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Modeling of hydraulic fracturing and designing of online pumping schedules to achieve uniform proppant concentration in conventional oil reservoirs

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ABSTRACT

We present a novel control framework for the closed-loop operation of a hydraulic fracturing process. Initially, we focus on the development of a first-principle model of a hydraulic fracturing process. Second, a novel numerical scheme is developed to efficiently solve the coupled partial differential equations defined over a time-dependent spatial domain. Third, a reduced-order model is constructed, which is used to design a Kalman filter to accurately estimate unmeasurable states. Lastly, model predictive control theory is applied for the design of a feedback control system to achieve uniform proppant concentration across the fracture at the end of pumping by explicitly taking into account the desired fracture geometry, total amount of proppant injected, actuator limitations, and safety considerations. We demonstrate that the proposed control scheme is able to generate a spatial concentration profile which is uniform and close to the target concentration compared to that of the benchmark, Nolte's pumping schedule.

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1. Introduction

Unconventional natural-gas resources include shale gas, tight gas, coalbed (coal-seam) methane, and gas hydrates. What characterizes these natural-gas resources as unconventional is that they are contained in rock formations of ultra-low permeability (0.01–0.0001 mD or even less), which makes gas extraction extremely difficult, because, in contrast to conventional resources, gas cannot easily flow through the reservoir rock and travel to the surface (Bhattacharya and Nikolaou, 2013). The combination of directional drilling (Economides et al., 1998) and hydraulic fracturing (Economides and Nolte, 2000) has transformed the paradigm of energy markets by enabling the extraction process of unconventional gas resources more economical, eventually leading to the shale revolution.

In practice, the ultimate goal of hydraulic fracturing is to increase the productivity of a stimulated (i.e., fractured) well. The hydraulic fracturing process begins with perforation, in which stage, a well is drilled and a wire equipped with explosive charges is dropped into the well, which are used to create initial fracture paths. Then, a high-pressure fluid (called pad) consisting mostly of water and a viscosifying agent is pumped to break the oil- or gas-bearing rock in tension and propagate fractures in the formation at perforated sites. Next, a fracturing fluid (called dirty volume) consisting of water, additives, and proppant is pumped into the wellbore at sufficiently high pressure and flow rate for further fracture propagation. After pumping is stopped and the remaining fluid leaks off to the reservoir, the fracture wall will trap the proppant inside the fracture. The trapped proppant increases fluid conductivity by creating conduits through which oil and gas can be transported easily.

The gas and oil industry has traditionally employed optimization techniques for a variety of purposes such as optimal well location and spacing of fracture stages (Yeten et al., 2002), field development under uncertainty (Goel and Grossmann, 2004), resource scheduling (Cullick et al., 2003; Iyer et al., 1998), maximization of net present value (Jansen et al., 2009; Brouwer et al., 2004), history matching of reservoir parameters (Jacquard and Jain, 1965; Cheng et al., 2004; Alvaro et al., 2011; Yin et al., 2011), development of well and reservoir simulators (Sundaryanto and Daryanto, 1999; Nyhavn et al., 2000; Durlofsky and Aziz, 2002; Litvak et al., 2002). In particular, Unified fracture design (UFD) was proposed by Economides et al. (2002), Daal and Economides

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(2006), Demarchos et al. (2004), Yang et al. (2012) to calculate optimal fracture geometry for conventional (high-permeability) oil and gas reservoirs to maximize well performance, and recently, the approach has been further extended to unconventional (low-permeability) resources by Bhattacharya et al. (2012).

In addition to producing fractures with desired geometry, it is also important to achieve uniform proppant concentration at the end of pumping, because it is directly related to the overall efficiency of the hydraulic fracture process. An initiative effort was made by Nolte (1986) where a power-law type pumping schedule was developed based on the conservation of fluid, particularly estimating the total volume of the fluid that leaks off to the formation during the hydraulic fracturing operation. This technique has been widely used because of its easy-to-implement nature, however it has a few practical limitations: (1) both practical constraints and proppant settling are not considered; (2) plant-model mismatch due to the use of a predefined form assuming a constant leak-off coefficient may lead to premature termination (i.e., the production of a fracture with short propped length); and (3) the pumping schedule is designed offline and applied to a hydraulic fracturing process in an open-loop manner.

To deal with the limitations of Nolte's pumping schedule, a pumping schedule design technique is developed by Gu and Desroches (2003) using a detailed forward numerical simulator. Specifically, an initial pumping schedule that consists of multiple substages with identical concentration is provided to the forward simulator. Then, based on the simulation result, the concentration of each substage in the pumping schedule is adjusted iteratively until the desired fracture geometry and fracture conductivity are achieved. This approach can outperform Nolte's pumping schedule at the expense of a high computational requirement. In an effort to develop a pumping schedule which is more accurate than Nolte (1986), but at the same time, computationally more efficient than Gu and Desroches (2003), a new pumping schedule design technique was proposed by Dontsov and Peirce (2014). However, they did not explicitly consider the relationship between fracture propagation and proppant concentration. Thus, the accuracy of this method is limited to low proppant concentration where the viscosity, which directly affects the fracture propagation, does not change significantly with proppant concentration.

The aforementioned pumping schedules viewed hydraulic fracturing processes as an open-loop problem, which has motivated this work that considers the closed-loop operation of a hydraulic fracturing process utilizing the available real-time measurements as feedback to adjust the pumping schedule online. Over the last ten years, the oil and gas production industry has applied model predictive control (MPC) theory to drilling processes to enhance pressure control flexibility and process safety (Hannegan, 2007; Godhavn et al., 2011; Breyholtz et al., 2010, 2009; Breyholtz and Nikolaou, 2012; Gravdal et al., 2010; Shishavan et al., 2014; Asgharzadeh Shishavan et al., 2015; Eaton et al., 2017, 2015; Bellout et al., 2012; Foss, 2012), however its application to hydraulic fracturing, particularly in the context of regulating the proppant distribution across the fracture, has not received much attention because of the following reasons: (1) limited access to real-time measurements, (2) presence of uncertainties in the measurement data, and (3) large computational requirements due to dynamic simulation of multiple highly-coupled partial differential equations (PDEs) defined over a time-dependent spatial domain. While some attempts to employ model-based control schemes have been made by Gu and Hoo (2014, 2015), these studies did not explicitly take into account practical considerations such as the desired fracture geometry, optimality and safety considerations, and uniformity in final proppant distribution across the fracture.

Motivated by these considerations, we focus on the development of a model predictive control framework to regulate the spatial variation of proppant concentration across the fracture at the end of pumping. Unlike other pumping schedules (Nolte, 1986; Gu and Desroches, 2003; Dontsov and Peirce, 2014; Yang et al., 2017), the proposed control framework will generate an optimal pumping schedule by utilizing the real-time measurements to estimate unmeasurable states as well as considering the fact that a pumping schedule consists of multiple substages where the concentration can be varied, and the desired fracture geometry that has to be satisfied at the end of pumping. More importantly, motivated by many studies devoted to proppant transport (Daneshy, 1978; Mobbs and Hammond, 2001; Shokir and Al-Quraishi, 2007; Shiozawa and McClure, 2016), the pumping schedule generated from the proposed framework will directly incorporate the relationship between the proppant concentration and fracturing fluid viscosity to enable the proposed approach applicable to a broad range of proppant concentration.

This paper is organized as follows: first, a dynamic model of hydraulic fracturing is constructed by taking into account elasticity theory, the conservation of fluid, lubrication equation, pressure–width relationship, leak-off model and Stokes' law. Then, a numerical simulator is developed to describe the spatiotemporal evolution of fracture geometry, suspended proppant concentration, and proppant bank formation across the fracture, effectively handling the computational requirement attributed to coupling of multiple equations over the time-dependent spatial domain. Next, a reduced-order model is developed using the simulation results, based on which a Kalman filter is designed to estimate unmeasurable states such as the proppant concentration inside the fracture. Lastly, a model predictive controller that utilizes the available state estimates is designed to achieve uniform proppant concentration across the fracture at the end of pumping.

2. Dynamic modeling of hydraulic fracturing processes

A dynamic model of a hydraulic fracturing process consists of two sub-processes: fracture propagation and proppant transport.

2.1. Modeling of fracture propagation

The fracture propagation is modeled based on the following assumptions: (1) fracture propagation is described by Perkins, Kern, and Nordgren (PKN) model (refer to Fig. 1); (2) the formation layers above and below are where the fractures have sufficiently large stresses such that the vertical fracture is confined within a single horizontal rock layer; (3) the rock properties (e.g., Young's modulus) remain constant with respect to time and space; and (4) because the fracture length is much greater than its width, the fluid pressure across the vertical direction is constant.

2.1.1. Fluid momentum (lubrication theory)

The fluid flow rate inside the fracture is determined by the following equation for flow of a Newtonian fluid in an elliptical section (Nordgren, 1972; Economides and Nolte, 2000):

$$\frac{dP}{dz} = -\frac{64\mu Q}{\pi H W^3} \tag{1}$$

where P is the net pressure, z is the spatial coordinate in the horizontal direction, μ is the fluid viscosity, Q is the local flow rate into the horizontal direction, H is the fracture height, and W is the fracture width.

2.1.2. Rock deformation (elasticity equation)

For a crack under constant normal pressure, the fracture shape is elliptical as shown in Fig. 1. The maximum fracture width (i.e., the minor axis of the ellipse) due to the loading by the fluid pressure is

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