Influence of Capillarity on Salt Precipitation during Primary CO_2-Brine Displacement

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Geological storage of CO_2 is currently considered as the most promising large-scale option to avoid emissions by industrial activities. As suitable subsurface containers, oil and gas reservoirs and the more abundant saline aquifers are considered. The injection of dry or under-saturated supercritical CO_2 into water-bearing formations leads to the formation of a dry-out zone due to evaporation/dissolution of the resident brine into the injected fluid and, thus, potential precipitation of formerly dissolved brine constituents. If minerals precipitate within the pore space of a rock formation, porosity and permeability are negatively affected, which potentially impairs injectivity. Even though the impairment of injectivity poses both operational and financial challenges, minor attention has been dedicated to this research area so far. What is the size of the affected zone itself? What is the impact of capillarity on the fluid transport therein?
In this presentation, the responsible evaporation of brine and fluid transport mechanisms are outlined and discussed, as well as the potential reduction of the formation permeability and with it the injectivity. A remaining important question is the zone of counter-current flow in the direction of the wellbore, which determines the amount of salt that potentially precipitates in the near-wellbore area and the accompanied porosity reduction. Current reservoir simulation tools are not accounting for this effect because they typically do not capture evaporation kinetics. Earlier studies indicate that in certain cases the respective permeability can be reduced by several orders of magnitude (Ott et al., 2021), which comes close to a loss of the injection well.
We approach this question with numerical simulations to determine the size of the zone affected by the undersaturated CO_2 that allows for salt to be transported toward the injector and the major parameters governing this zone and their dependencies as well as the fluid transport therein. We are currently developing and testing a reservoir simulation module based on DuMuX capable of describing reaction kinetics. In parallel, we built up a meter-scale core flood experimental setup that allows us to extract fluid saturation profiles and solid saturation (precipitation) via CT imaging of core samples. Besides that, by monitoring the differential pressure, we can determine changes in permeability and with it changes in injectivity.
This study aims to establish an experimental/numerical workflow to forward simulate, respectively design, and to history match experiments with a reservoir simulator to upscale the results to the field scale. The work is currently in progress – the applied workflow will be outlined in detail.