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Modeling fracture propagation and cleanup for dry nanoparticle-stabilized-foam fracturing fluids

Ali Qajar[a,*], Zheng Xue[b], Andrew J. Worthen[b], Keith P. Johnston[b], Chun Huh[a], Steven L. Bryant[c], Maša Prodanović[a]

[a] Center for Petroleum and Geosystems Engineering, University of Texas at Austin, 200 E Dean Keeton, Austin, TX 78712, USA
[b] Department of Chemical Engineering, University of Texas at Austin, Austin, TX 78712, USA
[c] Department of Chemical and Petroleum Engineering, University of Calgary, AB, Canada T2N 1N4

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ABSTRACT

Nanoparticle (NP)-stabilized foams can be generated at extreme water-deficient conditions (with quality as high as 95–99%) and yet with apparent viscosities >100 cP. This makes them greatly appealing for hydraulic fracturing applications, where minimal water consumption and leak-off to the reservoir are desired. Initial assessment of propensities of these novel fluids for fracturing applications requires field scale simulations. However, conventional fracturing models are difficult to employ because they do not consider true foam hydrodynamics. We have developed a mathematical model to simulate the transport of NP-stabilized foams for hydraulic fracturing. The model combines fluid transport in reservoir matrix and fracture with rock mechanics equations and thus allows for considering the effects of foam on fracture dynamics. Gas and water flow with mechanistic accounting of foam generation and coalescence are simulated using population balance models. Transport of nanoparticles through porous media was simulated using single site filtration model. The equations are discretized using finite-difference scheme. Settari's approach is used to embed fracture's moving boundary with the matrix to accordingly update transmissibility. Model's capabilities are verified with examples on fracture growth and fracture clean up processes to illustrate the benefits of using the NP-stabilized high quality foams. Fracture propagation was simulated for water, a conventional viscous fracpad and NP-stabilized foams of different qualities and textures. The simulations confirmed that larger foam viscosity generated wider fractures with smaller fracture half-length. In addition, fracture cleanup simulations show that fracturing fluid cleanup for foam based fracturing fluids could take the order of 10 days as opposed to that of viscous fracpad which could take up to 1000 days; demonstrating the advantage of using dry foams.

1. Introduction

Tight gas and shale plays offer substantial amounts of underground energy reserves (http://www.eia.gov/analysis/studies/worldshalegas/). However, due to the low porosity and permeability of these reservoirs their economical production heavily relies on advanced drilling, well stimulation and production technologies (Loucks et al., 2009; Loucks et al., 2012). The key to high reservoir productivity is to develop long conductive passages by propping open fractures within the reservoirs. Hydraulic fracturing is a well proved stimulation technique to increase the production surface area and hence the reservoir productivity (Mendelsohn, 1984; King, 2012; Fisher and Warpinski, 2011). Hydraulic fracturing fluids are typically composed of over 90 vol% of water accompanied by guar gum and other additives to carry the proppant sands into the fracturing zone (Potocki, 2012; Gidley, 1989; Rafiee et al.; Holditch, 1979). The procedure demands significant amount of water (i.e. an average of 1 million gallons of water per frac job). Injection of such huge amount of water at high pressures and flowrates (10–100 bbl/min) results in substantial fracpad leak off into the reservoir; which later impedes reservoir productivity by reducing permeability of the reservoir fluids near wellbore (Wang et al., 2010; Friedel, 2006; Tannich, 1975). The leak-off rate is a function of fracturing fluid rheology as well as petrophysical (e.g. porosity and permeability) and geomechanical (e.g. minimum stress) properties of the reservoir. Fracturing fluid leak-off is especially detrimental when the reservoir is water sensitive so that it loses its permeability and porosity upon contact with excess amount of water. Additives such as guar gum and other polymers favorably increase fracpad viscosity which lowers

* Corresponding author.
E-mail addresses: ali.qajar@utexas.edu (A. Qajar), zxue@utexas.edu (Z. Xue), andrew.worthen@utexas.edu (A.J. Worthen), johnston@che.utexas.edu (K.P. Johnston), chunhuh@mail.utexas.edu (C. Huh), steven.bryant@ucalgary.ca (S.L. Bryant), masha@utexas.edu (M. Prodanović).

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the leak-off rate; however, the polymers form gel at fracture face which yet again lowers the fracture conductivity. Breaking the gels from fracture face is still a challenge and requires complicated and expensive chemical treatments (Wang et al., 2010; Friedel, 2006; Tannich, 1975).

Previous studies have suggested that, for shale formations, reservoir properties such as porosity, permeability and capillary pressure are extremely influential on the quality of cleanup process (Wang et al., 2010). For reservoirs (with permeability below 1 md) the damage to the reservoir can be compensated if the conductivity of the fracture is sufficiently large (Friedel, 2006). Still, fracture face damage results in reduced hydrocarbon production (Tannich, 1975; Gdanski et al., 2005; Wang et al., 2008). On the other hand, high flow gas production and higher fracture conductivity can lead to faster fracture cleanup (Gdanski et al., 2005; Wang et al., 2008; Lolon et al., 2003). Damage to the fracture productivity occurs inside the fracture either due to proppant crushing or due to formation of skin at fracture face by polymers, clay swelling, and excessive leak-off (Wang et al., 2010; Gdanski et al., 2005). Furthermore, simulations for non-Newtonian viscous pads have shown that the cleanup process is nearly insensitive to the drawdown pressure yet the cleanup is a strong function of fracture conductivity (Gdanski et al., 2005).

Even though a wide variety of treatment practices are available to alleviate damages caused by water injection into low permeability reservoirs, typically only 20% of the injected water returns to the surface during flowback, while the rest is estimated to be trapped in high porosity neighboring rocks, in isolated fractures and in reservoir matrix. From numerous fracturing jobs and previous studies, it is understood that using novel fracturing fluid systems that lower water consumption and deliver the desired hydraulic pressure into the fracture is the best way to prevent reservoir damage. HiWAY fracking and development of energized fluids are some novel inventions aiming to reduce water consumption (Ribeiro and Sharma, 2012, 2013; http://www.slb.com/services/completions/stimulation/sandstone/hiway_channel_fracturing.aspx). Foams, on the other hand, lower water consumption, are able to deliver hydraulic pressure into the fracturing zone, and possess high apparent viscosities which can be used for carrying sand proppants into the fracturing zone (Grundmann and Lord, 1983; Blauer et al., 1974; Edrisi and Kam, 2012). Additionally, using foams lowers the amount of additives consumed to control the leak-off and clay swelling. Moreover, upon pressure reduction during flowback, expansion of the gas phase provides a favorable pressure kick to remove the fracturing fluid.

Recent advancement on the synthesis and characterization of nanoparticle stabilized CO_2–water foams offers them as effective sweeping fluids and fracturing pads for subsurface applications (Aroonsri et al., 2013; Worthen et al., 2013; Espinoza et al., 2010; Aminzadeh et al., 2013; Cai et al., 2012; Zhang et al., 1744, 2014; Prigiobbe et al., 2015; Li et al., 2010). Nanoparticles (with typical dia. of 5–20 nm) in synergy with polymers and surfactants enhance lamella stability for submicron lamella resulting in the synthesis of highly dry foams with more than 90% foam quality and 200 cP viscosity. Nanoparticles establishing near 90-deg contact angles at water-gas interface are capable of foam generation, as they irreversibly adsorb at the water–gas interface with adsorption energies of $\sim$100 kT (Aroonsri et al., 2013; Worthen et al., 2013).

Numerical studies on fracture propagation have resulted in the development of uncoupled or coupled models that are suitable for conventional fracturing fluids or energized fluids. Synthesis and development of formulations for the genesis of NP-stabilized foams are fairly new and conventional fracture simulators are not able to capture the true physics associated with fracture propagation and foam transport inside fracture and reservoir matrix. Reliable assessment of the propensities of nanoparticle stabilized foams as novel fracturing fluids requires customized models that combine foam transport in the fracture and inside reservoir matrix in a coupled approach (Nghiem et al., 1984; Kam, 2008a, 2008b; Kam and Rossen, 2003; Kam et al., 2007; Ji et al., 2004; Geertsma and de Klerk, 1969). Herein, we have developed a coupled simulator in which the mutual effects between fracture dynamics and fluid transport inside reservoir matrix are considered simultaneously. The simulator includes the mechanistic population-balance model to simulate foam transport inside the fracture as well as nanoparticle adsorption-filtration model to simulate nanoparticle loss inside the reservoir upon leak-off. The simulator is used to model fracture propagation upon the injection of NP-stabilized foams. In addition, since the reservoir fluid model is basically a two-phase flow model, it has been used to simulate fracture cleanup during the production phase.

Fig. 1 schematically compares gas–water ratio of water based fracturing fluids, including water, energized fluids, foam and NP-stabilized dry foams. Compared with water, energized fluids liberate volumes of gas upon pressure reduction which can provide energy to remove water from fracturing zone. Moreover, incorporation of high modulus surfactants can improve foaming of the fracturing fluids and result in high quality foams. When advanced nanofluids such as polymers and nanoparticles are added to the systems in synergy with the surfactants they substantially improve foam stability even under super dry conditions of above 95% foam quality. This notably reduces water consumption while still taking advantage of high viscosity of the foams for proppant transport.

2. Model development

Mass balance for Nc components in Np phases, where Darcy's law represents phase transport from one gridblock to another is given by

$$V_b\frac{\partial}{\partial t}(\varphi N_i)-V_b\nabla\bullet\sum_{j=1}^{Np}\frac{kk_{rj}}{\mu_j}\xi_j x_{ij}\left(\nabla P_j-\gamma_j\nabla D\right)-q_i=0 \tag{1}$$

where V_b, φ, N_i, k, k_{rj}, μ_j, ξ_j, x_{ij} denote bulk volume, porosity, moles of component i, permeability, relative permeability of phase j, viscosity of phase j, molar density of phase j, and composition of component i in phase j. P_j, γ_j, D, q_i represent pressure, and specific gravity of phase j, depth and molar rate of component i injected, respectively (Chang, 1990). Transport equations were applied to fluid transport in both low permeability matrix zone and high permeability fracture zone. The equations are derived in finite difference scheme with IMPEC approach where the pressure equations are solved implicitly, followed by component balance equations solved explicitly (Chang, 1990). The pressure equations form a set of elliptic partial differential equations. When boundary conditions are applied and the equations are discretized, they produce a linear positive definite system of equations as follows:

$$\left(V_p^0C_f-\frac{\partial V_t}{\partial P}\right)_{xyz}^{n}P_{xyz}^{n+1}-\Delta A\Delta P^{n+1}=\left(V_p^0C_f-\frac{\partial V_t}{\partial P}\right)_{xyz}^{n}P_{xyz}^{n}+\Delta t\sum_{i=1}^{nc+1}\left(\bar{V}_{ti}\right)_{xyz}^{n}q_i+\Delta t\left(B_{cap}+B_{grav}\right) \tag{2}$$

where V_p^0 is the pore volume in the reference pressure; C_f is the reservoir compressibility; $\frac{\partial V_t}{\partial P}$ is the overall reservoir fluid compressibility; ΔA is the spatial gradient of conductivity matrix calculated from transmissibility matrices; P_{xyz}^n is the pressure at grid block (x,y,z) and time step n; Δt is current time step; $\bar{V}_{ti}$ is the