Fractured reservoirs modelling: a review of the challenges and some recent solutions


Although the specific flow behaviour of fractured reservoirs was identified and modelled a relatively long time ago (Barenblatt et al., 1960; Warren and Root, 1963), until recently no consistent methodology and software really enabled the integration of field information about natural fracturing in reservoir engineering studies. The availability of direct information about fractures, in particular borehole images, was an incentive for such integration. The unexpected production behaviour of many fields arising from an insufficient consideration of fracture effects on flow also 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. A recent example concerns a giant Middle East Carbonate field where sub-seismic fracture swarms and stratiform super-K intervals were found to establish preferential flow paths between injection and production wells (Cosentino et al., 2001).

Therefore, the present trend in fractured field studies is toward the use of methodologies and software platforms to integrate all information about fractures into flow simulation models. The main features of those methodologies are described here, on the basis of fracture modelling examples set up using our own workflow (Bourbiaux et al., 2002). The latter involves the following steps:

- constrained modelling of the geological fracture network based on the analysis, interpolation, and extrapolation of fracture information acquired in wells and derived from seismic data, sometime completed by outcrop analogue data;
- characterizing 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 assigning to this model upscaled parameters derived from the flow-calibrated geological fracture model;
- simulating the reservoir flow behaviour on the basis of a physical assessment of multiphase flow mechanisms acting in transfers between matrix and fractures.

In the following, those four steps are reviewed and illustrated from a representative synthetic field case. Emerging techniques to further capture the complexity and flow behaviour of fractured reservoirs are also identified.

Building a geological model of faults and fractures

The proposed modelling methodology, described by Cacas et al., (2001) and summarized hereafter, starts with a careful geological analysis of natural fracturing information available from wellbores, surface seismic, and outcrops. The overall data integration workflow is shown in Figure 1.

Although geologists can provide a detailed classification of fractures with various sets associated with tectonic events and tensile or shear mechanisms, the reservoir engineer is led to discard and/or lump the sets expected to have negligible or similar impact on flows. That is, in practice, we generally end up with two main categories, the large-scale fractures or faults at seismic and sub-seismic scale, and the small-scale or diffuse fractures observed in wellbores.

Based on the previous analysis results, a multi-scale fracture model is then built using stochastic methods constrained by deterministic observations of fractures and by fracture genesis rules.

Figures 2 and 3 show a typical distribution of a multi-scale fracture network generated with our own fracture modelling software and including both large-scale and small-scale fractures. Figure 2 shows the large-scale, i.e. reservoir-scale, seismic and sub-seismic fault network model and Figure 3 the small-scale fracture network model that can be reconstructed at any location of this reservoir.

Large-scale fractures (faults). In practice, 3D seismic data provide the most reliable information to set up such a model. 3D seismic is firstly used to locate faults, identified...
as ‘deterministic’ objects. In addition, various 3D seismic amplitude attributes like coherency are analysed and turned into probability maps of sub-seismic fault presence. Such probability maps are used as constraints to ‘extrapolate’, through a stochastic modelling technique, the fault network to sub-seismic scales. Other modelling constraints for sub-seismic fault network generation are derived from the ‘deterministic’ fault map and include statistics of orientation and a fractal parameter for distribution in space.

Small-scale fractures. The important initial step consists in analysing and identifying the various fracture sets from wellbore image logs and cores. Different sets are defined according to given average orientations, which are related to structural features and/or tectonic events. The nature of rock facies constitutes another classification parameter as the expression of a fracturing event in a given facies or group of facies is closely related to its own mechanical properties. Once fracture sets and relevant facies in terms of fracturing properties have been identified, a fracture geomodel describing the distribution of fracture parameters – namely orientation and density – for each set in each facies, is built using the matrix geomodel as underlying information. In our example, the small-scale diffuse fracture network is made up of two sets of systematic joints and two facies have been defined in terms of fracture properties. The fracture density of one set is controlled both by the facies and by the reservoir curvature, whereas for the second set, the facies nature and the proximity to faults are the controlling factors. Finally, a stochastic model of the small-scale (diffuse) fracture network can be generated at any location of the reservoir on the basis of fracture geomodel parameters.

The 3D fracture network shown in Fig. 2 is generated in a reservoir sector of about 2 km wide and incorporates both the seismic/sub-seismic faults and the small-scale fractures. As can be observed, such images can now be reconstructed in reservoirs with complex structures, involving high dips and/or throws.

With such software tools, provided that sufficient facies and structural data are available, the geologist can now provide the reservoir engineer with a realistic model of the multi-scale fracture/fault network. However, such a Discrete Fracture Network (DFN) model will not be used as is in the field flow model, but will be simplified through homogenization procedures as described later on. Then, one may wonder about their usefulness. Actually, as shown in the next section, DFN models are first used to assess fracture hydraulic properties from available field flow data, such as well tests. Interpreting flow data using geologically-representative DFN models provide additional information about reservoir flow properties compared to conventional analysis methods, regarding flow anisotropy for instance. And also, they keep the link with the geological assumptions underlying the fracture model. Such a link is essential to interpret the impact of fracture sets on flow and drive further acquisition of geological data that are mostly relevant for fluid transport.

Challenges. Despite the recent progress, there still remains room for improvement of these geological fracture models, which are often poorly-defined for several reasons, among which:

- a limited amount of information provided by the few wells intersecting the fracture network;
- missing information about large-scale fractures below seismic resolution scale;
- poorly-defined fracture properties, especially fracture length, connectivity, and conductivity.

Seismic anisotropy analysis is probably one of the most promising solution for mapping fracture orientation and intensity between wells (Rasolofosaon, 2005). Indeed, assuming that pre-stack seismic data of good quality are available, the azimuthal anisotropy of seismic responses can be determined at various locations within the reservoir using a well-suited method and advanced processing tools. The principal direction of seismic

Figure 2 Reservoir-scale fault network.
Figure 3 Discrete element model of the whole fracture network at a given reservoir location: - small-scale (diffuse) fracture sets in yellow and blue - faults in green.
anisotropy can be related to the presence of rock discontinuities with mechanical compliance, a situation encountered in the presence of a single set or an anisotropic network of unsealed fractures. The results of seismic anisotropy analysis necessarily have to be corroborated with wellbore information about fracture presence and orientation in regions where both information are available, in order to check their consistency in wear-wellbore regions and allow a reliable use of seismic anisotropy results at a distance from the wells. Furthermore, the intensity of seismic anisotropy can also give information about the spatial variations of fracture density if the latter can be calibrated from wellbore data. Yet, although seismic anisotropy analysis is becoming a contributing part to fracture studies, the interpretation of results remain field-specific and mostly qualitative because:

- the vertical resolution scale of seismic response is some two orders of magnitude above that of wellbore core and log data, which leads to several possible interpretations of seismic anisotropy in terms of fracture presence;
- the theoretical models capable of relating wave propagation velocity and amplitude to fracture network geometrical and/or mechanical properties cannot yet be formulated and/or parameterized.

Thus, quantifying the uncertainty on the fracture information inferred from seismic anisotropy analysis is a key challenge for extended use of seismic data in fracture characterization studies.

Additional genetic and geo-mechanical rules can also further constrain the stochastic fracture models. Analogue experimental models (Daniel, 2004) are being used to mimic faulting processes, with real-time recording of transient deformation states by CT-scanning. Through the geo-mechanical simulation of experiments on finely-discretized models, the chronology and spatial organisation of rupture lineaments can be reproduced and interpreted. Such experiments are particularly useful to better constrain the generation of sub-seismic faults in relation with major lineaments.

To conclude, one has to recall that the reservoir engineering requirements drive fracture modelling studies and thus encourage the early integration of dynamic information in the geological fracture modelling process. Ongoing progress made in that direction will conclude this paper as it will actually lump the presently-reviewed modelling steps into a unique process.

Following the methodology presented in the introduction, the question of characterizing the hydraulic properties of a geological fracture model of geometric and static nature is examined.

Hydraulic characterization of the fracture geological model

The reservoir engineer needs to validate the geometry of the ‘static’ fault/fracture model provided by the geologist as regards fluid flow behaviour, and to calibrate missing flow properties such as conductivities.

To that end, a patented simulator was developed within our fracture modelling software platform. It simulates steady-state and transient well tests on the DFN model built by the geologist, for comparison with the actual field measurements of those tests (Sarda et al., 2002). Its original features consist in an optimal discretization of the DFN using a minimum number of cells defined by fracture intersections, and also in an accurate simulation of matrix-fracture transfers (Figure 4). The actual distribution of matrix block sizes and shapes is taken into account as each fracture node is associated with the proper matrix volume it can drain at this precise location, such matrix volume being determined through a specific processing of geological images. The range of application of this simulator was extended to highly-compressible fluid flows for application to fractured gas fields (Bassquet et al., 2004). Furthermore, a ‘dual-permeability’ option of this simulator (Lange et al., 2004) enables us to simulate matrix flows in the model regions where fractures are scarce or absent. Thus, the dynamic behaviour of any type of reservoir crossed by fractures or faults can be characterized, including poorly-connected fractured reservoirs, which actually turn out to be quite frequent in practice.

Considering the previous field-representative case, a build-up test of a well located in a fractured area and 200 m from a nearby fault was simulated on the geologically-representative model (Figure 3) including a discrete representation of both faults and fractures. The derivative curve shown in Figure 5 reveals successive flow regimes corresponding to the contributions from fracture and matrix media, and also to the impact of the fault. The latter establishes a hydraulic connection with the fractured medium far from wellbore and also with reservoir limits. This example illustrates the capabilities of DFN simulators to analyze the hydraulic behaviour of complex multi-scale fractured reservoirs as the analytical solutions underlying conventional interpretation techniques cannot take into account such a complexity.

Challenges. An early characterization of fault and fracture flow properties is a concern for reservoir engineers as only a few fractures generally contribute to most of the well deliverability. That is, the ‘flow-effective’ fault/fracture network turns out to be very different from the static geological images of those networks. Therefore, as will be underlined...
Setting up a flow-representative field-scale model

The complex DFN models derived from geological information are usable for simulating flow at the well-drainage-area scale but, for obvious computational limitations, cannot be used straightforwardly to simulate multiphase fluid flow at field scale. The field-scale simulation model is necessarily a simplified representation of the actual geology of the fractured medium. The simplification procedure depends on (i) the fracture scale compared to that of model grid cells, (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.

If a quasi-static equilibrium, in terms of fluids saturation, pressure or composition, is established between the different constitutive media at any time and location of the reservoir, then the fractured medium can be represented as a single equivalent medium. Such transfer conditions may be satisfied in some densely-fractured media or in the presence of poorly-differentiated fractures and matrix, or also in single-phase production conditions.

In other situations, the equilibrium between matrix and fractures does not follow any more the evolution of fracture parameters and flow conditions, and both media have to be simulated separately. That is, an homogenized single-medium model with averaged fracture and matrix properties can no more capture the flow features linked to a given medium. The well-known dual-porosity dual-permeability modelling approach, introduced by Barenblatt et al. in 1960, is then adopted assuming that matrix and fracture media behave as two separate ‘continua’ or equivalent media. A simplified option of this model, the dual-porosity single-permeability model, was proposed by Warren and Root (1963). This model assumes that the matrix medium is made up of discontinuous blocks exchanging fluids with the fracture network at any location of the reservoir. Warren and Root also adopted the well-known representation of matrix blocks as sets of identical parallelepipeds in order to formulate matrix-fracture transfers more easily. However, poorly-connected fracture networks and/or a hydraulic continuity of the matrix medium are frequent situations in practice. In those situations, the dual-permeability approach is required and the ideal representation of matrix medium as discontinuous blocks is no more valid at a local scale.

Single- or dual-medium modelling approaches require the determination of upscaled flow parameters of fractures and matrix taken respectively as a unique medium or as separate media. Procedures to perform such an upscaling were not available for field-scale applications until recently. The one we recently implemented (Bourbiaux et al., 1998) for dual-porosity models involves the determination of (i) equivalent fracture permeabilities from single-phase flow computations on the geological DFN at cell scale, (ii) equivalent block dimensions from an image processing technique analogous to a simplified representation of matrix-fracture fluid transfers. The application of such procedures to large full-field models, up to several million cells in size, requires efficient methods to assign equivalent parameter values to each cell. We recently implemented a multi-variable interpolation technique which offers some flexibility in the presence of complex and large fracture models.
In the presence of a multi-scale fault/fracture network, one remaining question concerns the possibility to define an equivalent medium for the multi-scale fault/fracture network. Indeed, the Representative Elementary Scale (REV), beyond which the network behaves like an anisotropic continuum, is generally far above the resolution scale of the flow simulation grid, i.e. cell size. In such a situation, the directionality of flow associated with large-scale conductive objects has to be preserved in the fracture upscaling procedure (Cosentino et al., 2001; Basquet et al., 2004).

Applying the previous procedure to our field example (Figure 6), the fracture/fault geological model was turned into a dual-medium simulation model in three steps. Firstly, the equivalent permeabilities of the diffuse fracture network and the equivalent block dimensions were computed and interpolated over the whole field. Secondly, the cell-to-cell fault transmissivities were determined taking into account their direction with respect to the grid orientation. Finally, fault transmissivity values were converted into equivalent permeability values which were added to those of the diffuse fracture network to constitute the ‘fracture’ grid permeability input of the dual-medium flow model.

Challenges. Lumping the large-scale conductive faults and the small-scale fracture network into a single fracture medium may be responsible for inaccurate flow predictions, especially in the presence of a few major faults responsible for flow bypassing between wells in multiphase displacement processes. For this reason, the future trend in fractured reservoir modelling is the adoption of multi-scale field flow models combining a discrete representation of major objects controlling flows and one or several equivalent media. To be usable at field scale, such flexible models have to provide accurate flow solutions at a minimum computational cost. In that perspective, we recently developed a multi-scale model (Henn et al., 2004) based on (i) the use of segregation concept to simulate flows within faults, thus avoiding the vertical discretization of these thin objects, and (ii) a coupling between faults and the surrounding medium avoiding grid refinement nearby the faults, while keeping a good predictability of the model (Figure 7).

Simulation of multiphase fluid transfers in a multi-medium field model

In many porous fractured reservoirs, the long-term production and recovery are controlled by matrix-fracture transfers which take place in the multiphase conditions resulting from depletion or the implementation of secondary/tertiary methods. Therefore, fractured reservoir simulators have to incorporate reliable formulations and algorithms in order to correctly represent the physics of multiphase transfers between the constitutive media, matrix, fractures, and/or faults. Considered on a general basis, the problem is complex as multiple physical mechanisms can be involved in those transfers, including pressure diffusivity, capillarity, gravity, viscous drive, molecular diffusion, and thermal conduction.

The single-medium approach offers far less flexibility than the dual-medium approach to simulate matrix-fracture transfers. Actually, pseudo-parameters, especially pseudo relative permeabilities (kr), have to be assigned to the cells of the single-porosity model in order to represent both the large-scale fluid transport in the fractures and the local exchanges with the matrix medium. Except in extreme situations (Van Lingen et al., 2001), 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, which will also be a dual-permeability approach if large-scale matrix flows have to be simulated.

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 remains, which concerns the formulation of multiphase matrix-fracture transfers because matrix blocks are generally not discretized in such...
models. Two constraints have to be satisfied, in priority the prediction of the final equilibrium of matrix blocks in terms of pressure, saturation, and composition, and also a satisfactory prediction of the transient states of the matrix block if transfers are delayed compared to the transport phenomena taking place in the fracture medium. Until now, most proposed solutions to simulate multiphase transfers is through the use of modified forms of the Pseudo-Steady-State (PSS) equation that was proposed by Warren and Root (1963) to interpret the wellbores pressures recorded during transient well tests of a fractured reservoir. This equation simply assumes a linear relationship between the overall matrix-fracture flux per unit volume of reservoir. This equation cannot be directly incorporated the equivalent parallelepiped matrix block, the cross-section area of each of the 6 matrix block lateral faces i (i= x-, x+, y- y+, z-, z+) and λi specific phase mobility function.

\[ q = \frac{k_n}{\mu} (p_m - p_f) \]  

where \( k_n \) is the matrix single-phase permeability, \( \mu \) the fluid viscosity and s the well-known shape factor accounting for matrix block dimensions and shape.

Modified forms of this PSS equation involve various shape factor expressions and/or tuned multiphase pseudofunctions however their range of validity remains most often restricted to the reservoir parameters and multiphase flow mechanisms and history under consideration. Actually, multiphase flow situations (Figure 8) involve ‘directional’ mechanisms, gravity forces at first and also viscous drive due to fracture flows in fractured medium with low matrix-to-fracture permeability contrast, which combine their effects with ‘diffusive’ mechanisms, like capillarity, pressure diffusivity, sometimes also molecular diffusion and/or heat conduction. Furthermore, the thermodynamical coupling between phases has to be taken into account in compositional gas-oil processes involving swelling or vaporisation of the matrix oil phase.

Being aware of this complexity, our preferred approach (Quandalle and Sabathier, 1987) implemented in our reservoir simulation software, consists in splitting the matrix-fracture transfer into the contributions of each involved physical mechanism, and assigning them scaling factors.

That is, the matrix-fracture transfer flux of a given phase \( p \) is expressed at cell scale as:

\[ f_p = \frac{\Delta \Phi_{p}}{D_{p}f_{p}} \]  

with \( D_{x},D_{y},D_{z} \) the cell dimensions, \( li \) (lx, ly, lz) the lateral dimensions of the equivalent parallelepiped matrix block, \( Ai \) the cross-section area of each of the 6 matrix block lateral faces i (i= x-, x+, y- y+, z-, z+) and  \( \lambda_{p} \) specific phase mobility function.

It is worth mentioning that this formulation does not require any shape factor input but directly incorporates the equivalent matrix block dimensions determined at cell scale from geological discrete fracture network images. \[ \Delta \Phi_{p} \] represents the potential difference, in phase \( p \) across exchange face i, between fracture and the representative matrix block of the cell:

\[ \Delta \Phi_{p} = \Delta p + C_{cp}p_{pp} + C_{gp}G_{p} + C_{vp}p_{f} \]  

where \( Dp \) is the matrix-fracture pressure difference in a given reference phase and \( Dp_{pp} \) the capillary pressure difference between both media. \( G_{p} \) represents an average value of the gravity head applied on the matrix block and \( dp_{f} \) 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, the scaling factors can be expressed analytically in order to satisfy the vertical equilibrium of fluids at the end of transfer (Sabathier et al., 1998).

Applying our workflow to the field example considered here, a 20-year water injection history was simulated on the field sector shown in Figure 9. For injectivity/productivity purposes, both vertical injection and production wells are completed in the mostly-fractured middle reservoir unit. Note the presence of numerous faults in this field sector, but located at a certain distance from each well. Water saturation maps of the fault/fracture grid after two and 10 years of injection show that the highly-conductive fault system is rapidly invaded by water via the diffuse fracture network. However, diffuse fractures themselves remain at an intermediate water saturation level during several years because of the oil transfer from the matrix medium to fractures that occurs gradually with time.

**Challenges.** Despite recent progress made to simulate complex transfers, in particular multiphase compositional ones (Lacroix et al., 2004), the prediction of matrix-fracture...
The key for integrating the previously-reviewed modelling steps is the capability to gradually alter the poorly-defined properties or the location of geological objects like faults while respecting other well-defined parameters of the geological/geo-statistical model (Hu, 2000).

Conclusions

Thanks to the recent development of integrated and flexible modelling methods and software, an integrated workflow can now be implemented to model naturally-fractured reservoirs, starting with the geological analysis of fractures and ending with the reservoir simulation of multiphase production profiles. The development of hydraulic characterization tools and of reliable upscaling methods based on geological DFN models was a major breakthrough that enabled the effective integration of geosciences and reservoir engineering. The consistency between geological/static observations and flow/dynamic data can thus be preserved.

The implementation of such a workflow takes benefit from all the observations and measurements that are available to assess the presence of fractures and their impact on production. The approach is all the more rewarding as available fracture-related data are abundant, of complementary nature and well distributed over the field. At the same time, the larger the amount of data, the higher the complexity of the data integration and reconciliation process.

Therefore, both the availability of fracture-related information and the capability to integrate diverse data sources remain challenges for a more widespread adoption of integrated workflows in fractured reservoir studies. In that respect, a significant progress is expected in the coming years from:

- additional fault/fracture modelling constraints derived from geomechanical concepts and from 3D/4D seismic surveys designed for fracture characterization;
- an improved reliability of field-scale flow simulators through the proper integration of multi-scale flow heterogeneities by means of mixed models coupling discrete and homogenized representations of geological fault/fracture objects;
- and also, the capability to drive the geological modelling of faults and fractures by efficient flow history matching procedures.

Hopefully, the development of flow-constrained geological modelling techniques in the near future will further reconcile the geoscientist and reservoir engineer representations of fractured reservoirs, and thus reduce prediction models uncertainty for the sake of optimised productivity and reserves.

References


