Analysis of Hydraulic Fracturing Stimulation of a Lateral Well in Barnett Shale

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A model was developed to better understand and characterize the propagation of induced hydraulic fracture networks (HFN) in naturally fractured shale formation. The model represents the HFN developing during a stimulation treatment by a growing stimulated shale volume. It consists of two perpendicular sets of vertical planar fractures with mechanic interactions among them and between injected fluid and fracture walls fully accounted for. The model is able to characterize an induced HFN based on microseismic and treatment data and reproduce HFN propagation based on characteristic HFN properties. This characterization includes the size of the stimulated volume, the spacing between fractures (for each set of fractures) and the fracture opening, especially the fractures filled with sand particles (proppant). It also gives insight on the magnitudes of the maximum and the minimum horizontal stresses.

We use four hydraulic treatment stages carried out from a lateral well to demonstrate the capability of the model and provide some insight on hydraulic fracture propagation in shales. This lateral belongs to a set of three laterals which were placed into a 220-m-thick Barnett Shale formation, stimulated by injecting slickwater with 100 and 40/70 mesh sand particles and monitored with microseismic activity. For each of the stages, the model was applied to obtain information of the introduced HFN, associated local stress field and proppant placement. The results indicate:

The average spacing of fractures parallel to the minimum horizontal principal stress for the first two stages are 8~14 m and 13~17 m, while they are 10~33 m and 21~54 m for those parallel to the maximum horizontal principal stress. Fracture spacing is smaller for the last two stages, 2~5 m and 5~14 m for fractures parallel to the minimum and maximum horizontal principal stresses, respectively.

The estimated differences between the two horizontal principal stresses are less than 1 MPa for all stages, consistent with a tectonically relaxed basin environment.

The minimum confining stress increased monotonically from 17.5 MPa at stage 1 to 24 MPa at stage 4. Possible explanations are either the influence of propped fractures from earlier stages or lowered share stress along fractures filled with injected fluids.

Most proppants were placed in near wellbore regions within 50 m from the corresponding injection points due to fast proppant settlement in the low-viscosity slickwater.