Performance and Damage Evaluations of Fracturing Fluid in Tight Sandstone Oil Reservoirs

X F Liu
College of Energy Engineering, LongDong Uniersity, Qingyang, 745000, China
E-mail: xuefen580@126.com

Abstract: Fracturing fluid from M oilfield, Ordos’s basin, China was investigated. The shear viscosity, emulsification and demulsification performance, residual content in gel breaking fluid, compatibility among foreign fluid and formation water, and permeability damage were separately analyzed. Results show that the fracturing fluid system has better shear properties and sand carrying capacity at high temperature. The emulsification rate reached more than 60%, while the demulsification rate was less than 25%. The compatibility among working fluid and the formation water was relatively poor and precipitation was easily to generate. The residue content in broken gel was relatively low but the residue particles were more likely to enter micro fractures; permeability damage was moderately weak in fractured samples.

1. Introduction
The development of tight sandstone reservoirs has become one of the most important energy resources worldwide [1]. Such reservoirs are extremely poor in physical properties with fine pore throat, low porosity, low permeability, high capillary pressure, partial development of micro-fracture, and ultra-low water saturation [2,3]. It is difficult to achieve effective development without assistance from technological processes, such as hydraulic fracturing [4]. Hydraulic fracturing can reduce flow resistance and improve fluid seepage. Therefore, the production/injection ability in oil wells/water wells can be enhanced and damage near wellbore can be relieved [5,6]. Fracturing fluid is the key to success fracture [7]. The current fracturing fluids are mainly water-based. The thickening agents, usually polymers, are cross-linked with the cross-linking agent to form super-large molecules with poor hydrolyzability. After fracturing, considerable amount of insoluble or incompletely degraded polymer restrained in the fractures, blocking the fluid seepage and reducing the fracturing effect [8-10]. Damages caused by fracture fluid include water blocking damage [11], reducing the rock hardness [12], solid-phase adsorption damage [13], filter cake damage [14]. Superposition of damages will lead to great decrease in fracture conductivity [15]. Therefore, the studies in performance and potential damage of the fracturing fluid in reservoir are critical to the improvement of fracturing effect in tight sandstone reservoirs. The main tasks in this paper include analyzing the performance of the fracturing fluid system, investigating the permeability damages caused by fracturing fluid to the micro-fracture developed tight sandstone reservoir.

2. Fracturing fluid performance tests
2.1. Fracturing fluid composition and preparation
The composition of fracturing fluid includes glue solution, cross-linking agent, pH adjuster, breaker. HPG, CX-307(Clean-up agent), Clay stabilizer, Bactericide, Borax, NaOH, Ammonium persulfate...
were used. Base fluid, cross-linking solution and glue solution were prepared and viscosity was tested under the instruction of the Industry Standard SY/T 5107-2005 [16].

2.2. Fluid compatibility

Emulsification rate and demulsification rate was tested and determined according to water-based fracturing fluid performance evaluation method “the Industry Standard SY/T 5107-2005” [16]. Compatibility between formation water and foreign fluid was tested. Broken fracturing fluid, drilling fluid filtrate (from oilfield), and the formation water was used. Tests included compatibility between formation water and broken fracturing fluid, formation water and drilling fluid filtrate, and broken fracturing fluid and drilling fluid filtrate. Firstly, mix the above fluid two by two at volume ratio of 1:2, 1:1, 2:1 at 60 °C, and set aside for 1 hour to observe precipitation; Secondly, separate precipitate by centrifugation, and filter it by filter paper; Finally, dry precipitate to constant weight.

2.3. Polymer residue determination

Polymer residue was determined according to water-based fracturing fluid performance evaluation method “the Industry Standard SY/T 5107-2005” [16] as well. The particle size of the broken fracturing gel was measured with a laser particle size analyzer at last.

3. Evaluation of permeability damage

3.1. Materials

Fractured tight sandstone samples from target reservoir were used for damage evaluation (table1). Broken fracturing fluid filtrate was used as invasion phase. Formation water was used to establish initial water saturation. The mixture of kerosene and crude oil at ratio of 3:1 was used as oil phase.

| Core # | Length (cm) | Diameter (cm) | Porosity (%) | Permeability ($10^{-3} \mu m^2$) | Fracture Width (µm) |
|--------|-------------|--------------|--------------|-------------------------------|---------------------|
| M1     | 4.43        | 2.42         | 6.61         | 0.260                         | 4.23                |
| M2     | 4.48        | 2.42         | 7.26         | 0.622                         | 5.65                |

3.2. Methodology

Permeability damage evaluation was conducted with core flow equipment. Experimental steps include: ①Select core samples and measure permeability and porosity (pulse method); ②Fracture the core and pretreat it at 7 MPa confining pressure for 3 hours, then measure permeability again and calculate the fracture width; ③Establish initial water saturation of 30%; ④Put the core in core holder and inject oil into the core under the critical flow rate with the confining pressure of 5MPa, until the oil displacement reaches 10 times of Pore Volume and the injection pressure become level; ⑤Measure the oil flow rate and calculate oil permeability $K_i$; ⑥ Inject broken fracturing fluid filtrate into the core in reverse direction at pressure same as that achieved in step④ for 2~3h, then close valves and make the core immersed in the filtrate for 12 hours; ⑦Displace oil in the same direction as step④, under the pressure a little higher than that in step⑥, ensuring that the fracturing fluid filtrate cleaned up. Finally, measure oil flow and calculate oil permeability $K_d$. Permeability damage is calculated by equation (1).

$$SI_f = \frac{K_i \cdot K_d}{K_i} \times 100\%$$

Where, $SI_f$ is the damage rate of fractured samples, %; $K_i$ is the initial oil permeability before damage, $10^{-3} \mu m^2$; $K_d$ is the oil permeability after damage, $10^{-3} \mu m^2$. 
4. Results and discussion

4.1. Viscosity test
The calculated viscosity of the base fluid and broken fluid was 38.73 mPa·s and 2.98 mPa·s at room temperature, respectively. The shearing viscosity of fracturing fluid tested by High Temperature Shear Viscometer at 66 °C and 100 r/min for 90 minutes maintained at 200mPa·s. Shearing pressure was 40Pa at the same condition, indicating a better pump ability and strong sand carrying capacity.

4.2. Fluid compatibility
The emulsification rate of oil and broken fracturing fluid at volume ratio of 3:1, 3:2, and 1:1 was 72.5%, 81.2%, and 69%, respectively, shown in figure1. However, the demulsification rate was less than 25% and happened during the first 60 minutes (figure 2). It reveals that controlling the invasion amount of fracture fluid and flow back timely is important to reduce damage caused by emulsification.

Results in table 2 show the compatibility between the injected fluid and the formation water. There was worst compatibility between the drilling fluid filtrate and formation water. Fracturing fluid has worse compatibility with formation water. It is likely to form precipitation as soon as the foreign fluid contact the formation water. Experimental results indicate that damage is more serious in the process of fluid loss during drilling than fracturing [17], and it is worst when the ratio is 1:1.

| Liquid type                          | Completion fluid filtrate: formation water | Fracturing fluid filtrate: formation water | Completion fluid filtrate: fracturing fluid filtrate |
|-------------------------------------|-------------------------------------------|-------------------------------------------|-----------------------------------------------|
| Volume ratios                       | 2:1                                       | 1:1                                       | 1:2                                           |
| Mixed liquid volume (mL)            | 30                                        | 20                                        | 30                                            |
| Precipitation (mg)                  | 138.5                                     | 136.5                                     | 73.9                                          |
| Content of precipitation (g/L)      | 4.62                                      | 6.83                                      | 2.46                                          |

4.3. Residue and particle size
The residue content of the broken gel was about 281 mg/L and the composition was mainly the flocculated macro-insoluble polymer [18]. As macromolecules in the fracture fluid is prone to agglomerate automatically in aqueous solution, they can adsorb and then deposit on the pores and fractures surface. That may cause channel narrowed or blocked and reduce the mass transport from matrix to fractures.

The size of the residue particles is shown in figure 3. It implied that diameter of particles that occupied 10% of the residue (d₁₀) was 15.181 μm, diameter of particles that occupied 50% of the residue (d₅₀) was 53.784 μm, and diameter of particles that occupied 90% of the residue (d₉₀) was
153.735 μm. Most of the particles size is much larger than the diameter of the pore throats (0.5~3.14μm) contributing greatly to reservoir permeability but is of the same magnitude as the average opening width of the fractures (>20μm) obtained by conventional logging. It indicates that the macromolecule in the broken fracture fluid is difficult to enter the pore throat but more likely to enter micro fractures. If it cannot flow back timely and restrain in the reservoir, the filter cake formed on the rock surface will block fluid flow from matrix to fractures and wellbore.

![Distribution curve and accumulative distribution of the broken gel.](image1)

Figure 3. Particle size distribution and accumulative distribution of the broken gel.

On one hand, the filter cake formed by residue on the rock surface can somewhat prevent fracture fluid and large particles from flowing deep into the formation. On the other hand, the smaller residual particles along with the fracturing fluid will pass through the filter cake and enter deeper part of the formation, making the throats and pores blocked and fracture conductivity reduced [19,20]. Complete blockage of the sand-filled fractures could result in fracturing failure. Anyway, the apparent viscosity of the breaking gel solution was 2.98 mPa·s, which also indicated that there were still short or branched molecules in the broken fluid.

4.4. Permeability Damage

Figure 4 shows the compare of oil permeability for fractured sample M1 and M2 before and after damage by fracturing fluid. The damage rate for M1 and M2 was 38.27% and 39.41%, respectively, indicating the damage extent was moderately weak. There are some tiny blocks falling from the core after it was taken out from core holder. It was similar to the result obtained by Zhou et al (2016) that there was a degree of mineral particle migration caused by alternative displacement and immersion [12]. During the process of displacing and injection, rock strength reduced because of fluid immersion and some weak bounded particles on the fracture surface fell off. Changes in rock strength after fluid immersion will intensify stress sensitivity damage [21].

![Compare of oil permeability before and after fracture fluid damage.](image2)

Figure 4. Compare of oil permeability before and after fracture fluid damage.
5. Conclusions
The paper investigated the performance of fracturing fluid from M oilfield, Ordos’s basin, China, and evaluated the damage caused by this fracturing fluid. Conclusions are given as follows.

The viscosity of the base fluid and broken fluid was 38.73 mPa·s and 2.98 mPa·s, separately. The shearing viscosity at 66 °C and 100 r/min was 200mPa·s and shearing pressure was 40Pa, indicating a better pump ability and strong sand carrying capacity.

The emulsification rates of oil and broken glue at different ratios were above 60%, but the demulsification rate was less than 25%. There was also poor compatibility among the foreign fluid and the formation water, which was easy to form sediment and block the pore throat. The residue content in the broken gel was about 281 mg/L. The size of most of residue particles was much larger than the diameter of the main throat but similar to the average opening of the micro fracture obtained by logging. The permeability damage of fracturing fluid to fractured tight samples was moderately weak.

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