Numerical Simulation of gas-water flow in heterogeneous wetting porous media

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Abstract

Wettability has significant effect on safe and long-term storage of CO2 in deep saline acquire, since it affects the seepage characters of caprock, in terms of relative permeability and capillary pressure. Wettability also determines the CO2 sealing capacity of saline acquire. Thus, it is vital to investigate the effect of wettability on fluid flow in porous media. Moreover, most of the natural reservoir cores are mainly heterogeneous wetting porous media and their pore space is partly water wet and partly hydrophilic. Thus, it has great significance to study effects of heterogeneity of wettability on gas-water flow at reservoir conditions. In this paper, we studied influence of heterogeneity of wettability on CO2-brine two phase flow behavior in the Berea sandstone sample based on pore network numerical flow simulation method which is considered one of the most efficient and economical methods of studying fluid flow in pore scale level.

The digital image of the core sample was obtained via X-Ray CT scanning, which was used to extract the corresponding pore network via Maximal Ball algorithm. Then An open sourced flow simulator was applied to predicate the relative permeability and capillary pressure of the CO2-brine displacement based on this pore network extraction. Grade pore quasi static flow simulation model was used for the flow simulation research. We aimed to study the effects of heterogeneity of wettability on CO2-brine two phase flow in porous media, thus, we have assumed the proportion of non-wetting pores was f and it changed from 0 (strong water wet) to 1 (strong CO2 wet) at each 0.2 interval. Firstly, the pore network model was assumed to be fully water saturated, then drainage cycle (CO2 flooding) was performed until the experimental initial CO2 saturation was reached. Finally, the process of imbibition (water flooding) was simulated and then CO2-brine relative permeability and capillary pressure were calculated. In this paper, the simulations were carried on the Berea sandstone sample at 323K, 12.4Mpa with 6g/L NaCl solution.

Results shown in Fig1, Fig2 indicates that, when system non-wetting proportion f changes from 0 to 1, both of the relative permeability and capillary pressure curves overlap with each other during the draining cycle. In other words, heterogeneity of wettability has no influence over the CO2-brine two phase flow behavior during the CO2 displacement process. On the other hand, when system non-wetting proportion f changes from 0 to 0.4, the aqueous phase relative permeability first increases then decreases while CO2 relative permeability decreases under the same water saturation conditions, for the imbibition cycle. As the non-wetting proportion of the pores f increasing, the more CO2 is trapped inside the pores and the residual gas saturation increases. However, when system non-wetting proportion changes from 0.6 to 1.0, due to the relatively good connectivity of both CO2 aqueous phase, the results are completely contrary to the former. The relative permeability of CO2-brine shows the same trend when f changes from 0 to 0.4 and from 0.6 to 0.8, former have relatively high residual gas saturation and short term of displacement process as well as high aqueous phase relative permeability value, while later have low residual gas saturation and long term of displacement process.
Furthermore, during the draining process, when f changes from 0 to 1, all the capillary pressure decreases dramatically until it reached 0 but no negative value accrues. While, during the imbibition process, as f increases, the capillary pressure decreases dramatically until it is stabilized for a while then it again decreases until it reaches a maximum negative value. When system non-wetting proportion f increases, the system becomes more CO$_2$ wet and liquidity of the aqueous phase will be enhanced, in the end, more CO$_2$ will be displaced by the aqueous phase. Therefore, a saline acquire with strong water wet properties might be the best site for CO$_2$ storage, due to the better CO$_2$ trapping mechanism of strong water wet porous media.

![Fig. 1. Relative permeability and capillary pressure curves of drainage cycle (a), (b).](image1.png)

![Fig. 2. Relative permeability and capillary pressure curves of imbibition cycle (a), (b).](image2.png)