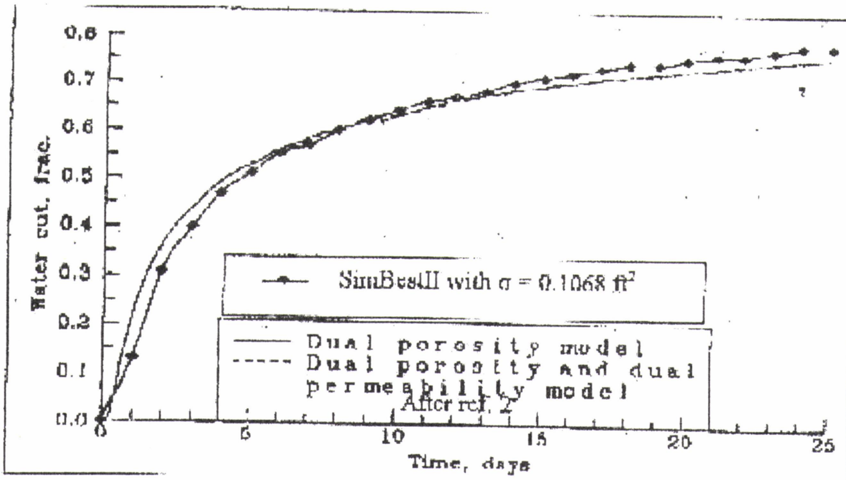

Fig. (5) Comparison of water cut history

The last point 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)** shows the values of L_S and the corresponding values of σ as calculated by equation 14. In **Fig. (7),** the water cut history is established for the values of u 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

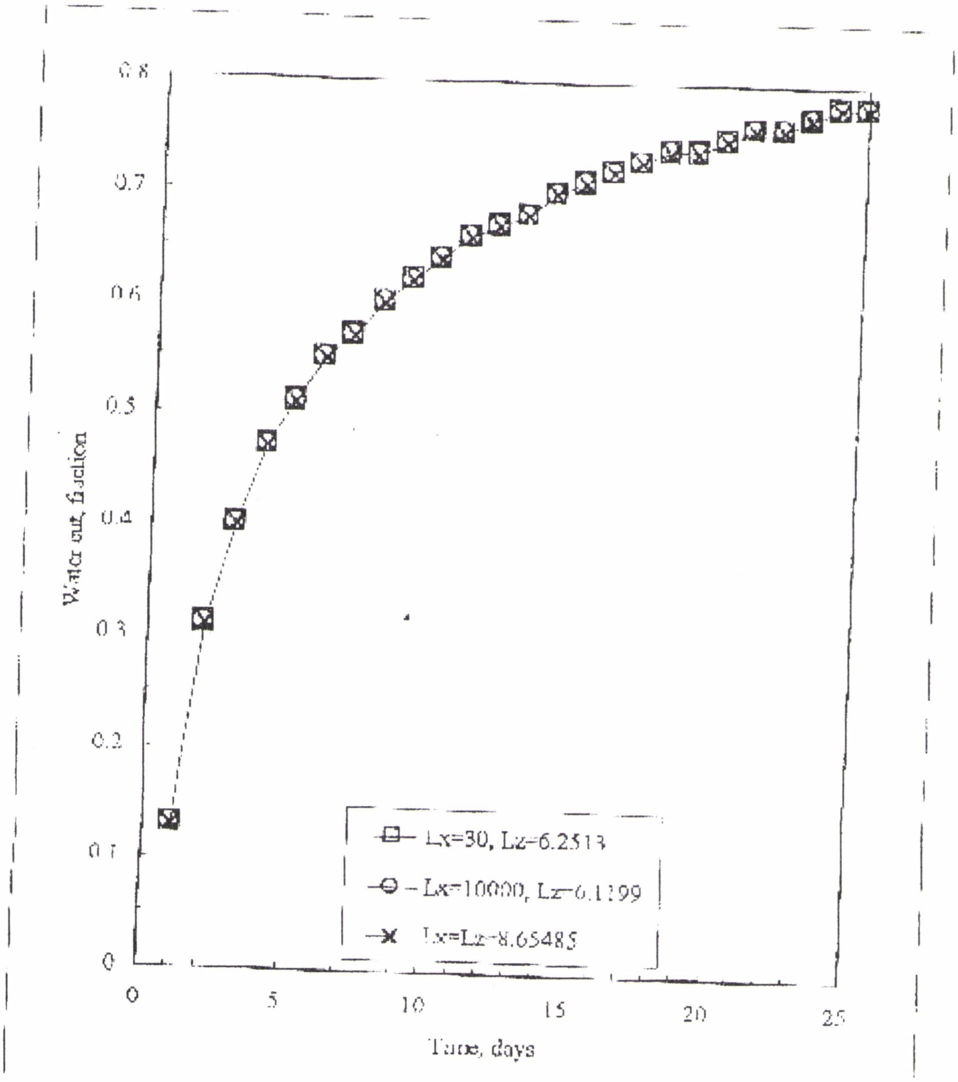

Fig. (6) Water cut history for three sete of Lx and Lz

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.

3- The method presented by (Kazemi , 1976) for estimating the shape factor is adopted by SimBestII

4- The comparison between the results of SimbestII and that of (Al-Jawad, 1997) 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.

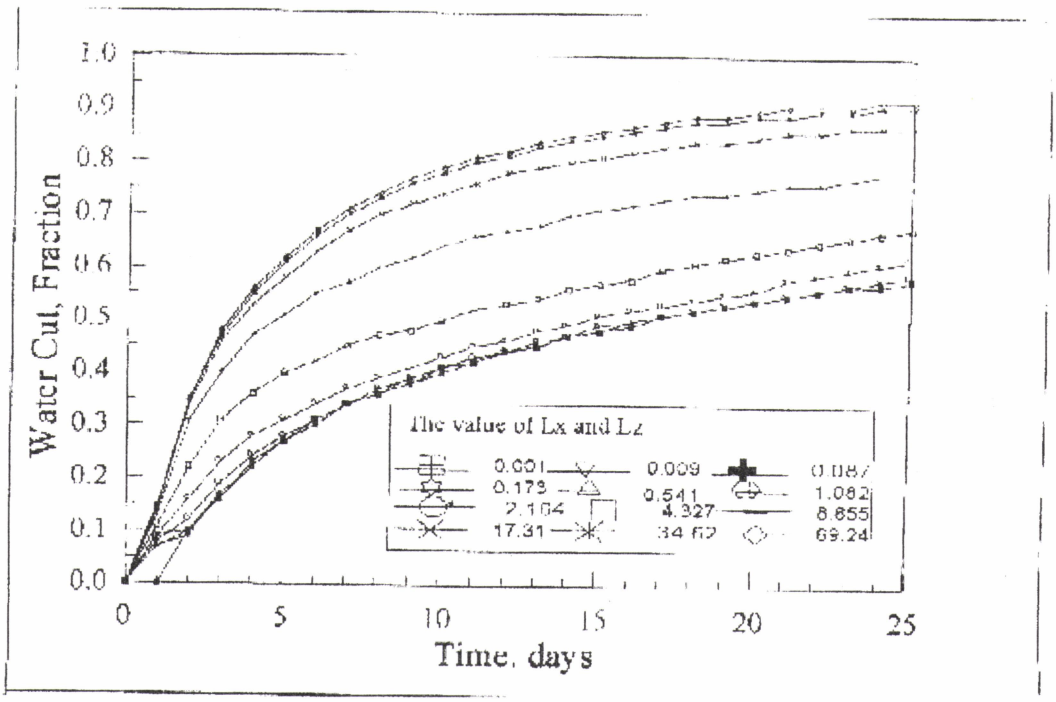

Fig. (7) Water cut history for various values of L_S

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NOMENCLATURE

b= Shrinkage factor, STB/RB
K= Absolute permeability, and
K,= Relative permeability
Ls= Dimension of the matrix block in s direction, ft
P= Pressure, psi

Pc= Capillary pressure, psi
Q= Flow rate, A3/day
S= Saturation, fraction
T= Transmissibility
Vb= Bulk volume, ft'
.S mbols
4= Finite difference operator
(h= Potential, psi
u= Viscosity, cp
6= Shape factor, ft-z
cp= 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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