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Use of Drill Cuttings and Flowback Fluid Compositions to Constrain Connected Fracture Height Growth in Low-Permeability Reservoirs

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Summary

Fracture height growth during hydraulic-fracturing operations in low-permeability ("tight") reservoirs is a key design consideration for development planning. For example, with multi-fractured horizontal wells (MFHWs) being the prevalent technology for developing tight reservoirs, fracture height growth should affect horizontal lateral spacing in the vertical plane; further, fracture height growth should be controlled to avoid contacting non-reservoir intervals. However, the prevailing surveillance technologies for estimation of fracture height growth (e.g. microseismic, tiltmeter) do not provide a direct indication of which geologic intervals are hydraulically connected to the well through the fracture.

In this work (full-length paper: Clarkson et al. 2016), an innovative method for estimating connected fracture height is demonstrated using field data from a liquid-rich tight reservoir in Western Canada. Geochemical (gas composition) data was obtained from cuttings samples collected from the vertical, bend and lateral sections of the subject MFHW while drilling in order to provide a "fingerprint" for each geologic interval. This information, combined with flowback fluid compositions, was used to constrain fracture height estimates from stochastic compositional numerical simulation, which in turn was used to history-match flowback fluid rates and pressures. A critical step in the model initialization was the estimation of layer-by-layer in-situ fluid compositions by combining cuttings gas compositional data with separator oil compositions.

Gas compositions (in particular C_1/C_2 ratios) obtained from drill cuttings displayed distinct trends; in particular, a "compositional marker" was identified in the reservoir above the horizontal lateral with a distinct shift in C_1/C_2. The flowback compositions were intermediate between the geologic intervals above and below the compositional marker, suggesting fracture height grew above the compositional marker. With the compositional (reservoir and flowback) constraints employed, an average propped fracture height of 175 ft was obtained from the numerical model match of flowback data. Without these constraints in place, fracture height estimates are much more uncertain.

This study demonstrates for the first time that fracture height growth estimates can be constrained using flowback data combined with gas compositional data obtained from cuttings data, if the geochemical fingerprints are distinct.

References

Clarkson et al. 2016. Estimation of Fracture Height Growth in Layered Tight/Shale Gas Reservoirs using Flowback Gas Rates and Compositions – Part II: Field Application in a Liquid-Rich Tight Reservoirs. *In press*: Journal of Natural Gas Science and Engineering.