Capillary limited flow behaviour of subsurface CO2 injection in sandstone aquifers

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Summary

A number of studies have demonstrated the prevalent impact that small-scale rock heterogeneity can have on larger scale flow characteristics in multiphase flow systems including petroleum production and CO2 sequestration [1]. Experimental and modeling studies have shown that capillary redistribution of fluids across cm-scale rock heterogeneities, e.g. laminations, have a significant impact on effective flow functions such as relative permeability [2, 3]. Larger scale modeling studies have shown that this has a significant impact on fluid flow and is possibly a significant source of inaccuracy in reservoir simulation [4, 5].

Due to historical protocols for measurement, relative permeability is often derived from core floods performed at conditions with high flow potential in which the impact of capillary heterogeneity is voided. A more accurate representation of flow would be obtained if measurements were made at flow conditions where the impact of capillary heterogeneity on flow is scaled to be representative of flow in the reservoir. Reynolds and Krevor (2015) [2] proposed the use of a continuum scale capillary number to design experimental core floods to capture these effects.

This presents significant practical difficulties, however, that this study seeks to address. First, relative permeability functions controlled by capillary heterogeneity will be flow rate and fluid property dependent, and will need to be obtained at a range of capillary numbers characteristic of flow regimes in the reservoir. Secondly, due to limitations of laboratory experimental apparatus, it is often impractical to obtain measurements at capillary numbers governed by reservoir flow physics. Finally, the laboratory observation will strongly depend on the orientation of the heterogeneity in the rock core which is generally uncontrolled in sample acquisition and will not likely resemble the orientation with respect to flow in the reservoir system.

We propose a new paradigm in core analysis to overcome these issues, allowing for the incorporation of the effects of small scale capillary heterogeneity into larger scale flow. In this work flow, the relative permeability at the range of capillary numbers relevant to flow in the reservoir is derived primarily from numerical simulations of core floods that include capillary pressure heterogeneity, e.g. [3]. The parameterization of the digital rock model for simulation becomes the focus of the laboratory measurement. In this work we present results in which such digital rock models have been constructed following an experimental program optimized to quantify capillary heterogeneity and intrinsic relative permeability in rock cores with a range of heterogeneity types.

References

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