Investigating microscopic seepage characteristics and fracture effectiveness of tight sandstones: a digital core approach

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Received: 2 December 2019 / Published online: 28 May 2020 © The Author(s) 2020

Abstract
Microscopic seepage characteristics are critical for the evaluation of tight sandstone reservoirs. In this study, a digital core approach integrating microscopic seepage simulation and CT scanning was developed to characterize microscopic seepage and fracture effectiveness (the ratio of micro-fractures that contributes to fluid flow) of tight sandstones. Numerical simulations were carried out for characterizations of tight sandstones. The results show that the axial permeability of the investigated cylindrical tight sandstone from Junggar Basin in China is 0.460 μm², while the radial permeability is 0.3723 μm², and the axial and radial effective fracture ratios are 0.4387 and 0.4806, respectively, indicating that cracks are not fully developed and the connectivity between micro-cracks is poor. Directional permeability that is difficult to measure by laboratory experiments can be obtained readily using the proposed method in this paper. The results provide important information for improving the exploration and development of tight sandstone reservoirs.

Keywords Tight sandstone · Digital core approach · CT scanning · Microscopic seepage characteristics · Fracture effectiveness

1 Introduction
Seepage characteristics of reservoir rocks are important information in exploration and development of tight oil and gas reservoirs. Most existing investigations on seepage characteristics are based on macroscopic scale studies (Li et al. 2019a, b; Lv et al. 2019; Zhang et al. 2019). Because the pore size of tight sandstone is relatively small (at micron level), it is necessary to carry out microscopic scale study of seepage characteristics of tight sandstone reservoirs (Babchin and Nasr 2006; Li et al. 2019a, b; Ren et al. 2018; Yin et al. 2019; Wang et al. 2020). The study of micro-seepage of reservoir rocks is usually through restoring the micro-pore structures of the rock in numerical models. On this basis, heterogeneous seepage models were developed and seepage characteristics of the rocks were analyzed through numerical simulations. Digital core technology has been extensively used to characterize the heterogeneity of rocks in the aspects of solid mechanics, mesoscopic mechanics, and rock damage (Lebourg et al. 2004; Nishank et al. 2019; Sadegh and Pejman 2019; Shan and Lai 2019). Some researchers have also used the digital core technology to study microscopic percolation mechanism of rocks. However, these applications of digital core technology are mostly based on random mathematical models (Song and Zhou 2019; Starnoni et al. 2017; Sun et al. 2019; Wang et al. 2019a, b).

Effectiveness of fractures can reflect the permeability of rocks (Zhang et al. 2013; Zhang and Mack 2017). Effective fracture ratio directly affects the production performance of oil and gas reservoirs, so it is an important index for evaluating oil and gas reservoirs. To date, the studies of fracture...
effectiveness are mostly based on qualitative analysis of well logging information (Tang et al. 2017), fracture genesis, and influential factors (An et al. 2016), while quantitative evaluation of fracture effectiveness is rare (Zhao et al. 2017). Therefore, this paper proposes a digital core approach to study heterogeneous seepage characteristics of tight sandstones by incorporating micro-CT scanning results into a numerical fluid flow model. Next, micro-seepage characteristics of tight sandstones are investigated using numerical simulations. Furthermore, fracture effectiveness is quantitatively determined based on the simulation results of micro-seepage.

2 Micro-CT scanning

Tight sandstone samples taken from the Jurassic Toutunhe Formation in Junggar Basin, China, were scanned with a MicroCT scanner—MicroXCT-200. A total of 5 sandstone samples were used for the experiments. A total number of 1008 2D grayscale images with 1024 × 1024 pixels and a reconstruction resolution of 2.3 μm (each pixel in the image corresponds to an actual length of 2.3 μm) were obtained for each rock sample. After omitting some invalid images at the beginning and the end of the scanning process, each sample had about 950 valid 2D grayscale images. Figure 1a shows an example of the 2D images. The dark black areas represent rock pores and micro-fissures, while the bright white areas are high-density mineral components of the rock (e.g., pyrite, calcite, etc.), and the intermediate gray color areas between dark black and bright white are feldspar and clay minerals.

By superimposing the effective 2D grayscale images of each sample, a 3D grayscale image of the rock sample can be obtained. An example is shown in Fig. 1b. In the following, a numerical fluid seepage model for the heterogeneous rock samples will be developed using the 3D image to simulate micro-seepage behavior of the rock and to evaluate fracture effectiveness.

3 Heterogeneous model of the tight sandstone

Using 3D grayscale CT scan images of the rock samples, 2D numerical models were established for various vertical cross section planes intersecting the axis of the core samples. To better capture the microscale seepage characteristics of the tight sandstone samples, a total number of 12 vertical cross section planes were selected for each sample with a 15° apart angle between each cross section planes. Figure 2 shows the selection of these planes, i.e., planes of 0°–180°, 15°–195°, 30°–210°, 45°–225°, 60°–240°, 75°–255°, 90°–270°, 105°–285°, 120°–300°, 135°–315°, 150°–330°, and 165°–345°. Figure 3 shows an example of the cross section plane of 0°–180°, with x and y directions corresponding to the axial and radial directions of the core sample, respectively.

Since different grayscale values (intensity) in the grayscale image correspond to different medium regions, the micro-cracks, pores and rock skeletons of each cross section can be distinguished by threshold segmentation of the gray value (the threshold value is 58). The black regions in the images correspond to cracks and pores. The distributions of the cracks are identified and imported into a 2D pore structure model in the multiphysics modeling software—COMSOL. The crack width is in the range of 2.3 to 9.2 μm interpreted from the images. Figure 4 shows the identified micro-crack distribution image of the 0°–180° plane and Fig. 5 shows the corresponding crack distribution in the pore structure model in COMSOL.

The fluid used in the simulations is assumed to be water with a density of 1000 kg/m³, a dynamic viscosity of 0.001 Pa/s, and a bulk modulus of 2.18 GPa. The fluid
can flow within micro-cracks and pores in the rock. Fluid is injected separately into the cross section in the \( x \) and \( y \) directions to study the axial and radial seepage characteristics of the core samples. In the \( x \) direction (i.e., axial direction of the core), the fluid injection pressure at the left boundary is 20 Pa and the outlet pressure at the right boundary is 0 Pa. For fluid injection along the \( y \) direction (i.e., radial direction of the core), the injection pressure at the bottom side of the 2D cross section plane is 10 Pa and the outlet pressure at the top side of the plane is 0 Pa. It should be noted that, because of the high scanning precision, micro-cracks and pores are basically captured. While fluid leakage and matrix adsorption eventually result in fluid entering the matrix, it is very difficult for the fluid to penetrate to the boundary of the model and the influence on permeability is negligible. Therefore, it is assumed that the fluid can only flow continuously in the micro-cracks and pores, and the boundary between the micro-cracks and matrix is set as impermeable boundary.

### 4 Analysis of microscopic seepage characteristics of tight sandstones

#### 4.1 Fluid flow model

To date, there are two main modeling approaches for the simulation of microscopic seepage of rock using digital core technology—the pore network model and the digital core model (Mutailipu et al. 2017). The pore network model replaces complicated pores and throats in the rock with capillaries of different diameters, thus transforming fluid flow in complex pore structure into flow in regular capillaries. It is obvious that considerable simplification of pore/throat structures of the rock should be made in the pore network model. Conversely, the digital core model is based on the real pore/throat/crack structure of the rock to study the seepage characteristics, which overcomes many shortcomings of the pore network model. Therefore, digital core modeling
technique is used in this study to characterize the micro-
seepage behavior of tight sandstones.

There are two main numerical fluid mechanics methods
for simulating microscopic fluid seepage in digital core
models—the Lattice Boltzmann method (LBM) based on
discrete medium assumption and the compute fluid dynamic
(CFD) method based on continuous medium assumption. In
this paper, the CFD method and Navier–Stokes equations
are used to model fluid seepage in the micro-structures of
tight sandstones.

Navier–Stokes equations are equations of motion that
describe the momentum conservation of fluids, expressed as:

\[
\begin{align*}
\frac{\partial \rho}{\partial t} + \nabla \cdot (\rho \mathbf{u}) &= 0 \\
\frac{\partial (\rho \mathbf{u})}{\partial t} + \nabla \cdot (\rho \mathbf{u} \mathbf{u}) &= \nabla \sigma + \nabla T \\
\frac{\partial (\rho e)}{\partial t} + \nabla \cdot (\rho e \mathbf{u}) &= \sigma \cdot \nabla \mathbf{u} - \nabla q
\end{align*}
\]

where \( \rho \) is the fluid density; \( \mathbf{u} \) is the fluid velocity; \( e \) is the
internal energy of the fluid; \( q \) is the heat flux; \( \sigma \) is the stress
tensor; \( \nabla \) is Laplace operator; \( t \) is time.

The vector expressions of Navier–Stokes equations are
as follows:

\[
\begin{align*}
\rho \frac{\partial \mathbf{u}}{\partial t} + \rho (\mathbf{u} \cdot \nabla) \mathbf{u} &= \nabla \cdot [-p + \mu(\nabla \mathbf{u} + (\nabla \mathbf{u})^T)] + \mathbf{F} \\
\rho \nabla \mathbf{u} &= 0
\end{align*}
\]

where \( \mathbf{F} \) is the force acting on the fluid; \( p \) is the pressure.

4.2 Simulation results of microscopic seepage
in tight sandstones

Simulations of microscopic seepage along \( x \) and \( y \) directions
of the twelve cross section planes in Fig. 2 were carried out.

The distributions of fluid flow velocity and fluid pressure
in the micro-cracks of in the \( x \) (corresponding to the axial
direction of core cylinder) and \( y \) directions (corresponding to
the radial direction of core cylinder) were obtained. To il-
strate the capability of the model, simulation results of the
\( 0^\circ–180^\circ, 45^\circ–225^\circ, 90^\circ–270^\circ, 135^\circ–315^\circ \) planes are shown
through Figs. 6, 7, 8, 9, 10, 11, 12 and 13.

From fluid pressure and flow velocity fields shown in
these figures, it can be observed that:

- Along fluid flow paths, larger pressure drop and larger
  flow velocity appear near the turning points of the flow
  paths.
- Many micro-cracks have essentially zero fluid flow veloc-
  ity, indicating the effectiveness of these micro-cracks is
  poor.

4.3 Calculation of permeability based
on the simulation results

Based on the simulation results of fluid seepage, the distribu-
tion of the flow velocity along the fluid exit boundary can
be obtained. For example, Fig. 14 shows the fluid discharge
velocity at the \( x \)-exiting boundary of the \( 0^\circ–180^\circ \) plane. The
flow rate can, therefore, be obtained by integrating the flow
velocity along the boundary. According to Darcy’s law, the
permeability at this direction can be expressed as:

\[
K = \frac{Q \mu L}{A \Delta P}
\]

where \( Q \) is the flow rate; \( A \) is the cross section area, 1896
\( \mu m^2 \) in the \( x \) direction and 1024 \( \mu m^2 \) in the \( y \) direction; \( L \) is
the length along the flow direction, 1896 \( \mu m \) in the \( x \) direc-
tion and 1024 \( \mu m \) in the \( y \) direction; \( \Delta P \) is the pressure dif-
ference, 10 Pa; \( \mu \) is the fluid viscosity, 0.001 Pa·s. The only
variable is the fluid flow rate \( Q \), which can be calculated by

Fig. 6 Fluid pressure field (a) and fluid velocity field (b) for \( x \) direction flow simulation in the \( 0^\circ–180^\circ \) cross section plane
integrating the flow velocity along the outlet boundary (as shown in Fig. 14).

The outlet flow rates and corresponding permeability in the $x$ direction (the axial direction of the core) of 12 cross section planes are summarized in Table 1. It can be found that the permeability of different planes vary greatly. The main reason for these differences is the strong heterogeneity of cracks and pores in the tight sandstone rock. The average permeability from numerical simulation is slightly higher than the measured permeability. The reasons for this small discrepancy could be due to the pore blockage by water-sensitive minerals in the laboratory measurement, which was not considered in the simulation; or due to the limitation of micro-CT scanning accuracy (identifications of some very tiny micro-cracks were poor).
Similarly, the permeability along the y direction (the radial direction of the core) of the 12 cross section planes was obtained through numerical simulations. The results are shown in Table 2. It can be seen that the radial permeability of core is quite different from the axial permeability, indicating strong heterogeneity of the micro-structure of the tight sandstone sample.

In conventional laboratory tests, the axial permeability is usually measured. However, it is not easy to directly measure the radial permeability. In order to experimentally measure directional permeability, rock samples cored at different directions must be prepared, which is usually time-consuming and expensive, or even not possible for some highly fractured rocks. The digital core approach using micro-CT
scanning and numerical simulation proposed in this paper can overcome these limitations and obtain permeability at any interested directions without complex coring process.

5 Quantitative evaluation of fracture effectiveness

According to the simulation results of fluid flow velocity, it can be observed that fluid velocity in many micro-cracks is essentially zero. Therefore, this part of micro-fractures can be regarded as ineffective fractures. A reason for this is the incomplete development of micro-fractures in the tight sandstone that results in poor connectivity among them. Therefore, the capability to quantitatively evaluate the effectiveness of fracture (i.e., the ratio of micro-fractures that contributes to fluid flow) is vital for the evaluation of tight sand reservoirs.

In this section, the effectiveness of micro-fractures is statistically analyzed based on the simulation results of micro-seepage. Specific analysis procedures of the analysis are as follows:

### Table 1 Simulation results of the axial permeability of the core sample

| Section direction | Export flow, m²/s | Simulated permeability, 10⁻³ μm² | Average permeability, 10⁻³ μm² | Standard deviation, 10⁻³ μm² | Measured permeability, 10⁻³ μm² |
|-------------------|-------------------|----------------------------------|-------------------------------|-------------------------------|-------------------------------|
| 0°–180°           | 2.2353 × 10⁻¹⁰    | 0.5405                           | 0.460                         | 0.185                         | 0.394                         |
| 15°–195°          | 1.9654 × 10⁻¹⁰    | 0.4531                           |                               |                               |                               |
| 30°–210°          | 1.1724 × 10⁻¹⁰    | 0.2691                           |                               |                               |                               |
| 45°–225°          | 2.9295 × 10⁻¹⁰    | 0.6739                           |                               |                               |                               |
| 60°–240°          | 2.0860 × 10⁻¹⁰    | 0.4807                           |                               |                               |                               |
| 75°–255°          | 2.7741 × 10⁻¹⁰    | 0.6371                           |                               |                               |                               |
| 90°–270°          | 3.7625 × 10⁻¹⁰    | 0.8648                           |                               |                               |                               |
| 105°–285°         | 1.959 × 10⁻¹⁰     | 0.2760                           |                               |                               |                               |
| 120°–300°         | 1.4274 × 10⁻¹⁰    | 0.3289                           |                               |                               |                               |
| 135°–315°         | 2.0389 × 10⁻¹⁰    | 0.4692                           |                               |                               |                               |
| 150°–330°         | 1.0646 × 10⁻¹⁰    | 0.2438                           |                               |                               |                               |
| 165°–345°         | 1.2393 × 10⁻¹⁰    | 0.2852                           |                               |                               |                               |
(1) Remove cracks with ‘zero’ flow velocity (velocity less than $1 \times 10^{-7}$ m/s) in the fluid velocity images. In this paper, the ‘nonfunctional’ cracks are essentially the isolated cracks (cracks not connected with other cracks), or some partially connected cracks that are not belonging to the main channels for seepage and fluid within them cannot flow freely. These cracks have no contribution to permeability calculation. The selection of $10^{-7}$ m/s as a criterion is because, in the simulated cloud maps of flow velocity, the velocities in the ‘nonfunctional’ cracks are generally below $10^{-7}$ m/s.

(2) Transfer the fluid flow images before and after removing zero-velocity fractures into grayscale images, and then carry out the processing of image segmentation.

(3) Count the number of pixels of all the fracture area ($N_{\text{all}}$) and that of the fracture area with nonzero flow velocity ($N_{\text{eff}}$).

(4) Calculate fracture effectiveness $n = N_{\text{eff}} / N_{\text{all}}$.

Figures 15 and 16 show the effective cracks in the $x$ and $y$ directions in the $0°–180°$ and $90°–270°$ cross section planes, respectively. A MATLAB program was developed to process the images of seepage simulation results. Tables 3 and 4 summarize the image processing results and calculated fracture effectiveness in the $x$ direction (axial direction of the core) and $y$ direction (radial direction of the core) of the 12 cross section planes, respectively. The axial and radial fracture effectiveness are 0.4387 and 0.4806, respectively, indicating the overall fracture effectiveness is low, which is unfavorable for the effective exploitation of oil and gas reservoirs. Reservoir stimulation operations should be conducted for optimal production performance.

6 Conclusions

(1) Larger pressure drop and fluid flow velocity appear at the fracture parts with larger curvatures.

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**Table 2** Simulation results of the radial permeability of the core sample

| Section direction, degree | Export flow, m$^3$/s | Calculated permeability, $10^{-3}$ μm$^2$ | Average permeability, $10^{-3}$ μm$^2$ | Standard deviation, $10^{-3}$ μm$^2$ |
|---------------------------|----------------------|------------------------------------------|---------------------------------|---------------------------------|
| 0–180                     | $3.5289 \times 10^{-10}$ | 0.4058                                   | 0.3723                          | 0.1399                          |
| 15–195                    | $2.5222 \times 10^{-10}$ | 0.2901                                   |                                |                                |
| 30–210                    | $2.5710 \times 10^{-10}$ | 0.2957                                   |                                |                                |
| 45–225                    | $5.2981 \times 10^{-10}$ | 0.6093                                   |                                |                                |
| 60–240                    | $3.5336 \times 10^{-10}$ | 0.4064                                   |                                |                                |
| 75–255                    | $2.184 \times 10^{-10}$  | 0.2551                                   |                                |                                |
| 90–270                    | $4.5987 \times 10^{-10}$ | 0.5703                                   |                                |                                |
| 105–285                   | $1.2377 \times 10^{-10}$ | 0.1423                                   |                                |                                |
| 120–300                   | $2.1425 \times 10^{-10}$ | 0.2464                                   |                                |                                |
| 135–315                   | $2.5598 \times 10^{-10}$ | 0.2944                                   |                                |                                |
| 150–330                   | $4.8811 \times 10^{-10}$ | 0.5613                                   |                                |                                |
| 165–345                   | $3.3969 \times 10^{-10}$ | 0.3910                                   |                                |                                |
Fig. 16  Distributions of x-direction (left) and y-direction (right) effective cracks of the 90°–270° cross section plane

Table 3  Image processing results and fracture effectiveness in the x (axial) direction of different cross section planes

| Plane direction, degree | Total fractures | Number of effective fractures | Fracture effectiveness | Average fracture effectiveness | Standard deviation |
|------------------------|----------------|-------------------------------|------------------------|-------------------------------|--------------------|
| 0–180                  | 92,773         | 38,454                        | 0.4145                 | 0.4387                        | 0.0804             |
| 15–195                 | 72,878         | 24,154                        | 0.3314                 |                               |                    |
| 30–210                 | 72,223         | 25,558                        | 0.3539                 |                               |                    |
| 45–225                 | 66,383         | 24,168                        | 0.3641                 |                               |                    |
| 60–240                 | 75,368         | 35,055                        | 0.4651                 |                               |                    |
| 75–255                 | 65,808         | 28,367                        | 0.4311                 |                               |                    |
| 90–270                 | 98,057         | 63,089                        | 0.6434                 |                               |                    |
| 105–285                | 60,178         | 24,991                        | 0.4153                 |                               |                    |
| 120–300                | 56,030         | 25,235                        | 0.4504                 |                               |                    |
| 135–315                | 70,241         | 29,673                        | 0.4224                 |                               |                    |
| 150–330                | 80,940         | 35,441                        | 0.4379                 |                               |                    |
| 165–345                | 63,774         | 34,080                        | 0.5344                 |                               |                    |

Table 4  Image processing results and fracture effectiveness in the y (radial) direction of different cross section planes

| Plane direction, degree | Total fractures | Number of effective fractures | Fracture effectiveness | Average fracture effectiveness | Standard deviation |
|------------------------|----------------|-------------------------------|------------------------|-------------------------------|--------------------|
| 0–180                  | 92,773         | 44,396                        | 0.4785                 | 0.4806                        | 0.0673             |
| 15–195                 | 72,878         | 37,020                        | 0.5080                 |                               |                    |
| 30–210                 | 72,223         | 36,517                        | 0.5056                 |                               |                    |
| 45–225                 | 66,383         | 25,330                        | 0.3816                 |                               |                    |
| 60–240                 | 75,368         | 40,803                        | 0.5414                 |                               |                    |
| 75–255                 | 65,808         | 29,689                        | 0.4511                 |                               |                    |
| 90–270                 | 98,057         | 61,282                        | 0.6250                 |                               |                    |
| 105–285                | 60,178         | 25,221                        | 0.4191                 |                               |                    |
| 120–300                | 56,030         | 20,879                        | 0.3726                 |                               |                    |
| 135–315                | 70,241         | 35,283                        | 0.5023                 |                               |                    |
| 150–330                | 80,940         | 37,454                        | 0.4627                 |                               |                    |
| 165–345                | 63,774         | 33,116                        | 0.5193                 |                               |                    |
(2) The simulation results indicate incomplete development of micro-cracks in the investigated tight sandstone core sample. The connectivity between micro-cracks is poor, resulting in zero flow velocity in many micro-cracks and low fracture effectiveness.

(3) The digital core approach using micro-CT scanning and numerical simulation can readily obtain permeability at any interested direction without complex coring process, overcoming the limitations of conventional experimental approach in measuring directional permeability.

(4) The digital coring approach proposed in this paper provides a method to quantify fracture effectiveness, important information for reservoir evaluation.

Acknowledgements This work was financially supported by the National Natural Science Foundation of China (Grant No. 41972138) and the Technology Major Project of China (Grant No. ZD2019-183-007, 2016ZX05002-002).

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