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Behavior of Flow through Low-Permeability Reservoirs

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It is well known that while pores and throats of low-permeability reservoir rock are very tiny, they have significant influence on flow behavior in low-permeability reservoirs. There may be large differences in throat sizes and their distribution in low-permeability formations, even though they may have similar storage space, fluid flowing channels, and porosity. In addition, it is also observed that equivalent radii of flowing throats for low-permeability reservoirs may be very different, even though they may have the same or similar permeability values measured from gas flow. Stronger liquid-solid interaction occurs within finer pore throats in low-permeability rock containing abundant hydrophilic clay with a large surface area-volume ratio. In general, the large contacting surface area of pore throats tends to hold water from flowing through.

This paper presents a systematic study of general flow behavior in low-permeability reservoirs, using three approaches: (1) a constant-rate mercury injection test, (2) a nuclear magnetic resonance (NMR) core analysis, and (3) a seepage experiment. NMR test results show that mobile fluid saturation in various low-permeability formations is very different from that in normal permeable reservoirs, because of the differences in pore configuration and clay materials. In general, the less clay content and the larger throat radii of the low-permeability rock, the larger the mobile fluid saturation. We conducted a series of well-controlled seepage tests, with the results showing that at low velocity seepage stage, the flow rate in low-permeability rock is not linearly correlated with pressure gradient (i.e., the permeability to single-phase water is no longer a constant), but rather is a function, increasing with the increase in pressure gradient. Based on experimental results, we propose a modified Darcy's law for describing the observed nonlinear flow phenomenon, which is implemented into a black-oil model simulator. Simulation results incorporating the nonlinear flow behavior show that effective permeability near oil production and water injection wells is higher, while the permeability further away from the wells is lower. Well performance predicted by the linear model overestimates production rates, while the simulation by the new, nonlinear model better matches the production data from oilfields.