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Saturation isn't what it used to be: towards more realistic petroleum fluid saturations and produced fluid compositions in organic-rich unconventional reservoirs

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Understanding that capillary forces will act to limit petroleum fluid saturations in water-wet fine grained rocks, including organic rich source rocks, dates back at least to King Hubbert in 1953. Likewise, Philippi in1965 noted relationships identifying sorption in/on organic matter as a significant storage mechanism in organic-rich rocks.

Contrast these early insights with current unconventional reservoir evaluation, where we observe a disconnect between 'in situ' (core exhumed to surface) measured total water saturations versus the produced cumulative water volumes from a given stimulated rock volume. Water-free production in gas shales, from gas-wet organic matrix pores, created an early impression that unconventional plays don't produce water. So, in more liquid-rich plays, water cuts were initially under-appreciated: e.g. >80% in the Wolfcamp (stock-tank basis). If measured Sw is so low (core-based calibration), where is the produced water coming from; or is there an alternative method to more accurately relate insitu to produced water and petroleum production?

Adapting organic sorption models from the 80's, we can split total hydrocarbon volatiles into sorbed and, by difference, non-sorbed fluid phase yields. Converting to volumes and adding back dissolved gas using a formation volume factor (FVF), we can estimate the bulk volume fluid phase. This new approach then yields observations regarding remaining water-filled pore volume versus sorbed and non-sorbed hydrocarbon volume explaining the high water cuts in the Permian Basin stratigraphy; and additionally may indicate sweet spots in pore systems in different parts of the rock compared to alternatively derived saturations.

The final piece of the puzzle comes from basin modeling of petroleum charging in the 90's. Some scientists applied conventional reservoir relative permeability to fine-grained rocks, but new research predicted that progressively finer grained rocks with higher irreducible water should be able to flow oil at progressively higher Sw: at 100 nD, both oil and water should flow at Sw > 80%. Lower petroleum phase saturations and adjusted relative permeability curves may better explain observed production behaviors and profoundly alter our view of recovery factors and stimulated rock volume.