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Full Length Article

Application of proxy-based MCMC and EDFM to history match a Vaca Muerta shale oil well

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ABSTRACT

Embedding complex discrete fractures in reservoir simulation is required to attain more realistic flow behavior of shale reservoirs. However, using local grid refinement to model discrete fractures is computationally expensive. Nevertheless, recent developments in a methodology called Embedded Discrete Fracture Model (EDFM) have overcome the computational complexity. In this study, we develop an efficient assisted history matching (AHM) workflow using proxy-based Markov chain Monte Carlo algorithm and integrating with the EDFM preprocessor. The workflow can automatically perform history matching, production forecasting and uncertainty quantification. It has been successfully applied on a shale oil well in Vaca Muerta formation.

1. Introduction

Vaca Muerta (VM) is a world-class organic rich shale formation in Neuqen Basin, Argentina. The area of the formation approximately covers 7.4 million acres and the reserve is estimated to be 308 Tcf of gas and 16 billion bbl of oil [32]. The development of VM has been in early stage where the first wells were drilled and completed in 2013 [8]. Several operators are committed to billions of dollars investment to explore and produce from the shale play.

Uncertainty quantification is a key process for economic success of reservoir development but history matching of shale plays is a very challenging task. The complexity of shale reservoirs includes uncertain fracture patterns, complex geomechanics properties, and fluid transport mechanisms in nanopores. Data availability is another challenging issue, especially when numerous wells are drilled during the early development stage but the data availability is limited. Different techniques have been implemented to history match unconventional oil and gas reservoirs. Samandarli et al. [15] used both analytical and semi-analytical solutions to history match Barnett shale-gas wells through tuning fracture permeability, matrix permeability, and fracture half-length. Herroro et al. [7] used rate transient analysis and analytical solution to history match Vaca Muerta shale-oil wells by modifying fracture half-length, fracture conductivity, and effective permeability. Clarkson et al. [5] demonstrated the application of an analytical solution to history match multi-fractured horizontal wells in liquid-rich resources. Although analytical or semi-analytical solutions are quick AHM approaches, their assumptions are overly-simplified, thus prohibiting their applications in realistic and complicated shale reservoirs.

Fracture geometry and connectivity are critical to production performance in shale play. According to Warpinski et al. [22], ultra-low shale permeability requires a complex fracture network with a relatively small spacing between fractures to achieve reasonable recovery factor. Shakiba et al. [16,17] analyzed the impact of fracture network on a synthetic tight gas well. The work demonstrates that adding only a few fractures into the fracture system greatly influences the fracture connectivity and significantly affects the well productivity. To attain realistic behaviors of reservoirs with complex fractures, discrete fractures modelling is required in reservoir simulation. Nejadi et al. [12] used ensemble Kalman filter (EnKF) to history match a shale-gas horizontal well in the Horn River resource play, Canada. Their workflow applied discrete-fracture-network (DFN) model before upscaling to dual porosity model for reservoir simulation. The upscaling method was the Oda's analytical approach [13] that is practical for highly-connected fracture network. Nevertheless, the method is compromised for sparsely-distributed fracture system since the fracture size and connectivity are neglected in the assumption.

Zhang and Fassihi [33] performed history matching a hydraulically-fractured shale-oil well in Eagle Ford. The fracture geometry was

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Nomenclature

AHM	assisted history matching
BHP	Bottomhole pressure, psi
DFN	discrete fracture network
DOE	design of experiment
E	actual RMSE, calculated by reservoir simulation
$\hat{E}$	proxy RMSE, calculated by proxy function
EnKF	ensemble Kalman filter
EDFM	embedded Discrete Fracture Model
KNN	K-nearest neighboring
LGR	local grid refinement
LHD	latin hypercube distribution
MCMC	Markov chain Monte Carlo
MH	metropolis Hastings
NNC	non-neighboring connections
PPD	posterior probability density (function)
RMSE	root-mean-square error
VM	Vaca Muerta (formation)
$A(\vec{\theta} \rightarrow \vec{\theta}^*)$	transition probability to move from the vector $\vec{\theta}$ to the vector $\vec{\theta}^*$ in MCMC
R^2	determination index
d	actual response, or observed data
$\hat{d}$	proxy response
λ	weight function, for KNN.
$\vec{\theta}$	uncertain-parameter vector representing a reservoir-model realization
$\vec{\theta}^*$	proposed uncertain-parameter vector in MCMC
σ^2	variance in Gaussian distribution

Subscript and Superscript

e	effective
f	fracture
s	segment
w	well-bore
max	maximum (upper boundary)
min	minimum (lower boundary)
obs	observed
sim	simulated
*	normalized

SI Metric Conversion Factors

ft × 3.048 e^{-01} m
ft^3 × 2.832 e^{-02} m^3
cp × 1.0 e^{-03} Pa·s
psi × 6.895 e^{+00} kPa
md × 1 e^{-15} e^{+00} m^2

assumed to be the classical, bi-wing, and planar pattern where local grid refinement (LGR) was applied to model the fracture geometry. The genetic algorithm with proxy was used to sample the history-matching solutions. Yang et al. [34] used proxy-based acceptance rejection sampling to history match a shale-oil well in Eagle Ford. The bi-wing planar fracture was again assumed and LGR was used to model the fracture. However, using LGR is computationally expensive and intrusive to a reservoir model. In addition, refining local grids is even more tedious if the fracture orientation is oblique to the coarse grid of the reservoir model. Even more challenging is the application of LGR in assisted history matching (AHM) process in which not only one simulation but extensive series of simulations need to generate. Recent developments in a method called Embedded Discrete Fracture Model (EDFM) [11,3,16,17,31,24,25,29,30,27,28] have overcome the computational complexity to model discrete fractures in reservoir simulations. Several advantages of EDFM include high computational efficiency, non-intrusiveness to the reservoir model, and accuracy that is comparable to LGR method [24].

In this study, we propose an integrated history matching workflow that combines EDFM and the proxy-based Markov chain Monte Carlo (MCMC) algorithm to history match a VM shale-oil well. The microseismic data is available and indicates non-planar and complex fracture pattern. The microseismic cloud is accounted to constrain the fracture

Table 1
Summary of given reservoir and fracture parameters for the validating case.

Parameter	Unit	Value
Reservoir pressure	psi	9500
Reservoir datum depth	ft	10,000
Reservoir length	ft	4897
Reservoir width	ft	2640
Number of fracture	–	53
Fracture spacing	ft	59
Permeability	mD	0.0867
Thickness	ft	295
Fracture half-length	ft	137
Water saturation	–	0.409
Porosity	–	0.0045
Formation compressibility	1/psi	1.00×10^{-6}
Fracture conductivity	md-ft	500

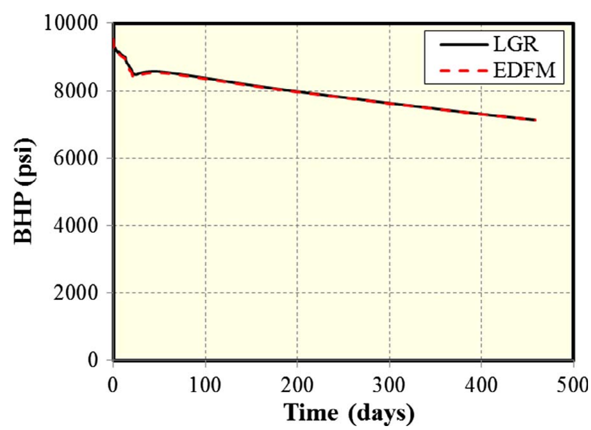

Fig. 1. Comparison of the simulated BHP profiles between LGR and EDFM.

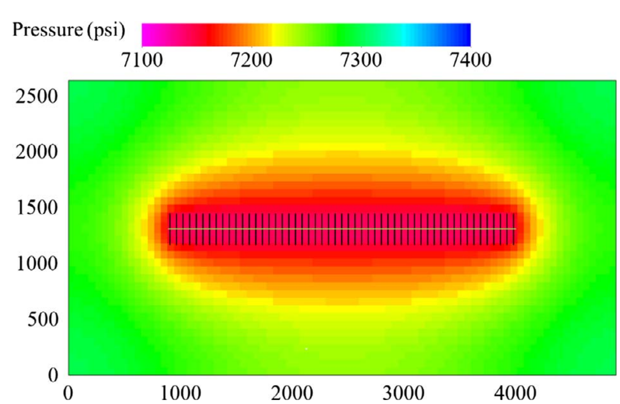

Fig. 2. Reservoir pressure map after 458 days of the validating case using LGR.