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Development of innovative and efficient hydraulic fracturing numerical simulation model and parametric studies in unconventional naturally fractured reservoirs ☆

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ABSTRACT

The most effective method for stimulating unconventional reservoirs is using properly designed and successfully implemented hydraulic fracture treatments. The interaction between pre-existing natural fractures and the engineered propagating hydraulic fracture is a critical factor affecting the complex fracture network. However, many existing numerical simulators use simplified model to either ignore or not fully consider the significant impact of pre-existing fractures on hydraulic fracture propagation. Pursuing development of numerical models that can accurately characterize propagation of hydraulic fractures in naturally fractured formations is important to better understand their behavior and optimize their performance.

In this paper, an innovative and efficient modeling approach was developed and implemented which enabled integrated simulation of hydraulic fracture network propagation, interactions between hydraulic fractures and pre-existing natural fractures, fracture fluid leakoff and fluid flow in reservoir. This improves stability and convergence, and increases accuracy, and computational speed. Computing time of one stage treatment with a personal computer is now reduced to 2.2 min from 12.5 min than using single porosity model.

Parametric studies were then conducted to quantify the effect of horizontal differential stress, natural fracture spacing (the density of pre-existing fractures), matrix permeability and fracture fluid viscosity on the geometry of the hydraulic fracture network. Using the knowledge learned from the parametric studies, the fracture–reservoir contact area is investigated and the method to increase this factor is suggested. This new knowledge helps us understand and improve the stimulation of naturally fractured unconventional reservoirs.

Introduction

In recent years, development of shale gas reservoirs (organic-rich gas bearing shale formation) has become a more important means of accessing fossil energy resources. The key to that development is to stimulate these low-permeability reservoirs with successful and effective fracture treatments. In addition to field pilot studies, numerical modeling of the hydraulic fracture process is vital means of in improving understanding and improving effectiveness of fracture treatments in gas shales. Robust modeling of fracture propagation requires an integration of fracture fluid flow mechanics, particle transport, rock mechanics, petrophysics and fluid flow through porous media. Rock properties include 3 dimensional Young's modulus, shear modulus and Poisson ratio, tensile strength, fracture toughness, 3 dimensional in situ stresses, etc. Fracture fluid properties of interest include rheological models, viscosity, density, leakoff behavior, proppant transporting capacity, etc. which may be pressure, temperature, and shear rate dependent.

In reservoirs with natural fractures, the opening fractures control fluid flow paths such that the production mechanism in

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Nomenclature

A	cross sectional area (ft^2)
B	formation volume factor (RB/STB)
C_w	compressibility of water (psi^{-1})
d	extended distance (ft)
f_{L1}, f_{L2}	fractions of fracture half-length (fraction)
G	shear modulus of rock formation (psi)
h	fracture gross height (ft)
h_f, H_{fl}	fracture height (ft)
k	permeability in the x, y and z direction (md)
K_f	coefficient of friction (frictional)
kr	relative permeability (md)
L_f, l	fracture length (ft)
p_f	fluid pressure in the fracture (psi)
q	fluid injection rate or flowrate of each grid block (bbl/min)
R_s	solution gas-oil ratio (SCF/STB)
s	distance along the fracture (ft)
S_w	water saturation (dimensionless)
T_o	tensile strength of the rock (psi)
v_{tip}	flow velocity at the tip of fracture (L/T)
w	fracture width (ft)
$\bar{w}$	Average fracture width (ft)
α_c	volumetric conversion factor (dimensionless)
βc	transmissibility conversion factor (dimensionless)
μ	fluid viscosity (cp)
ν	Poisson's ratio (dimensionless)
ρ	fluid density (lbm/ft^3)
σ_1, σ_2	far-field effective stresses (psi)
σ_h	minimum horizontal principal stress (psi)
σ_H	maximum horizontal principal stress (psi)
σ_n	normal stress acting on the NF plane (psi)
σ_t	stress acting parallel to the NF (psi)
φ	porosity (dimensionless)
γ	gravity of phase (psi/ft)

naturally fractured reservoirs is significantly different from that in conventional reservoirs. These natural fractures may close as the reservoir pressure drops, which also influences the growth and final geometry of hydraulic fractures that serve to enhance production (Lorenz and Warpinski, 1996; Teufel and Clark, 1984; Cipolla et al., 2010a,b). Because natural fractures will significantly impact stimulation behavior, knowing the properties and geometry of pre-existing natural fractures in a reservoir can facilitate the design of effective hydraulic fracturing for efficient resource recovery.

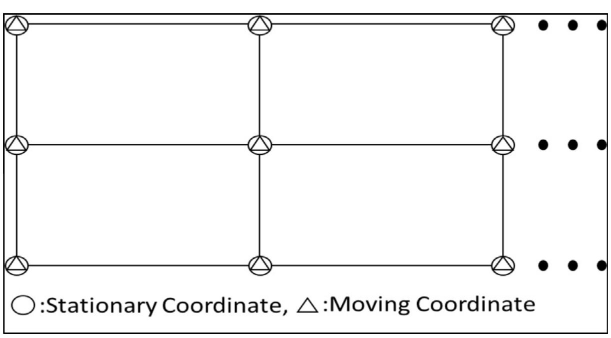

Fig. 1. Schematic of fracture domain discretization.

Table 1
Simulation time comparison between single porosity model vs. our model.

	Zeini Jahromi's single porosity model	Our model	Reduced %
Simulation time (min)	12.5	2.21	82.32

Numerous authors have investigated fracture propagation behavior in naturally fractured reservoirs both experimentally (Blanton, 1982; Renshaw and Pollard, 1998; Warpinski and Teufel, 1987) and numerically (Taleghani and Olson, 2011, 2013; Weng et al., 2011; Zhang et al., 2007a,b; Zhang and Jeffery, 2008; Keshavarzi and Mohammadi, 2012; Meyer et al., 2011; Yoon et al., 2014). The Renshaw and Pollard criterion has been extended to intersection at non-orthogonal angles by Gu et al. (2011). Mathematical models of interaction between hydraulic fracture and natural fractures were reviewed and summarized by Poltluri et al. (2005).

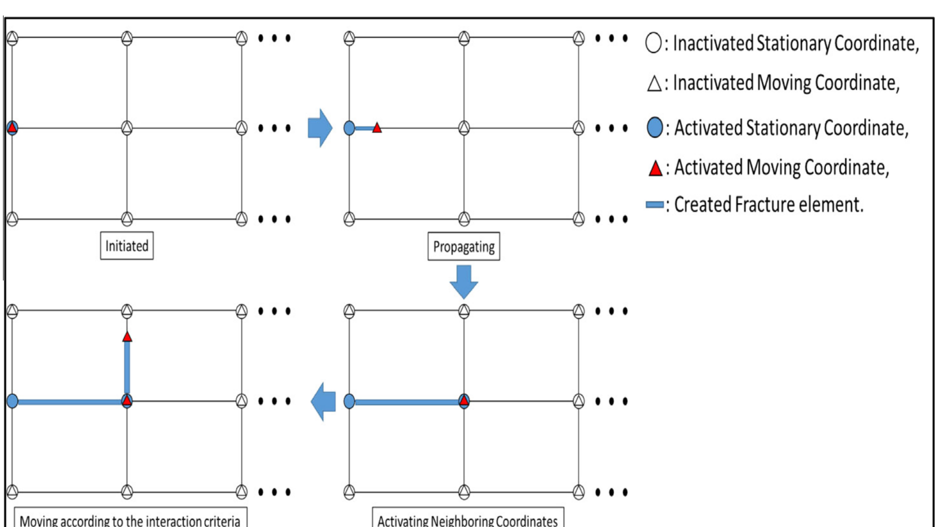

Fig. 2. Coordinate system during fracture propagation.