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Overview of numerical models for interactions between hydraulic fractures and natural fractures: Challenges and limitations

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ABSTRACT

The intersection of natural fractures with hydraulic fractures results in formation of complex fracture networks, including non-planar fractures or multi-stranded fractures. On one hand, opening of these natural fractures improves productivity of the formation; on the other hand, coalescence of these fractures into a hydraulic fracture makes pressure analysis and prediction of fracture growth very complicated. Overall, interactions between natural fractures and hydraulic fractures pose more challenges in the fracturing design and its execution. Investigation and understanding of their interaction are crucial in achieving successful fracture treatments in formations with pre-existing natural fracture network. In this paper, we will review the numerical works that have been done in the last decade to model opening of natural fractures during hydraulic fracturing, focusing especially on mechanical models that address propagation of hydraulic fractures in naturally fractures reservoirs. Linear elastic fracture mechanics, cohesive element methods and continuum damage mechanics techniques utilized to understand interaction of hydraulic fractures with natural fractures are discussed here based on their capability to reproduce experimental results and field observations.

1. Background

Hydraulic fracturing is an evolving technology that has been contributing to the boom of oil and gas production in the United States in the last decade, several decades after its initial appearance in the middle of the last century [34]. Massive hydraulic fracturing jobs have been conducted in the past two decades, which significantly relieved the increasing energy needs from both developed and emerging economies [42]. Meanwhile, concerns were raised by industry professionals and government regulatory agencies regarding the effectiveness of fracturing and possible hazards due to hydraulic fracturing [23]. The fact that hydrocarbon-bearing reservoirs are seldom homogeneous in terms of their geomechanical properties further complicates the hydraulic fracturing design. Specifically, the pre-existing natural fractures in some of these formations would interact with hydraulic fractures and inevitably impact the propagation, geometry and effectiveness of hydraulic fractures [19]. This paper provides an overview of different numerical methods used in the literature to incorporate the effect of natural fractures on hydraulic fractures growth.

Hydraulic fracturing is a well stimulation technique in which formation rock is cracked by excessive hydraulic pressure, and initiated fractures subsequently propagate and form high permeability flow pathways [42]. Continuous pumping of fracturing fluid enlarges the fracture volume and keeps the fracture propagating in the direction of lowest resistance or maximum energy release. The idea of hydraulic fracturing initially came from acid stimulations by Dow Chemical Company in 1930s, during which it was discovered that by injecting fluid at a sufficiently large pressure, it is possible to improve the effectiveness of acid stimulation by fracturing the formation surrounding the wellbore [30]. However, it was not until 1947 when the first commercial hydraulic fracturing treatment was performed in a gas well in Hugoton field, Kansas [28]. Since then, approximately 2.5 million fracturing treatments have been performed in the oil and gas industry worldwide. It is estimated that currently 60% of wells drilled are being fractured [42]. Hydraulic fracturing not only improves the rate of recovery of hydrocarbons, but also increases the quantities of producible oil and gas (ultimate recovery). Fracturing technology have added 9 billion barrels of oil and more than 700 trillion cubic feet of natural gas to the hydrocarbon reserves in the United States, which are otherwise not accessible nor economical through conventional production technology.

Large volumes of oil and gas have been found in low-permeability fractured reservoirs around the world. Tight sandstones are just a part of what is recognized as unconventional gas, which also includes coal bed methane, shale gas and natural gas hydrates.

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Because of the low permeability of these formations and the low conductivity of the natural fracture networks, stimulation treatments such as hydraulic fracturing are necessary to obtain economic production. The low hydraulic conductivity of the natural fractures could be caused by cements that precipitated during the diagenesis process (Laubach, 2003). The fact that natural fractures might be sealed by cements does not mean that they can be ignored while designing well completion processes. Cemented natural fractures can still act as weak paths for fracture growth [69,18]. However, the presence of pre-existing natural fractures is not always advantageous [32]. Unfortunately due to the limited access to the subsurface, monitoring the interaction between hydraulic fracture and natural fractures cannot be done by direct observation. Even, widely used techniques like microseismics may show the effect of natural fractures on hydraulic fracture growth qualitatively not quantitatively [65,17]. Rutledge and Phillips [50] showed through composite focal mechanisms both left- and right-lateral strike-slip faulting along near-vertical fractures that strike subparallel to maximum horizontal stress as indication of natural fractures activation during fracturing treatments. However, it is possible to obtain some qualitative information about fracture complexity from post job pressure analyses [12] and core studies. Efforts to understand this problem are not limited to field observations and mathematical modeling. Lab experiments were also performed to reproduce field data and examine mathematical models. Lamont and Jessen [37] performed 70 hydraulic fracturing experiments in six different rock types, using triaxial compression (up to 1140 psi) with different approach angles to understand the fracture crossing phenomenon. The size of their samples was less than a meter. Hydraulic fractures appeared to crossover closed pre-existing fractures at all intersection angles. However, Lamont and Jessen noted that the fracture propagation speeds in their lab models were considerably greater than the field tests, making their results less reliable. However the main problem in their experiments was lack of correct scaling as all these experiments were falling in toughness dominated regime rather than viscous dominated regime (see [25] for more discussions on scaling).

Daneshy [21], based on his experiments, argued that the hydraulic fractures appeared to be arrested when the natural fractures were open at the intersection point and appeared to cross the natural fractures when they were closed. Later, Anderson [3] showed the importance of friction on hydraulic fracture growth near unbonded rock interfaces. These tests were performed in Nugget sandstone and Indiana Limestone under uniaxial loading. The results lead to the concept of a threshold of normal stress below which hydraulic fracture growth is arrested by a natural fracture. They found that this normal stress is inversely proportional to friction between surfaces of the natural fracture. Blanton [8,9] conducted analogous experiments to generalize Anderson's [3] outcomes for various intersection angles. He performed experiment with blocks of a Devonian Shale cast in hydrostone to show crossing of a hydraulic fracture over the pre-existing fracture occur only under high differential stresses and high angles of approach. Blanton noted that in most cases fractures were either diverted or arrested by pre-existing fractures, but he did not provide any threshold for the approach angle to predict fracture arrest or fracture diversion. Cleary et al. [13] argued that fracture energy (due to its pressure) is high enough to open any fracture in any orientation, but they did not give any clear scheme or analysis for their claim. Furthermore, various post-treatment pressure analysis are not supporting this claim. Warpinski et al. [64] analyzed the characteristic of the cores recovered from the Williams Fork formation of Mesaverde group in the Piceance basin six years after the fracturing treatment. Authors identified two sets of propped multiple-fracture zones, which were offset by 75 ft. Hopkins et al. [33] studied several hydraulic fracturing treatments in a fractured Antrim shale reservoir located in Michigan. Their microseismic maps described a cloud of events within approximately 50 ft of the presumed fracture tips. These measurements were verified with eight hydraulic fractures recovered in cores from two deviated wellbores drilled across the hydraulic fracture direction. Despite the high differential stresses, they concluded that complex fracture paths are primarily controlled by Antrim Shale natural fractures geometry. This conclusion was in contrast with Blanton's theory [8], which limits natural fracture dilation to locations with low differential stresses.

Current industry practices in assessing and modeling hydraulic fracturing treatments relied on simplified fracture and fluid flow models, which could only provide approximated descriptions regarding the actual fracture geometry. For instance, common assumptions in fracturing modeling include homogeneous formation properties and limited fracture growth in a symmetric double-wing fashion; these assumptions are likely to be erroneous in many unconventional gas reservoirs where material properties and fracture development can be quite complicated [60]. For instance, the non-planarity of the fracture system hinders proppant transport through the network [63] or for instance in some papers, abnormally high net pressure has been accredited to simultaneously propagating multiple strands (for example see [57] as the sub-parallel pressurized fractures are pushing to close each other. Therefore, it is quite important to have a model to predict how hydraulic fracture geometry can be affected by natural fractures.

Despite significant advances in numerical modeling of the hydraulic fracturing through natural fractures, these models require an accurate description of natural fractures, which is often unknown to operators. Moreover, these numerical modeling techniques usually do not incorporate post-treatment data to reflect actual reservoir characteristics. However, there were few deterministic and stochastic efforts to address these challenges. Olarewaju et al. [43] developed a stochastic simulation method for evaluating the distribution of natural fractures. They utilized fracture density data from FMI logs in horizontal wells to infer the fracture distribution and short to large scale correlation structures by Sequential Indicator Simulation method. Anraku et al. [2] studied the Yufutsu field with stochastic fracture modeling. Considering the fact that natural fractures distribution do not look random on outcrops, some efforts were made toward applying fracture mechanics to generate more realistic fracture patterns. This approach attempted to reproduce the same fracture spacing, length and aperture distributions [70]. Young's modulus of elasticity, subcritical crack index, mechanical bed thickness, and tectonic strains (and/or pore pressure) are the input parameters of the mechanical model. Olson [44] has shown that fracture patterns (particularly with respect to clustering) are dependent on the subcritical index (SCI) for a constant strain, mechanical bed thickness, and elastic properties of rock. Puyang et al. [47] proposes a data integration workflow to estimate geometry of natural fractures based on logs, microseismic data, treatment data and production history, which is essentially based on defining a fit grid using least-square technique to obtain possible realizations of natural fractures from selected double-couple microseismic events. Forward modeling incorporating Discrete Fracture Network can then be utilized for matching bottom-hole pressure to further screen generated fracture realizations. Further discussions on these topics can be pursued in joint distribution papers; hence for the rest of the paper, we assumed that natural fracture geometry is provided somehow as an input to the modeler.

2. Governing equations

Before discussing different approaches in modeling interactions of hydraulic fractures and natural fractures, it would be beneficial