Hydraulic fracture propagation interacting with multiphase flow in porous media

Jihoon Kim[*] and Evan Schankee Um[†]

[*] Harold Vance Department of Petroleum Engineering
Texas A&M University
College Station, Texas, USA, 77843
E-mail: jihoon.kim@tamu.edu

[†] Earth and Environmental Sciences
Lawrence Berkeley National Laboratory,
Berkeley CA, USA, 94720
Email: evanum@gmail.com

ABSTRACT

Unconventional natural gas such as tight and shale gas has become an increasingly important source of natural gas over the past decade. Gas production from those gas reservoirs is based on horizontal wells and hydraulic fracturing techniques. Accurate prediction and control for the sizes of hydraulic fractured volume are important in order to optimize production of gas as well as to reduce environmental impacts (contamination of drinking water zones).

Many studies in numerical simulation on fracture propagation have been done for development of shale gas reservoirs in order to estimate the stimulated reservoir volume and the lengths of the created fractures. However, several assumptions for flow and geomechanics have frequently been employed in the study of hydraulic fracturing. For example, one of the assumptions is to ignore the effects of multiphase flow during fracture propagation. In particular, reservoir gas can be introduced near the fracture tip from the reservoir formation during fracture propagation, whereas the leak-off from the fracture into the reservoir is usually considered. Some studies have indicated that the existence of a gap between the fracture tip and the water front is possible [1, 2]. The introduced gas can affect total fluid compressibility and relative permeability in the multiphase flow system, dynamically changing capacity of storage and flow of flow. Furthermore, this complex behaviour needs to be accurately captured in order to detect migration of the injected fluid by using joint electromagnetic geophysical and coupled flow-geomechanical simulation [3].

In this study, we mainly investigate the effects of multiphase flow on fracture propagation numerically. We specifically consider the following parameters of the porous media; toughness, initial reservoir pressure, relative permeability, and viscosity. We take a staggered sequential method for the coupling between flow and geomechanics simulators. From numerical tests, we have found that the reservoir gas can be introduced into the fracture substantially (1) when the dry zone is large at the onset of the fracturing due to high toughness, (2) when the initial reservoir pressure is high, (3) when gas relative permeability is high, compared to that of the injected fluid, and (4) when viscosity of the injected fluid is low. For those cases, the injected fluid lags considerably within the fracture, where reservoir gas is saturated noticeably.

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