

# Estimating the seepage effect of SC-CO<sub>2</sub> and water fracturing with a steady-state flow model considering capillary and viscous forces at the pore scale

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Article Type: Full Length Article

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Research Data Related to this Submission

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Title: Data for: Estimating the Seepage Effect of SC-CO<sub>2</sub> and Water Fracturing with a Steady-state Flow Model: Consider Capillary and Viscous Forces in Pore Scale

Repository: Mendeley Data

<https://data.mendeley.com/datasets/78c992dpc8/draft?a=0c92bafb-a32c-4630-90e9-c5d3d3b2652f>

## Abstract

Supercritical carbon dioxide (SC-CO<sub>2</sub>) fracturing is a promising technology for unconventional energy development and carbon capture and storage. Experimental studies have shown that SC-CO<sub>2</sub> fracturing can form complex fracture networks and reduce crack initiation pressure, which are different results from those when fracturing with aqueous fluids. The complex fracture networks that form from SC-CO<sub>2</sub> fracturing may be the result of the strong seepage effect (i.e., low capillary and viscous forces). To understand the different injection behaviors induced by SC-CO<sub>2</sub> and aqueous fluids in low-permeability rocks, this study develops a new two-phase steady-state model based on the pore-scale network method. Although other models consider the viscous force, our model implements the capillary and viscous forces to reproduce the seepage effect. Because of the capillary force, the flow model is nonlinear and solved by iteratively solving matrix equations until a conservation of volumetric flux is satisfied. Simulation results show that the capillary force in a two-phase flow is not negligible on pressure distribution in small pore spaces. This leads to discontinuous pressure drops. This study shows that the seepage effect of SC-CO<sub>2</sub> is stronger than that of aqueous fluids.

**Keyword: Seepage effect; SC-CO<sub>2</sub> fracturing; Shale rock; Pore scale network model**

1 We have read the comments of reviewers and editors. These comments have been  
2 constructively helpful to our article. In order to answer the comments of the reviewers,  
3 we divided the opinions into five major questions as follows:

4 **Reviewers 1:**

5 **1. The fact that this model assumes steady-state conditions should be mentioned**  
6 **much earlier (including possibly the title) and more often.**  
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9 We modified the title, body, conclusion of this papers as your suggested.

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11 **2. Therefore, there may very well be capillary resistance during at least some (if**  
12 **not all) of the period of most interest (i.e., injection). This should at least be**  
13 **discussed and considered in the manuscript.**  
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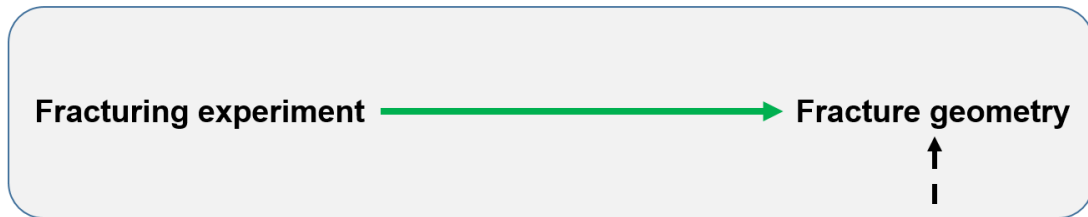
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17 According reviewer's comment, we added contents to discuss this problem.  
18 Fracturing process contains a pressurization stage by injecting fracturing fluid into a  
19 borehole. If this period is long enough, the fracturing fluid is mixed well with the  
20 formation fluid (e.g., hydrocarbon) and the capillary resistance can be neglected. In  
21 the experiment from Zhang et al. (2017), the period of SC-CO<sub>2</sub> injection was over 7.0  
22 minutes. We expect that this period could be long enough to mix between SC-CO<sub>2</sub>  
23 and formation fluid in the view of the high diffusion coefficient of SC-CO<sub>2</sub>. Even if  
24 the pressurization stage is not enough to make two different fluid mix well, the  
25 interfacial tension between SC-CO<sub>2</sub> and hydrocarbon is ultra-small. The interfacial  
26 tension between SC-CO<sub>2</sub> and hydrocarbon (gas) is less than 2mN/m (Li et al., 2017),  
27 while the interfacial tension between water and hydrocarbon (gas) is about 50mN/m.  
28 The capillary force between SC-CO<sub>2</sub> and hydrocarbon is much smaller than that  
29 between water and hydrocarbon. Thus, the effect of capillary force that occurs with  
30 SC-CO<sub>2</sub> is quite smaller than with water. Therefore, the capillary force between  
31 SC-CO<sub>2</sub> and formation fluid is neglected in our simulation.  
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35 **3. While the authors drew good comparisons between their modeling outputs and**  
36 **analytical solutions, I wonder why more effort was not given to match their**  
37 **models with the experimental results they reference so often (Zhang et al., 2017).**  
38 **There may be a very plausible explanation for this. If so, it should be mentioned.**  
39 **If not, I believe a comparison to these data is warranted.**  
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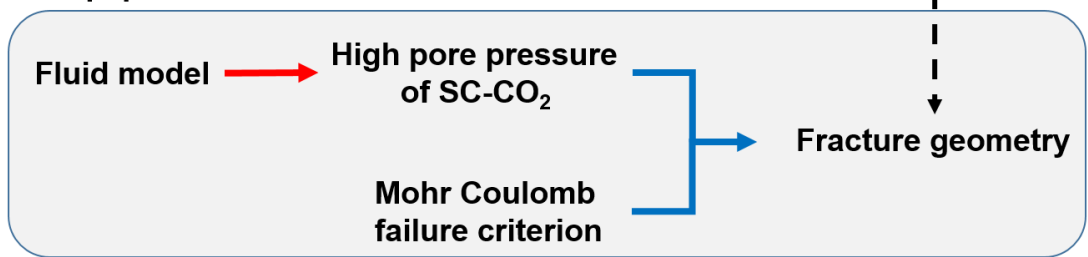
42  
43 Their experiment (Zhang et al., 2017) were conducted to study different fracture  
44 patterns induced by water injection and SC-CO<sub>2</sub> injection. They indicated that the  
45 mechanism of forming complex fracture patterns was the effect of strong seepage  
46 effect. Thus, understanding of flow behaviors of SC-CO<sub>2</sub> is a challenge that must be  
47 overcome in the beginning, and is essential for reproducing complex fracture patterns.  
48 Therefore, this paper focuses on developing a new flow model considering the effects  
49 of viscous and capillary forces. Our results indicated that SC-CO<sub>2</sub> injection leads to  
50 relatively high pore pressure distributions in a wide area away from the well. Based  
51 on the Mohr-Coulomb failure criterion, the high pore pressure distributions likely  
52 results in shear failure in a wide area and should generate complex fracture  
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distributions. This finding is consistent with the experimental results. If the experiment could provide pore pressure distributions, we could compare pressure distributions with our simulation results. However, it is difficult to measure pore pressure distributions in an experiment, and their paper presented fracture geometries only. Thus, in this paper comparison with experimental results was in discussion only. We argued this in our manuscript. In our future work, we will develop a solid model and couple it with the current flow model to simulate fracture geometry and compare with the experiment result (Zhang et al., 2017) directly.

**Zhang's experiment:**

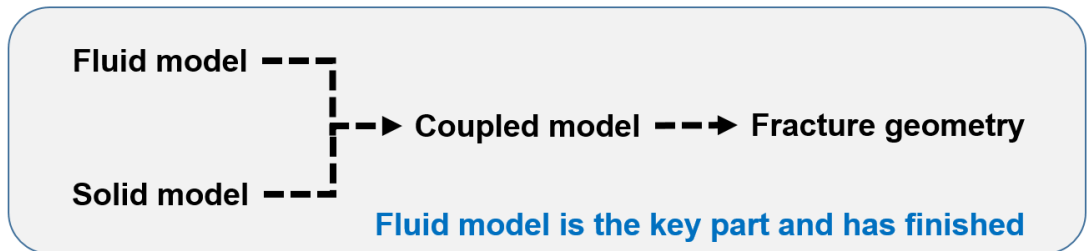


**Our paper:**



→ Numerical simulation      → Inference

**Future work:**



**4. Lastly, the writing of this manuscript needs a lot of work before it is publishable.**

Thanks for suggestion about the writing. We amended the figures and sentences. In addition, the article was checked by native speaker.

**Reviewers 2:**

**5. The abstract and Fig problems**

According to the comment of reviewer, we delete the Fig.1 and add more details of the flow model in the abstract.

1           **Reference**

2           Li, N., Zhang, C.W., Ma, Q.L., Jiang, L.Y., Xu, Y.X., Chen, G.J., Sun, C.Y., Yang,  
3           L.Y., 2017. Interfacial Tension Measurement and Calculation of (Carbon Dioxide  
4           + n-Alkane) Binary Mixtures. *J. Chem. Eng. Data* 62, 2861–2871.  
5           <https://doi.org/10.1021/acs.jced.7b00159>  
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10          Zhang, X., Lu, Y., Tang, J., Zhou, Z., Liao, Y., 2017. Experimental study on fracture  
11          initiation and propagation in shale using supercritical carbon dioxide fracturing.  
12          *Fuel* 190, 370–378. <https://doi.org/10.1016/j.fuel.2016.10.120>  
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# Estimating the Seepage Effect of SC-CO<sub>2</sub> and Water Fracturing with a Steady-state Flow Model: Consider Capillary and Viscous Forces in Pore Scale

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## Abstract

Supercritical carbon dioxide (SC-CO<sub>2</sub>) fracturing is a promising technology for unconventional energy development and carbon capture and storage. Experimental studies have shown that SC-CO<sub>2</sub> fracturing can form complex fracture networks and reduce crack initiation pressure, which are different results from those when fracturing with aqueous fluids. The complex fracture networks that form from SC-CO<sub>2</sub> fracturing may be the result of the strong seepage effect (i.e., low capillary and viscous forces). To understand the different injection behaviors induced by SC-CO<sub>2</sub> and aqueous fluids in low-permeability rocks, this study develops a new two-phase steady-state model based on the pore-scale network method. Although other models consider the viscous force, our model implements the viscous and capillary forces to reproduce the seepage effect. Because of the capillary force, the flow model is nonlinear and solved by iteratively solving matrix equations until a conservation of volumetric flux is satisfied. Simulation results show that the capillary force in a two-phase flow is not negligible on pressure distribution in small pore spaces. This leads to discontinuous pressure drops. This study shows that the seepage effect of SC-CO<sub>2</sub> is stronger than that of aqueous fluids.

**Keyword:** Seepage effect; SC-CO<sub>2</sub> fracturing; Shale rock; Pore scale network

1 **model**

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3 **1. Introduction**

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6 Supercritical carbon dioxide (SC-CO<sub>2</sub>) is a special fluid with a low viscosity  
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8 (like gas) and high density (like liquid). Experimental studies have shown that  
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10 SC-CO<sub>2</sub> has many potential advantages as a fracturing fluid. For instance, SC-CO<sub>2</sub>  
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12 fracturing reduces initiation pressure by 50% or more (Zhang et al., 2017). Fractures  
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14 induced by SC-CO<sub>2</sub> are irregular multiple cracks and easily form complex fracture  
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16 networks, which are different from fractures induced by conventional aqueous fluids  
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18 (Bennour et al., 2015; Ishida et al., 2016a; Zhang et al., 2017). These characteristics  
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20 of SC-CO<sub>2</sub> fracturing yield positive effects on unconventional energy developments,  
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22 including CO<sub>2</sub> sequestration and enhanced geothermal systems (Middleton et al., 2014;  
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24 Reynolds et al., 2018).

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34 Injected water can be an immiscible fluid in oil and gas reservoirs, whereas  
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36 injected SC-CO<sub>2</sub> can be a miscible fluid. When comparing water injection and  
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38 SC-CO<sub>2</sub> injection, two-phase flow should be considered. In addition, the different  
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40 performances of SC-CO<sub>2</sub> fracturing from aqueous fluid fracturing are generally  
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42 considered to derive from the strong seepage effects of SC-CO<sub>2</sub> (Ishida et al., 2016;  
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44 Watanabe et al., 2017; Zhang et al., 2017). The seepage effect may be influenced by  
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46 capillary and viscous forces in small pore spaces in a two-phase flow (Kantzas,  
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48 Apostolos; Bryan Jonathan; Taheri, 2015). Strong seepage effects occur because of  
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50 low viscous and low capillary forces, which may lead to increased percolation and  
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52 increased pore pressure. Some studies have investigated pore pressure distribution  
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1 during fracturing, but their flow models have considered only the viscous force  
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3 (Belytschko et al., 2000; Choo et al., 2016; Economides and Boney, 2000; Latham et  
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5 al., 2011; Lecampion et al., 2017; Liu et al., 2018; Peng et al., 2017; Shi et al., 2017;  
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7 Shimizu et al., 2011; Yan et al., 2016; Zhao et al., 2014). The capillary force cannot be  
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9 ignored in low-permeability porous media such as shale rock when a two-phase flow  
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11 occurs (Blunt, 2001; Higdon, 2013).  
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17 The pore-scale network model (PNM) has been developed to simulate flow in  
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19 porous media (Valvatne, 2004), and some studies have simulated the multiphase flow  
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21 in the pore scale using a PNM (Al-Gharbi and Blunt, 2005; Joekar-Niasar and  
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23 Hassanizadeh, 2012; Wang et al., 2015). Because a PNM can consider small pore  
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25 geometries, it is used to closely examine behaviors in the pore space.  
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31 In this study, a two-phase steady-state flow model is developed to investigate the  
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33 seepage effects of SC-CO<sub>2</sub>. The model integrates both capillary and viscous forces  
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35 based on the PNM. We analyze the characteristics of the pressure field during fluid  
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37 injection, which directly influence fracture geometries during fracturing. In addition,  
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39 the difference between injection SC-CO<sub>2</sub> and injection water is discussed.  
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## 45 2. Model description

### 46 2.1 Pore-scale network models

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48 The PNM is an effective model to represent flow in a porous medium through the  
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50 pores and throats. In the fracturing process, injection fluid is pushed into formations,  
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52 and the formation fluid is displaced. In general, three types of displacements can  
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54 occur during fracturing: piston-like, pore-body filling, or snap-off (Valvatne, 2004).  
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1 The piston-like displacement refers to invasion into throats by fluid that were  
2 previously present in pores. In a pore-body filling displacement, fluid in pores is  
3 displaced by the fluid in throats. Snap-off displacement describes invasion by wetting  
4 fluid at the corner of a cross section when the pressure of the invasion fluid is lower  
5 than the threshold of the capillary pressure. The effect of snap-off displacement is  
6 known to be considerably smaller than the effects of the other two types of  
7 displacements in shale rocks (Al-Gharbi and Blunt, 2005). Thus, the current model  
8 considers only piston-like displacement and pore-body filling. In our network model,  
9 the triangular cross section was selected to consider the wetting phase flow (film flow)  
10 at the corners (Mogensen and Stenby, 1998; Nguyen et al., 2006).

27 Let us consider that there are two adjacent elements  $i$  and  $j$ . (Note that whether  
28 they are pores or throats is irrelevant.) The flow rate from element  $i$  to element  $j$ ,  
29  $q_{ij}$ , is given by:

$$q_{ij} = g_{ij}(P_i - P_j + P_{c,ij}) \quad \#(1)$$

36 where  $g_{ij}$  is the flow conductivity between elements  $i$  and  $j$ .  $P_i$  and  $P_j$  are the  
37 pressures for elements  $i$  and  $j$ , respectively.  $P_{c,ij}$  is the capillary force between  
38 elements  $i$  and  $j$ . The flow conductivity equations are given by (Hughes and Blunt,  
39 2000):

$$g_{ij} = \int_0^L g(x) dx \quad \#(2)$$

$$g(x) = 1/C(x), 0 \leq x \leq L \quad \#(3)$$

47 where  $\mu$  is the fluid viscosity,  $L$  is the length between elements  $i$  and  $j$ , and  $C(x)$   
48 is the fluid conductance per unit length and is determined by the fluid configuration in

1 their cross sections.

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3 Two types of cross-section configurations (see Fig. 1(a)) can be generated when  
4 the injection fluid is different from the formation fluid: single-phase configuration (in  
5 a non-invaded element),  $C_{sp}$ ; and two-phase configuration (in an invaded element),  
6  $C_{tp}$ . The geometric parameters for calculating conductance and area are shown in Fig.  
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For single-phase configuration, the fluid conductance per unit length,  $C_{sp}$ , is given by (Aker et al., 1998; Al-Gharbi, 2004):

$$C_{sp} = \frac{\pi\mu_w}{128} \left( R + (A_t/\pi)^{\frac{1}{2}} \right)^4 \quad \#(4)$$

where  $A_t$  is the cross-section area of the element and  $R$  is the inscribed radius of the cross section. The cross-section area of the element,  $A_t$ , is:

$$A_t = R^2 \sum_{i=1}^n \cot \alpha_i \quad \#(5)$$

where  $\alpha_i$  is the half corner angle and  $n$  is the number of corners in the cross section.

For two-phase configuration, the wetting and non-wetting phases in the cross section should be considered. The fluid conductance per unit length for the two-phase configuration,  $C_{tp}$ , is described by:

$$C_{tp} = (C_{nw} + C_w) / C_{nw} C_w \quad \#(6)$$

where  $C_{nw}$  and  $C_w$  represent the conductance of the non-wetting phase and wetting phase fluids in the center and at the corner, respectively, which is given by (Aker et al., 1998; Al-Gharbi, 2004):

$$C_{nw} = \frac{\pi\mu_{nw}}{128} \left( R + (A_{nw}/\pi)^{\frac{1}{2}} \right)^4 \quad \#(7)$$

$$C_w = \mu_w \sum_{i=1}^n \left( \frac{A_{ci}(1 - \sin \alpha_i)\varphi_3}{\sin \alpha_i (1 - \varphi_3)(\varphi_2 + f\varphi_1)} \cdot \left( \frac{\varphi_2 \cos \theta - \varphi_1}{12} \right)^{\frac{1}{2}} \right)^2 \#(8)$$

The parameters  $\varphi_1$ ,  $\varphi_2$ , and  $\varphi_3$  depend on the half corner angle  $\alpha$  and the contact angle  $\theta$ . The parameter  $f$  indicates the capacity of fluid crossing the fluid interface (Piri and Blunt, 2005). In our model, the parameter  $f$  equals 1, which means that no flow occurs on the fluid interface. The area of the formation fluid (wetting phase fluid) at the corner,  $A_w$ , and injection fluid (non-wetting phase fluid) at the center,  $A_{nw}$ , are calculated by:

$$A_w = \sum_{i=1}^n A_{ci} \#(9)$$

$$A_{ci} = r^2 \left( \cos \theta (\cot \alpha_i \cos \theta - \sin \theta) + \theta + \alpha_i - \frac{\pi}{2} \right) \#(10)$$

$$A_{nw} = A_t - A_w \#(11)$$

where  $r$  is the radius of the curvature of the interface.

For elements invaded by injection fluid (see Fig. 1(b)), the flow rate  $q_{ij}$  as given in the following equation is divided into the flow rates of the wetting and non-wetting phases as:

$$q_{ij} = q_{nw,ij} + q_{w,ij} \#(12)$$

The flow rate of each phase from element  $i$  to element  $j$  is given by:

$$q_{nw,ij} = q_{ij} C_{nw,i} / (C_{nw,i} + C_{w,i}) \#(13)$$

$$q_{w,ij} = q_{ij} C_{w,i} / (C_{nw,i} + C_{w,i}) \#(14)$$

where  $C_{w,i}$  and  $C_{nw,i}$  represent the conductance of the non-wetting and wetting phase fluids in element  $i$ , respectively.

The capillary force ( $P_{c,ij}$ ) between element  $i$  and  $j$  is calculated using the

1 Young–Laplace equation:

$$2 P_{c,ij} = \frac{2\sigma \cos \theta}{r} \#(15)$$

3 where  $\sigma$  denotes interfacial tension between the two fluid phases.

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9 Considering the small compressibility of SC-CO<sub>2</sub> (Vilarrasa et al., 2010), the  
10 conservation equation is applicable to SC-CO<sub>2</sub> flow. For either single- or two-phase  
11 flow, the conservation of the volume flux at element  $i$  can be described by:

$$12 \sum_{j=1}^{Z_i} q_{ij} = \sum_{j=1}^{Z_i} (q_{nw,ij} + q_{w,ij}) = 0 \#(16)$$

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21 where  $Z_i$  is the number of elements connecting to element  $i$ . For instance, the pore  $i$   
22 connects throats 1–3 in Fig. 2. The conservation of volume flux at pore  $i$  can be  
23 expressed as  $q_{i2} + q_{i3} + q_{i1} = 0$ .

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30 Each pore connects more than one throat in our numerical model. Based on the  
31 flow rate of (1) – (16) and the topological structure of the network, the assembly  
32 equation can be formed as:

$$33 \begin{bmatrix} D_{11} & \cdots & D_{1j} \\ \vdots & \ddots & \vdots \\ D_{i1} & \cdots & D_{ij} \end{bmatrix} \begin{Bmatrix} P_1 \\ \vdots \\ P_i \end{Bmatrix} = \begin{Bmatrix} \sum_{j=1}^{Z_1} g_{1j} P_{c,1j} \\ \vdots \\ \sum_{j=1}^{Z_i} g_{ij} P_{c,ij} \end{Bmatrix} \#(17)$$

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where  $D_{ij}$  is the conductance matrix. When  $i = j$ ,  $D_{ij} = \sum_{j=1}^{Z_i} g_{ij}$ ; otherwise,  
 $D_{ij} = g_{ij}$ .

## 2.2 Computational procedure

Based on the previous discussion, we derived the quasi-steady-state pressure distribution. To simulate fluid injection, a time variation of the fluid flow was calculated. We iterated to obtain the steady-state pressure distribution at each time

step  $\Delta t$ . The computational procedure, as shown in Fig. 3, is described as follows:

1) Based on the initial condition, the conductivity of each element is calculated by using (4) – (11). Then, the integral conductance matrix  $D_{ij}$  and force matrix are assembled.

2) As  $P_{outlet}^t$  and  $P_{inlet}^t$  are known, the pressure distribution is obtained from (17). Based on the pressure distribution, the total flow rate  $q_{ij}$ , the non-wetting phase flow rate  $q_{nw,ij}$ , and the wetting phase flow rate  $q_{w,ij}$  can be solved through (1) and (12) – (14).

3) Calculate each phase fluid volume  $V_{w,i}^{t+\Delta t}$  and  $V_{nw,i}^{t+\Delta t}$  in element  $i$  at  $t + \Delta t$  by using (18) – (19). Update the meniscus position and fluid configuration of each element based on each phase fluid volume. The purpose of choosing  $\Delta t$  is to ensure every meniscus will not cross one throat element in  $\Delta t$ . Then, the initial condition can be updated according to the configuration at  $t + \Delta t$ .

The volume of each of the wetting and non-wetting phases in element  $i$  can be expressed by:

$$V_{w,i}^{t+\Delta t} = V_{w,i}^t + \Delta t \times \sum_{j=1}^{Z_i} q_{w,ij} \quad \#(18)$$

$$V_{nw,i}^{t+\Delta t} = V_{nw,i}^t + \Delta t \times \sum_{j=1}^{Z_i} q_{nw,ij} \quad \#(19)$$

### 3. Simulation condition

We simulated seepage effects (capillary and viscous forces) for SC-CO<sub>2</sub> and water fracturing as previously examined in the SC-CO<sub>2</sub> and water fracturing experiment conducted by Zhang et al (Zhang et al., 2017).

### 3.1 Structure of PNM

Two pore network structures were used in the simulation cases. One structure, labeled Network A, was used to validate the flow model and investigate the difference between injecting SC-CO<sub>2</sub> and water, as shown in Fig. 4(a). Network A was used to represent two types of porous media: homogenous porous medium (PNM-homo) and heterogeneous porous medium (PNM-hetero). For PNM-homo, a constant average radius of pores and throats was set for a single simulation. To investigate the effects of different radii, the radii of pores and throats varied from 0.01 to 0.15  $\mu\text{m}$  for each simulation. Thus, the sizes of the simulation models varied for different average radii of pores and throats, see Table 1. The lengths were normalized by the size of each simulation model. For PNM-hetero, the distributions of radii of throats and pores were generated based on the statistical data of sandstone (Bakke and Øren, 1997; Øren and Bakke, 2003, 2002), which is shown in Fig. 5. The other structure, Network B, was assumed to contain a pre-existing fracture (PNM-frac), which was to see pressure distribution around fracture. (see Fig. 4(b)). The size of Network B was consistent with the experimental sample of Zhang et al. (Zhang et al., 2017).

### 3.2 Fluid parameter and injection pressure

Four fluid systems and fluid viscosities, as listed in Tables 2 and 3, respectively, were used in the simulation and considered in the discussion. The formation fluid was gas or oil and the injection fluid was oil, water, or SC-CO<sub>2</sub>. SC-CO<sub>2</sub> is miscible with hydrocarbons and has a high diffusion coefficient. In the fracturing process, a pressurization stage occurs before crack initiation. At this pressurization stage, SC-CO<sub>2</sub> can fully dissolve with the formation fluid at the interface area. The interface between SC-CO<sub>2</sub> and hydrocarbon (gas or oil) disappears and the capillary force

1 decreases to zero. Before SC-CO<sub>2</sub> dissolves sufficiently into a formation fluid, the  
2  
3 interfacial tension between SC-CO<sub>2</sub> and hydrocarbon is very small, approximately 2  
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5 mN/m (Li et al., 2017). The interfacial tension between water and hydrocarbon is  
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7 approximately 50 mN/m. Thus, our simulation assumed that the capillary force  
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9 between SC-CO<sub>2</sub> and the formation fluids (oil or gas) was negligible.  
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14 The inlet and outlet pressure values were derived from the fracturing  
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16 experimental conditions of Zhang et al. (Zhang et al., 2017). In their experiment, the  
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18 injection pressure was approximately 5 MPa after fracture initiation. Considering the  
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20 pressure loss in tube, 4 MPa was used as the inlet pressure. However, 8 MPa was also  
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22 set as the inlet pressure to ensure that the inlet pressure was higher than the threshold  
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24 of the capillary force for different radii.  
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#### 31 4. Validation

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33 A validation of the flow model was conducted by comparing the analytical  
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35 solutions in different flow situations: a) single-phase flow (the injection and formation  
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37 fluids were the same); b) two-phase flow without considering the capillary force ( $P_c$ ).  
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40 The analytical solutions were based on the Buckley-Leverett theory (Buckley and  
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42 Leverett, 1942; Idowu and Blunt, 2010). These solutions and the numerical results  
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44 obtained from the flow model are plotted in Fig. 6. The numerical results of the  
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46 single- and two-phase flows without capillary force were confirmed to be in good  
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48 agreement with the analytical results derived from the homogeneous porous medium.  
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#### 55 5. Simulation and results

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58 To investigate the seepage effects of SC-CO<sub>2</sub> injection, five simulations were  
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1 conducted. Both capillary and viscous forces were integrated into the PNM to  
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3 simulate the pressure field for a two-phase flow. The different injection conditions are  
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5 listed in Table 4.  
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### 8 9 **5.1 Effects of capillary force**

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11 The effects of capillary force on two-phase flow are presented in Fig. 7. The  
12 PNM-homo was used to simulate the effect of the capillary force. The constant  
13 pore-throat radius was set to  $0.1 \mu m$ . The results yielded snapshots of the pressure  
14 distributions derived from water injection with and without capillary force. Water was  
15 injected from the inlet (normalized length = 0). The case without  $P_c$  only considered  
16 the effect of viscous force, whereas that with  $P_c$  considered the effects of both viscous  
17 and capillary forces. When the capillary force was considered, a discontinuous  
18 pressure drop (DPD) occurred. The capillary force posed an extra resistant force to  
19 block the invasion of water. This resistant force derived from the capillary force could  
20 cause a DPD in the two-phase flow.  
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### 38 39 **5.2 Effects of injection time**

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41 Water or SC-CO<sub>2</sub> injections were simulated in a homogeneous porous medium  
42 using PNM-homo. The constant average pore-throat radius was  $0.1 \mu m$ . The time  
43 variation of the pressure field is shown in Fig. 8. Water or SC-CO<sub>2</sub> was injected from  
44 the inlet (normalized length = 0), and the pressure field of the water injection, as  
45 shown in Fig.8(a), experienced a DPD that was caused by the capillary force. The  
46 injection fluid (water) was immiscible with the formation fluid (oil). When they met  
47 during injection, the capillary force was generated at the interface between water and  
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1 oil. With continuous injection, DPD continuously affected the pressure field. The  
2 positions of the DPD moved to the outlet side because of changes in the  
3 interfacial  
4 position between water and oil.  
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8 By contrast, the pressure field of the SC-CO<sub>2</sub> injection experienced no DPD, as  
9 shown in Fig. 8(b). Because SC-CO<sub>2</sub> and oil are miscible, no interface existed  
10 between them. In other words, no capillary force occurred between SC-CO<sub>2</sub> and oil,  
11 which means that no DPD occurred. Fig. 8(b) also shows that the slope of the pressure  
12 curve in the area displaced by SC-CO<sub>2</sub> (inlet side) was flatter than the area occupied  
13 by oil (outlet side). This was caused by both low viscous and low capillary forces of  
14 SC-CO<sub>2</sub>, (i.e., the seepage effect). Because the injected SC-CO<sub>2</sub> penetrated into pores  
15 easily given a small pressure drop, pressure propagation was advanced with a value  
16 that approximated the injection pressure. The change points of slopes could be  
17 considered the interfacial positions between SC-CO<sub>2</sub> and oil. The interfacial position  
18 between SC-CO<sub>2</sub> and oil was ahead of that between water and oil. This indicated that  
19 the seepage effect of SC-CO<sub>2</sub> promoted the advancement of the interfacial front.  
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### 42 5.3 Effects of pore and throat radii

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44 The influence of different pore-throat radii on the pressure field was investigated  
45 when considering the capillary and viscous forces using PNM-homo. The average  
46 pore-throat radii and corresponding permeability are listed in Table 5. These  
47 parameters were derived from the experiments with shale rocks (Lu et al., 2018). The  
48 sizes of simulation models for each pore radius are listed in Table 1.  
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57 Fig. 9(a) and (b) show the differences in the pressure fields between water and  
58 SC-CO<sub>2</sub> injections, respectively, in a homogeneous porous medium. Fig. 9(a) reveals  
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1 that the values of DPDs varied for the different average pore-throat radii. The DPD  
2 was influenced by the geometries of pore and throat. Because the DPD occurred as a  
3 result of the capillary force, the simulation results indicate that the capillary force  
4 could not be neglected due to the low permeability of rock when the injection fluid  
5 (water) was immiscible with the formation fluid (oil).  
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12 By contrast, with the SC-CO<sub>2</sub> injection, no DPD occurred, as shown in Fig. 9(b).  
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14 The pressure field for the SC-CO<sub>2</sub> injection was controlled solely by the viscous force.  
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16 Because of the low viscosity of SC-CO<sub>2</sub>, the pressure distributions for different  
17 average pore-throat radii in small distances were nearly the same.  
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#### 24 5.4 Heterogeneous porous medium

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26 Rock for the most part is a heterogeneous porous media. Thus, investigating the  
27 pressure performances of water and SC-CO<sub>2</sub> injections in heterogeneous porous media  
28 is necessary. In our study, even the radius distributions were random, where the total  
29 average radius of the pore-throat for all pores and throats was 0.02  $\mu\text{m}$ . The  
30 corresponding sample sizes are listed in Table 1.  
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40 A DPD occurred with water injection (Fig. 10(a)), but no DPD occurred with  
41 SC-CO<sub>2</sub> injection (Fig. 10(b)) in the heterogeneous porous medium. This indicated  
42 that the capillary and viscous forces affected the pressure fields in heterogeneous  
43 rocks. The results reveal that DPD clearly occurred when the injected fluid (water)  
44 was immiscible with the formation fluid (oil). For SC-CO<sub>2</sub>, the property of miscibility  
45 with hydrocarbon produces a strong seepage effect.  
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#### 57 5.5 Well injection with pre-existing fracture

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59 Similar conditions as those in the experiment of Zhang et al. (Zhang et al., 2017)  
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1 were simulated using the PNM-frac. The formation fluid was assumed to be gas,  
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3 which was intended to represent shale gas rock (hydrocarbon wet). The average  
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5 pore-throat radius was set to 0.01  $\mu\text{m}$ . The simulation results of pressure distributions  
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7 for water and SC-CO<sub>2</sub> injections are presented in Fig. 11. The simulation results  
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9 revealed that the DPD derived from the capillary force between water and gas blocked  
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11 the spread of pressure (see Fig. 11(a)). However, in the case of SC-CO<sub>2</sub> injection,  
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13 pressure spread easily without blocks because of the absence of capillary forces, as  
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15 shown in Fig. 11(b). This indicated that the capillary force could cut off the pressure  
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17 when the injection pressure was insufficient to overcome the threshold of the capillary  
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19 force. It should be noted that the pore pressure in non-invaded elements in this model  
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21 was set to 0 MPa.  
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## 31 5.6 Discussion of capillary force effect on the fracture geometry

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33 In general, fracturing with water leads to tensile failure, which in turn generates  
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35 fractures, and these fractures extend directly in the direction of the main stress. The  
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37 simulation results for water injection suggested that the pressure spread was blocked  
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39 by the capillary and viscous forces. However, the effect of capillary force on SC-CO<sub>2</sub>  
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41 injection was negligible, and the viscous force for SC-CO<sub>2</sub> injection was lower than  
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43 for water injection. The pressure could penetrate into the pore and throat around any  
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45 pre-existing fracture. This can cause the pore pressure to increase considerably as  
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47 compared with using water as injection fluid. When the pore pressure increased, the  
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49 effective stress decreased. If we consider the Mohr-Coulomb failure criterion, shear  
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51 failure events occur easily with a small effective stress (i.e., high pore pressure), as  
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1 shown in Fig.12(a). Therefore, increased pore pressure due to SC-CO<sub>2</sub> injection likely  
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3 initiates shear failure cracks. Typically, a crack caused by shear failure is not parallel  
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5 to a fracture caused by tensile failure (Labuz and Zang, 2012; Patton, 1966).  
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7 Fracturing due to SC-CO<sub>2</sub> injection may lead to more branched and high tortuous  
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9 fractures as well as rough fracture surfaces. Thus, the fracture geometry derived from  
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11 SC-CO<sub>2</sub> injection should be more complex than water injection because of shear  
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13 failure cracks (see Fig. 12(b)). These inferred behaviors are consistent with the  
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15 experimental results of Zhang et al., who showed that the fracture geometry of  
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17 SC-CO<sub>2</sub> was more complex than water fracturing.  
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25 In fact, this paper is based on a flow model to study different pressure  
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27 performance when injecting water and SC-CO<sub>2</sub>. On this basis, combined with the  
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29 Mohr-Coulomb failure criterion, it is concluded that SC-CO<sub>2</sub> fracturing should induce  
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31 complex fracture. But this conclusion is not directly obtained through simulation.  
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33 Therefore, in the following work, we will develop a solid model and couple it with the  
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35 flow model to verify the aforementioned results that the fracture pattern induced by  
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37 SC-CO<sub>2</sub> fracturing is complex fracture networks.  
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## 44 6. Conclusion

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47 A two-phase steady-state flow model considering the effects of capillary and  
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49 viscous forces was developed to investigate differences between aqueous and SC-CO<sub>2</sub>  
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51 injections. The results of this study can be summarized as follows.  
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55 With respect to aqueous fluid injection, the pressure field was influenced by the  
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57 capillary force because of immiscibility. The capillary force produced DPDs at the  
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1 interfacial points. The effects of capillary force on aqueous fluid were significant with  
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3 respect to low-permeability reservoirs. However, miscible fluid such as SC-CO<sub>2</sub>  
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5 reduced the effect of the capillary force and prevented DPD. Miscibility with  
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7 hydrocarbon and the low viscosity of SC-CO<sub>2</sub> led to a strong seepage effect. The  
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9 strong seepage effect of SC-CO<sub>2</sub> increased pore pressure in wide areas and induced  
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11 shear fractures. This typically leads to the formation of complex fracture networks.  
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## 17 **Acknowledgement**

18  
19 Thank you for previous researchers who use SC-CO<sub>2</sub> to be fracturing fluid and who  
20  
21 contributed to the development of PNM. Their research laid the foundation for my  
22  
23 research.  
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26

## 27 **Author contributions**

28  
29 B. Liu planed and conducted the study. A. Suzuki contributed the design of the study.  
30  
31  
32 T. Ito contributed on the examination of the paper structure. All authors participated in  
33  
34 the discussion and interpretation of results, as well as the writing of the manuscript.  
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## 47 **Nomenclature**

48  
49  $g$  conductance,  $m^3/(\text{Pa}\cdot\text{s})$ ;  
50  
51

52  
53  $L$  length of an element,  $m$ ;  
54  
55

56  
57  $n$  number of corners;  
58

59  
60  $z$  number of elements connecting to element  $i$ ;  
61  
62  
63  
64  
65

1  $\alpha_i$  half corner angle at corner  $i$ ;  
2  
3  $P$  pressure, Pa;  
4  
5  
6  $P_c$  capillary pressure, Pa;  
7  
8  
9  $q$  volumetric flow rate,  $m^3/s$ ;  
10  
11  
12  $r$  the curvature radius of corner interface,  $m$ ;  
13  
14  
15  $R$  inscribed radius of a cross-section,  $m$ ;  
16  
17  $\Delta t$  time-step size,  $s$ ;  
18  
19  
20  $\theta$  contact angle, radian;  
21  
22  
23  $\sigma$  interfacial tension between two fluid phases,  $N/m$ ;  
24  
25  
26  $\mu$  fluid viscosity,  $Pa \cdot s$ ;  
27  
28  $V$  fluid volume in an element,  $m^3$ ;  
29  
30  
31  $nw$  non-wetting phase;  
32  
33  
34  $w$  wetting phase;  
35  
36  
37  $C$  conductance of fluid in cross section,  $Pa \cdot s/m^4$   
38  
39  $S_H, S_h$  Maximum principal stress and minimum principal stress  
40

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1                    **Estimating the Seepage Effect of SC-CO<sub>2</sub> and Water Fracturing with a**  
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3                    **Steady-state Flow Model: Consider Capillary and Viscous Forces in Pore Scale**  
4

5  
6                    Bailong Liu, Anna Suzuki, and Takatoshi Ito  
7

8  
9                    Institute of Fluid Science, Tohoku University., Japan  
10

11                    **Abstract**  
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13  
14                    Supercritical carbon dioxide (SC-CO<sub>2</sub>) fracturing is a promising technology for  
15                    unconventional energy development and carbon capture and storage. Experimental  
16                    studies have shown that SC-CO<sub>2</sub> fracturing can form complex fracture networks and  
17                    reduce crack initiation pressure, which are different results from those when  
18                    fracturing with aqueous fluids. The complex fracture networks that form from  
19                    SC-CO<sub>2</sub> fracturing may be the result of the strong seepage effect (i.e., low capillary  
20                    and viscous forces). To understand the different injection behaviors induced by  
21                    SC-CO<sub>2</sub> and aqueous fluids in low-permeability rocks, this study develops a new  
22                    two-phase steady-state model based on the pore-scale network method. Although  
23                    other models consider the viscous force, our model implements the capillary and  
24                    viscous forces to reproduce the seepage effect. Because of the capillary force, the flow  
25                    model is nonlinear and solved by iteratively solving matrix equations until a  
26                    conservation of volumetric flux is satisfied. Simulation results show that the capillary  
27                    force in a two-phase flow is not negligible on pressure distribution in small pore  
28                    spaces. This leads to discontinuous pressure drops. This study shows that the seepage  
29                    effect of SC-CO<sub>2</sub> is stronger than that of aqueous fluids.  
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58                    **Keyword: Seepage effect; SC-CO<sub>2</sub> fracturing; Shale rock; Pore scale network**  
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1 **model**

2  
3 **1. Introduction**

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6 Supercritical carbon dioxide (SC-CO<sub>2</sub>) is a special fluid with a low viscosity  
7  
8 (like gas) and high density (like liquid). Experimental studies have shown that  
9  
10 SC-CO<sub>2</sub> has many potential advantages as a fracturing fluid. For instance, SC-CO<sub>2</sub>  
11  
12 fracturing reduces initiation pressure by 50% or more (Zhang et al., 2017). Fractures  
13  
14 induced by SC-CO<sub>2</sub> are irregular multiple cracks and easily form complex fracture  
15  
16 networks, which are different from fractures induced by conventional aqueous fluids  
17  
18 (Bennour et al., 2015; Ishida et al., 2016a; Zhang et al., 2017). These characteristics  
19  
20 of SC-CO<sub>2</sub> fracturing yield positive effects on unconventional energy developments,  
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22 including CO<sub>2</sub> sequestration and enhanced geothermal systems (Middleton et al., 2014;  
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24 Reynolds et al., 2018).

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34 Injected water can be an immiscible fluid in oil and gas reservoirs, whereas  
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36 injected SC-CO<sub>2</sub> can be a miscible fluid. When comparing water injection and  
37  
38 SC-CO<sub>2</sub> injection, two-phase flow should be considered. In addition, the different  
39  
40 performances of SC-CO<sub>2</sub> fracturing from aqueous fluid fracturing are generally  
41  
42 considered to derive from the strong seepage effects of SC-CO<sub>2</sub> (Ishida et al., 2016;  
43  
44 Watanabe et al., 2017; Zhang et al., 2017). The seepage effect may be influenced by  
45  
46 capillary and viscous forces in small pore spaces in a two-phase flow (Kantzas,  
47  
48 Apostolos; Bryan Jonathan; Taheri, 2015). Strong seepage effects occur because of  
49  
50 low viscous and low capillary forces, which often lead to increased percolation and  
51  
52 increased pore pressure. Some studies have investigated pore pressure distribution  
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1 during fracturing, but their flow models have considered only the viscous force  
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3 (Belytschko et al., 2000; Choo et al., 2016; Economides and Boney, 2000; Latham et  
4  
5 al., 2011; Lecampion et al., 2017; Liu et al., 2018; Peng et al., 2017; Shi et al., 2017;  
6  
7 Shimizu et al., 2011; Yan et al., 2016; Zhao et al., 2014). The capillary force cannot be  
8  
9 ignored in low-permeability porous media such as shale rock when a two-phase flow  
10  
11 occurs (Blunt, 2001; Higdon, 2013).  
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17 The pore-scale network model (PNM) has been developed to simulate flow in  
18  
19 porous media (Valvatne, 2004), and some studies have simulated the multiphase flow  
20  
21 in the pore scale using a PNM (Al-Gharbi and Blunt, 2005; Joekar-Niasar and  
22  
23 Hassanizadeh, 2012; Wang et al., 2015). Because a PNM can consider small pore  
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25 geometries, it is used to closely examine behaviors in the pore space.  
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31 In this study, a two-phase steady-state flow model is developed to investigate the  
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33 seepage effects of SC-CO<sub>2</sub>. The model integrates both capillary and viscous forces  
34  
35 based on the PNM. We analyze the characteristics of the pressure field during fluid  
36  
37 injection, which directly influence fracture geometries during fracturing. In addition,  
38  
39 the difference between injection SC-CO<sub>2</sub> and injection water is discussed.  
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## 45 **2. Model description**

### 46 **2.1 Pore-scale network models**

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48 The PNM is an effective model to represent flow in a porous medium through the  
49  
50 pores and throats. In the fracturing process, injection fluid is pushed into formations,  
51  
52 and the formation fluid is displaced. In general, three types of displacements can  
53  
54 occur during fracturing: piston-like, pore-body filling, or snap-off (Valvatne, 2004).  
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1 The piston-like displacement refers to invasion into throats by fluid that were  
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3 previously present in pores. In a pore-body filling displacement, fluid in pores is  
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5 displaced by the fluid in throats. Snap-off displacement describes invasion by wetting  
6  
7 fluid at the corner of a cross section when the pressure of the invasion fluid is lower  
8  
9 than the threshold of the capillary pressure. The effect of snap-off displacement is  
10  
11 known to be considerably smaller than the effects of the other two types of  
12  
13 displacements in shale rocks (Al-Gharbi and Blunt, 2005). Thus, the current model  
14  
15 considers only piston-like displacement and pore-body filling. In our network model,  
16  
17 the triangular cross section was selected to consider the wetting phase flow (film flow)  
18  
19 at the corners (Mogensen and Stenby, 1998; Nguyen et al., 2006).

27  
28 Let us consider that there are two adjacent elements  $i$  and  $j$ . (Note that whether  
29  
30 they are pores or throats is irrelevant.) The flow rate from element  $i$  to element  $j$ ,  
31  
32  $q_{ij}$ , is given by:

$$33$$

$$34 \quad q_{ij} = g_{ij}(P_i - P_j + P_{c,ij}) \#(1)$$

$$35$$

36  
37 where  $g_{ij}$  is the flow conductivity between elements  $i$  and  $j$ .  $P_i$  and  $P_j$  are the  
38  
39 pressures for elements  $i$  and  $j$ , respectively.  $P_{c,ij}$  is the capillary force between  
40  
41 elements  $i$  and  $j$ . The flow conductivity equations are given by (Hughes and Blunt,  
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43  
44  
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46  
47 2000):

$$48$$

$$49 \quad g_{ij} = \int_0^L g(x) dx \#(2)$$

$$50$$

$$51$$

$$52 \quad g(x) = 1/C(x), 0 \leq x \leq L \#(3)$$

$$53$$

54  
55 where  $\mu$  is the fluid viscosity,  $L$  is the length between elements  $i$  and  $j$ , and  $C(x)$   
56  
57 is the fluid conductance per unit length and is determined by the fluid configuration in  
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1 their cross sections.

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3 Two types of cross-section configurations (see Fig. 1(a)) can be generated when  
4 the injection fluid is different from the formation fluid: single-phase configuration (in  
5 a non-invaded element),  $C_{sp}$ ; and two-phase configuration (in an invaded element),  
6  $C_{tp}$ . The geometric parameters for calculating conductance and area are shown in Fig.  
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For single-phase configuration, the fluid conductance per unit length,  $C_{sp}$ , is given by (Aker et al., 1998; Al-Gharbi, 2004):

$$C_{sp} = \frac{\pi\mu_w}{128} \left( R + (A_t/\pi)^{\frac{1}{2}} \right)^4 \quad \#(4)$$

where  $A_t$  is the cross-section area of the element and  $R$  is the inscribed radius of the cross section. The cross-section area of the element,  $A_t$ , is:

$$A_t = R^2 \sum_{i=1}^n \cot \alpha_i \quad \#(5)$$

where  $\alpha_i$  is the half corner angle and  $n$  is the number of corners in the cross section.

For two-phase configuration, the wetting and non-wetting phases in the cross section should be considered. The fluid conductance per unit length for the two-phase configuration,  $C_{tp}$ , is described by:

$$C_{tp} = (C_{nw} + C_w) / C_{nw} C_w \quad \#(6)$$

where  $C_{nw}$  and  $C_w$  represent the conductance of the non-wetting phase and wetting phase fluids in the center and at the corner, respectively, which is given by (Aker et al., 1998; Al-Gharbi, 2004):

$$C_{nw} = \frac{\pi\mu_{nw}}{128} \left( R + (A_{nw}/\pi)^{\frac{1}{2}} \right)^4 \quad \#(7)$$

$$C_w = \mu_w \sum_{i=1}^n \left( \frac{A_{ci}(1 - \sin \alpha_i)\varphi_3}{\sin \alpha_i (1 - \varphi_3)(\varphi_2 + f\varphi_1)} \cdot \left( \frac{\varphi_2 \cos \theta - \varphi_1}{12} \right)^{\frac{1}{2}} \right)^2 \#(8)$$

The parameters  $\varphi_1$ ,  $\varphi_2$ , and  $\varphi_3$  depend on the half corner angle  $\alpha$  and the contact angle  $\theta$ . The parameter  $f$  indicates the capacity of fluid crossing the fluid interface (Piri and Blunt, 2005). In our model, the parameter  $f$  equals 1, which means that no flow occurs on the fluid interface. The area of the formation fluid (wetting phase fluid) at the corner,  $A_w$ , and injection fluid (non-wetting phase fluid) at the center,  $A_{nw}$ , are calculated by:

$$A_w = \sum_{i=1}^n A_{ci} \#(9)$$

$$A_{ci} = r^2 \left( \cos \theta (\cot \alpha_i \cos \theta - \sin \theta) + \theta + \alpha_i - \frac{\pi}{2} \right) \#(10)$$

$$A_{nw} = A_t - A_w \#(11)$$

where  $r$  is the radius of the curvature of the interface.

For elements invaded by injection fluid (see Fig. 1(b)), the flow rate  $q_{ij}$  as given in the following equation is divided into the flow rates of the wetting and non-wetting phases as:

$$q_{ij} = q_{nw,ij} + q_{w,ij} \#(12)$$

The flow rate of each phase from element  $i$  to element  $j$  is given by:

$$q_{nw,ij} = q_{ij} C_{nw,i} / (C_{nw,i} + C_{w,i}) \#(13)$$

$$q_{w,ij} = q_{ij} C_{w,i} / (C_{nw,i} + C_{w,i}) \#(14)$$

where  $C_{w,i}$  and  $C_{nw,i}$  represent the conductance of the non-wetting and wetting phase fluids in element  $i$ , respectively.

The capillary force ( $P_{c,ij}$ ) between element  $i$  and  $j$  is calculated using the

1 Young–Laplace equation:

$$2 \quad 3 \quad 4 \quad 5 \quad 6 \quad 7 \quad 8 \quad 9 \quad 10 \quad 11 \quad 12 \quad 13 \quad 14 \quad 15 \quad 16 \quad 17 \quad 18 \quad 19 \quad 20 \quad 21 \quad 22 \quad 23 \quad 24 \quad 25 \quad 26 \quad 27 \quad 28 \quad 29 \quad 30 \quad 31 \quad 32 \quad 33 \quad 34 \quad 35 \quad 36 \quad 37 \quad 38 \quad 39 \quad 40 \quad 41 \quad 42 \quad 43 \quad 44 \quad 45 \quad 46 \quad 47 \quad 48 \quad 49 \quad 50 \quad 51 \quad 52 \quad 53 \quad 54 \quad 55 \quad 56 \quad 57 \quad 58 \quad 59 \quad 60 \quad 61 \quad 62 \quad 63 \quad 64 \quad 65$$

$$P_{c,ij} = \frac{2\sigma \cos \theta}{r} \#(15)$$

where  $\sigma$  denotes interfacial tension between the two fluid phases.

Considering the small compressibility of SC-CO<sub>2</sub> (Vilarrasa et al., 2010), the conservation equation is applicable to SC-CO<sub>2</sub> flow. For either single- or two-phase flow, the conservation of the volume flux at element  $i$  can be described by:

$$\sum_{j=1}^{Z_i} q_{ij} = \sum_{j=1}^{Z_i} (q_{nw,ij} + q_{w,ij}) = 0 \#(16)$$

where  $Z_i$  is the number of elements connecting to element  $i$ . For instance, the pore  $i$  connects throats 1–3 in Fig. 2. The conservation of volume flux at pore  $i$  can be expressed as  $q_{i2} + q_{i3} + q_{i1} = 0$ .

Each pore connects more than one throat in our numerical model. Based on the flow rate of (1) – (16) and the topological structure of the network, the assembly equation can be formed as:

$$\begin{bmatrix} D_{11} & \cdots & D_{1j} \\ \vdots & \ddots & \vdots \\ D_{i1} & \cdots & D_{ij} \end{bmatrix} \begin{Bmatrix} P_1 \\ \vdots \\ P_i \end{Bmatrix} = \begin{Bmatrix} \sum_{j=1}^{Z_1} g_{1j} P_{c,1j} \\ \vdots \\ \sum_{j=1}^{Z_i} g_{ij} P_{c,ij} \end{Bmatrix} \#(17)$$

where  $D_{ij}$  is the conductance matrix. When  $i = j$ ,  $D_{ij} = \sum_{j=1}^{Z_i} g_{ij}$ ; otherwise,  $D_{ij} = g_{ij}$ .

## 2.2 Computational procedure

Based on the previous discussion, we derived the quasi-steady-state pressure distribution. To simulate fluid injection, a time variation of the fluid flow was calculated. We iterated to obtain the steady-state pressure distribution at each time

1 step  $\Delta t$ . The computational procedure, as shown in Fig. 3, is described as follows:

2  
3  
4 1) Based on the initial condition, the conductivity of each element is calculated by  
5  
6 using (4) – (11). Then, the integral conductance matrix  $D_{ij}$  and force matrix are  
7  
8 assembled.

9  
10  
11 2) As  $P_{outlet}^t$  and  $P_{inlet}^t$  are known, the pressure distribution is obtained from (17).  
12  
13 Based on the pressure distribution, the total flow rate  $q_{ij}$ , the non-wetting phase flow  
14  
15 rate  $q_{nw,ij}$ , and the wetting phase flow rate  $q_{w,ij}$  can be solved through (1) and (12) –  
16  
17 (14).  
18  
19

20  
21  
22 3) Calculate each phase fluid volume  $V_{w,i}^{t+\Delta t}$  and  $V_{nw,i}^{t+\Delta t}$  in element  $i$  at  $t + \Delta t$  by  
23  
24 using (18) – (19). Update the meniscus position and fluid configuration of each  
25  
26 element based on each phase fluid volume. The purpose of choosing  $\Delta t$  is to ensure  
27  
28 every meniscus will not cross one throat element in  $\Delta t$ . Then, the initial condition can  
29  
30 be updated according to the configuration at  $t + \Delta t$ .  
31  
32

33  
34  
35 The volume of each of the wetting and non-wetting phases in element  $i$  can be  
36  
37 expressed by:  
38  
39

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42 
$$V_{w,i}^{t+\Delta t} = V_{w,i}^t + \Delta t \times \sum_{j=1}^{Z_i} q_{w,ij} \#(18)$$

43  
44  
45 
$$V_{nw,i}^{t+\Delta t} = V_{nw,i}^t + \Delta t \times \sum_{j=1}^{Z_i} q_{nw,ij} \#(19)$$

46  
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48  
49 **3. Simulation condition**

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52 We simulated seepage effects (capillary and viscous forces) for SC-CO<sub>2</sub> and  
53  
54 water fracturing as previously examined in the SC-CO<sub>2</sub> and water fracturing  
55  
56 experiment conducted by Zhang et al (Zhang et al., 2017).  
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### 3.1 Structure of PNM

Two pore network structures were used in the simulation cases. One structure, labeled Network A, was used to validate the flow model and investigate the difference between injecting SC-CO<sub>2</sub> and water, as shown in Fig. 4(a). Network A was used to represent two types of porous media: homogenous porous medium (PNM-homo) and heterogeneous porous medium (PNM-hetero). For PNM-homo, a constant average radius of pores and throats was set for a single simulation. To investigate the effects of different radii, the radii of pores and throats varied from 0.01 to 0.15  $\mu\text{m}$  for each simulation. Thus, the sizes of the simulation models varied for different average radii of pores and throats, see Table 1. The lengths were normalized by the size of each simulation model. For PNM-hetero, the distributions of radii of throats and pores were generated based on the statistical data of sandstone (Bakke and Øren, 1997; Øren and Bakke, 2003, 2002), which is shown in Fig. 5. The other structure, Network B, was assumed to contain a pre-existing fracture (PNM-frac), which was to see pressure distribution around fracture. (see Fig. 4(b)). The size of Network B was consistent with the experimental sample of Zhang et al. (Zhang et al., 2017).

### 3.2 Fluid parameter and injection pressure

Four fluid systems and fluid viscosities, as listed in Tables 2 and 3, respectively, were used in the simulation and considered in the discussion. The formation fluid was gas or oil and the injection fluid was oil, water, or SC-CO<sub>2</sub>. SC-CO<sub>2</sub> is miscible with hydrocarbons and has a high diffusion coefficient. In the fracturing process, a pressurization stage occurs before crack initiation. At this pressurization stage, SC-CO<sub>2</sub> can fully dissolve with the formation fluid at the interface area. The interface between SC-CO<sub>2</sub> and hydrocarbon (gas or oil) disappears and the capillary force

1 decreases to zero. Before SC-CO<sub>2</sub> dissolves sufficiently into a formation fluid, the  
2  
3 interfacial tension between SC-CO<sub>2</sub> and hydrocarbon is very small, approximately 2  
4  
5 mN/m (Li et al., 2017). The interfacial tension between water and hydrocarbon is  
6  
7 approximately 50 mN/m. Thus, our simulation assumed that the capillary force  
8  
9 between SC-CO<sub>2</sub> and the formation fluids (oil or gas) was negligible.  
10  
11  
12

13  
14 The inlet and outlet pressure values were derived from the fracturing  
15  
16 experimental conditions of Zhang et al. (Zhang et al., 2017). In their experiment, the  
17  
18 injection pressure was approximately 5 MPa after fracture initiation. Considering the  
19  
20 pressure loss in tube, 4 MPa was used as the inlet pressure. However, 8 MPa was also  
21  
22 set as the inlet pressure to ensure that the inlet pressure was higher than the threshold  
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24 of the capillary force for different radii.  
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#### 30 **4. Validation**

31  
32 A validation of the flow model was conducted by comparing the analytical  
33  
34 solutions in different flow situations: a) single-phase flow (the injection and formation  
35  
36 fluids were the same); b) two-phase flow without considering the capillary force ( $P_c$ ).  
37  
38 The analytical solutions were based on the Buckley-Leverett theory (Buckley and  
39  
40 Leverett, 1942; Idowu and Blunt, 2010). These solutions and the numerical results  
41  
42 obtained from the flow model are plotted in Fig. 6. The numerical results of the  
43  
44 single- and two-phase flows without capillary force were confirmed to be in good  
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46 agreement with the analytical results derived from the homogeneous porous medium.  
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#### 55 **5. Simulation and results**

56  
57 To investigate the seepage effects of SC-CO<sub>2</sub> injection, five simulations were  
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1 conducted. Both capillary and viscous forces were integrated into the PNM to  
2  
3 simulate the pressure field for a two-phase flow. The different injection conditions are  
4  
5 listed in [Table 4](#).  
6  
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### 8 9 **5.1 Effects of capillary force**

10  
11 The effects of capillary force on two-phase flow are presented in [Fig. 7](#). The  
12  
13 PNM-homo was used to simulate the effect of the capillary force. The constant  
14  
15 pore-throat radius was set to  $0.1 \mu m$ . The results yielded snapshots of the pressure  
16  
17 distributions derived from water injection with and without capillary force. Water was  
18  
19 injected from the inlet (normalized length = 0). The case without  $P_c$  only considered  
20  
21 the effect of viscous force, whereas that with  $P_c$  considered the effects of both  
22  
23 capillary and viscous forces. When the capillary force was considered, a  
24  
25 discontinuous pressure drop (DPD) occurred. The capillary force posed an extra  
26  
27 resistant force to block the invasion of water. This resistant force derived from the  
28  
29 capillary force could cause a DPD in the two-phase flow.  
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### 39 **5.2 Effects of injection time**

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42 Water or SC-CO<sub>2</sub> injections were simulated in a homogeneous porous medium  
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44 using PNM-homo. The constant average pore-throat radius was  $0.1 \mu m$ . The time  
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46 variation of the pressure field is shown in [Fig. 8](#). Water or SC-CO<sub>2</sub> was injected from  
47  
48 the inlet (normalized length = 0), and the pressure field of the water injection, as  
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50 shown in [Fig.8\(a\)](#), experienced a DPD that was caused by the capillary force. The  
51  
52 injection fluid (water) was immiscible with the formation fluid (oil). When they met  
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54 during injection, the capillary force was generated at the interface between water and  
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1 oil. With continuous injection, DPD continuously affected the pressure field. The  
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3 positions of the DPD moved to the outlet side because of changes in the interfacial  
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5  
6 position between water and oil.  
7

8  
9 By contrast, the pressure field of the SC-CO<sub>2</sub> injection experienced no DPD, as  
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11 shown in Fig. 8(b). Because SC-CO<sub>2</sub> and oil are miscible, no interface existed  
12  
13 between them. In other words, no capillary force occurred between SC-CO<sub>2</sub> and oil,  
14  
15 which means that no DPD occurred. Fig. 8(b) also shows that the slope of the pressure  
16  
17 curve in the area displaced by SC-CO<sub>2</sub> (inlet side) was flatter than the area occupied  
18  
19 by oil (outlet side). This was caused by both low viscous and low capillary forces of  
20  
21 SC-CO<sub>2</sub>, (i.e., the seepage effect). Because the injected SC-CO<sub>2</sub> penetrated into pores  
22  
23 easily given a small pressure drop, pressure propagation was advanced with a value  
24  
25 that approximated the injection pressure. The change points of slopes could be  
26  
27 considered the interfacial positions between SC-CO<sub>2</sub> and oil. The interfacial position  
28  
29 between SC-CO<sub>2</sub> and oil was ahead of that between water and oil. This indicated that  
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31 the seepage effect of SC-CO<sub>2</sub> promoted the advancement of the interfacial front.  
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### 41 **5.3 Effects of pore and throat radii**

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44 The influence of different pore-throat radii on the pressure field was investigated  
45  
46 when considering the capillary and viscous forces using PNM-homo. The average  
47  
48 pore-throat radii and corresponding permeability are listed in Table 5. These  
49  
50 parameters were derived from the experiments with shale rocks (Lu et al., 2018). The  
51  
52 sizes of simulation models for each pore radius are listed in Table 1.  
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56  
57 Fig. 9(a) and (b) show the differences in the pressure fields between water and  
58  
59 SC-CO<sub>2</sub> injections, respectively, in a homogeneous porous medium. Fig. 9(a) reveals  
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1 that the values of DPDs varied for the different average pore-throat radii. The DPD  
2 was influenced by the geometries of pore and throat. Because the DPD occurred as a  
3 result of the capillary force, the simulation results indicate that the capillary force  
4 could not be neglected due to the low permeability of rock when the injection fluid  
5 (water) was immiscible with the formation fluid (oil).  
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11  
12 By contrast, with the SC-CO<sub>2</sub> injection, no DPD occurred, as shown in [Fig. 9\(b\)](#).  
13 The pressure field for the SC-CO<sub>2</sub> injection was controlled solely by the viscous force.  
14 Because of the low viscosity of SC-CO<sub>2</sub>, the pressure distributions for different  
15 average pore-throat radii in small distances were nearly the same.  
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#### 22 **5.4 Heterogeneous porous medium**

23  
24 Rock for the most part is a heterogeneous porous media. Thus, investigating the  
25 pressure performances of water and SC-CO<sub>2</sub> injections in heterogeneous porous media  
26 is necessary. In our study, even the radius distributions were random, where the total  
27 average radius of the pore-throat for all pores and throats was 0.02  $\mu\text{m}$ . The  
28 corresponding sample sizes are listed in [Table 1](#).  
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39  
40 A DPD occurred with water injection ([Fig. 10\(a\)](#)), but no DPD occurred with  
41 SC-CO<sub>2</sub> injection ([Fig. 10\(b\)](#)) in the heterogeneous porous medium. This indicated  
42 that the capillary and viscous forces affected the pressure fields in heterogeneous  
43 rocks. The results reveal that DPD clearly occurred when the injected fluid (water)  
44 was immiscible with the formation fluid (oil). For SC-CO<sub>2</sub>, the property of miscibility  
45 with hydrocarbon produces a strong seepage effect.  
46  
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#### 57 **5.5 Well injection with pre-existing fracture**

58  
59 Similar conditions as those in the experiment of Zhang et al. ([Zhang et al., 2017](#))  
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1 were simulated using the PNM-frac. The formation fluid was assumed to be gas,  
2  
3 which was intended to represent shale gas rock (hydrocarbon wet). The average  
4  
5 pore-throat radius was set to 0.01  $\mu\text{m}$ . The simulation results of pressure distributions  
6  
7  
8 for water and SC-CO<sub>2</sub> injections are presented in Fig. 11. The simulation results  
9  
10 revealed that the DPD derived from the capillary force between water and gas blocked  
11  
12 the spread of pressure (see Fig. 11(a)). However, in the case of SC-CO<sub>2</sub> injection,  
13  
14 pressure spread easily without blocks because of the absence of capillary forces, as  
15  
16 shown in Fig. 11(b). This indicated that the capillary force could cut off the pressure  
17  
18 when the injection pressure was insufficient to overcome the threshold of the capillary  
19  
20 force. It should be noted that the pore pressure in non-invaded elements in this model  
21  
22 was set to 0 MPa.  
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## 31 **5.6 Discussion of capillary force effect on the fracture geometry**

32  
33 In general, fracturing with water leads to tensile failure, which in turn generates  
34  
35 fractures, and these fractures extend directly in the direction of the main stress. The  
36  
37 simulation results for water injection suggested that the pressure spread was blocked  
38  
39 by the capillary and viscous forces. However, the effect of capillary force on SC-CO<sub>2</sub>  
40  
41 injection was negligible, and the viscous force for SC-CO<sub>2</sub> injection was lower than  
42  
43 for water injection. The pressure could penetrate into the pore and throat around any  
44  
45 pre-existing fracture. This can cause the pore pressure to increase considerably as  
46  
47 compared with using water as injection fluid. When the pore pressure increased, the  
48  
49 effective stress decreased. If we consider the Mohr-Coulomb failure criterion, shear  
50  
51 failure events occur easily with a small effective stress (i.e., high pore pressure), as  
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1 shown in Fig.12(a). Therefore, increased pore pressure due to SC-CO<sub>2</sub> injection likely  
2  
3 initiates shear failure cracks. Typically, a crack caused by shear failure is not parallel  
4  
5 to a fracture caused by tensile failure (Labuz and Zang, 2012; Patton, 1966).  
6  
7  
8 Fracturing due to SC-CO<sub>2</sub> injection may lead to more branched and high tortuous  
9  
10 fractures as well as rough fracture surfaces. Thus, the fracture geometry derived from  
11  
12 SC-CO<sub>2</sub> injection should be more complex than water injection because of shear  
13  
14 failure cracks (see Fig. 12(b)). These inferred behaviors are consistent with the  
15  
16 experimental results of Zhang et al., who showed that the fracture geometry of  
17  
18 SC-CO<sub>2</sub> was more complex than water fracturing.  
19  
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25 In fact, this paper is based on a flow model to study different pressure  
26  
27 performances when injecting water and SC-CO<sub>2</sub>. On this basis, combined with the  
28  
29 Mohr-Coulomb failure criterion, it is concluded that SC-CO<sub>2</sub> fracturing should induce  
30  
31 complex fractures. But this conclusion is not directly obtained through simulation.  
32  
33 Therefore, in the following work, we will develop a solid model and couple it with the  
34  
35 flow model to verify the aforementioned results that the fracture pattern induced by  
36  
37 SC-CO<sub>2</sub> fracturing is complex fracture networks.  
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## 44 **6. Conclusion**

45  
46 A two-phase steady-state flow model considering the effects of capillary and  
47  
48 viscous forces was developed to investigate differences between aqueous and SC-CO<sub>2</sub>  
49  
50 injections. The results of this study can be summarized as follows.  
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53

54  
55 With respect to aqueous fluid injection, the pressure field was influenced by the  
56  
57 capillary force because of immiscibility. The capillary force produced DPDs at the  
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1 interfacial points. The effects of capillary force on aqueous fluid were significant with  
2  
3 respect to low-permeability reservoirs. However, miscible fluid such as SC-CO<sub>2</sub>  
4  
5 reduced the effect of the capillary force and prevented DPD. Miscibility with  
6  
7 hydrocarbon and the low viscosity of SC-CO<sub>2</sub> led to a strong seepage effect. The  
8  
9 strong seepage effect of SC-CO<sub>2</sub> increased pore pressure in wide areas and induced  
10  
11 shear fractures. This typically leads to the formation of complex fracture networks.  
12  
13  
14  
15

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17  
18 Thank you for previous researchers who use SC-CO<sub>2</sub> to be fracturing fluid and who  
19  
20 contributed to the development of PNM. Their research laid the foundation for my  
21  
22  
23 research.  
24  
25  
26

### 27 **Author contributions**

28  
29 B. Liu planed and conducted the study. A. Suzuki contributed the design of the study.  
30  
31  
32 T. Ito contributed on the examination of the paper structure. All authors participated in  
33  
34 the discussion and interpretation of results, as well as the writing of the manuscript.  
35  
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38

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42  
43 commercial, or not-for-profit sectors.  
44  
45  
46

### 47 **Nomenclature**

48  
49  $g$  conductance,  $m^3/(\text{Pa}\cdot\text{s})$ ;  
50  
51

52  
53  $L$  length of an element,  $m$ ;  
54  
55

56  
57  $n$  number of corners;  
58

59  
60  $z$  number of elements connecting to element  $i$ ;  
61  
62  
63  
64  
65

1  $\alpha_i$  half corner angle at corner  $i$ ;  
2  
3  $P$  pressure, Pa;  
4  
5  
6  $P_c$  capillary pressure, Pa;  
7  
8  
9  $q$  volumetric flow rate,  $m^3/s$ ;  
10  
11  
12  $r$  the curvature radius of corner interface,  $m$ ;  
13  
14  
15  $R$  inscribed radius of a cross-section,  $m$ ;  
16  
17  $\Delta t$  time-step size,  $s$ ;  
18  
19  
20  $\theta$  contact angle, radian;  
21  
22  
23  $\sigma$  interfacial tension between two fluid phases,  $N/m$ ;  
24  
25  
26  $\mu$  fluid viscosity,  $Pa \cdot s$ ;  
27  
28  $V$  fluid volume in an element,  $m^3$ ;  
29  
30  
31  $nw$  non-wetting phase;  
32  
33  
34  $w$  wetting phase;  
35  
36  
37  $C$  conductance of fluid in cross section,  $Pa \cdot s/m^4$   
38  
39  $S_H, S_h$  Maximum principal stress and minimum principal stress  
40

## 41 **Reference**

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## \*Highlights

The seepage effect estimation model for supercritical CO<sub>2</sub> and water fracturing in unconventional gas reservoir is proposed.

The simulation results show that capillary force has strong effect on seepage effect.

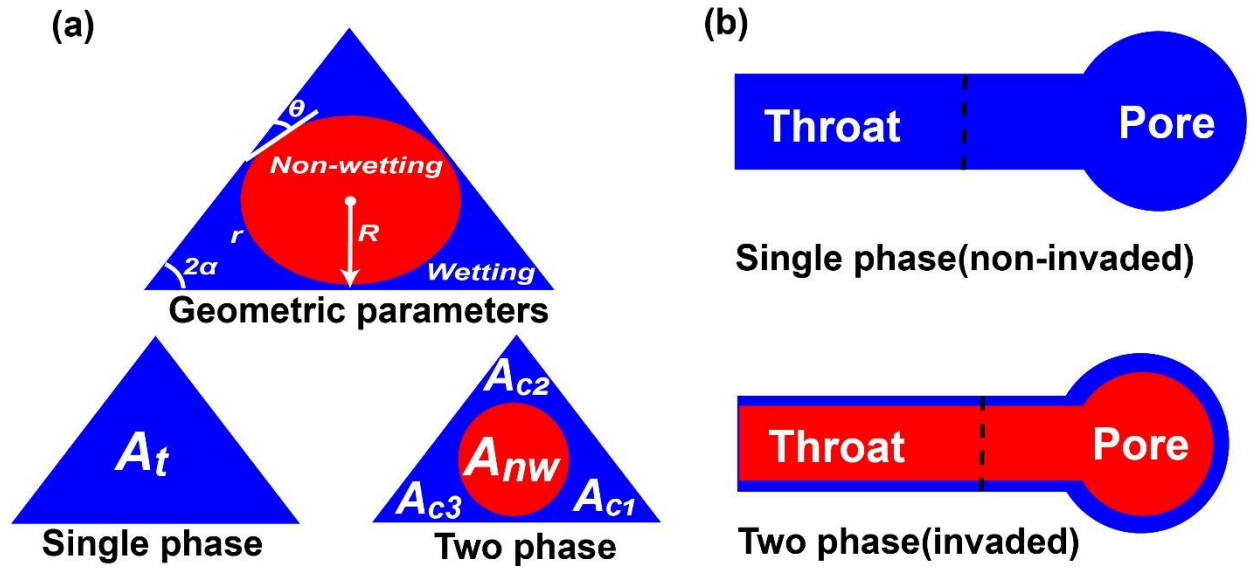
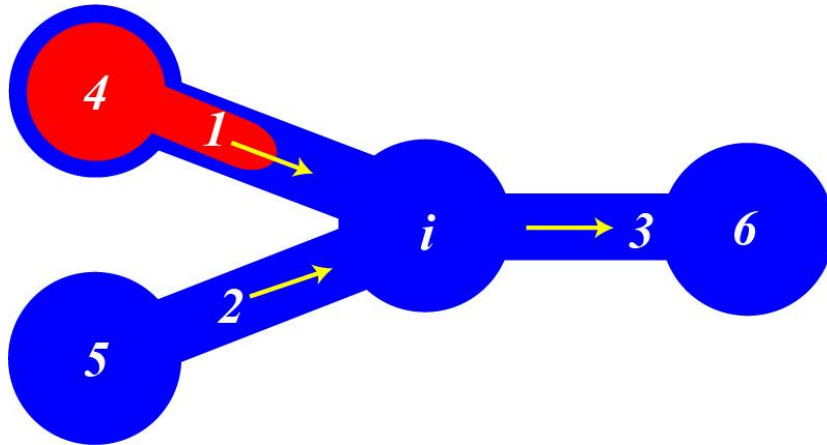
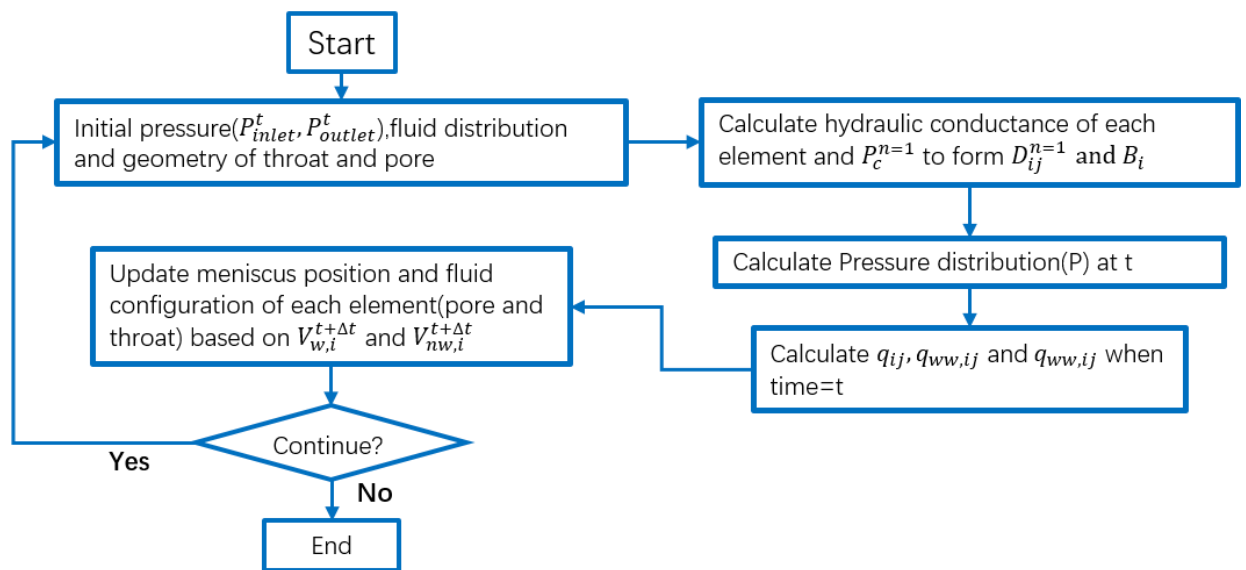


Fig. 1. Schematic image of configuration.



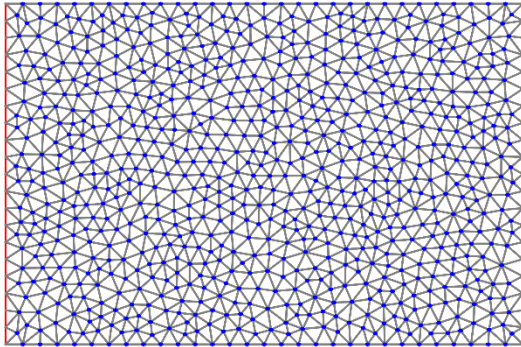
**Fig. 2.** Schematic diagram of volume flux conversation. The yellow arrows represent the flow direction.








**Fig. 3.** Computational procedure.

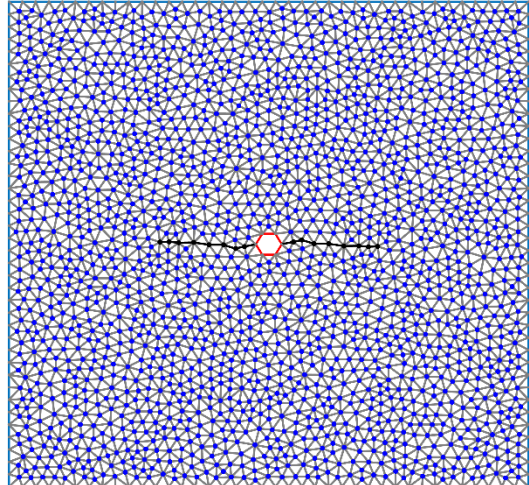


Network A:

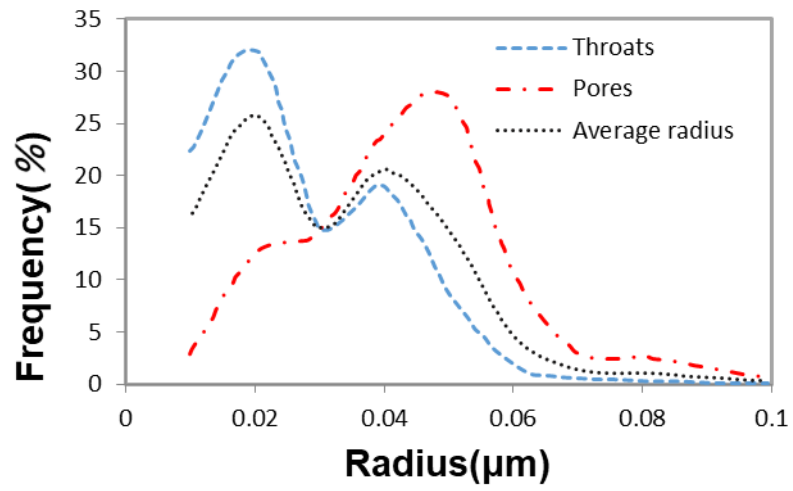


Inlet side:		Pore:	
Outlet side:		Throat:	
Fracture:			

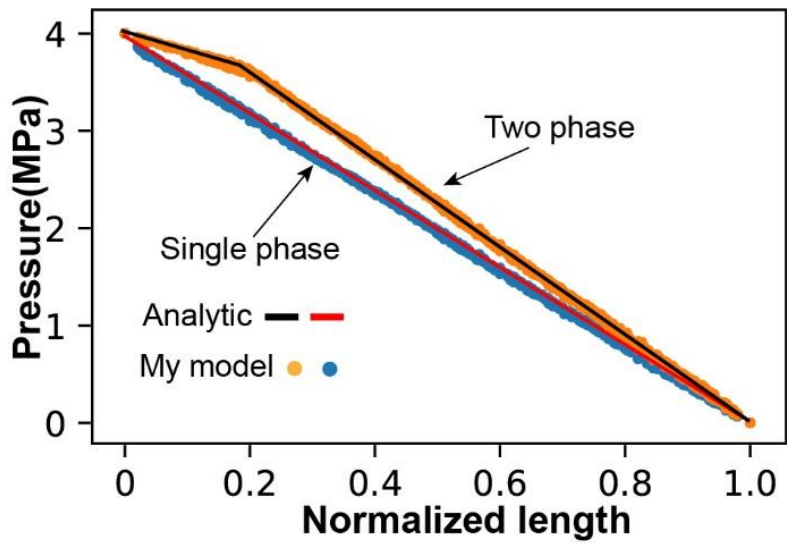
Network B:



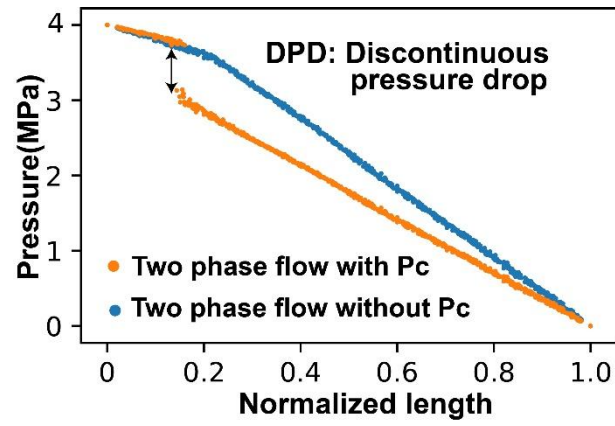
**Fig. 4.** Structure of pore network for simulation.



**Fig. 5.** Pore and throat size distributions for heterogeneous porous medium (PNM-hetero).



**Fig. 6.** Validation of flow model using PNM-homo.



**Fig. 7.** Effect of capillary force on pressure field using PNM-homo.

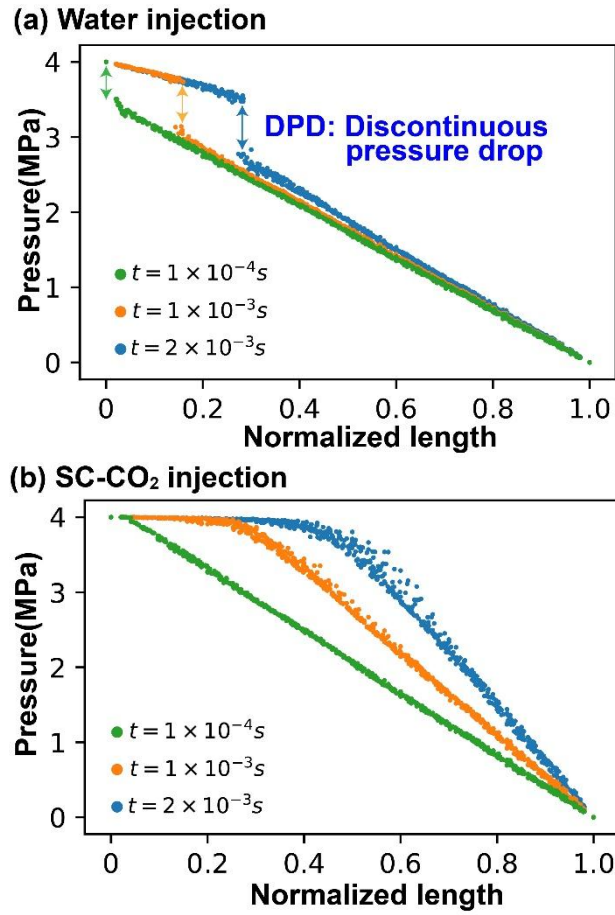
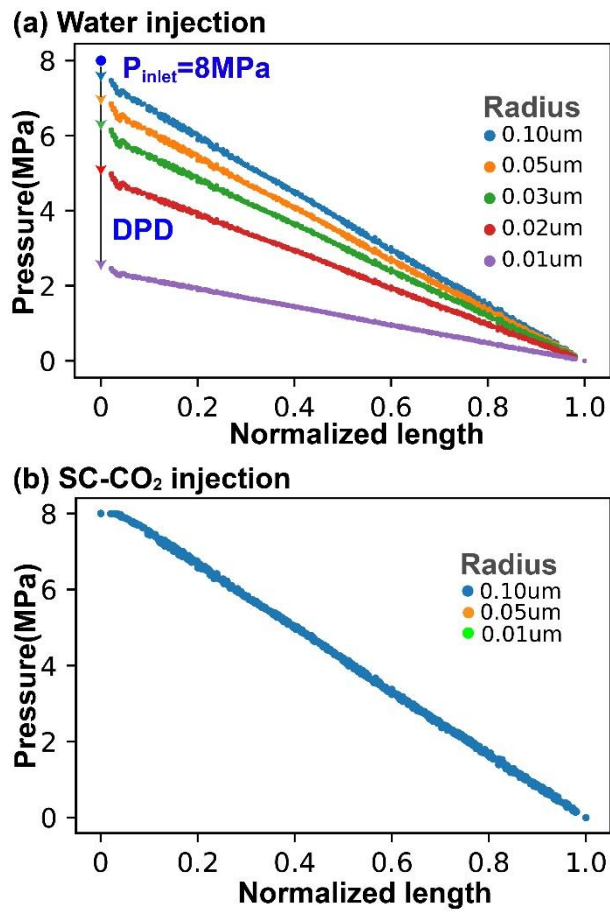
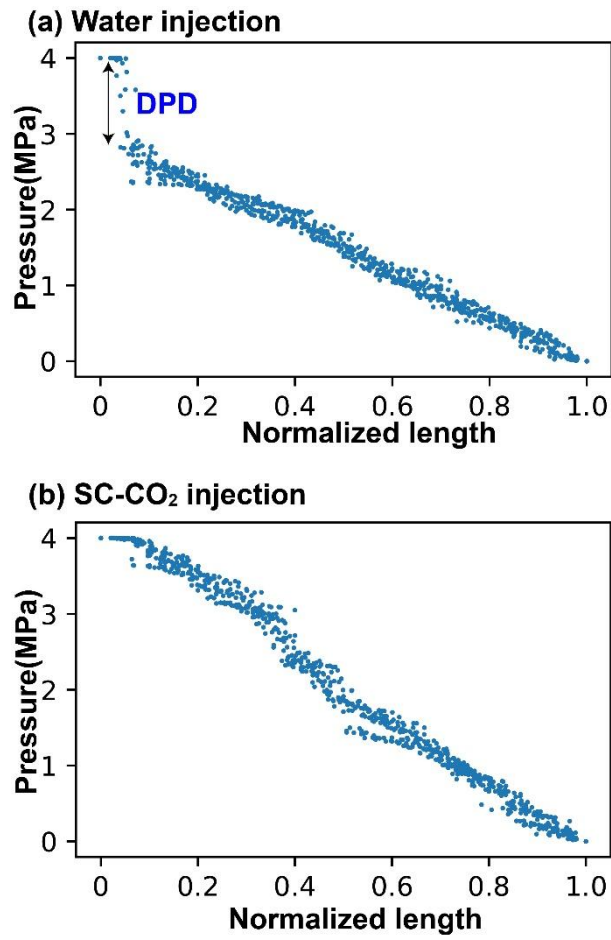


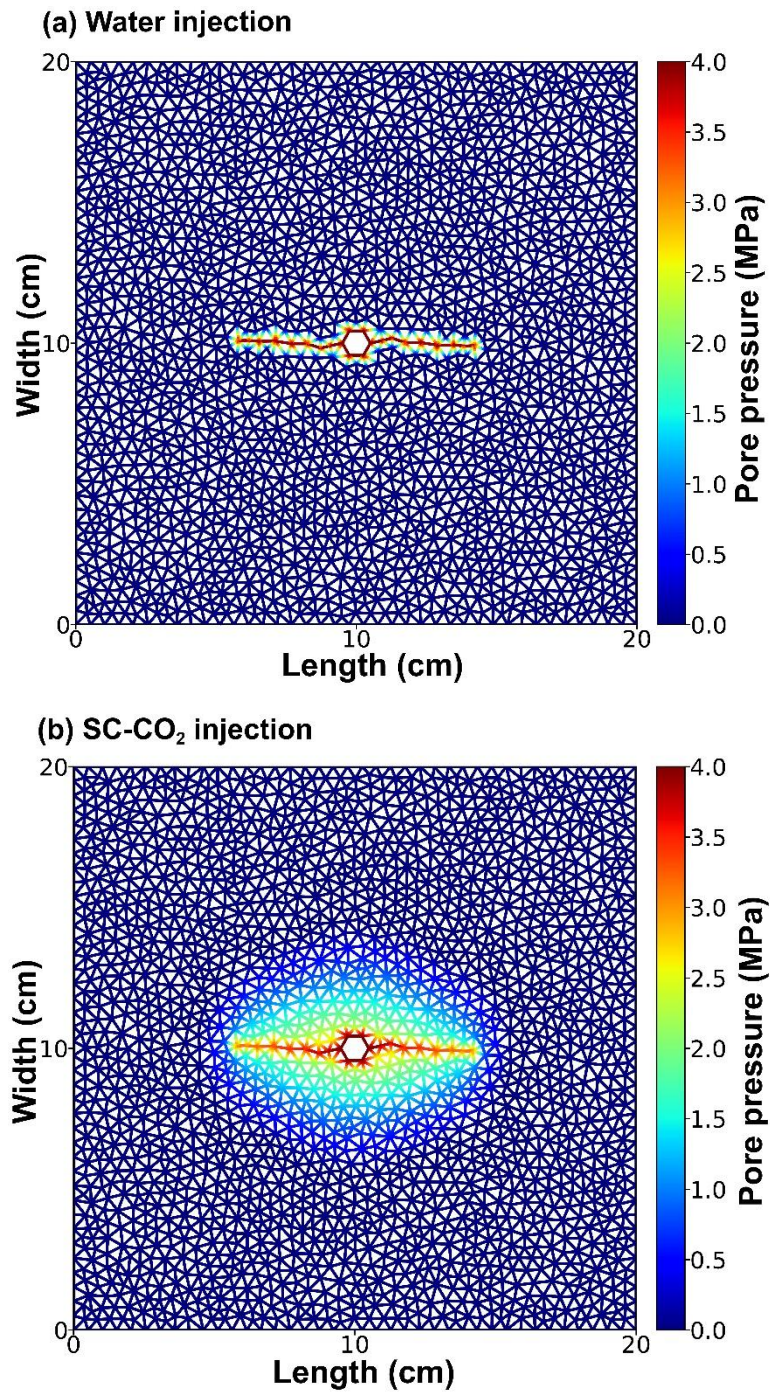
Fig. 8. Pressure field of different injection time using PNM-homo.



**Fig. 9.** Pressure field of different pore-throat radius using PNM-homo.

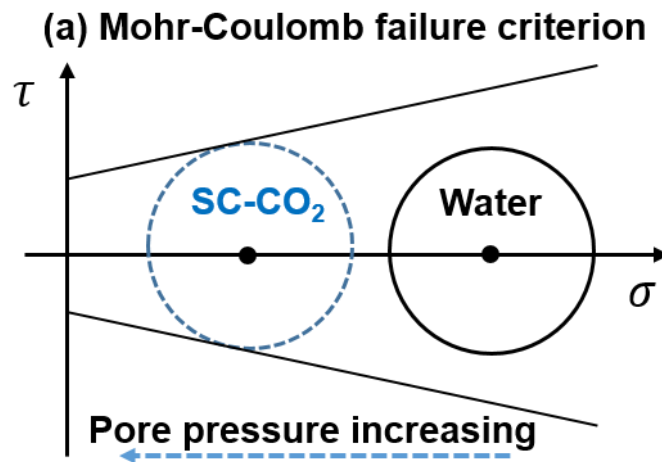


**Fig. 10.** Pressure field of two-phase flow considering capillary force using PNM-hetero.

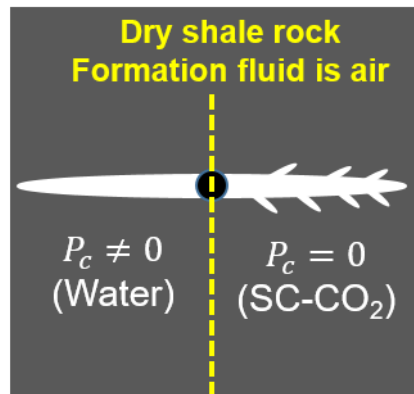


**Fig. 11.** Pressure field due to water injection and SC-CO<sub>2</sub> injection in homogenous porous medium with pre-existed fractures using PNM-frac.





(b) Geometry of fracture



**Fig. 12.** (a) Schematic diagram of Mohr-Coulomb failure criterion and (b) geometry of different type of fractures.

**Table 1** Simulation sample size and average radius of pore-throat.

Simulation sample	Average pore-throat radius ( $\mu m$ )	Size of model ( $mm \times mm$ )
1	0.15	$0.225 \times 0.15$
2	0.10	$0.150 \times 0.10$
3	0.05	$0.075 \times 0.05$
4	0.03	$0.045 \times 0.03$
5	0.02	$0.030 \times 0.02$
6	0.01	$0.015 \times 0.01$

**Table 2** Fluid systems for simulation.

Fluid system (injection - formation)	Contact angle ( $deg$ )	Interfacial tension ( $mN/m$ )
Water-Gas	0	50.0
SC-CO <sub>2</sub> -Gas	Miscible	Miscible
Water - Oil	30	30
SC-CO <sub>2</sub> -Oil	Miscible	Miscible

**Table 3** Fluid viscosity.

Fluid	Viscosity ( $mPa \cdot s$ )
Gas	0.011
Water	0.89
Oil	4.0
SC-CO <sub>2</sub>	0.02

**Table 4** Simulation cases.

Simulation	Injecting fluid	Formation fluid	Inlet pressure (MPa)	Outlet pressure (MPa)	Injection time ( $10^4$ s)	Network
Validation	Oil/Water	Oil	4.0	0	2.0	PNM-homo
5.1	Water	Oil	4.0	0	2.0	PNM-homo
5.2	Water/SC-CO <sub>2</sub>	Oil	4.0	0	1.0-20	PNM-homo
5.3	Water/SC-CO <sub>2</sub>	Oil	8.0	0	2.0	PNM-homo
5.4	Water/SC-CO <sub>2</sub>	Oil	4.0	0	2.0	PNM-hetero
5.5	Water/SC-CO <sub>2</sub>	Gas	4.0	0	1200	PNM-frac

**Table 5** Classification of shale oil reservoirs.

Classification	Permeability ( $10^{-3} \mu m^2$ )	Average pore-throat radius ( $\mu m$ )
I	> 1	> 0.15
II	1~0.4	0.15~0.07
III	0.40~0.05	0.01~0.07
IV	< 0.05	< 0.01