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Numerical analysis of fracture propagation during hydraulic fracturing operations in shale gas systems

Jihoon Kim [a,b,*], George J. Moridis [a]

[a] Earth Sciences Division, Lawrence Berkeley National Laboratory, 1 Cyclotron Road 74R316C, Berkeley, CA 94720, USA
[b] Harold Vance Department of Petroleum Engineering, Texas A&M University, 3116 TAMU 407 K Richardson Building College Station, TX 77843, USA

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ABSTRACT

We perform numerical studies on vertical fracture propagation induced by tensile hydraulic fracturing for shale gas reservoirs. From the numerical simulation, we find that tensile fracturing occurs discontinuously in time, which generates saw-toothed responses of pressure, the fracture aperture, and displacement, and that fracture propagation is sensitive to factors such as initial condition of saturation, a type of the injection fluid, heterogeneity, tensile strength, elastic moduli, and permeability models. Gas injection induces faster fracturing in shale gas reservoirs than water injection, for the same mass injection, because of high mobility of gas. However, water injection to highly water-saturated formations can contribute to fast pressurization and high mobility of water, resulting in large fracturing. For moderate initial water saturation, complex physical responses within the fracture result from strong nonlinear permeability and multiphase flow with gravity.

Pressure diffusion and pressurization within the fracture are also affected by permeability. High intrinsic and high relative permeabilities result in fast fluid movement of injected fluid, followed by fast fracturing. High Young's modulus and high Poisson's ratio do not seem favorable to fracture propagation, although they are not significantly sensitive. For heterogeneity, a geological layer of high strength between near surface and above the shale gas reservoirs can prevent vertical fracture propagation, changing the direction of fracturing horizontally.

1. Introduction

The potential natural gas resource from shale gas is estimated between 14.16×10^{12} m^3 and 28.3×10^{12} m^3, and, from its huge quantity, shale gas has been taken as one of the future energy resources [1,2]. For example, abundant shale gas in the U.S is found in Barnett Shale, Haynesville/Bossier Shale, Antrim Shale, Fayetteville Shale, New Albany Shale, and Marcellus Shale [3]. Despite abundance of the shale gas, geological formations of shale gas are extremely low permeable [4], and thus the shale gas reservoirs are considered unconventional resources.

Hydraulic fracturing has been introduced to production of the shale gas reservoirs in order to enhance permeability, creating artificial fractures within extremely low permeable formations [5,6]. Horizontal wells along with hydraulic fracturing are operated in order to increase productivity of gas production [7,8]. The horizontal wells and hydraulic fracturing techniques made gas production from Barnett shale successful, and the success has led to gas production of other shale reservoirs such as Marcellus shale, one of the largest natural gas resources in the United States [1,9].

Many studies have been made on hydraulic fracturing and shale gas reservoirs. Vermylen and Zoback [5] investigated two different scenarios for hydraulic fracturing along horizontal wells: alternatively fractured (zipperfrac) and simultaneously fractured (simulfrac) wells, and they found significant differences in stimulation for the two fracturing procedures. Fisher and Warpinski [6] analyzed fracture propagations induced by hydraulic fracturing with real geophysical field data, and concluded that the fracture propagations were limited in the vertical direction, compared with the horizontal direction. They claimed that an unstable fracture propagation up to near surface is not possible because, for example, (1) the formations between the near surface and the shale gas reservoirs are not homogeneous and (2) the horizontal total stress is higher than the vertical total stress at shallow depth, which can block the growth of the fracture along the vertical direction. However, there are still some loose worries that the fractures might propagate too fast and unstably [10]. Osborn et al. [11] investigated the methane concentrations in the drinking aquifers for the active and inactive areas of shale gas production, and found that groundwater was contaminated around the active area of the gas production, where methane

* Corresponding author at: Harold Vance Department of Petroleum Engineering, Texas A&M University, 3116 TAMU 407 K Richardson Building College Station, TX 77843, USA. Tel.: +1 979 845 2205.
E-mail addresses: JihoonKim@lbl.gov, jihoon.kim@pe.tamu.edu (J. Kim), GJMoridis@lbl.gov (G.J. Moridis).

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possibly originated from the shale gas reservoir, based upon the isotope analysis. Zoback et al. [8] overviewed potential environmental impacts from hydraulic fracturing, for example, due to failure of the proper cementing around the wellbore casing, treatment of the proppants used for hydraulic fracturing, storage and management of chemicals and waste water. Thus, rigorous simulation of material failure and coupled flow and geomechanics is strongly suggested for more systematic and accurate analysis of gas production and hydraulic fracturing.

There are several numerical methods used for the fracturing modeling. The discrete (distinct) element method considers intact rock and fractures separately, and models fracture propagation by splitting nodes [12–14]. This method is natural because the numerical scheme follows the physical process of fracturing. This discrete element method can be suitable for small scale problems that can represent intact rock and fractures individually. However, it requires huge computational cost for large scale problems in the full 3D system. On the other hand, the extended finite element method and the enhanced assumed strain method are based on the continuum approach [15,16]. These methods use discontinuous interpolation functions for discontinuous displacement in order to represent fractures, not requiring the remeshing procedure. Yet, the applications in the full 3D problems result in considerable complexities and huge coding effort. In reservoir engineering, Ji et al. [17] proposed a numerical algorithm for hydraulic fracturing, which is based on tensile strength, incorporating poromechanical effects. Dean and Schmidt [18] fundamentally employed the same fracturing algorithm of Ji et al. [17], while they used different criteria of the fracture propagation based on rock toughness of fracture mechanics. Yet, hydraulic fracturing that can consider dynamic interrelations between flow and geomechanics has still been little investigated, although tight coupling between them is necessary to consider, particularly for the cases of hydraulic fracturing and gas production in shale gas reservoirs.

In this study, we focus on physical responses related to hydraulic fracturing, while those during production are analyzed elsewhere [19]. For hydraulic fracturing, creation, propagation, and the aperture of the fractures depend on several factors such as initial reservoir condition of saturation, injected fluid pressure or injection rate, geomechanical moduli, heterogeneity, criteria of tensile failure, a type of fluid within the fractures, and permeability models. We will analyze fracture propagations induced by hydraulic fracturing for Marcellus shale gas reservoirs with various test cases.

2. Shale gas reservoirs

We describe a fracturing scenario, initial condition, and tensile strength of shale gas reservoirs in this section. Hydraulic fracturing in shale gas reservoirs is usually performed with several horizontal wells, where the direction of the horizontal wells is typically parallel to that of the compressive minimum principal total stress, S_h. Then artificial fractures created by hydraulic fracturing are normal to the direction of S_h. Many fracturing stages per horizontal well can be performed to maximize fractured areas [8].

This fracturing scenario has been applied to shale gas plays such as Barnett shale, Woodford shale, Marcellus shale, Eagle Ford shale. Among them, much attention has currently been paid to vertical fracture propagation in Marcellus shale, related to possibility of contamination in drinking water [11]. Fig. 1 shows real data of the microseismic signals (inferred fracture propagation) in Marcellus shale [6]. From the figure, all the fractures are below 4500 ft (1372 m) in depth, 3500 ft (1067 m) lower than the deepest fresh water wells, which are likely deeper ‘aquifers’, and the lowest injection depth is approximately 5000 ft (1524 m) in depth. The fractures propagated preferably upward, but, from the

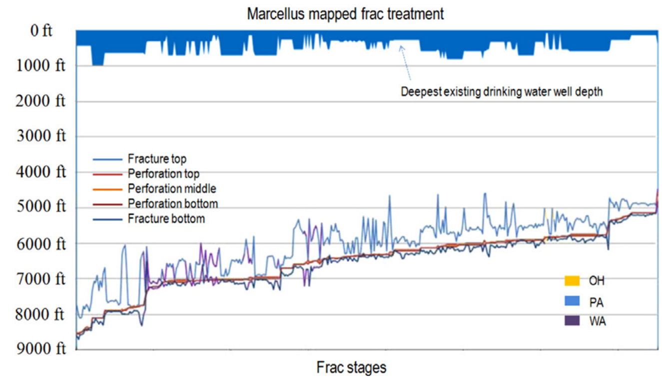

Fig. 1. Real data for the fracture propagations of Marcellus shale [6].

data, the fracture propagations do not seem dangerous when we consider the distance between fracture tops and the water well bottoms. Among the fractures whose tops are close to the surface, their maximum vertical lengths from the center of perforation are approximately no greater than 460 m.

Overburden stress, S_V, can be estimated by density of geomaterials, ρ_b. For example, the density of Marcellus shale ranges from 2200 kg/m^3 to 2600 kg/m^3 [20,21]. For horizontal stresses (i.e., S_H and S_h), where S_H is the compressive maximum horizontal principal total stress, there are several equations that relate S_V to S_H and S_h [22]. In this study, we use one of the equations as follows:

$$\frac{S_h}{S_V}=\frac{0.15}{h_z}+0.65, \quad \frac{S_H}{S_V}=\frac{0.27}{h_z}+0.98, \tag{1}$$

where h_z is the depth in km. When considering a simulation domain from $h_z = 1.0$ km, we approximately have $S_h = 0.8 \times S_V$ and $S_H = 1.2 \times S_V$.

For reservoir temperature, we use 0.025 °C/m of the geothermal gradient, used for normal subsurface environments and reservoirs [23]. Then, the temperature of a shale gas reservoir at 1.35 km in depth can be estimated to be 58.5 °C, when the surface temperature is 25.0 °C.

Geomechanical properties of shale gas reservoirs vary within a wide range. According to Sondergeld et al. [21], Young's modulus ranges approximately from 9 GPa to 70 GPa for the confining pressure between 10 MPa and 20 MPa, and from 7 GPa to 25 GPa for the confining pressure between 20 MPa and 30 MPa. Poisson's ratio varies from 0.1 to 0.38 for the confining pressure between 10 MPa and 20 MPa, and from 0.1 to 0.25 for the confining pressure between 20 MPa and 30 MPa. From Eq. (1), the confining pressure at $h_z = 1.0$ km is between 21.6 MPa and 25.5 MPa, and thus the corresponding Young's modulus and Poisson's ratio are around 10 GPa and 0.2, respectively.

It seems that geomechanical properties of oil shale are similar to those of shale gas reservoirs, as described below. According to Eseme et al. [24], the geomechanical properties depend on a degree of organic content and temperature, T. As the organic carbon content (or grade) and temperature increase, Young's modulus and rock strength decrease. For example, Young's modulus, E, ranges from 6.0 GPa to 12.0 GPa around T=58.5 °C. Poisson's ratio, ν, ranges from around 0.2 to 0.4, depending on temperature and the organic content. Tensile strength of oil shale, T_c, ranges from 5.0 MPa to 10.0 MPa, where it is determined from a tension test such as the Brazilian test. From the similarity between oil shale and shale gas reservoir, we can infer tensile strength of Marcellus shale from data of oil shale, although there is no available data of tensile strength in Marcellus shale.

Since we focus on risk analysis of fracture propagation, we take geomechanical values and initial conditions that are favoable to fracturing. Specifically, we use $\rho_b = 2200$ kg/m^3 for