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An Integrated Workflow to Account for Multi-Scale Fractures in Reservoir Simulation Models: Implementation and Benefits

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Abstract

The recent years have seen the emergence of detailed field data acquisition and efficient modelling tools to characterize reservoirs and model their complex internal structure in a realistic way. This progress led to the detection of multi-scale fractures in most reservoirs, and enabled to interpret unexpected field production features such as early breakthroughs. Therefore, the availability of a workflow and an integrated modelling methodology becomes more and more crucial to take into account the geological information about fractures/faults into the reservoir dynamic simulation process for optimizing field productivity and reserves. This paper reviews and illustrates the overall methodology and the specifically-involved procedures and tools we have gradually built from the experience acquired in various fractured field case studies.

The main steps of this multidisciplinary approach include (a) the detection, geological analysis and modeling of multi-scale natural fracture network from seismic and well data, (b) its validation and calibration from dynamic field information such as well tests, (c) the choice of an equivalent simulation model applicable at reservoir scale, and its construction thanks to innovative flow up-scaling procedures applied to the realistic model provided by the geologist, (d) the implementation of predictive and numerically-efficient algorithms to represent the physics of flow transfers occurring both at local and large scale during multiphase field production.

Thanks to this consistent workflow, field simulation models remain interpretable in geological terms, which is helpful for subsequent model updating. Thus, specialists in geosciences and reservoir engineers can cooperate in a very effective way to improve the management of fractured reservoirs.

Introduction

The presence of fractures and faults in petroleum reservoirs has always been an issue for the assessment of field productivity and reserves. The internal structure and flow behaviour of fractured reservoirs[1,2,3] has been fairly well understood for a long time however, until recently, no consistent methodology and software enabled to integrate field information about natural fracturing for field production purposes. The recent development of new field data acquisition techniques, such as borehole imaging and 3D seismic, was an incentive for such integration. The unexpected production behaviour of many fields[4] arising from an insufficient consideration of fracture effects on flow emphasized the need for better characterizing the distribution of fractures at various scales and transferring the meaningful part of this information to field simulation models.

Taking into account the availability of fracture-related information and flow simulation issues, we developed an integrated methodology involving the following steps (**Fig. 1**):

- constrained modelling of the geological fracture network based on the analysis, interpolation and extrapolation of fracture information acquired in wells and seismic surveys, sometime completed by outcrop analogue data;
- characterizating the hydrodynamic properties of this natural network from flow-related data;
- choosing a flow simulation model suited to the role played by fractures and faults at various scales and involving upscaled parameters derived from the flow-calibrated geological fracture model;
- simulating reservoir flow behaviour on the basis of a physical assessment of multiphase flow mechanisms prevailing in transfers within and between media.

Using terminology found in the literature,[5] the first two steps of this methodology combine a forward approach mainly based on geosciences and an inverse approach based on reservoir engineering. The flow upscaling procedures involved in the last two steps ensure consistency between the flow-calibrated geological model and the single-medium, multi-medium and/or explicit modelling approach(es) chosen for field simulation. The four steps of this integrated approach are presented, discussed and illustrated hereafter.

Building a geological model of faults and fractures.

The methodology is extensively described by Cacas *et al.*[6] and is briefly summarized hereafter (**Fig. 2**).

The fault/fracture model integrates the information about fracture position and geometry acquired *both at local scale* within a few wells (cores, bore-hole images, logs), *and at large scale* from seismic surveys, with a possible additional input from the study of analogous outcrops. This information can be interpreted in terms of fracture genesis mechanisms based on mechanical concepts. This way, two main types of fractures are defined in relation with the strain effects: shear fractures called faults, and extension fractures called joints. However, on a reservoir engineering point of view, the classification of fractures is rather based on their impact on flows. For this reason, the reservoir engineer generally distinguishes large-scale fractures cross-cutting the reservoir and small-scale diffuse fracturing preferentially located in given reservoir layers. Following this criterium, clustered joints of large vertical extension, named fracture swarms, and (sub-)seismic faults fall into the same class as regards flow simulation purposes.

Fractures of each class are then split into different sets according to given geometrical properties such as orientation or spacing, in relation with past tectonic episodes. The geologist has a central contribution in such fracture classification, which constitutes the starting point of fracture model construction.

The subsequent step consists in re-constructing the fracture network model of the field. Such a model incorporates

(i) a *deterministic* description of large-scale faults above seismic resolution,

(ii) a *constrained statistical* realization of other multi-scale faults and fractures, namely sub-seismic faults or fracture swarms, and small-scale fractures.

In the following, we will focus on the various methods usable to build a statistical fracture network representative of the reservoir. The reliability of a statistical model of the fracture network depends on the amount of constraining data or rules which are involved in the modelling procedures. The parameters involved in the modelling of a statistical fracture network include fracture orientations, lengths and spacing or density.

Some of these parameters, such as the length distribution and the dispersion of orientations are derived from quantitative *fracture/fault analysis* and are generally considered constant for a given set within the reservoir. Such an analysis is performed (i) on the seismic fault map at field scale, (ii) on the small-scale fracture network observed in well-documented wells. We should however note that the fracture length distribution of small-scale fractures is not accessible from field data and require other type of information such as analogue outcrop data.

The other parameters, namely fracture/fault spacing and local average orientation, are space-dependent parameters controlled by multiple factors of geological/geomechanical nature. Hence, we chose to model them as follows.

The geocellular fracture model. The model of space-dependent fracture parameters is called the *geocellular fracture model*, as it is based on the same discretization grid as the facies geocellular model. This choice is justified by the fact that lithology and bedding very often control the distribution of fracture spacing in a sedimentary context. Modelling of fracture parameters involves interpolation or kriging methods if such parameters are available in a high number of wells.

However, very often, few wells provide such information and the distribution of fracture parameters has to be inferred from that of fracture-related parameters. The latter include:

- facies-related parameters controlling fracture spacing (or density) :
  - lithology: for instance, shaliness or dolomite content,
  - petrophysics: most often facies porosity,
- structural parameters related to the field geomechanics, such as:
  - reservoir horizons curvature: their direction and intensity of curvature control fracture orientation and fracture density respectively,
  - proximity to faults: often used to constrain the density of fault-associated fractures.

  3D seismic data constitute the main source of information to derive reliable structural parameters and infer the presence of multi-scale fractures. In addition to the morphological analysis of horizons, the 3D seismic cube can also be analyzed in terms of coherency between seismic markers, or of amplitude attributes. However, the latter need to be calibrated in terms of fracture occurrence in near-wellbore regions.

The resulting geocellular model of fracture parameters, along with the map of deterministic seismic faults, are major input constraining the statistical modelling procedures of the discrete fracture network.

The statistical Discrete Fracture Network (DFN) model. Two types of discrete fracture models are built, a unique discrete model of major fractures or faults at reservoir scale, and local models of small-scale fractures at any location within the reservoir.

As regards large-scale fractures, *i.e.* sub-seismic faults or fracture swarms, the constraining information consists of:

- an orientation map based on seismic faults information,
- statistical parameters related to the distribution law of fault lengths, which have been inferred from the previous fault analysis step,
- information driving the spatial location of large-scale fractures to be modelled, which may be for instance:
  - a fractal distribution law determined on the observed fault network;
  - a curvature intensity map converted into a probability map of fault occurrence.
- additional rules such as a minimum spacing between faults or abutting in order to respect the chronology of fault sets.

As regards small-scale fractures, the statistical modelling is based on:

- primarily, the geocellular fracture model which provides:
  - maps of local orientation of fracture sets;

- maps of local density of each fracture set, which depends on both facies nature and bed thickness.
- the dispersion of fracture set orientations which has been inferred from the well data analysis step;
- statistical parameters related to the distribution law of fracture lengths: those poorly-defined parameters generally have to be assessed from other sources of data than wells, i.e. analogue outcrop data for instance;
- various constraints for the statistical modelling procedure, which may be for instance:
  - a local density correction map derived from geomechanical information,
  - probabilities of fracture crossing across layer interfaces,
  - fracture observations in wells, which constitute deterministic constraints.

To summarise, the previous modelling procedures integrate any available field information which can be interpreted in terms of fracture occurrence. The approach does not give a priority *a priori* to any given type of information whatever its nature, geometrical, lithological or structural/geomechanical. Information availability and the geological interpretation of this information in terms of fracture property guide the fracture modelling. The latter differs from other existing approaches, either more focused on a given type of information, of geomechanical nature for instance,[7] or giving less importance to geological interpretation of data.[8]

The implementation of our integrated approach required setting up a very modular and flexible fracture analysis and modelling tool to account for the diversity of fracturing contexts in oil and gas fields. The two following examples illustrate two contrasted field situations, one with small-scale facies-dependent fractures, the other one with large-scale fracture swarms.

Field example 1: small-scale facies-controlled systematic joints. The typical reservoirs concerned consist of an alternance of facies characterized by different natural fracturing properties, due to different shaliness or dolomite content for instance.

The first step consists in identifying the various fracture sets and determine their respective parameters. This is carried out using wellbore data such as log data for facies identification and fracture imaging. The polar diagrams built from a few wellbores enable to identify different fracture sets characterized by different statistical distributions of orientation and dip. The main sets have to be interpreted in terms of tectonic episodes undergone by the reservoir. The fracture densities of each set are also estimated for each of the facies, independently of the bed thickness which constitutes an additional parameter controlling fracture density.

Then, the fracture orientation and density of each fracture fracture set within each facies have to be interpolated between wells thanks to other fracture-related parameters than facies Very often, geomechanical information is used, such as structural deformation. Consistently with its genetic origin, the local orientation and spacing of a given fracture set is then related to respectively the local direction and intensity of curvature of well-identified geological markers. This enables to build a map of local fracture orientation and a map of structural correction factor of the local fracture density.

Finally, the fracture parameters of each set in each facies, the orientation and density correction maps, and the facies geomodel of the reservoir enable to reconstruct realistic stochastic models of the fracture network at various reservoir locations.

When the parameters of fracture length distribution cannot be estimated with a sufficient accuracy and reliable outcrop analogues are not available, a range of uncertainty remains on the generated stochastic networks. In such situations, further hydraulic characterization of the stochastically-generated Discrete Fracture Networks (DFN) using dynamic data such as well tests, are indispensable. Actually, thanks to the strong dependence between fracture length and network connectivity, irrealistic fracture length values will be discarded.

To summarize, the lithologic model constitutes the basic information underlying the fracture distribution model of such fractured fields where lithology closely controls fracture occurrence. However, structural data and dynamic tests remain essential to constrain poorly-defined fracture parameters, such as length, of the corresponding fracture models.

Field example 2: large-scale fracture swarms in carbonate fields. The typical issue is to explain early water breakthroughs observed in some parts of those prolific fields subjected to peripheral water injection. The presence of super-permeable layers and/or fracture swarms are generally suspected to be responsible for the irregular water front progression. Extensive reservoir characterization campaigns are therefore undertaken. In addition to an advanced modelling of rock types based on facies petrophysical properties, the distribution of fracture swarms over the field has to be inferred from various data including seismic interpreted maps, wellbore image logs and flowmeters. Seismic-derived depth maps are converted into curvature intensity maps which are used as probability maps of fracture swarm occurrence in the stochastic generation process. Image logs in horizontal wells enable to derive deterministic information about the presence and local orientation of fracture swarms. Flowmeters are used to estimate the hydraulic conductivity values of those swarms crossing the wells.

Fig. 3 shows a typical fracture swarm network stochastically generated at kilometric field scale. Such a map integrating both faults directly visible from the seismic and stochastically-generated faults is used to determine the cell-to-cell fracture transmissivities in a reservoir simulation model.

To conclude, seismic-derived structural information is essential to model sub-seismic faults and fracture swarms.

Meanwhile, wellbore data remain indispensable to prove the structural control of fracture swarm occurrence, to constrain modelling and also to calibrate fracture flow properties.

Hydraulic characterization of the fracture geological model.

The reservoir engineer needs to validate the geometry of the fault/fracture network provided by the geologist and to quantify the conductivity of the connected fracture network. To perform this dynamic characterization, various sources of information are used:

- mud loss data, to locate fractured sections along wellbore and estimate fracture conductivity and aperture of major fractures intercepting wellbore;
- caliper logs or leak-off tests to derive the orientation and intensity of the present maximum horizontal stress, which may be related to fracture aperture;
- the distribution of productivity/injectivity indices at overall field scale, which can be correlated with fault or joint density maps;
- steady-state production logs such as flowmeters;
- transient well tests including drawdown, buildup and interference tests.

We recently developed a specific module to simulate steady-state and transient well tests on the Discrete Fracture Networks built with the methodology described before.[9] The specific features of this simulation module, most of which patented, are summarized hereafter:

- the fracture network is discretized using a minimum number of nodes placed at fracture intersections and extremities in each geological layer (**Fig. 4**);
- a matrix block volume is delimited around each fracture cell using a fast image processing algorithm applied to the geological fracture network (Fig. 4) ,
- for each fracture node, a pseudo-steady-state formulation of matrix-fracture transfer is applied with a transmissivity depending on the local matrix permeability and on the geometry of the matrix block volume previously defined,
- matrix-to-matrix flows are computed using a two-point method assuming flows orthogonal to matrix blocks edges.

This simulation procedure differs from other recently-developed methods[10,11] in that it takes the actual distribution of matrix block sizes and shapes into account and is applicable to poorly-connected fractured media. It has also been extended to highly-compressible fluid flows for application to fractured gas fields.

In the following, we show on a field-representative example how transient well tests results are used to validate the geometry of a joint network model resulting from geological data integration and to calibrate it in terms of fluid flow.

Transient well test simulation example. The purpose of this example is to illustrate the possibilities offered by well test simulations on DFNs to validate fracture models and characterize the fractured medium flow behaviour.

The region of the fractured reservoir subjected to the test, shown in **Fig. 5**, has a lateral dimension of 600 m, a thickness of 50 m and is crossed by two fracture sets, with respective orientations of 120° and 45° from North and respective spacings of 8 m and 4 m. The matrix medium has a porosity of 20% and a horizontal permeability of 0.1 md. A horizontal well is perforated over 200 m in the middle of the reservoir region considered.

Figs. 6 and **7** visualize the flow rates within the fracture network at two stages of a drawdown test. The first image corresponds to the very short times of the well test, where fracture flows alone control well response. The second one corresponds to the beginning of the pseudo-steady-state period during which both matrix and fractures control well response.

In practice, the simulated pressure response should be tuned to the actual field response. This tuning enables (i) to validate the geometry of the fracture network, (ii) to determine the average conductivity or the parameters of the conductivity probability distribution function to be assigned to each constitutive fracture set. A conventional well test interpretation based on existing analytical solutions can also be carried out and compared to the tuned numerical response. Whereas the conventional interpretation leads to the determination of an overall matrix-fracture exchange factor, the DFN-simulated response takes intrinsically into account a local description of matrix-fracture exchanges. Thus, the interpretation of well response in reservoirs crossed heterogeneously-distributed fractures can be greatly improved.

Setting up a flow-representative field-scale model.

For obvious computational limitations, the complex geological fracture network model cannot be used straightforwardly to simulate multiphase fluid flow production scenarios at field scale. The reservoir model to be used for such simulation is necessarily a simplified representation of the actual geology of the fractured medium. The simplification procedure depends on (i) fracture scale compared to that of model grid cells,[12] (ii) the continuity or connectivity of each medium and (iii) the time scale of flow interaction between media compared to the time scale of fluid transport within a given medium. That is, a hierarchical approach with respect to scale is necessary but does not suffice.

Let us explicit our methodology of choice (**Fig. 8**). We have to deal with different media, namely matrix and fractures of different scales l_f. The scale categories can be classified with respect to model grid cell dimensions Δx. If Δt represents the typical simulation timestep, a quasi-static equilibrium of pressure, saturation or compositions between media can be reasonably assumed if this equilibrium is established within a time t_e less than Δt. The connectivity criterium also has to be taken into account at various scales.

1st case: fracture average dimension, l_f, less than cell size, Δx.

(1a) fractures are disconnected: this situation occurs in the presence of microfractures inducing a matrix permeability anisotropy but no dual medium flow since matrix is the single continuum ensuring flow from one cell to another. A single-medium model has to be constructed with equivalent flow properties of the overall medium determined at cell scale.

(1b) fractures constitute a connected network and t_e is less than Δt: this situation concerns densely-fractured media delimiting small matrix blocks for which exchanges with connected fractures may be considered instantaneous. This quasi-static equilibrium between matrix and fractures is very often satisfied in single-phase flow conditions but not so often in multi-phase conditions. As before, a single-medium model can be used with equivalent permeabilities and saturation end points accounting for the contribution of both media.

(1c) fractures constitute a connected network and t_e is higher than Δt: matrix-fracture transfers can no more be considered instantaneous. In this case, the use of a dual-medium model is recommended to reproduce the kinetics of matrix-fracture transfer. If the matrix medium only acts as a source of fluids, a dual-porosity single-permeability approach is well-suited. But if flow interaction between successive blocks has to be taken into account, especially for gravity-driven production processes, a dual-porosity dual-permeability is required.

2nd case: fractures have an average dimension, l_f, close to or exceeding cell size, Δx, but remain below reservoir scale

(2a) fractures still form a connected network: as in case 1c, the dual-medium approach is recommended as the fracture medium is again the conductive medium at large scale, with t_e generally higher than Δt. As block size may be of the same order of magnitude or exceed cell size, matrix flows from cell to cell generally have to be taken into account using a dual-porosity dual-permeability model.

(2b) fractures do not constitute a connected network all over the reservoir, some areas being sometimes not fractured at all: in this situation, both fracture and matrix media are treated as two continua when they co-exist; the use of dual-medium approach remains adapted, provided the possibility to switch to a matrix single-medium model in non-fractured areas. The dual-porosity dual-permeability approach intrinsically offers such a possibility. However, by comparison with previous situations, the large-scale fracture flows often need to be simulated more accurately to match injected fluid breakthroughs for instance. To this end, the fracture transmissivities of the dual-medium model are derived from the actual discrete fracture network.[4]

3rd case: fractures have a dimension, l_f, largely exceeding cell size, Δx, and constitute major identified conduits, which vertically cross-cut the reservoir with possible throw between delimited faults. This situation is encountered in some carbonate fields where conductive faults contribute to fluid transport at reservoir scale and constitute bypass between wells. An explicit representation of those faults is necessary to properly match multiphase flow behaviour involving early breakthroughs at given well locations. As an explicit modelling approach is computer intensive, we recently implemented a specific "conductive fault model".[13,14] The latter is based on the segregated flow concept avoiding any vertical gridding of those faults and the associated numerical constraints. Thanks to adapted relative permeability functions, this fault model can be coupled to a single-porosity or dual-porosity model of the surrounding medium without having to resort to a grid refinement of fault neighbourhood.

The various situations described above assume the presence of fractures/faults crossing a porous matrix. For non-porous fractured reservoirs, a conventional single-medium model is generally adequate except if major fractures control large-scale flow of fluids produced from microfractures or vugs having no direct access to macro-fractures. In this situation, a dual-porosity approach may still be required. On the opposite side, non-fractured heterogeneous reservoirs including numerous high-permeability beds sparsely distributed among tighter layers can be conveniently represented by a dual-porosity dual-permeability model.

Determination of effective flow parameters. Once a modelling approach is chosen, flow properties have to be assigned to each reservoir cell.

Until recently, the determination of such effective parameters remained a difficult task for the reservoir engineer. The possibility to reconstruct realistic models of fracture networks and the availability of methods and software to compute flows within these models now enables to compute those effective parameters in a systematic way.

When a single-porosity model is used, permeabilities equivalent to both matrix and fracture media are required. Those equivalent permeabilities have to account for flows within each medium plus interactions between them. That is, they cannot be taken as the sum of the permeabilities of each separate medium, especially for fracture networks close to the percolation threshold.[15] Methods to compute effective permeabilities are based on a discrete fracture model and the contribution of matrix flows is taken into account either through the solving of coupled boundary integral equations[16] or using an explicit matrix block approach.[9]

Dual-porosity models require the determination of equivalent fracture permeabilities and of equivalent matrix block dimensions or shape factors. Various computation methods have recently been implemented to determine the equivalent permeability tensor of a fracture network. Whereas some methods involve a discretization of each fracture[17] into finite elements, we adopt a minimum discretization of the network based on fracture intersections in each sedimentary layer[18] in order to reduce computation costs and enable equivalent fracture permeability calculation for complex 3D networks in a large number of reservoir cells. Considering that fractures are generally sub-orthogonal to the bedding planes, we determine the following partial tensor of equivalent fracture permeability by computing steady-state flows in 3 directions with different boundary conditions, either linearly-varying pressure or zero flow rate:

$$\begin{pmatrix} k_{xx} & k_{yx} & 0 \\ k_{xy} & k_{yy} & 0 \\ 0 & 0 & k_{zz} \end{pmatrix}$$

This partial permeability tensor gives access to the main directions of flow in the bedding planes with the associated equivalent permeabilities. The fracture conductivities involved in these permeability computations have been calibrated during the previous hydrodynamic characterization step.

As regards equivalent blocks or shape factors, because fractures are most often sub-orthogonal to layer boundaries, matrix medium is continuous in the direction orthogonal to bedding. Therefore, the problem addressed is 2D and consists in determining the square or rectangular section of an equivalent matrix block in each layer or group of layers having similar fracturing features. To this end, a fast geometrical method,[19] which actually simulates a 2D piston-type matrix invasion process, has been developed. For complex situations where the matrix capillary continuity is interrupted in the direction orthogonal to layering, a "vertical" block size has to be determined. A similar method is used except that it reflects the predominant control of matrix invasion by gravity mechanism.

In practice, these equivalent parameters are generally not computed for every cell of the reservoir grid for several reasons. Actually, in spite of efficient algorithms, the computational resources may become prohibitive for several hundreds of thousands cells with dense fracture networks. In addition, it is more straightforward to derive effective properties directly from the fracture parameters values picked in the geocellular fracture model than to generate the corresponding DFN models and compute equivalent flow parameters on these models. Hence, we determine the effective flow parameters of a set of cells chosen in order to cover the range of values of fracture parameters encountered in the studied field. The effective flow parameters of these cells constitute a data base within which the effective parameters of all the other cells are interpolated. The use of such a data base was adopted because existing correlations between equivalent parameters and fracture parameters,[20] which are valid for a single fracture set, cannot be easily extended to multiple sets.

The method described before to determine the fracture equivalent permeabilities of the dual-porosity model becomes inaccurate for large-scale low-density objects such as fracture swarms or sub-seismic faults. For such objects, cell-to-cell transmissivities reflecting the exact flowpaths are computed[4] directly from the reservoir-scale fracture/fault map. This method is also applied to reservoirs including thin high-permeability (or highly-fractured) layers analogous to large horizontal fractures. It is worth mentioning that its fast and easy implementation enables to perform sensitivity analysis of reservoir simulation results to geological uncertainties on these large-scale objects.

To end with, as regards explicitly-modelled large-scale conductive faults, a conductivity, expressed as the product of longitudinal permeability and thickness, has to be assigned to the cells representing those objects. This conductivity may be estimated from well tests, using conventional and/or DFN simulation approaches, or, by default, from history matching.

Simulation of fluid transfers in multi-medium field model.

Ending our workflow, the reliability of the fractured reservoir flow predictions also depends on the physical representativity of the multiphase transfer modelling between the constitutive media, matrix, fractures and/or faults. The physical mechanisms involved in those transfers include fluids and pore volume compressibility, capillarity, gravity, viscous drive and compositional effects. The approaches adopted to account for these multiphase multi-component transfers depend on the modelling approach, involving a single or a dual medium and/or explicitation.

Single-medium simulation. The multi-phase flow properties of a single-porosity model have to account for the respective contributions of fracture and matrix media. Pseudo parameters, especially pseudo relative permeabilities (kr), have to be assigned to the cells of the model. Those pseudo-kr can be fairly easily determined in two extreme situations, where fracture and matrix media are flooded either simultaneously or successively. The former situation concerns matrix blocks imbibed or drained as rapidly as the two-phase front progresses within the fracture network. The latter concerns large matrix blocks with low capillary interaction between fracture and matrix.[21]

For other situations involving variable interactions between matrix and fractures, pseudo-parameters can hardly be determined as they depend on all factors controlling matrix-fracture exchanges which, in addition, are history-dependent. Such difficulties constitute one of the main reasons justifying the choice of a dual-porosity simulation approach.

Dual-medium simulation. Thanks to a separate representation of flows taking place in each medium, the dual-porosity concept enables a better understanding and simulation of flow interactions between contrasted media. However, one major difficulty consists in formulating those interactions, i.e. the so-called matrix-fracture transfers. Warren and Root[22] proposed to formulate the overall matrix-fracture flux by a pseudo-steady-state equation:

$$q = \sigma \frac{k}{\mu}(p_m - p_f)$$

where q is the exchange flow rate per unit volume of matrix, p_m, p_f are the respective average pressures of matrix and fracture media, k_m the matrix single-phase permeability and σ

the well-known shape factor accounting for matrix block dimensions and shape.

The extension of such an expression to multiphase transfers mainly consists in replacing the average matrix-fracture pressure difference by phase matrix-fracture potential differences linked with the various forces in presence, and in introducing proper phase transmissivities and mobilities. This encounters major difficulties linked to:

- the representation of driving mechanisms having a directional effect like gravity, in conjunction with other non-directional, *i.e.* diffusive, mechanisms, like capillarity (**Fig. 9**);
- the durable transient states of the matrix medium involved in multi-phase transfers, which can hardly be reproduced without discretizing the matrix blocks.

For these reasons, multiphase transfer formulations involve pseudo kr and p_c functions and/or various expressions of the shape factor. Some authors determine pseudo p_c based on the vertical equilibrium concept[23] and tune the shape factor to match the kinetics of transfer computed a finely-gridded matrix block model, while other authors propose two given shape factor expressions referring to capillarity and gravity[24] and determine the pseudo p_c function which matches the reference solution computed on a finely-gridded matrix block model.[24,25]

However, this procedure of calibration of matrix-fracture transfers is valid for given transfer mechanisms and given matrix parameters including block dimensions. These limitations result in a poor reliability of dual-porosity simulations of heterogeneous reservoirs with a complex production history.

For these reasons, a discretization of the matrix blocks has been proposed[26] and introduced in some simulators.[27,28] Because it offers the possibility to reproduce the displacement process within the matrix, the matrix discretization approach is attractive however, it involves computation requirements which cannot be met for large and/or complex reservoir models.

Attempts were also made to introduce analytical matrix-fracture transfer functions as source terms in the fracture flow equations[29,30] however such functions still involve matching parameter(s) to be determined from fine-grid simulations as for pseudo-curves.

This short review indicates that no rigourous formulation of multi-phase flow transfers is presently available, especially when at least two mechanisms, such as capillarity and gravity, control transfers. To deal with such limitations, our selected approach[31,32] consists in splitting transfers into the contributions of each physical mechanism of transfer, and assigning them scaling factors. Let us explicit simply our approach in a black-oil context. The matrix-fracture transfer flux of a given phase p is expressed at cell scale as:

$$f_p = \frac{\Delta X \Delta Y \Delta Z}{l_x l_y l_z} \sum_{i=1}^{6} \lambda_p^i \frac{2A_i}{l_i} \Delta \Phi_p^i$$

with $\Delta X, \Delta Y, \Delta Z$ the cell dimensions, l_i (l_x, l_y, l_z) the lateral dimensions of the equivalent parallelepiped matrix block, A_i the cross-section area of each of the 6 matrix block lateral faces i (i= x-, x+, y- y+, z-, z+) and λ_p^i a specific phase mobility function.

No shape factor input is required using this formulation since it is implicitly defined from matrix block dimensions.

$\Delta \Phi_p^i$ represents the potential difference, in phase p across exchange face i, between fracture and the representative matrix block of the cell:

$$\Delta \Phi_p^i = \Delta p + C_{cp}.\Delta p_{cp} + C_{gp}.G_i + C_{vp}.\delta p_f$$

where Δp is the matrix-fracture pressure difference in a given reference phase and Δp_{cp} the capillary pressure difference between both media. G_i represents an average value of the gravity head applied on the matrix block (if i= z-, z+), and δp_f the viscous pressure drop applied on the block in the direction considered. C_{cp}, C_{gp} and C_{vp} are scaling factors referring respectively to capillarity, gravity and viscous flow mechanisms.

By setting those scaling factors to 0 or 1, one can assess the role of capillarity, gravity and viscous drive in matrix-fracture exchanges. In addition, for typical transfers governed by capillary and gravity forces alone, they can be expressed analytically in order to satisfy the vertical equilibrium of fluids at the end of transfer.[32]

Other displacement mechanisms, such as molecular diffusion and convection, may also have to be taken into account in the simulation of fractured reservoirs. Molecular diffusion may play a significant role in reservoirs with decimetric to metric blocks subjected to non equilibrium gas injection, for instance nitrogen[33] or air injection. Whereas the application of Fick's law does not pose any problem to simulate inter-cell diffusion within a given phase, the simulation of inter-phase inter-cell diffusion involved in swelling phenomena requires specific adaptations as regards flash calculations in single-phase cells.

The production data of some well-fractured reservoirs sometimes reveal fluid convection in fractures, a phenomenon which generally occurs in synergy with matrix-fracture molecular diffusion. Convection can be considered as an accelerated diffusion process and therefore simulated using Fick's law with very high diffusion coefficients.[34]

To conclude, there remains a need for research and development on matrix-fracture transfer up-scaling to better predict complex flow situations, for instance 3D gravity drainage,[35] and also complex transfers, such as multiphase compositional thermal exchanges.

Coupling explicit model and single- or dual-porosity model. As mentioned before, it may worth expliciting conductive faults if they explain the behaviour of some wells. The segregation assumption we apply enables to make multiphase flow simulation within such objects less computer-intensive. In addition, one has to take into account the size contrast between narrow fault cells and the surrounding cells. To avoid grid refinement close to faults and the corresponding computational limitations, the fault exchanges with the surrounding medium are based on an approach similar to that used for matrix-fracture transfers in a dual-porosity model. If the reservoir crossed by faults behaves like a dual medium in some regions, then faults are coupled to the fracture medium alone in those regions, and to the matrix medium elsewhere.

Conclusions

The recent development of integrated and flexible modelling methods and software enabled us to adopt a really-integrated workflow to model naturally-fractured reservoirs. This workflow starts with the geological analysis of fractures and ends with the reservoir simulation of multiphase production profiles:

- fracture models representative of the actual geology can be built through the integration of information of various origins - seismic, wells, outcrop -, of various nature - structural, sedimentological - and through the application of genetic concepts and constraints based on geology and geomechanics;
- the capability to simulate flows within Discrete Fracture Networks for hydraulic characterization and effective-flow-property determination was a major breakthrough which enabled the effective integration of geoscientists and reservoir engineers' disciplines;
- fractured/faulted reservoirs are complex media characterized by different flow-property contrasts at various scales. Flows cannot be simulated with the same accuracy at any scale. Therefore, various possible flow simulation methods based on single-porosity, dual-porosity or explicit models have to be considered with possible coupling;
- finally, the complexity of multiphase flow transfers in fractured media leads us to recommend the use of flexible simulation options which keep track of the physical mechanisms prevailing at each scale.

Development of those modelling methods and tools is going on, driven by various field case studies, to further constrain geological fracture models, to extend the capabilities of DFN simulation whatever the fracture density and connectivity, and to increase the predictability of multi-medium simulation of complex recovery processes.

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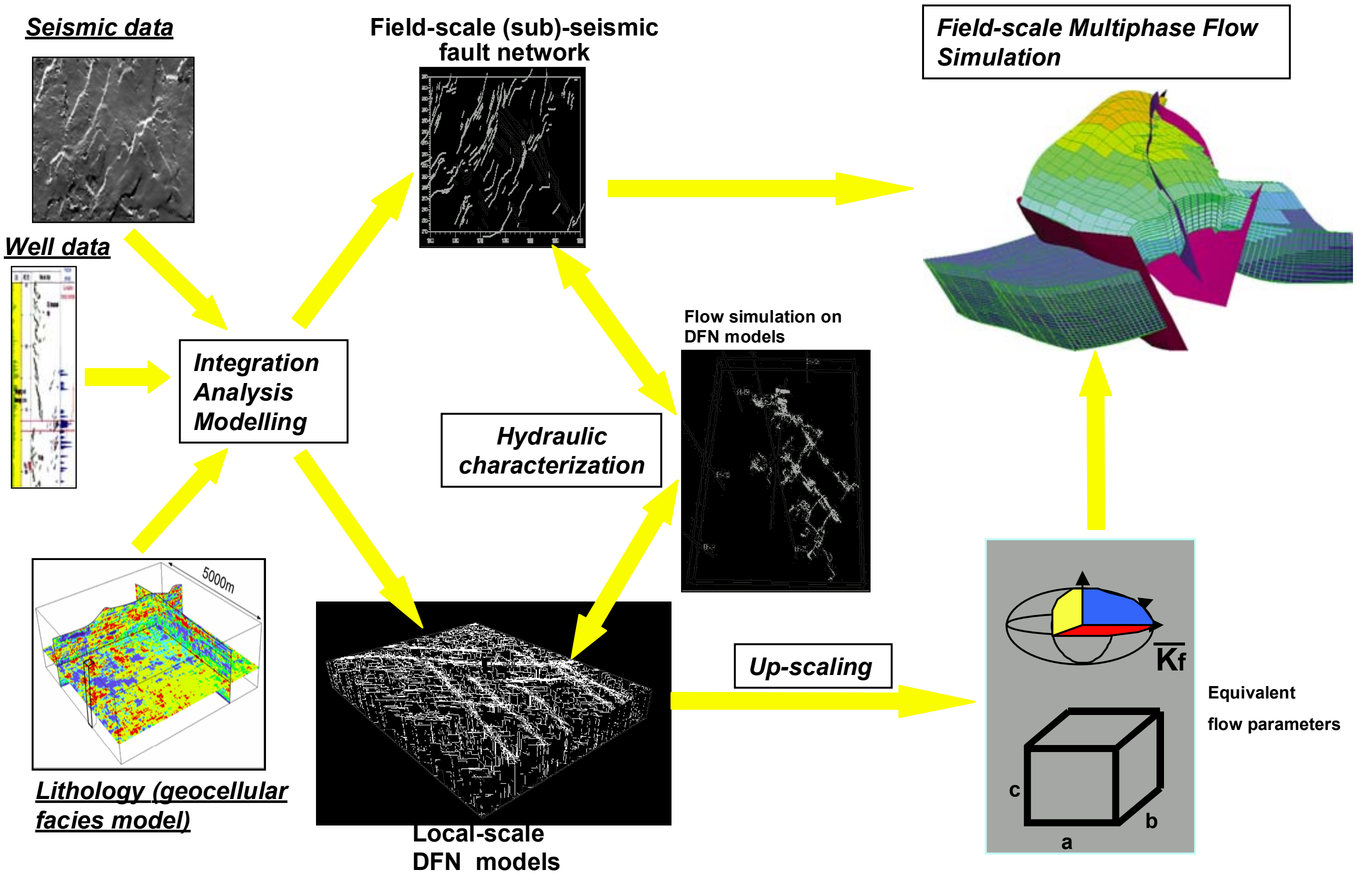

Fig. 1 – Modelling naturally-fractured reservoirs: overall approach

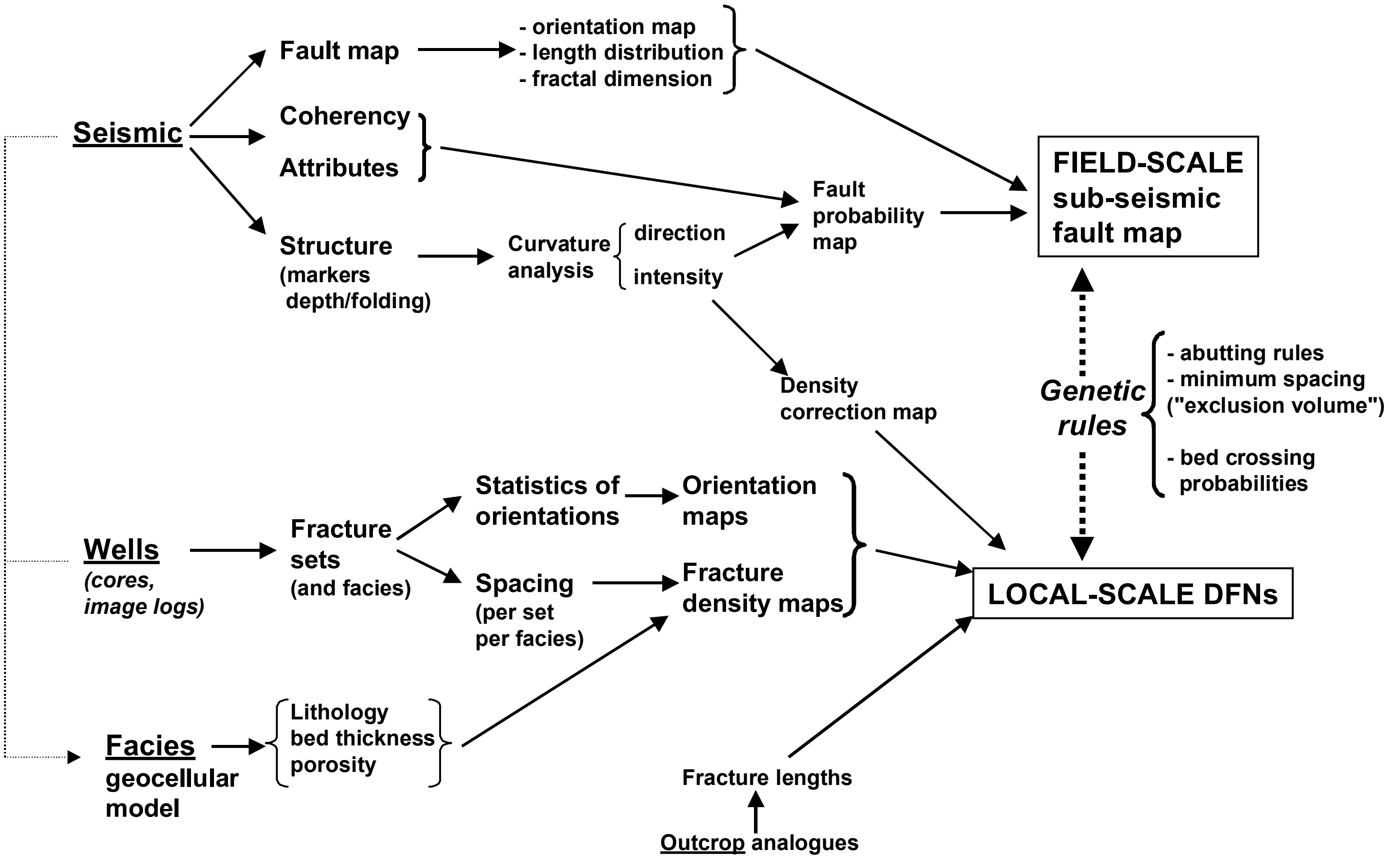

Fig. 2 – Geological modelling of multi-scale fractures (faults and joints): overall approach

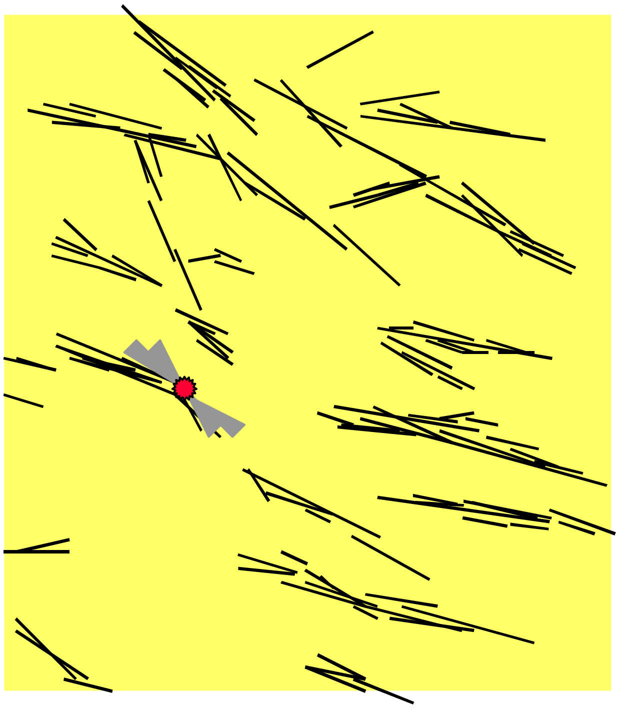

Fig. 3 – Typical fracture swarm network at pluri-kilometric field scale.

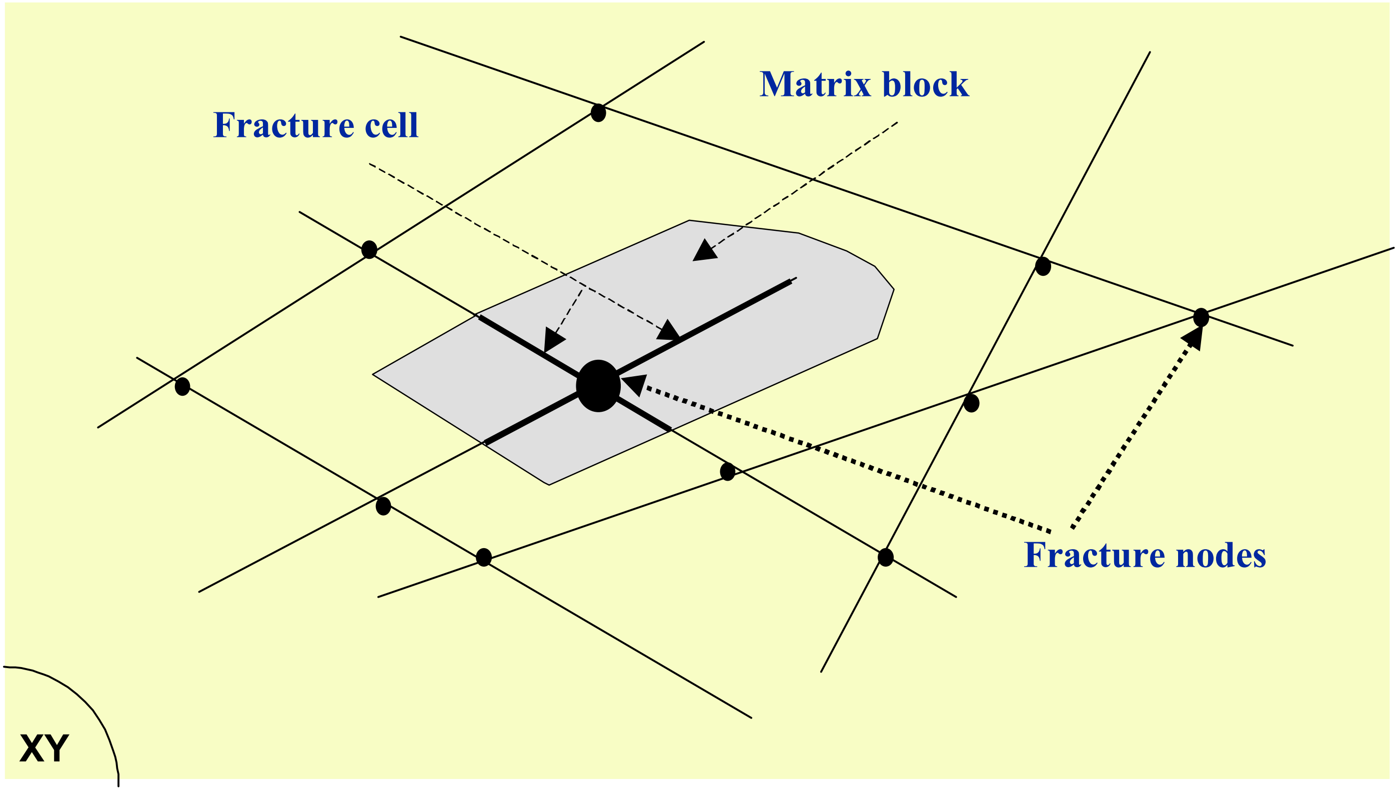

Fig. 4 – Discretization of a Discrete Fracture Network and assignment of matrix blocks to fracture nodes.

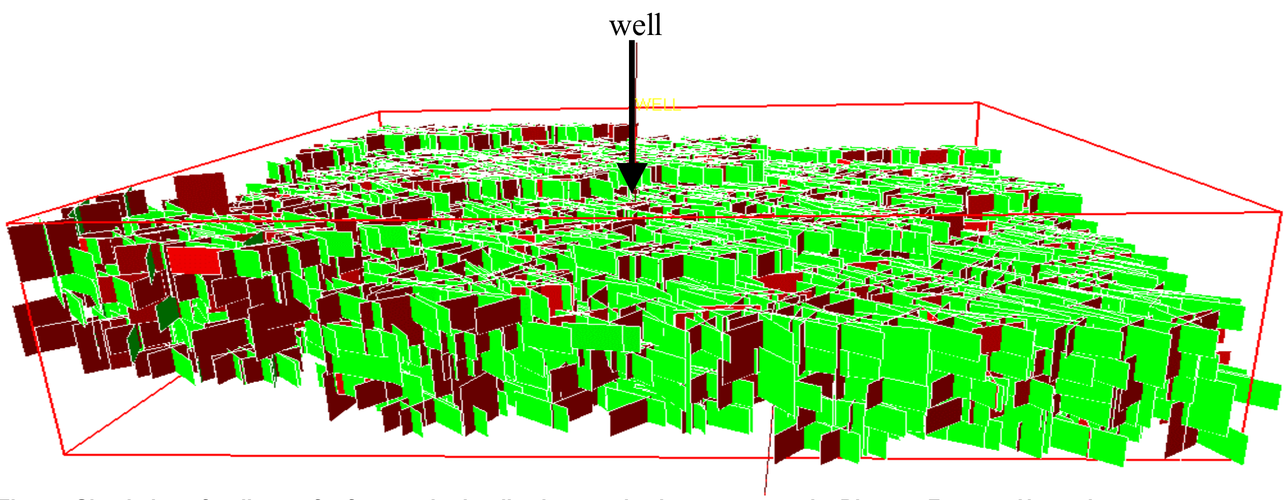

Fig. 5 – Simulation of well tests for fracture hydraulic characterization purposes: the Discrete Fracture Network.

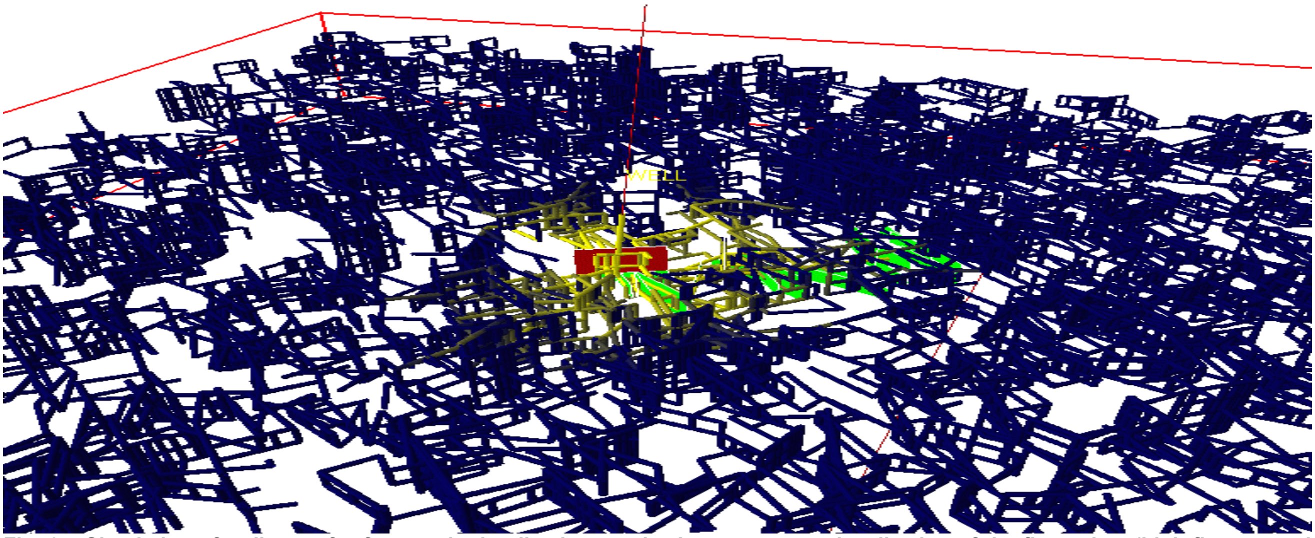

Fig. 6 – Simulation of well tests for fracture hydraulic characterization purposes: visualization of the flow tubes (high-flow-rate tubes in bright colour) during the initial phase of drawdown by a horizontal well (fracture flow regime) - note the flow anisotropy.

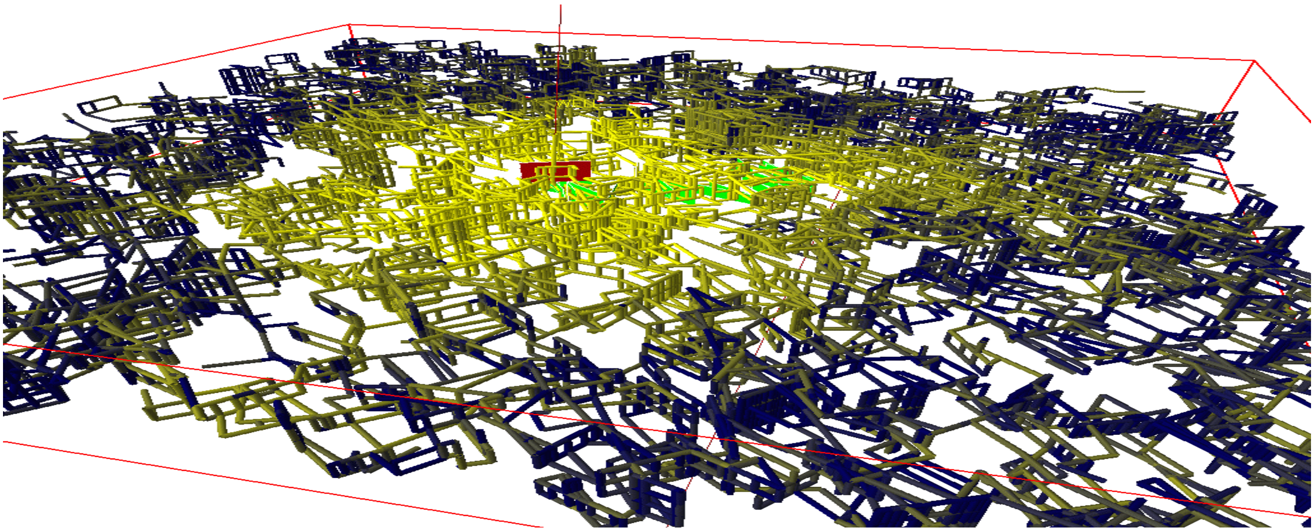

Fig. 7 – Simulation of well tests for fracture hydraulic characterization purposes: visualization of the flow tubes (high-flow-rate tubes in bright colour) during the late phase of drawdown by a horizontal well (pseudo-steady state flow regime).

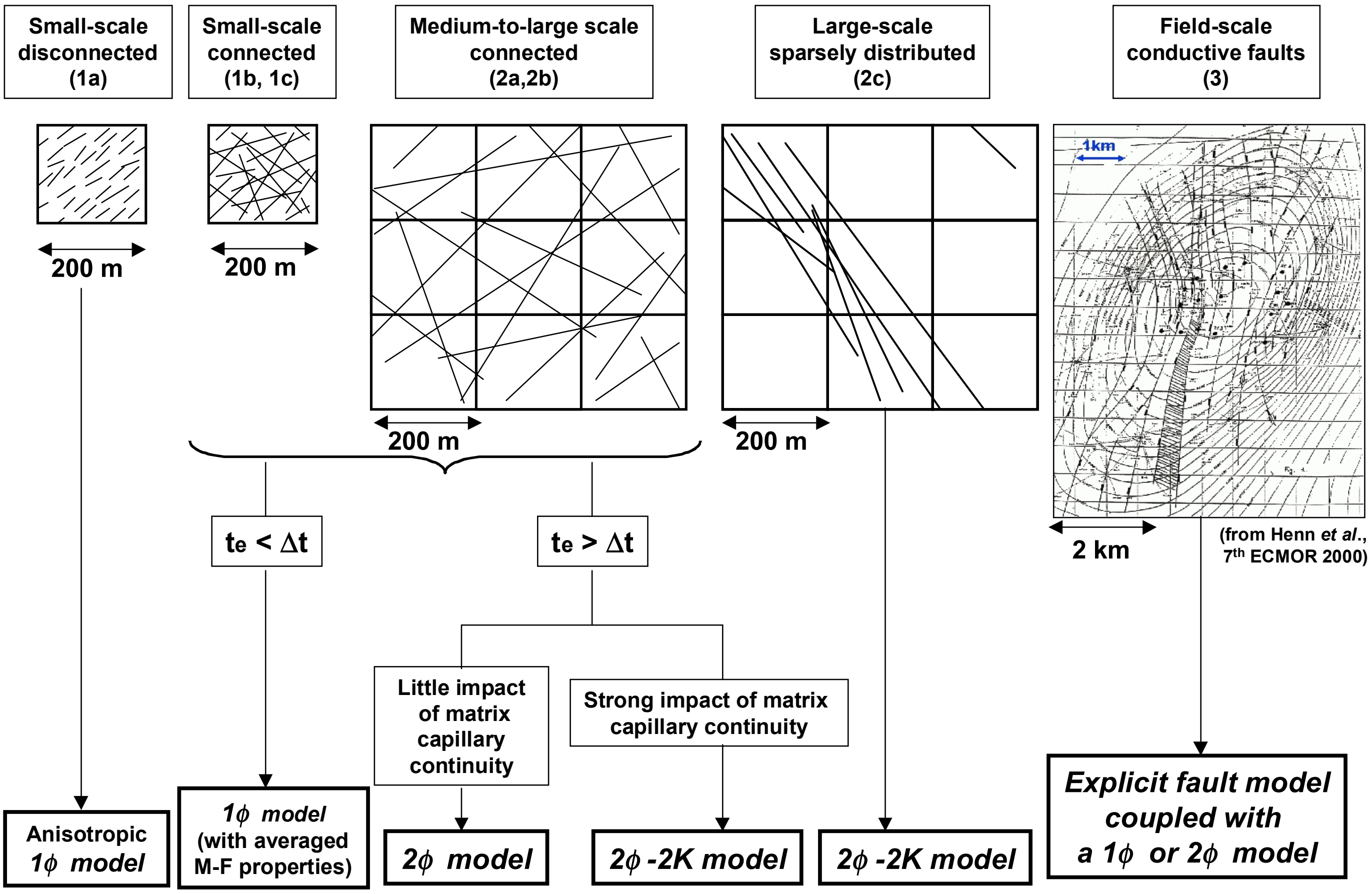

Fig. 8 – Methodology of choice of a flow simulation approach.

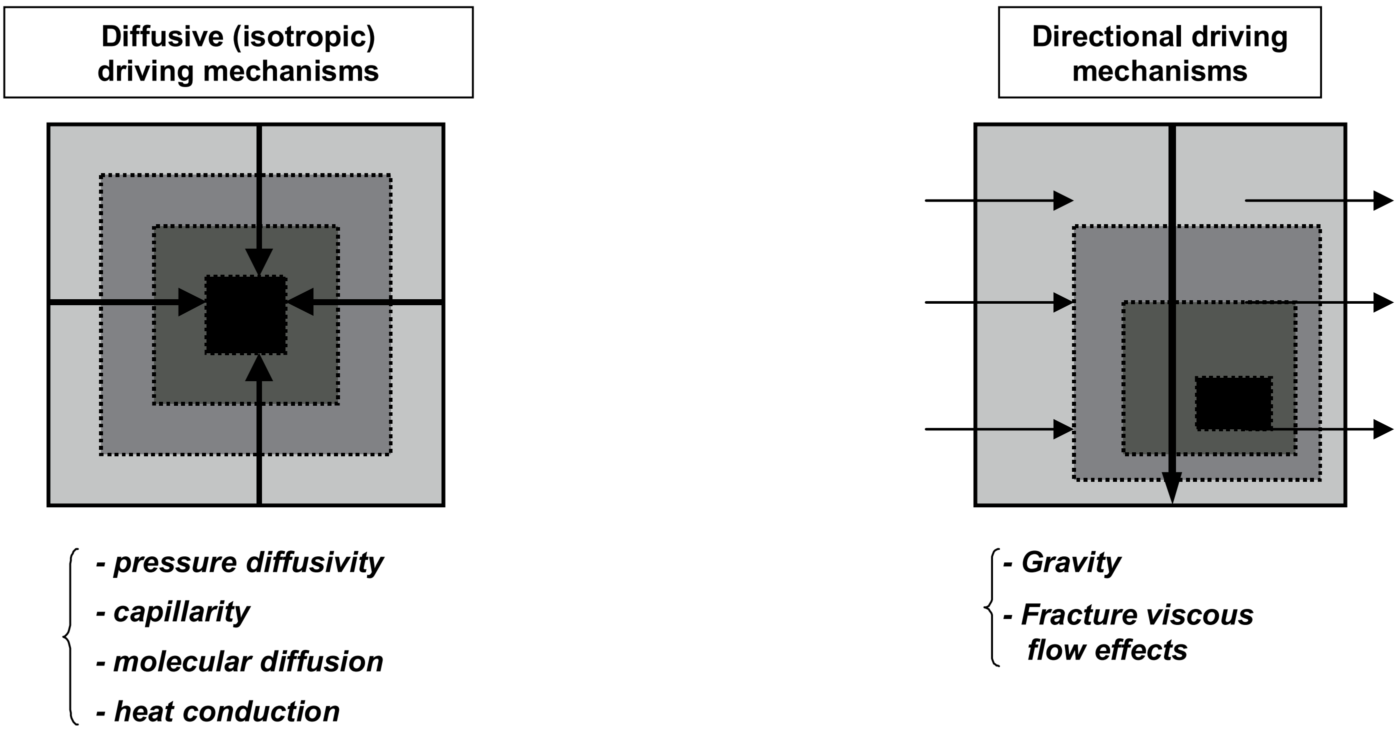

Fig. 9 – Different types of physical mechanisms involved in matrix-fracture transfers