IN THE FIELD

Fracturing and production analysis of the efficacy of hydraulic fracture stage reduction in the improvement of cost-effectiveness in shale oil development: A case study of Jimsar shale oil, China

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Abstract
The effective production of shale oil is important for the cost-effectiveness in the oil and gas industry. Oil price volatility and uncertainty require suitable hydraulic fracturing schemes to maximize production and to minimize fracturing costs. Since the reduction of fracture stage saves bridge plugs and fracturing costs, it is considered as a possible method to improve the cost-effectiveness. To maintain the stimulated reservoir volume, cluster numbers per stage are consequently increased, which may induce nonuniform fracture propagation and interference which affects the stimulation efficiency. This study conducts a comparative study for single-stage (reduced) and two-stage (not reduced) fracturing schemes with the same fracturing fluid volume. Reservoir geomechanics and rock mechanics analyses are conducted for Jimsar shale oil in north-western China with a single-stage multicluster fracturing model established. Fracture geometries and key factors are investigated followed by the evaluation of the fractured well production. The relationship between multicluster parameters and production is quantified. Meanwhile, two-stage fracturing modeling is also set up to compare with single-stage fracturing modeling. Fracturing results show that although single-stage fracturing results in nonuniform fracture propagation, the overall stimulation is satisfactory. Production results show that the nonuniform growth of fracture clusters leads to different contributions to the production from individual clusters and the production from inner fractures is significantly inhibited. Compared with two-stage fracturing with the same pumping volume, it is found out that single-stage fracturing can lead to cost-effective horizontal well production in Jimsar shale oil given certain values of hydraulic fracturing costs, and the reduced stage scheme is preferable in low oil price and high uncertainty scenarios.

Keywords
hydraulic fracturing, multistage fracturing, numerical simulation, production prediction, shale oil
1 | INTRODUCTION

Shale oil reservoirs are usually characterized by low permeability and high heterogeneity, and hydraulic fracturing is usually required for the effective production of shale oil. Cost-effectiveness has always been a key issue in the development of shale oil reservoirs, especially during the time when the industry is experiencing oil price volatility and high uncertainties. Some of the major shale oil reservoirs are located in continental shale, and it usually requires horizontal wells with hydraulic fracturing to obtain commercial production.1–3 In the field, reducing the stage number can decrease the cost by saving bridge plugs and by reducing expenditures in hydraulic fracturing operations. Meanwhile, cluster numbers within individual stages can be increased to keep the fracturing volumes at similar levels. Thus, it is important to quantify the relationship between the saved cost and the alterations in the fracture geometry and the corresponding production performance when using the reduced fracture stage scheme. This scheme should only be implemented when the saved costs exceed the possible loss in revenue caused by production decrease. Geology, rock mechanical analysis based on well logs, hydraulic fracturing modeling, production prediction, and economic analysis is useful in the analysis of the efficacy of multicluster fracturing with reduced fracture stages in the cost-effective development of shale oil reservoirs.4

Accurate rock mechanical analysis in the study area is the premise of the analysis of the efficacy of multicluster fracturing. Jin et al9 proposed a method to evaluate the in-situ stress, tensile strength, and fracture toughness based on logging data such as acoustic logs, density logs, gamma-ray logs. This method was then validated with field fracturing data. Hou et al10 and Hou et al11 indicated that Young's modulus, Poisson's ratio, brittleness, natural fractures, fracture toughness, in-situ stress contrast, formation angle, and anisotropy are key indices for the evaluation of fracability, while well-cementing quality, perforations, fracturing fluid viscosity, and fracture schedules contribute to the evaluation process as well. In-situ stress is one of the controlling factors for fracture propagation path. Consequently, it is relevant to accurately evaluate in-situ stress using differential strain analysis, stress measurement based on the Kaiser effect, and multipole acoustic array logs.8,9 Further investigations in the Kaiser effect10 indicated that integrating regional elastic data can reduce the measurement error caused by sample selection. Therefore, the use of rock mechanical experiments and well logs can help to improve the reliability of rock mechanical analysis in the target area, which is beneficial for the evaluation of the efficacy of multicluster fracturing.

Fracture propagation modeling is the key component in the study of the simultaneous fracture growth patterns in multicluster hydraulic fracturing in horizontal wells. Based on the classic KGD and PKN models, many fracture models describing the fracture half-length, fracture heights, and fracture widths were then derived.17–14 One important consideration is the interfraction stress interference induced by simultaneous grown hydraulic fractures within a single stage, where the nonuniform fracture growth is the key for the evaluation of the asymmetric fracture networks.15 In the modeling of complex fracture-network propagation, coupled flow-geomechanics, finite element methods, extended finite element methods, and boundary element methods are usually used in the numerical analysis for the fracture path, height, width, stress evolution, and fluid pressure in the fracturing process.16,17 In-situ stress evolution caused by fracturing and pressure depletion in return affects fracture network growth and induces nonuniform and asymmetric fracture networks.18,19 Reduced fracture spacing and cluster spacing usually intensify the curvature in fracture paths and lead to competitive growth of individual fracture clusters.20 In addition, fracture propagation modeling can also consider fractures’ interaction with weak bedding layers, and claimed that rock mechanical properties and pumping schedule affect the interaction.21,22 Except for weak bedding layers, the effect of natural fractures on fracture network complexity is also relevant, and Zhang et al23 introduced a numerical method to assess the uncertainties of fracture geometries caused by depletion, frac hits, fault reactivation, and induced seismicity. After the establishment of fracture networks, it is also critical to quantify the fracture conductivity, as it directly governs the productivity of the fractured well. Zhang et al24 and Zhang et al25 proposed a method involving the discrete element method and computational fluid dynamics to examine the correlation between proppant embedment and conductivity. Their correlations were matched by lab data. They found out that the increase of proppant usage improves the conductivity of fractures.

Jimrsar shale oil is one of the first shale oil reservoirs that obtained commercial oil production in China. Due to the recent oil price volatility and the need for cost-effectiveness, it is meaningful to carry out a numerical analysis of the efficiency of the use of multicluster fracturing in the reduction of stage numbers for the purpose of reducing fracturing costs. In the study, geology, logging, and production data from a horizontal well in the Upper Permian Lucaogou Formation are used for the numerical analysis integrating fracturing modeling and reservoir modeling. Keeping the overall fracturing fluid volume constant, two scenarios are modeled and compared: the first involves a single-stage fracturing scheme (representing the reduction in stage number) with seven clusters per stage while the second involves a two-stage fracturing scheme (representing the unreduced stage number). Their fracture geometries, long-time production, reservoir depletion, and simplified economic performances are quantitatively compared. This study numerically investigates a possible alternative fracturing design and its cost-effectiveness in preparation for possible low oil prices in future. It also
provides a set of criteria based on oil prices and discount rates as a reference for whether to use the fracture stage-reduction strategy in the future development of the Upper Permian Lucaogou Formation in Jimsar shale oil.

2 | STUDY AREA

The target well JX24 is located in the Upper Permian Lucaogou Formation in the east of the Jimsar Sag in Junggar Basin in Xinjiang in north-western China (Figure 1). The well is already under production and the hydraulic fracture stages have 6-7 clusters in each of them. The thickness of the PayZone is 10 m with feldspathic siltstones. Reservoir pressure in the PayZone is 36 MPa with a depth of 2820 m, which exhibits a characteristic of high-pressure gradients. The average porosity is 14.5% and the average oil saturation is 68.9%. PVT tests indicate black oil in the reservoir with an average temperature of 80°C.

Well stability analysis in the target area indicates that the direction of the maximum horizontal stress is NW-SE with an azimuth of 158°. Lab measurements in this area reported strong brittleness of the rock samples, while the existence of beddings increases the anisotropy in the rock mechanical parameters. Based on well logs and laboratory experiments, Wang et al. established a static–dynamic correlation for rock mechanical parameters in this area as:

\[ E_s = 0.925E_d - 10,882 \]  
\[ C = 43.057E_s^{3 \times 10^{-8}} \]  
\[ S_t = 0.0282 \left( \frac{\rho}{AC} \right)^{2.844} \]

where \( E_s \) is the static elastic modulus in MPa; \( E_d \) is the dynamic elastic modulus in MPa; \( C \) is the compressive strength in MPa; \( S_t \) is the tensile strength in MPa; \( \rho \) is the density of rock in kg/m³; \( AC \) is the P-wave slowness in μs/m. Young’s modulus in the region is within 25-30 GPa; Poisson’s ratio in the region is within 0.26-0.28; tensile strength in the region is within 3-10 MPa. It is also noted that the existence of dolomite increases the tensile strength in the shale reservoir.

Horizontal wells drilled, fractured, and produced in this area were characterized by large fracturing volume with multiple stages and clusters. As a complement to the current development strategy, considering the volatility in oil price and possible downturns in the future, the operators intentionally decreased stage numbers and increased single-stage cluster numbers in well JX24 as an attempt to improve the cost-effectiveness in this shale play. A thorough modeling analysis is then carried out to evaluate the efficacy of this attempt.

3 | MATHEMATICAL MODEL

In order to quantify the fracture network and the corresponding production from fractured horizontal wells, it is important to establish hydraulic fracture modeling and reservoir modeling schemes. In this study, finite element methods and cohesive zone methods are used to simulate the hydraulic fracture growth. Reservoir modeling is based on finite element methods and two-phase flow diffusivity equations.

3.1 | Hydraulic fracture model

Based on the cohesive zone theory, the criterion for fracturing is based on the stress in the tensile direction and in the tangential direction as:

\[ \left( \frac{\sigma_n}{\sigma_{n,\max}} \right)^2 + \left( \frac{\tau_s}{\tau_{s,\max}} \right)^2 + \left( \frac{\tau_t}{\tau_{t,\max}} \right)^2 = 1 \]
where $\sigma_n$ is the stress in the normal direction in Pa; $\tau_s$ and $\tau_t$ are stresses in the tangential directions in Pa; $\sigma_{n,max}$ is the critical stress in the normal direction in Pa; $\tau_{s,max}$ and $\tau_{t,max}$ are the critical stress in the tangential directions in Pa.

The damage to the rock is described by the degradation in elastic modulus as:

$$E = (1 - d) E^0$$  \hspace{1cm} (5)

where $E^0$ is the undamaged elastic modulus in Pa; $E$ is the damaged elastic modulus in Pa; $d$ is the damage factor, which can be further expressed as:

$$d = \frac{\delta_m^f \left( \delta_{m,max} - \delta_m^0 \right)}{\delta_{m,max} \left( f - \delta_m^0 \right)}$$  \hspace{1cm} (6)

where $\delta_{m,max}$ is the maximum displacement in m; $\delta_m^f$ is displacement with full damage in m; $\delta_m^0$ is the displacement at the beginning of damage in m. Equations (5) and (6) describe the evolution from the beginning of damage to full damage.\textsuperscript{27–29}

The Griffith theory and its Irwin modification are then used to determine the stress intensity factor $K_{IC}$ and the critical fracture energy $G_{IC}$ as

$$K_{IC} = \sqrt{\frac{2E_FY_F}{1 - Y_F^2}}$$  \hspace{1cm} (7)

$$G_{IC} = 2Y_F$$  \hspace{1cm} (8)

where $Y_F$ is the surface energy in J/m\(^2\). They are used as the criteria for fracturing.

After the initialization of fractures, fractures propagate as fracturing fluids are pumping in the fracture networks. The flow of the Newtonian fluid in the fracture channels is characterized as:

$$q = \frac{w^3}{12\mu} \nabla p_f$$  \hspace{1cm} (9)

where $q$ is the flow rate in m\(^3\)/s; $w$ is the fracture width in m; $\mu$ is the viscosity in Pa-s; $p_f$ is the fluid pressure in Pa.

Since the matrix connected to fractures has low permeability, the leak-off effect is considered where the fluid flows into the matrix through the walls of the fracture networks as:

$$q_l = c \left( p_f - p_b \right)$$  \hspace{1cm} (10)

where $q_l$ is the leak-off rate in m\(^3\)/s; $c$ is the leak-off coefficient; $p_b$ is the pore pressure at the fracture wall in Pa.

Thus, the initiation and propagation of fractures are calculated with fluid distribution in fracture clusters, and the nonuniform propagation of simultaneous fracture growths can be evaluated.

### 3.2 Reservoir model for fractured well production

In addition to the evaluation of hydraulic fracture network, the quantification of production from fractured horizontal wells is useful in the evaluation of hydraulic fracturing efficacy. Based on mass balance and flow diffusivity,\textsuperscript{30} a two-phase model is established to simulate the production of a fractured horizontal well in the reservoir.

The two-phase flow diffusivity equation is expressed as:

$$\frac{\partial \left( \phi S_i \rho_i \right)}{\partial t} + \nabla \cdot \left( \rho_i u_i \right) = s_i$$  \hspace{1cm} (11)

where $\phi$ is porosity; $S_i$ is the saturation of phase $i$; $\rho_i$ is density of phase $i$ in kg/m\(^3\); $t$ is time in s; $u_i$ is velocity of phase $i$ in m/s; $s_i$ is production rate of phase $i$ in kg/(m\(^3\)s).

Based on the definition of saturation,

$$\sum S_i = 1$$  \hspace{1cm} (12)

In addition, velocity can be expressed as:

$$u_i = -\frac{k_{ri}}{\mu_i} \left( \nabla p + \rho_i g \right)$$  \hspace{1cm} (13)

where $k$ is permeability in m\(^2\); $k_{ri}$ is relative permeability; $\rho$ is pore pressure in Pa.

Considering the slightly compressible fluids in the formation, fluid compressibility is written as:

$$\chi_i = \frac{1}{\rho_i \frac{\partial \rho_i}{\partial p}}$$  \hspace{1cm} (14)

where $\chi_i$ is the compressibility in 1/Pa.\textsuperscript{31,32}

The equations above present the flow diffusivity equations based on mass balance, which describes the flow from the reservoir to the fractured horizontal well. They can be used to quantify the production performance and reservoir pressure depletion and to evaluate the efficacy of hydraulic fracturing from the perspective of oil production.

### 4 Numerical analysis

#### 4.1 Field data

Before the numerical modeling for the pilot well of JX24 in the Upper Permian Lucaogou Formation in the study area,
field data are analyzed to understand the well configuration, rock mechanics, and fracturing designs. The maximum measured depth of the well is 4448 m. The length of the horizontal wellbore is 1638 m. Figure 2 presents the well-logging and interpretation of the well. It also includes the determination of the fracturing stages. Previous wells in this study area generally have three clusters in each stage, while 6-7 clusters were designed for individual stages in well JX24 as an attempt to reduce the stage numbers and the related costs.

In this study, due to the limitation of numerical simulation capacity and for the purposes of more specialized comparison, stage 2 of well JX24 is used to carry out the hydraulic fracturing simulation and reservoir simulation. Figure 3 presents the pumping rate and pressure data for the fracturing of stage 2. Figure 4 records the 30-day cumulative production from stage 2. Due to the lack of production logging data, this production is estimated: based on the cumulative production of the entire well, stage 2 production is normalized by the fracturing fluid volume. There are only 30-day production data as well JX24 is a new well with limited production records. Fracturing data in Figure 3 are used to simulate and obtain the fracture network, while production data in Figure 4 are used to calibrate the reservoir simulation model for the production prediction of stage 2 in the fractured well. Table 1 records the perforation locations of the seven clusters in stage 2 of well JX24, and the cluster spacing is reduced to around 20 m. In Figure 3, the field data for pumping rate are used as input in the hydraulic fracturing model. The modeling of fracture propagation provides results of hydraulic fracture geometries and pressure. In the pumping pressure results in Figure 3, the dotted red curves are the simulated results while the blue curves are the field data. It is noted that they have generally matched trends and magnitudes.

### 4.2 | Hydraulic fracturing modeling

#### 4.2.1 | Multicluster fracturing in a single-stage

Based on the previous rock mechanical analysis and fracturing data, the simulation for the hydraulic fracture propagation in stage 2 in well JX24 is carried out with perforation depths ranging from 4249 m to 4373 m. Figure 5 presents the fracture network geometry at the final step. It shows that the fracture half-lengths are from 60 m to 82.5 m, and the rounded-up half-lengths from left to right for each fracture are 80 m, 60 m, 75 m, 77 m, 70 m, 60 m, and 83 m, with an average fracture half-length of 72 m. Stage 2 exhibits nonuniform growth of fractures, and competitive growth is observed in the simulation with seven simultaneously grown fractures.

Normalized field production data in Figure 4 are used to calibrate the fracture geometry obtained in Figure 5. After the calibration of fracture conductivity, a match of production is obtained as in Figure 6. It is noted that, due to the limited

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**Figure 2** Well logs and interpretations for well JX24
4.2.2 | Two-stage comparative case

The previous section discusses the fracture geometry achieved by the implementation of a 7-cluster fracture design. Field data are also used to improve the reliability of the results. Additionally, it is meaningful to introduce a multistage fracture design to obtain its fracture geometry and corresponding production performances. Thus, a comparison is achieved to evaluate the efficacy of stage reduction in maintaining production performance while reducing fracturing costs.

In the two-stage comparative study, the fracturing volume is kept the same as in the single-stage multicluster scenario. Perforation locations are set the same as in Table 1, while stage 1 includes the first three clusters and stage 2 includes the following 4 clusters. Therefore, in the comparative case, both interfracture stress interference and interstage stress interference are induced during the multistage hydraulic fracturing process, while in the base case there is no interstage stress interference as it is only a single-stage process.

Figure 7 shows the fracture geometry of the two-stage fracturing case. In stage 1, the rounded-up fracture half-lengths of three fractures from left to right are 96 m, 73 m, 86 m. In stage 2, the half-lengths from left to right are 27 m, 90 m, 71 m, 90 m. The average fracture half-lengths is 76 m, which is a 4 m (or 1.3%) increase compared to the single-stage scenario. It is noted that the interstage fracturing interference is noticeable due to the close stage spacing, with the half-length of the leftmost fracture in stage 2 largely reduced to 27 m. This indicates that although the number of simultaneously growing fractures decreases in the comparative case, interstage stress interference is introduced and the growth of certain fractures is inhibited by the stress shadow.

Based on the comparison between the two fracturing designs, it is noted that the general fracture network widths and lengths are similar, while the single-stage multicluster fracturing design can save bridge plugs and fracturing operation costs and exhibits the potential of improving cost-effectiveness. However, there is a limitation in the evaluation of the efficacy of fracturing by only using fracturing modeling. To improve the comprehensiveness, production prediction of the horizontal wells fractured by the aforementioned two schemes is then simulated.

In order to better present the effect of stage reduction on the nonuniformity of fracture half-lengths, fracture half-lengths from these two scenarios are compared in Table 2. The reduction of stage number actually reduces the average half-lengths from 76 m to 72 m. However, it leads to better uniformity of the fracture network with lower standard deviation. In addition, it is noted that the two-stage fracturing strategy leads to strong interstage interference and the average fracture half-length in stage 2 is much shorter than stage 1. Also, the sequential fracturing strategy leads to stronger nonuniformity in stage 2, which indicates uneven fracture growth and implies heterogeneous depletion of the shale oil reservoir.

4.3 | Reservoir simulation

In the previous section, the average fracture half-length in the two-stage scheme is 1.3% greater than that in the single-stage
scheme. To better present the difference between these two fracturing schemes, reservoir simulation is carried out to quantify the difference in production performances. The correlation between fracture opening and fracture conductivity proposed by Zhang et al.\(^\text{25}\) is used to convert the simulated hydraulic fracture widths to fracture conductivity in the reservoir simulation.

Figure 8 presents the two-dimensional pore pressure distribution in the reservoir after production of 30 days and 1500 days for the single-stage fractured well scenario. After 30 days of production, the depletion area is mainly overlapped with the fractures. Outside the fractures, the depletion is observed within 5 m away from fractures. Since the fracture spacing is around 30 m, the area between fractures is largely intact. After 1500 days of production, continued depletion further decreases the pressure within the fractures, while the depletion near the fractures also becomes greater. The reservoir between fractures is more produced, and this phenomenon is especially pronounced between fractures 4 and 5 and their fracture spacing is the smallest. Figure 9 further depicts these pressure depletion profiles in x-direction, where five different y-coordinates are used. \(Y = 150\) m is the location of the horizontal wellbore, and the other plotting locations are separated by a spacing of 25 m. In Figure 9A, after 30 days of depletion, the extent of pressure depletion caused by each fracture is around 10 m in x-direction. The pressure profile along \(Y = 250\) m is not affected by the depletion; the other pressure profiles are significantly affected by the depletion. This indicates the governing effect of fracture geometry on pressure depletion in the early stage of production. In Figure 9B, after 1500 days of production, all five pressure profiles are affected by depletion. The profiles are closer to the horizontal wellbore experience greater depletion. This indicates that after a long period of production, fractures and their nearby reservoir areas both experience depletion, and the stimulated reservoir volume is better produced.

Figure 10 shows the two-dimensional pressure depletion in the reservoir after 30 days and 1500 days of production for the two-stage fractured scenario. Similar to what is observed in Figure 10, the depletion is mainly governed by the fracture network in the early stage of production and the reservoir areas outside fractures are generally undepleted. As production continues, fracture geometry remains the governing

| Stage | Bridge plug depth/m | Cluster number | Perforation location/m |
|-------|---------------------|----------------|------------------------|
|       |                     |                | No. 1   | No. 2   | No. 3   | No. 4   | No. 5   | No. 6   | No. 7   |
| 2     | 4386                | 7              | 4373    | 4351    | 4332    | 4316    | 4295    | 4271    | 4249    |

FIGURE 5 Fracture geometry in stage 2 with 7 simultaneously grown clusters

FIGURE 6 Fracture geometry calibration based on production data

FIGURE 7 Fracture geometry in the comparative study with two stages

TABLE 1 Normalized cumulative oil production from stage 2

Cumulative Oil Production

| Time/d | Field data | Simulated data |
|--------|------------|----------------|
| 0      |            |                |
| 5      |            |                |
| 10     |            |                |
| 15     |            |                |
| 20     |            |                |
| 25     |            |                |
| 30     |            |                |

FIGURE 8 Two-dimensional pore pressure distribution in the reservoir after production of 30 days and 1500 days for the single-stage fractured well scenario.
factor of the depletion area, while unfractured reservoir areas also experience certain pore pressure depletion. Since the average fracture half-length in Figure 10 is greater than that in Figure 8, the extent of depletion in y-direction is greater in Figure 10. However, it is also noticed that, due to the inhibited fracture growth caused by strong interstage fracture interference, the depletion area caused by fracture 1 in stage 2 is more limited, leading to insufficient depletion in the interstage area between stage 1 and stage 2. To better quantify the pressure depletion characteristics, the one-dimensional pore pressure profiles in x-direction at five y-coordinates are plotted using the plotting scheme similar to Figure 9. In the comparison between Figure 9A and Figure 11A, it is noted that although it is in the early stage of production, the leftmost fracture in the two-stage scenario is able to slightly deplete the reservoir at \( Y = 250 \) m due to the fact that it has the greatest fracture half-length. In the comparison between Figure 9B and Figure 11B, it is found out that pressure depletions at \( Y = 225 \) m and 250 m for the two-stage scenario are greater. This is caused by the fact that the average fracture half-length of this scenario is greater. Another observation is that although fracture 1 in stage 1 in the two-stage scenario is significantly shorter, it still leads to sufficient depletion for \( Y = 150 \) m and \( Y = 175 \) m. This substantiates that fractured reservoir area can be well depleted, while unfractured area usually experiences insufficient depletion. This insufficient depletion can be improved by prolonged well production for near-fracture areas and cannot be effectively improved for far-field areas.

Figure 12 presents the cumulative production over 1500 days from each individual fracture in the single-stage scenario. It is observed that the outer fractures tend to produce better than the inner fractures. This is because the outer fractures experience weaker competition for production as they can drain more intact reservoir areas. Specifically, fracture 7 (the rightmost) has the highest cumulative production, followed closely by fracture 1 (the leftmost). Cumulative productions of fractures 3 and 4 are less than fracture 1. Fractures 2, 5, and 6 have relatively low cumulative production, which can be explained by the fact that their half-lengths are shorter and porous media flow moves to longer neighboring fractures.

Based on the results in Figures 8 and 10, it is evident that the effect of stage reduction directly shapes the pressure drop fronts regardless of production time. For example, on day 30, due to the linear flow in fractures, depletion areas are primarily governed by the network of fractures. On day 1500, the hydrocarbon in the fractures is already largely produced, and reservoir volumes in between fractures experience depletion due to the bilinear flow within the target domain. The flow between fractures is also linear, which is largely governed by the hydraulic fracturing quality. Based on results in Figures 9 and 11, it is also clear that the pressure profiles

| Fracture | Single-stage | Two-stage |
|----------|--------------|-----------|
| Fracture 1 | 80 m | 96 m (stage 1) |
| Fracture 2 | 60 m | 73 m (stage 1) |
| Fracture 3 | 75 m | 86 m (stage 1) |
| Fracture 4 | 77 m | 27 m (stage 2) |
| Fracture 5 | 70 m | 90 m (stage 2) |
| Fracture 6 | 60 m | 71 m (stage 2) |
| Fracture 7 | 83 m | 90 m (stage 2) |
| Average | 72 m | 76 m |

| Standard deviation | 9.2 m | 23.5 m | 11.5 m (stage 1) |
|                   |       |       | 29.7 m (stage 2) |

**Figure 8** Pore pressure distribution after 30-d and 1500-d production of the single-stage fractured well
in the wellbore direction are directly controlled by the distribution of fractures. Profiles penetrating fractured reservoir volumes exhibit strong depletion while profiles outside the stimulated volumes usually experience insignificant pressure drops.

Figure 13 shows the cumulative production over 1500 days from individual fractures in the two-stage fractures. In stage 1, fracture 1 has the greatest production while fracture 2 has the lowest production. This is in accordance with the observation in Figure 12 where inner fractures bring in lower production than outer fractures. However, in stage 2, the leftmost fracture (fracture 1) brings in the overall lowest cumulative production, which is because it has much-limited fracture growth. Therefore, depletion competition between fracture 3 of stage 1 and fracture 1 of stage 2 is not strong, which explains why fracture 3 of stage 1 is an inner fracture and it still has high cumulative production.

From the results shown in Figures 12 and 13, it is suggested that although the fracture networks obtained by the single-stage fracturing scheme and the two-stage fracturing scheme have many similarities, production prediction indicates that their individual cumulative productions exhibit significant discrepancies. Fracture location, fracture half-length, fracture spacing, stage and cluster design, and production time all affect the production profile of a certain fracture.

In Figure 14, the total cumulative production from all fractures is compared between the two scenarios based on well JX24 data and modeling. Figure 14A plots the summation of the individual fracture production depicted in Figure 12 using the single-stage fracturing scheme. It shows that the production curve starts with a sharp increase and then enters a more stable period. The final cumulative production reaches 1100 metric tons. Figure 14B plots the value of cumulative production of the two-stage scheme minus cumulative production of the single-stage scheme. In the first 196 days, the single-stage fracturing scheme actually leads to a better production profile with the greatest difference of 8.5
metric tons in cumulative production. Based on the homogeneity of fracture half-lengths, the single-stage case has better uniform depletion in the early production stages, and the fractured volumes and reservoir volumes around the fractures can be more uniformly depleted. In contrast, the two-stage case leads to more uneven growth of fractures and stronger interstage interference. Thus, in the early production stages, the depletion within fractured volumes and near-fracture reservoir volumes in the two-stage case is more uneven than the single-stage case, and the single-stage case exhibits better initial production rates.

However, the two-stage fractured well provides a better cumulative production profile afterward. After 1500 days of production, the overall difference reaches 36.8 metric tons or 3.3%. This means that the single-stage fracturing scheme can lead to better production in the early stage with a limited period of time, and then the two-stage fracturing scheme provides better cumulative production.

### 4.4 Simplified economic analysis

After the numerical analysis of hydraulic fracturing modeling and fractured well production prediction, the overall cumulative production curves are obtained. Based on the production prediction, a simplified economic analysis is carried out to improve the comprehensiveness of the cost-effectiveness.

Since the cumulative production is higher in the two-stage fracturing scenario, its corresponding revenue by oil production is higher. However, the single-stage fracturing scenario saves at least one bridge plug and the related fracturing costs. Therefore, it is important to evaluate the revenue difference between the two scenarios.

The present value equation is used to convert future revenue to the preset as:

\[
PV = \frac{CF}{(1 + r)^t}
\]
where \( PV \) is the present value in USD; \( CF \) is the future cash flow or revenue in USD; \( r \) is the yearly discount rate; \( t \) is the time in years.

Using the cumulative production of the two scenarios in Figure 14, the present values of the single-stage scenario \( PV_1 \) and of the two-stage scenario \( PV_2 \) for a production period of 1500 days are acquired. In the analysis, three discount rates are used: 5%, 10%, and 15%; four oil price scenarios are tested: 30 USD, 40 USD, 50 USD, and 60 USD. Table 3 records \( PV_2 - PV_1 \) in various combinations of discount rates and oil prices.

Results obtained in Table 3, in fact, provide criteria for the determination of whether to use the single-stage fracturing scheme or not in the development of the Upper Permian Lucaogou Formation. As an example, when the oil price is 30 USD with a discount rate of 5%, if the saved expenditures per stage exceed 7145 USD, the single-stage scheme should be applied. In contrast, if the save expenditures are less than 7145 USD, the two-stage scheme should be implemented.

It is also noted in Table 3 that the single-stage fracturing scheme with reduced stage numbers work better for low oil prices and high discount rates, and both parameters represent higher uncertainties and risks. That is to say when oil prices are relatively high and uncertainties are relatively low, reducing stage numbers and increasing cluster number per stage could not bring in satisfactory cost-effectiveness.

### 5 | CONCLUSION AND RECOMMENDATION

In this study, rock mechanical parameter analysis, hydraulic fracturing, reservoir modeling, and simplified economic analysis are conducted to thoroughly investigate whether to reduce the fracture stage numbers in the horizontal well development of the Upper Permian Lucaogou Formation. Field data in the study area, finite element methods, mass balance, and present value calculation are used in the analysis.

In conclusion:

1. In terms of fracture geometry, although there are more clusters per stage in the single-stage fracturing scheme and denser fracture spacings, this fracturing scheme avoids the inter-stage fracturing interference and its inhibition on fracture growth. As a result, fracture half-lengths are more uniform.
2. In the early stage of fractured well production, fracture geometry is the dominant factor controlling the shape and area of reservoir depletion, and the un-fractured inter-fracture area is largely un-depleted. After continued production, the depletion propagates outside fractures with pressure drop gradients.
3. In this numerical study for Jimsar shale oil, the single-stage fracturing scheme provides better cumulative production in the first 186 days while the two-stage fracturing scheme provides a better overall cumulative production over a long period of time.
4. Whether to reduce the fracture stage number to improve cost-effectiveness is closely related to the oil price, uncertainty, and fracturing costs. The reduction in stage number is preferable for unstable scenarios where discount rates are high and oil prices are low. In contrast, this strategy is not effective in more stable scenarios where oil prices are relatively high and uncertainties are relatively low.

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