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# An efficient method for fractured shale reservoir history matching: The embedded discrete fracture multi-continuum approach

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ABSTRACT

In this study, we established a more efficient approach for fractured shale reservoir modeling with an emphasis on simplifying and automating the workflow for assisted history matching and uncertainty quantification. The improvement is especially notable for the process of history matching since the fracture geometry and properties can be directly set as parameters to be history matched. The resultant approach not only shows a significant reduction in the computational time while maintaining model accuracy, but also provides an automatic method for modifying the fracture related parameters - a laborious process in the traditional workflow.

In the forward reservoir model, we implemented and extended the Embedded Discrete Fracture Model (Embedded DFM) approach for fractures with arbitrary strike and dip angle to a multiple porosity/permeability setting. The fractures are naturally discretized by the boundary of parent matrix grid blocks. Control volumes of fracture segments are generated according to the specific geometry of each of the segments. Three types of non-neighbor connections are then generated, namely the connection between the fracture segment and its parent matrix grid blocks, the connection between two intersecting fracture segments from different fractures, and the connection between two neighbor fracture segments from the same fracture. For each of the non-neighbor connections, transmissibility can be calculated honoring the physics of the flow.

In our approach with Embedded Discrete Fracture Multiple-Porosity Model, the matrix is sub-divided into three porosity types, namely organic matrix (kerogen), inorganic matrix and natural fractures, with the necessary physics included for each of the porosity types. The macro fractures are explicitly represented with Embedded DFM. The proposed model provides a coherent method for characterizing the organic matrix, inorganic matrix, micro fractures as well as the hydraulic fractures of shale reservoirs. It offers a computationally efficient approach for modeling the severe heterogeneity due to hydraulic and natural fractures. Compared with traditional discrete fracture models, fewer grid blocks and lower levels of refinement are required. Compared with multiple porosity method, the proposed model has desirable accuracy for the simulation of reservoirs with large scale fractures.

In the history matching and uncertainty quantification stage, due to the low efficiency of traditional Markov Chain Monte Carlo (MCMC) method when applied to reservoir history matching, a more advanced algorithm of two-stage MCMC is employed to evaluate the uncertainty for all the parameters. Since no upscaling of the fracture related parameters is required, the reservoir model can be generated by a pre-processor based on the proposed parameter, which maintains the adequacy of a Gaussian distribution assumption. Therefore, the workflow can be completely automated. By incorporating Embedded DFM and multiple porosity/permeability approaches, the improved model facilitates the history matching of fractured shale reservoirs by cutting the total amount of grid blocks, reducing the complexity of the gridding process, as well as improving the accuracy of fluid transportation within and among different porosity types.

## 1. Introduction

Hydraulic and natural fractures play a major role in controlling the fluid transportation within shale reservoirs, therefore, it is essential to understand the distribution and properties of these fractures in order to accurately model the production dynamics of shale reservoirs.

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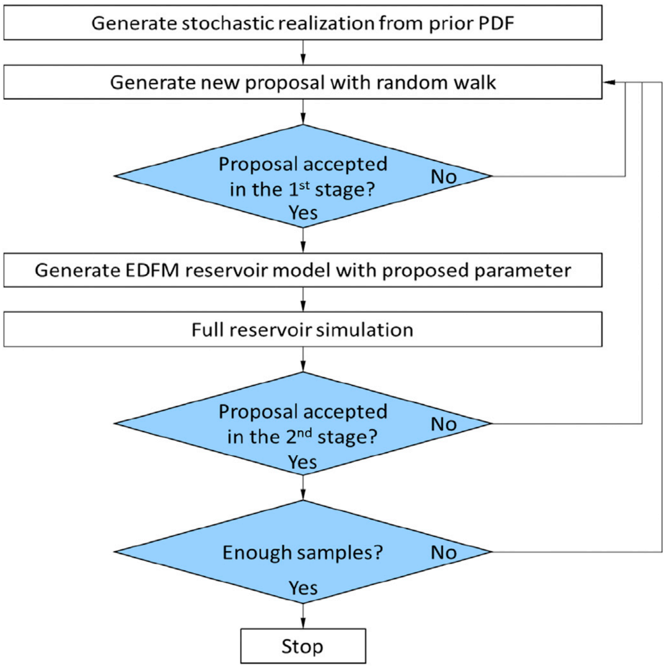


**Fig. 1.** Flowchart of history matching and uncertainty quantification of fractured shale reservoirs with Embedded DFM model.

Production data provides invaluable information, based on which the quality of the reservoir model can be improved. However in many cases, due to the limitation of the model assumptions, the well data couldn't be utilized adequately to quantify the property of the fracture networks.

Over the past few decades different models were established to simulate fractured reservoirs. One of the earliest methods is the classic dual porosity model introduced by Warren and Root (1963), and the model was recently extended to multiple porosity model by Yan et al. (2013) and Hinkley et al. (2013) to account for more complex porosity types in shale reservoirs. This type of model provides an efficient approach to simulate micro scale fractures, but is limited in its capability to model large scale fractures and the corresponding severe heterogeneity.

An alternative approach is to discretize the fractures explicitly. Sarda et al. (2002) proposed a 2-D discretization scheme for fractured reservoirs which would greatly reduce the total number of grid blocks. This approach does not require fine gridding near the fractures, but the domain can only be discretized when fractures are intersecting with each other, and the procedure could be very complicated when extended to 3-D cases. Karimi-Fard et al. (2004) proposed a discrete fracture model with unstructured gridding to explicitly represent the fractures and employed two point flux approximation to account for the mass transfer between grid blocks. Sandve et al. (2012) extended the method from two point flux approximation to multiple point approximation and obtained improved accuracy. Sun and Schechter (2015) employed the perpendicular bisector (PEBI) grid scheme with variable fracture properties and studied their influence on shale well production. For these type of models, multiple point flux is usually needed in order to obtain better accuracy, and the gridding process can be much more complicated for 3-D cases.

Another approach is to use traditional Cartesian gridding for the matrix, while the fractures are explicitly included in the model and discretized by the boundary of the matrix grid blocks. The concept is first proposed by Lee et al. (2000). The fracture segment within each of the grid blocks is represented by a control volume and is connected to the parent matrix grid blocks and other fracture grid blocks with non-neighbor connections. This concept was implemented by Li and Lee (2008) to vertical fracture cases for simplicity. Moinfar et al. (2014) extended the implementation to a more general case of non-vertical fractures, in which the fracture can have arbitrary dip and strike angles.

On the other hand, the history matching of fractured shale reservoirs is also proved to be challenging due to the high computational cost and the difficulty to represent the fracture system. Gang and Kelkar (2006) proposed a formulation to upscale the permeability of natural fractures to a dual porosity model for history matching. Nejadi et al. (2014) took a similar approach of upscaling a DFN model to dual porosity model and applied the EnKF algorithm. However different upscaling approaches may lead to very different dual porosity models that would affect the result of the history matching, as Ahmed Elfeel et al. (2013) discussed in their work. Lu and Zhang (2015) introduced a new parameterization method to deal with the non-Gaussian distribution of the properties for fractured reservoirs, but the model is based on a single porosity model in which fracture properties are upscaled to Cartesian grid blocks.

In this paper, we incorporate the multi-continuum model and the Embedded DFM model for shale reservoirs, which enables us to characterize properly different porosity types within the reservoir, namely the kerogen part of the matrix, the inorganic part of the matrix, micro fractures and macro fractures. The model maintains a high accuracy compared to discrete fracture models, while greatly reducing the number of grid blocks and computational cost, and the improved model makes it possible to quantify uncertainties of fractured shale reservoirs by reducing the time of a single run, as well as simplifying the gridding process. We then incorporate the MCMC approach to the history matching process for uncertainty quantification. In order to avoid the low accept ratio of MCMC, we modified and implemented the approach of two-stage MCMC, first introduced by Ma et al. (2008), which would greatly increase the accept ratio of the proposed sample for simulation therefore reduce the time for sampling.

The flowchart for the history matching process in this work is shown in Fig. 1. A stochastic sample is generated from the prior PDF as the starting point of the MCMC chain. In the first stage of the MCMC sampling, a proxy model is used to estimate the posterior probability of the proposal, and the proposal is either accepted or rejected based on the Metropolis-Hastings criterion. Only the proposals that are accepted in the first stage would generate the reservoir model and run the full simulation. In the second stage the proposal is either accepted or rejected based on the same Metropolis-Hastings criterion, the only difference is that the posterior probability is calculated with the actual simulation result.

The organization of this paper is as follows. First the background and methodology of multiple porosity models and Embedded DFM are discussed, then the approach of history matching and uncertainty quantification is introduced, after which the workflow is illustrated by a simple example case, and finally conclusions are drawn based on the history matching results.

## 2. Methodology

### 2.1. Multiple porosity modeling

In this paper, we implemented the multiple porosity model proposed by Yan et al. (2013) and Hinkley et al. (2013), in which there can be 3 or more porosity types and mass transfer can take place between any two different porosity types and within any single porosity type. The new model is a multiple porosity multiple permeability model, in which the Darcy flux term for inter-porosity mass transfer can be expressed as:

$$q_i = T_{mn}\left[\lambda_{ro}\tilde{\rho}_o x_i(\Phi_{no} - \Phi_{mo}) + \lambda_{rg}\tilde{\rho}_g y_i\left(\Phi_{ng} - \Phi_{mg}\right)\right] \tag{1}$$

$$T_{mn} = \overline{k}_{mn}\sigma\Delta x\Delta y\Delta z \tag{2}$$

$$\overline{k}_{mn} = \frac{1}{3}\left(\frac{k_{mx}k_{nx}}{k_{mx}+k_{nx}} + \frac{k_{my}k_{ny}}{k_{my}+k_{ny}} + \frac{k_{mz}k_{nz}}{k_{mz}+k_{nz}}\right) \tag{3}$$