Key Petrophysical Factors Affecting Fluid Flow in Geopressured Haynesville Shale

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Haynesville Shale in Louisiana and Texas is one of a unique North American gas-shale play. With a geopressure gradient of >0.9 psi/ft and relatively high porosity ranging from 8 to 14%, it has become one of the most productive gas shales as well. Because of its high porosity, low connate water saturation, and relatively low total organic content (TOC), most free gas is stored in the inorganic mudrock matrix. In addition to natural fractures and high pressure, high calcite and quartz contents, ranging from 14 to 35%, can further enhance the shale's brittleness. One of the unique features of Haynesville production is that significantly less frac water than injected has flowed back during production. The lost of frac water has made water a critical issue in the area. The objectives of this study are to investigate the origin of low connate water saturation and its impacts on fluid flow in gas shales.

The low connate (residual to subirreducible) water saturation in gas shales is attributed to the combined effect of (1) hydrocarbon generation and migration, (2) burial history, and (3) capillary hysteresis. High (paleo) temperature and formation pressure during gas generation and migration (drainage) result in excessive drying of shale, and capillary hysteresis keeps the water saturation low in subsequent uplift events.

The low connate water saturation impacts fluid flow in gas shales by (1) preventing water from production and (2) creating a powerful capillary suction of water, which results in less injected frac water flowing back. Because geopressured gas shales are considered to be confined systems with limited aquifer support, they are likely at subirreducible connate water saturation, which is significantly lower than the residual water saturation from imbibition capillary pressure data at the same temperature. Cooling by drilling and fracturing fluids can increase the residual water saturation around stimulated areas and further escalate the effect of imbibition suction. Therefore, a significant amount of frac water can be imbibed into shale formation through capillary suction and retained as residual water, which will not flow back during production.