Journal of Natural Gas Science and Engineering 55 (2018) 495–507

Contents lists available at ScienceDirect

Journal of Natural Gas Science and Engineering

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

Using Embedded Discrete Fracture Model (EDFM) in numerical simulation of complex hydraulic fracture networks calibrated by microseismic monitoring data

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ARTICLE INFO

Keywords:
Microseismic monitoring
Embedded discrete fracture model
Complex fracture network
Hydraulic fracturing
Reservoir simulation

ABSTRACT

Hydraulic stimulation of unconventional shale and tight reservoirs often creates a complex induced fracture network, which requires a comprehensive characterization for successful exploitation and development. One of the major technologies applied over the past decade to image hydraulic fractures is microseismic monitoring, which analyzes seismic information recorded during hydraulic stimulation to locate the rock deformation. Results of the microseismic data interpretation are then used to generate and calibrate a model of the hydraulic fracture network. However, because of the complexity of the fracture model and the shortcomings of reservoir simulators, direct application of these complex fracture networks has been very limited. Instead, oversimplified models are used to assess the efficiency of the hydraulic fracturing treatment. Such assessment techniques, without further modeling and simulation of hydrocarbon production and pressure drainage, fail to represent an accurate view of the connectivity and complexity of the fracture system.

In this paper, we present the application of an Embedded Discrete Fracture Model (EDFM) in numerical simulation of realistic geometry of fractures. With EDFM, each fracture plane is embedded inside the computational matrix grid and is discretized by cell boundaries. We have implemented EDFM in The University of Texas at Austin (UT) in-house reservoir simulator UTCOMP. We discuss the implementation approach using non-neighboring connections. Using the developed simulator, we studied gas production from hydraulic fracture networks calibrated from actual microseismic monitoring data. We investigated the impact of fracture network geometry on the overall performance of these hydraulic stimulations.

Simulation results indicate that the efficiency of well treatment is primarily controlled by the interconnectivity of hydraulic fractures and the distribution of conductivity within the fracture network. For a given microseismic cloud, a wide range of production responses was observed by changing the degree of connectivity in the calibrated model. Moreover, the study showed that taking into account the role of aseismic deformations (such as tensile openings) significantly increased cumulative production forecasts. Neglecting the effect of these fractures may lead to underestimation of ultimate recovery.

1. Introduction

Economic exploitation of unconventional oil and gas reservoirs is feasible via hydraulic fracturing of ultra-low permeability formations. Hydraulic fracturing creates highly conductive pathways inside the formation and brings a large section of host rock into direct contact with the well. The pattern of hydrocarbon drainage inside the formation is mainly controlled by an induced fracture system. Thus, rigorous characterization of hydraulic fractures is necessary for accurate prediction of reservoir performance and for optimization of subsequent well treatments.

Fracture-diagnostic technologies have received significant attention over the past decade. One of the most popular fracture-imaging technologies is microseismic monitoring, with which energy emissions from rock deformation during hydraulic fracturing are captured by downhole or surface arrays of receivers or geophones. Arrival times and amplitudes of the received P- and S-waves are analyzed to locate the source of microseismic events and to investigate the failure mechanism. Often, the location of microseismic events is superimposed on a map view of the targeted formation to visualize the extent and growth of hydraulic fractures. In a simple analysis, the bulk volume of the microseismic cloud—the Stimulated Reservoir Volume (SRV)—is used as a proxy to

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https://doi.org/10.1016/j.jngse.2018.04.019
Received 26 June 2017; Received in revised form 12 March 2018; Accepted 17 April 2018
Available online 19 May 2018

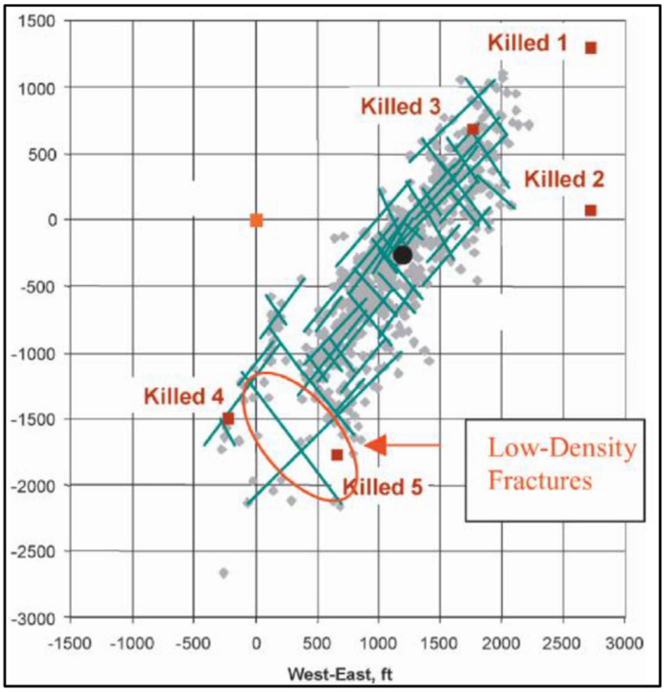

Fig. 1. A hydraulic fracture network fitted to observed microseismic events. Gray diamonds are microseismic events and green lines are hydraulic fractures. (After Fisher et al., 2004, their Fig. 4.).

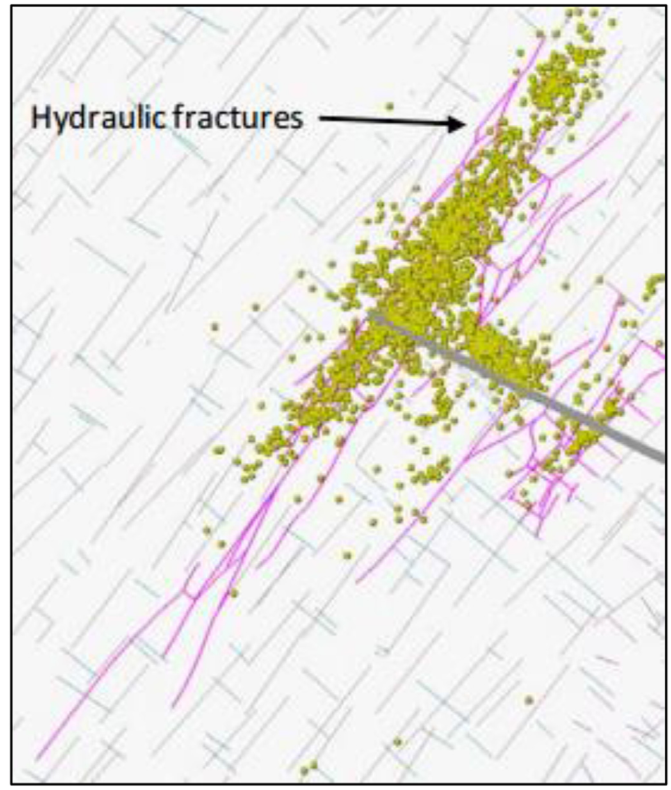

Fig. 2. A hydraulic fracture network generated based on a fracture propagation model. Green dots are microseismic events and pink lines are hydraulic fractures. Gray lines show background natural fracture network. (After Cipolla et al., 2011, their Fig. 15.).

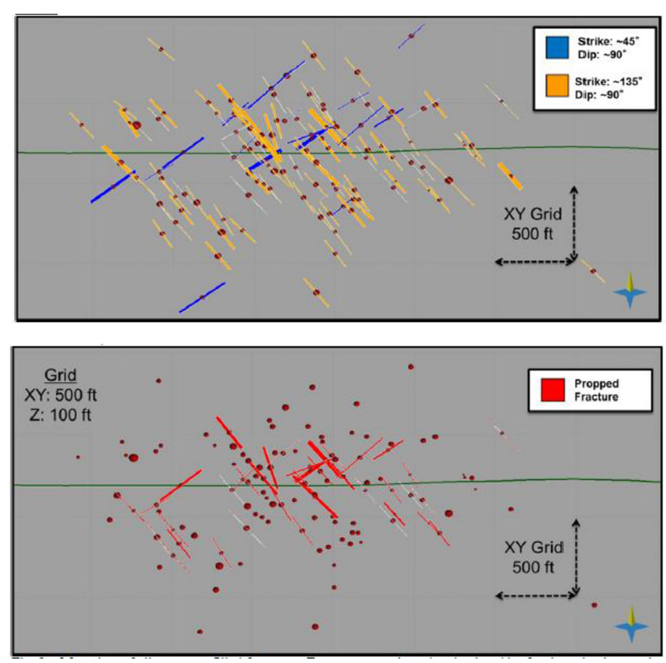

Fig. 3. A fracture network developed based on location and source mechanism of microseismic events using a forward method. Top image shows all detected fracture planes, and bottom image shows propped fractures. (After McKenna, 2013, his Figs. 1 and 2.).

assess the efficiency of well stimulation. The total volume of reservoir cells containing microseismic events is calculated on the premise that each of these cells contributes to the production (Mayerhofer et al., 2010). Although such analysis is fast, it ignores some important characteristics of the fracture system, including fracture connectivity and variation of conductivity within the network.

Microseismic monitoring has also been used to create and calibrate models of hydraulic fracture networks. The goal is to fit a network of fractures to the distribution of observed microseismic events using various algorithms. Fig. 1 shows the overlay of a complex hydraulic fracture network on top of the microseismic events obtained from a hydraulic fracturing treatment in the Barnett Shale (Fisher et al., 2004). The fit is performed by linear regression. In this figure, the network of fractures (green lines) matches the extension of microseismic events (gray diamonds).

Alternatively, in a more physics-based approach, a geomechanics-based fracture propagation model coupled with in situ stress parameters can be used to simulate the propagation of hydraulic fractures (Rogers et al., 2010; Cipolla et al., 2011; Weng et al., 2011; McClure, 2012; Wu, 2014). The assumption is that a background network of natural fractures controls propagation of hydraulic fractures. The generated fracture networks are then inspected against the distribution of observed microseismic events for the validation. Fig. 2, an example of a fracture network created with this method, indicates the results of stage 1 in a hydraulic fracturing project in the Barnett Shale.

In another class of models, recorded microseismic data are used in a forward method to build a discrete fracture network (DFN). A subset of high-quality data (with high signal-to-noise ratio and amplitude) is used in this process. Using various designs of surface-monitoring arrays, the source mechanics of rock failure are measured for each microseismic event. Then, fracture planes are placed at the location of microseismic events, while the area and aperture of the fractures are estimated based on event magnitude (Kanamori, 1977). In addition, fracture orientation is determined from source-attributes characterization (Williams-Stroud, 2008; Williams-Stroud and Eisner, 2010). Fig. 3 displays a complex fracture network generated with this approach (McKenna, 2013). Note that two sets of discrete fractures are detected in this example. Unlike the geomechanics-based approach, isolated fractures (dry fractures) are also generated.

High-resolution instruments and robust processing algorithms allow