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A Fracture Conductivity Model for Channel Fracturing and Its Implementation with Discrete Element Method

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Abstract: This paper introduces a new method to predict conductivity in channel fracturing by implementing analytical solution in Discrete Element Method (DEM). First, an analytical model for channel fracturing conductivity is proposed. Then, a DEM model calibrated by using experimental results is set up to investigate the deformation of proppant pillar. Finally, the analytical model of fracture conductivity is implemented in the DEM model to predict conductivity during fracture closing. Parametric analyses are carried out to understand the effects of four factors: proppant size combination, concentration, time ratio $\tau$ and elastic modulus to stress ratio $\lambda$. Conductivity generally decreases during fracture closing and increases with the increasing proppant size and proppant concentration. The ratio of the pulsing time of proppant laden fluid to the pulsing time of the clean fluid is the key parameter for the field operation. A large time ratio could enhance the pillar stability though it may lead to the damage of fracture conductivity. For given rock modulus, closing stress and proppant size, the optimal range of time ratio can be given as a guidance for field operation. The field application of channel fracturing in the Shengli Oilfield proves that the optimized range of time ratio $\tau$ based on the proposed theoretical model is valid. The porosity of proppant pillar first decreases due to compression and then increases during fracture closing period because of the breakdown of the proppant pillar and the resulted particle movement outward. This paper gives insights for understanding the channel fracture conductivity and provides a practical tool for the optimization of channel fracturing design in the field.

Keywords: channel fracturing; proppant pillar; fracture conductivity; optimization; Discrete Element Method
List of Symbols

\( \tau \) The ratio of the pulsing time of proppant laden fluid to the pulsing time of clean fluid, dimensionless

\( \rho_s \) Pillar density, kg/mm\(^3\)

\( \rho_{pf} \) Density of proppant laden fluid, kg/mm\(^3\)

\( \mu \) Fluid dynamic viscosity, Pa·s

\( \phi \) Pillar porosity, dimensionless

\( \eta \) Effective porosity rate, dimensionless

\( N \) Perforation number, dimensionless

\( r \) Pillar radius, mm

\( d_{ave} \) Average diameter of proppants, mm

\( k_p \) Pillar permeability, mm\(^2\)

\( k_f \) Channel permeability, mm\(^2\)

\( k_i \) Permeability of area i, mm\(^2\)

\( k_0 \) Fracture permeability in channel fracturing, mm\(^2\)

\( Q \) Flow rate of fracturing fluid, mm\(^3\)/s

\( Q_i \) Flow rate of area i, mm\(^3\)/s

\( t_p \) Pulsing time of proppant laden fluid, s

\( t_f \) Pulsing time of clean fluid, s

\( t_{tot} \) Duration of one pulsing period, s

\( w_0 \) Initial fracture aperture, mm

\( w_f \) Fracture aperture, mm

\( l \) Length of channel fracture, mm

\( A_i \) Cross-section area of strip i, mm\(^2\)

\( \Delta p \) Pressure drop in pillar, Pa

\( \Delta p_i \) Total pressure drop for strip i, Pa

\( x \) Pillar length along x axis, mm

\( \Delta y_i \) Width of strip i, mm

\( E_c \) Apparent modulus in DEM, GPa

\( k_n \) Contact normal stiffness in DEM, N/m

\( k_s \) Contact shear stiffness in DEM, N/m

\( k^n \) Parallel bond normal stiffness in DEM, Pa/m

\( k^s \) Parallel bond shear stiffness in DEM, Pa/m

\( D \) Particle diameter in DEM, mm

\( K \) Conductivity, \( \mu \)m\(^2\)·cm

\( E \) Rock elastic modulus, GPa

\( \sigma \) Closing stress, MPa

\( \lambda \) The ratio of rock elastic modulus to closing stress, dimensionless
1 Introduction

In the past few years, channel fracturing has become an attractive completion technique in the oil and gas industry. Channel fracturing is firstly proposed by Gillard et al. (2010) and is mainly composed of three technical components, i.e., the pulse pumping technique, the multi-cluster perforating process, and the injection of fracturing fluid mixed with fibers. Fibers are added to proppant laden fluid to keep proppant pulses cohesive and prevent them from spreading when traveling through fracture slots. Proppant laden fluid and clean fluid are alternately injected into the rock formation with respectively specified amount of time to create proppant pillars. In the fracturing fluid flowback process, the void space between proppant pillars forms the highly conductive fluid channels which greatly improve the overall fracture conductivity during the production period.

The channel fracturing technique was first used to stimulate twelve full horizontal wellbores in the Eagle Ford formation in Hawkville field in October 2010. Production data indicated a 46% increase of condensate production (Rhein et al. 2011). Later applications of channel fracturing in Burgos basin, Talinskoe oilfield, Egyptian western desert, Taylakovskoe oil field, Ordos Basin, South East Kuwait, Barnett Shale, further confirmed the feasibility of this technique which managed to save 43% of proppant usage by average (Valenzuela et al. 2012; Kayumov et al. 2012; Gawad et al. 2013; Valiullin et al. 2015; Li et al. 2015; Gazi et al. 2016; Samuelson et al. 2012; Medvedev et al. 2013). Application of channel fracturing in tight oil and gas reservoirs in Ordos Basin, China produced 2.4 times as much oil and 4 to 5 times as much gas as conventional fracturing did (Li et al. 2015).

Discrete pillars created by channel fracturing set a totally different transportation pattern for proppants and hydrocarbons from conventional fracturing, to which conventional theoretical models to study proppant embedment and conductivity are no longer applicable. In recent years, a number of studies were carried out to investigate the mechanism of channel fracturing. Gillard et al. presented a laboratory study on channel fracturing conductivity and the results showed that the permeability of channel fracturing fractures was 1.5 to 2.5 orders higher than that of conventional fracturing fractures (Gillard et al. 2010). Nguyen et al. conducted a series of experiments to study the stability of proppant pillars (2014). A fast compression stage could be observed in stress-strain curves of proppant pillars. Zhang et al. studied proppant embedment and conductivity by using surface modification agent (SMA) treated proppants for both traditional and channel fracturing (Zhang 2014; Zhang and Hou 2016). Yan et al. developed an analytical model to represent the physical deformation of channel-fracturing fractures and Darcy-Brinkman equation was applied to simulate flow in pillars and fluid channels (Yan et al. 2016). Zheng et al. derived the formula of fracture conductivity based on Hertz contact theory and analyzed the effects of proppant distribution density and proppant pillar radius on fracture conductivity (Zheng et al. 2017). Hou et al. used Kelvin-Voigt model to describe the viscoelastic deformation of proppants and rock based on
theoretical models proposed by Li et al. (Hou et al. 2016; Li et al. 2015). Guo et al. established an analytical model to describe fracture aperture change and conductivity for cuboid shaped pillars (Guo et al. 2017). Most of the above studies were conducted on the basis of classical Hertz contact theory. But few of them paid attention to fracture deformation when calculating the fracture aperture. More importantly, proppant pillars were hypothetically deemed as a continuum by using Hertz contact theory. The microstructure, as well as the mechanical properties of proppant pillar may change dramatically under increasing loadings with the given nature of porous media. As one of the key factors in investigating channel fracturing conductivity, the constitutive behavior of proppant pillars is not properly realized in these studies.

Hou et al. assumed that proppant pillars were standard cylindrical indenters based on Hertz contact theory (Hou et al. 2016). Pillar spacing and pulsing time were used to optimize the residual fracture aperture. Meyer et al. presented a solution methodology for designing open channels and for flow around pillars in propped fractures (Meyer et al. 2014). Conductivity were formulated for different types of channel based on analysis of half-space loading property. These two solutions took fracture deformation into consideration, which was ignored in studies mentioned before. But proppant pillars were assumed to be rigid body. This assumption, contradictory with the physical reality, may result in inaccuracy when pillar deformation plays a major role during fracture closing.

Discrete Element Method (DEM) was first proposed by Cundall and Strack to study the mechanical characteristics of rock and soils (Cundall and Strack 1979). In Recent years, it has been widely used to study the mechanism of hydraulic fracturing (Zhou et al 2015a, Zhou et al 2015b b, Zhang et al. 2017), however, the application of DEM on proppant conductivity is less often seen. The first DEM study of proppant stability can be traced back to 1995. Asgian et al. first used DEM to study the mechanism of proppant backproduction in hydraulic fracturing (Asgian et al. 1995). Later, Deng et al. proposed a DEM model to investigate the shale–proppant interactions and evaluate the fracture aperture under different proppant sizes, Young’s moduli and pressure levels (Deng et al. 2014). Zhang et al. developed an integrated DEM-CFD modeling work flow to model proppant embedment and fracture conductivity (Zhang et al. 2017). Bolintineanu et al. studied the effects of proppant packings on porosity, permeability and conductivity by using DEM (Bolintineanu et al. 2017). Zhu et al. (2018) simulated the deformation and stability properties of proppant pillar during flowback with DEM-CFD coupling method. The effects of fibers are modeled by implementing the bonded particle model. Several phenomena are observed with relation to flow and proppant pillar distribution, which promotes current understandings for channel fracturing.

Various analytical models have been proposed to predict the change of fracture opening and conductivity for channel fracturing. But few of them investigated the constitutive characteristics of proppant pillar. Pillar deformation was calculated by taking a pillar as an entity instead of an assembly of particles. In this study, we firstly propose an analytical model.
2 An analytical model of channel fracturing conductivity

Figure 1 plots the schematic of pillars and fluid channels of channel fracturing. The yellow quarter disks represent the proppant pillars and the rest of the area in the plot represents the fluid channels, assuming that proppant pillars are arranged in the matrix form with uniform spacing. The pumping schedule of channel fracturing alternates the proppant laden fluid pulse and the clean fluid pulse. According to Zheng et al. (2017), for a proppant laden fluid pulse, the following equation can be derived,

\[ \pi r^2 w_0 \rho_s = \frac{t_p Q \rho_{pf}}{N \eta} \]  

where \( r \) is pillar radius, mm; \( w_0 \) is initial fracture aperture, mm; \( \rho_s \) is pillar density, kg/mm\(^3\); \( t_p \) is the pulsing time of proppant laden fluid, s; \( Q \) is flow rate (constant in both proppant laden stages and clean fluid stages), mm\(^3\)/s; \( \rho_{pf} \) is the density of proppant laden fluid, kg/mm\(^3\); \( N \) is perforation number, dimensionless; \( \eta \) is the effective perforation rate, dimensionless.

Considering that the proppant laden fluid is incompressible, it’s reasonable to assume that pillar density \( \rho_s \) is equal to the density of proppant laden fluid \( \rho_{pf} \). Eq. (1) is then rewritten as,

\[ \pi r^2 w_0 = \frac{t_p Q}{N \eta} \]  

A similar relationship can be found in one pulsing period,
where \( l \) is the length of a channel fracture in Figure 1, \( mm \); \( t_{\text{tot}} \) is the duration of one pulsing period, \( s \); \( t_{\text{i}} \) is the pulsing time of clean fluid, \( s \).

Combining Eqs. (2) – (4), in one pulsing period, the ratio of the pulsing time of proppant laden fluid to the pulsing time of the clean fluid is expressed as,

\[
\tau = \frac{\tau_p}{\tau_f} = \frac{\pi (r/l)^2}{1 - \pi (r/l)^2}
\]  

where \( r/l \) lies in the range of \([0, 0.5]\). 

\( r/l \) is an index for the stability of proppant pillars. If \( r/l \) is too small, the fracture might not be effectively propped and the fracture conductivity cannot be sustained. On the other hand, if \( r/l \) is too larger, the fracture is effectively propped by pillars, but the fracture conductivity can be limited due to narrow fluid channels. An optimized time ratio \( \tau \) then can be obtained, which meets the requirement of proppant stability but also gives the maximum fracture conductivity.

The permeability of proppant pillar and fluid channel can be calculated separately. The permeability of proppant pillar \( k_p \) is calculated based on Kozeny-Carman formula in Eq. (6) and the permeability of fluid channel \( k_i \) is calculated using the parallel plate model in Eq. (7) (Gillard et al. 2010; Bear 1972). Both pillar porosity \( \phi \) and fracture aperture \( w_f \) in Eq. (6) and Eq. (7) need to be obtained from numerical simulation.

\[
k_p = \frac{d_{\text{ave}}^2 \phi^3}{180(1 - \phi)^2}
\]  

\[
k_i = \frac{w_f^2}{12}
\]

where \( k_p \) is proppant pillar permeability, \( mm^2 \); \( k_i \) is fluid channel permeability, \( mm^2 \); \( d_{\text{ave}} \) is the average diameter of proppants, \( mm \); \( \phi \) is pillar porosity, dimensionless; \( w_f \) is fracture aperture, \( mm \).

The schematic plot in Figure 1 can be further divided into four equal pieces. We further take one piece as a calculation unit. As shown in Figure 2, the seepage area is cut into small strips. Zheng et al. (2017) derived fracture permeability by ignoring the pressure drop of fluid channel in strips. Here we consider the pressure drop for both proppant pillars and fluid channels. Applying Darcy’s law to the strip \( i \) in Figure 2, we can get the following relationship,
where \( Q_i \) is the flow rate of strip \( i \), mm\(^3\)/s; \( k_i \) is fracture permeability, mm\(^2\); \( A_i \) is the cross-section area, mm\(^2\); \( \mu \) is fluid dynamic viscosity, Pa·s; \( \Delta P_p \) is pressure drop in pillar, Pa; \( \Delta p \) is the total pressure drop for strip \( i \), Pa; \( x \) is pillar length along \( x \) axis, mm; \( l/2 \) is the length of strip \( i \) and half fracture length in Figure 1, mm.

The permeability of strip \( i \) is rewritten as,

\[
k_i = \frac{k_p k_i l}{k_p l + 2(k_i - k_p)x}
\]  

Thus the permeability of channel fracture is expressed by using integration,

\[
k_0 = \sum_{i=1}^{n} k_i \frac{\Delta y_i}{l/2} = \int_0^l \frac{2k_p k_i}{k_p l + 2(k_i - k_p)x} dy
\]

where \( \Delta y_i \) is the width of strip \( i \), mm; \( k_0 \) is channel fracture permeability, mm\(^2\).

When \( y > r, x = 0 \). Therefore, the fracture permeability is rewritten as
Accordingly, the channel fracture permeability $k_0$ can be calculated from Eq. (11), where $k_p$ and $k_i$ are determined from Eq. (6) and Eq. (7), respectively.

### 3. Implementation of channel fracturing conductivity model with DEM

#### 3.1 DEM model setup

DEM models the movement and interaction of particles in granular material. Physical properties of particles are predetermined by assigning micro-parameters like stiffness and bond strength for particles and contact nodes between them. These micro-parameters can be then adjusted to reproduce the macroscopic properties of granular material (Cundall and Starfield 1979, Potyondy and Cundall 2004).

Figure 3 shows the numerical model for studying channel fracturing based on DEM. The upper and lower shale plates are composed of blue particles arranged in a body-centered structure, while the proppant pillar is composed of particle assembly in yellow. Two plates are loaded with up to 50 MPa stress to model fracture closing and pillar deformation.

![Figure 3 DEM model for channel fracturing](image-url)

(1) Rock property calibration

The model is benchmarked by comparing the experimental results and DEM modeling results of triaxial tests, as shown in Figure 4. Rock cores from Shengli oilfield, China are processed into 9 samples with diameter of 25 mm and height of 50 mm. Triaxial tests are carried out on 9 rock core samples using RTR-1000 triaxial testing system. Results show rock
elastic modulus of 28.6-40.9 GPa, Poisson's ratio of 0.25-0.28 and compressive strength of 200.7-230.2 MPa.

Table 1 lists the micro-scale parameters used in numerical triaxial tests. The bonded particle model (Potyondy and Cundall 2004) is implemented to simulate the rock material. Since the modulus and strengths of rock can be independent of the particle size in DEM, rock particles are generated in same radius of 0.2 mm to achieve effective computation (Ma and Huang 2018a). The same micro-scale parameters are used in the following sections for numerical investigations.

**Figure 4** Stress-strain curves of X23 sample from laboratory triaxial test and DEM triaxial test

| Micro-parameters | Linear contact | Parallel bonds |
|------------------|----------------|----------------|
| Apparent modulus | $E_c$/GPa      | 5.7            |
| Normal stiffness | $k_n$/(N/m)    | 2.6$k_s$       |
| Shear stiffness  | $k_s$/(N/m)    | 2DE$_c$        |

Table 1 Micro-scale parameters of rock

(2) Proppant pillar property calibration
Fibers used in proppant-laden fluid increase the inter-particle cohesion and friction, which can enhance the stability of proppant pillars and resist the fracture closing. In order to include this effect, proppant particles are allowed to bond with each other, similar with the rock material. The microscale parameters for proppant particles in the DEM model are calibrated by comparing the experimental results and DEM modeling results of proppant pillar compression. Figure 5 shows proppant pillar in experiment, made up with Combo proppants and short fibers, and proppant pillar in DEM modeling. Table 2 lists the microscale parameters for proppant particles after the calibration (see Figure 6).

It should be noted that, in Figure 6, the initial quick drop of the curves in the experiments might be related to the initial loose packing state, while the numerical curves appear to be smoother. Though results from simulation are different from experimental results when the closing stress is less than 10 MPa, it shows good agreement with experimental results under high stresses. Since the real underground stress is rather high, the stress-strain relationship of proppant pillar under high stresses, which is well calibrated, is the key factor that determines the effectiveness of calibration.

![Figure 5](image-url) (a) proppant pillar in experiment, (b) proppant pillar in DEM modeling

| Size combination | 40/70 | 30/50 | 20/40 |
|------------------|-------|-------|-------|
| Micro-parameters |       |       |       |
| Linear contact   |       |       |       |
| Apparent modulus | $E_c$/MPa | 85 | 85 | 85 |
| Normal stiffness $k_n/(N/m)$ | $2DE_c$ |       |       |       |
| Shear stiffness $k_s/(N/m)$ | $k_a$ |       |       |       |
| Parallel bonds   |       |       |       |
| Apparent modulus | $E_c$/MPa | 85 | 85 | 85 |
| Normal stiffness $\bar{k}^n/(Pa/m)$ | $E_c/D$ |       |       |       |
| Shear stiffness $\bar{k}^n/(Pa/m)$ | $\bar{k}^n$ |       |       |       |
| Normal bond strength | 500 |       |       |       |
Shear bond strength /MPa

500

Radius multiplier

1

Friction

0.9

Density /(kg/m³)

2650

Particle radius (D/2)/mm

| 0.21-0.42 | 0.3-0.6 | 0.42-0.84 |

Figure 6 Comparison between numerical and experimental testing results for pillar compression

3.2 Acquisition of porosity and fracture aperture

While fracture permeability can be calculated from Eq. (11), pillar porosity and fracture aperture need to be obtained from DEM simulation in advance.

(1) Acquisition of proppant pillar porosity

During the fracture closing process, proppant pillar porosity changes with increasing stress. The “measurement sphere” logic is applied to log the pillar porosity. The measurement sphere needs to be larger enough to be a representative element volume but also small enough to maintain the accuracy. Meanwhile, the size of the measurement sphere should also be smaller than the aperture after the closing so that no particle from the rock plate is included in the measurement sphere. Thus, the size of the measurement sphere is set to be 7 times particle size. Figure 7 shows a total of 81 small measurement spheres in the proppant pillar for logging pillar porosity in this DEM investigation.
Figure 7 Placement of 81 small measurement spheres in the pillar, (a) top view, and (b) lateral view

(2) Acquisition of fracture aperture

Figure 8 shows some particles on the fracture walls that are used tracking spots for logging the fracture aperture width. Figure 9 shows aperture distribution along the fracture wall at the closing stress of 41.4 MPa for three proppant concentrations. As expected, apertures near the center of plate (where fracture is supported by the proppant pillar) tend to be larger than those at the far ends of plate (where flow channel lies). In this study, we chose the fracture apertures measured at the far ends of plate for any calculation.

Figure 8 Particles for logging fracture apertures along fracture wall
Figure 9 Aperture distribution along the fracture wall (under 41.4 MPa stress)

3.3 Calculation of fracture conductivity

After gaining the porosity and fracture aperture from DEM simulation, Eq. (6) and Eq. (7) are solved to get pillar permeability $k_p$ and channel permeability $k_f$ and therefore channel fracture permeability $k_0$ can be calculated by using Eq. (11). Finally, the fracture conductivity is calculated as follows,

$$K = k_0 w_f$$

where $K$ is fracture conductivity, $\mu m^2$·cm.

4 Parametric analysis of channel fracture conductivity

4.1 Effect of proppant size combination

Figure 10 shows the proppant pillar porosity and fracture aperture at different closing stress for three proppant size combinations, 20/40 mesh, 30/50 mesh and 40/70 mesh. The proppant concentration is 8 kg/m$^3$ for all three cases. The height and diameter of the proppant pillar are 6 mm and 10 mm, respectively. The elastic modulus of the reservoir rock is 32 GPa. The same proppant pillar size and reservoir rock elastic modulus are applied to all cases in this study unless specifically mentioned. It can be seen that all three cases have the same U shape curves indicating that the proppant pillar porosity decreases first and then increases with the closing stress. The 20/40 mesh case has the most reversing trend of porosity change while the 40/70 mesh has the least. As the closing stress increases, the fracture aperture gradually decreases. Smaller proppant size has larger aperture decrease during closing, consistent with the results of uniform layer of proppant (Zhang et al. 2017).
Figure 10 Proppant pillar porosity and fracture aperture at different closing stress for three proppant size combinations, 20/40 mesh, 30/50 mesh and 40/70 mesh

Figure 11 shows the fracture conductivity, calculated based on Eq. (12), at different closing stress for three proppant size combinations. The 20/40 mesh case has the largest aperture after closing, therefore it has the largest $k_f$ based on Eq. (7). Meanwhile, although Figure 10 shows that the proppant pillar porosity with 20/40 mesh is slightly smaller than the other two cases at closing stress below 18 MPa, with the advantage of larger particle size, it still keeps the largest $k_p$ based on Eq. (6). Thus, similar to the conventional fracturing method with uniform layer of proppant, large proppant size leads to better fracture conductivity after closing.

Figure 11 Fracture conductivity at different closing stress for three proppant size combinations, 20/40 mesh, 30/50 mesh and 40/70 mesh
4.2 Effect of proppant concentration

Figure 12 shows the proppant pillar porosity and fracture aperture at different closing stress for three proppant concentrations, 6 kg/m³, 8 kg/m³, and 10 kg/m³. All three cases have the same proppant size of 20/40 mesh. With the same size of proppant pillar, the case with 6 kg/m³ has the loosest initial proppant pack and the case with 10 kg/m³ has the densest initial proppant pack. The proppant pillar porosity for all three cases has the similar decreasing to increasing transition as the closing stress gradually increases. The fracture for these three cases decreases rapidly initially and levels off as the closing stress increases. The aperture difference among these three cases increases first due to the varied compaction and decreases towards the end of the loading. The aperture difference between 10 kg/m³ and 8 kg/m³ is 0.82 mm with the closing stress of 10 MPa, and reduces to 0.39 mm at the end of the loading with the closing pressure of 41.4 MPa.

Figure 12 Proppant pillar porosity and fracture aperture at different closing stress for three proppant concentrations, 6 kg/m³, 8 kg/m³, and 10 kg/m³

Figure 13 shows that the fracture conductivity for these three cases decreases quickly at the early stage of the loading, due to the fact that both fracture aperture and proppant pillar porosity experience a rapid decrease. When the closing stress rises from 5 MPa to 10 MPa, the fracture conductivity with the proppant concentration of 6 kg/m³, 8 kg/m³, and 10 kg/m³ decreases by 52.3%, 53.5%, and 52.4%, respectively. After the closing stress exceeds 30 MPa, the fracture conductivity levels off, despite that the proppant pillar porosity changes from decreasing to increasing. It can be concluded that the aperture change contributes more to the fracture conductivity than the proppant porosity change.
Figure 13 Fracture conductivity at different closing stress for three proppant concentrations, 6 kg/m$^3$, 8 kg/m$^3$, and 10 kg/m$^3$.

### 4.3 Effect of time ratio $\tau$

To investigate the effect of time ratio $\tau$ on the fracture conductivity, a series of tests with $\tau$ ranging from 0.03 to 1.01 are carried out. The initial proppant pillar height is assumed to be 6 mm, the proppant pillar radius varies for different $\tau$. The proppant concentration is 8 kg/m$^3$ for all cases. Figure 14 plots the proppant pillar porosity and cumulative parallel bond failures versus closing stress for different $\tau$. With the increase of closing pressure, the porosity of proppant pillar decreases first and then increases. The bigger the $\tau$, the less of the porosity change reversing. The number of parallel bond failures also decreases dramatically with the increase of $\tau$. As expected, the plot of fracture aperture versus closing stress for different time ratio $\tau$ (Figure 15) shows that larger $\tau$ leads to less closing of fracture aperture. The fracture aperture converges to the value for conventional fracturing when uniform layer of proppant is applied.
Figure 14 Proppant pillar porosity and cumulative parallel bond failures versus closing stress for different time ratio $\tau$

Figure 15 Fracture aperture versus closing stress for different time ratio $\tau$

Figure 16 shows the fracture conductivity versus time ratio $\tau$ for different closing stress. The fracture conductivity in general increases with the decrease of fracture closing stress. For the given closing stress, the fracture conductivity increases first with the time ratio $\tau$ and turns to decrease later on as $\tau$ further increases. The reason is that although larger $\tau$ can lead to larger aperture as shown in Figure 15, the decrease of fluid channel width could damage more of the overall fracture conductivity. The peak of fracture conductivity lies at about $\tau = 0.75$. The results suggest that the optimized range of $\tau$ is about [0.5, 1.2].
4.4 Effect of elastic modulus to closing stress ratio

The ratio of elastic modulus of reservoir rock to closing stress is used as an index to evaluate the feasibility of channel fracturing.

\[ \lambda = \frac{E}{\sigma} \]  

(13)

The effect of elastic modulus to closing stress ratio \( \lambda \) on the fracture conductivity is studied by varying the elastic modulus of the reservoir rock and the fracture closing pressure. Figure 17 plots the fracture aperture versus ratio \( \lambda \) for different reservoir rock elastic modulus. The fracture closing stress is 41.4 MPa. The proppant size is 20/40 mesh and the proppant concentration is 8 kg/m\(^3\). For the same \( \lambda \) value, the larger the reservoir rock elastic modulus, the larger the closed pressure, the smaller the fracture aperture. The plot of fracture conductivity versus ratio \( \lambda \) for different rock elastic modulus (Figure 18) shows that the fracture conductivity increases as \( \lambda \) increases, and the fracture conductivity change is more sensitive to smaller elastic modulus.
Figure 17 Fracture aperture versus ratio $\lambda$ for different reservoir rock elastic modulus

Figure 18 Fracture conductivity versus ratio $\lambda$ for different reservoir rock elastic modulus

Figure 19 and Figure 20 plot the fracture aperture and fracture conductivity, respectively, at different ratio $\lambda$ and different closing stress. According to the Eq. (13), with the same closing stress, the increase of $\lambda$ means the increase of the elastic modulus of the rock. Both fracture aperture and fracture conductivity increase slightly with the increase of elastic modulus. It indicates that stiffer reservoir rock leads to larger fracture aperture after closing. This observation is consistent with the study of Deng et al. (2014).
5 Discussions

5.1 Evolution of proppant pillar porosity

The proppant pillar porosity during fracture closing generally decreases initially but tends to increase as the closing stress further increases. To investigate the evolution of proppant pillar porosity during fracture closing, parametric study of proppant particle bonding strength is carried out, which can be viewed as effectively varying the fiber strength. Figure 21 plots the proppant pillar porosity and cumulative parallel bond failures at different closing stress for four bonding strength, 50 MPa, 70 MPa, 80 MPa and 500 MPa. The proppant concentration is 8 kg/m³. The bond between two neighboring proppants will sustain the
applied force until the force exceeds the bond strength, which may lead to bond failure and form microcracks. The results in Figure 21 reveals the link between the proppant pillar stability, indicating by the number of bond failures, with the porosity increasing at the later stage of the loading.

![Figure 21](image)

**Figure 21** Proppant pillar porosity and cumulative parallel bond failures at different closing stress for four bonding strength, 50 MPa, 70 MPa, 80 MPa and 500 MPa

Figure 22 shows the profile of proppant pillar for the bond strength of 50 MPa and 500 MPa with bond failures displayed in pink and blue. Though whether parallel bond fails in tension or in shear does not directly correlate with a tensile or shear failure mechanism at the macro-scale, the parallel bond failures show micro-scale failure mechanism for pillars (Ma and Huang 2018b). A large number of bond failures occur between the proppant particles when the bond strength is small. And particles move outward and spread in a larger crossing section area. This can explain the decreasing to increasing transition of porosity as the closing stress is large enough to lead to the breakdown of the proppant pillar. The same explanation can be applied to the effect of $\tau$ on the porosity change as shown in Figure 14. Larger $\tau$ leads to larger diameter of the proppant pillar, thus the pillar becomes more stable and can maintain the integrity at the end of the loading. As a result, the cases with larger $\tau$ do not have the porosity increasing at the later stage of the loading.
Figure 22 Profile of proppant pillar under the fracture closing stress of 41.7 MPa, (a) 50 MPa bonding strength, and (b) 500 MPa bonding strength; the pink and blue segments represent the tensile and shear failures, respectively

5.2 Consideration of selecting $\tau$ in the field

The above analysis indicates that the time ratio $\tau$ is the key parameter for fracturing design for field application of channel fracturing. For given rock modulus, closing stress and proppant size, the relationship between fracture conductivity and time ratio $\tau$ can be calculated by the proposed model in this study. Thus, the optimal range of $\tau$ can be given as a guidance for field operation. In field practice, however, the arrangement and shapes of proppant pillars might not be as ideal as assumed in the model. Consequently, a slightly larger value of $\tau$ is recommended to better maintain the proppant pillar stability.

It was pointed out that if the ratio $\lambda$ is less than 275, the reservoir is not suitable for channel fracturing technology (Schlumberger 2012). In order to evaluate the reliability of this criterion, we calculate relationship between conductivity and time ratio $\tau$ for different $\lambda$, as shown in Figure 23. The results show that for small elastic modulus of rock (e.g., $E = 16$ GPa in Figure 23(a)), the fracture conductivity is not negligible when $\lambda = 100$ or 200 and channel fracturing might still be feasible.
5.3 Analysis of field application of channel fracturing

Channel fracturing was tested in the A11 block of Shengli Oilfield of China and compared with the conventional fracturing technique. A total of three conventional fracturing wells and four channel fracturing wells were completed. The thickness of the reservoir layer in the A11 block is 32.5-51.5 m. The reservoir pressure coefficient is 1.47-1.64 g/cm³, the permeability is 12.3-23.2 mD, and the porosity is 2.80%-16.10%. The minimum principal stress is 49-56 MPa, the elastic modulus is 34 MPa, and the Poisson’s ratio is 0.28. In the channel fracturing treatment, the pump injection rate was 5-6 m³/min and the total injection time was 75 minutes. The single pulse pumping time with 30/50 mesh proppant is 2-2.3 min and the pumping time without proppant is 1.8-2 min. The detailed parameters for the seven wells are listed in Table 3.
Table 3 Parameters of three conventional fracturing wells and four channel fracturing well in the A11 block of Shengli Oilfield

| Well id | Fracturing Type | Depth /m | Pay zone depth /m | Pressure Coefficient g/cm³ | Minimum horizontal stress MPa | Permeability /10⁻³ µm² | Porosity | t₁ /min | t₂ /min | Proppant mass /m³ | λ | τ |
|---------|----------------|----------|--------------------|-----------------------------|-------------------------------|------------------------|----------|---------|---------|-----------------|---|---|
| A11-X1  | Conventional   | 3578.0-3 670.0 | 30.2 | 1.48 | 50 | 23.2 | 10.20% | 90 | 680 |
| A11-X5  | Conventional   | 3636.8-3 766.0 | 36.6 | 1.47-1.64 | 51 | 6.7 | 10.20% | 80 | 667 |
| A11-X7  | Conventional   | 3676.5-3 719.1 | 30.3 | 1.47-1.64 | 51 | 12.3 | 10.20% | 82 | 667 |
| A11-X2  | Channel        | 3612.4-3 812.8 | 23.9 | 1.48 | 52 | 5.3 | 10.20% | 2.04 | 1.82 | 52.7 | 654 | 1.12 |
| A11-X3  | Channel        | 3531.8-3 814.3 | 37.6 | 1.47-1.64 | 49 | 15.0 | 2.80%-16.10% | 2 | 1.8 | 36.6 | 694 | 1.11 |
| A11-X4  | Channel        | 3587.4-3 883.0 | 30.7 | 1.47-1.64 | 50 | 18.0 | 2.80%-16.10% | 2 | 1.8 | 52.8 | 680 | 1.11 |
| A11-X6  | Channel        | 3546.4-3 621.3 | 32.5 | 1.47-1.64 | 56 | 15.5 | 10.20% | 2.23 | 2 | 41 | 607 | 1.12 |
Figure 24 compares the cumulative oil production of channel fracturing wells and conventional fracturing wells in the A11 block. The channel fracturing wells generally exhibit significantly higher production rate than conventional fracturing wells. The average 90-day oil production, 180-day oil production, and 360-day oil production increase 262%, 274%, and 294%, respectively, compared with the conventional fracturing wells. At the same time, the average growth rates of conventional fracturing wells from 90 days to 180 days and from 180 days to 360 days are 48.4% and 53.3%, respectively, while the average growth rates in channel fracturing wells are 53.2% and 58%, which indicates that the fracture conductivity of channel fracturing is more effective than conventional fracturing. For the A11-X2 well with the lowest reservoir permeability, the channel fracturing has also achieved great success. The 360-day cumulative oil production is 2.5 times larger than that of the conventional fracturing well A11-X5. The time ratio $\tau$ of the channel fracturing in the A11 block is between 1.11 and 1.13, which falls into the optimized range recommended based on the proposed theoretical model in this work.

Figure 24 Comparison of cumulative oil production for three conventional fracturing wells and four channel fracturing wells in the A11 block of Shengli Oilfield

6 Conclusions

In this study, an analytical model for channel fracturing conductivity is proposed by regarding pillar and channel as two different flow media. The analytical solution is then implemented in DEM modeling, which is capable of accounting for fracture closing and pillar deformation. During the fracture closing process, the proppant pillar porosity first decreases due to compression and then increases due to the breakdown of the proppant pillar and the
resulted particle movement outward, while the fracture conductivity generally decreases.

Channel fracturing conductivity increases with the increasing proppant size and proppant concentration. The ratio of the pulsing time of proppant laden fluid to the pulsing time of the clean fluid is the key parameter for the field operation. The numerical results show that a large value of time ratio $\tau$ is able to enhance the pillar stability though it may lead to the damage of fracture conductivity. For given rock modulus, closing stress and proppant size, the optimal range of $\tau$ can be given as a guidance for field operation. The field application of channel fracturing in the Shengli Oilfield proves that the optimized range of time ratio $\tau$ based on the proposed theoretical model in this work is valid. This paper gives insights for understanding the channel fracture conductivity and provides a practical tool for the optimization of channel fracturing design in the field.

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