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Characteristic fracture spacing in primary and secondary recovery for naturally fractured reservoirs

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ABSTRACT

If the aperture distribution is broad enough in a naturally fractured reservoir, even one where the fracture network is highly inter-connected, most fractures can be eliminated without significantly affecting the flow through the fracture network. During a waterflood or enhanced-oil-recovery (EOR) process, the production of oil depends on the supply of injected water or EOR agent. This suggests that the characteristic fracture spacing (or shape factor) for the dual-porosity/dual-permeability simulation of waterflood or EOR in a naturally fractured reservoir should account not for all fractures but only the relatively small number of fractures carrying almost all the injected water or EOR agent ("primary," as opposed to "secondary," fractures). In contrast, in primary production even a relatively small fracture represents an effective path for oil to flow to a production well. This distinction suggests that the "shape factor" in dual-permeability reservoir simulations and the repeating unit in homogenization should depend on the process involved: specifically, it should be different for primary and secondary or tertiary recovery. We test this hypothesis in a simple representation of a fractured region with a non-uniform distribution of fracture flow conductivities. We compare oil production, flow patterns in the matrix, and the pattern of oil recovery with and without the "secondary" fractures that carry only a small portion of injected fluid.

The role of secondary fractures depends on a dimensionless ratio of characteristic times for matrix and fracture flow (Peclet number), and the ratio of flow carried by the different fractures. In primary production, for a large Peclet number, treating all the fractures equally is a better approximation of the original model, than excluding the secondary fractures; the shape factor should reflect both the primary and the secondary fractures. For a sufficiently small Peclet number, it is more accurate to exclude the secondary fractures in calculation of the shape factor in the dual-porosity/dual-permeability models than to include them and, in effect, assume they play an equally important role in transport to and from the matrix. For waterflood or EOR, in most cases examined, the appropriate shape factor or the repeating-unit size should reflect both the primary and secondary fractures. If the secondary fractures are much narrower than the primary fractures, then it is more accurate to exclude them for calculating the shape factor in a dual-porosity/dual-permeability model. Yet-narrower "tertiary fractures" are not always helpful for oil production, even if they are more permeable than matrix. They can behave as capillary barriers to imbibition, reduce oil recovery.

We present a new definition of Peclet number for primary and secondary production in fractured reservoirs that provides a more accurate predictor of the dominant recovery mechanism in fractured reservoirs than the previously published definition.

1. Introduction

A significant amount of hydrocarbon reserves across the world resides in naturally fractured reservoirs [1]. Accurate simulation of oil recovery is required for the efficient exploitation of these naturally fractured reservoirs. However, because of the complexity and limited information regarding the sub-surface fracture networks, field-scale reservoir simulation requires simplified description of reservoir conditions.

If the fracture network is well-connected, this is often done with a dual-porosity or dual-permeability (DP/DK) simulation. In the DP/DK concept, the fracture and matrix systems are treated as separate domains; the interconnected fractures serve as fluid-flow paths between injection and production wells, while the matrix provides fluid storage

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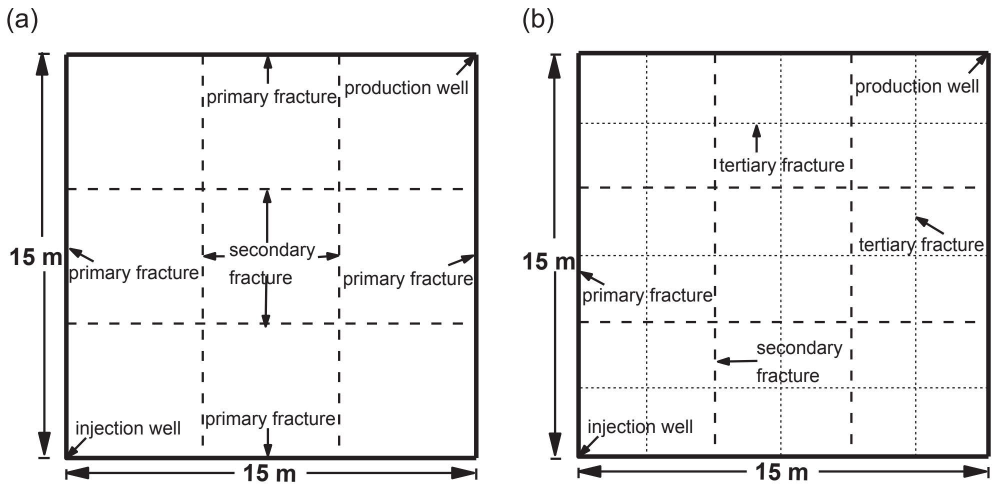

Fig. 1. Schematic of the region of study. The fractured region (unit cell) studied is 15 m × 15 m, with the injection and production wells placed at the bottom-left and the top-right corners, respectively. The injection well and production well are directly connected to the primary fractures without contacting the matrix block. (a) The region is bounded by the primary fractures, and penetrated by the secondary fractures. The number of the secondary fractures varies in different cases. In the case shown, $R_n = 1/3$. (b) Tertiary fractures are included in some cases. As in the cases examined below, there are as many tertiary fractures as primary and secondary fractures combined.

Table 1
Summary of petrophysical properties assumed in this study.

Parameter	Units	Value
Matrix porosity	fraction	0.2
Fracture porosity	fraction	1
Oil viscosity	Pa·s	0.0015
Water viscosity	Pa·s	0.00105
Oil density	kg/m^3	835
Water density	kg/m^3	999

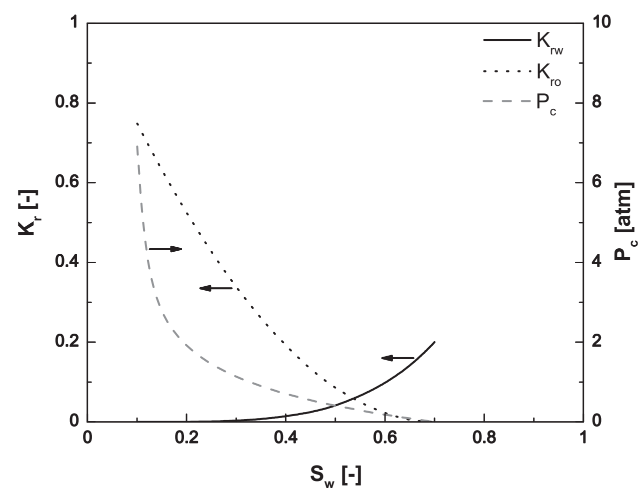

Fig. 2. The relative-permeability and capillary-pressure functions for the matrix blocks used in all the cases in this study.

for nearby fractures. Limited fluid flow between matrix blocks is allowed in dual-permeability models [2,3]. The interaction between the fracture network and matrix is represented by an exchange function which is characterized by a shape factor [4–6]. During the last few decades, discrete-fracture models (DFMs) have attracted increasing research interest. In these models, the fracture geometry and complex flow patterns in fracture networks are simulated more accurately [7–12]. However, DFMs are typically computationally too expensive for field-scale reservoir simulations. Also, even if detailed geological information is provided, it is difficult to predict the flow pattern through the fracture networks; some simplification is needed. Thus, although the DP/DK models are much-simplified characterizations of naturally fractured reservoirs, for the reservoirs with many fractures and a very high degree of interconnection, they are still more feasible than the DFM methods. To generate a DP/DK model, it is necessary to define average properties for each grid block, such as porosity, permeability and matrix-fracture interaction parameters (typical spacing or shape factor) [13]. Therefore, the discrete fracture network considered to generate the DP/DK model parameters is crucial. If homogenization is applied, the matrix-fracture exchange can be treated more accurately than in the DP/DK simulations [14], but, again, one needs a characteristic matrix-block size. However, if the fracture network shows non-uniform flow, then characterizing the fracture spacing or shape factor can be ambiguous.

As we presented in a previous study [15], even in a well-connected fracture network, there is a dominant sub-network which carries almost all the flow, but it is much sparser than the original network. In this study we refer to the fractures in the dominant sub-network as “primary” fractures, and the remaining fractures as “secondary” fractures. The primary fractures tend to be wider, but they are not necessarily the widest, longest or most highly connected fractures in the network [15]. The flow-path length of the dominant sub-network can be as little as 30% of that of the corresponding original fracture network. This suggests that in secondary production or enhanced oil recovery (EOR), the injected water or EOR agent flows mainly along a small portion of the fracture network. In contrast, in primary production even relatively small fractures can be an efficient path for oil to flow to a production well.

In fractured reservoirs, oil is produced by different recovery mechanisms. During primary production, oil is mainly recovered by fluid expansion. In secondary production, spontaneous imbibition is the dominant recovery mechanism in water-wet reservoirs. In primary recovery, production depends only on a path to the well, whereas in secondary recovery or EOR, it depends on the injected agent reaching the matrix. This difference suggests that the relevant fracture spacing should be different for primary recovery and for waterflood or EOR [16].

The purpose of this study is to show the implications of non-uniform flow for the definition of the shape factor or characteristic fracture spacing in a dual-porosity/dual-permeability simulation of primary

Table 2
Values of parameters in Eqs. (1) and (2) adopted in this study.

Parameter	Units	Value
n_o	–	2
n_w	–	4
k_{ro}^{o}	–	0.75
k_{rw}^{o}	–	0.2
B	Pa	1.01×10^5