In-situ Estimation of Unpropped Fracture Conductivity in Shale and Assessing its Role during Stimulation and Production*

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Abstract

Formation productivity is determined by the matrix quality (the permeability, organic content, etc.) and by the formation's ability to fracture. The formation's ability to fracture is the degree to which injection can create a large and productive fracture network. Considerable disagreement exists about what parameters control a formation's ability to fracture. The term "brittleness" is often used to refer to a formation's ability to fracture, but this is a rather ill defined term. Yang et al. (2013) compared a variety of brittleness indices defined in the literature and found that they were not well correlated when compared against each other.

Introduction

We have approached the concept of a formation's ability to fracture from the perspective of field scale stimulation modeling. Simulations were performed using CFRAC (Complex Fracturing Research Code), which is a two-dimensional discrete fracture network simulator that fully couples fluid flow with the stresses induced by fracture opening and sliding and is efficient enough to perform field scale simulations with hundreds or thousands of fractures (McClure and Horne, 2013).

We performed sensitivity analysis simulations, which demonstrated the importance of unpropped fracture conductivity (UFC) for stimulation success. We also have identified and applied three methodologies for estimating UFC from in-situ measurements: a tendency for shear stimulation test, well-log analysis, and field scale inverse modeling. Our results and methodologies have direct application for stimulation design and sweet spot identification.

We performed a sensitivity analysis on the effect of eight parameters to estimate their effect of magnitude of the stimulated rock volume (SRV): shear modulus, Poisson's ratio, stress anisotropy, shear dilation angle, fracture stiffness, initial fracture aperture, fracture toughness, and the coefficient of friction. Field-scale simulations of a single fracturing stage were performed with CFRAC. Two-hundred simulations were performed with a uniform space filling design: a low discrepancy quasi-random sequence uniformly filling the hyperparameter space. Eight hundred additional simulations were performed according to the algorithm of Saltelli et al. (2008) for estimating the "total-effect index" of each variable. Each simulation used a different stochastically generated natural fracture network (though each was statistically similar in terms of fracture orientation, density, and length distribution). The effect of the variables on SRV was assessed based using three techniques: (1) multivariate linear regression, (2) a form of Monte Carlo filtering to estimate the effect of each variable on producing extreme values, and (3) assessment of the total-effect index for each variable. For all three methods of analysis, the parameters most strongly correlated to a large stimulated rock volume (SRV) were the variables controlling the conductivity of the stimulated fractures, especially the shear dilation angle. An example of a simulation result is shown in Figure 1.

Further sensitivity analysis simulations were performed to assess the effect of natural fractures in the context of different hypotheses about the processes that generate network complexity. Simulations were performed of five fracture stages along a horizontal well, with five perforation clusters at each stage. Three different conceptual models of stimulation were used: (1) planar fractures forming at each perforation cluster with no surrounding natural fractures, (2) continuous planar fractures forming at each performation cluster but surrounded by a dense network of natural fractures, and (3) propagating fractures terminating against natural fractures, creating a branching network of both new and preexisting fractures. Simulations were performed with different values of matrix permeability and natural fracture conductivity. The results were compared based on net pressure during injection, stress anisotropy reduction in the region around the well, length of the SRV, and the degree to which stress effects and heterogeneity effects dominated network generation. The results showed that simulations without natural fractures were excessively stress-effect dominated, required unrealistically high matrix permeability to prevent excessively long fractures, and had unrealistically low net pressure. In type (2) and (3) simulations, simulation results were only realistic if natural fractures were initially low conductivity but experienced significant stimulation in response to injection. The simulation results that resulted in the most realistic field scale results were the simulations with branching due to termination of hydraulic fractures against natural fractures.

Methods

We have identified three methods that may be used to quantify fracture stimulation parameters. The first is a tendency for shear stimulation (TSS) test, which was previously described by McClure and Horne (2014). The idea is to perform injection at pressure slightly less than the minimum principal stress in order to cause slip on natural fractures but not to form hydraulic fractures. If significant stimulation occurs and remains even after flowback, this indicates unpropped natural fractures are capable of sustaining significant flow through the reservoir.

The second method is to estimate unpropped fracture conductivity based on well log measurements. There is not a straightforward link between well log measurements and unpropped fracture conductivity, but we have identified several promising approaches. The methodology has been applied to a suite of well logs from a well in a domestic shale play.

The third method is field-scale inverse modeling. Given field scale information such as net pressure or SRV, inverse modeling can be used with a field scale hydraulic fracturing simulator to reduce uncertainty in model input parameters. This procedure allows model input parameters to be selected that allow simulation results to match known field data. The challenge is that there may be a large number of model parameters and each simulation can take several hours. Using simulations performed with a space filling design of the parameter hyperspace, nonparametric proxy models were constructed for efficient and approximate prediction of simulation SRV. Two types of proxy models were tested: radial basis functions (RBF) and multivariate adaptive regression splines (MARS). Based on cross-validation, MARS performed modestly better. The proxy models were fed into a genetic algorithm (GA) to find combinations of model parameters that matched the known data. The GA was run multiple times, and the best combination from each GA run was then fed into an actual CFRAC simulation to validate. The procedure was successful in finding combinations of parameters that provided a good match to the "known" data. However, the match was non-unique because many possible combinations of parameters in the hyperspace could provide a reasonable match to the data. We are currently applying a Bayesian framework to implement an integration of the proxy models with a Gibbs sampler to derive the full multidimensional joint probability distribution of model parameters that can match the known data. This probability distribution could be applied to hydraulic fracture design optimization. The framework could be easily adapted to incorporate a variety of additional information, such as results from well logs or a TSS test.

Discussion and Results

Our sensitivity analysis study has demonstrated that stimulated, unpropped fracture conductivity is critical for determining the ability of a formation to fracture. Furthermore, the interaction of hydraulic fractures with natural fractures or other planes of weakness can help explain a variety of field-scale observations, such as elevated net pressure, commonly observed fracture lengths, and asymmetry in the microseismic cloud and other heterogeneity related observations. Three methods for assessing UFC have been identified, each based on in-situ observations: a TSS test, well log analysis, and field scale inverse modeling. As these techniques continue to be developed and tested, opportunities will arise for them to be combined with other geophysical measurements such as seismic, helping development of additional predictive methodologies by providing a means for validation.

Characterizing UFC has direct practical application. In formations with high UFC, stimulation treatments should be designed with less proppant, larger fluid volume, and wider well spacing and stage spacing. In formations with lower UFC, stimulation treatments should be designed with more proppant, less fluid volume, and closer well and stage spacing. These concepts also have direct application for sweet spot identification

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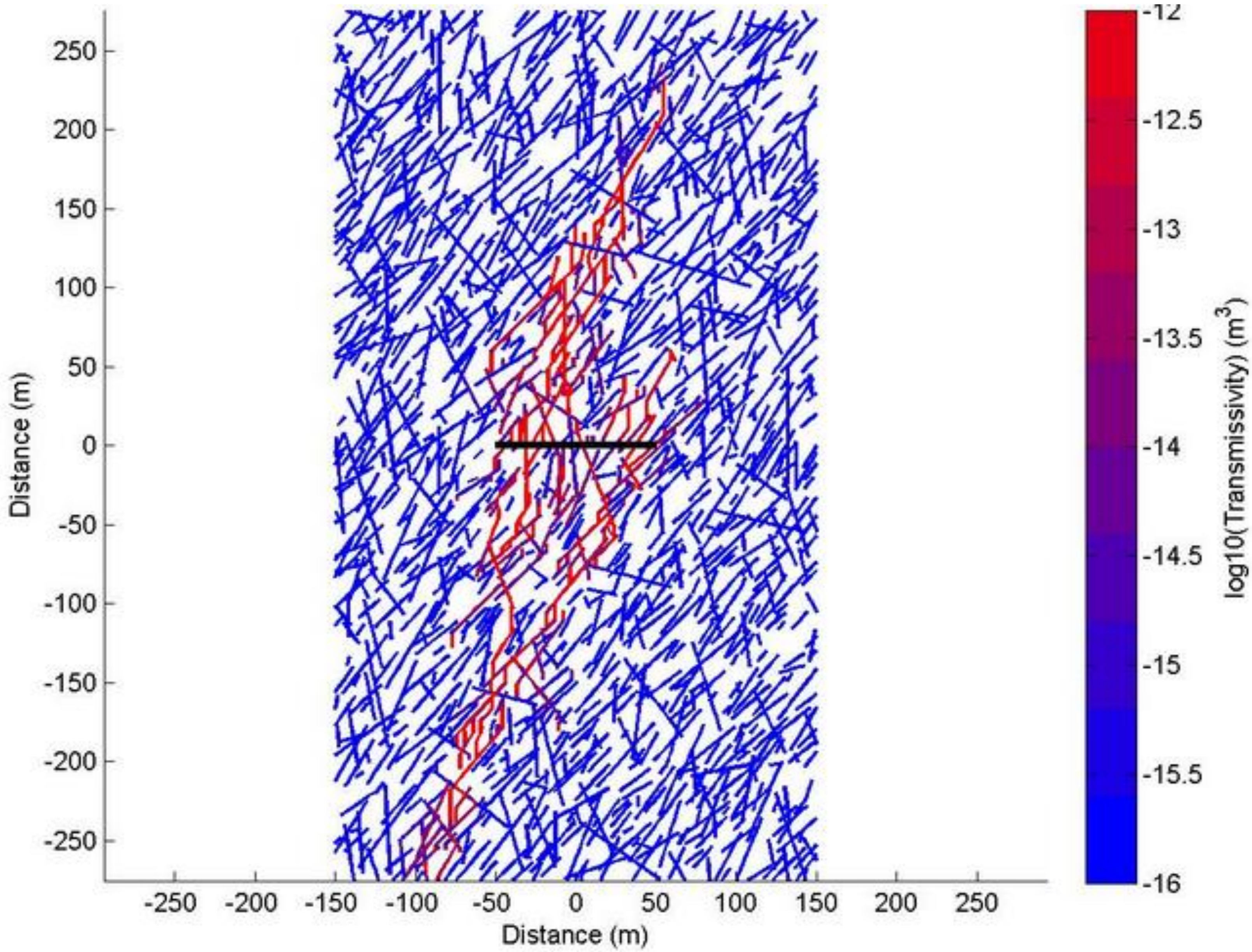

Figure 1. Example CFRAC simulation of one hydraulic fracturing stage. The black line is the wellbore. The reservoir is viewed from above. Natural fractures have been generated stochastically. The simulation involves both flow in natural fractures and formation and propagation of new fractures.