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Integrating Fracture Diagnostics for Complex Hydraulic Fracture Development Model

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Abstract

In shale reservoirs, determining the complex hydraulic fracture geometry is still a big challenge. Modelling hydraulic fracture propagation has proven to be a very important tool for calculating fracture geometry and optimizing fracturing treatments. However, this technology has some limitations for accurately predicting fracture geometry because of some uncertain input parameters. Diagnostic technologies are very useful to explain some fracture behaviors. But no single diagnostic method can give enough information to describe fracture geometry. Hence, integration of diagnostic technologies with modelling can aid in accurate prediction of fracture geometry. In this study, distributed temperature sensing (DTS) and distributed acoustic sensing (DAS) are combined with our complex hydraulic fracture development model to determine fluid volume distribution between multiple fractures and calculate complex fracture geometry.

The complex hydraulic fracture development model is developed to simulate multiple hydraulic fracture propagation from horizontal wellbores in naturally fractured reservoirs. The numerical model is coupled rock mechanics and fluid flow to consider the interaction between fractures, based on a simplified three dimensional displacement discontinuity method and finite difference method. The mechanical interaction can enhance opening or induce closing of certain crack elements or induce non-planar propagation. Fracture propagation and fluid invasion into pre-existing fractures are both driven by an incompressible, non-Newtonian fluid in a permeable homogenous reservoir. The fracture propagation path can be determined by the maximum circumferential stress theory. Fluid flow in the fracture and the associated pressure drop are based on the lubrication theory, assuming the fracture is analogous to a slot between parallel plates and the fluid is non-Newtonian. The rock mechanics and fluid mechanics are coupled together numerically in an iterative algorithm.

Distributed temperature sensing (DTS) and distributed acoustic sensing (DAS) are two well-known fiber-optic technologies that can be deployed to determine the fluid distribution between different perforation clusters within a stage at various times during a fracturing treatment. Our complex fracture propagation model also can provide fluid distribution at different time steps. The fluid distribution is mainly affected by stress shadow effects, hydraulic fractures intersecting with natural fractures, viscosity of pumping fluid, perforation friction and wellbore friction.

Through matching fluid distribution given by our model with DTS and DAS, the effects of the five influence factors can be calibrated. Without the effects of natural fractures, most of fluid flow into exterior fractures. Generally, one or two fractures will dominate the others and immature fractures are developed in a stage. When hydraulic fractures propagate in the naturally fractured reservoirs, natural fractures retard the growth of hydraulic fractures and change the fluid distribution between multiple fractures. Fluid distribution obtained from DTS and DAS in real time can reflect whether or not hydraulic fractures intersect with natural fractures, and also might be able to reveal the location of natural fractures through combining with fracture trajectory provided by our model. Therefore, the sights from integration of diagnostic technologies with the complex hydraulic fracture development model can be valuable for predicting fracture propagation and optimizing unconventional development.