Experimental Study of Imbibition with Normal Fracturing Fluid in Low-permeability Reservoirs

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Abstract. As the volume of fracturing fluid injected in the formation is getting larger and larger, there is more attention paid to the imbibition efficiency of the broken fracturing fluids. The fracturing fluids, including water-base gel fracturing fluid, thickened water fracturing fluid, slippery water fracturing fluid, emulsified fracturing fluid and clean fracturing fluid were chosen to do the spontaneous imbibition experiment with natural core samples from the Ordos Basin. Furthermore, the correlation between the parameters including viscosity, interfacial tension and contact angle and the recovery ratio was studied respectively. The result showed that the broken fracturing fluids of water-base gel and thicken water performed the highest recovery ratio of spontaneous imbibition, which were 23.1% and 20.6% respectively. Meanwhile, the correlations between those parameters and recovery ratio were contact angle, viscosity of broken fluids and interfacial from in turn in the experimental situation. What’s more, both the contact angle and the viscosity showed negative correlation to imbibition recovery ratio while the interfacial tension showed positive correlation. This study provides help to the researchers to understand the mechanism of fracturing fluids imbibition in low permeability reservoirs.

1. Introduction
Thanks to the progress of fracturing technology, the scale of reservoir fracturing is increasing year by year. Consequently, more and more low-permeability reservoirs have been developed effectively. Due to small pore throat and strong capillary force, imbibition is an important oil recovery mechanism in low permeability reservoir [1, 2]. Making full use of hydraulic fracturing fluid to replace oil via imbibition can not only improve crude oil production, but also reduce the flowback treatment workload of waste liquid.

Many scholars at home and abroad have conducted relevant research on imbibition oil recovery of fracturing fluid, and the results show that in low permeability reservoir, the effect of fracturing fluid imbibition is significant [3-7]. There are many hydraulic fracturing fluid systems with different properties. Nevertheless the difference among the imbibition efficiencies of these fracturing fluid systems that important to choice the appropriate fracturing fluids have not been studied well. Therefore, the commonly used fracturing fluid systems in the low-permeability reservoirs were selected to conduct...
the spontaneous imbibition experiment with the natural core of Ordos Basin. The imbibition effect of different systems were assessed with the imbibition recovery rate as the index. Furthermore, the impacts of the gel breaking fracturing fluid parameters such as oil-water interfacial tension, viscosity and contact angle on spontaneous imbibition recovery degree were analyzed.

2. Experimental materials and apparatus

2.1. the core samples, oil and water
Core samples are low-permeability natural cores from Chang 6 formation in Ordos Basin. The specific parameters of core samples are shown in Table 1. According to Zhao Jingzhou's classification of sandstone reservoir in Ordos Basin [8], they belong to the ultra-low permeability reservoir with small pores and micro roars. The experimental oil is the simulated oil with a volume ratio of 1:4 of Chang 6 crude oil and kerosene, with a density of 0.81 g/cm3 and a viscosity of 7.25 mPa·s (under room temperature). The experimental water is a 1 wt% KCl solution of deionized water.

Table 1. Parameters of the core samples

| Core Number | Diameter (mm) | Length (mm) | Apparent Volume (cm3) | Porosity (%) | Permeability (mD) |
|-------------|--------------|-------------|-----------------------|--------------|------------------|
| 1           | 25.62        | 60.42       | 31.15                 | 14.05        | 0.18             |
| 2           | 25.54        | 65.58       | 33.60                 | 14.77        | 0.15             |
| 3           | 25.54        | 64.20       | 32.89                 | 14.52        | 0.19             |
| 4           | 25.52        | 72.40       | 37.03                 | 12.54        | 0.16             |
| 5           | 25.56        | 73.24       | 37.58                 | 11.55        | 0.16             |
| 6           | 25.40        | 66.38       | 33.64                 | 17.24        | 0.19             |
| 7           | 25.50        | 68.78       | 35.13                 | 12.57        | 0.16             |
| 8           | 25.46        | 70.90       | 36.10                 | 11.82        | 0.15             |
| 9           | 25.56        | 71.36       | 36.62                 | 11.89        | 0.17             |
| Average     |              |             |                       | 13.44        | 0.17             |

2.2. Fracturing fluids
Five typical fracturing fluid systems, including water-based gel fracturing fluid, sliding hydraulic fracturing fluid, thickened hydraulic fracturing fluid, emulsion (oil in water) fracturing fluid and clean fracturing fluid (cationic type), have been selected and prepared for they are the most widely used hydraulic fracturing of low-permeability reservoir. The main components of each system are shown in Table 2.

Table 2. Formulas of different kinds of fracturing fluid

| Fracturing fluids                        | Additives                  | Agents                        | Mass fraction (%) |
|------------------------------------------|----------------------------|-------------------------------|------------------|
| Water based gel fracturing fluid (crosslinking ratio 100:10) | Crosslinker | Borax                         | 0.40             |
|                                          | Breaker                    | Ammonium persulfate           | 0.50             |
|                                          | Thickener                  | Hydroxypropyl guar            | 0.30             |
|                                          | Clay stabilizer            | Potassium chloride            | 1.00             |
| Sliding hydraulic fracturing fluid       | Drag reduction agent       | Hydroxypropyl guar            | 0.10             |
|                                          | Clay stabilizer            | Potassium chloride            | 1.00             |
|                                          | Demulsifier and cleanup additive | Methanol                     | 0.15             |
|                                          |                            | Sodium chloride               | 0.15             |
| Thickened hydraulic fracturing fluid     | Thickener                  | Carboxymethylcellulose        | 0.30             |
|                                          | Clay stabilizer            | Potassium chloride            | 1.00             |
|                                          | Temperature regulator      | Sodium bisulfite              | 0.05             |
| Emulsion (oil in water) fracturing fluid | Thickener                  | Xanthan gum                   | 0.30             |
|                                          | Cleanup & Demulsifier      | Methanol                      | 0.35             |
|                                          |                            | Sodium chloride               | 0.35             |
|                                          | Emulsifier                 | Sodium dodecylbenzene sulfonate | 0.40         |
| Clean fracturing fluid                   | Cationic surfactant        | Octadecyl trimethyl ammonium chloride | 4.00    |
|                                          | Anti ion salt              | Sodium salicylate             | 2.00             |
|                                          | Clay stabilizer            | Potassium chloride            | 1.00             |
2.3. Apparatus
Core vacuum saturation device, core displacement device, electric mixer, DV3TLVTJ0 viscometer (Brookfield), Precise electronic balance, imbibition bottle, TX-500c interfacial tension tester (CNG Enterprises Inc.), SL200KB optical contact angle tester (USA KINO Industry co. Ltd.)

3. Experimental method and procedure
The spontaneous imbibition recovery degree was studied via the experiments with the natural core samples in different fracturing fluids. The main procedure of the experiment as following.

1) Test the interfacial tension and viscosity of the simulated oil and the gel breaking liquid;
2) Test the contact angle of the simulated oil and the gel breaking liquid on the corresponding experimental core;
3) Maintain the cores in the vacuum saturation device for 48 h under the pressure of less than -0.09 MPa to vacuum and saturate the core samples with water in the core;
4) Drive the core with water to saturate water more well in the cores using the core displacement device. Terminate water flooding when the outlet liquid volume reaches 5 PV, and weigh the weight of the cores saturated with water. Eventually, record the quantity of the saturated water;
5) The core displacement device is used to drive the oil and water until there is no water at the outlet end and the oil is stable for 5 PV. Therefore, the oil-saturated cores with bound water is obtained;
6) Set the oil-saturated cores in the simulated oil and aged for 120 h;
7) Dip the cores in the imbibition bottles full with different fracturing fluid system as the imbibition medium. The experimental temperature was 20 ℃. When the oil production is less than 0.01 ml/10 h, it is considered that the imbibition is over.

4. Results and analysis

4.1. Apparatus
The results of the different fracturing fluids property parameters testing experiments were shown in Table 3, as well as the potassium chloride solution used as the blank control group.

| Gel breaking fracturing fluids                  | Interfacial tension (mN • m⁻¹) | Viscosity (mPa • s) | Contact angle (°) | Contact angle cosine |
|-----------------------------------------------|--------------------------------|--------------------|-------------------|---------------------|
| Water based gel fracturing fluid              | 0.98                           | 2.45               | 68.1              | 0.37                |
| Sliding hydraulic fracturing fluid            | 1.65                           | 4.28               | 69.9              | 0.34                |
| Thickened hydraulic fracturing fluid          | 2.00                           | 4.55               | 52.6              | 0.61                |
| Emulsion fracturing fluid                     | 0.53                           | 4.07               | 105.2             | -0.26               |
| Clean fracturing fluid                        | 0.75                           | 1.58               | 135.4             | -0.71               |
| Potassium chloride solution (1 wt %)          | 25.31                          | 0.98               | 36.1              | 0.81                |
The results of spontaneous imbibition experiments and oil recovery of different fracturing fluid systems were shown in Fig. 1. It can be seen from the figure that the initial imbibition speed of the core in the water-based gel fracturing fluid was the fastest, and the final recovery rate of imbibition was the largest, which was 23.1%. The next was KCl solution, which had 21.7% imbibition recovery rate. The third was thickened hydraulic fracturing fluid, which had 20.6% imbibition recovery rate. The imbibition recovery rates of other fracturing fluid systems were below 15%.

4.2. Analysis

In the spontaneous imbibition procedure, the velocity of the interface between different phrases depends on the viscosity difference between these phrase, the radius of the pores, capillary pressure, imbibition time and the total length of the pore canal [9].

\[ v = \frac{r^2 p_c}{8 \left[ (\mu_2 L)^2 - (\mu_1 - \mu_2) \frac{r^2 t}{4} p_c \right]} \]  

(1)

Where, \( v \) is the two-phase interface moving speed, \( r \) is the radius of the suction hole, \( \mu_1 \) and \( \mu_2 \) are the viscosity of the gel breaker and the simulated oil, \( L \) is the length of the suction hole, \( t \) is the suction time, and \( p_c \) is the capillary force. The capillary force can be expressed as [9]:

\[ p_c = \frac{2\sigma \cos \theta}{r} \]  

(2)

In the formula 2, \( \sigma \) is the interfacial tension between the breaker and the simulated oil, \( \theta \) is the three-phase contact angle between the breaker, the simulated oil and the experimental core.

It can be seen from Table 1 that the physical properties of the cores used in the experiment are similar. Therefore, it can be approximately considered that the radius \( r \) and the length \( L \) had little influence.
on the difference of the imbibition recovery degree. Therefore, the main factors affecting the imbibition recovery degree of each experimental group are the interfacial tension, the viscosity of the gel breaker $\mu^i$ and the contact angles of gel breaking fluids on the cores. In order to determine the influence of the above factors on the imbibition, it is necessary to carry out correlation analysis. The experiments conducted with different fracturing fluid systems including KCl solution were used as experimental samples to calculate the correlation coefficients between the interfacial tension, viscosity and wetting angle of the fracturing fluid and the spontaneous imbibition recovery.

Note $\text{Cov}(X,Y)$ as the covariance of variable $X$ and variable $Y$; $D(X)$ is the variance of variable $X$, as well as $D(Y)$. Then the overall correlation coefficient $p_{XY}$ between variable $X$ and variable $Y$ can be expressed as formula (3) [10], and the calculation process and results were shown in Table 4 and Figure 2.

**Table 4. Analysis of the correlation between the factors and imbibition**

| Items                  | Interfacial tension (mN·m⁻¹) | Viscosity (mPa·s) | Contact angle (°) | Imbibition recovery degree (%) |
|------------------------|------------------------------|-------------------|-------------------|-------------------------------|
| Experimental samples   |                              |                   |                   |                               |
| Water based gel        | 0.98                         | 2.45              | 68.10             | 23.10                         |
| Thickened              | 2.00                         | 4.55              | 52.60             | 20.60                         |
| Emulsion               | 0.53                         | 4.07              | 105.20            | 11.50                         |
| Clean                  | 0.75                         | 1.58              | 135.40            | 15.40                         |
| 1 wt% KCL              | 25.31                        | 0.98              | 36.10             | 21.70                         |
| Average                | 5.20                         | 2.99              | 77.88             | 17.20                         |
| Variance               | 97.35                        | 2.32              | 1319.78           | 28.41                         |
| Covariance             | 22.34                        | -3.73             | -108.13           |                               |
| Correlation coefficient| 0.42                         | -0.46             | -0.56             |                               |

\[
p_{XY} = \frac{\text{Cov}(X,Y)}{\sqrt{D(X)D(Y)}}
\]  
(3)

![Fig. 2 Bar graph of the correlation between the factors and imbibition](image)
The positive and negative correlation coefficients reflect the promotion or inhibition of the corresponding factors on the spontaneous imbibition recovery degree, while the absolute value reflects the influence intensity of the factors on the imbibition and recovery degree. It can be seen that under the experimental conditions, the correlation coefficient between wettability (contact angle) and spontaneous imbibition recovery degree is the largest, that is to say, wettability has the greatest influence on spontaneous imbibition recovery degree. Next in turn is gel breaking viscosity and interfacial tension. The correlation coefficient between the viscosity and contact angle of gel breaker and the imbibition recovery degree is negative, which indicates that the imbibition recovery tends to decrease with the increase of contact angle or the viscosity of gel breaking fluids. On the contrary, with the increase of interfacial tension (on the one hand, the capillary force of imbibition increases, on the other hand, the Jiamin effect becomes more sensitive), the degree of imbibition tends to increase. Because the interfacial tension of all systems except KCl solution is very small under the experimental conditions, and the impact of the interfacial tension change on capillary force is greater than that on Jamin effect.

5. Conclusion
1) For low-permeability reservoir, different water-based fracturing fluid shows great difference in the spontaneous imbibition recovery degree, in which the water-based gel fracturing fluid and the thickened hydraulic fracturing fluid have the highest recovery degree, which can reach more than 20%, significantly higher than the other fracturing fluid systems.
   2) Based on the analysis of capillary dynamics and flow resistance factors in the process of imbibition and oil drainage, it is shown that the viscosity, interfacial tension and contact angle of gel breaking fluids have a decisive influence on the degree of imbibition recovery. Under the experimental conditions, the increase of contact angle and viscosity of gel breaking liquid can inhibit the degree of imbibition recovery, while the appropriate increase of interfacial tension can promote that.
   3) It is of great significance to improve the imbibition effect of gel breaking fracturing fluid to make full use of the big amount of fluid used in the fracturing process and improve the utilization degree of reservoir matrix crude oil. The imbibition effect of gel breaking fracturing fluid can be improved by reducing the viscosity and contact angle of fluids and reasonably controlling the interfacial tension of gel breaking fluid.

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