EXPERIMENTAL INVESTIGATION OF MODIFIED RESERVOIR PROPERTIES DUE TO HYDRATION/DEHYDRATION OF ILLITE/SMECTITE CLAY MINERALS IN SHALE PLAYS

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ABSTRACT

U.S. experience a low total recovery of tight oil (5%-10%) and shale gas (12%-30%) for shale hydrocarbon exploration and production on more than 30 year's time. Hydrocarbon movement through shale reservoirs control by two factor: one is pore size distribution (geometry), and another one is pore connectivity(topology). One of the key obstacles for sustainable shale development is related to the low recovery factor, which still needs much investigation. In my research, I have collected samples from different prominent shale hydrocarbon producing basins from USA (Barnett, Haynesville, Niobrara, Wolfcamp and Woodford shale). I have examined pore structure, pore geometry, wetting characteristics, and imbibition behavior with the following complementary tests: Mercury Injection Capillary Pressure (MICP), Focused Ion Beam Scanning Electron Microscopes(FIB-SEM), contact angle measurement of various fluids, and fluid imbibition into initially dry shale. Experimental results indicate that different basin different depths samples have diverse geologic (mineralogy) and reservoir characteristics (e.g., total organic content, porosity, and permeability). The wettability and imbibition tests use different types of wetting fluids (DI water, brine, n-decane, acetone and 20% isopropyl alcohol with DI water). At the time of imbibition test, most of the shale showed late-time imbibition slope close to ¼ for DI water, the ½ slope for n-decane and acetone (a zwitter fluid) for shows an imbibition slope of ~1. Most of the causes high tortuosity value from Mercury Injection Capillary Pressure (MICP) analysis and spontaneous water imbibition indicated that most of the shale matrix has low pore connectivity. MICP analysis of different shales from various basin represents that median pore throat diameter for rock samples is 3.1 to 10.5 nm and almost 50–85% pore throats by volume are smaller than 100 nm. Based on the mineral composition and maturity, median pore throat diameter varies for different shale basin. I have performed some samples with contact with acetone (for 2-3 hours) to examine the potential changes. The results showed that acetone-exposed siliceous shales have 5-15% porosity increase and 20-30% permeability increase, while calcareous mudstone show little change in both porosity and permeability. In another research project, I am working on the presence of different swelling clay within the shale hydrocarbon reservoir how changes the reservoir quality (porosity/permeability) of mudrock matrix. Smectites and mixed-layer illites are the most common swelling clays found in shale reservoir rock within the US. Swelling clays within a reservoir generated problems when it got contact with drilling fluid or fracking fluid. In this research project, I am exposing different basins core samples (higher clay content shale) with various type of fluid and see how pore geometry and pore connectivity changes with time. Based on this research, I will be able to answer some fundamental question of shale hydrocarbon reservoir.
1) What is the cause of initial steep production decline and low recovery from shale rock?
2) Why low-recovery wells give production spike after the shutdown of well for a short time (few week to a month)? The findings of this research will help establish a method to related nanopores; their pore throats and fluid movement within a clay mineral-rich reservoir rock.

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