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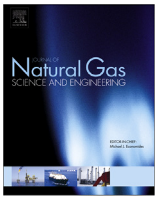

Integrating fully coupled geomechanical modeling with microsesmicity for the analysis of refracturing treatment

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ABSTRACT

In this work, fully coupled geomechanical modeling and microseismic analysis was integrated to study the impact of isolation and near-wellbore friction on the refracture treatment of a typical Eagle Ford well. The case study shows that depletion-induced changes in stress can enhance diversion, and the distribution of fluid between fractures in depleted and undepleted areas evolves during the treatment. The geomechanical model is used to identify the characteristic pressure signature and microseismic patterns associated with different hydraulic fracture geometries. A practical diagnostic of diversion effectiveness based on microseismic moment is derived from advanced microseismic analysis of the geomechanical response, and some options for completion optimization are suggested. While conventional microseismic analysis is often inadequate to determine whether refracture treatments stimulate undepleted areas or simply re-stimulate already-depleted areas, the Eagle Ford refracture treatment case study in this paper demonstrates the application of microseismic geomechanics to assess the effectiveness of diversion and estimate the distribution of fluid between previously stimulated and unstimulated areas.

1. Introduction

Hydraulic fracturing in shale reservoirs is considered to be largely different from conventional hydraulic fracturing (Geertsma and Haafkens, 1979; Hubbert and Willis, 1957; Perkins and Kern, 1961; Zheltov, 1955) due to the interactions between the created hydraulic fracture and the pre-existing natural fractures (S. Maxwell, 2014; Maxwell and Cipolla, 2011). Because of the low permeability of shale reservoirs, it is generally assumed that production occurs only from those parts of the reservoir that are close to the hydraulic fracture or to natural fractures activated by the stimulation process (King, 2010). Many older horizontal wells were stimulated with ten or fewer stages, with the stages separated by some distance, due to limitations of completion hardware technology. This resulted in sub-optimal stimulation and some areas of the laterals were not stimulated at all. In addition, the reduction in oil prices has increased interest in lower-cost methods of increasing production. As a result of these factors, refracturing these older wells has been seen as an opportunity for oil and gas operators to increase production at a lower cost than drilling new wells (Roussel and Sharma, 2013; Strother et al., 2013).

A successful refracture treatment can potentially enlarge the fracture geometry including length and height, improve the fracture conductivity, re-stimulate the natural fractures and therefore can greatly increase the well productivity. However, although refracture treatments have been widely applied, it is very common to see failed refracture stimulation (Vincent, 2010). A refracture treatment typically includes four key steps: well candidate identification, diversion design, refracture execution and diagnostics, and production analysis and diagnostics (Grieser et al., 2016). Any inappropriate operation in the above four steps could lead to the failure of the whole refracture process.

One of the key factors that affect the refracture treatment is the stress and reservoir pressure. Since refracture treatments are carried out when the well has experienced some period of depletion, the stress and reservoir pressure could be largely changed compared with the original in-situ values. The depletion of reservoir pressure could cause the reduction of stress based on the framework of Biot theory (Biot, 1956; Detournay and Alexander, 1993) while stress is one of the most important factors governing

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the propagation of fractures (Detournay, 2016). Meanwhile, depletion could also cause the reorientation of maximum and minimum horizontal stress (Mack et al., 2016; Singh et al., 2008). Therefore, the timing of a refracture treatment and the associated stress and pressure field can greatly affect the effectiveness of refracture treatment.

Another important factor in refracturing treatments is the effectiveness of diversion. During refracturing, diverters are used to block access to open fractures and redirect the refracture treatment to stimulate new areas around the wellbore that were not accessed by the initial treatment. It is important to know whether the diversion is successful or if the initial fractures are simply being reopened. However, it has been technically very difficult to diagnose the effectiveness of diversion in the field. Most field operation related to diversion is still based on trial and error.

In this paper, a workflow combining fully coupled geomechanical modeling and microseismic analysis is proposed to study the impact of isolation and near-wellbore friction on the refracture treatment of a typical Eagle Ford well. Microseismic data is often used as a tool to visually infer the geometry of hydraulic fractures, and the related stimulation (Cipolla et al., 2011; Maxwell, 2014; Warpinski, 2009; Warpinski et al., 2013; Yang and Zoback, 2014). This paper shows that this simplistic approach (assuming that microseismic activity is associated with fluid flow and stimulation) is inadequate for refracturing. A more complete workflow and modeling methodology is demonstrated using an Eagle Ford case study.

This paper is organized as follows. Section 2 describes the numerical methods as well as the model setup. Section 3 presents the results of initial stimulation and depletion. Section 4 describes the results of geomechanical modeling for different refracture scenarios, followed by the discussions in section 5. This work demonstrates the potential of utilizing geomechanical models and microseismic analysis for the diagnosis of diversion effectiveness.

2. Model description

2.1. Numerical scheme

Itasca software *3DEC* was used in this study (Itasca Consulting Group, 2015). The numerical scheme in *3DEC* is based on the three dimensional distinct element method (DEM) for discontinuum modeling (Cundall, 1988; Hart et al., 1988). The fractured rock mass is approximated by an assembly of tightly packed rock blocks while the contacts between blocks represent the rock joints. The rock is modeled with the concept of synthetic rock mass (Mas Ivars et al., 2011). The propagation of hydraulic fractures in the fractured rock mass is realized by breaking the predefined fracture plane in either tensile opening or slip (Damjanac and Cundall, 2016; Nagel et al., 2013). The hydro-mechanical behavior is simulated in a fully coupled manner, which means that the existence of fluid in the natural fractures results in pore pressure on the blocks while the deformation of blocks also affects the fluid flow in the fractures by changing the aperture size. Furthermore, the dynamic rupture of the fracture or fault can be assessed enabling a direct prediction of the occurrence of microseismicity, including the timing, location, magnitude and source mechanism/moment tensor (Zhang et al., 2013). The hydraulic fracturing workflow of combining geomechanics and microseismicity based on *3DEC* was described in (Maxwell et al., 2016).

2.2. Model setup

Fig. 1(a) shows the perspective view of the model with embedded DFN (discrete fracture network) and Fig. 1(b) shows the schematic plot of the horizontal well. The length (along x axis), width (along y axis) and height (along z axis) of the model are, 1000 m, 480 m and 320 m, respectively. A total of two initial fracturing stages and one refracturing stage were modeled. The model can be considered as one segment of a multi-stage horizontal well. Each fracturing stage has three clusters. The red solid lines and blue dashed lines represent the clusters of initial fracturing stage and refracturing stage, respectively. A uniform cluster spacing of 18.288 m was used for both the initial fracturing stages and the refracturing stage.

The key assumptions in this model are listed below,

i) At each cluster, the trajectory of the primary hydraulic fracture was predefined by a vertical contact plane perpendicular to the Shmin direction (i.e., along y axis). Those predefined planes were joined together initially but can be allowed to open governed by the stress change due to the injection fluid.
ii) The depletion after the initial fracturing stages was not directly modeled. The fracture network after the initial fracture treatment, including the created hydraulic fractures and stimulated natural fractures, was assumed to have the same bottomhole pressure. The reservoir pressure inside the depletion zone was determined based on the bottomhole pressure and original reservoir pressure by interpolation.
iii) Proppant transport as well as the calculation of fluid diffusion in the matrix is not included in this study.

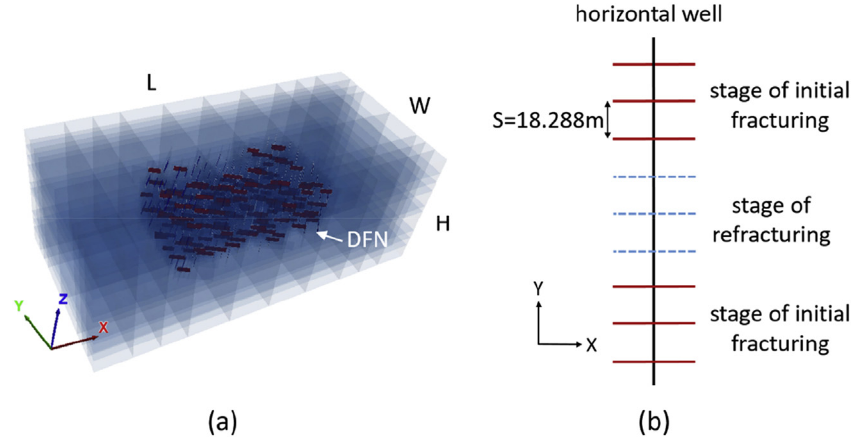

Fig. 1. (a) Perspective view of the model with embedded DFN, and (b) schematic plot of horizontal well.