

1 Does low-viscosity fracturing fluid always create complex
2 fractures?

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9 **Abstract:** Lower-viscosity fluids are commonly believed to be able to create more
10 complex fractures in hydraulic fracturing, however, the mechanism remains stubbornly
11 unclear. We use a new grain-scale model with accurate coupling of hydrodynamic
12 forces to simulate the propagation of fluid-driven fracturing. The results clarify that
13 fracturing fluid with a lower viscosity does not always create more complex fractures.
14 The heterogeneity in the rock exerts the principal control on systematic evolution of
15 fracture complexity. In homogeneous rock, low viscosity fluids result in low breakdown
16 pressure, but viscosity exerts little influence on fracture complexity. However, in
17 heterogeneous rock, lower viscosity can lead to more complex network of fracturing. A
18 regime map shows the dependence of fracture complexity on the degree of rock
19 heterogeneity where low viscosity fracturing fluid more readily permeates weak defects
20 and creates complex fracture networks.

21 **Keyword:** hydraulic fracturing, fracture complexity, solid-fluid coupling, grain-scale
22 modeling
23

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24 **1. Introduction**

25 Hydraulic fracturing is an important stimulation technique in tight or
26 unconventional reservoirs to enable gas or oil production [*Economides and Nolte*, 1989;
27 *Montgomery and Smith*, 2010]. In this process, a significant volume of fluid (fracturing
28 fluid) is injected into the wellbore under high pressure to fracture the rock and
29 drastically increase the permeability-of and production-from the formation
30 [*Economides and Nolte*, 1989]. Hydraulic fracturing is a strongly-coupled fluid-solid
31 process with its efficiency depending on the properties of both the fluid and the rock.
32 The mechanical properties and stress-state of the rock are intrinsic for a specific
33 reservoir, so various fracturing fluids have been used to achieve different fracturing
34 outcomes – principally related to a desired increase in fracture complexity [*Barati and*
35 *Liang*, 2014; *Wanniarachchi et al.*, 2017]. High viscosity fluids such as cross-linked
36 gels are typically used due to their capacity to effectively transport proppants
37 [*Wanniarachchi et al.*, 2017]. Such fracturing fluids typically result in a single bi-wing
38 planar crack as described by classical theories of hydraulic fracturing [*M K Fisher et*
39 *al.*, 2002]. The single bi-wing planar fracture is suitable for reservoirs with moderate
40 permeability, which is equivalent to increasing the length or surface area of the wellbore.
41 However, in ultra-low permeability reservoirs, such as gas shales, a simple planar
42 fracture is ineffective – it cannot provide large contact area with the reservoir and
43 reduced diffusive pathway lengths and fails to improve productivity [*M K Fisher et al.*,
44 2002; *M J Mayerhofer et al.*, 2010]. For example, Barnett Shale was rendered
45 commercially successful by a shift in fracturing fluids in 1998 [*M Fisher et al.*, 2004].

46 A blend of water with friction reducers (slickwater) was able to generate more complex
47 fracture networks and yield economically viable production of gas [*M Mayerhofer et*
48 *al.*, 1997]. After that “water fracs” and the concept of “Stimulated Reservoir Volume”
49 (meaning extremely complex fracture network) were widely accepted [*M J Mayerhofer*
50 *et al.*, 2010; *M J Mayerhofer et al.*, 2006]. The development of hydraulic fracture
51 operations indicates that fracturing fluid has a significant effect on the fracture
52 complexity. This effect is usually qualitatively attributed to the fluid viscosity, but the
53 direct quantitative evidence is still lacking and understanding the in-depth mechanism
54 remains insufficiently clear [*Song et al.*, 2019]. Owing to the difficulty in
55 experimentally observing the fracturing behavior, numerical explorations is needed to
56 reveal what happens in rock during the hydraulic fracturing process.

57 Generally, there are two kinds of methods in simulating hydro-fracturing,
58 continuum-scale models and grain-scale models. Continuum-scale models such as
59 KGD and PKN representations are routinely applied in the design of hydraulic fracture
60 treatments[*Geertsma and De Klerk*, 1969; *Nordgren*, 1972], where a single planar crack
61 is usually assumed and typically exclude the potential for complex fracturing behavior
62 [*Adachi et al.*, 2007; *Barbati et al.*, 2016; *Detournay*, 2016; *Hubbert and Willis*, 1972].
63 To consider the fracture network, discrete fracture network (DFN) model is widely used
64 to predict the hydro-fracturing in unconventional reservoirs. *Li and Zhang* (2019)
65 simulated the gases fracturing by DFN, and found CO₂ can induce more complex
66 fracture network than water [*Li and Zhang*, 2019]. However, in DFN models, the
67 fracture information (such as fracture direction, length and amount) should be preset,

68 and the complex fracturing behavior in rock (such as branching and fracture-fracture
69 interaction) is difficultly described. As an alternative, grain-scale models are developed
70 to explore the deeper mechanisms [Al - Busaidi *et al.*, 2005; S. A. Galindo-Torres *et*
71 *al.*, 2013; Shimizu *et al.*, 2011], and among them discrete element method (DEM)
72 [Cundall and Strack, 1979; S Galindo-Torres *et al.*, 2012] is a promising one. Different
73 from the traditional material such as metal, rock is a “discontinuum” material,
74 comprising grains, pores and pre-existing flaws, so its fracturing behavior is peculiar
75 and complex. DEM directly represents the grain-scale structure of rock by treating each
76 grain as a DEM particle and can hence capture the complex fracturing of rock
77 automatically.

78 In this work a LBM-DEM coupled model [Z Chen and Wang, 2017; Z Chen *et al.*,
79 2016; S. A. Galindo-Torres, 2013; Min Wang *et al.*, 2016] is used to explore why
80 different fluids result in different fracturing behaviors, and in particular focuses on the
81 role of viscosity on evolving fracture complexity. In such models, rock deformation and
82 fracturing behavior is described by DEM. More important, fluid flow is simulated by
83 solving the Navier-Stokes equations directly using the lattice Boltzmann method
84 (LBM), which overcomes the limitation of Darcy’s law in continuum-scale models.
85 Darcy’s law is based on the creep flow assumption, but during the hydro-fracturing
86 Darcy’s law may break down owing to the extremely high fluid pressure. We introduce
87 this grain-scale numerical method in Section 2, which combines the lattice Boltzmann
88 method (LBM), discrete element method (DEM) and the improved IMB method. We
89 then apply this method to explore the evolution of fracture complexity when rock

90 heterogeneity and variable viscosity fluids are used to develop fluid-driven fractures.

91 **2. Grain-scale numerical models for hydro-mechanical coupling**

92 Discrete element methods (DEM) are popular in simulating the mechanical
93 behavior of granular system such as sand, soil, and rock [Z Chen *et al.*, 2018a; Cundall
94 and Strack, 1979; Damjanac and Cundall, 2016; S Galindo-Torres *et al.*, 2012]. In
95 DEM, the material is discretized as an assembly of discrete bonded particles where the
96 mechanical behavior is obtained by tracking the movement of each particle by
97 integrating Newton's Second Law in time. The external force acting on the DEM
98 particles includes two parts - the collision force and the cohesive force. Current DEM
99 framework is based on the open source software MechSys developed by [S. A. Galindo-
100 Torres, 2013], where non-spherical particles can be considered.

101 In order to consider the effects of cementation, cohesive forces between two
102 adjacent particles are assumed in normal (\mathbf{n}) and tangential (\mathbf{t}) directions, which are
103 given by [S. A. Galindo-Torres *et al.*, 2013]

$$104 \quad \begin{cases} \mathbf{F}_n^{cohe} = M_n^{cohe} A \varepsilon_n \mathbf{n} \\ \mathbf{F}_t^{cohe} = M_t^{cohe} A \varepsilon_t \mathbf{t} \end{cases}, \quad (1)$$

105 where \mathbf{F}_n^{cohe} and \mathbf{F}_t^{cohe} are cohesive forces, M_n^{cohe} and M_t^{cohe} are the elastic moduli
106 of the virtual cements, ε_n and ε_t are the strains as the two adjacent faces separate
107 and A is the shared interface area. When the strain reaches a threshold value ε_{th} ,

$$108 \quad \frac{|\varepsilon_n| + |\varepsilon_t|}{\varepsilon_{th}} > 1, \quad (2)$$

109 the cohesive forces vanish, and a crack is induced along the common interface shared
110 by the two adjacent particles.

111 The second external force is the collision force and results when two particles
 112 collide. In the current simulation, a spring model is used

$$113 \quad \begin{cases} \mathbf{F}_n^{cont} = K_n \Delta l_n \mathbf{n} \\ \mathbf{F}_t^{cont} = K_t \Delta l_t \mathbf{t} \end{cases}, \quad (3)$$

114 where \mathbf{F}_n^{cont} and \mathbf{F}_t^{cont} are collision forces, K_n and K_t are spring stiffnesses, Δl_n and
 115 Δl_t are the length of interpenetration in the normal and tangential directions,
 116 respectively. The efficiency of current DEM scheme in simulating mechanical behavior
 117 of the rock material can be found in our previous work [Z Chen *et al.*, 2018a].

118 The lattice Boltzmann method (LBM) is a numerical method for fluid flow and
 119 makes the Navier-Stokes equations solved [S Chen and Doolen, 1998]. However,
 120 different from the traditional computational fluid dynamics (CFD) methods, the basic
 121 variable in LBM is the density distribution function rather than more usual macroscopic
 122 parameters (such as pressure and velocity). Here, a three dimensional 15-speed model
 123 (D3Q15) is applied [Moran Wang and Chen, 2007; Zhang and Wang, 2017], where the
 124 evolution equation is written as

$$125 \quad f_i(\mathbf{x} + \mathbf{e}_i \delta_t, t + \delta_t) = f_i(\mathbf{x}, t) - \frac{1}{\tau} (f_i(\mathbf{x}, t) - f_i^{eq}(\mathbf{x}, t)), \quad i = 0-14, \quad (4)$$

126 where f_i is the density distribution in the i -th the discrete velocity direction \mathbf{e}_i , f_i^{eq}
 127 is the corresponding equilibrium distribution, and δ_t is the time step. Parameter τ is
 128 the dimensionless relaxation time and reflects the fluid kinematic viscosity

$$129 \quad \nu = \frac{(\tau - 1/2) \delta_x^2}{3 \delta_t}, \quad (5)$$

130 where δ_x is the grid size. In the D3Q15 model, the discrete velocity \mathbf{e} has 15 directions

$$\mathbf{e} = c \begin{bmatrix} 0 & 1 & 0 & -1 & 0 & 0 & 0 & 1 & 1 & 1 & 1 & -1 & -1 & -1 & -1 \\ 0 & 0 & 0 & 0 & 0 & -1 & 1 & -1 & -1 & 1 & 1 & -1 & -1 & 1 & 1 \\ 0 & 0 & 1 & 0 & -1 & 0 & 0 & 1 & -1 & -1 & 1 & 1 & -1 & -1 & 1 \end{bmatrix}, \quad (6)$$

where $c = \delta_x / \delta_t$. The equilibrium distribution in the i -th direction is written as

$$f_i^{eq}(\rho, \mathbf{u}) = \rho \omega_i \left[1 + \frac{3\mathbf{e}_i \cdot \mathbf{u}}{c^2} + \frac{9(\mathbf{e}_i \cdot \mathbf{u})^2}{2c^4} - \frac{3\mathbf{u} \cdot \mathbf{u}}{2c^2} \right], \quad (7)$$

where the weighting factors are

$$\omega_i = \begin{cases} 2/9, & i = 0 \\ 1/9, & i = 1-6 \\ 1/72, & i = 7-14 \end{cases}. \quad (8)$$

The fluid density and velocity are calculated as

$$\rho = \sum_i f_i, \quad (9)$$

$$\rho \mathbf{u} = \sum_i f_i \mathbf{e}_i, \quad (10)$$

and the pressure p is given by

$$p = \frac{1}{3} \rho c^2. \quad (11)$$

In the previous LBM-DEM coupled models, an immersed moving boundary (IMB) is typically applied to facilitate fluid solid interaction [S. A. Galindo-Torres, 2013; Noble and Torczynski, 1998; Min Wang et al., 2016] – however, the hydrodynamic force provided by this method is insufficiently accurate to represent stresses at fluid-filled crack-tips. To overcome this limitation, an improved IMB method proposed in our previous work is applied in this work.

In this improved IMB method, the evolution equation in LBM is modified as

$$f_i(\mathbf{x} + \mathbf{e}_i \delta_t, t + \delta_t) = f_i(\mathbf{x}, t) - (1 - B) \frac{1}{\tau} (f_i(\mathbf{x}, t) - f_i^{eq}(\mathbf{x}, t)) + B \Omega_i^s. \quad (12)$$

The parameter Ω is the fluid-solid interaction term, which is calculated by the bounce-back for the non-equilibrium part of the density distribution

$$\Omega_i^s = [f_{-i}(\mathbf{x}, t) - f_{-i}^{eq}(\rho, \mathbf{v}_p)] - [f_i(\mathbf{x}, t) - f_i^{eq}(\rho, \mathbf{v}_p)], \quad (13)$$

where \mathbf{v}_p is the DEM particle velocity at position \mathbf{x} , weighting factor B is a function of the dimensionless relaxation time (τ) and solid volume fraction of the LBM cell at position \mathbf{x} (γ) and is given as

$$B = \frac{\gamma(\tau - 0.5)}{(1 - \gamma) + (\tau - 0.5)}. \quad (14)$$

The hydrodynamic force \mathbf{F} is calculated by the change in momentum of the fluid covered by the DEM particles, which is given by

$$\mathbf{F} = \rho_f V \frac{\mathbf{u}_s(t) - \mathbf{u}_s(t - \delta_t)}{\delta_t} - \sum_n \sum_i \frac{\delta_x^3 B_n}{\delta_t} \Omega_i^s \mathbf{e}_i, \quad (15)$$

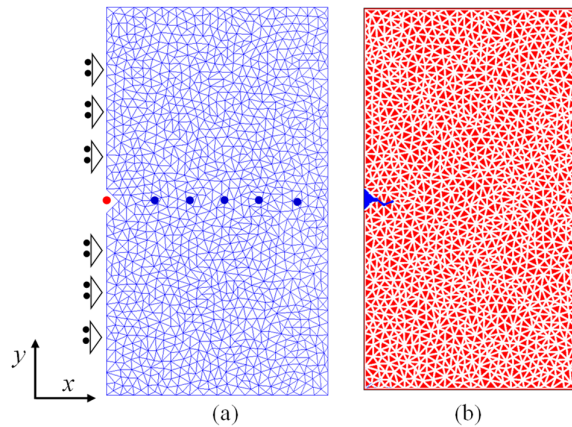
$$\mathbf{T} = I_f \frac{\boldsymbol{\omega}_s(t) - \boldsymbol{\omega}_s(t - \delta_t)}{\delta_t} - \sum_n \left(\sum_i \frac{\delta_x^3 B_n}{\delta_t} \Omega_i^s \mathbf{e}_i (\mathbf{x}_n - \mathbf{x}_{cm}) \right). \quad (16)$$

Compared with the original IMB method, the internal fluid correction (the first term on the right-hand-side of Eqs. 15 and 16) is added to ensure the accuracy of the hydrodynamic force calculation. Parameter V is the volume of the solid particle, \mathbf{u}_s and $\boldsymbol{\omega}_s$ are the linear and angular velocities of the DEM particle, respectively, I_f is the moment of inertia for the internal fluid covered by the DEM particle, \mathbf{x}_n is the fluid cell position, and \mathbf{x}_{cm} is the mass center of the DEM particle. The validations of this revised LBM-DEM model are given in the Appendix.

3. Results and discussion

The physical model in the current simulation is shown in Figure 1, where the rock matrix is discretized as an assembly of triangular particles bonded with each other (see Figure 1(a)). Fluid is injected into a hole on the left side of the domain with an initial crack introduced near this hole. The sizes of triangular particles in Figure 1(a) are

172 reduced by a small distance to provide flow channels (white part in Figure 1(b)) within
 173 the assemblage. Fluid flows only within these channels (simulated by LBM) with the
 174 hydrodynamic force imposed on the interior triangular particles calculated by the
 175 improved IMB method. These ensemble fluid forces results in the propagation of the
 176 discrete hydraulic fracture. In order to capture the effects of the newly formed fracture
 177 on flow conductivity a fracture-dependent flow conductivity is applied. When the bond
 178 is intact, a high virtual solid volume (γ in Eq. 14) is introduced in the flow channel,
 179 corresponding to a low conductivity. When the bond is broken, γ in the corresponding
 180 flow channel is set to zero, resulting in high permeability for the newly formed fracture
 181 [S Wang *et al.*, 2011]. The purpose of this work is to invest the fluid viscosity effect on
 182 the fracture complexity, so to avoid the influence from the confining stresses the
 183 samples are unconfined in current model. More details of this LBM-DEM scheme for
 184 hydraulic fracture propagation can be found in our previous work [Z Chen and Wang,
 185 2017; Z Chen *et al.*, 2018b].



186
 187 Figure 1. Schematic for LBM-DEM simulation of hydraulic fracturing. (a) Discretization of the
 188 rock matrix by triangular particles, where a borehole is set on the left edge to allow fluid
 189 injection. (b) The sizes of triangular particles in (a) are reduced by a small distance to provide

190 flow channels (white) in the rock, where an initial crack (blue) is introduced to guide the
191 subsequent propagation of the hydraulic fracture.

192 During the simulation, the left edge of the computational domain is set as a
193 symmetric boundary, with the DEM particles to the left fixed in the x -direction but free
194 to displace in the y -direction. The rock sample is unconfined on other three edges. In
195 order to explore why different fluids potentially generate different fracturing behaviors,
196 various viscosity fluids are injected. Parameters represented in the DEM and LBM
197 models are listed in Table 1.

198

199 **Table 1.** Parameters in DEM and LBM models.

Parameters	Value
Normal stiffness, K_n	$1 \times 10^8 \text{ N/m}$
Tangential stiffness, K_t	$1 \times 10^8 \text{ N/m}$
Particle friction coefficient, μ_{fric}	0.4
Normal elastic modulus, M_n^{cohe}	$2.0 \times 10^9 \text{ Pa}$
Tangential elastic modulus, M_t^{cohe}	$4.17 \times 10^9 \text{ Pa}$
Rock matrix bonding strength, ε_{th}	0.01
Fluid density, ρ	$1 \times 10^3 \text{ kg/m}^3$
Lattice size in LBM, δ_x	$1.0 \times 10^{-4} \text{ m}$
Time step in LBM, δ_t	$2.0 \times 10^{-7} \text{ s}$

200

201 Figure 2 shows the resulting hydraulic fracture driven by different viscosity fluids,
202 where (a), (b) and (c) are fracture geometries for kinematic viscosities of $\nu = 2 \times 10^{-3} \text{ m}^2/\text{s}$,
203 $1 \times 10^{-3} \text{ m}^2/\text{s}$ and $5 \times 10^{-4} \text{ m}^2/\text{s}$, respectively. Figure 2(d) is the pressure evolution in the
204 borehole (red point in Figure 1(a)) during the progress of the hydraulic fracturing, and

Figure 2(e) is the pressure distribution when the fracture is initially induced, as measured along the central part of the computational domain (1 red point and 5 blue points in Figure 1(a)).

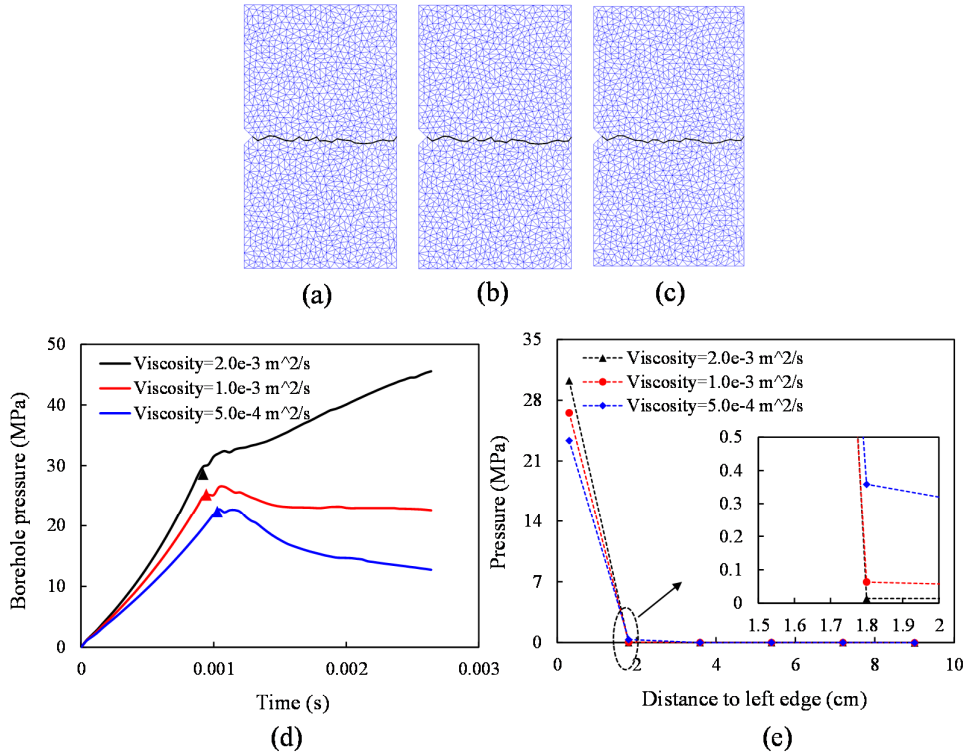


Figure 2. Hydraulic fracture evolution for fluids with contrasting viscosities. Figures (a), (b) and (c) are fracture geometries for kinematic viscosities of $\nu = 2 \times 10^{-3}$ m²/s, 1×10^{-3} m²/s and 5×10^{-4} m²/s, respectively. (d) Pressure evolution in the borehole (red point in Figure 1(a)) during the hydraulic fracturing process. (e) Pressure distribution when the fracture is initially induced.

The evolution of pressure in the borehole is an important indicator of hydraulic fracture propagation. The first pressure drop represents the initiation of the fracture – referenced as the breakdown pressure. Figure 2(d) shows that the pressure increases most rapidly for a higher viscosity and slowest for low viscosity with the breakdown pressure also reducing with a reduction in viscosity. Similar results have also been observed in other experimental and numerical studies [Chitralla et al., 2012; Gan et al.,

219 2015; *J Wang et al.*, 2018]. In order to explain this phenomenon, the pressure
220 distribution along the rock sample is plotted when the fracture is initially induced
221 (Figure 2(e)). The leftmost points in Figure 2(e) are the breakdown pressure for
222 different viscosity fluids. It can be seen that for the low viscosity cases, the breakdown
223 pressure is low although the pore pressure directly adjacent to the hole is high. High
224 pore pressure reduces the effective stress and promotes weakening of the borehole wall.
225 The high pore pressure in the rock matrix for the low viscosity fluid can be attributed
226 to two reasons. First, fluid with low viscosity more easily penetrates into the rock matrix
227 owing to the low flow resistance. Secondly, the pressure buildup for low viscosity case
228 is slow (Figure 2(d)), so fluid has more time to increase the pore pressure adjacent to
229 the borehole wall.

230 However, these current simulations seem to suggest that viscosity has little effect
231 on fracture geometry. The hydraulic fractures induced by the different fluids are near
232 identical (see Figure 2(a)-(c)), and a thorough-going simple fracture is generated in all
233 samples. However, previous experimental results show that the fluid viscosity is an
234 important parameter affecting the fracture geometry [*Bennour et al.*, 2015]. When high
235 viscosity fluid is used, such as oil, a simple fracture is formed. However, when the fluid
236 viscosity is low, a complex fracture geometry can be induced. Thus, further exploration
237 is needed to deal with this inconsistency.

238 In the prior simulations, the rock sample is homogeneous - with bond strengths
239 uniformly distributed. However, strength heterogeneity is an important feature of rock
240 owing to the different mineral components. This strength heterogeneity may be

241 quantitatively represented as a Weibull distribution [McClintock and Zaverl, 1979].

242 Thus, the impact of strength heterogeneity may be considered, by setting the bonding

243 strength threshold (ε_{th}) as a random field following the Weibull distribution

$$244 \quad f(\varepsilon_{th}) = \frac{m}{\varepsilon_{th}^0} \left(\frac{\varepsilon_{th}}{\varepsilon_{th}^0} \right)^{m-1} \exp \left(- \left(\frac{\varepsilon_{th}}{\varepsilon_{th}^0} \right)^m \right), \quad (17)$$

245 where ε_{th}^0 is the average bond strength threshold, and $m > 0$ is the shape parameter

246 describing the degree of dispersion of ε_{th} . In current work more than 3000 DEM

247 particles are used, which is considered sufficiently to represent the Weibull distribution

248 [Rossi and Richer, 1987]. In order to quantify the degree of heterogeneity, an index (h)

249 between 0 and 1 is proposed, representing the normalized standard deviation of the

250 Weibull distribution as

$$251 \quad h = \frac{\sigma_{std}}{E_{mean}} = \frac{\Gamma(1+1/m)}{\sqrt{\Gamma(1+2/m) - (\Gamma(1+1/m))^2}}, \quad (18)$$

252 where Γ is the gamma function, σ_{std} is the standard deviation, and E_{mean} is the mean

253 of the distribution. When $m=1$, $h=1$ and this corresponds to a highly heterogeneous

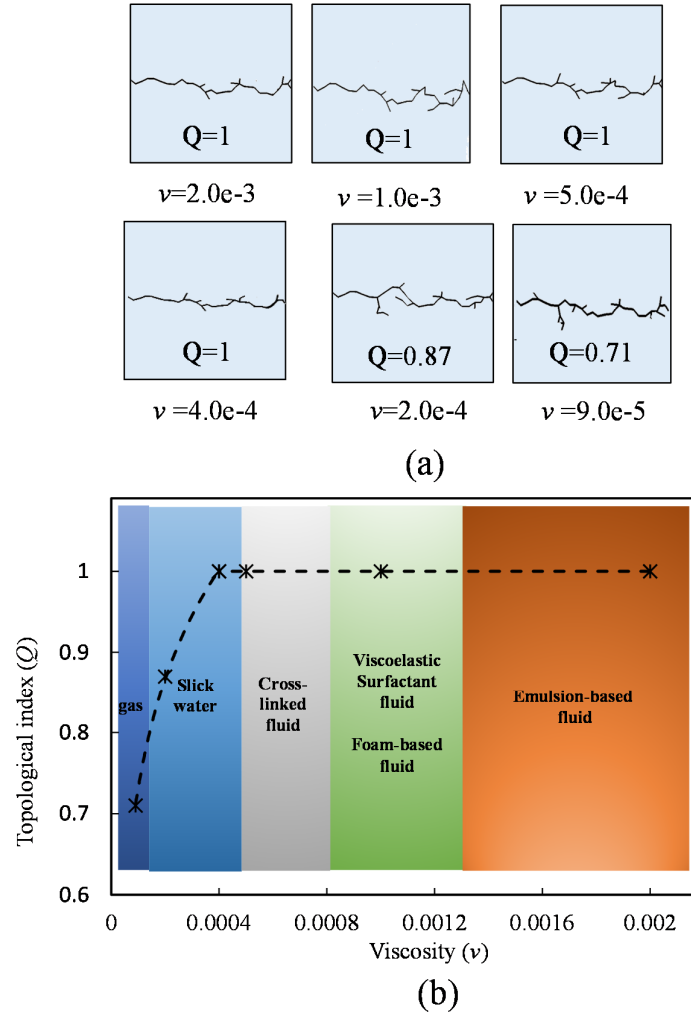
254 system. Conversely, $h=0$, represents a totally homogeneous sample.

255 Figure 3 shows the evolution of the hydraulic fracture in a highly heterogeneous

256 rock sample ($h=0.52$), where (a) is the fracture geometry induced by fluids with

257 different viscosities. The fracture geometry induced by a low viscosity ($9 \times 10^{-5} \text{ m}^2/\text{s}$)

258 fluid is more complex than that induced by a high viscosity ($2 \times 10^{-3} \text{ m}^2/\text{s}$) fluid.



259
 260 Figure 3. Evolution of a hydraulic fracture in heterogeneous samples. (a) Fracture geometry
 261 induced by fluid with viscosity of $\nu=2 \times 10^{-3} \text{ m}^2/\text{s}$, $1 \times 10^{-3} \text{ m}^2/\text{s}$, $5 \times 10^{-4} \text{ m}^2/\text{s}$, $4 \times 10^{-4} \text{ m}^2/\text{s}$, 2
 262 $\times 10^{-4} \text{ m}^2/\text{s}$ and $9 \times 10^{-5} \text{ m}^2/\text{s}$ respectively. (b) Modified topological index representing the
 263 various cases - quantitatively indicates that lower viscosity fluids result in more complex
 264 fracture networks in heterogeneous rock.

265 In order to provide a quantitative comparison of fracture complexity induced
 266 by different fluids, a modified topological index (Q) is calculated for each case. The
 267 parameter Q is an index [Z Chen and Wang, 2017] to quantify the complexity of the
 268 resulting fracture geometry $0 < Q < 1$ with a lower Q corresponding to a more complex
 269 fracture geometry. Figure 3(b) shows that for low viscosity fluids the topological index
 270 Q is smaller, which quantitatively demonstrates that in heterogeneous rock low

viscosity is conducive to the formation of complex fracture network, similar to experimental observations [Bennour *et al.*, 2015]. Thus, fracturing fluid effects on fracture complexity depends on the rock properties. In homogeneous rock, fluid viscosity has little effects on fracture complexity, but in heterogeneous rock, lower viscosity may result in more complex fracture networks. In order to explain this rock-dependent effect, the evolving pressure distribution in the rock sample is plotted in Figure 4.

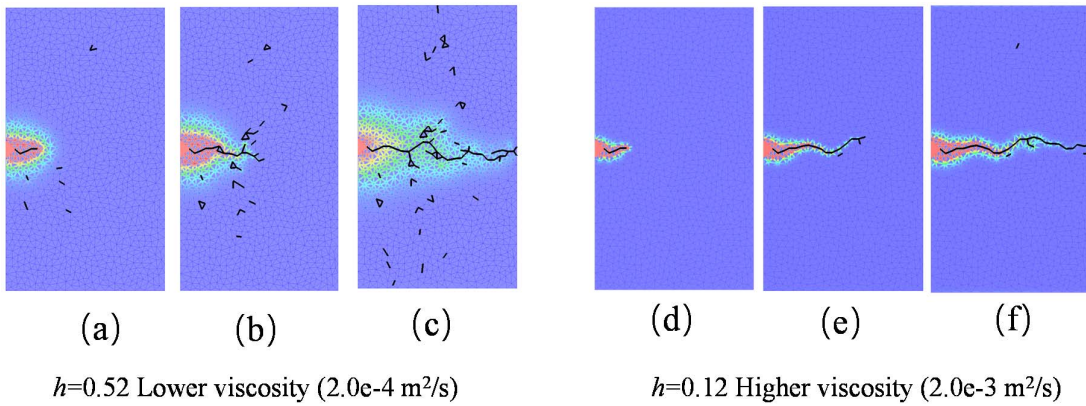


Figure 4. Pressure distribution in rock samples. (a), (b), (c) Evolving pressure distribution with time in highly heterogeneous rock ($h=0.52$) with low viscosity fluid ($2 \times 10^{-4} \text{ m}^2/\text{s}$), and (d), (e) and (f) are the evolving pressure distribution in homogeneous rock ($h=0.12$) with high viscosity fluid ($2 \times 10^{-3} \text{ m}^2/\text{s}$).

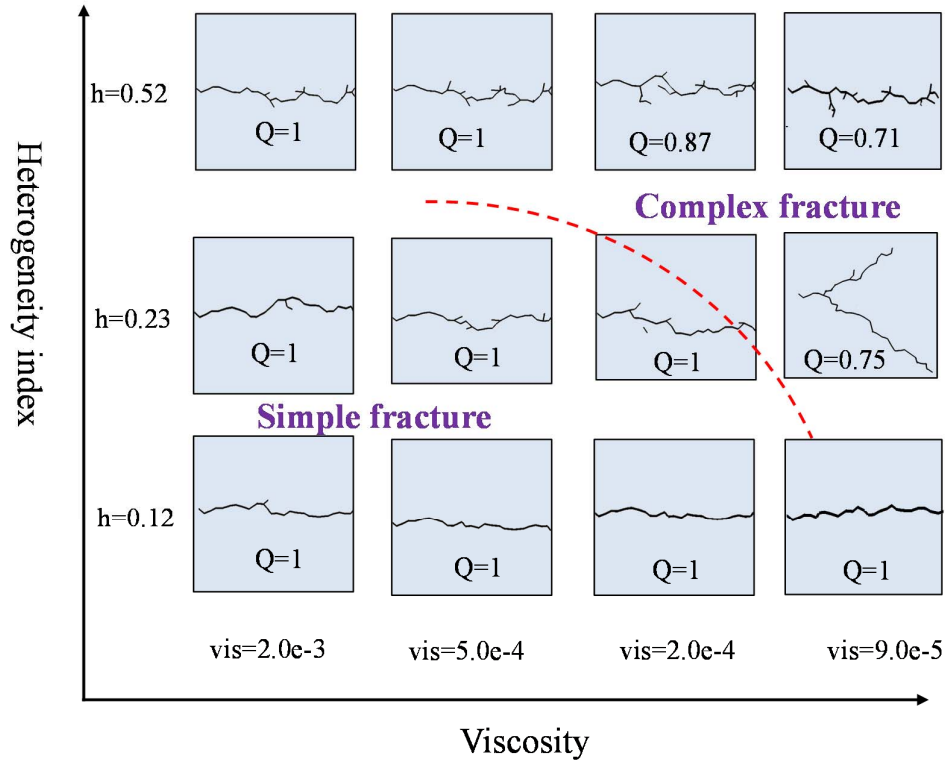
Low viscosity fluid readily penetrates into the rock matrix and elevates pore pressure around the main fracture (see Figure 4(a), (b) and (c)). In heterogeneous rock ($h=0.52$), the weak bonds close to the main fracture are readily broken by the high induced pore pressure (low viscosity injection), allowing the nucleation of cracks. These nucleated cracks connect to the main fracture and form a connective branch (see Figure 4(c)), generating the nucleus of a nascent complex fracture network. However, in homogeneous rock, bond strengths are uniformly distributed with no weak bonds

290 existing to form such crack nucleation and branches. Thus, although low viscosity fluid
291 can result in high pore pressures in homogeneous samples, the generation of complex
292 fracture networks is impeded.

293 In summary, it is the degree of heterogeneity of the rock that controls the impact of
294 fluid viscosity on the ensuing fracture complexity. In homogeneous samples, fluid
295 viscosity does not affect the fracture complexity, just as the prediction in continuum-
296 based models. However, in heterogeneous samples, a lower viscosity fluid results in the
297 development of more complex fracture networks - consistent with experimental
298 observations in real rock.

299 To probe the evolution of fracture complexity under different conditions, the
300 impacts of heterogeneity and viscosity are explored by systematically varying both
301 heterogeneity ($h=0.12, 0.23$ and 0.52) and viscosity ($v=2\times 10^{-3}$ m²/s, 5×10^{-4} m²/s, 2
302 $\times 10^{-4}$ m²/s and 9×10^{-5} m²/s) to explore the parameter space. Figure 5 is a regime map
303 showing fracture complexity (Q) as a function of that (h, v) parameter space. The
304 evolution of complex fractures fall at the intersection of the higher heterogeneity and
305 lower viscosity regions. Conversely, simple fractures evolve for the lower heterogeneity
306 and higher viscosity cases. For each heterogeneity index h , a critical viscosity exists,
307 below which the transition from a simple crack to a complex fracture network occurs.
308 This critical viscosity increases with an increase of the degree of heterogeneity of the
309 rock. Thus, if a complex hydraulic fracture network is desired then two key points
310 should be noted. First, a necessary condition exists such that the degree of heterogeneity
311 of the rock must be high - such as in reservoirs rich with natural fractures. And second,

312 networks of complex fractures are maximally promoted where a fracturing fluid with a
 313 low viscosity is utilized, such as in “gas fracturing”.



314
 315 Figure 5. Regime map showing the distribution of fracture complexity (Q) in a (h, γ) diagram.
 316 Complex fractures fall at the intersection of regions of high heterogeneity and low viscosity.
 317 Simple fractures are favored for reduced heterogeneity and elevated viscosity.

318 4. Conclusions

319 In this study, a grain-scale LBM-DEM coupled model is applied to simulate the
 320 evolution of hydraulic fractures with a focus on why different fluids result in different
 321 fracturing behaviors. To improve the accuracy of the hydrodynamic force calculation,
 322 an improved IMB method is applied. The fluid viscosity impacts fracturing behavior
 323 only through the level of heterogeneity of the rock. In homogeneous rock, fluid
 324 viscosity only impacts the breakdown pressure (low viscosity corresponding to low

breakdown pressure) to initiate a fracture, but exerts little influence on the ensuing fracture complexity (a similar simple fracture is induced no matter what kind of fluid is used). Conversely, in heterogeneous rock, fluid viscosity significantly impacts fracture complexity, with lower viscosity fluids resulting in more complex fracture networks. This is contributed by the presence of weak bonds (representing natural fractures or weak defects) present near the main fracture, which are easily broken by the invading high pore pressure and form discrete fracture branches. The low viscosity fluid promotes the ready buildup of pore pressures in the rock matrix enabling a complex fracture network to be more readily induced. A regime map showing the fracture complexity (Q) distribution in an (h , v) diagram is presented, which indicates that complex fracturing is promoted in the intersection of the low viscosity and high heterogeneity regions. Thus, rock properties (heterogeneity) and fluid properties (viscosity) are two key factors governing the evolution of fracture complexity during hydraulic fracture treatments. Thus, in unconventional reservoirs, the development of complex fracture networks from heterogeneous reservoirs probed by lower viscosity fluids may increase both the rate and absolute recovery of the hydrocarbon resource.

341

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345

Appendix

In this part, current hydro-mechanical coupled framework is validated, including lattice Boltzmann method in simulating the fluid flow, discrete element method in describing the fracturing behavior of rock and the improved immersed boundary method in calculating the hydrodynamic force.

A1.Validation of lattice Boltzmann method

To test the current LBM model, fluid flow in a two dimensional channel is simulated. The physical model is presented in Figure A1 (a), where L and H is the length and width of the channel respectively. A pressure difference ΔP is applied in the Y direction. In the equilibrium state, fluid velocity distribution in the X direction can be obtained analytically

$$u = \frac{1}{2\mu} \frac{\Delta P}{L} \left[\frac{H^2}{4} - \left(x - \frac{H}{2} \right)^2 \right]. \quad (A1)$$

Figure A1 (b) shows the comparison between the analytical solution and numerical results, and good agreement is obtained.

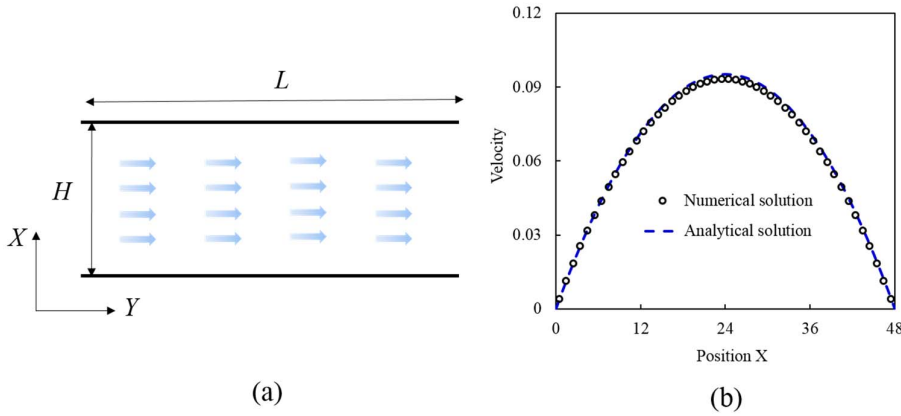


Figure A1. (a) Physical model of LBM simulation of fluid flow along 2 dimensionless channel, where L and H is the length and width of the channel respectively. A pressure difference is applied in Y direction to drive the fluid motion. (b) Comparison between analytical solution and numerical result, which shows that good agreement is obtained.

A2.Validation of discrete element method

To validate the current DEM model in capturing the fracturing behavior of rock, Brazilian test is simulated, where a disc sample, discretized into a collection of triangle particles (see Figure A2 (a)), is compressed along the direction parallel to its diameter.

Figure A2 (b) shows the disc is split into two halves along the diameter, which is the typical feature of Brazilian test. The stress-strain relation during the compression process is also recorded, and the slope and peak value in Figure A2 (c) corresponds to the elasticity modulus and tensile strength, respectively.

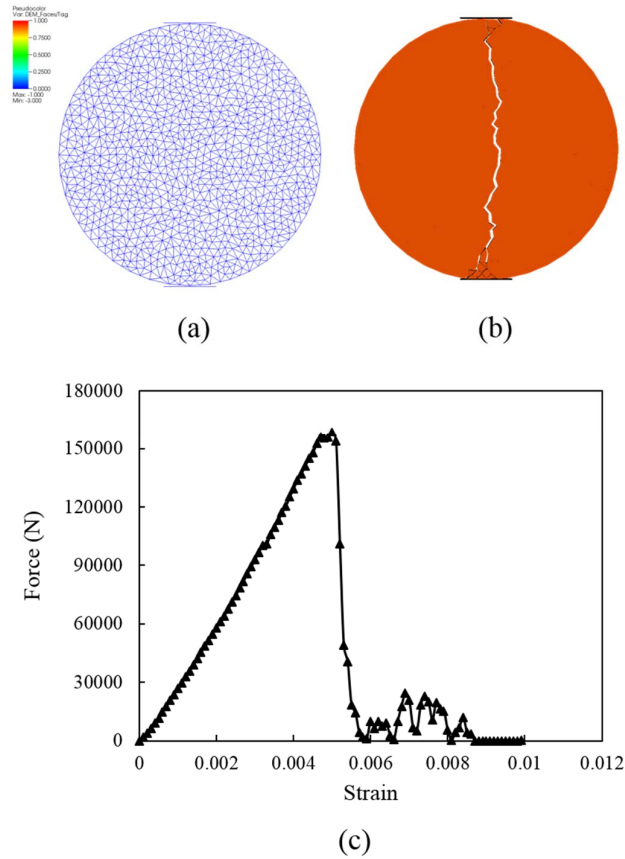
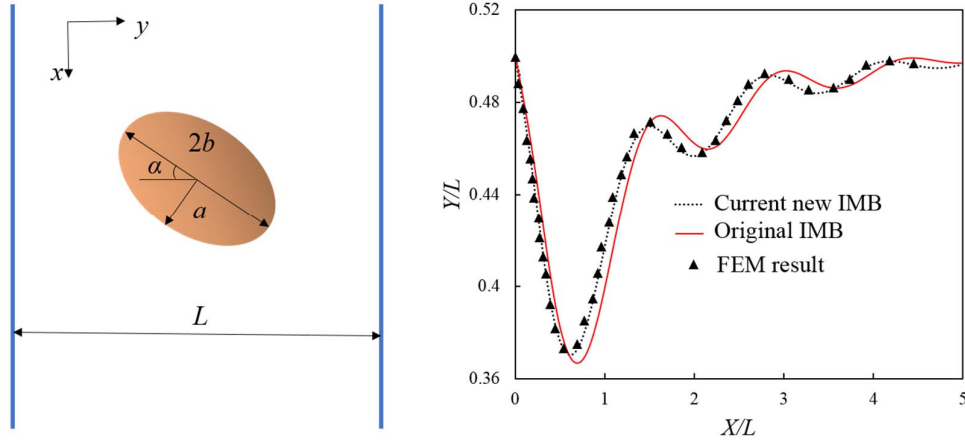


Figure A2. (a) Physical model of Brazilian test simulation, where the disc sample is discretized into a collection of triangle particles, which is compressed along the diameter. (b) The resulting fracture after the Brazilian test, which shows that current DEM model successfully capture the main feature of the fracturing behavior of rock. (c) Stress-strain relation during the compression process, where the slope and peak value corresponds to the elasticity modulus and tensile strength, respectively.

A3. Validation of improved immersed moving boundary

In hydro-mechanical coupled model, a key point is the accurate calculation of the hydrodynamic force imposed on the solid surface. In this part, a single elliptical particle sedimentation in the Newtonian fluid is simulated to validate current improved IMB method. The physical model is presented in Figure A3 (a), where a and b is the length of the semiminor and semimajor axis of the elliptical particle, respectively. The width

389 of channel is 0.4 cm , and the length is long enough (12 cm) to avoid the boundary
 390 influence. The particle is initially placed at the position ($1.2 \text{ cm}, 0.2 \text{ cm}$) with $\alpha=3\pi/4$.
 391 A constant gravity force in the x direction is applied on the particle, which determines
 392 the terminal particle Reynolds number ($Re=Vb/\nu$). In this case, the terminal particle
 393 Reynolds number is equal to 6.6. The particle trajectory obtained with different methods
 394 is shown in Figure A3 (b). Current model agrees well with the FEM results in Ref. [Xia
 395 *et al.*, 2009], but the deviation exists in previous one. Thus, current improved IMB
 396 model can give the accurate calculation of hydrodynamic force applied on the solid
 397 surface.



398
 399 Figure A3. (a) Physical model of an elliptical particle sedimentation in the Newtonian fluid,
 400 where a and b is the length of the semiminor and semimajor axis of the elliptical particle,
 401 respectively. A constant gravity force is applied on the particle to drive its motion in the x
 402 direction. (b) The particle trajectory obtained with different methods, which shows that current
 403 model agrees well with the FEM results in Ref. [Xia *et al.*, 2009], but the deviation exists in
 404 previous one.

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