Hydraulic Fracturing Fluid Interaction with Fracture Surfaces in an Unconventional Reservoir

AMBER E ZANDANEL[1], JOHN P. KASZUBA[1,2]*, JANET DEWEY[1]

[1]Dept. of Geology and Geophysics, University of Wyoming
[2]School of Energy Resources, University of Wyoming
(*correspondence: John.Kaszuba@uwyo.edu)

Interaction of injected fluids with unconventional oil reservoirs drive changes to fluid chemistry and total organic carbon, which in turn affects fracture-face mineralogy. Four hydrothermal experiments were performed to simulate interactions between hydraulic fracturing fluid and unconventional reservoir rock under high-TOC and low-TOC conditions.

Cretaceous interbedded sandstone and shale from an unconventional reservoir in the Powder River Basin, Wyoming, USA was combined with formation brine at in-situ reservoir conditions and reacted for ~35 days to approach steady-state. A simulated hydraulic fracturing fluid was then injected and reactions proceeded for another ~35 days. Fluid samples were collected throughout the experiment. Two experiments use rocks chemically processed to remove hydrocarbons (low-TOC); two react samples that retain naturally-occurring oil (high-TOC). All experiments use 0.5-1 cm cubes to emulate fracture faces.

Experimental results show greater increases in Ca concentration in the low-TOC experiment (from ~0.1 mmol/L Ca in all to ~1.1 mmol/L in low-TOC and ~0.6mmol/L in high-TOC experiments). After injection, calcite saturation indices reach SI >0 after 18 days in the low-TOC experiment and SI >0 after 5 days in the high-TOC experiment. Kaolinite saturation indices in the low-TOC experiment are higher (SI = 0.5-1.0 after injection) than those in the high-TOC rock experiment (SI = ~0.0 after injection). Results suggest that unconventional reservoir rock with low TOC is more sensitive to mineralogical changes when exposed to hydraulic fracturing fluid than rock with high TOC.