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Research papers

A new estimation of equivalent matrix block sizes in fractured media with two-phase flow applications in dual porosity models

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ABSTRACT

Single and multiphase flows in fractured porous media at the scale of natural reservoirs are often handled by resorting to homogenized models that avoid the heavy computations associated with a complete discretization of both fractures and matrix blocks. For example, the two overlapping continua (fractures and matrix) of a dual porosity system are coupled by way of fluid flux exchanges that deeply condition flow at the large scale. This characteristic is a key to realistic flow simulations, especially for multiphase flow as capillary forces and contrasts of fluid mobility compete in the extraction of a fluid from a capacitive matrix then conveyed through the fractures. The exchange rate between fractures and matrix is conditioned by the so-called mean matrix block size which can be viewed as the size of a single matrix block neighboring a single fracture within a mesh of a dual porosity model.

We propose a new evaluation of this matrix block size based on the analysis of discrete fracture networks. The fundaments rely upon establishing at the scale of a fractured block the equivalence between the actual fracture network and a Warren and Root network only made of three regularly spaced fracture families parallel to the facets of the fractured block. The resulting matrix block sizes are then compared via geometrical considerations and two-phase flow simulations to the few other available methods. It is shown that the new method is stable in the sense it provides accurate sizes irrespective of the type of fracture network investigated. The method also results in two-phase flow simulations from dual porosity models very close to that from references calculated in finely discretized networks. Finally, calculations of matrix block sizes by this new technique reveal very rapid, which opens the way to cumbersome applications such as preconditioning a dual porosity approach applied to regional fractured reservoirs.

1. Introduction

Conventional oil reservoirs are often housed in fractured rocks, especially in carbonates environments, and one can estimate that more than 30 % of world oil reserves are concealed in densely fractured systems, oil being mainly trapped in the host rock matrix. Paradoxically, these geological structures may trigger contrasted effects on large-scale two-phase flow patterns by increasing oil recovery due to high local permeability values, or on the opposite, by decreasing oil extraction rates because of early water invasion, viscous fingering, etc. The same type of behavior is also encountered in the context of water decontamination and can become even more complex if oil (and/or water) is swept by injections of miscible gas.

Modeling two-phase flow in fractured reservoirs is now often employed for the purpose of various applications, for instance to assess the relevance of different oil recovery strategies or to investigate on the feasibility of in-situ water decontamination processes (Bourbiaux, 2010). This fact makes that modeling single phase or multiphase flow in fractured media is still a fertile research domain even though pioneering works on the topic started in the early sixties (e.g., in Lemonnier et al., 2010a,b).

In this context, flow simulations relying upon finely gridded discrete fracture networks and their associated (discretized) matrix blocks are becoming increasingly popular because of the availability of high performance computers, the progress in algorithms for meshing complex geometries, and the availability of sophisticated numerical techniques for solving partial differential equations (Landereau et al., 2001; Noetinger et al., 2001; Adler et al., 2005; Matthai and Nick, 2009; Fourno et al., 2013). This exhaustive approach is critical to bring us reference solutions and various benchmarks with which simpler approaches can be

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compared. Nevertheless, gridded discrete fracture networks may be poorly documented and include flawed information in the case of real-world applications. In addition, finely gridded systems remain hardly usable for current practical applications to large-scale systems that result in cumbersome model parameterizations and heavy computations. This downside is emphasized in the domain of petroleum engineering usually dealing with both non-linear multiphase flow and dense fracture networks requiring huge discretization efforts (Landereau et al., 2001; Adler et al., 2005; Fourno et al., 2013). Applicability is also hindered by duplicated calculations if the study encompasses tests of various model designs, various model parameterization and various flow scenarios.

Fortunately, dense fracture networks are also good candidates to homogenization at the scale of reasonable elementary mesh sizes (on the order of 5–100 m) by resorting for example to the dual porosity approach to fractured media initially developed by Barenblatt et al. (1960). The dual porosity formulation conceptualizes a fractured system as two overlapping continua merging a fracture medium and a matrix medium with contrasts of hydraulic properties between the two continua. Flow is then described by a set of equations in each continuum (this set depends on the type of flow and the fluid phases present in the system) associated with an exchange term ruling the fluid fluxes percolating between continua.

This exchange term is all the more important that in general fractures are conveying flow as the matrix stores fluid volumes. In transient problems as for example forced flow between injecting and extracting wells, the way the relationship establishes between storage capacity and conduction property conditions the overall response of the reservoir (e.g., Acuna and Yortsos, 1995). In the specific cases of two-phase flow (water and oil), the absence or the weak incidence of capillary forces in open fractures makes that flow is locally mainly of single-phase type conveying either oil or water (with sharp saturation fronts in between) at different locations in the fracture network. For its part, the way the matrix blocks are soaked (water invades the matrix and pushes oil away) or drained (oil pushes water) strongly depends on matrix block sizes and on the petro-physics properties of the matrix, making that extraction from the matrix of a fluid by the other is mainly driven by capillary forces or by capillary forces plus viscous forces (single-phase Darcian flow to make it simple).

When a discrete fracture network is connected enough and handled at an elementary scale larger than a representative elementary volume, the exchange term in the dual porosity models is proportional to an equivalent matrix block size. Intuitively, a REV for a fracture network is a volume within which mean properties of the network such as fracture density, fracture aperture, fracture hydraulic conductivity have some statistical meaning (Long et al., 1982; Neuman, 1988). In a dual porosity model, the REV is also associated with the capability to represent the actual fracture network as a synthetic network made (in three-dimensional problems) of three regularly spaced fracture families, each family developing fracture planes normal to one of the three main directions of flow. The so-called DFN homogenized as a "sugar-cube" model (Warren and Root, 1963) is at the origin of the notion of the equivalent matrix block size in relation with the dimensions of the elementary "sugar piece" separating neighbor fractures in the homogenized DFN (Kazemi et al., 1976).

There exist two types of methods to evaluate the elementary matrix block size. The first type relies upon exercises matching actual well test drawdown curves with analytical solutions that inherit from rigorous mathematical homogenization or large-scale averaging techniques (Arbogast, 1990; Quintard and Whitaker, 1993; Noetinger et al., 2001; Unsal et al., 2010; Noetinger and Jarrige, 2012). The downside of these techniques is that sometimes actual well testing in fractured rock do not exist and when these tests exist, the damaged zone in the close vicinity of a well may not fully reflect flow conditions in the natural fracture network. The second type of methods is based on geometrical considerations regarding the fracture network. These considerations led to three geometrical approaches that are the geometrical imbibition method (GI, Bourbiaux et al., 1997), the enhanced general imbibition method (EGI, Bourbiaux et al., 2006), and the mean spacing method (MS, Narr, 1996). These approaches can only be applied if a minimum prior knowledge about the fracture network geometry is available.

In this contribution we propose a new geometrical method that can to some extent overlook the actual geometry of the fracture network because the method relies upon the identification of a sugar-cube DFN equivalent to the actual network (see details hereafter). The method also allows us to calculate matrix block sizes along directions parallel to the main flow directions that are conditioned by the geometry of the fracture network (or its equivalent as a sugar-cube model). Section 2 (and Appendix A) is focused on the theoretical framework we rely upon to build the so-called oriented block size (OBS) method that we propose. For the sake of clarity, a few features about dual-porosity models are also reminded. The matrix block sizes stemming from the OBS technique are then compared to that from the other geometrical techniques (GI, EGI, and MS, see above). The comparison is performed by way of a suite of calculations applied to synthetic random fracture networks for which we explicitly control both the geometric and hydraulic properties of the networks and the mean size of matrix blocks between fractures. As told earlier, only dense and well-connected fracture networks are considered because sparse networks cannot be homogenized via a dual porosity model at the scale of a complete underground reservoir. Section 4 evaluates the OBS technique and also the other geometrical approaches within the framework of dual-porosity models compared with exhaustive calculations discretizing the fracture network and the matrix blocks. The two-phase flow scenarios are either dominated by capillary forces or viscous forces in an exercise which consists in draining oil from matrix blocks by injecting water in fractures. These complex flow scenarios are performed over synthetic test cases in which we control the reference calculations (in a fully discretized system). This procedure enable us to clearly emphasizes the main theoretical findings regarding matrix block size in dual porosity models before envisioning further concrete field-scale applications.

2. Theoretical background

In various approaches to fractured systems, the duality of fracture networks embedded in a host rock matrix is often represented as two overlapping continua merging a fracture medium and a matrix medium. In a so-called dual porosity – single permeability model, the fractures are usually highly conductive and poorly capacitive as the matrix is highly capacitive but with small to negligible flow triggered by fluid pressure gradients (weak permeability). As an example, single-phase Darcian flow in a dual continuum approach results in the resolution of two equations in the form

$$\frac{\partial(\rho\phi^f)}{\partial t} + \nabla\cdot\left(-\rho\frac{\mathbf{k}^f}{\mu}\cdot\nabla(P^f+\rho gz)\right) - E^{m\to f} = 0 \tag{1}$$

$$\frac{\partial(\rho\phi^m)}{\partial t} + E_p^{m\to f} = 0; \quad E_p^{m\to f} = \rho\boldsymbol{\sigma}\frac{\mathbf{k}^m}{\mu}(P^m - P^f) \tag{2}$$

For the sake of simplicity, references to space ($\mathbf{x}$) and time (t) for parameters and state variables have been dropped. The indexes f and m refer to fracture and matrix continua, respectively. ρ