Journal of Petroleum Science and Engineering 124 (2014) 468–483

Contents lists available at ScienceDirect

Journal of Petroleum Science and Engineering

journal homepage: www.elsevier.com/locate/petrol

Applying complex fracture model and integrated workflow in unconventional reservoirs

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ARTICLE INFO

Article history:
Received 26 August 2013
Received in revised form
10 September 2014
Accepted 22 September 2014
Available online 2 October 2014

Keywords:
hydraulic fracturing
complex fracture
fracture modeling
unconventional
design workflow
interaction with natural fractures

ABSTRACT

In this paper we present a comprehensive and yet efficient complex fracture network model that simulates hydraulic fracture networks created during the stimulation treatment and proppant placement. The theoretical framework of overall complex fracture modeling is described. The paper then focuses on two critical components of the model that address hydraulic fracture–natural fracture interaction (the crossing model) and interaction between hydraulic fractures (stress shadowing). The details of the model and its validation against experimental data and other numerical simulations are presented. A field example involving both slick water and crosslinked gel treatment is simulated using the complex fracture model and the results are compared to the microseismic monitoring.

Due to the complex fractures generated in stimulation of unconventional reservoirs, proper reservoir characterization is essential to obtain more reliable input to the fracture model and to reduce the uncertainties. Complex fractures also present new challenges for the reservoir simulators to properly model the production through the often partially propped complex fracture networks. To enable efficient development and optimization of the completion strategy and treatment design, the fracture model must be closely integrated in a platform that provides efficient workflow to easily build or leverage available geological and geomechanical models as input to the fracture model, calibrate against microseismic measurement, and link to the reservoir simulator for production simulation. This paper presents the integrated workflow in which the complex fracture model is built and illustrates the design optimization process through an example.

1. Introduction

Economic production from ultra-low permeability unconventional reservoirs depends greatly on the effectiveness of hydraulic fracturing stimulation treatment. Microseismic measurements and other evidences suggest that the creation of complex fracture networks during fracturing treatments may be a common occurrence in unconventional reservoirs (Maxwell et al., 2002; Fisher et al., 2002; Warpinski et al., 2005). It has long been observed in mine-back experiments and core-throughs (Warpinski and Teufel, 1987; Warpinski et al., 1993; Jeffrey et al., 1994; Jeffrey et al., 2009a, 2009b) that hydraulic fracture interaction with natural fractures is likely to result in complex fractures. The created complexity is strongly influenced by the pre-existing natural fractures and in-situ stresses in the formation. However, due to the lack of industry's modeling capability in simulating complex fractures and lack of proper characterization of key reservoir properties, completion and stimulation design for the unconventional reservoirs in the past heavily relied on imprecise estimate of the Stimulated Reservoir Volume (SRV) from microseismic observations and through trial-and-error, a highly inefficient approach. Not being able to accurately simulate complex fractures generated during the fracture treatment presents a major limitation that promotes a cookie-cutter completion and fracture design rather than one that is optimized based on the well conditions and formation properties. Fracture simulation can provide information such as propped vs. unpropped fracture surface area, proppant distribution and conductivity, all of which are critical to the short and long term production from the unconventional reservoir, and cannot be obtained from microseismic measurement alone (Cipolla et al., 2011b).

In recent years, new hydraulic fracture models have been developed, or existing geomechanics models adapted, for simulating complex fracture networks in a hydraulic fracture treatment of unconventional reservoir (Xu et al., 2009; Dershowitz et al., 2010; Weng et al., 2011; Meyer and Bazan, 2011; Nagel et al., 2011; Fu et al., 2011; McClure, 2012; Savitski et al., 2013; Wu and Olson, 2013).

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http://dx.doi.org/10.1016/j.petrol.2014.09.021
0920-4105/

However, the process of hydraulic fracture propagation in a formation with preexisting natural fractures is very complex. Realistic simulation of this process requires proper consideration of the key physical elements governing the process that are important for ultimate reservoir production, including rock deformation, fracture propagation, fluid flow in the complex fracture networks, interaction between the hydraulic fractures and natural fractures, interaction among different hydraulic fractures, fracture height growth, and proppant transport in the fracture networks. Although complete and rigorous simulation of all the key underlying processes is technically very challenging and most models have simplifying assumptions, it is important that the models capture the most essential elements so that simulation reasonably represents the real process. Today many complex fracture models are still evolving and are applicable to the limited conditions where the model assumptions are valid, or missing important elements to fully simulate the complete fracturing process.

Wide microseismic events cloud as often observed in fracture treatments in shale is a hallmark of complex fractures. Microseismic events are mostly attributed to shear failures along natural fractures or faults surrounding a hydraulic fracture (Rutledge et al., 2004; Williams-Stroud et al., 2012). The events cloud forms a “halo” surrounding the hydraulic fracture. In conventional sandstone formations, the observed events cloud has a relatively narrow width, whereas in unconventional reservoirs a much wider events cloud is observed (Fisher et al., 2002). A wide microseismic cloud may possibly be explained by either deep fluid penetration into natural fractures in the shale while the induced hydraulic fracture remains planar or simple (Savitski et al., 2013), or by the creation of complex hydraulic fracture network. Although deep fluid penetration into a highly permeable and initially well-connected natural fractures network is certainly possible (Zhang et al., 2013), many unconventional plays have very low effective permeability, and observation of cores shows that most natural fractures in these shales are healed or mineralized (Gale et al., 2007; Gale and Holder, 2008; Han, 2011; Williams-Stroud et al., 2012). Therefore, in very low permeability shale, fluid penetration in the natural fractures network is limited. Fluid penetration into natural fractures can also occur due to dilation of natural fractures as a result of shear slippage, but this typically occurs under the condition of large stress anisotropy and for natural fractures oriented 30–60° from the principal stress directions (Murphy and Fehler, 1986). For many shale reservoirs where the tectonic environment is relaxed and the difference between the horizontal stresses is low, a wide microseismic cloud is a strong indication that complex, open hydraulic fracture networks are being created, although the hydraulic fractures may follow the paths of the natural fractures. The field case in Barnett shale presented by Fisher et al. (2002), in which fracturing fluid unexpectedly connected to and brought down the production of several adjacent wells not on the expected fracture plane provided the supporting evidence of complex hydraulic fracture networks. In the analysis of a field case in Barnett shale, Cipolla et al. (2010) showed that the predicted fracture length from a planar fracture model far exceeded the fracture length indicated by the microseismic data, unless a very low fluid efficiency (less than 10%) is assumed in the simulation in order for a planar fracture to accommodate the large volume of fluid injected. Such low efficiency is not consistent with the very slow pressure decline observed during the shut-in in most shale formations. In contrast, complex hydraulic fracture networks can explain the much larger fluid volume stored in fracture networks for the same fracture length and yet still high fluid efficiency (low leakoff).

A critical consideration of a complex fracture model is the interaction between the hydraulic fracture and the natural fracture. For a formation that initially contains a large number of well-connected natural fractures, fracturing fluid is directly injected into and dilates the existing natural fracture network. In this case, the induced hydraulic fractures follow the natural fracture network, and relatively few new fracture paths are created. To simulate this scenario, modeling of fracture propagation is not required, and a static numerical grid properly modeling the natural fracture system can be used to simulate the problem. A coupled geomechanics-reservoir model that is capable of solving the coupled fracture (or joint) deformation and fluid flow in the fracture networks is well suited for this kind of simulation (e.g., Nagel et al., 2011). In formations that contain a large number of isolated or poorly connected natural fractures, the natural fractures are only hydraulically activated when intersected by hydraulic fractures and then can alter the path or cause branching of the hydraulic fractures. The induced hydraulic fracture that travels along an isolated natural fracture can change direction when it reaches the ends of the natural fracture or when it intersects other natural fractures. In the limiting case when no natural fracture exists in the formation, the induced fractures become planar fractures. To properly simulate the fracture treatment in this type of reservoirs, the model needs to simulate hydraulic fracture propagation. A general purpose, complex fracture model must have the capability to simulate both scenarios, (i.e. including fracture propagation and interaction between hydraulic fracture and natural fracture).

As evidenced in the mineback experiments, a hydraulic fracture can cross a natural fracture without change of direction under some conditions, but may be arrested or branch off along the natural fracture in other situations (Boyer et al., 1986; Jeffrey et al., 2009a, 2009b). To require a complex fracture model be capable of simulating the interaction between hydraulic and natural fractures presents a major technical challenge for commercial fracture models. This is because of the fact that fracture interaction is driven by the highly localized stress field and natural fracture activation near the hydraulic fracture tip right before and after it intersects the natural fracture. To model this process numerically requires a very fine simulation grid and is computationally cost-prohibitive if each fracture intersection point is to be simulated accurately in a large complex fracture networks. Using the typical reservoir-scale numerical grid cannot correctly represent the fracture interaction unless the simulator builds in a separate crossing model that can predict the crossing behavior accurately and efficiently. An analytical or semi-analytical crossing model is an ideal approach for this purpose.

In this paper, we present a general complex fracture model, referred to as UFM unconventional fracture model that is based on the same construction as the pseudo-3D planar hydraulic fracture model but is capable of simulating a complex fracture network with a multitude of propagating fracture tips. An analytical sub-model for hydraulic fracture-natural fracture interaction (also called the OpenT crossing model) that evaluates local activation and re-initiation at a contacted fracture is integrated within the UFM model for crossing prediction (Chuprakov et al., 2013a). The crossing model takes into account fluid flow and viscosity effect and is validated against the experimental data and independent fine-grid numerical simulations. Integration of the analytical crossing model into the reservoir-scale UFM model makes the model computationally efficient and also properly captures the fracture interaction behaviors. We also discuss the modeling of interaction among the hydraulic fractures, the so-called stress shadow effect. A field example involving both slick water and cross-linked gel treatment is simulated using the UFM model and the results are compared to the microseismic monitoring.

The introduction of complex hydraulic fracture models provides a critical component by which to integrate the completion and stimulation treatment with microseismic interpretation, production