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Impact of thermally reactivated micro-natural fractures on well productivity in shale reservoirs, a numerical study

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A R T I C L E I N F O

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A B S T R A C T

Recovered core samples and extensive outcrops studies have proved the existence of natural fractures in many tight formations. These natural fractures are likely filled with digenetic materials such as clays, quartz or calcite. In this numerical study, we suggest that small cemented natural fractures, exposed to the surface of the hydraulic fracture, can be opened by the induced tensile stress due to the temperature difference between the cold fracturing fluid and hot formation. Cohesive zone model (CZM) is utilized here to simulate these natural fractures. Tensile strength of digenetic cements, temperature difference between the fracturing fluid and formation, fractures spacing, and rock conductivity are the parameters controlling the opening and length of reactivated micro-fractures. Reactivated natural fractures may improve the rock permeability in the vicinity of the hydraulic fracture; however, the amount of permeability enhancement depends on the density and width of reactivated fractures. Contribution of these micro natural fractures to cumulative gas production from a shale reservoir is investigated by modifying the transmissibility coefficient in the dual porosity and dual permeability model. Transmissibility coefficient is then modified accordingly to estimate increase in gas production from the reactivated natural fractures in the reservoir simulator. Reservoir simulation results suggest that reactivated natural fractures in the tight formations at early stages can improve gas production up to 25% which may improves net present value of the project; however, their effect significantly reduces to 3% in long term cumulative production.

1. Introduction

Hydraulic fracturing treatments have played a crucial role in boosting hydrocarbon production from low permeability reservoirs. Induced fractures significantly improve wellbore-formation contact area and consequently increase the production rate. Injection of highly pressurized fracturing fluid fractures the formation to create a highly permeable conduit for the reservoir fluid to produce. The direction of hydraulic fracture propagation depends on the direction of the minimum principal stress as well as natural fractures (Economides and Nolte, 2000; Dahi-Taleghani and Olson, 2011). Core and outcrop studies, advanced logging tools, microseismic techniques and well testing analysis have proved the existence of natural fractures in many unconventional reservoirs. In naturally fractured reservoirs, arrest and diversion of hydraulic fracture front into the pre-existing natural fractures have been the subject of many experimental and theoretical studies (Warpinski and Teufel, 1987; Potluri et al., 2005; Dahi Taleghani et al., 2013; Gonzalez-Chavez et al., 2015).

Natural fractures are mechanical discontinuities with the lengths varying from micrometers to kilometers (Narr et al., 2006). These fractures may act as conductive paths for the fluid flow in the low permeability reservoirs affecting the ultimate recovery. However, they can also increase the leakoff volume during the fracturing treatments leading to early screenouts or poorly propped hydraulic fractures. Contribution of natural fractures in the hydrocarbon recovery is more significant in the tight formations with low permeability than permeable reservoirs (Nelson, 2001). Existence of natural fractures in the outcrop samples could be an indicative of their existence in the subsurface; however, characterization of natural fractures in subsurface is not a trivial task. Most of the outcrop studies are qualitative and the existing models studying the interaction of natural fractures with the hydraulic fracture mainly consider the contribution of large natural fractures, i.e. fractures with the dimensions comparable to the size of hydraulic

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fracture, on the hydraulic fracture growth (Jeffrey et al., 2009; Dahi Taleghani and Olson, 2014). However, the lognormal distribution of natural fractures, shown in Fig. 1, demonstrates that small natural fracture exist orders of magnitudes more frequent than the large natural fractures. Hence, the role of small-size natural fractures may be as important as the large natural fractures since the small fractures exist in large numbers. Length of Small natural fractures varies from micro-to centimeter; therefore, injected proppants cannot enter inside these small fractures to keep them open.

In contrast to the driving force of the main hydraulic fracture, the magnitude of induced thermal stresses, only a few MPa, is not large enough to initiate new fractures in the rock, but it may be sufficient for opening pre-existing micro natural fractures even if they are filled with the digenetic materials. Cement bonding is usually much weaker than the rock strength. Parameters controlling the opening of these small fractures are tensile strength of cement materials filling the fractures, temperature difference between the fracturing fluid and the formation, and microfractures' density. Induced thermal stress in a homogenous isotropic elastic half-plane due to heat conduction can be shown by Equation (1) (Nemat-Nasser et al., 1978). The elastic half-plane is at the initial temperature of T_0; however, temperature at its surface suddenly drops to the temperature of T_1. δ is a length scale where s specific temperature gradient has been formed. The rest of parameters are defined in the nomenclature.

$$\frac{d\sigma}{dx} = \frac{2D_T\beta_s(T_0 - T_1)}{3\sqrt{\pi}}e^{-\left(\frac{x\sqrt{3}}{\delta}\right)^2}, \ \delta = \left(\frac{tk}{\rho C}\right)^{0.5} \tag{1}$$

Rock thermal failure due to injection/circulation of cold water into the brittle hot rocks is a known phenomenon (Perkins and Gonzalez, 1985). The effect of temperature changes in stress redistribution and consequently fracture opening is mainly studied in hot dry geothermal reservoirs rather than hydrocarbon reservoirs. For instance, Zhou et al. (2010) have only considered thermal fracture initiation in a homogeneous rock. In a reservoir with multiple natural fracture sets, stress shadow effect of neighbor cracks may lead to competition or arrest of advancing cracks. Opening of small fractures in large numbers may significantly improve well productivity by increasing fracture-formation contact area and rock overall permeability. Since the fracturing fluid is injected at the ambient temperature at the surface and it has a high velocity in the tubing, its temperature is lower than the reservoir temperature when it initially exposes to the surface of hydraulic fracture. This temperature difference induces tensile stress on the surface of the hydraulic fracture. If the induced stress exceeds the tensile strength of cementitious materials filling the natural fractures, natural fractures starts opening to relax the excessive stress. The required energy to open small natural fractures is less than the energy required for opening large natural fractures. Temperature gradient as the driving force for thermal failure is a function of parameters like injection rate, tubing size, fracture width and length. This study aims to quantitatively estimate the impact of opening small pre-existing natural fractures due to thermal stress and its contribution to the hydrocarbon recovery. The potential shale gas reservoirs to show this phenomenon should have high temperature like Eagle Ford in South Texas or Haynesville in Texas/Louisiana. These reservoirs are deep enough to have high temperature. For the low temperature fracking fluid, liquid nitrogen can used to cooling the fracturing fluid.

2. Natural fractures characterization

Fractures are discontinuities formed to alleviate excessive pore pressure or stress in the rock mass with possibly self-affine or fractal structures like the fracture pattern shown in Fig. 2. Natural fractures can cause significant heterogeneity and anisotropy in permeability and strength of the rock. There are several ways to guess fracture patterns in the subsurface like outcrop studies, production data, reservoir core study and image logs (Narr et al., 2006). Among these methods, outcrops, if available, are the most direct way to study natural fractures geometry. Natural fractures may be identified during drilling phase by considerable mud loss, bit chatting and bit drops, or in the early stages of production by heterogeneity in production and productivity index. Natural fracture characterization may also be achieved by integration of microseismic data, well log, treatment data and production history which involved more complicated workflow (Puyang et al., 2015).

Natural fractures may play an important role in well stimulation as they act as preferred paths for fracture path development. Open natural fractures increase reservoir overall permeability and consequently the hydrocarbon production, however, fully cemented fractures may act as barriers against fluid flow. Degree of

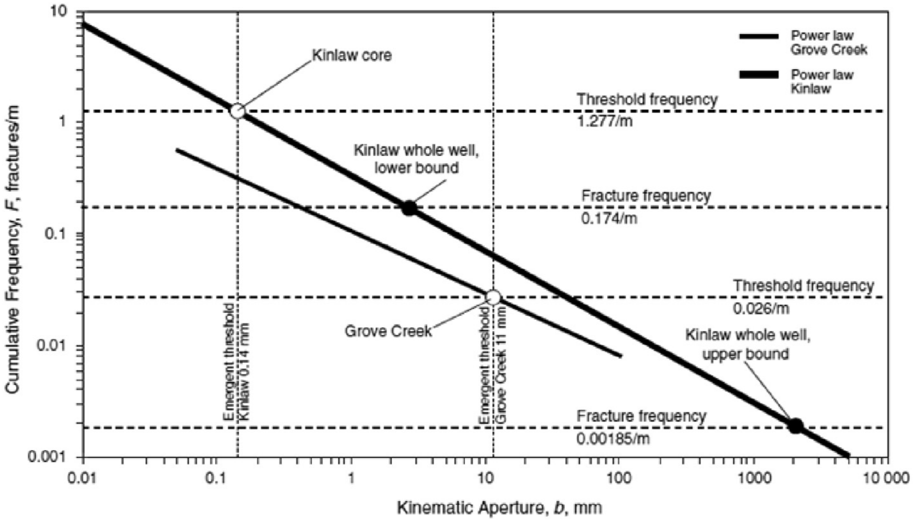

Fig. 1. Power-law aperture-size distribution in Groove Creek and Kinlaw formations shows micro-fractures have larger frequency than large size fractures (Plot borrowed from Gale, 2002).