A new impulse-stage sand fracturing technology and its pilot application in the western Sichuan Basin

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Abstract

A better placement of proppants has been always the goal pursued in sand fracturing in order to get longer effective fractures and higher flow conductivity. However, it is always difficult to achieve satisfactory effects by conventional processes. On the basis of theoretical analysis and simulation with FracproPT software, basic experiments, and innovative physical modeling experiment, a new impulse-stage fracturing process has been developed by combining a special pumping process with fiber, liquid and other auxiliary engineering means. Compared with conventional fracturing, the open seepage channel created by the new fracturing process has an obvious edge in effective fracture length and flow conductivity. Moreover, the open seepage channel can also improve fracture cleanliness and reduce pressure loss in artificial fractures, thus reaching the goal of prolonging the single-well production time and maximizing productivity. After the research on principles and optimal design of this new process, on-site pilot test and detailed post-fracturing evaluation were conducted. The results indicated that (1) the new process is highly operable and feasible; (2) compared with the adjacent wells with similar geological conditions, the proppant cost is reduced by 44%–47%, the ratio of effective fracture length to propped fracture length is increased by about 16%, the fracturing fluid recovery rate is up to 63% after 18 h in the test, and the normalized production is 1.9–2.3 times that of the adjacent wells; and (3) the new process can significantly lower the cost and enhance production. The process has a broad application prospect in shallow-middle sand gas reservoirs and shale gas reservoirs in western Sichuan Basin.

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As early as the 1960s, demands on enhancing oil and gas reservoir productivity led to some practical measures taken to enhance fracture conductivity. Efforts in early stage focused on enhancing flow rate in proppant propped layers (actually, porous medium layers). Flow resistance shown in the form of pressure loss is the collective reflection of the following factors [1]: damages caused by residues left after flowback of low-quality fracturing fluid, migration of fine particles, multiphase flow, loss in fluid dynamics (β factor), resistance (throttle resistance), capillary force, crushing and embedding of proppants. To overcome these negative factors, a series of modifications have been adopted, such as application of gel breakers in fracturing fluid, wetting agents, energized fracturing fluid, clean fracturing fluid (polymer free), reduction of viscosifier concentration, enhancement of strength and sphericity of proppants, optimization of fracture parameter design to obtain larger fracture width and dozens of other measures. All these optimization measures have one objective: to make the layers propped with even proppants reach maximum theoretical flow conductivity. However, some post-fracturing assessment results show actual fractures generated have flow conductivity lower than expected, or in other words, these fractures have shorter effective fracture length than expected.

The newly developed impulse-stage sand fracturing process aims to create an open flow network within fractures to enhance flow conductivity significantly, thus making propped fracture
layers cleaner and the pressure loss of fluid lower, and creating longer effective fracture half-length. All these would benefit the productivity of oil and gas wells in both short and long terms.

1. Principles of the new process

1.1. Theoretical foundations of the new process [2].

Is the theoretical permeability of open fracture channels higher than that of the layers propped with conventional proppant? This is the first question came to the authors’ mind.

In conventional hydraulic fracturing, fluid flow capacity in layers propped with proppant can be described by using the Darcy Formula, in which productivity is related to viscosity and pressure loss of the fluid, i.e.:

\[ q = \frac{K_f w \Delta p}{\mu L} \]  

Where, \( q \) is volumetric flow rate in unit fracture height; \( K_f \) is permeability of the fracture, \( w \) is the width of layer propped by proppant; \( \mu \) is fluid viscosity, \( \Delta p/L \) is unit pressure loss.

The product of permeability and width of the fracture is commonly used to characterize flow conductivity of the fracture mentioned earlier. Under such circumstances, fracture permeability is a collective manifestation of the proppant used and the closure stress under which the proppant lives.

In the case of fluid passing thorough open channels without proppant, Navier–Stokes equations can be used to characterize the conductivity. Research results show that non-linear part of Navier–Stokes equations can be neglected under typical production conditions, so only the linear section of the equation is considered. The following flow equation can be obtained from the integration of 1D section of the Navier–Stokes equations.

\[ q = \frac{w^2 \Delta p}{12 \mu L} \]  

Equation (2) represents the relationship between laminar flow rate and pressure loss in open channels. When Equation (1) is compared with Equation (2), effective permeability in open fracture channels can be defined as follows:

\[ K_{eff}^f = \frac{w^2}{12} \]  

It can be seen from Equation (3) that even a relatively narrow seepage channel can be much higher in permeability than proppant propped layers. For example, a seepage channel of 1 mm wide has a permeability of 83,300 D, whereas layers with proppants of 20/40 meshes may provide flow conductivity of 400–500 D under closure stress of 27–35 MPa. It can be seen that effective permeability of open channels is two-order-magnitude higher.

1.2. Tests of flow conductivity in open seepage channels

1.2.1. Experimental devices and methods

The experiment was performed on testing and analyzing system for fracture flow conductivity (Fig. 1), which is equipped with a conducting chamber and relevant auxiliary facilities conforming to API standards (API RP 61, 1989).

The volume of proppants required in each layer was calculated according to the area of conductor chamber. Then, the proppant was placed in two ways – conventional even placement and open seepage channel placement (Fig. 2). Flow conductivity and permeability under different closure stresses were tested.

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If the unevenly distributed proppant masses forming the open seepage channels slip or move under closure stress, and fill up the entire free space (to make relevant results more persuasive, smooth steel plate was used in the experiment to simulate rough hydraulic fracture surfaces, in other words, the experimental condition was much harsher than real reservoir condition), flow conductivity and permeability measured under the same stress should be identical or similar. See Fig. 3 for the experimental results.

The experiment was conducted under the closure stress of 10–50 MPa. With proppant arranged in masses to form open seepage channels, the permeability and flow conductivity are 3–8 times and 4–9 times higher than that generated by evenly distributed proppant respectively. The experimental results indicate that proppant masses forming open seepage channels in a closure stress of 10–50 MPa were not pressed into a single layer, instead, the proppant maintained certain height during the closure of fractures and consequently provided favorable conditions to generate open channels with minor flow resistance. See Fig. 4 for proppant distribution after
Experiment and see Fig. 5 for microscopic view of local structure characterized by the stacking of multiple layers.

### 1.3. Experiment on the formation of open seepage channels and simulation of profiles with FracproPT software

#### 1.3.1. Physical modeling experiment on the formation of open seepage channels

A transparent physical modeling unit was designed for the experiment. In the experiment, a variable speed pump was used to inject alternating sand-carrying fluid and gel into the transparent model at different speeds to simulate impulse-stage sand fracturing. Through the transparent glass on the model, flow patterns of alternating sand-carrying fluid and gel in the simulated fractures, flushing and carrying capacity of fluid to proppant, accumulation, distribution and the proppant distribution section after gel breaking can be observed. See Fig. 6 for the experimental devices.

According to the simulated calculation, the advance speed of sand-carrying fluid in the formation was 5–8 m/min at a pumping rate of 3.0–3.5 m³/min and a fracture height of 20–30 m. With inner diameter of an inlet pipe of 6 mm, output capacity of the pump was calculated to be 40–80 mL/min; the designed total volume of simulated fracture was 1800 mL. The pump, pipeline and simulated fractures matched each other quite well. See Fig. 7 for flow pattern in alternating sand-carrying fluid and gel fracturing, and the proppant section after gel breaking.

After the flowback of sand-carrying fluid and gel breaking, it can be seen that seepage channels in gully shape can be formed in the simulated fracture according to the distribution of proppant (Fig. 7), which are the high-speed seepage channels needed for oil and gas development.
1.3.2. Proppant placement section simulation with FracproPT software

Under identical completion parameters, reservoir properties, proppant and fracturing fluid, FracproPT software was used to simulate proppant distribution profiles generated by the conventional sand fracturing and the new impulse-stage sand fracturing. See Figs. 8 and 9 for relevant results.

Simulation with FracproPT software also shows that the impulse-stage sand fracturing can form proppant section with uneven masses in the fracture.

1.4. Function of fiber in the new impulse-stage sand fracturing process

Fibers can significantly reduce vertical precipitation speed of proppants. Precipitating speed of proppant grains in the fluid is proportional to the grain diameter and density, and inversely proportional to the fluid viscosity. Upon the introduction of fibers, the precipitation of proppant particles doesn’t follow Navier–Stokes equations any more under such circumstances, fibers contained in fracturing fluid and proppant particles form a network structure (Fig. 10) [3] to prevent the settling of particles, thus improving the distribution section of proppant in the fracture height direction.

In the direction of horizontal fracture length, experiment of proppant placement was conducted by using a semi-transparent container with slots of 0.76 cm to find out the effect of fibers on preventing proppant dispersion and reduction of proppant concentration during the interactive displacing of sand-carrying fluid and gel. During the experiment, sand-carrying fluids with different proppant concentration were injected from the top of the container. The proppant mass placement with time can be monitored and quantitatively assessed by using a visualization device. Fig. 11-a shows the position of proppant masses at the beginning. Fig. 11-b shows the position of proppant masses with fibers, whereas Fig. 11-c shows the position of proppant masses without fiber after an identical injection time.

It can be seen from Figs. 10 and 11 that proppant masses with fibers show lower precipitation rate and better integrity. The experiment results show that fibers can not only reduce proppant precipitation rate vertically (this is very important for the distribution of proppants in the direction of fracture height), but also minimize the dispersion of proppants horizontally, so the volume of the open seepage channels can be maximized to enhance the permeability of the formation after closure of the fracture. In addition, adding fibers in fracturing can prevent the flowback of proppants, and thus significantly reduce damages to wellhead facilities caused by sand production [4].

2. Pilot tests on site

Well N in the pilot test, drilled on the north wing of the $T_2^1$ seismic reflection structure in the Xinchang Structure, is a directional development well of Sinopec Southwest Branch Company. Earlier, Layer $F_1$ (2557.0–2567.0 m) and $F_2$ (2685.0–2690.0 m) were treated by layered sand fracturing and post-fracturing comparison was performed, which confirmed that these two intervals are low-productivity gas-
bearing layers. Later on, Layer F\textsubscript{3} (2341.0–2347.0 m) was chosen for sand fracturing. It is inferred from the mechanical properties, thickness and physical properties of the reservoir, and the fracturing results of neighboring wells, that the new impulse-stage sand fracturing is suitable for the layer.

2.1. Assessment of reservoir properties

With a vertical thickness of 20 m, the target layer F\textsubscript{3} is mainly made up of medium lithic arkose. Well logging results show that: drilling time dropped from 21 to 3 min/m; drilling fluid density dropped from 1.67 to 1.60 g/cm\textsuperscript{3}; drilling fluid viscosity rose from 40 to 45 s; 15% pointed gas bubbles were detected at wellhead; gas logging \( \sum C_n \) rose from 0.17% to 19.89%. Logging data assessment results show that the layer is gas-bearing. Features of log curves can be summarized as follows: natural GR: 42 API; deep and shallow lateral resistances have slight positive differences with measured value of 26 and 24 \( \Omega \text{m} \), respectively; average acoustic time: 81 \( \mu \text{s/ft} \) (1 ft = 0.3048 m, the same below); compensated neutron: 12%; lithologic density: 2.34 g/cm\textsuperscript{3}. See Fig. 12 for log curves and relevant processing results. Features of log curves show that this layer is pure in lithology and good in physical properties, with \( POR = 13.5\% \), \( S_w = 35\% \), \( PERM = 0.25 \text{ mD} \). It is identified as a gas layer by a comprehensive assessment.

2.2. Design optimization

According to the reservoir quality, fracturing results of neighboring wells, and considering the optimized volume of sand, leading ratio, average sand ratio, maximum sand concentration, gradient of sand concentration, liquid nitrogen, fibers, impulse sand fracturing interval and other technical parameters of the new impulse-stage sand fracturing, the fracturing was simulated with fracturing design software. The results show that the fracturing formed hydraulic fractures of 136.6 m in half length, channel length of 121.5 m, fracture flow conductivity of 5736 mD/m, dimensionless flow conductivity of 123.6 and fracture height of 39.8 m. See Fig. 13 for fracture shape.

![Fig. 13. Fracture configuration and proppant distribution.](image)

![Fig. 12. Log curves and processing results of the 2320.0–2370.0 m interval in Well N (1 in = 25.4 mm, 1 ft = 0.3048 m, the same below).](image)
2.3. Application and testing of the new impulse-stage sand fracturing process

Layer F3 (2341–2347 m) was stimulated with sand fracturing in tubing injection mode on May 11, 2013. No sand production, sand plugging or equipment failure were encountered during the operation, and all operation parameters coincided well with the design. See Fig. 14 for operation plots.

After fracturing, the flowback of the well showed early gas production, a fast flowback (with a back-flow rate of 63% at 18 h after fracturing) and a high ultimate back-flow rate (69%). In addition, no sand production or other undesirable conditions were observed. Thirty six hours after fracturing, critical flow meter of 3 mm × 8 mm in size was used for trial production, with wellhead tubing pressure of 14 MPa and casing pressure of 16.5 MPa, the natural gas productivity was 24562 m³/d.

2.4. Post-fracturing assessment and evaluation of production enhancement

No packer was set during the fracturing of the well (Fig. 14), and pressure was monitored over the entire course. FracproPT and Fekete FAST softwares were used to match net pressure and production performance, the results are shown in Fig. 15. The results of net pressure match show that: dynamic fracture length is 130.8 m, and the length of the propped fracture is 130.8 m; the height of the propped fracture is 31.2 m, and the average fracture width is 1.05 cm; the average concentration of proppant is 3.41 kg/m², and the dimensionless flow conductivity is 20.145. Production performance match resulted in the volume of injected sand of 20 m³, formation pressure of 23.5 MPa; skin factor of 0; permeability (x) of $3.5 \times 10^{-3}$ mD; permeability (y) of $3.1 \times 10^{-3}$ mD; permeability (z) of 0.01 mD; effective fracture half-length of 65.6 m, production of $147.9 \times 10^4$ m³, total estimated production of $283.8 \times 10^4$ m³, and expected gas recovery of 80%.

Effective fracture length is one of the key indexes in evaluating the stimulation of tight sandstone reservoirs with low permeability and low porosity. The above matching results show that the well had a propped fracture length of 130.8 m, effective fracture half-length of 65.6 m, and a ratio of these two values of 50.15%, which is approximately 16% higher than the 33.75% in the neighboring Well C2.

Neighboring wells with the same layer include C1 and C2. See Tables 1 and 2 for basic data and fracturing parameters of the neighboring wells.

It can be seen from Tables 1 and 2 that Well N has similar $AC$, $\phi$, $K$, $TVD$ and other major geologic parameters with the neighboring Well C2, but the total thickness of its pay zone is

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**Fig. 14.** New impulse-stage sand fracturing plot of Layer F3 in Well N.

**Fig. 15.** Matching of net pressure and production performance.
slightly smaller than that of the two pay zones in Well C1. All of the three wells penetrated gas-bearing formations. Well N had a sand intensity of 1 m$^3$/m, Well C2 and Well C1 had a sand intensity of 1.9 m$^3$/m and 1.8 m$^3$/m respectively, indicating that Well N can save proppant cost of about 47.4% and 44.4% than the other two wells respectively. After sand fracturing, in terms of normalized productivity of major reservoir considering the reservoir quality, the productivity of Well N fractured with the new impulse-stage sand fracturing is 2.3 times higher than that of the neighboring Well C2 and 1.9 times higher than the total productivity of the two layers in Well C1. It can be seen that the new impulse-stage sand fracturing has achieved good results in the pilot Well N in the western Sichuan Basin, and the process has a broad application prospect in shallow sand gas reservoirs and shale gas reservoirs in western Sichuan Basin [5].

3. Conclusions

1) Theoretical analysis and flow conductivity experiment results show that the new impulse-stage sand fracturing can generate open seepage channels much higher in permeability and flow conductivity than conventional fractures propped by proppants, which is conducive to improving fracture cleanness, minimizing pressure loss in artificial fractures, and increasing effective fracture length. Thus, the purpose of extending individual production well life and enhancing productivity and profit of wells can be realized.

2) Simulation with FracProPT software shows that the new impulse-stage sand fracturing technology can generate open seepage channels. Physical modeling experiment can directly show the formation process of the open seepage channels and the section after gel breaking.

3) Fibers added in the new process play two roles: slowing down proppant precipitation vertically and preventing sand masses from dispersion horizontally.

4) The application of the new process in pilot test Well N in the western Sichuan Basin resulted in proppant cost saving of 44%—47%, the increase of ratio of effective fracture length to dynamic facture length of about 16%, and normalized productivity of 1.9—2.3 times that of the neighboring wells, indicating significant cost saving and production improvement. The process has a broad application prospect in shallow-middle depth sand gas reservoirs and shale gas reservoirs in western Sichuan Basin.

References


