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Short and long-term strength of shale rocks

Erik Rybacki and Georg Dresen
GFZ German Research Centre For Geosciences, Potsdam, Germany (erik.rybacki@gfz-potsdam.de)

Stimulation of oil and gas bearing shales commonly utilizes advanced hydraulic fracturing techniques to enhance the production rate. Successful hydrofrac campaigns depend on the geomechanical properties of the reservoir. For example, the short term strength and brittleness may control the hydraulic breakdown pressure and borehole stability. The long term creep properties may determine the closure rate of hydraulically induced fractures, for example by proppant embedment.
We performed a series of mechanical tests on shales with different mineral content, porosity and maturity. Cylindrical samples of 1-5 cm in diameter and 2-10 cm in length were deformed at confining pressures of 0.1 – 400 MPa and temperatures of 25°-400°C in constant strain rate and constant stress mode in order to evaluate the influence of loading conditions and composition on their strength and ductility.
Short-term constant strain rate tests show that, at fixed loading direction with respect to bedding orientation, the peak strength and Young's modulus vary with mineral content, humidity and porosity, but depend also on applied pressure, temperature and strain rate. The (porosity-corrected) variation of peak strength and Young's modulus with composition can be roughly estimated from the mechanical behavior of all components at given pressure-temperature conditions and their volumetric proportion. Samples deforming in the brittle-semibrittle regime may be characterized by empirical brittleness indices based on their deformation behavior, Young's modulus, or bulk composition. These indices are correlated at low pressure-temperature conditions (corresponding to < about 4 km depth).
First long-term deformation experiments at constant load show transient viscoplastic creep behavior. The associated strain rates increase with increasing differential stress, increasing temperature and decreasing pressure, accompanied by slight porosity reduction. Therefore, estimates of fracture healing rates by proppant embedment require to account for their pressure and temperature dependence, which likely varies with shale composition and porosity.