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Research Article

Effective Stress Factor Analysis of Proppant for Multi-stage Fracturing in Horizontal Wells

Bo Cai ,[1,2] Rui Gao,[1,2] Chunming He,[1,2] Jin Chen,[3] Ning Cheng,[3] Tiancheng Liang,[1,2] Guifu Duan,[1,2] Chuanyou Meng,[1,2] Haifeng Fu,[1,2] and Haoyu Zhang[1,2]

[1]*PetroChina Research Institute of Petroleum Exploration & Development, Beijing 100083, China*
[2]*CNPC Key Laboratory of Oil & Gas Reservoir Stimulation, Langfang, Hebei 065007, China*
[3]*PetroChina Xinjiang Oilfield Company, Karamay 834000, Xinjiang, China*

Correspondence should be addressed to Bo Cai; caibo69@petrochina.com.cn

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In order to determine the effective stress factor of proppants during the multi-stage hydraulic fracturing operation in horizontal wells and select the appropriate proppant type, the analysis of the effective stress characteristics of proppants is carried out. This analysis considers the geomechanics and long-term production characteristics of multi-stage fractured horizontal wells in reservoirs like Xinjiang Mahu shale oil and Southwest China shale gas. The analysis of influencing factors is also carried out. The results show that, during the multi-stage hydraulic fracturing operation in horizontal wells, the stress on proppants is not only related to geological factors such as reservoir closure stress, but also closely related to total injection volume, cluster spacing, liquid type, injection displacement and post fracture management. First, increasing injection intensity, reducing fracture spacing, using low viscosity fracturing fluid, adopting high injection displacement and utilizing reasonable flowback system can effectively supplement reservoir energy, postpone the effective stress peak of proppants, and increase the effective conductivity of proppants. Second, the production performance analysis results of nearly 300 horizontal wells (from Xinjiang oil field, Erdos tight oil reservoir, Sichuan shale gas reservoir, etc.) shows that: the effective stress of proppants in horizontal wells is only 50–60% of that in vertical wells, which results in a different proppant selection criterion in the volume stimulation of horizontal wells and provides the geomechanics basis of replacing ceramsite proppant with quartz sand to reduce cost and increase efficiency. Based on the above conclusions, the field test of replacing ceramsite proppant with quartz sand was carried out. The proportion of quartz sand increased from less than 30% in 2014 to 69% in 2019. Without any impact on production, the annual investment cost was decreased by more than 1 billion yuan, which set a great example for the promoted low-cost development of unconventional oil and gas reservoirs under low oil price background.

1. Introduction

Common reservoir stimulation techniques include matrix acidizing, acid fracturing [1, 2] and hydraulic fracturing. In hydraulic fracturing, proppant is one of the most important materials. Since the North American shale oil and gas revolution featured by large-scale deployment of multi-stage fracturing in horizontal wells, the amount of proppant consumption has doubled and its cost consists about 20% of the total cost of well construction [3–6]. In 2019, the number of horizontal wells being fractured in the United States were nearly 25,000, which is 2.5 times more than that in 2014. In China the number has reached ~2,000, a new high in the history [7, 8]. With the increasing scale of fracturing operations year by year, the amount of material used, including proppant, has also increased significantly. In North America, the average amount of proppant used in a single well rose from 2500 tons in 2015 to 10,000 tons in 2018, with the cost proportion of proppant increasing from less than 10% to 19% meanwhile. Since 2014, due to the impact of low oil prices, North American oil and gas companies have replaced most of ceramic they used to use by sand. Now they even strive to use locally-produced sand, and/or run a sand mill by themselves, achieving significant economic benefits in shale business. The cost of natural sand is as low as 200 US dollars/ton compared to that of artificial ceramic (about 700 US dollars/ton). The average single well cost of proppant in horizontal wells can be reduced by 7 million Yuan because of the huge amount consumed. Therefore, in the past five years, sand has gradually become the mainstream proppant. By the end of 2018, 100 million tons of sand had been used in the United States, accounting for more than 95% of the total proppant consumption, with the cost reduced by more than hundreds of millions of Yuan. Taking Permian Basin in the United States as an example, the amount of locally-produced sand consumed in the basin in 2018 was 28 million tons, saving about 2.2 billion US dollars in proppant cost [9]. Inspired by the low-cost development of unconventional oil and gas in North America, technical feasibility justification and pilot tests on fracturing with sand were carried out in the tight fields in Changqing, Xinjiang, and Southwest China in 2016. The proportion of sand as proppant increased from less than 30% to 69%, with 2.75 million tons of sand consumed. There is basically a consensus on the use of sand in stimulation of reservoirs not deeper than 2000 m. For Mahu oilfield in Xinjiang ceramic has been largely replaced by sand [10] in reservoirs not deeper than 3500 m, with significant results achieved. However, due to the difference in low-cost operation approach in North America and the “Practice first, theory second” philosophy in unconventional resource development, there is less research on the theoretical basis of sand application. In this context, some research work on this issue has been carried out domestically, and especially in the last five years, the research has been getting more and more in-depth. In 2016, Shaoyan andYong [11] reviewed the evolving history of proppants and summarized the advantages, disadvantages and evolving trends of commonly used proppants such as ceramic and sand. In 2017, Hongli et al. [12] further summarized the evolving history of proppants both at home and abroad in recent years, and elaborated the characteristics of several conventional proppants. In 2018, Lifeng et al. [13] and Xinping et al. [14] described the experimental research on fracturing conductivity upon replacement of ceramic by sand in shale gas reservoirs, and predicted the economic potential and the effect of field application of sand in shale gas development. In 2019, Jiaxiang et al. [15] analyzed the transport and distribution of proppants in circuitous micro-fractures. In 2020, Linhu et al. [16] devised an experimental facility which can be used to evaluate the diversion and transport of proppants during multi-stage fracturing of horizontal wells where complex fracture network can be generated, and revealed the law governing the diversion. The aforementioned research work preliminarily put forward the correlation between sand characteristics and fracture conductivity for shale reservoirs, and proposed the proppant transport law in the complex fracture system. All the work together laid a foundation for studying the stress on the proppant and selection of proppant in shale reservoir development, and further confirmed the necessity of research on low-cost sand application. However, for multi-stage fracturing in horizontal wells in unconventional reservoirs, the effective stress acting on the proppant is still not thoroughly understood. At present, the selection of proppant is still mainly based on the formation closure pressure, which hinders cost reduction in development of unconventional reservoirs. Especially under the influence of the persistent low oil price, the research and application of low-cost materials has become an important focus of the business. For this reason, the characteristics and influential factors of the effective stress acting on the proppant during massive fracturing of horizontal wells in unconventional reservoirs were analyzed in this paper, in combination with the tracking of long-term production performance of horizontal wells in Xinjiang tight oil and Southwest shale gas fields.

2. Characteristics of the Stress on the Proppant

The stress on proppants has always been a hot research topic. It is generally believed that the stress on proppants is related to the in-situ stress and pore pressure in formations. If the main fracture is, as usual, perpendicular to the direction of the minimum principal stress, the effective stress on the proppant in the main fracture during the early production phase is the differential between the closure pressure (which at this time is theoretically equal to the minimum principal stress) and the pore pressure. As the production goes on, the pore pressure gradually decreases, and thus the stress on proppants increases [17]. In this paper the equation for calculating the stress proposed by Wilson [18] was compared with that by Yang [13], indicating that the equations are pretty similar to each other. Hence the equation proposed by Yang was used for our analysis in this paper, shown as equation (1) here.

$$\sigma_e(t) = \sigma_c + \frac{\nu}{1-\nu}\left[\sigma_{\text{now}}(t) - p_o\right] - p_{\text{now}}(t), \tag{1}$$

where σ_e is the effective stress acting on proppants, MPa; σ_c is the original in-situ stress in the reservoir, MPa; ν is the Poisson’s ratio of the rock, dimensionless; σ_{now} is the closure pressure in the artificial fracture, MPa; t is the production time, day; P_o is the original pore pressure, MPa; $P_{\text{now}}(t)$ is the pore pressure in the artificial fracture corresponding to time t, MPa.

Equation (1) shows that the effective stress on the proppant is related to the in-situ stress itself of the reservoir, which is in turn related to the burial depth of the reservoir, in-situ stress gradient, and tectonic stress. Generally speaking, the deeper the reservoir, the higher the in-situ stress, and accordingly the greater the stress on proppants [19]. The in-situ stress, Poisson’s ratio and initial pore pressure are all uncontrollable (fixed) factors, but the stress on proppants and the fluid pressure within the fracture are closely related to fracturing operation. Analysis of the equation shows that the stress on proppants is negatively correlated to the volume of fracturing fluid injected, and the fluid pressure in the fracture is positively correlated to the volume injected. The higher the volume injected, the higher the fluid pressure in the fracture, and the lower the effective stress on the proppant. During fracturing in vertical wells in the past, due to the small volume of fluid injected, the stress on the proppant was basically equivalent to the original in-situ stress, that is, the closure pressure. However, during massive stimulation of horizontal wells with huge volume injected, how the fluid volume, fluid type, fracture parameters, and interaction between the fractures affect the magnitude of the stress on proppants remains a question. In-depth understanding of all the issues will have important guiding significance to selection of proppants and optimization of fracturing operations.

3. Analysis of the Factors Influencing the Effective Stress

To further analyze the factors influencing the effective stress acting on proppants during multi-stage massive fracturing of horizontal wells, the reservoir properties and fracturing operation parameters of Mahu tight oil reservoir in Xinjiang [20] were used in this study. The reservoir properties included: average permeability (0.1 mD), average effective porosity (8.5%), reservoir thickness (30 m), burial depth (3800 m), oil saturation (55%), and reservoir pressure coefficient (1.1). The latter included: threshold injection pressure gradient (1.3 MPa/m), length of horizontal section (1500 m), length of each stage (60 m), number of perforation clusters in one stage (3, 6, or 12), spacing between clusters (5, 10, or 20 m), fracturing flowrate (5, 8, or 10 m^3/min), and injection intensity (10, 20, 30, 40 m^3/m). The fracturing fluid is slick water or guar gum fluid, with viscosity being 5 mPa·s or 35 mPa·s (0.25% concentration) respectively. The production performance data used in our study were all from production wells which had been producing for more than 600 days. Based on all the data collected, analysis of the factors influencing the effective stress on the proppant, such as fluid injection intensity, spacing between fractures, fluid type and post-fracturing production management, was conducted.

3.1. Fluid Injection Intensity. In order to effectively analyze the influence of injection intensity on the stress on proppants, four levels of injection intensity, 10, 20, 30, 40 m^3/m of horizontal section, were simulated to study the characteristics of pore pressure change. The results indicated that with the increase in the volume injected, the pore pressure in the formation increases significantly, so does the pressure within the fracture. When the injection intensity is 10, 20, 30, and 40 m^3/m, the average pore pressure in the formation increases by 1.1, 2.6, 3.2 and 3.6 MPa respectively, while the pressure within the fracture increases from 0 MPa to 3.4, 7.5, 14 and 21 MPa respectively (Figure 1). As shown in the figure, the average pore pressure near the fracture in the reservoir gradually increases with the increase in injection intensity. However, when the injection intensity reaches 30 m^3/m, the increase rate of pore pressure decreases as the injection intensity increases. To be more specific, the pore pressure increases from 3.2 MPa at 30 m^3/m to 3.6 MPa at 40 m^3/m. In contrast, the pressure increase rate in the artificial fractures increases as the injection intensity increases.

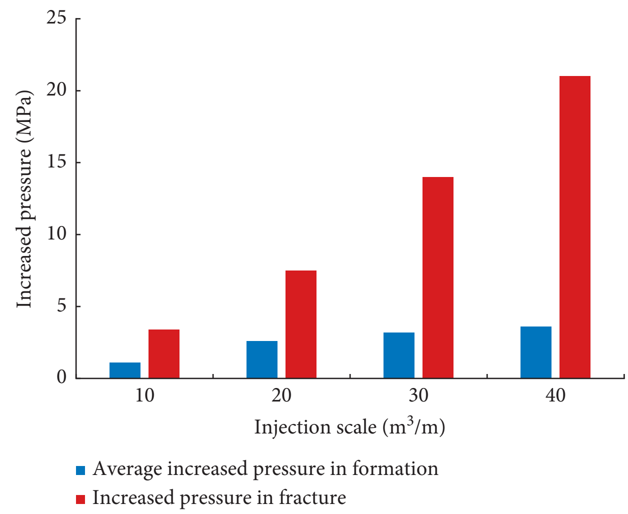

Figure 1: Average formation pressure and pressure increase in fractures under different injection scales.

Specifically, the fracture pressure increases from 14 MPa at 30 m^3/m to 21 MPa at 40 m^3/m. A large amount of fluid which cannot enter the pores remains in fractures instead. Combining reservoir numerical simulation results and equation (1), the conclusion can be drawn that the stress on proppants was basically the same in the early days for the three intensity levels of 20, 30, 40 m^3/m. As the pressure was released after fracturing operation and the fluid was flowed back gradually, the proportion of the fluid flowed-back increased rapidly for 30 m^3/m and 40 m^3/m intensity; upon back flowing for 120 days the pressure within the fracture was basically the same for the three injection intensity levels. The high injection intensity only increased the pressure in the fracture in the early days, but it did little for decreasing the stress later on. Consequently, the injection intensity of 30 m^3/m for Mahu tight oil is reasonable. The actual production data for 30 m^3/m intensity in horizontal wells and those of previous vertical wells was compared and the stress on proppants is calculated using equation (1) in each case. It was found that the stress on proppants increased from 5 MPa in the early days to 25 MPa after flowing back for 550 days for the horizontal well case while from 5 MPa to 45 MPa across the same time interval for the vertical case. For vertical wells, the proportion of flow-back fluid in 90 days is 100%. For horizontal wells, this number is only 13% in 90 days and 34% in 600 days. The large amount of retained fluid greatly decreases the stress on proppants. The stress on proppants in multi-stage fractured horizontal wells is only 50–60% of that in vertical wells (Figure 2), so the principle of selecting proppants based on closure stress in the past no longer works for horizontal wells. Therefore, it is more reasonable to use equation (1) to calculate the stress on proppants in horizontal wells. Based on the above analysis, more and more sand has been used instead of ceramic as proppants in Mahu oilfield in Xinjiang, China since 2017. The results of a pilot test in Block Ma-131 involving 25 wells show that, at the same proppant consumption (1.5 m^3/m), sand and ceramic resulted in average oil production of 18.1 t/

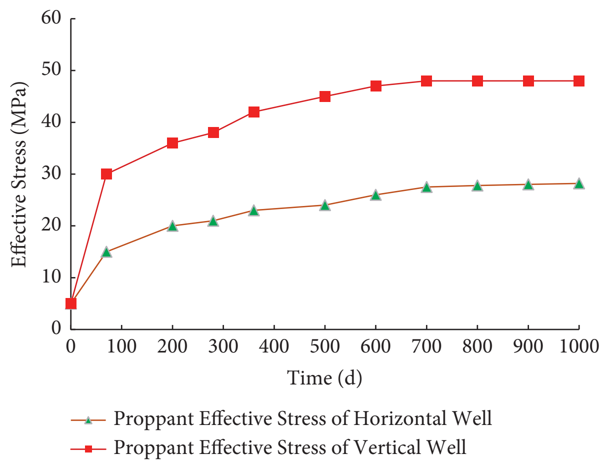

Figure 2: Changes in the effective stress of proppants in tight oil vertical and horizontal wells in Junggar Mahu.

d and 18.4 t/d in the initial 30 days, and 16.0 t/d and 15.3 t/d in the initial 360 days, respectively, with cumulative production being also roughly the same, which verified the feasibility of using sand as proppant. At the end of Dec. 2019, sand had been used in all reservoirs with burial depths less than 3500 m in Mahu oilfield, and the annual consumption of sand was 115,000 m^3, saving nearly 300 million Yuan in investment [21].

3.2. Spacing between Fractures. The influence of the number of perforation clusters on the stress on proppants was analyzed by simulating 3, 6, and 12 perforation clusters in one 60 m stage with spacing between clusters being 20 m, 10 m and 5 m, respectively. The characteristic parameters used in the simulation are also from Mahu oilfield. The simulation results show that, with all the other conditions being the same, pressure in the fracture was the highest for the 3-cluster scenario, but the pressure transmission was limited to a short range around the fracture. As the number of clusters increased to 6 and then to 12 (the spacing decreased in proportion), the pressure in the fracture successively decreased, but the pressure transmission extended to a larger range (Figure 3(a)). Production performance of 1 year after fracturing was analyzed. For the 3-cluster scenario, little oil was produced and most of the crude oil is remained in place because of the unfavorable reservoir properties and threshold pressure drawdown. Fluid flow from the formation to the artificial fractures was restricted, resulting in a significant pressure drop in the fractures. Most of the fracturing fluid flowed back, so the proppant suffered heavy effective stress in this case, and the loss of fracture conductivity was also substantial. For the 6-cluster scenario, the pressure transmission extended to a larger range, and the artificial fractures overcame the unfavorable reservoir properties and threshold pressure drawdown, resulting in a higher recovery rate. The pressure in and near the fractures increased, so did the reservoir energy. In this case the effective stress on proppants is lower, and the decrease of conductivity slows down. For the 12-cluster scenario, all the consequences become even more favorable (Figure 3(b)). The actual data of the first-year production in a block in Mahu further confirmed the above simulation results. Flowback volume for the three cases, 3, 6, and 12 clusters, was compared. The proportion of fluid flowing back was only 29% in the 6-cluster and 12-cluster cases, compared to 78% in the 3-cluster cases. The effective stress on the proppant was 24 MPa in the 6-cluster and 12-cluster cases and 33 MPa in the 3-cluster case, indicating a chance of using low-cost sand in the 6-cluster and 12-cluster cases. The average production also increased from 22.3 m^3/d in 3-cluster case to 31.4 m^3/d in 12-cluster case (Figure 4). The above analysis also confirmed the mechanism of outstanding achievements by decreasing the spacing between clusters (usually 5–10 m) and replacing ceramic with sand totally in North America [22]. It is also a strong support to conducting more pilot tests on multiple-cluster fracturing with sand in domestic shale gas and tight oil development. Taking well Chang-7 as an example, a horizontal well in a tight oil reservoir, the stage length was reduced from 110 m to 60 m, and the spacing between clusters was shortened from 30 m to 10 m. As a result, its single well production during well testing was 18.6 t/d, which was 8.3 t/d higher than that of offset wells.

3.3. Fluid Type and Injection Parameters. In order to effectively carry out single factor analysis, 10 core plugs (2.5 × 2 cm each) were cut from a 2.5 × 25 cm outcrop core sample corresponding to the target tight oil zone of well Chang-7. In this way the properties and other parameters of various plugs are basically the same, so deviation caused by the difference in sample properties can be ignored. The propagation characteristics of fracturing fluid, here slick water and low-concentration guar gum solution (0.25%), were analyzed under the same experimental conditions. Nuclear magnetic resonance CT was used in the experiments to study the hesitation time of the two fluids propagating through the core [23, 24]. The results showed that, compared with low-concentration guar gum solution, more slick water was retained in both the micro-pores (retention time 0.1–10 ms) and meso-pores (retention time 10–100 ms). High-speed centrifugation for dewatering showed that, at the same centrifugal speed, the flowback proportion of slick water was only about 50% of that of the guar gum solution, indicating that the slick water replaced the original liquid (mainly oil) in the pores through imbibition, and retained within the core, which increased the pore pressure and supported the core. Further observations of the core also confirmed that slick water is more likely to propagate along the pore throats evenly (the red circle in Figure 5 is the zone invaded by slick water), which helps to extract the oil in deep micro-pore throats, while the low-concentration guar gum solution is more likely to propagate unevenly and the propagation depth was only about 45% of the slick water. Therefore, use of slick water in unconventional reservoir fracturing is more conducive to increasing the fluid penetration depth and the pore pressure in the disturbed area (Figure 5). With the same amount of fluid injected, increasing the flow rate can also increase the penetration depth

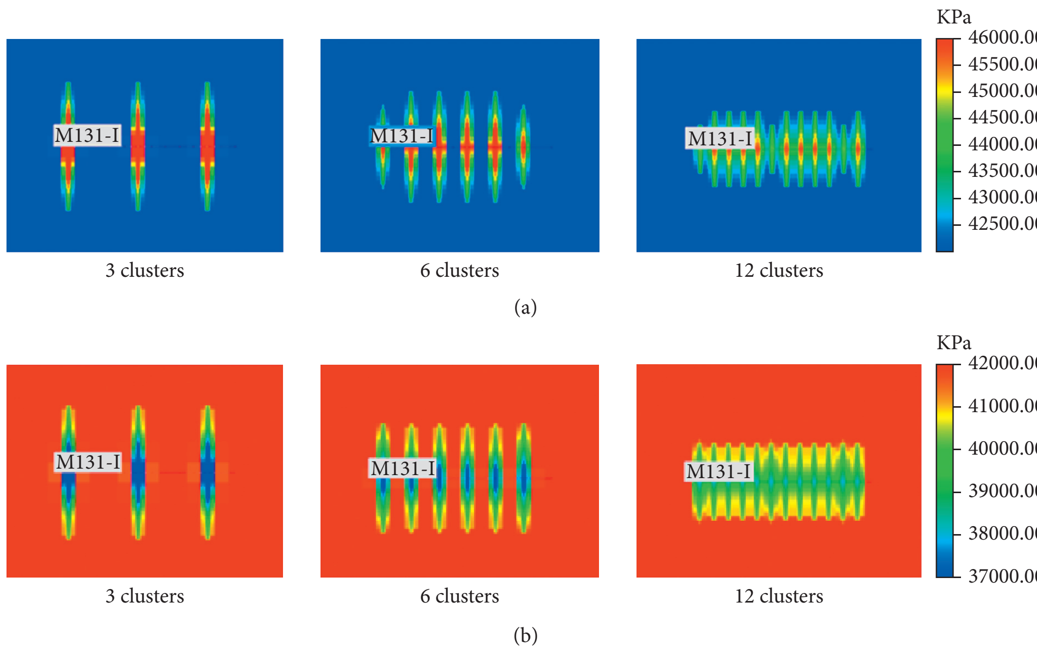

FIGURE 3: (a) Pressure change of the fracturing process when the number of perforation clusters in a single stage is 3, 6, and 12 clusters respectively. (b) Pressure change of the flowback process when the number of perforation clusters in a single stage is 3, 6, and 12 clusters respectively.

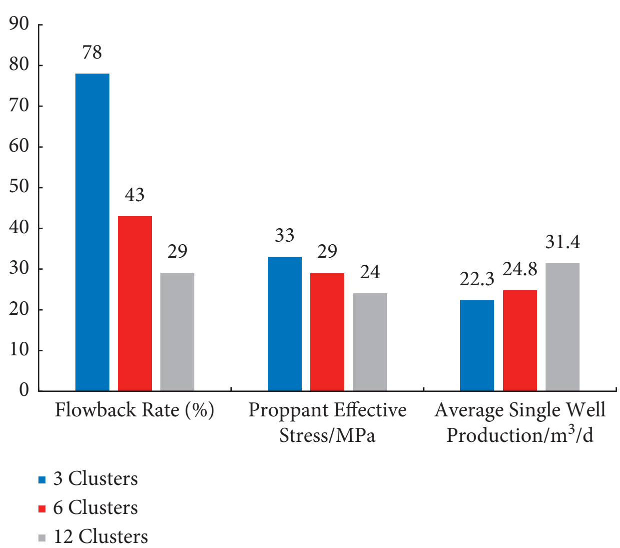

FIGURE 4: Flowback rate, proppant effective stress and daily production changes under different cluster numbers.

and pore pressure. This is why slick water accounts for more than 90% and 70% of fracturing fluid in unconventional resources abroad and domestically. High flow rate is more conducive to increase penetration depth, raise pore pressure, supplement energy, and reduce the effective stress acting on proppants, all favoring the use of low-cost sand as proppant.

3.4. Post-fracturing Production Management. In this section, how the production mode affects the stress on proppants and thus affects the fracture conductivity and production rate is studied. The conductivity was measured by lab experiments with sandstone core plates [25]. The experimental conditions were: temperature–90°C, fluid–2% KCl, proppant–20/40 mesh sand, and crevice (simulating the fracture) width–5 mm (Figure 6). When the effective stress rose to 70 MPa, the fracture conductivity dropped drastically, by as much as 70% because of compaction of the proppant packing and crushing of proppant grains. The effective stress was stabilized at 70 MPa for 72 h, and the conductivity dropped from 78 μm^2·cm to 29 μm^2·cm in this time interval, marking a 63% decrease. The dropping of conductivity was "fast first and then slow." At the end of the 72 hours, the effective stress was alternated between 65 MPa and 75 MPa, and the conductivity exhibited "step-like" dropping. After the alternation the conductivity at effective stress of 70 MPa was 11 μm^2·cm, with a drop of 60%. The result told us that frequent opening and shutting-in of wells during production would lead to a significant decrease in the conductivity of the proppant packing layer, which is unfavorable for use of sand instead of ceramic. Therefore, it is essential to avoid frequent choke replacement and downhole operations etc. that interrupt continuous production, and to rationally optimize the production mode.

4. Field Application of the Understandings

New understandings of the effective stress acting on the proppant in multi-stage fracturing of horizontal wells were gained in this research, which can be guidance for the design optimization of horizontal well stimulation in shale gas and tight oil development. The volume injected during multi-stage fracturing of horizontal wells is at least 5 times more

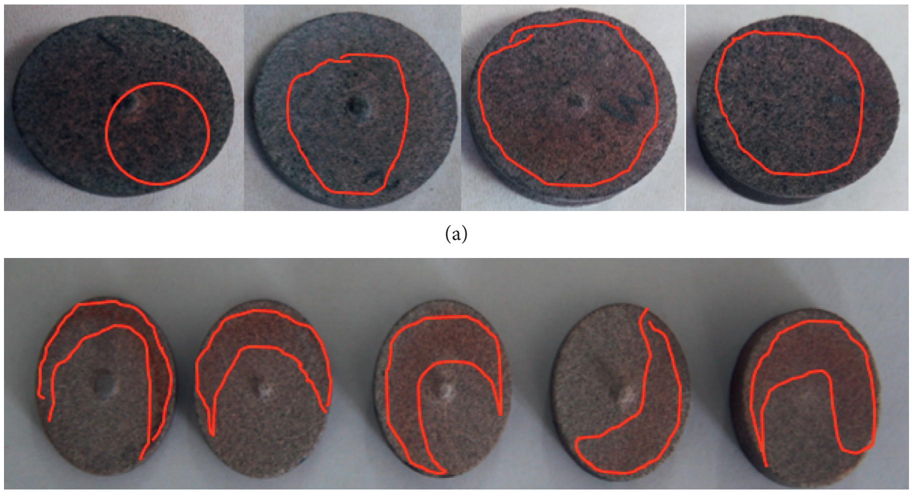

FIGURE 5: Comparison of the propagating of different fluids injected into tight oil cores. (a) Slick water injection and propagating. (b) Low-concentration guar gum solution injection and propagating.

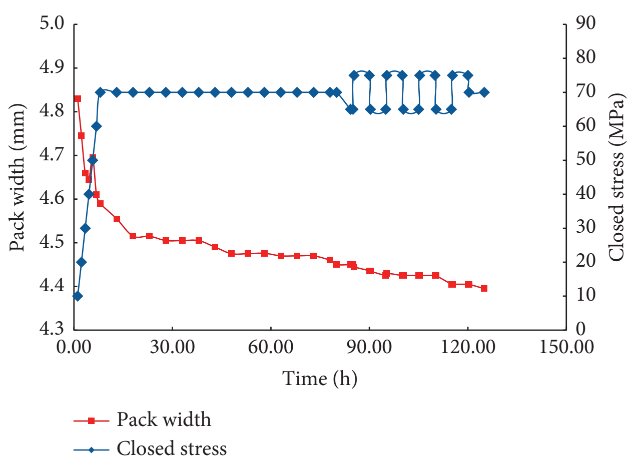

FIGURE 6: Proppant pack width change under different time and stress.

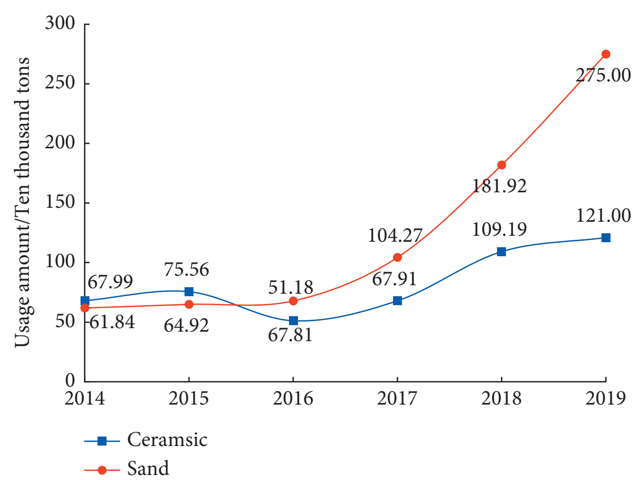

FIGURE 7: Consumption of ceramsic and sand in CNPC from 2014 to 2019.

than that during fracturing of vertical wells. The number of stages has been increased from 10 to more than 20; the number of clusters in one stage has been increased from 2 to 3 to 5–10; and the spacing between clusters has been reduced from 50–60 m to 10–30 m. Among all fracturing fluids, the proportion of low-viscosity slick water has increased from less than 30% to more than 60%. The combination of the above measures greatly decreases the stress on proppants. Analysis of production performance of nearly 300 horizontal wells in the tight oil fields in Xinjiang and Ordos, and shale gas fields in Sichuan showed that the effective stress on proppants during and after multi-stage fracturing of horizontal wells is only 50–60% of that for the vertical wells. This finding changed the criterion for selecting proppant for the multi-stage fracturing and provided a theoretical basis for promoting the use of low-cost sand as proppant. Since 2016, ceramic has been gradually replaced by sand in shale gas development in Sichuan, and tight oil development in Ordos, Xinjiang, and Songliao basins etc. The proportion of sand has increased from less than 30% in 2014 to 69% in 2019. As for the absolute volume, the consumption has increased from 680,000 tons in 2016 to 2.75 million tons in 2019 (Figure 7), with annual investment saved by more than 1 billion Yuan, which is a significant economic benefit. For example, a field test was implemented at Pad YS112H4 and Pad YS112H5 in Zhaotong shale gas reservoir to compare the cost and profit of 5, 7, and 11 clusters in one stage, with the spacing between clusters reduced from 20 m to 5–12 m. With the injection intensity being the same (30 m^3/m), the injected sand volume increased from 1.67 t/m to 3.18 t/m. The single well production increased from 100,000–200,000 m^3/d by conventional fracturing to 300,000–400,000 m^3/d, and the wellhead pressure remained at a relatively high level. The EUR per well is 120–160 million m^3, higher than the average 99 million m^3 in the same block. The replacement of ceramic by sand reduced the fracturing cost per well by 2 million Yuan.

5. Conclusions and Prospecting

With more and more applications of multi-stage massive stimulation of unconventional oil and gas horizontal wells, the scale of the stimulation gradually increases, causing a substantial cost increase in equipment, materials etc. The consumption of proppants has doubled, accounting for 20% of the cost of well construction. In this paper, analysis of the effective stress acting on proppants for the unconventional horizontal well fracturing, together with field tests, indicated that the stress is closely related to injection volume, cluster spacing, fluid type, injection flowrate and post-fracturing production management. Large injection volume, short cluster spacing, low-viscosity fluid and high flowrate are conducive to decreasing the effective stress on proppants. Analysis of production performance of nearly 300 horizontal wells in the tight oil fields in Xinjiang and Ordos, and shale gas fields in Sichuan showed that the effective stress on proppants for the multi-stage fractured horizontal wells was only 50–60% of that for the vertical wells. This finding changed the criterion for selecting proppants for the multi-stage fracturing operation, further explained the feasibility of replacing ceramic with sand in North America, and provided a theoretical basis for large-scale application of sand as proppant in China. The proportion of sand has increased from less than 30% in 2014 to 69% in 2019, with annual investment saved by more than 1 billion Yuan, showing a good prospect. Under the low oil price context, the conclusions are of pragmatic significance for reducing cost and increasing profit during the development of China's unconventional oil and gas in the future.

Data Availability

The test data used to support the findings of this study are available from the corresponding author upon request.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

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