# Study on the Influencing Factors of Pre-$CO_2$ Blowback After Pressure

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**Abstract.** This paper studies the main control factor analysis of shale oil fracturing fluid backflow, and calculates and sorts the weight of each influence factor under 285 samples in west 233 and Zhuang 183 blocks by grey correlation method, the main control factors of shale oil fracturing fluid reflow are segment number, sand ratio and volume of reflow, and the correlation between influencing factors and reflow rate is established based on fuzzy set theory. Taking the construction parameters of Huxx well as an example, a pre-co2 fracturing model of shale oil is established, based on the effects of different CO2 injection rate, pressure difference and muffle well time on slippage water reflow rate, CO2 reflow rate and cumulative oil production, the optimal injection rate of CO2: the injection rate of subsequent slip water (including sand-carrying fluid, displacement fluid, etc.) should be more than 20%, the optimal shut-in time is 15 days, and the optimal bottom hole flowing pressure is 8 mpa.

**Keywords:** Pre-co2 · re-discharge after pressure · influencing factors


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# 1 The Correlation Analysis Between the Influencing Factors and the Flowback Rate Based on Fuzzy Set Theory

A well with high flowback rate is a well with high flowback rate, and a well with low flowback rate is a well with low flowback rate. How to classify high flowback rate and low flowback rate is a key problem. In this part, the data of 285 Wells fractured by shale oil are analyzed, and it is found that the distribution of scatter points in the scatter diagram among each single factor has the characteristics of clutter and chaos, and it is difficult to determine the trend and law of the data according to this scatter diagram. However, after classifying the production Wells based on the fuzzy set theory, it is found that the flowback rate shows a good rule between each single factor (Fig. 1).

Based on the fuzzy set theory, the correlation between the influencing factors and the flowback rate is studied. Among them, the number of clusters, the amount of sand added, the amount of fluid injected into the ground and the sand ratio are negatively correlated with the flowback rate. There is no obvious linear relationship between stage number, displacement and flowback rate.

# 2 The Numerical Model of Shale Oil Pre-Co2 Fracturing Backflow is Established

According to the gray correlation degree analysis, the correlation degree coefficient reflects the influence degree of each factor on the fracturing effect. It can be seen that the correlation degree ranking of each influencing factor is that the main factors affecting the flowback rate of West Block 233 are sorted as displacement, number of stages and sand ratio, while the main factors affecting the flowback rate of Zhanzhuang Block 183 are sorted as sand ratio, displacement and number of stages.

## 2.1 Numerical Model Mechanism of Shale Oil Pre-Co2 Fracturing Backflow

2.1.1 Considering the flow of fracturing fluid under the coexistence of natural fracture and hydraulic fracture, a double permeability DK model of dual media is established, and the main fracture is simulated by matrix grid, the natural fracture grid corresponding to the infill grid is used to simulate the secondary fractures, so as to realize the flow of matrix to production wells and fracture to production wells.

2.1.2 Considering the high expansion of liquid carbon dioxide in the underground, the volume expansion coefficient of carbon dioxide is 1:517, and the gas expansion of liquid carbon dioxide in the formation greatly increases the reservoir energy, the fracturing fluid can be quickly discharged in a short time.

2.1.3 Considering the imbibition of fracturing fluid to matrix under the action of capillary force, the fracturing fluid in shale reservoir will migrate to matrix under the action of imbibition (Fig. 3)

2.1.4 Considering the diffusion of carbon dioxide and the swelling and viscosity reduction of crude oil, the interaction (density and viscosity) between carbon dioxide and crude oil was studied by using PR equation of state DIFFC keywords are used to simulate the diffusion of carbon dioxide.

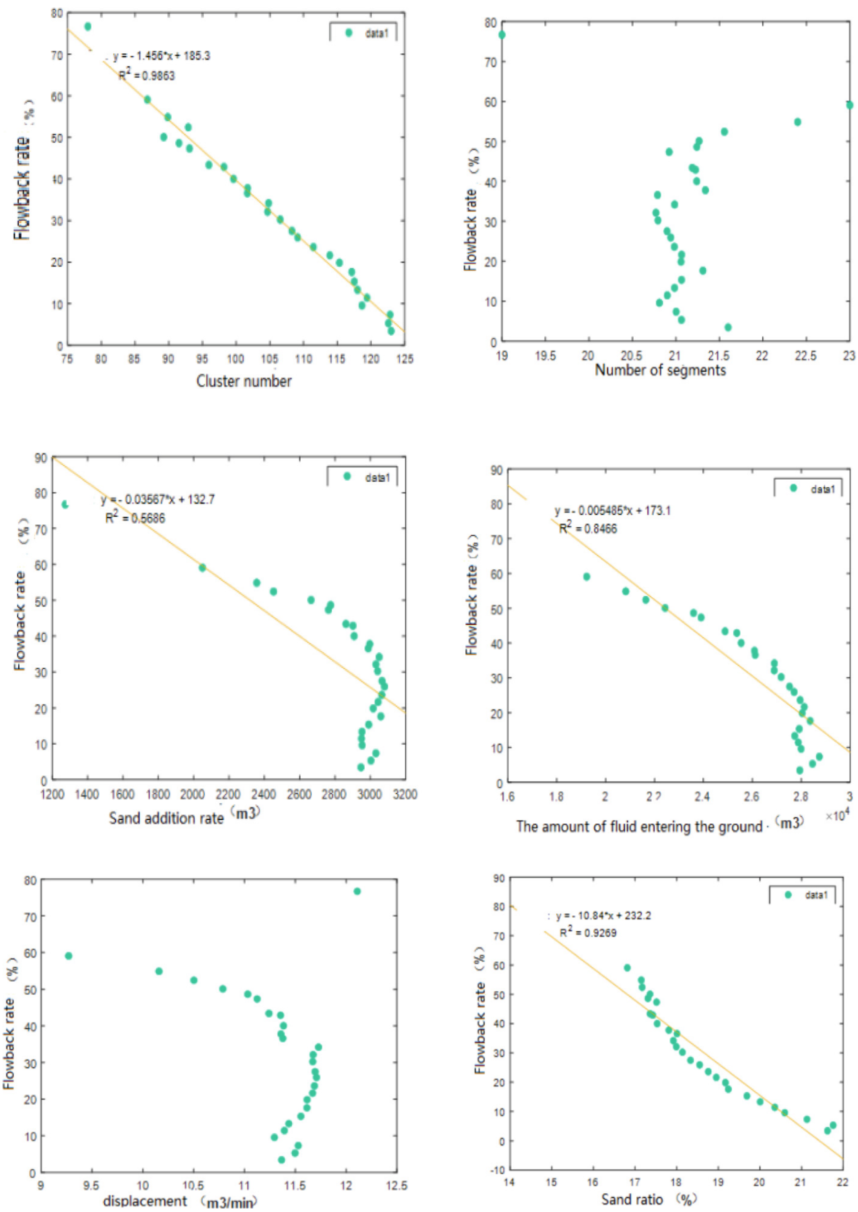


**Fig. 1.** The correlation between the relevant parameters of fuzzy set classification and the flowback rate

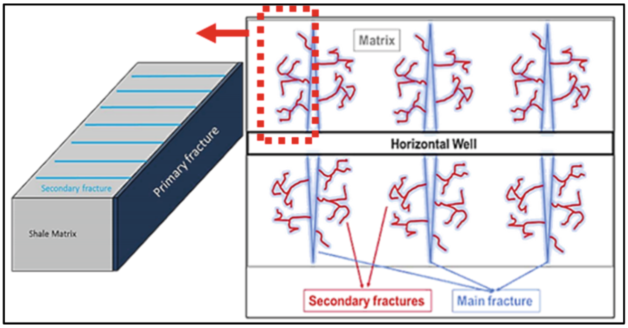


**Fig. 2.** A conceptual model for the distribution of primary and secondary fractures in hydraulic fracturing

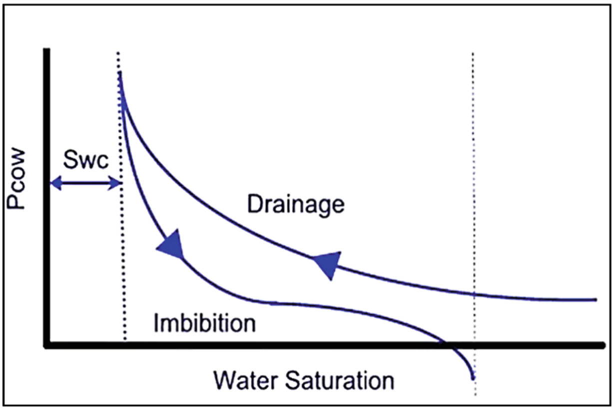


**Fig. 3.** Sketch of oil-water capillary pressure displacement and dialysis curve considering imbibition

## 2.2 The Numerical Model of Shale Oil Pre-Co2 Fracturing Backflow is Established

A two-component model is established to simulate multi-stage fracturing in horizontal wells by using logarithmic infill grid, and the seepage field near the fracture is described by using main fracture and secondary fracture. The grid is divided into 43 * 43 * 4, the length of horizontal segment is 1750 m, and the top depth is 1849 m. The simulation process is divided into two stages, the first stage of constant production to reduce pressure production, the second stage of constant pressure to reduce production development, the simulation process to ensure that the first stage of production remains unchanged, the second stage to change the bottom hole flow pressure, analyze the development effect (Fig. 4).

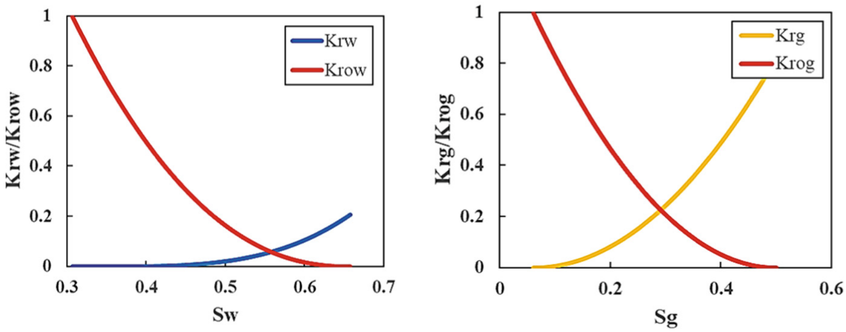


**Fig. 4.** Oil-water and oil-gas phase permeability curves

## 3 Characteristics of Pre-Co2 Fracturing Process

A three-dimensional geological model reflecting the reservoir characteristics of the study area is established, and the pressure change of the injection system, the migration law of carbon dioxide, the amount of carbon dioxide and the back discharge of fracturing fluid are analyzed by means of numerical simulation, the distribution characteristics of carbon dioxide in the formation after recoil are quantitatively characterized by analyzing the degree of CO2 producing crude oil and the recoil efficiency. Taking well Hua H32-1 as an example, the first section fracture unit is studied by injecting 264 $m^3$ pre-liquid carbon dioxide at 2 $m^3$/min, followed by injecting 1610 $m^3$ gliding water fracturing fluid at 12 $m^3$/min, the results are compared with those of pure glide fracturing under the same injection volume (Fig. 5).

According to the above-mentioned different injection and closed well during the return of carbon dioxide concentration and water saturation changes. It can be seen that the injection of carbon dioxide pre-fluid or slip water will spread to the perimeter of the main fracture surface during the injection period While the sliding water in the main fracture is absorbed into the secondary fracture area and matrix under the action of capillary force, which results in the decrease of water content in the main fracture, at the same time, the carbon dioxide pre-slug diffuses further during the shut-in period, which makes the effective spread wider; The water content and carbon dioxide concentration in the main fracture increase, and the rate of return discharge reaches the maximum and reaches the stable value after a certain production time. By comparing the pre-fracturing with the pre-fracturing with the pre-fracturing with the same injection volume, it can be seen that the re-flowing rate of pre-fracturing with the same injection volume increases by about 25% and the cumulative oil production increases by about 3,448 $m^3$, carbon dioxide in crude oil swelling viscosity reduction and as a front slug leading to a more obvious increase in energy, the amount of liquid will be relatively more.

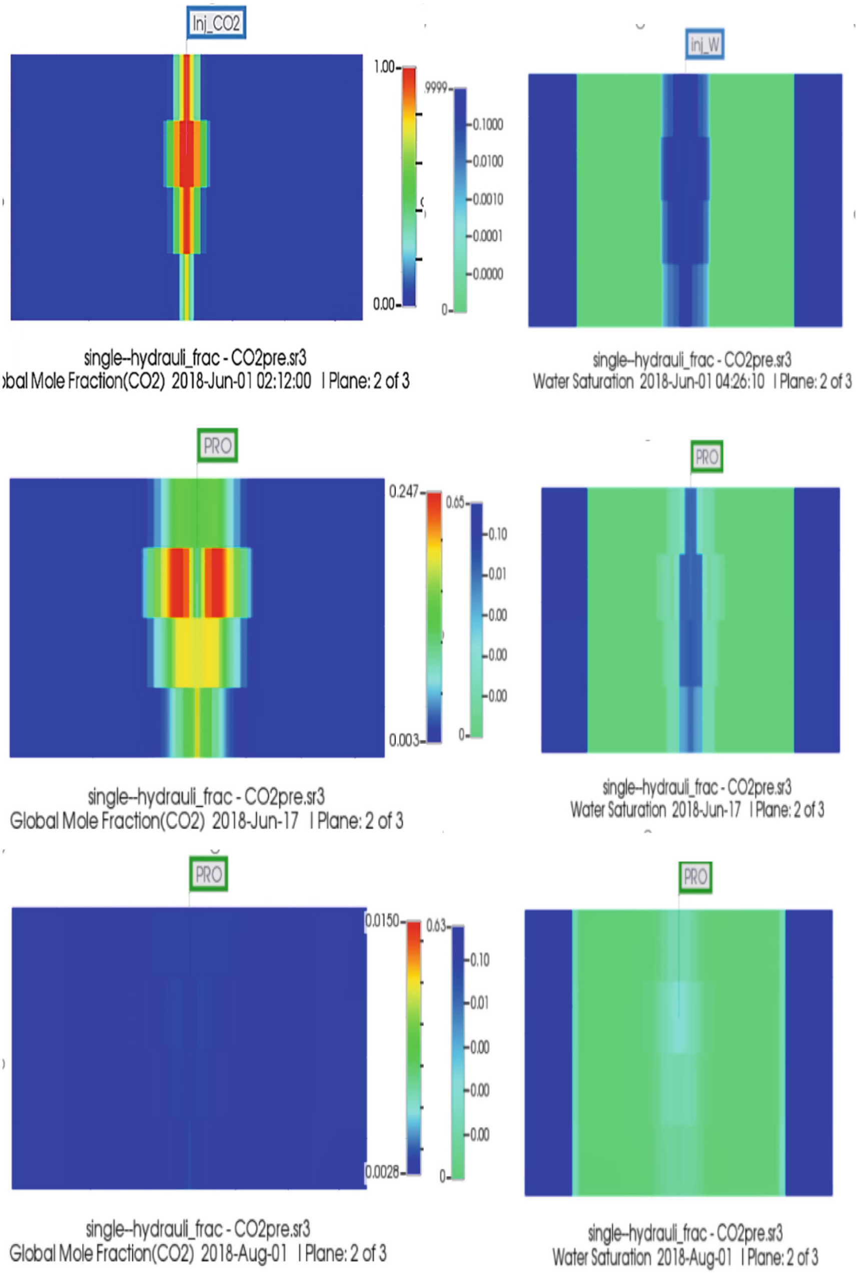


**Fig. 5.** Changes of $CO_2$ concentration and water saturation in different injection and flowback processes

## 4 Experimental Device and Process

Ten natural outcrop cores (38 mm * 80 mm) were selected for experiments, and the physical properties of rock samples were measured in accordance with the national industry standard SY/T 5336-2006 Core Analysis Method.

The flowback rate of CO2 fracturing fluid under unit pressure was studied by step-down flowback experiment. The specific experimental steps include: (1) Testing the physical properties of the core foundation: after the core splits, 40–70 mesh sand is filled to create artificial cracks, and the sand is mixed with AB glue and then filled into the cracks of the core splits. After drying, the sand and the core are consolidated into one, and the pore volume of the core is calculated; ② Establish bound water saturation: the displacement oil sample is injected into the core at a constant rate, and the displacement pressure and the water output at the core outlet are recorded every 1h. When the outlet water does not increase, the bound water saturation is established. Calculate the core bound water saturation and oil saturation. (3) Reservoir aging was simulated for 72h by maintaining the formation conditions; (4) According to the designed discharge rate, the CO2 pre-fluid and the slackwater fracturing fluid are injected into the set injection amount, and the well is suffocated for a certain time; ⑤ Reduce the core holder system to a certain pressure (such as back pressure of 5MPa, 10MPa and 15MPa), collect and measure the quality of the returned liquid by using drying pipes and absorbent cotton, measure the amount of returned gas by using saturated sodium carbonate solution, record the volume of drained slip water and crude oil, and compare the amount of liquid discharged under different injection parameters and backflow system. The effect of CO2 on return capacity was analyzed.

A. If the flowback pressure difference is 3 MPa, 5 MPa, 10 MPa, and 15 MPa, repeat the preceding steps to calculate the flowback displacement under different pressure differences.

B. Preferably under the flowback pressure difference, change the injection amount to 0.2PV, 0.4PV and 0.6PV and repeat the above steps;

C. Under the optimal flowback pressure difference and injection volume, change the boring time to 2h, 6h, 12h and repeat the above steps.

Shale oil slip-water flowback rate experiment: The test device is shown in Fig. 2. The experimental temperature is 60 °C, and the specific experimental steps include: ①–⑤ repeated enhancement experiment process; ⑥ Control the flowback pressure difference of 10MPa, reverse oil flooding from the other end of the core holder with the pressure of the system balance until no more water is produced, record the displacement pressure, measure the volume of discharged water, and calculate the slipwater fracturing fluid flowback rate. ⑦ Core oil washing, drying. The specific experimental parameters are designed as shown in Table 3–2, and the Settings of parameter values will be adjusted according to the actual experimental conditions.

# 5 Study on Main Controlling Factors of Carbon Dioxide Backflow in Pre-fracturing

By changing different injection parameters, the influence rules of injection parameters such as injection pressure, injection amount and time of backflow on the backflow of fracturing fluid are studied, and the main influencing factors are determined.

## 5.1 Differential Back Discharge Pressure

The numerical simulation of CO2 backflow rate under 5 different bottom hole flowing pressures from 4 mpa to 12 MPA was established, with the increase of fluid utilization capacity, the return rate of gliding water increases correspondingly, and the increase of the return rate increases with the increase of pressure difference, when the bottom hole flowing pressure is less than 8 mpa, the oil production increase obviously decreases. According to the simulation results, the optimal bottom hole flowing pressure is 8 mpa.

## 5.2 The Amount of Carbon Dioxide Injected

A numerical simulation of the CO2 re-emission rate was established for five groups of different proportions of CO2 pre-solution from 5% to 25%, when the ratio of pre-placed liquid is more than 10%, the rate of return of water decreases obviously, and the amount of carbon dioxide return increases linearly with the increase of the ratio of pre-placed liquid When the proportion of carbon dioxide pre-liquid is more than 20%, the cumulative oil production can be improved obviously. Considering the effect of increasing production and the factors of reflow, the better effect can be achieved when the proportion of carbon dioxide injection is more than 20% according to the simulation results.

## 5.3 Time to Muffle

The numerical simulation of the carbon dioxide (CO2) re-emission rate of five groups of well closure time from 5 days to 60 days was established, when carbon dioxide enters the deep formation under the action of diffusion, both slippage water and carbon dioxide return degree will decrease correspondingly, considering the pressure change, stimulation effect and reflow factor, the optimal reflow time is 15 days according to the simulation results.

# 6 Conclusion

The weight of each influencing factor of 285 samples in west 233 and Zhuang 183 blocks is calculated by grey correlation method and sorted. The main influencing factors of shale oil fracturing fluid reflow are section number, sand ratio and displacement, the main factors affecting the return of fracturing fluid from pre-co2 fracturing of shale oil are CO2 injection, return pressure difference and muffle well time.

A pre-co2 fracturing model for shale oil is established by taking the construction parameters of HXX well in Hua oilfield as an example, based on the effects of different

CO2 injection rate, pressure difference and muffle well time on slippage water reflow rate, CO2 reflow rate and cumulative oil production, the optimal injection rate of CO2: the injection rate of subsequent slip water (including sand-carrying fluid, displacement fluid, etc.) should be more than 20%, the optimal shut-in time is 15 days, and the optimal bottom hole flowing pressure is 8 mpa.

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