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Real structure micromodels based on reservoir rocks for enhanced oil recovery (EOR) applications

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Although the microfluidics application is not new in the petroleum industry, the upscaling of fluid flow behavior from micromodels to reservoir rocks is still challenging. In this work, an attempt to close the gaps between micromodels and reservoir rocks was performed by constructing micromodels based on the X-ray micro-computed tomography (µCT) images of a Bentheimer core plug. The goal of this work was to build a digital 3D model of reservoir rocks and transforming its rock properties and morphological features such as porosity, permeability, pore and grain size distribution into a 2D microfluidics chip. The workflow consists of several steps which are (1) rock property extraction from µCT image stack of core plug, (2) micromodel pore structure design, (3) lithographic mask construction and (4) fabrication. Flooding experiments, including single- and two-phase flow experiments, were performed to confirm the micromodels design. As a result, the real structure micromodels show similar rock properties, as well as a comparable fluid flow behavior to the Bentheimer core plug during typical water flooding and EOR polymer application. This framework demonstrates the potential for the general applicability of micromodels to support EOR studies on a larger scale, such as in the sandpack or core plug before field implementation.

1 Introduction

The microfluidics applications in the oil and gas industry have been started in the early 1950s when Chatevenever and Calhoun inserted glass spheres in between two glass plates to observe the fluid flow behavior in porous media. Since then microfluidics have been used for several applications such as in EOR studies for example polymer flooding, surfactants or combination of them with alkali (ASP), miscible gas injection, and other EOR methods such as microbial, foam and nanoparticles flooding. With all the advantages offered, microfluidics applications could be used to support well-established technologies such as sandbox and core flooding experiments in the EOR screening process before field implementation. However, until now, the acceptance of microfluidics in the oil and gas industry is still relatively low. One reason for this could be the difficulty to upscale the fluid flow behavior from microfluidics to reservoir rocks.

The pore structure and surface characteristics of microfluidic chips or micromodels need to be analogous to real rocks so that a relationship between them can be established. Reservoir rocks typically contain various minerals, and until now, micromodels are generally fabricated with homogeneous material (i.e., silica, glass, or polymers). Several studies have investigated surface modification techniques of micromodels to mimic the surface characteristic of reservoir rocks. Wang et al. (2017) and Yun et al. (2020) developed a nanofabrication process to homogeneously cover the original surface of micromodels from silica to calcium carbonate (CaCO3). Their result showed that the modified chips could be used to investigate EOR methods in carbonate reservoirs. Moreover, the pore structure is one main factor that governs fluid flow behavior in reservoir rocks. This pore structure is generally quantified with several properties such as porosity, permeability as well as pore and grain size distribution. It is crucial to design micromodels that have the same rock properties as reservoir rocks. Therefore, this paper focuses on constructing a digital 3D image of reservoir rocks and transforming its properties/morphology into micromodels. However, modifications of the surface characteristics of micromodels are not covered in this work.

Karadimitriou and Hassanizadeh (2012) classified micromodel pore structures into regular models (entirely and partially), irregular patterns and fractal patterns. Regular micromodels, generally constructed with identical grains where they can be randomly-distributed or in specific patterns. Gunda et al. (2011) and Wu et al. (2012) used Delaunay triangulation and Voronoi tessellations respectively to generate an ir-
regular network of the micromodels. Additionally, Cheng et al. (2004)\textsuperscript{23} and Nolte et al. (1989)\textsuperscript{23} designed and constructed micromodels based on flow area fraction (fractals geometry) of SEM micrographs. All of these patterns can be designed to reproduce the basic properties of reservoir rocks, such as porosity and permeability. However, little attention has been paid to the direct comparison of all rock properties between micromodels and reservoir rocks. Therefore, in this work the pore structure of micromodels was designed based on \(\mu\)CT images of a Bentheimer core plug; thus, the rock properties between them can be compared before the fabrication process.

Conventionally, the properties of reservoir rocks can be measured directly in laboratories. Nowadays, with the availability of high-resolution imaging techniques such as microscale x-ray computed tomography (\(\mu\)CT), focused ion beam scanning electron microscope (FIB-SEM) or nuclear magnetic resonance (NMR), the rock properties can be computed by using digital rock physics (DRP) methodology\textsuperscript{27}. In this work, the DRP approach was used to extract rock property information from \(\mu\)CT images of the Bentheimer core plug; subsequently these properties were used to design the pore structure of micromodels. This pore structure was then etched on silicon material sealed with glass layers to enable direct optical visualization during experiments. Several studies have reported the advantages of glass-silicon-glass micromodels for enhanced oil recovery (EOR) experimental studies\textsuperscript{5,28,29}.

It is generally accepted that a high degree of heterogeneity in reservoirs can cause poor oil displacement efficiency. When the permeability of the rocks is significantly different, the displacing fluid only flows through the high-permeability zone while the low permeability zone remains unswept. To mimic this condition, we constructed heterogeneous micromodels with two different permeability zones (low and high permeability). Afterward, we performed single- and two-phase flooding experiments to confirm the capability of micromodels. Furthermore, one example of EOR applications (polymer flooding) was performed to investigate the oil sweep efficiency improvement in heterogeneous porous media.

2 Materials and methods

2.1 Design and construction of micromodels.

Here we describe a novel workflow to produce micromodels which resemble flow characteristic of porous media. The workflow is described in the following steps: (i) rock property extraction from \(\mu\)CT image-stack of core plug, (ii) micromodel pore structure design, (iii) lithographic mask design and (iv) micromodel fabrication. These steps are described in the subsequent sections.

2.1.1 Rock property extraction from \(\mu\)CT image stack of core plug.

The DRP methodology consists of three main steps, which are the acquisition of high-resolution images of the core plug, image processing and computation of the rock properties\textsuperscript{30}. In this study, a Bentheimer core plug (length = 50 mm and diameter = 10 mm) was scanned to obtain more than one thousand two-dimensional (2D) high-resolution (1 pixel = 5 \(\mu\)m) \(\mu\)CT images with dimension of 1850 x 10000 pixels (Fig 1a and b). The raw \(\mu\)CT images were converted to binary images using the Otsu’s threshold method to differentiate pores and grains pixels. Several of the 2D binary images (\(N\)) were then used to reconstruct a 3D image stack. Fig 1c illustrates the image stack of Bentheimer core plug with dimension 1850 x 10000 x 100 pixels. The number of images used to reconstruct the image stack should be sufficient enough to exceed a representative elementary volume (REV). The REV is the minimum volume needed for rock properties computation so that the results can be representative of the larger domain (macroscopic scale)\textsuperscript{31}. In this work, the REV value was obtained based on porosity values. Then by using this image stack, rock properties such as pore and grain size distribution and permeability were calculated.

![Fig. 1](image_url)

Fig. 1 (a) An image of Bentheimer sandstone core plug (b) A 2D cross-section \(\mu\)CT image of the same sample with a resolution 5 \(\mu\)m (c) A 3D \(\mu\)CT image stack after binary segmentation.

Pore and grain size distribution are critical parameters that affect fluid flow in porous media. A maximal ball algorithm was used to estimate the pore and grain size distribution of the image stack. This approach was performed by assigning virtual spheres to all voxels and calculating the maximum radii of the spheres. The radii of the spheres were estimated based on the distance from the sphere’s center to the closest grain points\textsuperscript{32}.

Another main rock property that also influences the fluid flow...
behavior in porous media is tortuosity. This property describes the ratio of the shortest geometric flow path to the actual straight-line length of the porous media. In this study, a percolation path algorithm was used (Math2Market GmbH) to estimate the tortuosity of the image stack. By defining a sphere with a specific diameter, the shortest path length of the sphere to pass through the porous media can be estimated. Furthermore, pore-network modeling is also enabling the calculation of fluid transport properties such as permeability. Since the fluid flow in oil reservoirs is typically in the laminar regime; therefore, the Stokes-Brinkmann approach was used (Eq. 1). A constant pressure drop and no-slip boundary applied on the grain surface of the porous media were used as boundary conditions.

\[ -\mu \Delta u + \mu K^{-1} u + \nabla p = f \]  

Here \( K^{-1} \) is the inverse of the permeability tensor, \( \mu \) is the fluid viscosity, \( p \) is the pressure drop between inlet and outlet boundary, \( u \) is the velocity and \( f \) is a force density.

### 2.1.2 Micromodel pore structure design

#### Pore body extraction

Micromodels are porous media that have a two-dimensional pore structure. Therefore, to construct its pore structure based on real rocks, the pore morphology information from a 3D domain (image stack) needs to be transformed into a 2D field. By using the same image stack as in the previous step (Fig. 2b), a grain density topographic map (Fig. 2c) was calculated. This map was generated by applying a single-threshold value that subdivides the grain density matrix into pores and grains (Fig. 2d). As it can be seen in the image, most of the pore body are not connected. This appearance occurs because some morphology information disappeared during the matrix transformation from the 3D to the 2D domain. Therefore, pore-throat information was needed to connect all of these pore body.

#### Pore throats extraction

The pore throats map was extracted based on the medial axis algorithm applied to the grain density topographic map. One of the earliest works was reported by Lindquist et al., where the medial axis algorithm was used to detect the centrally located pore-skeleton of real rocks based on 3D tomographic images. In this work, before the medial axis extraction, a morphological operation called "opening-closing reconstruction" was performed to generate a more flat grain density map. This operation was executed by eroding and dilating the topological map using a radial structure element with a specific size. The purpose of this approach was to reveal all the possibilities of the medial axis on the map. Then, grains distribution was generated by calculating the local maxima of the "new" topological map. By applying the Euclidean distance transform on the grains distribution map, the distance between pore pixels to the nearest grain pixels was calculated. The medial axis (skeleton) of the pore space was then obtained by using a "watershed" approach on the distance matrix. In the 2D grains distribution map, the medial axis is the watershed ridgelines between two neighboring grains.

The number and size of pore throats are primary factors that govern the pore size distribution of micromodels. Fig. 3 shows the medial axis extraction from the grain density map with two different structure elements, which resulted in two different amounts of pore throats. As illustrated in this figure, the white

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**Fig. 2** Schematic overview of pore space characterization for generating the pore body map. (a) Exemplary of gray-scale \( \mu \)CT image stack (1000 x 1000 x 500 \( \mu \)m). (b) The binary image stack of the same domain. (c) A grain density map generated based on the binary image stack. (d) A pore body map calculated from the grain density map by using a single-threshold value.

**Fig. 3** A schematic overview of pore throats extraction from the grain density map. The pore throats are watershed ridgelines (black line) between two local maxima (white). The grain density map overlayed with pore throats extracted with structural elements of 5 pixels (a) and 7 pixels (b). The pore throats maps (c and d), respectively.
The rock properties of ROCs are mainly dependent on the number of local maxima depends on the size of structural elements used in the morphology operations. By using a smaller structural element (size = 5 pixels), more maxima were detected (Fig. 3a and c), thus more pore throats could be extracted compared to the larger structural element (size = 7 pixels, Fig. 3b and d). Furthermore, as indicated in this image, the extracted medial axis has the same dimension (uniform) at each position in the matrix. This medial axis does not reflect real reservoir rocks where the pore throats size is non-uniform. Therefore, in the next step, the width of the medial axis was adjusted based on the actual distance between the center of the medial axis to the nearest grain pixels.

Rock on the chip. After the pore body (Fig. 2a) and pore throats (Fig. 2b) maps were extracted, the pore structure of micromodels can be constructed by superimposing these two matrices (Fig. 4a). This new structure, in this work referred to as "rock on the chip (ROC)," was then used for the rock properties calculation. In this work, the pore throats matrix based on structural element 7 pixels was selected for the ROC construction. The reason for this selection was because this ROC showed more similar rock properties (e.g., pore size distribution) to the Bentheimer core plug. Then the same algorithms used for computing rock properties of the Bentheimer image stack were also used for the ROC; thus, the comparison between them could be performed. The rock properties of ROCs are mainly dependent on the number and size of pore body and pore throats. To match the rock properties of the image stack, three previously described parameters were thoroughly adjusted. These parameters were (1) the single-threshold value for defining the size and number of pore

Fig. 4 (a) An image of rock on the chip (ROC) obtained by superimposing the pore body and pore throats map. The pore throats of ROC initially have a uniform size (one voxel or 5 \( \mu m \)). (b to d) The image of ROCs which have non-uniform pore throats. The size of pore throats was defined based on the actual distance of the medial axis to the nearest grain pixel. The permeability of the ROCs are 3.5, 2.0 and 0.8 Darcy respectively.

The algorithm developed in this work enables the design of several micromodel realizations while still accommodating the pore morphology of real rocks. With this algorithm, pore structures with different permeabilities can be easily generated by adjusting the pore throats size. In this work, a total of five ROC realizations were generated, which consist of three homogeneous and two heterogeneous pore structures. The three homogeneous structures, namely "Structure-1, Structure-2 and Structure-3" have an average permeability of 3.5, 2.0 and 0.8 Darcy respectively (Fig. 4a-d). Additionally, to facilitate the investigation of oil displacement efficiency, two heterogeneous structures, namely "Structure-A and Structure-B, were designed with two different zones: low permeability zones on the sides of micromodels and high permeability zone in the middle. The difference between these two structures was the permeability at the high-permeability zone. The high-permeability zone of the Structure-A was designed to be 2 Darcy and 3.5 Darcy for the Structure-B. For both structures, the low-permeability zones have a permeability of 0.8 Darcy.

2.1.3 Lithographic mask

After finalizing the pore structure design, a "flooding flow approach" was introduced to make connections for fluids freely entering the micromodel during experiments. In this approach, an inlet and outlet of the micromodel, as well as artificial channels, were implemented on the ROC, which can be seen in Fig. 5. The inlet and outlet boreholes (diameter = 1.2 mm) were connected to the pore structure with a trapezoid shape to provide a homogeneous fluid flux across the micromodel. Previous experimental results showed that in linear micromodels with centrally located boreholes (without artificial channels), the displacing fluid velocity was faster in the middle of the micromodels inlet rather than on the sidewall. This phenomenon could be explained by the friction on the sidewall of micromodels. To minimize this effect, the artificial channels (width = 25 \( \mu m \)) were added around the inlet and outlet to connect the trapezoid base and the pore structure. The design of these artificial channels follows a convex shape to provide a linear shock-front of injected fluid when
entering the micromodel system. The length of channels was designed longer on the edges of micromodels than in the middle. Therefore, the length of artificial channels varies from 1 to 6 mm. The result, as presented in the next section, is promising where the fluid front around the inlet of micromodel is relatively linear. However, it is clear that much additional work, such as pore-scale simulation and particle image velocimetry (PIV), is required to estimate the precise size of artificial channels. Thus a uniform fluid velocity alongside the micromodel width can be reached before entering the pore structure. Furthermore, after the flooding flow approach has been added, the final design of the micromodel, namely "Lithographic Mask," was delivered to the manufacturing process.

2.1.4 Micromodel fabrication

Several materials such as quartz, glass, Poly(methylmethacrylate) (PMMA), Polydimethylsiloxane (PDMS) and silicon can be used for micromodels fabrication. Each of these materials has advantages and disadvantages and also requires different fabrication techniques. Details of materials and techniques selection are described by Wegner (2015). In this work, silicon material was selected as a substrate sealed by two glass layers. The fabrication of micromodels consists of several major steps from the photo-lithography until the bonding process. The process started with transferring the lithographic mask to the substrate, which is UV light-sensitive layer - then followed by removing the photo-resist material which was affected by the UV-light. As a next step, the etching process was performed to project the pattern of the pore network onto silicon material. A dry etching method was selected instead of wet etching to avoid slopping effects on the silicon walls. The etching depth in this process was 50 +/- 1 μm. With this technique, the ratio between the depth and the width of pore channels obtained was 6:1, and the angle of vertical walls was 82°- 90°. The minimum pore size of fabricated micromodels was about 8 μm. This value was considered to be acceptable since, as previously described, the resolution of μCT images is 5 μm. It is generally recognized that the pore size of reservoir rocks, particularly in unconventional tight reservoirs, can be at the nanoscale (5 - 900 nm). The approach presented in this study could also be applied to design the pore structures and morphology features at the nanoscale level, especially with finer-resolution images (e.g., FIB-SEM images). However, it is evident that considerable additional work is required to manufactured micromodels contain nanoscale pores.

After the etching process finished, the remaining photo-resist material was removed. Afterward, an anodic bonding process was performed to seal the silicon substrate with two transparent glass layers that enable visual access to the porous structure. In this work, Borofloat33 material, with a thickness of 0.5 mm and a high degree of flatness, was used. The anodic bonding was performed separately; the first glass was bonded on the top side of the silicon, followed by the second glass, in which two boreholes were powder blasted. Since the grain size of the micromodels was relatively small, there was not enough bonding surface between silicon and glass materials. Therefore to avoid the contact problem between the materials, micromodels were baked in the oven at 400°C and an electric field of 400V was applied for 9 hours.

2.2 Experimental setup and procedure.

The experimental microfluidics setup used in this study is depicted in Fig. 6. This setup mainly consists of three systems, first is the fluid handling system, including influent bottles with HLPC caps, tubing, microfluidics valves, pump and effluent bottles. During the flooding experiments, a low-flow syringe pump (Harvard pump 11 Elite Series, Harvard Apparatus Ltd.) was used to provide high-accuracy injection rates. The differential pressure across the micromodel was measured by using a differential pressure transmitters of the PD-33X (Keller GmbH). The image acquisition system was used in microfluidics applications for obtaining images or videos during the flooding process. An inverted epi-fluorescence microscope (Axio Imager.Z2m Carl Zeiss GmbH), which is equipped with a CCD camera, was used to obtain high-resolution images during the flooding process, particularly at the small pore size. A fluorescent light source (Visitron Systems HXP 120) was used to differentiate the aqueous phase with crude oil. However, by using this configuration, only a limited area of the micromodel can be observed at the same time, because the optical window of the microscope only covers a small area. Therefore to investigate the displacement process in the macroscopic scale (whole area of the micromodel), an integrated microfluidic flooding device equipped with a high-resolution camera was used (InspitOR, HOT Microfluidics GmbH). The last system is the micromodel system, which consists of the micromodel and a holder integrated with a heating system. The holder includes a Borosilicate glass coated with Indium Tin Oxide (ITO) layer as a heating source. This ITO glass received an electrical current from a power supply through four spring pins mounted below it. Moreover, the temperature of the micromodel was measured by using a temperature sensor (SA1-RTD-80, Omega Engineering GmbH). An algorithm developed in the LabVIEW framework was used to
control a constant working temperature of the micromodel during the experiments.

A wetting phase fluid used in this study is scientific-subsea-water (SSW) brine, which has salinity 35 g/l of TDS. The oil (non-wetting) is the original crude oil from a Rumanian oil field which has viscosity 14 mPa.s at a shear rate of 10 1/s. The interfacial tension (IFT) of the oil and brine is 14.3 mN/m, which was measured in the laboratory using the Du Noüy ring method. For the EOR application, a commercial polymer (Flopaam 3530) with molecular weight 8 million Dalton was used. The concentration of the polymer of 1500 ppm was designed to obtain a mobility ratio close to one. The details of the fluid properties can be seen in Table 1.

### Table 1 Fluid properties used in micromodel flooding experiments

| Properties at room temperature | Fluids | Crude oil | Brine | Polymer solution |
|-------------------------------|--------|----------|-------|-----------------|
| Density (kg/m³)               | 869    | 1013     | -     |
| Viscosity at 10 s⁻¹ (mPa.s)   | 13.82  | 1.1      | 14.02 |
| IFT between oil and brine (mN/m) | 14.29  | 35000    | -     |
| Salinity (ppm)                | -      | -        | 1500  |
| Polymer concentration (ppm)   | -      | -        | -     |

Before the experiments started, the micromodel was saturated with N₂ or CO₂ to avoid gas bubbles forming during the experiments. Injection of the distilled water was performed to displaced all the gas bubbles, followed by the injection of brine. During this injection, the pressure drop across the micromodel was measured to estimate the absolute permeability. This value will be used to validate the computed permeability of the micromodels. Then the crude oil was injected into the brine-saturated micromodel at an injection rate of 0.1 µl/min equivalent to 1 ft/day Darcy's velocity. The oil initialization was conducted until differential pressure across the micromodel had stabilized and followed by higher injection rates (bump rates, e.g., 10 - 50 ft/day). As the initial oil saturation (So) condition was reached, a standard secondary mode of brine flooding was performed to investigate the oil displacement efficiency in micromodels. The brine was injected at an injection rate of 0.1 µl/min into the micromodel. During the brine injection, images of the micromodel were obtained using a camera. The images were then used to estimate fluid saturations inside the chip by using an image processing tool developed in MATLAB. Furthermore, 5 PV of the polymer solution was then injected into the micromodel (tertiary mode) at a similar injection rate (0.1 µl/min) to investigate the sweep efficiency improvement.

Additionally, all flooding experiments were performed at room temperature and 1 Bar(g) backpressure. This back pressure was established to avoid the gas bubbles forming in the micromodel during the experiments. Based on the pressure test, the fabricated micromodels could operate at a maximum of 25 - 30 Bar differential pressure under atmospheric conditions.

### 3 Results

Fig. 7 shows an example of the design and image of micromodel after the fabrication of heterogeneous structure A with two different permeability zones. As previously described, this micromodel has two permeability zones, which are low (k = ~800 mD) on the edges and high (k = ~2000 mD) at the middle. In this section, the rock properties of micromodels and core plug and the result of flooding experiments are presented.

#### 3.1 Rock properties of Bentheimer core plug.

The total elementary volume of the Bentheimer core plug based on image acquisition was ~2.3 · 10³ mm³. This value was calculated based on the one thousand two-dimensional (2D) µCT images with the dimension of 1850 x 10000 pixels (1 pixel = 5 µm). The calculated REV of the Bentheimer image stack was ~200 mm³ or 10% of total elementary volume. The porosity of the image stack started to converge to the porosity level of 0.238. This value was within very good agreement with our measurement data using a gas pycnometer, which showed the porosity of the Bentheimer core plug in the range of 0.24 to 0.26. The REV value estimated in this study was slightly higher than the value calculated by Halisch (2013), which showed the REV of Bentheimer µCT image of 8% (REV domain with an edge length of 500 voxels from a maximum of 1750 voxels). This difference might be due to the variation in µCT image resolution.

Results of the rock properties computation of the Bentheimer core plug are summarized in Table 2. As can be observed in this table, the median pore size of the 3D µCT image stack calculated was about 46.42 µm, while 10% of all pores have a diameter less than 18.55 µm (D10) and 90% below 94.46 µm (D90). This result was comparable to the pore size distribution of Bentheimer sandstone that was found in the literature (39–41 µm). Maloney et al. (1990) reported that the Bentheimer sandstone might have a broad range of pore size values from 1 - 140 µm. Their results showed that using a visual microscopic and an image analysis technique, the median pore diameter of Bentheimer sandstone was in the range of 60 to 140 µm while smaller pore diameter values were obtained based on the mercury intrusion method, which was in the
range of 1 - 60 \( \mu m \).

Based on the computation, 90% of the grains of the Bentheimer image stack have a diameter of less than 180 \( \mu m \) (D90) while the median value was approximately 124 \( \mu m \) (D50). These values were slightly lower than the results reported by Peksa et al. (2015)\(^4\). Their results, based on the analysis of 20 thin sections, showed the median grain size of Bentheimer sandstone was 235 \( \mu m \) while 320 \( \mu m \) based on \( \mu \)CT scans\(^5\). Moreover, the calculated tortuosity of the image stack was about 1.11 and 1.12 for the X and Y direction, respectively. These values were comparable with the study reported by Kahl et al. (2013) that investigated the pathways of elastic waves through the Bentheimer sandstone for the tortuosity estimation. Their result showed a tortuosity of 1.05 both for the X and the Y direction\(^2\).

As outlined in the methodology, the absolute water permeability of the Bentheimer image stack was calculated based on the Stokes-Brinkmann approach. The permeability values of the image stack were 3.1 and 3.5 Darcy in the X and Y direction, respectively. These values were similar to data from the literature\(^6\). According to Peksa et al. (2015), the absolute permeability of Bentheimer sandstone can be in the range of 1.4 to 3.09 Darcy based on laboratory measurement techniques such as Ruska gas and liquid permeameter or core flooding experiments\(^7\). However, some literature also reported variations of Bentheimer sandstone permeability\(^8\). The permeability of Bentheimer sandstone could vary, depending on the environmental conditions during the deposition of the rocks. An extensive study of Bentheimer sandstone with different sedimentation environments was reported by Traska et al. (2013), which showed the permeability of Bentheimer sandstone could vary in the range of 0.1 to 4.1 Darcy\(^9\).

### 3.2 Rock properties of micromodels and comparison to the Bentheimer core plug.

As mentioned previously, a total of five realizations of the micromodel pore structures were evaluated. Table 3 shows the results of the rock properties computation of these structures. As listed in this table, the homogeneous Structure-1, which was generated based on the image stack, matched the rock properties of the Bentheimer core plug. To obtain this ROC, the single threshold value used for defining the pore body map was 0.55; the structural element size was seven pixels and the ratio of pore throat diameters to the actual distance was about 32%. The porosity, pore size distribution, tortuosity and permeability of this structure, as expected, were in line with the properties of the image stack. However, the grain size distribution of this structure, which was in the range of 98.9 - 240.3 \( \mu m \) was slightly higher than the image stack. This deviation was related to the number of pore throats extracted, which intentionally was reduced to match the pore size distribution during the pore structure design. Consequently, few numbers of “large” grains appeared in the pore structure matrix.

Table 3 also shows the properties of heterogeneous Structure-A and Structure-B. As predicted, the rock properties of these structures lie in between the properties of low and high permeability zones. For example, the calculated average permeability of the micromodel Structure-A was \( \sim 1.2 \) Darcy (Y-direction), where the permeability of the low and high-permeability zone was \( \sim 0.86 \) and 1.9 Darcy, respectively.

In general, the rock properties of the micromodels indicate a more reasonable relationship to the Bentheimer core plug compared to other methods from the literature\(^2,24,44,45\). The approach presented in this study allows the construction of pore structures with realistic porosity while still maintaining the con-
Table 3 Rock properties of micromodel for all realization structures

| Rock Properties | Homogeneous | Heterogeneous |
|-----------------|-------------|---------------|
| Porosity (-)    | 0.245       | 0.192         |
| Pore size (µm)  |             |               |
| D10             | 16.97       | 11.52         |
| D50             | 40.86       | 28.08         |
| D90             | 107.91      | 105.12        |
| Grain size (µm) |             |               |
| D10             | 98.93       | 97.28         |
| D50             | 174.13      | 176.86        |
| D90             | 240.30      | 249.67        |
| Tortuosity in X-dir [-] | 1.11 | 1.13 |
| Tortuosity in Y-dir [-] | 1.09 | 1.11 |
| Permeability in X-dir (mD) | 3200 | 112.52 |
| Permeability in Y-dir (mD) | 3563 | 177.39 |

The D10/50/90 means that 10%/50%/90% of all pores have diameter smaller than values shown.

Connections between pore bodies. Buchgraber et al. (2011) and Gauteplass et al. (2014) reported the micromodels based on a thin section of sandstone with porosities close to 50%. The reason for these high porosity values was to provide flow connections across micromodels. A similar result was also described by Karadimitriou (2013), where porosities of micromodels generated based on Delaunay triangulation were ∼ 50%. An irregular network micromodel based on Voronoi tessellations constructed by Wu et al. (2012) showed a porosity of 0.11 - 0.20 and a permeability of 0.42 to 0.55 Darcy. However, these micromodels were constructed with uniform pore throats, which were ∼ 10 µm to connect all the pore bodies. As described previously, this situation most likely does not occur in reservoir rocks; therefore, in this work, the size of pore throats in the micromodels was designed to be non-uniform. Fig. 8 shows the pore size comparison between the Bentheimer image stack and micromodels with uniform and non-uniform pore throats. As can be seen, the difference of the mean pore diameter between them was only ∼ 5µm. As for the uniform pore throats, the difference to the image stack was noticeable, because the uniform pore throats dominated the distribution. Furthermore, the relationship between the local porosity-permeability of the micromodel was also compared to the Bentheimer image stack. As illustrated in Fig. 9, the local porosity-permeability of the micromodel was in agreement with the Bentheimer core plug.

3.3 Micromodel flooding experiments.

As previously described, during the injection of water and brine, the differential pressure across the micromodel was measured. This pressure data was then used to estimate the absolute permeability based on Darcy’s law. The measurement results were then compared to the computed values based on the pore-scale simulation. The results show that permeability values based on simulation and measurement were in good agreement with a deviation of ± 5%. As a continuation, the crude oil was injected into the brine-saturated micromodel at an injection rate of 0.1 µl/min equivalent to 1 ft/day Darcy’s velocity. This oil initial-
In this work, a novel approach for generating micromodels based on real reservoir rocks has been presented. The digital rock physics (DRP) approach was used to extract the rock properties of Bentheimer sandstone based on microscale x-ray computed tomography (µCT) images. By using this approach, the information about the pore body and pore throats of reservoir rocks were obtained and then transferred to a 2D pore structure of micromodels. The algorithm presented offers the flexibility to adjust the number and size of the pore body and pore throats. Therefore, the porosity, pore and grain size distribution and tortuosity, as well as permeability of micromodels, can accurately mimic the properties of real rocks. Furthermore, the algorithm is also enabling us to construct heterogeneous micromodels with different permeabilities.

The results of flooding experiments show the absolute permeability of the micromodel matched the simulated values. It was also found that during typical brine flooding experiments (secondary mode), most of the oil was produced from the high permeability zone and only small fractions from the low permeability zones. This result suggested that the areal sweep efficiency of this micromodel during brine flooding was relatively low; therefore, it is an excellent potential for conformance improvement in EOR applications such as the polymer, gel or microbial (MEOR) injection. An increase of the oil recovery factor was observed during polymer flooding (tertiary mode) application, where extra oil was

The oil injection with a higher rate (0.5 µl/min or equivalent to 2 ft/day Darcy’s velocity) was performed after oil initialization and at the brine breakthrough time. As indicated in this image, the water-front at the high permeability zone and only small fractions from the low permeability zones. This result suggested that the areal sweep efficiency of this micromodel during brine flooding was relatively low; therefore, it is an excellent potential for conformance improvement in EOR applications such as the polymer, gel or microbial (MEOR) injection. An increase of the oil recovery factor was observed during polymer flooding (tertiary mode) application, where extra oil was

Fig. 10 Images of micromodel during oil initialization obtained by a microscope with objective 5X magnification. Fluorescent light was used to differentiate between the aqueous and oil phase. (a) An image covering the micromodel which contains 100 tiles images (b) A section of micromodel after oil injection with injection rate 0.2 µl/min or equivalent to 2 ft/day Darcy’s velocity. (c) The same section of micromodel after oil injection with an injection rate of 0.5 µl/min.
Images of micromodel during brine flooding. (a) An image of the micromodel at initial condition (b) at water breakthrough (c) after injection ten pore volume of brine.

### Table 4 Two-phase flooding experiments using micromodels

| Parameters                  | Whole Chip | Low Perm 1 | High Perm | Low Perm 2 |
|-----------------------------|------------|------------|-----------|------------|
| Initial Oil Saturation [-]  | 0.79       | 0.78       | 0.83      | 0.75       |
| RF at breakthrough (%)      | 19.65      | 9.02       | 41.78     | 3.56       |
| RF brine flooding 10 PV (%) | 31.34      | 25.60      | 44.48     | 20.87      |
| RF after Polymer (%)        | 36.01      | 29.08      | 47.38     | 28.92      |
| ΔRF after Polymer (%)       | 4.67       | 3.48       | 2.90      | 8.05       |

mainly produced from low permeability zones. This result indicates that an improvement of macroscopic conformance could be obtained in the heterogeneous micromodels.

Furthermore, the results demonstrate the benefits gained from the digital rock physics method in the construction of micromodels and could be used to support the EOR studies on a larger scale, for example, sandpack or core plug or even for quick EOR screening before field application. Therefore, future work should focus on a direct comparison of oil displacement efficiency between micromodels and the corresponding core plug to validate the construction workflow. By comparing these two approaches (core plug and micromodel), the differences between them could be quantitatively estimated and beneficial for improving the construction of micromodels.

An important question for future studies is to integrate the presented approach with the surface modification techniques to mimic the surface heterogeneity of reservoir rocks. As previously described, several studies have investigated coating processes to cover the silicon materials of micromodels. Extensive research was reported by Saefken et al. (2019), where the surface

![Fig. 11 Images of micromodel during brine flooding. (a) An image of the micromodel at initial condition (b) at water breakthrough (c) after injection ten pore volume of brine.](image-url)
wettability of the silicon and glass micromodels could be altered by coating the silicon and glass material with Trichlorosilane. Moreover, an in situ growing process of calcium carbonate layer suggested by Wang et al. (2017) and Yun et al. (2020) could be beneficial to obtain micromodels that mimic carbonate reservoir rocks.

**Conflicts of interest**

There are no conflicts to declare.

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**Fig. 12** The oil recovery factor and the differential pressure during brine (secondary mode) and polymer flooding (tertiary mode) experiments in the micromodels.
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