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Effect of foam quality on effectiveness of hydraulic fracturing in shales

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ABSTRACT

The goal of this work is to study the effect of foam quality on the gas productivity of fractured wells in shales. A numerical model of fracture propagation is developed which incorporates a 2D fracture model, proppant transport, and foam rheology. The fracture conductivity distribution is computed from the local proppant concentration, which is incorporated in a reservoir simulation model to predict the gas production by depressurization. Given the rock mechanical properties, the fracturing fluid, proppants, and rock permeability control the shape and conductivity of the fractures created during hydraulic fracturing. The shape and conductivity of the fracture, in turn, control the gas productivity of such a well. Foam quality, proppant size, proppant concentration, and rock permeability are varied. The results show that, in most cases, the gas production is optimum at an intermediate foam quality (of about 65%) because it creates the largest propped fracture area and minimizes leak-off. Only for the case of 0.1 micro-Darcy rock, low proppant concentration and large proppant size, the gas production increases monotonically with foam quality because high quality foam can place a partial monolayer of proppants. Fracturing with water as the initial pad and a high quality (65–85%) foam as the proppant carrier is more effective than using the same foam for both pad and slurry.

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1. Introduction

Natural gas production has increased during the past decade all around the world mainly due to the development of unconventional gas (tight and shale gas). It is reported in 2011 Annual Energy Outlook from U.S. Energy Information Administration (EIA) that more than 40% of the natural gas produced in US came from tight and shale gas resources. The success of gas production from ultra-low permeability reservoirs like shale (matrix permeability is commonly less than 1 μD) can be mainly attributed to horizontal drilling and multiple hydraulic fracturing stimulation [1]. The hydraulic fracturing is a technique to create high conductive conduits (fractures) in low permeable formations by injecting a pressurized fluid and proppants which improve hydrocarbon production rate and ultimate recovery.

The early days of trial and error experiences in the Barnett play show that pumping slickwater and relatively small proppants (80/100, 40/70 mesh) can create economically sound wells [2,3]. The success of the slickwater jobs was attributed to its easy-to-obtain characteristic, cost containment, low friction loss, better fracture containment, and the capability of generating long and skinny fractures extending to a wider area. However, high rate of gravity settling of conventional proppants, like sands (specific gravity: 2.65) in slickwater leads to a large amount of upper and deeper fracture surface not propped [4]. Another concern is the water loss into the matrix during fracturing, resulting in the high water saturation and low gas relative permeability [5,6]. Furthermore, if clays are present, the water may be absorbed by the clay, causing swelling and decreasing the absolute permeability of the matrix. Another issue is the increase in water usage as the number of fractures increases along a single well. Around the world, the environmental issues related to the large water consumption in the hydraulic fracturing, such as fresh water sourcing, transport, handling and disposal are attracting more and more attention from the government and the public [7].

To improve the efficiency of the fracturing in shale gas reservoirs, a non-damaging fracturing fluid needs to be developed, which can not only place the proppant more efficiently, but also minimize water use and disposal fluids. Foams can be used as a fracturing fluid to address water consumption, sand-settling, fluid leakage into the formation, and fracture clean-up due to gas expansion [8,9]. The common fracturing foams are composed of water, a foaming agent (surfactant), a stabilizer/viscosifier (polymer additives as guar gum, HPG, or Xanthan gum) and a gas [10–13]. To extend the foam fracturing into shale reservoirs, polymer additive should be avoided because they can plug the small pores of the formation [14,15]. Stable aqueous foams without any polymer additives can be formulated and the rheology of such foams was studied in a large scale circulating rheometer at typical reservoir temperature and pressure conditions [16].

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Several models have been developed in the past to describe the fracture opening during hydraulic fracturing, such as two-dimensional fracture models [17–21], pseudo-three-dimensional models [22,23], and fully three-dimensional models [24–26]. Perkins and Kern [18] developed a two-dimensional fracture propagation model by assuming fracture height is fixed and is much smaller than the fracture length. Plane strain is considered in the vertical direction perpendicular to the direction of fracture propagation. The other assumptions include neglected fracture toughness, the elliptical cross section, and constant pressure along the vertical direction. Later Nordgren [20] improved this model by adding fluid loss term; this model is commonly known as the PKN model. Another classical 2D model is the KGD model developed by Khristianovitch and Zheltov [17] and Geertsma and de Klerk [19]. It assumes that flow rate and pressure are constant along the majority of the fracture length, except for a small region close to the fracture tip. In this model, plane strain is assumed to be in the horizontal direction, which holds true if fracture height is much greater than fracture length. When the fracture height is comparable with the fracture propagated length, there was another better 2D model, known as the Penny-shaped or radial model [21]. In this mode, the fracture propagates in a given plane, and the geometry of the fracture is symmetrical with respect to the point at which fluids are injected. The above 2D models are simple, fast, good approximations, but they are not able to simulate both vertical and lateral propagation. The pseudo-3D models, evolving from the 2D PKN model, assume the height grows with time and varies along the propagating direction [22,23]. Additionally, a vertical fluid flow component is added in flow equations in P3D models. The even more complex fully 3D models are developed to simulate fractures of arbitrary shape and orientation in the heterogeneous reservoir by solving a set of coupled equations governing the deformation of a 3D rock and the 2D fluid flow in the fracture [24–26]. They are mathematically more rigorous, but expensive to run. Many researchers have studied the impact of proppant distribution and its mechanical properties on the residual fracture profiles [27], mechanics of proppant bridging at the fracture tip [28], fracture reorientation and multiple fracture interaction and completion with each other [29], and measurement of the minimum in-situ stress [30].

For naturally fractured shale formations, hydraulic fracturing can result in complex-fracture-network growth. This makes the traditional bi-wing fracturing model (e.g. PKN) unsuitable for designing fracture treatments in a shale reservoir where complex fracturing is evident. Numerical models have been developed [31,32] to study the details of mechanical fracture interactions without explicit consideration of fluid flow. Zhang and Jeffrey [33] presented a more rigorous hydraulic-fracture model incorporating a full solution of coupled elasticity and fluid flow equations, but it is limited to the 2D plane-strain conditions. Weng et al. [34] developed a pseudo-3D model for fracture propagation in a formation with multiple pre-existing natural fractures. But the model calculates the stress shadows separately using the displacement discontinuity method to incorporate the mechanical interactions between the hydraulic fracture and the natural fractures. Sesetty and Ghassemi [35] developed a numerical model to simulate the complex fracture network while taking into account the influence of natural fractures on the in-situ stress distribution. Commercial simulators such as Mangrove from SLB, 3DEC from Itasca, MFrac from Baker Hughes and StimPlan from NSI Technology have developed their own unconventional modules for simulating fracture propagation in naturally fractured shales and tight gas reservoirs.

Foams can be formulated with different quality (i.e., gas volume fraction). The quality of the foam affects its rheology which would affect the opening of the fracture as well as the transport of proppants and fluid loss. This, in turn, would affect the fracture geometry and conductivity which would influence the effectiveness of the fracture in gas production. The goal of this work is to study the effect of foam quality on the effectiveness of hydraulic fracturing by numerical simulation. To simplify the problem, this study only focuses on non-naturally fractured shale reservoirs, where the bi-wing planar fracture scenario is acceptable. A two-dimensional fracture propagation simulator is developed based on the PKN model and the foam rheology model developed in our previous study [16]. The proppant transport equation is coupled with the fluid flow equation to calculate the proppant placement within the fracture. The proppant concentration distribution is then converted to the conductivity distribution based on correlations developed in previous studies [36–38]. The fracture conductivity distribution is input into a commercial reservoir simulator (CMG-IMEX) to evaluate the fracture gas productivity. The effectiveness of hydraulic fracturing with polymer-free foams of different quality is compared with the commonly-used slickwater fractures under different treatment designs and reservoir conditions.

2. Methodology

2.1. Foam rheology model

In the previous experimental work [16], the rheology of the polymer-free foam with 0.5 wt% anionic surfactant (Bioterge AS40; 39% activity as supplied) was evaluated in a flow loop at varied pressures and temperatures. In the loop, shear stress versus shear rate was measured for the foams with different qualities (Q) at 95 °F. The foams exhibited power-law rheological behavior,

$$\tau = K\gamma^n \tag{1}$$

where n is the power law index, and K is the consistency index. The apparent foam viscosity is calculated by

$$\mu_{ap} = K\gamma^{n-1} \tag{2}$$

Foams exhibited shear thinning behavior at qualities above 60%, non-shear dependent behavior from 50% to 60%, and apparent shear thickening behavior below 50% (due to turbulence). The temperature impact on the foam viscosity is negligible from 95 °F to 155 °F, while the pressure increased the foam viscosity for quality above 60%. This effect becomes less at a higher pressure. These aqueous foams are half as viscous as 20 lbm/Mgal guar foams and over 20 times more viscous than water, under a typical fracturing shear rate of 511 s^{-1}.

The power law index (n) and the consistency index (K) were observed to depend on quality (Q) and pressure (P) in psi as follows:

$$n = \begin{cases} (1.54 - 1.64Q^2) & 0\% \le Q < 60\% \\ (1.54 - 1.64Q^2) - (0.89Q - 0.21)[\log(P/1000)] & 60\% \le Q < 85\% \end{cases} \tag{3}$$

and

$$K = \begin{cases} 10^{(5.89Q^2 + 0.43Q - 4)} & 0\% \le Q < 60\% \\ 10^{(5.89Q^2 + 0.43Q - 4)} + 8.6 \times 10^{-11} e^{21Q}(P - 1000) & 60\% \le Q < 85\% \end{cases} \tag{4}$$

The rheology of the foam depends solely on the foam quality for qualities below 60%, and is dependent on both quality and pressure at qualities above 60%.

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