PRJ, Vol. 5 (January 1993); P. 6–15, 16 FIGS.

DESCRIPTION OF NATURALLY FRACTURED RESERVOIRS FOR SIMULATION STUDIES

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وصف المكامن المتشققة طبيعياً لأجل المحاكاة

جين كلود ساباتير

تتناول هذه الورقة المكامن المتصلة تشققاتها في وضع شبكي (على الأقل في بعض أجزاء الحقل) عندما تكون المواد الهيدروكربونية في مكامن داخل الوطاء.

الهدف من وصف المكامن المتشققة طبيعياً لأجل المحاكاة هو تعريف المعايير التي يلزم ادخالها في المحاكي. وتقدم هذه الورقة أولاً أنماط المخططات المكمنية والمحاكيات المتوفرة حالياً ثم تناقش كيف يتم اختيار الأنسب بناءاً على خصائص المكمن. كما أخذ في الإعتبار خصائص التشققات والوطاء (المسامية، النفادية، النفادية النسبية، الضغوط الشعرية). ويتم تحليل تعريف أبعاد كتل الوطاء وذلك بمراجعة مختصرة للوسائل المتاحة. وقد تم التركيز على أهمية الإستمرارية العمودية الجزئية المتناسقة. كما تم القاء بعض الضوء على استعمال محاكيات المكامن مع الوصف المكمني.

ABSTRACT

In this paper we only consider fractured reservoirs where fractures are inter-connected in a continuous network (at least in some part of the field) and where mobile hydrocarbons are initially in place in the matrix.

The description of naturally fractured reservoirs for simulation studies aims to define the parameters which have to be input in the simulator. Thus this paper first presents the different types of reservoir schematisations and the types of simulators which are presently available and discusses how to choose the most appropriate one according to the reservoir characteristics. Characterization of the fracture and matrix media (porosity, permeability, relative permeabilities, capillary pressures) are furtherly considered. The definition of the geometry of the matrix blocks is analyzed with a brief review of the presently available tools. The importance of an even partial vertical continuity is emphasized. Possible influence of the gas-oil interfacial tension, diffusion, and thermal convection is also presented. Some considerations are also given on the use of reservoir simulators in connection with reservoir description.

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RESERVOIR SCHEMATISATION

The presence of fractures has been observed in many hydrocarbon reservoirs of different lithologies. Fractures crossing the wellbore improve the well productivity which may be out of range with the potential corresponding to a matrix reservoir. However fractures may also result in a specific reservoir behaviour needing a specific modelling. We shall consider only this case which happens when fractures are interconnected, creating a continuous network, or when they are parallel and extended, *and* if the matrix contains mobile hydrocarbons. In such cases, most of the initially in place hydrocarbon volume is in the matrix rock while fractures provide the main path for fluid flows in the reservoir. The first objective in characterizing a reservoir where fractures have been identified is to know (from geology and well tests) if it has to be considered as a fractured reservoir as defined above.

Natural fractures happen in brittle rocks under the action of stresses connected to:

- the tectonic history of the formation (folding, faulting…),
- erosion resulting on unloading and expansion of the upper sediments,

- compaction of shales (loss of water, mineral changes...).

Tectonic fractures are generally organized in systems, i.e. in sets of parallel fractures whose intersections delimit parallelepiped matrix blocks. Examples of conjugated patterns have been reported by Stearns and Friedman [1]. However, due to other sources of fracturing, reservoir heterogeneities and further diagenetic phenomena, the actual network of open fracturs in a reservoir may be very irregular without defining a recognizable block structure (Fig. 1).

The column type models (ref. 2, p. 704–749) favor the vertical description of the reservoir and assume that fluid flows are mainly in the vertical direction. The field is represented by a few sectors (which may communicate). In each sector the fractures define a series of identical piles of blocks. There is a complete vertical fluid segregation in the fractures and no horizontal flow in the fractures of a given sector. The model computes for one (or a few) column(s) of each sector the fluid flows within each matrix block and between each block and the surrounding fractures (Fig. 3–4). Each block is fully characterized and subgridded while fractures, in the model, are used to impose boundary conditions for matrix flow computations. Reimbibition of the oil flowing out of a block in the next lower block may be included in the computations.

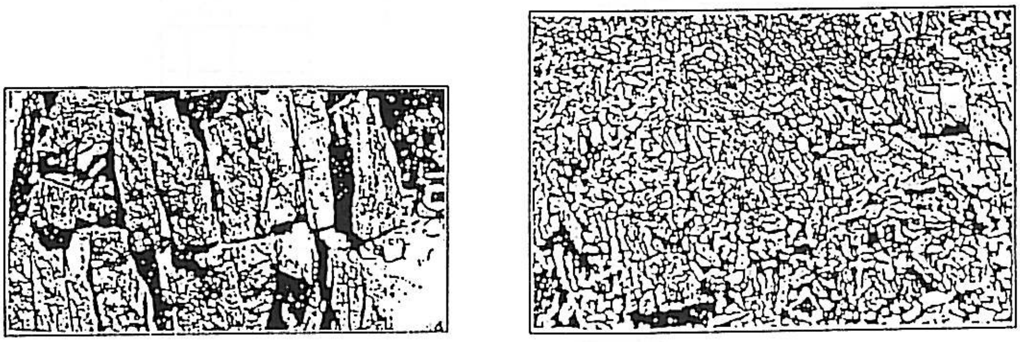


FIG. 1. Fractured formations (outcrops).

In the numerical models a very smplified assumption has to be made. Fractures are assumed to be distributed among rectangular systems respectively parallel to the coordinates planes (X–Y, Y–Z, Z–X). Thus the matrix (Fig. 2) may be distributed in:

- rectangular parallelepipeds (sugar cube model),
- horizontal layers (plate model),
- vertical columns (pillar model).

Dual porosity models (Fig. 5) view the reservoir as made of two continuous media. Space is discretized in cells, for numerical purposes, which are reservoir space elements. All the fractures of the cell are represented by a "fracture node" and all the matrix medium is represented by a "matrix node". The two nodes are generally both located at the center of the cell. Fluids are flowing between fracture nodes according to the characteristics of the fracture system. Fluid flows are also computed between the fracture and matrix nodes of the same cell (dual permeability models also allow fluid flows between matrix nodes). Such models are well suited to describe 3-D flows in the fracture system but have to simplify the matrix-fracture flow computations. The matrix node represents several matrix blocks (supposed to be

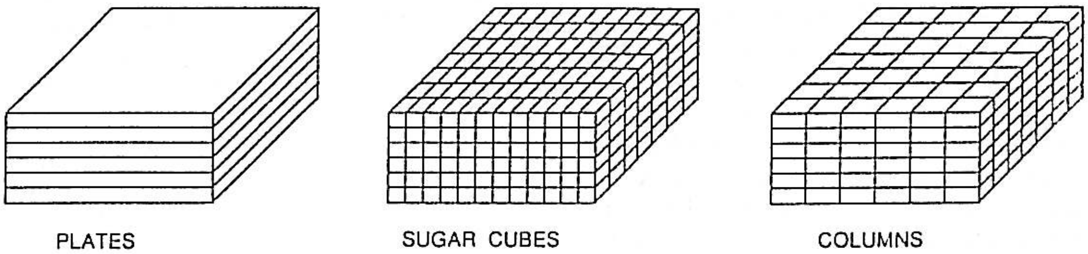
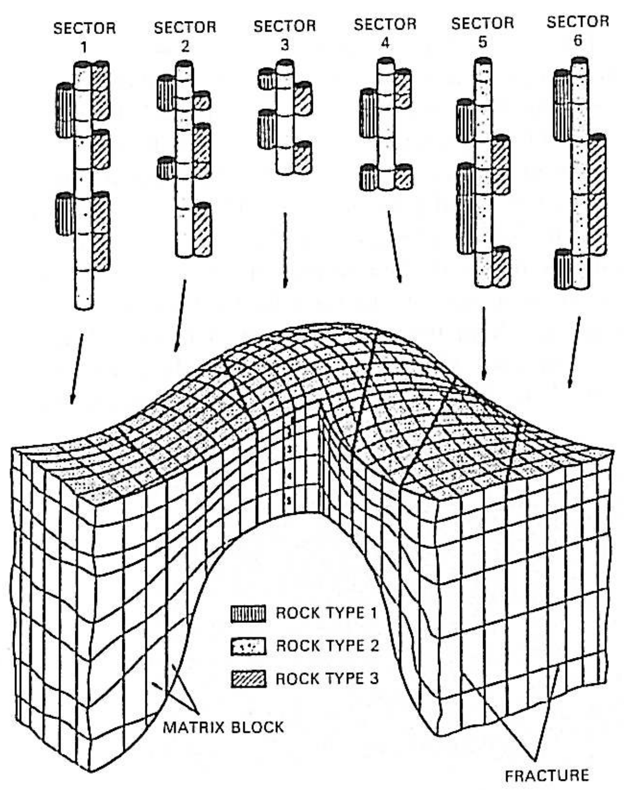


FIG. 2. Fractured reservoir schematization.

TYPE OF SIMULATOR

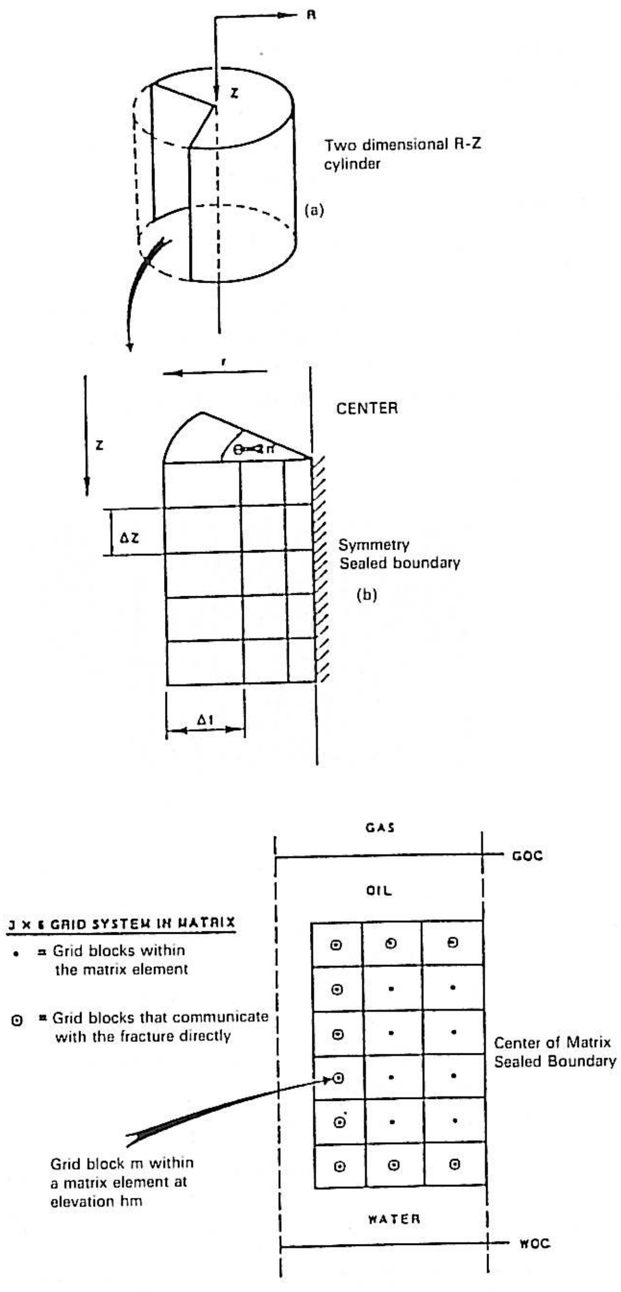
There are basically two types of simulators to model fractured reservoirs. They correspond to different types of reservoirs and consequently it is necessary to identify first the reservoir type to be able to select the most suitable simulator (or to know the limitations of the only available one). The two types of simulators are:

- the "column type" models,
- the "dual porosity" models.



(After ref. 2, p. 705)

FIG. 3. Representation of a reservoir with a column type model.



(After ref. 2, p. 706)

FIG. 4. Matrix element in a column type model.

identical) areally and vertically distributed within the cell and the model can only compute the behaviour of an "average" block. These computations are indeed critical and valuable results may be expected only if the model is able to directly account for the different driving forces (viscous, capillary and gravity forces), gravity and capillary being mandatory [3]. Generally the block is not subgridded (this is theoretically possible when the cell height is equal to the block height) thus pseudo-steady state conditions are assumed to prevail for matrix-fracture flow computations. Reimbibition between blocks in a cell, which is a very important phenomenon, cannot be directly computed and is even not at all accounted for in several models which consequently must be carefully used.

The column type models are consequently preferable when large sectors of the field behave uniformly, which is generally the case when the fractures are sufficient to provide a high overall permeability. In such reservoirs this type of model is specially recommendable when the pseudo-steady state hypothesis for matrix-fracture flow is no more acceptable because of the block size and many result in significant errors.

The dual porosity models are preferable when gradients develop over the field so that the hypothesis of homogeneous sectors with horizontal gas-oil and oil-water interfaces is no more valid. This is generally the case when fractures are small and/or irregularly distributed.

It must also be observed that if the matrix block has a sufficient permeability it is rapidly (within a time step) in equilibrium with the surrounding fractures so that the reservoir may be viewed as one composite system which can be simulated with a conventional single porosity model. Indeed petrophysical properties input in this model will have to account for the fractured character of the reservoir (pseudos) which means that the reservoir description must be the same as when using a dual porosity model.

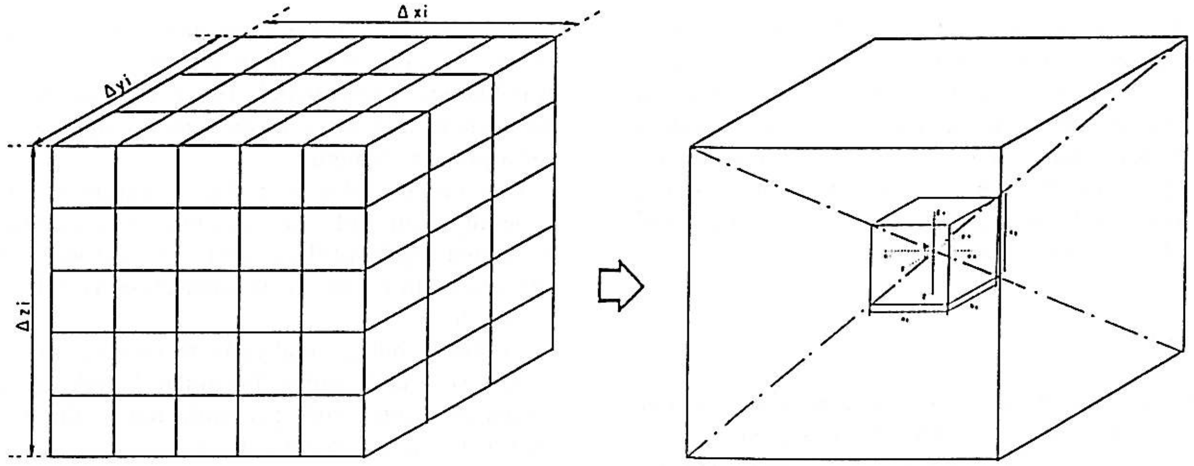


FIG. 5. Dual porosity model.

CHARACTERIZATION OF THE FRACTURE SYSTEM

In a dual porosity model the fracture system is characterized by the same parameters as the porous medium in a single porosity model. In the column type model only the porosity versus depth is needed.

The degree of fracturation may widely vary all over the field with even possibly unfractured areas. When the well pattern is large, which is common in fractured fields, these variations of fracturation may be difficult to map. Programmes have been written to help determine the intensity of fracturing resulting from the tectonic history of the reservoir. The successive shapes of the reservoir are determined and the resulting stresses are computed by the model from the mechanical properties of the rock [4]. The model maps a "relative chance of fracturation" index corresponding to the maximum stresses computed in simplified hypothesis (Fig. 6).

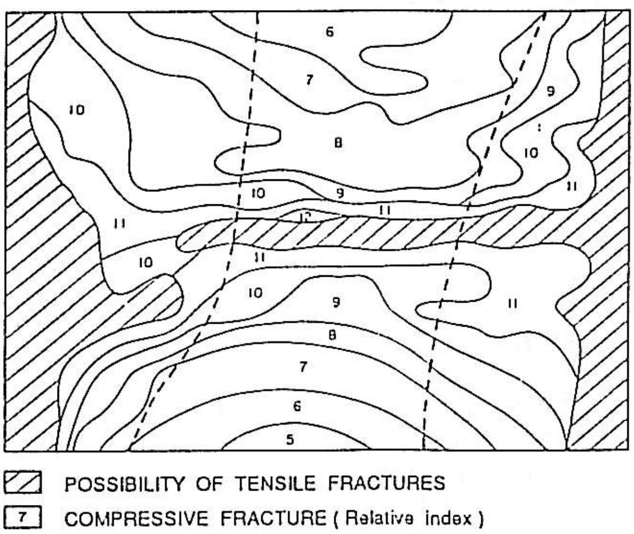


FIG. 6. Chance of fracturing index.

Permeability

This parameter is normally computed from the well productivity and the production test analysis. When interpreting production tests, attention has to be paid to the flow pattern in the reservoir (radial or vertical) mainly if there is a gas-cap (Fig. 7). If the fractures are organized in systems of parallel fractures of possibly different permeability (different fracture thickness and/or density) as evidenced by well interferences, the grid will be accordingly oriented to be able to model the fracture network anisotropy.

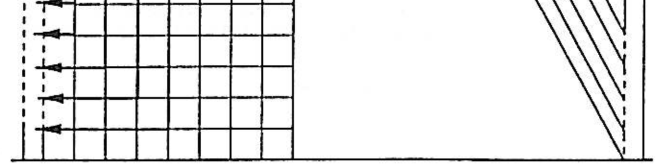


FIG. 7. Fluid flow through fractures around a well.

Another possibly important problem is the variation of the fracture permeability with the reservoir pressure. In 1975 Jones published results of laboratory experiments [5] showing a strong permeability decrease with pressure. However in actual fields this decline is generally much lower, if any. Only a periodic survey of the well productivity indices may allow to estimate the reduction of permeability with pressure in the fracture system.

Vertical permeability may be difficult to evaluate when vertical fractures have a limited extension. In carbonate reservoirs, stylolites may sometimes interrupt fracture interconnections and consequently limit the vertical connections. In some cases they are also related to some type of fracturing. Thus in carbonate reservoirs stylolites are an important feature and should be carefully described.

Porosity

The fracture porosity is low, generally less than 0.3%, and cannot be directly measured by any present logging tool. Applying Poiseuille's law for laminar monophasic flows between plates gives a relationship between the fracture thickness and its permeability. Thus knowing the fracture density and supposing they are identical, it is theoretically possible to compute the porosity of the fracture system from its equivalent permeability (porosity is proportional to the cubic root of the permeabiliy). Practically, even in the most favorable cases (large and extended fractures), very erroneous figures may be derived from this computation due to the fact that all the fractures do not contribute to the flow towards the producing well (and thus the geometry of the fracture network must be known) and that a large part of the pressure drop may be due to fracture joints, restrictions, fracture tortuosity....

Interpretation of well production tests with a dual porosity flow model may provide, in the best cases, the value of the ω parameter which is practically the ratio of the fracture to matrix expansibilities. As the porosity and compressibility of the marix may be independently estimated, the expansibility of the fracture medium may be computed. Thus the fracture porosity could be computed if the compressibility was known. Unfortunately this parameter may vary between 10 and 100 fold the values commonly used for a porous medium.

Fracture porosity is in fact a parameter which, generally, can only be adjusted by matching the measured depths of the gas-oil and water-oil levels in the observation wells i.e. in connection with the other parameters.

Compressibility, as already mentioned, may vary over a very large range. Formulae based on experiments with constraints perpendicular to the fracture planes give a maximum value [5].

Relative Permeabilities

Within one single fracture the relative permeability concept is not valid as one fluid is flowing either discontinuously (droplets, bubbles) or under film flow conditions. In a fracture network, experiments have shown that each fluid flows separately through a definite set of fractures. Relative permeabilities can be defined only at the scale of the network and are generally considered as equal to the phase saturations. However the performances of a fractured medium worsen when fractures have different thicknesses (Fig. 8).

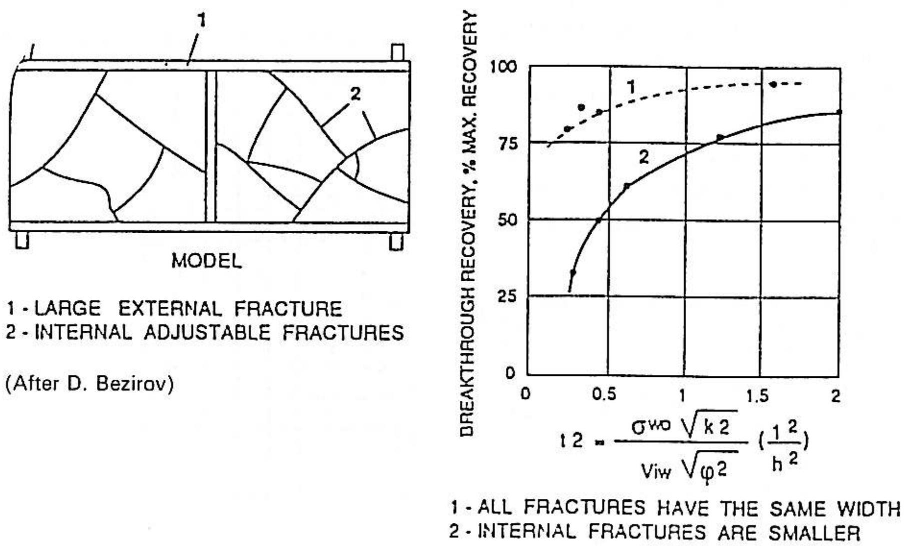


FIG. 8. Effect of fracture heterogeneity.

Capillary Pressures

The thickness of the wetting phase film which is adsorbed along the walls of the fracture is only a fraction of micron, thus, in most cases, the residual saturations and the capillary pressures may be ignored.

Some models are however using both gas-oil and oil-water capillary curves in the fracture medium for numerical reasons. Pseudo curves may also be input for capillary pressures and relative permeabilities.

CHARACTERIZATION OF THE MATRIX MEDIUM

Rock Properties

The usual rock characteristics (porosity, permeability, capillary and relative permeability curves ...) have to be input in the model and are measured with the same techniques as in porous single porosity reservoirs. However as well production tests cannot be used to compute the matrix permeability, this parameter has to be measured on cores and/or estimated by using log transforms.

If an initial gas-cap exists or if a secondary gas-cap is anticipated, it is mandatory to accurately measure the gas-oil capillary pressure curve. This parameter is generally neglected in single porosity reservoirs but, in fractured reservoirs producing by gas-cap expansion (with or without gas injection) and having relatively small blocks, the final recovery is directly dependent on its value (Fig. 9).

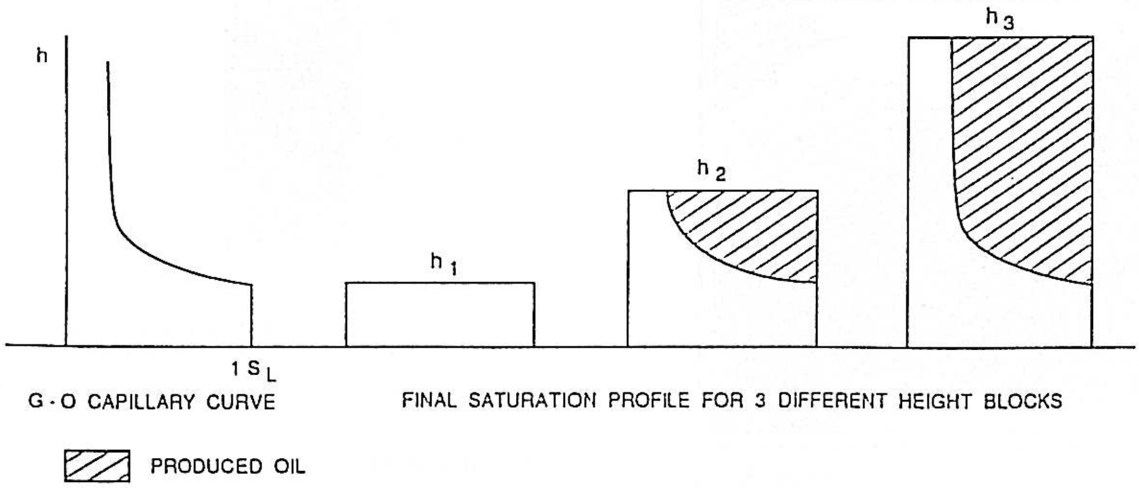


FIG. 9. Gravity drainage. Block height influence.

Relative permeabilities and capillary pressure curves have to be measured in drainage and imbibition conditions if the movements of the gas-oil and water-oil contacts in the fractures may reverse in some parts of the field. Wettability is an important problem each time fractures are invaded by water.

Matrix Block Size

Defining the geometry of the marix blocks is a key problem to solve when building a fractured reservoir model. A geological picture must be first obtained and furtherly simplified to meet the simulator input requirements.

Block description is obtained either from the observation of outcrops of the same formation (Fig. 1) or/and from the determination of the location, orientation and dip of the fractures crossing the wells.

The fracture network observed on outcrops is indeed not necessarily identical to the one prevailing in the reservoir even in the same geological formation and mainly if there is evidence of an irregular fracturing. However outcrop observations may help to relate the fracture characteristics to the lithology and the structural location.

Aerial photography allows to define regional fracture trends (Fig. 10) which may be considered as no depth dependent in tectonically undisturbed areas.

Core description, when recovery is good, provides the fracture density, their length, dip, strike (oriented cores), filling materials.... Fracture induced by drilling may be recognized and discarded. Thickness of the fractures in reservoir conditions cannot be obtained from cores.

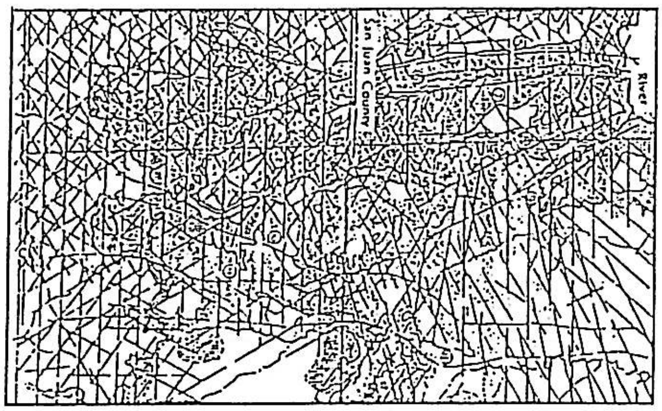


FIG. 10. Regional joint trend.

Mud losses are also an indication of large fracturing, recorded on surface. However it does not allow to determine the number and location of the fractures.

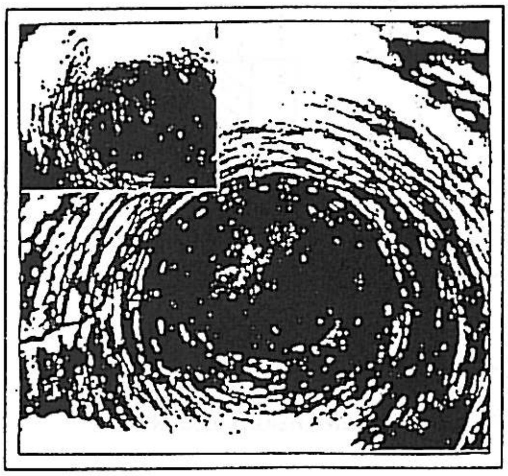
Seismic profiles may also sometimes indicate fractured zones. In such cases it may help to determine the extension of the fractured areas but cannot indeed give information on the block size.

Several types of measurements in the well may be used (generally in conjunction) to locate the fractures more or less precisely:

- In some specific cases camera pictures may give very valuable information (Figs. 11–12) but the constraints of photography make it rarely possible.
- Production logging (flowmeters, temperature logs) may indicate the location of open fractures if the hole conditions are good.
- Many efforts have been done to use electric logs (mainly the sonic log) for detecting fractures. Most of them are reported in [2], [6], [7]. In some specific conditions good results are obtained by interpreting log "anomalies" as fractures. However there is no general validated method and such interpretations have to be checked and calibrated on a regional basis. Schlumberger uses a programme (DETFRA) which computes a probability index of fracturing from individual indices defined with the available logs.
- Two tools give "false pictures" of the wellbore with visualisation of the fractures:

  - the Borehole Televiewer (BHTV) which is an ultrasonic scanner providing a sonar type picture (Fig. 13),
  - the "Formation Micro Scanner"™ (Schlumberger) which combines the reading of dense arrays of electrical sensors set on the pads of a four arm caliper (Fig. 14).

Pictures given by these two tools are generally very clear and allow to make the same measurements as on cores. However they must be closely analysed to detect "false fractures" corresponding to pictures generated by other heterogeneities.

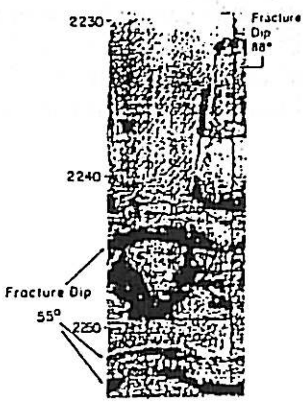


(After Fons)

FIG. 11. Photograph of fracture obtained with a borehole camera.

(After ref. 6, p. 25)

FIG. 12. TV pictures in Emeraude field wells.

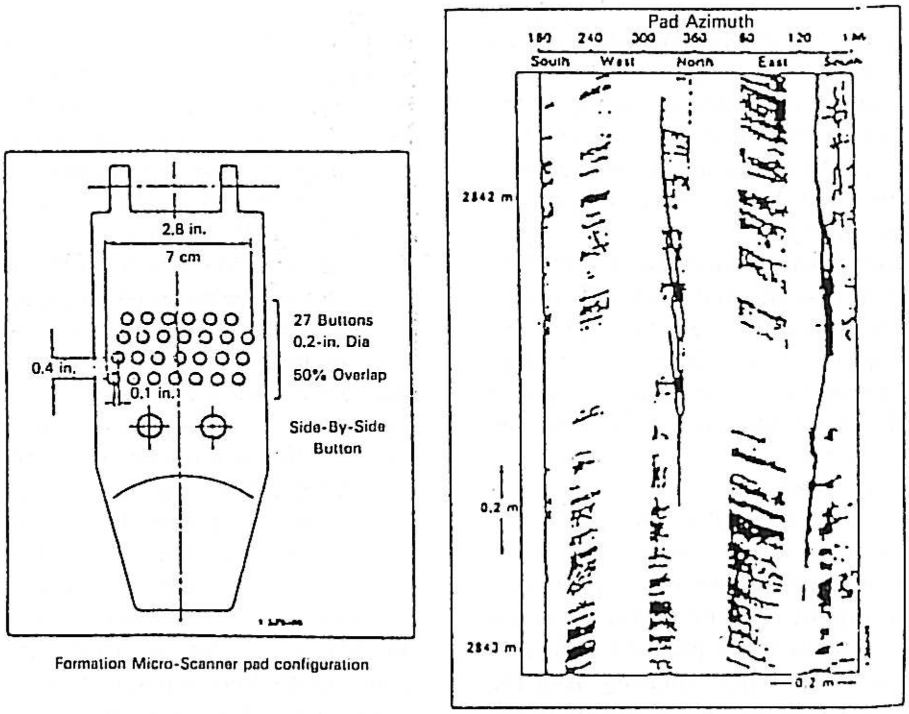


(After Kai Hsu et al)
JPT, June 1987

FIG. 13. BHTV log.

- Production test analysis are sometimes used to define an "average" block height. In favorable cases the dual porosity flow model allows to compute the value of the parameter $\lambda=\alpha\cdot(km^2)\cdot(rw^2)/kf$ where α is a geometric factor equal to $12/(hm^2)$ in the plate model (hm = thickness of the matrix bed). α (dimension $1/L^2$) is dependent upon the block shape. On the other hand as only monophasic flows are analysed by this method it should be at best possible to approach an "equivalent" length (volume/surface ratio) of the block, which is not enough to characterize the matrix medium.

When all the information about well fracturing are obtained, they are processed in order to get a space description of the fracture system and a definition of the matrix blocks as consistent as possible



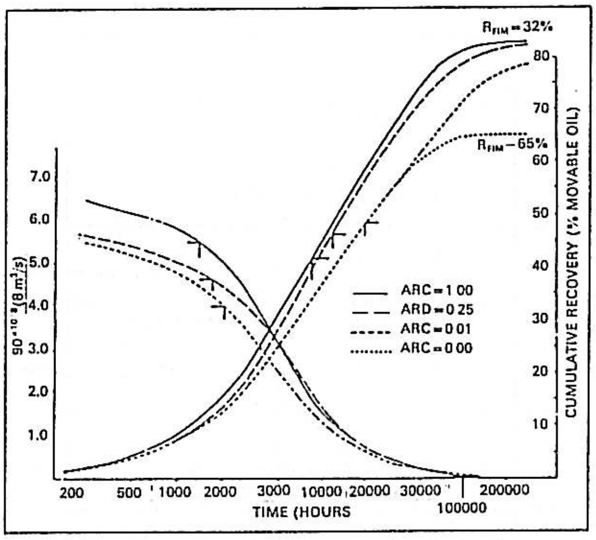
Formation Micro-Scanner pad configuration

-FMS display showing open fractures

FIG. 14. FMS log.

with *all* the available data. When a complete information is availabe a statistical processing may be necessary to define the characteristics according to depth, lithology.... It must also be reminded that very few subvertical and practically no vertical fractures have a chance to be observed in a well.

The next step is to simplify the geological description according to the model input requirements. When fractures are large and extended they often clearly define a pattern which may be easily schematized by one of the accepted model pictures (plates, columns or sugar lumps). When fractures are small and short they are also irregular and the typical form of the blocks is no more obvious. A very important parameter to evaluate is the partial continuity which often exists in such reservoirs. This continuity, mainly in the vertical direction, is critical for the recovery by gravity drainage as even a limited unfractured section between two blocks may give (Fig. 15) practically the same performances as a full vertical connection [8]. It is the author's opinion that very often such reservoirs are simulated with a sugar cube scheme using too small blocks and that a column type model should be more appropriate. It must be kept in mind that each time fractures are invaded by gas, gravity drainage is the main recovery factor and the final recovery depends on the block height compared to the extension of the capillary transition zone.



ARC = Area of contact (fraction) between the two blocks (After ref. 8)

FIG. 15. Partial block continuity.

OTHER PARAMETERS

Among the other parameters which have to be defined in any simulation but which have a specific importance for fractured reservoirs, we have mentioned the gas-oil capillary curve. This one is not only dependent on the matrix rock but also on the *gas-oil interfacial tension*. This one is pressure and gas composition dependent. The increase of the interfacial tension when pressure decreases may be very significant and may largely modify the final oil recovery. In such cases the model must account for this variation. Similarly if an external gas is injected the interfacial tension may vary with gas composition and the model has to make the corresponding computations.

Diffusion is a slow process and, consequently, may often be neglected in conventional reservoirs as it is efficient in only a small volume close to the fluid fronts. In fractured reservoirs the distance from matrix rock to the next fractures remains small and diffusion may be an efficient displacement mechanism between the fracture and marix media.

In highy fractured reservoirs, *thermal convection* is acting in the fracture system, resulting in initially uniform oil properties all through the column. If convection is fast enough, it maintains uniform oil properties in the fractures during the reservoir depletion with a bubble-point pressure close to the pressure at the gas-oil contact. Gas is consequently diffusing from the matrix to the fractures resulting in a reduction of the matrix oil bubble-point. This phenomenon is evidenced by a production at declining GOR from the bottom part of the oil column down to pressures much lower than the initial bubble point (Fig. 16). Before

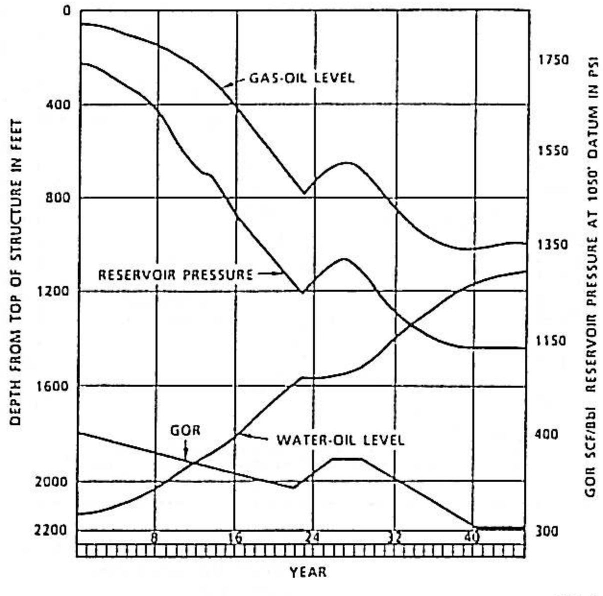


FIG. 16. Example of convection-diffusion effects.

production, convection may be evidenced by a constant temperature all through the reservoir.

RESERVOIR SIMULATION AND RESERVOIR DESCRIPTION

Due to the large number of parameters involved in a fractured reservoir model, it is unrealistic to expect that matching the field past performances will allow to fix the reservoir properties at their correct values. The history match is only a way to check the consistency of the reservoir characterization previously performed by the reservoir engineer and to adjust some parameters within a range of acceptable values and according to the general reservoir picture. If such a "limited" adjustment is not sufficient, the general description must be reviewed before any new simulation.

On the other hand, engineers sometimes hesitate to embark in a fractured reservoir simulation because data are not sufficient to describe the fracture system. It is clear that large efforts have to be done to improve this description and modern tools may be very helpful. However, even in cases where the fracture system is poorly known (lack of data, very complicated system), a numerical simulation may give significant results if properly used.

A first use of the simulation is to test on a limited model (cross section, sector) the relative importance of some poorly known parameters (within their realistic range of variation) in order to decide a cost effective programme of data acquisition. The second use of the model is as an engineer's tool in a reservoir engineering study. When requested by his management, the reservoir engineer must provide production profiles, development/completion programmes.... Answers must be given even if very few or/and very poor data are available. The model is a way to forecast the field behaviour according to the best reservoir picture based on the presently available data and engineer's experience. The model has to be chosen to represent the actual physical phenomena even if their magitude remains uncertain. In other words very simplified data should never give accurate detailed results but may provide a satisfactory estimate of the whole reservoir behaviour if the relative influence of the different drive mechanisms is correctly evaluated *and* if these mechanisms are correctly simulated. If a field is considered as a fractured field (as above defined) the different forces (viscosity, capillarity, gravity) do not act as in a single porosity reservoir and a specific model is better suited to simulate it even with poor data. The model is also able to give an estimate of the uncertainties by modifying the relative importance of these forces (specific coefficients have been introduced in our model, FRAGOR, to easily and independently modify each force and thus to be able to run rapidly several sensitivity cases).

CONCLUSIONS

The description of a fractured reservoir is indeed a challenge. Important improvements of the logging tools help to a better analysis and improvements of the simulators and allow a better computation of the different fluid flows in such reservoirs. The main point to clarify before starting to use a numerical model is to know if the fractures which have been recognized to exist are developed in a system such that the reservoir may be viewed as a series of separated matrix elements. If so, the engineer's judgement remains the key factor to correctly choose the suitable conceptual description (cubes, columns, layers). This choice is basic as it may strongly modify the way the different forces competitively act in the reservoir.

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