7th European Conference on the Mathematics of Oil Recovery, ECMOR7, Baveno, Lago Maggiore, Italy, 5-8 September 2000

Modelling Fluid Flow in Reservoirs Crossed by Multiscale Fractures : A New Approach

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ABSTRACT

Some of the most productive oil and gas reservoirs are found in formations crossed by multiscale fractures/faults. Among them, conductive faults may closely control reservoir performance[1]. However, their modelling encounters numerical and physical difficulties linked with (a) the necessity to keep an explicit representation of faults through small-size gridblocks, (b) the modelling of multiphase flow exchanges between the fault and the neighbouring medium, especially if the latter is fractured and modelled as a dual medium. In the present work, a physically-representative and numerically-efficient modelling approach is proposed to incorporate sub-vertical conductive faults in single- and dual-porosity simulators. To validate our approach and demonstrate its efficiency, simulation results of multiphase displacements in representative field sector models are presented.

INTRODUCTION

Naturally fractured petroleum reservoirs pose a real challenge to engineers. The description of fractures, combined with the knowledge of the physics of multiphase flow in fractured porous media and numerical modelling, provide the basis for understanding and forecasting the performance of these reservoirs. Fractured media are characterized by a matrix possessing a high storage capacity and high-permeability fractures which support the main transport in the medium. Most naturally fractured reservoirs include fractures with multiple length scales. In this paper, we distinguish two length scales (a) high-density small-scale fractures, called fissures, whose characteristic size is smaller than the typical gridblock size of reservoir models, (b) large-scale conductive faults that cross the reservoir horizontally over several kilometers. With regard to fissures, the dual-medium approach, first introduced by Barenblatt *& al* [2], assumes that the fissured porous medium can be represented by two overlapping media. Currently, most reservoir simulators are using this dual-medium approach to model flow in fissured media. As to faults, they are responsible for altering reservoir continuity. In reservoir engineering, two main types of faults have to be taken into account : (a) totally or partially sealing faults, (b) conductive faults, which lead to high velocity fluid flows along the fault plane. Contrary to fissures and sealing faults, conductive faults have never been well modelled in reservoir engineering. Previous methods are discussed below:

(1) The most straightforward method is to use high-permeability, very narrow gridblocks to model both the fault and the vicinity of the fault. This method leads to a good physical representation of the fault zone but unacceptable run time due to the numerical resolution (Hearn *& al* [3]).
(2) A more flexible approach is to model the faults as part of the fissure grid system of a dual-medium model. Nevertheless, this method is not convenient since it cannot dissociate the roles of fissures and faults (Gilman *& al* [4]).
(3) Conductive faults could be modelled by normal-size gridblocks that are assumed to contain embedded fault zones. The fault gridblocks are assigned equivalent permeabilities to simulate the fluid flow in the faults. This method entails three drawbacks : (a) building such a model is time-consuming for complex network, (b) it overestimates breakthrough times, (c) coarse grids do not allow to simulate development scenarios with a close well spacing in densely-faulted zones [3].
(4) Lee *& al* [5] presented a model to simulate flow in reservoirs crossed by multiple length-scale fractures. To model conductive faults, they propose the well-like approach used in conventional reservoir simulators. They introduce a transport index, similar to the productivity index in well modelling, to formulate the fluid exchanges between the fault and the gridblock enclosing the fault. As the well-like equations imply no accumulation terms, this approach does not model the distribution of fluids within faults and cannot predict the gravity exchange between the fault and the neighbouring medium. Moreover, like the previous method, this approach is not adapted for the simulation of infill drilling scenarios in densely-faulted regions.

The description of these methods shows us that a multiscale fractured reservoir model is needed with precise and flexible modelling as regards fault geometry and fluid displacements, and with a high numerical performance. The conductive fault model proposed in this paper has been introduced into a conventional reservoir simulator based on a black-oil thermodynamic model, a fully-implicit numerical scheme and cartesian grids (Henn *& al* [6]). This paper reviews the physical basis of our approach. Coupling between this explicit conductive fault model and the dual-medium approach is the main focus of this paper.

MODELLING OF FLUID FLOW IN CONDUCTIVE FAULTS

In our approach, fluid flow in conductive faults is modelled on the basis of the Vertical Equilibrium (VE) assumption[6]. Considering that capillary forces are low in faults, we assimilate the VE concept to the gravity segregation concept (GSC). Coats *& al* [7] defined a criterion for testing the validity of the gravity segregation concept in a given flow situation. The GSC permits to model explicitly conductive faults by a row of fault gridblocks, which are not subgridded in the vertical direction.[6] Modifications applied to this one-dimensional flow model are equivalent to the input of pseudo-relative permeabilities $\overline{kr_p}$ and pseudo-capillary pressures $\overline{Pc_p}$ for a given phase p in the Darcy's law, which expresses the phase velocity $\vec{V}_p$ along the fault plane direction Y as:

$$\vec{V}_p = -K_Y \frac{\overline{kr_p}}{\mu_p}\left(gr\vec{a}d\left(P - \overline{Pc_p}\right) - \rho_p \vec{g}\right) \qquad (1)$$

with

$$\overline{kr_p} = \frac{\int_{z_{BOT}}^{z_{TOP}} K_Y(z) kr_p\left(S_p(z)\right) dz}{\int_{z_{BOT}}^{z_{TOP}} K_Y(z) dz} \quad \text{and} \quad \overline{Pc_p} = \left(\rho_o - \rho_p\right)\left(z_{op} - z_c\right)\left|g\right|$$

where ρ, μ and g are respectively the density, the viscosity and the gravity acceleration. P is the pressure at the fault center and is defined in the oil phase. All vertical positions z are detailed in Fig. 1.

At a given vertical position z, we can determine a saturation S_p, a relative permeability kr_p and a permeability K_Y.

MODELLING OF FLUID FLOW BETWEEN A CONDUCTIVE FAULT AND ITS NEIGHBOURING MEDIUM

Local approach

A fault gridblock is generally of a much larger height than neighbouring blocks. A direct coupling between the conductive fault gridblock pressure and saturation and the neighbouring gridblock pressures and saturations would be inaccurate. A more detailed description within the fault block is required. The local approach [6] consists in discretizing fictitiously the fault gridblock in the vertical direction with respect to the neighbouring medium discretization. The segregated state in the fault allows to determine the local values of each phase saturation and pressure in each fault subgridblock. Consequently, each local mass flow rate takes into account precisely expansion, capillary and gravitational forces during the exchange process.

Dual-Porosity Model

Naturally fissured reservoirs contain many fissures that cross different regions of the reservoir, occurring with greater intensity near the faults. As a fissure network is extremely complicated, a detailed gridding of such a network is practically impossible. To overcome this problem, simplified models have been developed. In most reservoir simulators, flow modelling in a fissured reservoir is performed by using the dual-medium model introduced empirically by Barenblatt and Zheltov [2] in 1960.

In their work, the fissured medium is described by two equivalent media corresponding to the fissures and matrix blocks respectively (Fig. 2). In 1963, Warren and Root [8] presented an analytical solution for interpreting well tests in a naturally fissured reservoir. They introduced the dual-porosity model which considers that primary flow occurs within the fissures with local exchange between the fissure system and the matrix blocks. To get an expression of the fissure-to-matrix transfers, their work assumed a continuous system of orthogonal fissures parallel to each of the principal axes of permeability. Superimposed on this system, a set of identical rectangular parallelepipeds represents the matrix blocks (Fig. 2). The development of conventional dual-porosity simulators for fissured reservoir evaluation was based on the Warren and Root model. Although there is a permanent interest in matrix-fissure transfer formulations (Bourbiaux *& al* [9]), this paper does not focus on their improvements. Nevertheless, we present hereafter an improvement of the modelling of fissure-to-matrix exchanges that is also applied for fault-to-matrix flow modelling. Darcy's law governing the flow of a phase *p* between the fissure and the matrix media is written as :

$$\vec{V}_p = -K\frac{kr_p^d}{\mu_p}\left(gr\vec{a}d\left(P - Pc_p\right) - \rho_p\vec{g}\right) \qquad (2)$$

where kr_p^d is the relative permeability, which will characterize the exchange. It is a function of the phase saturation S_p. When discretizing flow equations, Darcy's law allows to calculate the mass flow rate between a matrix gridblock and its neighbouring fissure gridblock. At this interface, the choice of the discrete relative permeability $kr_{p,fm}^d$ is a key issue that may lead to difficulties. In conventional numerical models, reservoir engineers use the "upstream" scheme when calculating discretized flow rates between two gridblocks, denoted by *i* and *j* (Eq. 3).

"Upstream" scheme

$$kr_{p,ij} = \begin{cases} kr_{p,i} & \text{if flow is from i to j} \\ kr_{p,j} & \text{if flow is from j to i} \end{cases} \qquad (3)$$

"Midpoint" scheme

$$kr_{p,ij} = \frac{1}{2}\left(kr_{p,i} + kr_{p,j}\right) \qquad (4)$$

The "upstream" scheme leads to two advantages : (a) it is numerically stable [10], contrary to the "midpoint" scheme (Eq. 4), (b) it cancels the flow of a given phase *p* which is absent in the upstream gridblock. Nevertheless, it has two drawbacks : (a) a larger numerical dispersion than the "midpoint" scheme [11], (b) a bad restitution of the phase velocities at the interface of two media, as matrix and fissure, having strong differences in relative permeability and/or capillary pressure properties. [11] This last problem is enhanced when fluids flow from a tiny gridblock to a large gridblock. In the dual-medium model, the fissure thickness is supposed negligible compared to the size of the matrix blocks so that the whole flow takes place within the matrix block during the fissure-matrix exchange process. Therefore, the "upstream" scheme is not consistent with the physical problem when fluids flow from fissure to matrix. To counteract this difficulty, we calculate for a given phase p the flow rate between a matrix gridblock and a fissure gridblock, denoted by m and f respectively, considering the exchange relative permeability $kr^d_{p,fm}$ as follows:

$$\begin{cases} kr^d_{p,fm}(S_{f,m}) = S_{p,f} * \widetilde{kr}_{p,m} & \text{if flow is from fissure to matrix} \\ kr^d_{p,fm}(S_{p,m}) = kr^d_{p,m}(S_{p,m}) & \text{if flow is from matrix to fissure} \end{cases} \quad (5)$$

This corresponds to a specific "upstream" scheme except that the phase saturation in the fissure $S_{p,f}$ is weighted by a characteristic value of the matrix relative permeability when fluids flow from the fissure to the matrix. In this way, we maintain the advantages of the "upstream" scheme while considering both the medium in which fluids flow and the physical process of the exchanges. In Eq. 5, $\widetilde{kr}_{w,m}$, $\widetilde{kr}_{g,m}$, $\widetilde{kr}_{o,m}$ are the matrix relative permeabilities respectively to water at the maximum water saturation which can be reached by water imbibition, to gas at the maximum gas saturation which can be reached by gas drainage, and to oil at the maximum oil saturation.

Coupling between the conductive fault medium and a single-porosity model

Regarding the fault-matrix exchanges, the problem is to find an optimal relative permeability enabling to reproduce these exchanges with a coarse discretization of the matrix medium in the vicinity of the fault planes. As in the case of the fissure-matrix exchanges, the classical upstream scheme is not physically consistent when fluids flow from fault to matrix because these flows are governed essentially by matrix properties. Thus, we define fault-matrix relative permeabilities $kr_{p,Fm}$ similarly to the fissure-matrix relative permeabilities $kr^d_{p,fm}$. $S_{p,F}$ is equal to the local saturation of phase p in the fault section facing the neighbouring matrix gridblock.[6] To illustrate this point, we simulated the establishment of a phase equilibrium between a fault element and a horizontal slice of matrix for a water-oil imbibition process. The model is one-dimensional (Fig. 3). It consists in juxtaposing a fault gridblock, filled with water and two types of matrix grid (a) a single coarse matrix gridblock (b) a row of small matrix gridblocks (reference model). Contrary to the fault medium, water-oil capillary pressures are present in the matrix medium. At the initial time, the matrix medium is saturated with oil. Upstream relative permeabilities have been used in the fine-grid model. In the coarse-grid model, both upstream relative permeabilities and the fault-matrix relative permeabilities have been tested.

The oil recovery factor in the matrix medium versus time is given in Fig. 4. Regarding the water-oil imbibition process, results are sensitive to the choice of the relative permeability formulation. Conclusions are that (a) the standard upstream option overestimates significantly the exchange kinetics between the conductive fault and the matrix medium (b) although the fault-matrix relative permeabilities slightly underestimate the exchange kinetics, they give a better match of the reference model. Identical results were obtained with a two-dimensional model taking into account gravity effects.

Coupling between the conductive fault medium and a dual-porosity model

Naturally fractured reservoirs may contain both conductive faults and fissures. Therefore, it is necessary to get an efficient triple-medium simulator able to model multi-scale fractures. To determine how fluids circulate within a triple-medium system (matrix, fissure and fault), we built a finely-gridded two-dimensional model *XZ* in which each medium is gridded explicitly (Fig. 5). This model represents an idealized fissured medium (Fig. 1). We neglect capillary pressures in the fractures. We define the fissure-matrix equivalent permeability ratio K^*_{fm} as defined by Quintard and Whitaker [12] with the assumption that $e_f << e_m$:

$$K^*_{fm} = \frac{K^*_f}{K^*_m} = \frac{K_{Xf} * e_f}{K_{Xm} * e_m} \qquad (6)$$

where K_{Xi} is the local permeability of medium *i* facing the conductive fault. Subscripts *f* and *m* correspond to the fissure and matrix media respectively, e_m is the block height and e_f is the fissure aperture.

Transfers between the conductive fault and the other media are governed by physical processes, as capillarity and gravity, and by the equivalent permeability ratio K^*_{fm}. To get a better understanding of these exchanges, we run two simulations: (a) water-oil simulation : the fault is filled with water and the two other media with oil, (b) gas-oil simulation : the fault is filled with gas and the two other media with oil. Regarding water-oil simulations, two water saturation maps, corresponding to two different values of K^*_{fm}, are plotted at a given time (Fig. 6-7). If K^*_{fm}=10, we observe that: (a) each matrix block facing the fault is watered out by capillary imbibition, (b) water flows from fault to fissure by gravity, first at the bottom of the system, and, then, imbibes the matrix blocks. If K^*_{fm}=1000, we observe that the imbibition of the matrix blocks neighbouring the fault is controlled by water invasion of the fissures surrounding the blocks and that the fault plays the same role as the fissures.

Regarding gas-oil simulations, one gas saturation map is plotted at a given time (Fig. 8). The chosen value of K^*_{fm} is 10. Gas invasion mechanisms in fissure and matrix media take place chronologically as follows: (1) fast invasion of the fissure network thanks to gravity, with fissures located at the top of the structure invaded first, (2) occurrence of two simultaneous phenomena: (a) gravity drainage of the top matrix blocks until gravity-capillarity equilibrium is reached, (b) oil reimbibition in the lower matrix blocks. The process is repeated until the matrix blocks located at the bottom of the system are at equilibrium. There is no gas exchange between the fault and the matrix blocks.

As illustrated by the finely-gridded simulations, water-oil capillary effects induce a water flow from the fault to the neighbouring matrix blocks. However, this exchange is only important for small values of the equivalent permeability ratio K^*_{fm}. Regarding gas-oil simulations, matrix blocks desaturation is driven by gravity drainage and gas invading the matrix comes quasi-exclusively from the fracture network. Because gas-oil capillary pressures hinder fault-matrix exchanges, it is not necessary to couple these two media for gas-oil simulations in a triple-medium system.

Our multiscale approach consists in modelling conductive faults explicitly whereas a conventional reservoir simulator models the fissured medium through a dual-porosity concept. How can we couple the discrete fault model with the homogenized representation of the fissured medium? In this paper, we propose a triple-medium model in which the fissured medium is "homogenized" thanks to the dual-porosity method (Fig. 9). The conductive fault medium is included in the fissure grid of the dual-medium system and it can exchange fluids only with the fissure medium. In this model, water-oil imbibition between the fault cell and adjacent matrix cells is not possible directly because fluids have to transit by the fissure cells associated to the matrix cells (Fig. 10). To estimate the error induced by such a model, we compared it with the finely-gridded model (reference), in which fault-matrix connections exist (Fig. 5). Fig. 11 shows the matrix oil recovery curves predicted by the two models, for two values of the fissure-matrix permeability ratio K^*_{fm}.

Both models give similar results. However, a slight delay is observed if K^*_{fm} is equal to 10. This delay decreases rapidly when the permeability ratio is increased (K^*_{fm}=100), that actually leads to reduced fault-to-matrix exchanges, as illustrated previously by the fine grid simulations. The reason for this delay is mainly due to the modelling of the fault-matrix exchange as two exchange terms, the first one linking fault and fissure gridblocks within the fracture grid and the second one linking the superposed fissure and matrix gridblocks. Hence, in addition to the magnitude of fault-matrix exchanges, the gridblock size may also play a role in the delay of kinetics obtained with the triple-medium system. However, this inaccuracy should remain within acceptable limits for practical purposes. Regarding gas-oil flows, there is no fault-matrix exchanges. Consequently, the coupling between explicit and homogenized approaches, *i.e.*, conductive fault medium and dual-porosity medium, is valid to model exchanges between a fault and a fissured porous medium. These examples have validated our approach, and we are now able to perform efficient reservoir simulation studies in which both large- and small-scale fractures play a significant role.

CASE STUDIES

Many field applications have been tested with our conductive fault model. In this paper, we present two flow simulations in a sector of a field crossed by a dense network of conductive faults (Fig. 12). The first simulation concerns a water-oil flow in a single-porosity medium including faults. In this case, there is a water flow along faults inducing both an early water breakthrough and a rapid increase of the water-cut at producers. The second simulation concerns a gas-oil flow in a dual-porosity medium including faults. The sector is a 3D panel edged by two faults (Fig. 12). Thanks to symmetry, the panel behaviour could be modelled on a half-panel edged by one fault (Fig. 13).

The fault conductivity is equal to the longitudinal permeability of the fault times its thickness e_F, *i.e.*, 15 D.ft (4.86E-12 m^3). Regarding the reservoir simulations, our objective is to get both a good physical representativity and a high numerical performance, *i.e.*, a reliable prediction of the production behaviour at a reasonable numerical cost. Herein, we compare our conductive fault model with finely-gridded models. The two main features of the proposed model are (a) a one-dimensional segregated flow model representing conductive faults and (b) specific fault-matrix exchange relative permeabilities avoiding the use of small gridblocks in the vicinity of the fault. Comparative models allow to determine the contribution of both features.

Water-Oil Simulation (Conductive Fault + Single-Porosity Model)

At the initial time, the matrix is saturated with oil. The fault is assumed to be in connection with an active aquifer. Hence, we define a fictitious water injector located at the bottom of the structure within the fault (Figs. 14). There is one producer in the matrix panel at the top of the structure. The matrix permeability is isotropic and equal to 20 mD (1.97E-14 m^2). Water-oil capillary pressures are only present within the matrix. In addition to our conductive fault model (Fig. 13), we define two models, (a) model 1 (Fig. 14a) : both fault and matrix are finely-gridded respectively in the vertical direction and in the horizontal direction perpendicular to the fault plane (X), (b) model 2 (Fig. 14b) : it corresponds to model 1 except that the matrix is coarsely-gridded in the horizontal direction perpendicular to the fault plane. In both models, upstream relative permeabilities are used to compute water flow from fault to matrix. Because it is finely-gridded, model 1 predicts the exact flow behaviour. The evolution of the production water-cut versus time is plotted in Fig. 15 for the three models (a) model 1, (b) model 2 and (c) conductive fault model.

The comparison of the three models (Fig. 15) shows that model 2 predicts a delayed breakthrough time at the production well.[1,3]

When using both coarse matrix grid and upstream relative permeabilities, the kinetics of fault-matrix transfers is overestimated. Consequently, water front progression in the fault is slower in model 2 and water invades the producer later than in model 1. When using our coarsely-gridded fault model, we get a better match of fault-matrix exchanges, of the water flow within the fault and, finally, of the production data. Table 1 compares the numerical and computational performance results of the three simulations. Linear systems were solved with the conjugate gradient method. We used a SUN Ultra 30 workstation

Model 2 and the conductive fault model gives similar numerical and computational results. Therefore, the segregated flow model does not improve the numerical performance, especially when the numerical scheme is implicit.[6] On the contrary, our model gives better numerical results than model 1 in the sense that it is approximately 4 times faster. Actually, the fine gridblocks present in the vicinity of the fault in model 1 entail time-expensive linear system resolutions.
Regarding water-oil simulation in a fault panel, we conclude that our model provides both an exact physical response and good numerical performance.

Gas-Oil Simulation (Conductive Fault + Dual-Porosity Model)

Herein, we simulate a gas injection scenario. The injector and the producer are located within the fault panel far from the fault plane. Wells are defined in the fissure grid as shown in Figs. 16. At the initial time, the matrix and fissure media are saturated with oil. The matrix and fissure permeabilities are isotropic and equal respectively to 1 mD (9.87E-16 m^2) and 20 mD (1.97E-14 m^2). Gas-oil capillary pressures are only present within the matrix. In each matrix gridblock of the dual-porosity model, the matrix blocks are cubic and their dimension is equal to the height of the gridblock. As the main fault-fissure exchange process is gravity drainage, production results are independent of the horizontal size of gridblocks edging the fault plane.[6] Therefore, we define two models in which the dual-porosity model is coarsely-gridded in the horizontal direction *X*, (a) model 3 (Fig. 16a) : fault is gridded with 16 gridblocks in the vertical, (b) model 4 (Fig. 16b) : fault is gridded with 4 gridblocks in the vertical direction. As the fault is finely-gridded, model 3 gives an accurate prediction of gravity drainage and the exact two-phase flow response at producer. The evolution of the production gas-oil ratio at producer versus time is plotted in Fig. 17 for the three models (a) model 3, (b) model 4 and (c) conductive fault model (Fig. 13).

Whatever the model, the injected gas flows from the injection well to the production well via two main paths schematized in Fig. 16a, (a) the fissure network path and (b) the conductive fault path. In this case, because of the relative proximity of the wells to the fault, the immediate gas breakthrough time is obtained via the conductive fault path. The comparison of models 3 and 4 shows the influence of the vertical gridding of the fault. A coarsely-gridded model overestimates the production gas-oil ratio. The conductive fault model and model 3 give identical results. Concerning gas-oil fault-to-fissure exchanges, the main process is gravity drainage.

To model it efficiently, an accurate calculation of the pressure and saturation values within the fault gridblocks is required. Thanks to the local approach, the conductive fault model allows to estimate these values accurately and predicts an exact physical response at the producer, in agreement with the finely-gridded model (model 3). The numerical and computational performances of our model are good compared to those of the time-expensive model 3.
Again, we conclude that our model provides both an exact physical response and a high numerical performance for gas-oil simulations.

CONCLUSION

A conductive fault model based on the segregation concept has been introduced into a conventional black-oil dual-porosity reservoir simulator. It predicts fluid flow in reservoirs crossed by multiscale fractures. Physical and numerical conclusions are :

- Thanks to the local approach and to specific exchange relative permeabilities, the kinetics of the fluid transfer between fault planes and the neighbouring medium can be reproduced accurately with coarse grids edging conductive fault gridblocks.
- A fine study of the coupling between a conductive fault medium and a dual-porosity medium shows that in the presence of fissures , the coupling between the fault and the matrix medium is not necessary.

- The physical response accuracy and numerical performance of our triple-medium model are highlighted from the simulation of water-oil and gas-oil flows in a fault panel.

Hence, the conductive fault model described in this paper provides a practical solution for the dynamic simulation of reservoirs crossed by multiscale fractures.

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symbols

			Subscripts
kr	VE relative permeability	*p*	Phase
Pc	VE capillary pressure, Pa	*top*	Top of fault gridblock
K	Permeability, m^2	*bot*	Bottom of a fault gridblock
V	Filtration velocity, $m.s^{-1}$	*op*	Contact between oil and p phase
μ	Viscosity, $Pa.s^{-1}$	*c*	Center of a fault gridblock
P	Pressure, Pa	*f*	Fissure
ρ	Density, $kg.m^{-3}$	*m*	Matrix
g	Gravity acceleration, $m.s^{-2}$	*F*	Fault
z	Vertical coordinate	*X*	Horizontal direction orthogonal to the
S	Saturation	*Y*	fault plane
e	Thickness, m	*Z*	Fault plane direction
F	Water-cut	*w*	Vertical direction
GO	Production gas-oil ratio,	*o*	Water
R	cft/bbl	*g*	Oil
N	Number of gridblocks		Gas
I	Index of gridblock		

FIGURES

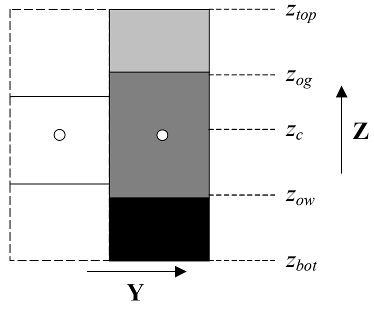

Fig. 1 . Fault gridblock

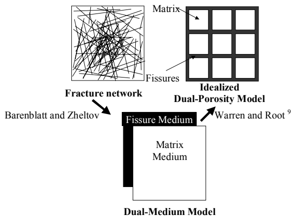

Fig. 2 . Dual-Medium Concept

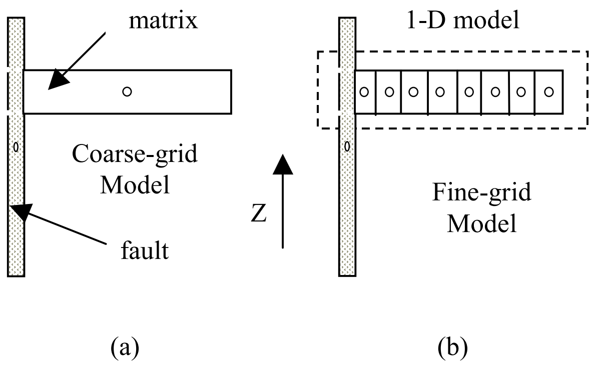

Fig. 3 . Description of the models

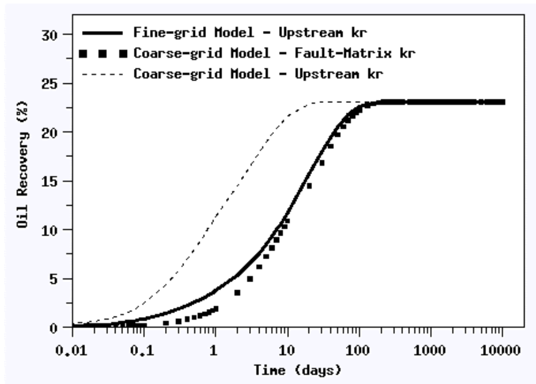

Fig. 4. Oil recovery in the matrix medium

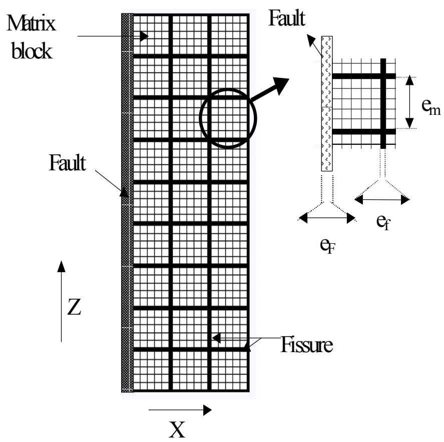

Fig. 5. Description of an idealized triple-medium system

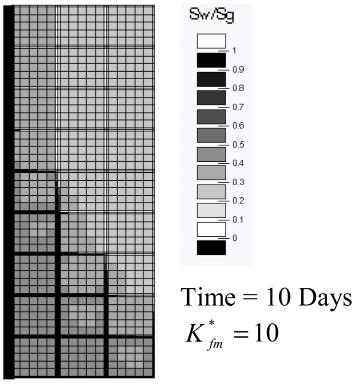

Fig. 6 . Water-oil simulation

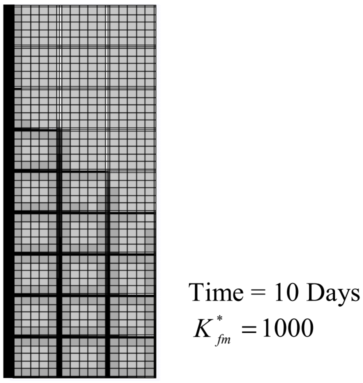

Fig. 7 . Water-oil simulation

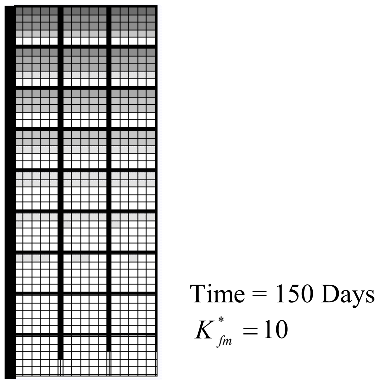

Fig. 8 . Gas-oil simulation

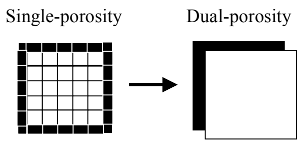

Fig. 9. Idealized fractured medium

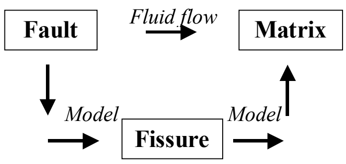

Fig. 10. Fluid flow in the triple-medium model

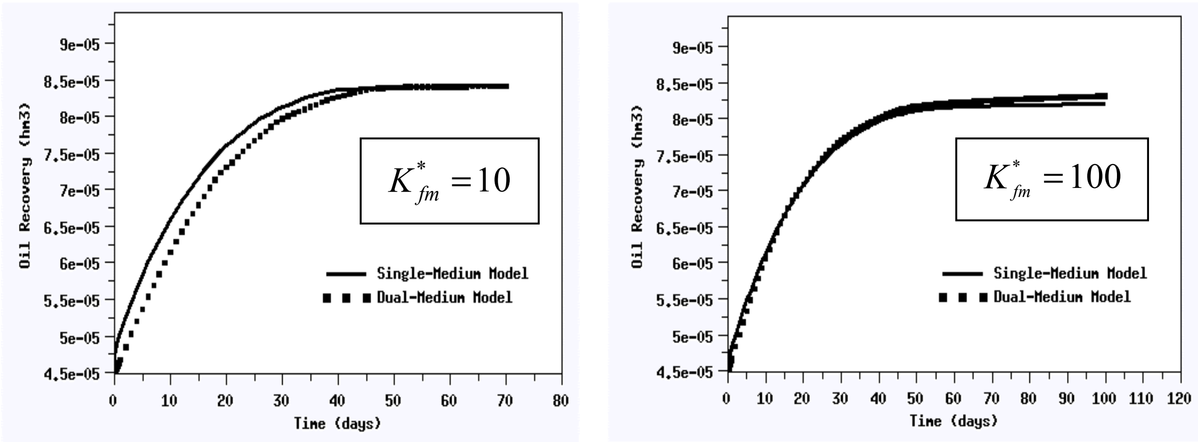

Fig. 11. Oil recovery from the matrix medium in a triple-medium system

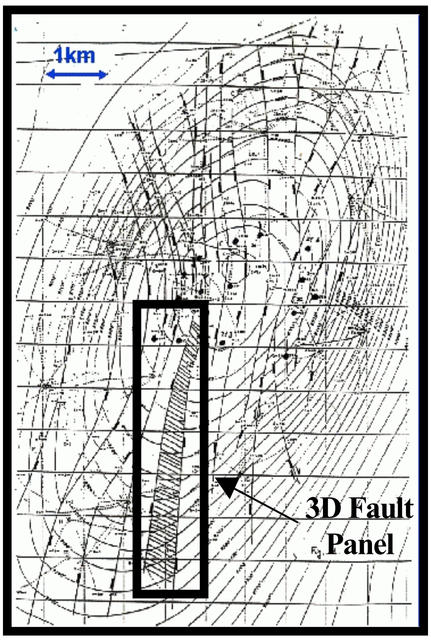

Fig.12. Structural map of a field crossed by conductive faults

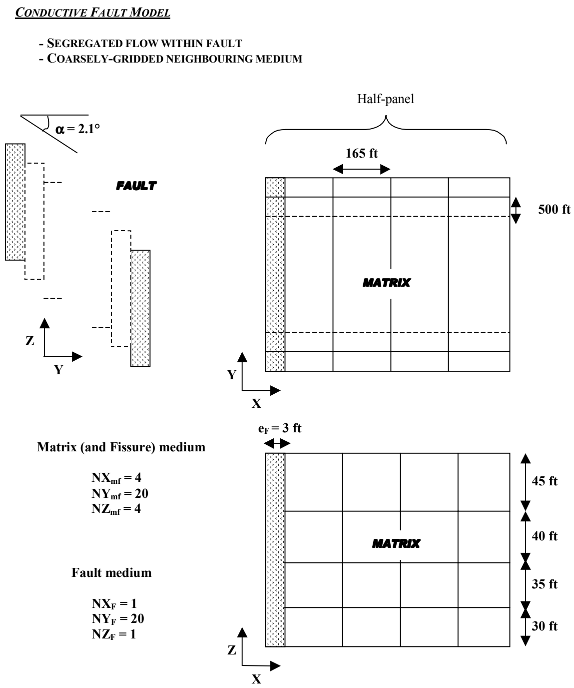

Fig. 13. Description of the conductive fault model

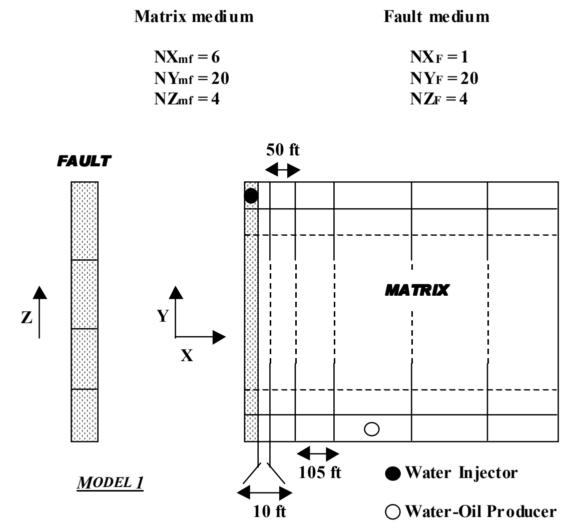

Fig. 14a . Description of the comparative model 1

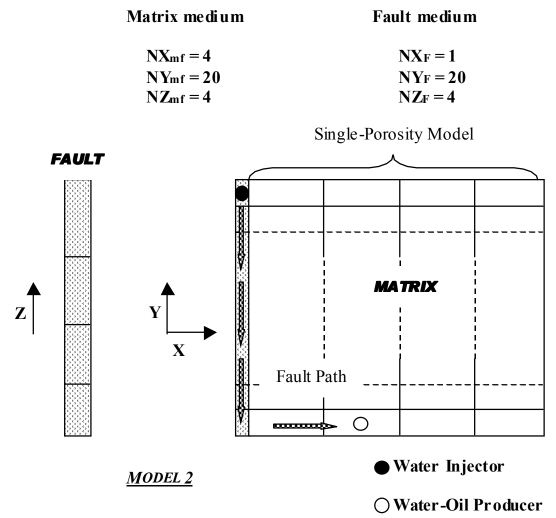

Fig. 14b . Description of the comparative model 2

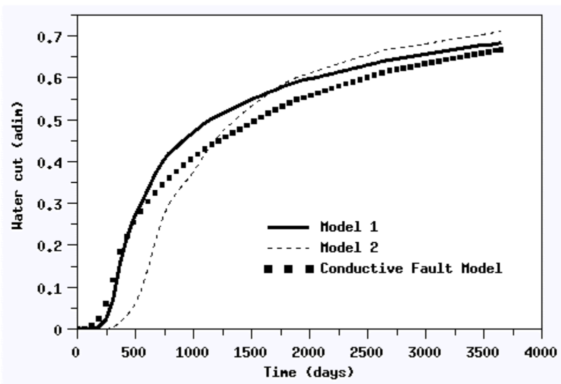

Fig.15. Water-cut (Fig. 14)

	Model 1	Model 2	Conductive Fault Model
Number of Gridblocks	560	400	340
Number of Time Steps	223	207	211
Number of Newton Iterations	229	210	211
Number of Solver Iterations	26172	9942	8231
CPU Time (s)	**252**	**75**	**64**

Table 1. Numerical performance

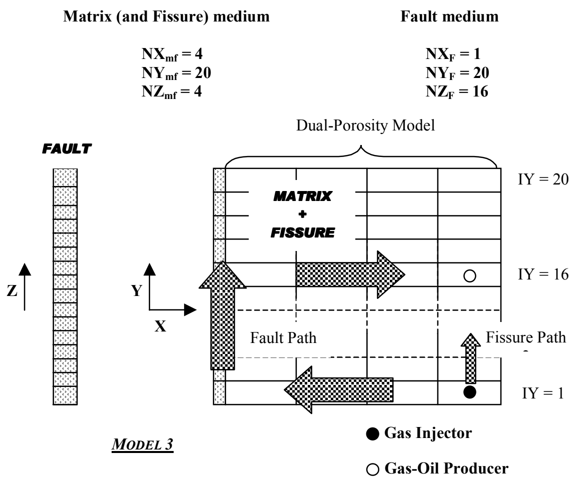

Fig. 16a. Description of the comparative model 3

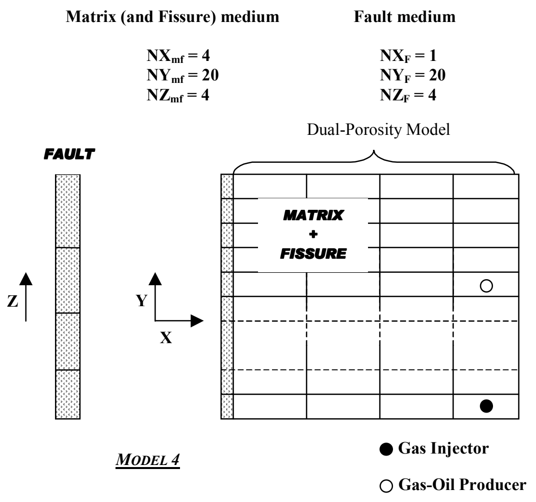

Fig. 16b. Description of the comparative model 4

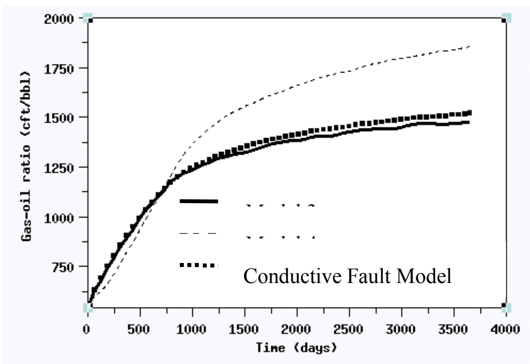

Fig. 17. Gas-oil ratio (Fig. 16)