Drainage Capillary Pressure Distribution and Fluid Displacement in a Heterogeneous Laminated Sandstone

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Abstract We applied three-dimensional X-ray microtomography to image a capillary drainage process (0–1,000 kPa) in a cm-scale heterogeneous laminated sandstone containing three distinct regions with different pore sizes to study the capillary pressure. We used differential imaging to distinguish solid, macropore, and five levels of subresolution pore phases associated with each region. The brine saturation distribution was computed based on average CT values. The nonwetting phase displaced the wetting phase in order of pore size and connectivity. The drainage capillary pressure in the highly heterogeneous rock was dependent on the capillary pressures in the individual regions as well as distance to the boundary between regions. The complex capillary pressure distribution has important implications for accurate water saturation estimation, gas and/or oil migration and the capillary rise of water in heterogeneous aquifers.

Plain Language Summary Carbon-dioxide storage, hydrocarbon migration, and the capillary rise of water in heterogeneous aquifers and reservoirs are all controlled by capillary pressure. The capillary pressure varies dependent on the pore-space heterogeneity. We used X-ray microtomography to image capillary drainage in a laminated sandstone as an exemplar of a highly heterogeneous rock. The distribution of capillary pressure and pore-scale configuration of fluid during displacement were measured and related to distinct heterogeneities in the rock. Differential imaging is used to characterize the larger macropores and subresolution porosity. We show that fluid displacement is controlled by pore size, connectivity, and proximity to the boundaries between regions with different pore-space characteristics. Our study demonstrates how to characterize the complex capillary pressure distribution and fluid displacement in highly heterogeneous porous media.

1. Introduction

The experimental determination of representative capillary pressures as a function of saturation is of vital importance in many multiphase flow applications, such as hydrology, hydrocarbon recovery, carbon storage, and contaminant transport (Blunt, 2017; Fredd & Fogler, 1998; Gaus et al., 2008; Gelhar et al., 1992; Kalam et al., 2006). The capillary pressure is used to determine the initial fluid distribution in the system and subsequent flow properties. The most common techniques for measuring capillary pressure, normally at the cm-scale, are the porous plate method, mercury intrusion (MICP), and the centrifuge method (Dalling, 2005; Hassler & Brunner, 1945; Kalam et al., 2006; Pini et al., 2012). These methods all have limitations: The porous plate method is time consuming; MICP is fast but destructive, does not use representative fluids, and can be inaccurate for heterogeneous samples with laminations; while use of a centrifuge introduces capillary pressure gradients. Furthermore, in all cases it is impossible to capture the pore-scale displacement to understand and interpret the results without imaging.

Multiphase flow has been experimentally studied in heterogeneous rocks that include pores which cannot be explicitly resolved in the image (Alhammadi et al., 2020; Gao et al., 2019; Lin et al., 2021). It has been demonstrated that flow through this microporosity provides additional flow pathways which can have a significant impact on the measured relative permeabilities. There are also modeling studies in carbonates that have predicted multiphase flow behavior accounting for the impact of subresolution porosity (Bauer et al., 2012; Bultreys et al., 2015; Mehmami & Prodanović, 2014; Norouzi Apourvar & Arns, 2016). However, more work is needed to characterize multiphase flow and displacement at the pore scale in heterogeneous...
porous media—one exemplar of this category is a laminated sandstone that we will use in this study. In this type of porous medium different heterogeneities may exist even in a small mm-cm sized sample which can additionally complicate the physics of fluid displacement.

X-ray microtomography has been used to identify and categorize different rock types and quantify heterogeneity (Arns, Knackstedt, Pinczewski, & Marty, 2004; Garboczi, 2002; Schmitt et al., 2016; Turner et al., 2004). In particular, the Minkowski functionals, which are a series of three-dimensional morphological measurements combining volume, surface area, and curvature have been applied to characterize the material structure (Armstrong et al., 2019; Arns, Knackstedt, & Mecke, 2004; Jiang & Arns, 2020a, 2020b; Li et al., 2018; Lin et al., 2018, 2019; Mecke & Wagner, 1991; Renard & Allard, 2013; Schröder-Turk et al., 2013; Vogel et al., 2010). However, experimental measurement and characterization of capillary pressure and fluid displacement in highly heterogeneous rock has hitherto not been provided at the pore scale.

To understand the flow behavior during drainage in a complex porous system, a Differential Imaging-based Porous Plate method (DIPP), which combines tomography with a capillary drainage process using a porous plate, has been developed to obtain capillary pressure throughout the entire sample at capillary equilibrium with no flow and to capture the fluid displacement in the pore space, including subresolution pores (Lin et al., 2016, 2017). Although the capillary pressure can be measured, further quantification of fluid displacement processes in subresolution pores still poses significant challenges. One of the main barriers is that most of the existing quantification methods rely on image segmentation which is difficult and uncertain for complex systems where key features contain subresolution pores.

The main objective is to apply DIPP to study multiphase displacement in the complex pore space of a reservoir sandstone containing three regions with distinct pore space characteristics: poorly connected macro pores; well-connected macro pores; and a microporous fine lamination. This extends previous work on sandstones comprising principally of a single pore class, or well-connected macro pores and laminations only (Lin et al., 2017). The behavior is distinct from that seen in sandpacks where the pore sizes are larger and can be resolved with micro-CT imaging. We develop a characterization workflow to quantify fluid saturation and displacement by using the gray-scale values of the micro-CT images directly to avoid potential uncertainties from segmentation when dealing with subresolution features. We place an emphasis on quantification and interpretation of pore-scale fluid displacement and the sequence of invasion. Furthermore, we focus on examining the parameters (including capillary pressure and the distance to region boundaries) controlling flow in individual regions (the submillimeter scale), at their boundaries, and across the whole system (cm-scale). We show how the results have implications for large-scale predictions of initial gas saturation in laminated sandstones. This work is useful to validate numerical models when studying fluid flow in complex porous systems with small-scale heterogeneities.

2. Materials and Methods

The rock sample used in this study was an aeolian polymodally sorted sandstone from a deeply buried Rotliegend gas reservoir in Germany. These aeolian dune deposits are from the Wustrow Formation and characterized by individual laminations of mm to cm widths of various different grain sizes. The micro-CT samples were drilled into cylindrical volume (6.0 mm in diameter and 23.5 mm in length) from the original core (30 mm in diameter). The helium porosity for the original core was 0.219 ± 0.015. The core was attached to a hydrophilic porous ceramic plate, which is permeable only to the wetting phase thus preventing breakthrough of the nonwetting (displacing) phase, with 1,500 kPa breakthrough pressure. This ensures that the pressure of the wetting phase remains constant throughout the core at equilibrium conditions. The core was then placed into a fluoropolymer elastomer (Viton) sleeve and the whole core assembly was placed into an X-ray transparent core holder (see Figure S1 in the supporting information for the experimental apparatus).

The brine solution was made from deionized water with 30 wt% Potassium Iodide (KI) to enhance the image contrast, particularly for brine in subresolution micropores. After taking the N2 scan where the pore space contains only N2, the core was flooded with gaseous carbon-dioxide (CO2) for 30 min to remove N2. Brine was then injected to fully saturate the sample (scan taken), followed by injecting N2 at a constant pressure controlled by a regulator. The capillary pressure was measured by a high precision differential pressure transducer. The nonwetting phase (N2) displaced the wetting phase (KI doped brine) and was prevented...
from escaping the system by the porous plate. At each capillary pressure, when there was no more brine displaced by N₂, which was indicated by no further droplets coming out from the production side (connected to the atmosphere), a scan was taken of the core partially saturated with brine when there was no flow. Since the maximum capillary pressure in the reservoir from which the laminated sandstone originated is \( \sim 1,000 \) kPa (the maximum capillary number of brine during displacement is approximately \( 1.7 \times 10^{-8} \)), this is therefore the highest capillary pressure applied in this study. The recorded mean capillary pressures for each injection steps are: 4.90, 15.00, 35.07, 69.30, 120.63, 200.45, 349.69, 617.99, and 1,000.61 kPa (see Figure S2).

3. Results and Discussion

We first quantify the pore structure, identifying three distinct regions by dividing all the pore space into different categories (Section 3.1). This is then followed by an analysis of overall capillary pressure behavior in terms of macroresolution and subresolution porosity as a function of brine saturation (Section 3.2). In Section 3.3, we further characterize the fluid displacement at different capillary pressures for regions with distinct pore-scale characteristics. Furthermore, we investigate the effect of boundaries between regions on the capillary pressure behavior. We demonstrate the capability of our methodology to combine flow experimentation and advanced image analysis techniques to capture, characterize and understand flow behavior in a laminated sandstone with a complex pore structure and geometry.

3.1. Quantification of the Pore Structure

We first introduce a method to obtain porosity \( \phi \) for the core sample in the field of view using gray-scale images of the dry scan containing only N₂ (Figures 1a and 1b) and the brine-saturated scan (Figure 1c) directly without conducting image segmentation:

\[
\phi = \frac{CT_{\text{brine scan}} - CT_{N_2 \text{ scan}}}{CT_{\text{brine phase}} - CT_{N_2 \text{ phase}}}
\]  

where \( CT_{\text{brine scan}} \) is the average gray-scale CT value for the sample saturated with brine, \( CT_{N_2 \text{ scan}} \) is the average gray-scale CT value of the dry sample that only contains N₂, \( CT_{\text{brine phase}} \) is the average gray-scale CT value for the brine phase, and \( CT_{N_2 \text{ phase}} \) is the average gray-scale CT value for the N₂ phase. The calculated porosity using Equation 1 was 0.200 ± 0.014, which agreed with the porosity obtained using the differential imaging method (0.205 ± 0.011, Figures 2d–2f) (Lin et al., 2016) and is consistent within experimental uncertainty with the helium-measured value for the original core (0.219 ± 0.015).

We further quantify the pore structure using differential imaging, see Figure 1. First we obtain the differential image (Figure 1d) using the brine-saturated scan and the N₂ scan (Figures 1b and 1c), followed by an application of nonlocal means edge preserving filter (Buades et al., 2005) to reduce the image noise and a gray-scale based image segmentation (Otsu, 1979), which segments the image into solid phase, macropores, and five levels of subresolution pores (micro 1–5), Figure 1e. Note that in this study, we use the word “level” to define voxels containing different porosities from 0 to 1 (0 for solid, 1 for macropores, and values in between for subresolution micropores). Macropores are defined as regions of the pore space with the lowest X-ray adsorption whose structure can be explicitly resolved in the image. Microporosity is defined as residing in voxels with intermediate absorption: a microporous voxel contains a mixture of solid and void space. The segmented image can be mapped with the brine-saturated scan from which the histogram of the gray-scale values for all segmented phases (Figure 1f) can be obtained to determine the average porosity from 0 to 1 (0: solid, 1: macropores) in each phase, \( \phi_{\text{micro},i} \), using (Lin et al., 2016):

\[
\phi_{\text{micro},i} = \frac{CT_{\text{micro},i} - CT_{\text{solid}}}{CT_{\text{macro}} - CT_{\text{solid}}}
\]  

where \( CT_{\text{micro},i} \) is the average gray-scale CT value for each level of subresolution pores, \( CT_{\text{solid}} \) is the average gray-scale CT value for the solid, and \( CT_{\text{macro}} \) is the average gray-scale CT value for the macropores. The sum
of all the porosity values based on the segmented differential image is 0.205 ± 0.011, which is consistent with the total porosity measured directly with gray-scale images using Equation 1 (0.200 ± 0.014).

To identify the boundary of the lamination, we obtain the porosity profile within and across regions by defining a distance parameter (\(d\)) which is the shortest distance between each voxel and its nearest region boundary. Within each region, by setting a series of upper and lower distance values (\(d = 0, 40, 80, 160, ..., d_{\text{max}}, \text{unit: \(\mu\)m}), the porosity for the voxels within each three-dimensional region defining the distance range can be computed as a function of boundary location (Figure 2c). Based on the porosity profile, we divide the image as shown in Figures 2a and 2b—poorly connected pores due to the existence of anhydrite (Region 1, blue), well-connected pores (Region 2, green), and the fine lamination layer (Region 3, red). The location of the region boundaries is determined at the point where the change in porosity with distance is greatest. Note that we use the word “region” throughout the study to represent regions within the sample with different geological properties and pore-size distributions.

We then used a network extraction tool to identify individual macropores and associated throats from the image: subresolution microporosity was not included (Dong & Blunt, 2009; Raeini et al., 2017). We use the radius of the largest sphere that can fit entirely in the pore as the representative pore radius. Figures 2d and 2e shows the pore-size distribution and coordination number (the coordination number for a pore is the number of neighboring pores connected to a pore through throats) distribution for the resolvable macropores. We observe that the average radius for the fine laminations (Region 3) is smaller for the other parts and that they are poorly connected through the resolvable pore space, as reflected by the small coordination numbers. The pore size in Region 1 is larger than in Region 2, but the coordination numbers are lower,
Geophysical Research Letters

because much of the pore space is completely blocked by anhydrite—see Figure 1b. We cannot calculate the pore-size distribution in the microporosity, since this pore space cannot be explicitly resolved in the image.

3.2. Average Brine Saturation and Capillary Pressure

Figure 3 shows the same slice showing N₂ displacing brine in the pore space at different capillary pressures (the brine phase appears to be the brightest). The overall brine saturation for the entire sample, and the local saturation throughout the sample with different levels of porosity, at each capillary pressure ($S_{w}$) can be calculated accurately using the average CT values for the image:

$$S_{w} = \frac{CT_{\text{two-phase scan}} - CT_{N_{2} \text{ scan}}}{CT_{\text{brine scan}} - CT_{N_{2} \text{ scan}}} \quad (3)$$

In general, we can select any subset of voxels in the image and compute the saturation in this subset at any imposed capillary pressure. Later we will do this to study the capillary pressure as a function of saturation in different parts of the image, including microporosity, different rock regions, and as a function of distance between regions. Note that we first observed the gas phase in the pore space at a capillary pressure of 15 kPa.

Figure 2. (a, b) The sample contains three regions with different geological properties, including poorly connected pores (Region 1, blue), well-connected pores (Region 2, green), and the fine lamination layer (Region 3, red). The distance, $d$, is the shortest distance between each voxel to the nearest boundary between regions (highlighted in yellow). (c) The porosity profile of different regions. The average porosity for Regions 1, 2, and 3 are 0.17, 0.22, and 0.12, respectively. The region boundaries are shown by the dashed line. (e, f) Pore-size distribution and coordination number distribution for the resolvable macropores. The macropores can also be connected via subresolution pores, which are not included in this analysis.
Assuming an interfacial tension $\sigma = 72 \text{ mN/m}$, using $P_c = \sigma/r$, where $r$ is the radius of curvature of the meniscus, we find $r = 4.8 \mu\text{m}$. As the imaging voxel size is $3.58 \mu\text{m}$, the resolution is insufficient to measure curvature directly from the image and use this to estimate capillary pressure (Armstrong et al., 2012).

From Figure 3, a two-stage displacement can be observed in this capillary drainage process: Displacement in the macropores followed by further displacement in the small pores and fine laminations. This has also been observed in our previous study (Lin et al., 2017). In the later sections, we will perform a more detailed quantification for fluid displacement to understand the displacement mechanism in the pore space with different average porosities (micro 1–5, macro) and their associated regions (1–3).

**Figure 3.** (Top) The same slices in different scans after drainage at different capillary pressure values. The bright voxels in the images represent brine while the dark voxels are $\text{N}_2$. (bottom) Capillary pressure as a function of brine saturation for the entire field of view, including subresolution pores (micro 1–5), and macropores.
3.3. Fluid Displacement in Different Regions

The average brine saturation for any portion of the pore space that is associated with a rock region (1–3) can be calculated using Equation 3 as a function of local porosity and for the different rock regions, shown in Figure 4. The irreducible brine saturation (the remaining brine saturation at $P_c = 1000.61$ kPa) for each region and pore level (micro 1–5 and macro) are shown in Table S2.

From Figure 4a, it can be observed that the entry pressure for Region 3 is the highest, where we observe a clear saturation decrease at a capillary pressure of approximately 35 kPa. This is also consistent with the smallest pore size for Region 3 (Figures 2d and 2e). In addition, at each capillary pressure, the brine saturation in Region 3 is always the highest, followed by the saturation in Regions 1 and 2. This saturation order is also consistent with the order for the overall pore sizes.

Figures 4b–4d show the capillary pressure as a function of brine saturation and the local porosity level. There is a clear trend that the brine in the macropores is displaced first. Where subresolution pores are
present, we also observe that brine is displaced first where the average porosity is highest (decreasing order from micro 1–5). This indicates that in micropores lower porosity is associated with a smaller average pore radius. Moreover, this saturation order is respected in terms of pore connectivity in different regions, where the poorest connectivity is in Region 3 while the highest connectivity is in Region 1 (Figure 2).

To further quantify the displacement and understand the boundary effect caused by the fine lamination, the shortest distance to the nearest boundary for each voxel (Figure 2a), \(d\), was computed and the local capillary pressure in the pore space for each region is plotted as a function of \(d\) and saturation, see Figures 5a–5c (see Table S1 for the total number of voxels within each distance range). Larger values of \(d\) indicate pore space further away from the boundaries.

From Figures 5a and 5b, for Regions 1 and 2 which are more porous than Region 3, it can be seen that the capillary pressure decreases with distance from the region boundaries 1–3 and 2–3. This indicates that the brine in the pore space which is further away from the fine laminations is more easily displaced by \(N_2\) resulting in a lower brine saturation. For sufficiently large distances, however, the capillary pressures become largely independent of \(d\). The significance of this lamination boundary effect in Regions 1 and 2 decreases with distance. In contrast, an inverse trend is observed in the lamination itself, Region 3, with a strong dependence on distance from the boundaries 1–3 and 2–3 where the brine in the pores closer to the boundaries get displaced first and the capillary entry pressure is lower. With a further increase in distance the capillary pressure increases, consistent with the lower porosity and inferred smaller pore sizes in the middle of the lamination—see Figure 2c.

We further analyzed the brine displacement in Region 3 and its distance dependence in Figures 5c–5f. The pore-size distribution for macropores is similar for all distance ranges (see Figure 5e). Within each distance range, a clear trend at different average porosities can be seen, Figure 5d. At low capillary pressure below 35 kPa, the brine in the macropores in the regions with largest distance values (160 < \(d\) ≤ 244 μm) is displaced later than in the regions with shorter distance values and higher capillary pressure. This means that in the laminated region, the flow displacement is mainly dominated by the pore size, connectivity, and accessibility, which is related to the shortest distance to the more porous regions.

In hydrocarbon operations, the distribution of initial water saturation is used to quantify the amount of oil and/or gas in the subsurface. The saturation at the end of the experiment in each pore region and for each level of microporosity is provided in Table S2 of the supporting information. The saturation varied from only 0.07 in the porous region 1 with large macropores to 0.44 in the lamination, Region 3. In the macropores overall the remaining water saturation was only 0.02 to 0.03; in the microporosity the saturation ranged from 0.07 to 0.68 with a tendency for the lower porosity domains to have a higher saturation. However, the saturation in a given porosity level varied considerably for different regions, indicating that connectivity and pore size also played a role in determining the saturation distribution. This means that in the lamination region, the flow displacement is mainly dominated by the pore size, connectivity, and accessibility, which is related to the shortest distance to the more porous regions.

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4. Conclusions

In this study, we characterized drainage capillary pressure in a highly heterogeneous porous medium. We used a DIPP to perform drainage in a complex laminated sandstone by injecting \(N_2\) (nonwetting phase) to displace brine (wetting phase) in the pore space. The fluid configurations at a range of capillary pressure (0–1,000 kPa) were imaged using X-ray microtomography. We introduced a method which uses the average gray-scale values for the micro-CT images to compute the porosity and fluid saturation.
Figure 5. (a–c) Capillary pressure as a function of brine saturation within different distance ranges for different regions (refer to Figure 2a for the definition of \( d \)). (c) For Region 3, the capillary pressures as a function of brine saturation for different porosity levels (micro 1–5, macro) within different distance ranges are compared. (d, e) Pore-size distribution and coordination number distribution for macropores only in Region 3.
We further extended the analysis of capillary pressure and fluid saturation by coupling pore-scale image analysis with pore categorization. The entire pore space was divided dependent on average porosity (micro 1–5, macro), as well as into three regions with distinct geological properties. The pore size and coordination number distributions in each region were characterized using a network extraction tool to identify individual macropores. Region 1 contained poorly connected pores due to the existence of anhydrite, Region 2 contained well-connected pores, while Region 3, the fine lamination layer, contained a few smaller macropores and significant subresolution pores.

We observe a two-stage displacement in this capillary drainage process: N_2 (nonwetting phase) displaced brine (wetting phase) in the larger pores first, followed by smaller pores. By coupling the displacement analysis with pore categorization, the pore space in the lamination (Region 3) had the highest displacement entry pressure, followed by Regions 1 and 2, which is consistent with the macropore-size distributions. Furthermore, where subresolution porosity was present, brine was preferentially displaced from where the porosity was highest first. We also characterized the impact of the boundaries between regions on the capillary pressure. While in the more porous Regions 1 and 2, consisting of larger pores, capillary pressure decreased with distance from the boundaries, in the laminated Region 3 the opposite behavior was shown.

Overall, we have demonstrated how to characterize drainage capillary pressure in a highly heterogeneous rock. Heterogeneity in capillary pressure and its impact on fluid displacement can now be better described at the pore scale with applications in carbon storage, gas/oil recovery and groundwater hydrology.

Data Availability Statement

The relevant data sets can be accessed via the Digital Rocks Portal: https://doi.org/10.17612/dnt0q-h551.

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