Journal of Petroleum Science and Engineering 167 (2018) 486–497

Contents lists available at ScienceDirect

Journal of Petroleum Science and Engineering

journal homepage: www.elsevier.com/locate/petrol

Application of proxy-based MCMC and EDFM to history match a shale gas condensate well

Silpakorn Dachanuwattana[a], Zhaohui Xia[b], Wei Yu[c,*], Liangchao Qu[b], Ping Wang[b], Wendi Liu[a], Jijun Miao[c,d], Kamy Sepehrnoori[a]

[a] Department of Petroleum and Geosystems Engineering, The University of Texas at Austin, Austin, TX, USA
[b] Research Institute of Petroleum Exploration & Development, Beijing, China
[c] Department of Petroleum Engineering, Texas A&M University, College Station, TX, USA
[d] SimTech LLC, Katy, TX, USA

ARTICLE INFO

Keywords:
Assisted history matching
Shale gas
Embedded discrete fracture model
Markov chain monte carlo
Uncertainty quantification

ABSTRACT

History matching is an important process for uncertainty quantification of reservoir performance. Hundreds of reservoir simulation cases, or more, are typically required to sample the posterior probability density function of the uncertain parameters. The process is extremely challenging for shale reservoirs due to large uncertainties including reservoir heterogeneity, wide range of permeability, gas desorption, and fracture properties. Direct application of stimulated rock volume or dual continuum model fails to capture fracture connectivity and fracture conductivity that dominate the fluid transport in most shale developments. Embedding discrete fractures in reservoir simulation model is thus a preferable method to attain more realistic reservoir behavior. However, the option of using local grid refinement to embed the fractures is computationally expensive as well as intrusive to a reservoir model. Even more challenging is generating a huge set of fracture-embedded reservoir cases during the history matching process. Nevertheless, recent developments in a methodology called Embedded Discrete Fracture Model (EDFM) have successfully overcome the computational complexity to include discrete fractures in reservoir simulations. We demonstrate the implementation of the assisted history matching workflow coupled with EDFM to history match a real field case of shale gas condensate reservoir in Duvernay Shale, Canada. In the workflow, the EDFM preprocessor is fully coupled with a commercial reservoir simulator and proxy-based Markov chain Monte Carlo (MCMC) algorithm. Moreover, to further reduce the computational cost, the single-fractured submodel is used to represent the full reservoir model for this case study. Using the proposed assisted history matching workflow and the appropriate submodel enables efficient and successful uncertainty quantification of this shale play.

1. Introduction

Uncertainty inherently exists in reservoir simulation models due to several inevitable factors such as sparse sampling of information, reservoir heterogeneity, or measurement error. History matching is thus the critical process for quality decision making based on reservoir simulation. To conduct the process, uncertain parameters in reservoir model must be conditioned to available known data. History matching process is considered as an inverse problem widely known to have multiple solutions. For uncertainty quantification, not only one solution but these multiple solutions with the correct distribution, in other words, the whole posterior probability density (PPD) function, are required.

History matching in shale reservoirs poses several unique challenges compared to that in conventional reservoirs. Ultra-low permeability of shale formation causes slow depth of investigation during the transient flow. As a result, the majority of a shale reservoir could remain uninvestigated even after a couple years of production. In addition, fractures, which are primary flow conduit in most shale developments, generally have uncertain geometries and properties since the current fracture diagnostic technologies, such as microseismic, could not measure these features at high resolution. Shakiba and Sepehrnoori (2015) demonstrated that adding only a few fractures into a fracture system influences the fracture connectivity and substantially affects the production performance of a shale well.

The progress in history matching of unconventional reservoirs has increasingly gained wider attention from researchers. Wide spectrums of methodologies have been conducted ranging from relatively simple

* Corresponding author.
E-mail address: yuwei127@gmail.com (W. Yu).

https://doi.org/10.1016/j.petrol.2018.04.025
Received 25 December 2017; Received in revised form 11 April 2018; Accepted 12 April 2018
Available online 16 April 2018

analytical solutions to complex numerical simulations. The history matching schemes span over extensive breadth of sampling algorithms including gradient-based optimization, Ensemble Kalman Filter (EnKF), and Bayesian methods. Ogunyomi et al. (2016) developed a new linear dual porosity analytical solution and used the solution to history match unconventional condensate reservoirs. Samandarli et al. (2011) used the analytical and semi-analytical solutions to history match fracture permeability, matrix permeability, and fracture half-length in Barnett shale gas wells. Clarkson et al. (2014) demonstrated the application of an analytical solution to history match a multi-fractured horizontal well in a liquid-rich resource. Analytical or semi-analytical solutions are quick history matching approaches but their applications are limited due to their specific assumptions, which are too simplified to apply in real-world complex reservoirs.

Numerical simulations have been widely implemented for assisted history matching (AHM) in unconventional reservoirs. Gang and Kelkar (2008) used the adjoint method to history match by adjusting fracture permeability and capillary pressure curves. Yin et al. (2011) used the proxy-based genetic algorithm (GA) to history match a synthetic shale gas well. In addition to the production data, SRV was used in their history matching as an additional constraint to reduce the uncertainty of the tuning parameters. Nejadi et al. (2015) applied EnKF, discrete-fracture-network (DFN) model, and an upscaling technique to history match a shale-gas horizontal well in the Horn River resource play, Canada. However, the method is compromised for sparsely-distributed fracture system since the fracture size and connectivity are neglected in the assumption. Zhang and Fassihi (2013) performed history matching a hydraulically-fractured shale-condensate well in Eagle Ford using the proxy-based genetic algorithm and the fracture model using local grid refinement (LGR). Yang et al. (2015) implemented proxy-based acceptance rejection algorithm and the LGR model to history match a shale condensate well in Eagle Ford. Wantawin et al. (2017) used iterative response surface methodology (RSM) with high-order polynomial proxy and LGR to history match a Marcellsus shale gas well. However, the application of LGR is computationally expensive and intrusive to a reservoir model, especially when the local grids representing the fracture are not orthogonal to the coarse grid of the reservoir matrix, more discussion can be found in the work by Xu et al. (2017).

Recent developments in a method called EDFM (Moinfar et al., 2014; Cavalcante Filho et al., 2015; Shakiba and Sepehrnoori, 2015; Zuloaga-Molero et al., 2016; Xu et al., 2017; Zhang et al., 2017) have overcome the computational complexity to model discrete fractures in reservoir simulations. As demonstrated by the work of Xu et al. (2017), EDFM offers several advantages including high computational efficiency, non-intrusiveness to the reservoir model, and accuracy comparable to LGR method. Cavalcante Filho et al. (2015) used EDFM and Simplex optimization algorithm (Nelder and Mead, 1965) to perform history matching of gas and water rate of a fishbone pilot well in the Austin Chalk formation. Although multiple solutions were found by Simplex, the solutions were not correctly distributed since the optimization algorithm is not designed for uncertainty quantification.

One sampling technique capable of constructing the correct PPD is the proxy-based MCMC algorithm. The algorithm is an extension of MCMC but takes advantage of using proxy model to replace computationally expensive reservoir simulation. The proxy-based MCMC has been applied in many AHM workflows (Eide et al., 1994; Slotte and Smorgrav, 2008; Goodwin, 2015). Although the workflow proposed by each researcher shares several similarities, the workflow may be different in details, including specific class of MCMC used, type of proxy, and termination criteria.

In this study, we extend the application of EDFM for assisted history matching by coupling the EDFM preprocessor with the proxy-based MCMC algorithm. The cases study is real field case of a shale gas condensate reservoir with compositional fluid model. The structure of this paper will proceed as follows. Firstly, the brief introduction of EDFM is explained and then the description of the field case is provided. In the next section, we demonstrate the advantage of using single fracture submodel to represent the multiple fracture model in this study. Finally, the AHM workflow is applied on the representative submodel to perform history matching and the key findings are concluded at the end.

2. Embedded discrete fracture model (EDFM)

EDFM is an efficient method for modelling discrete fractures in reservoir simulation. In this method, each fracture plane is discretized by matrix cell boundaries then the influence of the fracture is explicitly calculated as the transmissibility factor. To account for the transmissibility factor, EDFM automatically generates virtual grids to the appending to the original matrix grids, then assign the non-neighboring connections (NNC) between these virtual grids and matrix grids. Four types of transmissibility factors are possible including the flows between (1) matrix-fracture, (2) fracture segment-fracture segment in a single fracture, (3) fracture segment-fracture segment of two different fractures, and (4) well-fracture. Since the insertion of fracture using EDFM is not intrusive for the original reservoir model and also does not require LGR, the method is more efficient than the unstructured grid technique. The other most common method to handle fracture is the continuum approach including dual-porosity or dual-permeability model. The approach assumes uniformly distributed fractures and upscales the fracture domain. The assumption is practically applicable in several cases. However, unlike discrete fracture modelling such as EDFM, this simplification of the fracture domain, is not adequate to model complex fractures that can be non-uniform or irregularly spaced.

The detailed calculation of the NNC transmissibility factors can be found in Xu et al. (2017). In short, the calculation is mainly based on two-point flux approximation governed by Eq. (1). The EDFM only calculates the phase-independent part of the transmissibility whereas the relative mobility is calculated by the reservoir simulator.

$$q_l = \lambda_l T_{NNC} \Delta P, \tag{1}$$

where q_l is the volume flow rate of phase l, λ_l is the relative mobility of phase l , $T_{NNC}$is the NNC transmissibility factor, and ΔP is the potential difference between two points.

For the matrix-fracture connection, Eq. (2) is used to calculate the NNC transmissibility.

$$T_{NNC} = \frac{k_{NNC} A_{NNC}}{d_{NNC}}, \tag{2}$$

where $T_{NNC}$is the transmissibility, k_{NNC} is the matrix permeability in the direction normal to the fracture plane, A_{NNC} is the contact area of the plane inside the matrix block, and d_{NNC} is the average normal distance from matrix block to fracture plane.

For the fracture segment-fracture segment connection, T_{NNC} is the harmonic average between the transmissibility factors of the two segments. The formulation for calculating transmissibility of the fracture segment also depends on whether the two segments belong to an individual fracture or belong to two different fractures.

For the well-fracture intersection, the effective well index is calculated and assigned to the intersection. The formulation used for the well index calculation is Peaceman (1983) equation, as shown in Eq. (3).

$$WI_f = \frac{2\pi k_f w_f}{\ln\left(\frac{r_e}{r_w}\right)},\ r_e = 0.14\sqrt{L_S^2 + H_S^2}, \tag{3}$$

where WI_f is the well index representing well-fracture intersection, k_f is the fracture permeability, w_f is the fracture aperture, L_s is the length of the fracture segment, H_s is the height of the fracture segment, r_e is the effective radius, and r_w is the wellbore radius.

According to in Xu et al. (2017), the accuracy of EDFM have been verified with LGR and a semi-analytical solution. Also, application of EDFM has been demonstrated in both 2D and 3D cases, and for both