Advances in Geo-Energy Research

Vol. 6, No. 6, p. 535-536, 2022

Research highlight

Reservoir characterization and multiphase flow property in the upper Minnelusa sandstone: Implication for geological carbon storage

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Keywords:
Reservoir characterization
multiphase flow property
geological carbon storage

Cited as:
Kou, Z., Wang, H., Alvarado, V. Reservoir characterization and multiphase flow property in the upper Minnelusa sandstone: Implication for geological carbon storage. Advances in Geo-Energy Research, 2022, 6(6): 535-536.
https://doi.org/10.46690/ager.2022.06.10

Abstract:
This report summarizes the reservoir characterization [Wang et al., J. Hydrol., 2022] and multiphase flow property [Kou et al., J. Hydrol., 2021] in a target deep saline aquifer, upper Minnelusa sandstone in Wyoming. Multiscale petrophysical characterization and flow unit classification were carried out to identify two different facies groups: cross-bedded and massive sandstone. Based on the rock typing results, two representative core samples were selected accordingly to conduct coreflooding experiments. Results illustrate that the sub-core scale heterogeneity significantly affects CO_2-brine multiphase flow properties. As a result, the sub-core scale heterogeneity should be considered during CO_2 injection to reduce the uncertainties in storage and fluid flow.

The presence of elevated concentration of greenhouse gases in the atmosphere have been linked to climate change, so reduction in their emissions into atmosphere is pressing. Geological carbon storage (GCS) in deep saline aquifers stands alone as a strategy in mitigating greenhouse gas emissions into atmosphere (Guo et al., 2021). Their widespread geographically makes them an attractive subsurface storage system. CO_2, injected into deep saline aquifers, can be trapped through hydrodynamic and geochemical mechanisms. A relevant study has confirmed that CO_2 hydrodynamic trapping, e.g., structural and residual trapping, significantly contributes to overall storage at a relatively early time ($\leq$ 100 years) (Benson and Cole, 2008). Therefore, reservoir characterization and multiphase flow properties are critical for predicting CO_2 migration and distribution in deep saline aquifers. However, most current studies regarding these issues focused on hydrocarbon development, and the relevant work on GCS are rare.

As the CO_2 injectivity, migration, trapping mechanisms, and storage capacity vary with rock types, especially for eolian sandstones, reservoir rocks classification is necessary for predictive geological modeling and reservoir simulation for GCS (Wang et al., 2022). In this work, well log, and porosity and permeability were firstly applied to identify two main facies groups: cross-bedded (CB) and massive (MS). Transverse nuclear magnetic resonance (NMR) relaxation time (T_2) distribution and pore throat-size distribution were used to differentiate the two facies groups from pore architecture. For ease of field-scale application, curve fitting on the specific core samples between their well log and lab measurement was adopted to determine the empirical coefficients from two models: Schlumberger Doll Research (SDR) and Timur-Coates (TC). The rest of well-log data were corrected using the

Yandy Scientific Press

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Received July 1, 2022; revised July 27, 2022; accepted August 7, 2022; available online August 10, 2022.

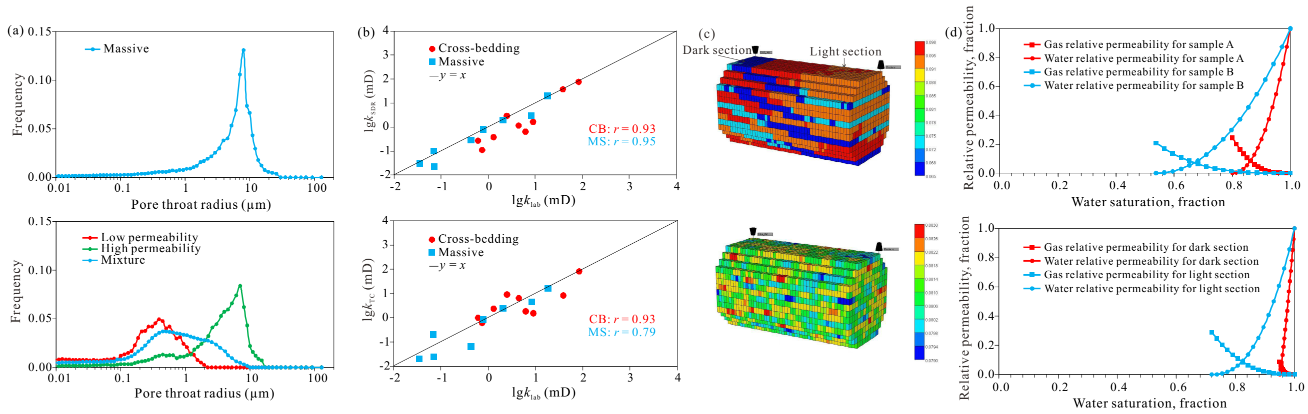

Fig. 1. (a) Pore-throat radius distributions of the massive (top) and cross-bedding (bottom) samples. (b) Cross-plot of k_{lab} vs. k_{SDR} (top) and k_{lab} vs. k_{TC} (bottom) for the cross-bedding and massive facies groups. (c) Porosity distributions of the developed cross-bedding sandstone model A (top), where the blue color refers to the low-permeability dark section and red and orange colors refer to the high-permeability light section, and massive sandstone model B (bottom). (d) Relative permeability curves for samples A and B (top) and relative permeability curves for dark and light sections of sample A (bottom).

models and the flow units were classified accordingly. This study shows that reservoir qualities are dominantly controlled by depositional environments and dolomite cement content. T_2 distribution and pore throat-size distribution (Fig. 1(a)) demonstrated the pore structure complexities in the CB facies group, whereas for the MS group, pore (throat) sizes are wider and more uniform. Permeability (k) evaluated from the SDR and the TC models utilizing lab T_2 distribution and Combinable Magnetic Resonance (CMR) logging data (Fig. 1(b)), and porosity estimated by the CMR log exhibit a desirable correlation with lab measurements, suggesting the merit of NMR techniques in petrophysical characterization of eolian reservoirs compared with conventional well logs.

Based on the rock typing results, representative core samples were selected thereafter. The unsteady state CO_2-brine coreflooding experiments were carried out on the selected samples. Then, the core-scale relative permeability curves were obtained by developing numerical models (Fig. 1(c)) and applying assisted history matching. T_2 distribution and pore throat-size distribution were further utilized, from the sub-core scale viewpoint, to interpret the varied relative permeability curves (Fig. 1(d)). Additionally, the sub-core scale relative permeability curves were also determined applying a downscaling technique (Fig. 1(d)), which was to study the CO_2 saturation distribution and the impacts of sub-core scale properties on bulk brine production. This reveals that the sub-core scale laminated structures were dominant in determining the CO_2-brine multiphase flow properties in the CB core sample. The laminated structures act as a capillary entry barrier that guides fluid flow at CO_2-brine front, whereas the CO_2-brine multiphase flow exhibits homogeneous-like state in MS sandstone. Therefore, evaluating the CO_2 injectivity based solely on the core-scale porosity and permeability could result in inadequately predicting the CO_2 migration behaviors in saline aquifers. Sub-core scale heterogeneity during CO_2 injection cannot be ignored in this type of sediments, because it will create large uncertainties in storage and fluid flow (Kou et al., 2021).

This study provides a new way to perform multiscale petrophysical characterization and flow unit classification, followed by coreflooding experiments to illustrate the effect of sub-core scale heterogeneity on CO_2-brine multiphase flow properties. Overall, it provides us with a deeper understanding of core-scale CO_2-brine multiphase flow properties for GSC in heterogeneous sandstones and gives insights into CO_2-brine multiphase flow upscaling in heterogeneous geological models.

Acknowledgement

This work was supported by the Department of Energy for funding through the grants DE-FE0031624 and DE-FE0031891.

Conflict of interest

The authors declare no competing interest.

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