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Experimental Study of the Damage of Fracturing Fluid

XUE Jieqiong [a],[b],*; XU Yaohui[a],[b]; JIANG Long[c]; MA Yunlong[d]; ZHAO Nan[e]

[a]College of Resources and Environment, Yangtze University, Wuhan, China.
[b]Key Laboratory of Exploration Technology for Oil and Gas Research (Yangtze University) Ministry of Education, Wuhan, China.
[c]School of Petroleum Engineering, China University of Petroleum, Qingdao, China.
[d]Dowhole Technology Service Company, BHDC, PetroChina, Cangzhou, China.
[e]Engineering and Technology Research Institute, North China Branch, Sinopec, Zhengzhou, China.
*Corresponding author.

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Abstract

Hydraulic fracturing is an effective way to stimulate the production rate for reservoirs with low permeability. However, the infiltration of the fracturing fluid will damage the permeability of the reservoir matrix and the conductivity of the proppant pack. The commonly used HPG and CMHPG were selected to study the gel-breaking performance of the fracturing fluid with different mass concentration, and further to study the damage to the matrix and the proppant pack. Results showed that: The gel-breaking performance of CMHPG is better than that of HPG, the viscosity and the residue content of gel broken solution are significantly reduced; the solid phase damage is the main factor that causes the matrix damage. The smaller the reservoir permeability, the greater the damage rate caused by the fracturing fluid; the greater the amount of the thicker, the greater the amount of residue in the broken gel, and the greater the damage to the conductivity of the proppant pack.

Key words: Fracturing fluid; Reservoir damage; Proppant pack; Gel-breaking performance

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INTRODUCTION

Hydraulic fracturing is the most important stimulation technology for the development of unconventional oil and gas resources at this stage.[1] In the process, the fracturing fluid plays the role of pressure transmission and proppant carrying. However, the fracturing fluid can also cause different degrees of damage to the reservoir, while creating oil and gas seepage channels.[2] The data show that the infiltration of the fracturing fluid filtrate into the rock matrix can reduce the permeability of reservoirs by more than 50%. The types of the fracturing fluid damage include the permeability damage of the matrix caused by the infiltration of the fracturing fluid filtrate, and the fracture conductivity damage of the proppant pack caused by the fracturing fluid residue and the filter cake.[3]

With the development of fracturing fluid, it has undergone oil-based fracturing fluid to water-based fracturing fluid to foam fracturing fluid.[4] In recent years, new fracturing fluid systems such as viscoelastic surfactant have been developed. However, the water based fracturing fluid systems are still the most widely used.[5] The main components of the water-based fracturing fluid are thicker, crosslinking agent and breaker. The main types of thicker are plant gum, cellulose and synthetic polymers.[6]

Hydroxypropyl guar gum (HPG) and carboxymethyl hydroxypropyl (CMHPG) guar gum are most widely used plant gum in oilfield application.[7] Therefore, the two kinds of guar gum were selected and the static gel-breaking performance was studied. On this basis, the water-sensitive damage, the water-locking damage, and the solid phase damage caused by the two mentioned types of fracturing fluids to the core were investigated by flow experiments, and the damage rate of reservoirs with different permeabilities were determined. Besides, the damage to the proppant pack was studied by investigating the change of conductivity. The results can be used in optimizing the fracturing fluid, improving the performance, and developing of tight reservoirs effectively.

1. EXPERIMENTAL

The additives of the fracturing fluid used in the experiment such as HPG, CMHPG, cross-linking agents, breakers, clay stabilizers, drainage aids agents, bactericides and the like were all provided by the oilfield, and the dosage was based on the field application. The agents used in preparing the simulated formation water, such as NaCl, $CaCl_2$, $MgCl_2$, were all analytical grade and purchased from Sinopharm. The simulated oil phase was aviation kerosene which was refined in our laboratory.

2. RESULTS AND DISCUSSION

2.1 Gel-Breaking Performance of Guar Based Fracturing Fluid

Gel-breaking process happens to the gar based fracturing fluid quickly under the effect of strong oxidizer in a specific temperature. However, it is difficult to degrade completely, leaving some precipitate in the **gel borken solution**. According to the characteristics of guar based fracturing fluid, the viscosity of the gel borken solution prepared by different concentrations of thicker, the content of solid residue, as well as the particle size of the residue were studied. The results are shown in Table 1.

Table 1
Characteristics of the Gel Borken Solution of HPG and CMHPG Fracturing Fluid

Types of thicker in the fracturing fluid	Mass concentration/%	Viscosity of gel borken solution /mPa·s	Mass concentration of solid residue/ $mg \cdot L^{-1}$	Median size/μm
HPG	0.3	1.9	178.6	90.03
	0.4	2.6	265.2	92.19
	0.5	3.6	405.3	94.11
CMHPG	0.3	2.1	86.5	86.35
	0.4	2.3	113.1	89.26
	0.5	2.5	168.9	91.03

It can be seen from Table 1 that the viscosities of the gel borken solution prepared by different concentrations of thicker are less than 5mPa • s, which meets the application requirements of the oilfield and can flow back from the formation after hydraulic fracturing; with the increase of thicker concentration, the viscosity of gel broken solution gradually increases; the viscosity of the gel borken solution of HPG is higher than that of CMHPG, under the same concentration. For the content of solid residue and the particle size, also show the similar change as the viscosity. The requirements for the fracturing fluid is lowering the viscosity of the gel borken solution, with the purpose of helping to flow back easily, and lowering the content of solid residue and the particle size, with the purpose of reduce the risk of blockage of reservoir and proppant pack. Therefore, according to the above principles, it can be known that gel-breaking performance of CMHPG fracturing fluid is better than that of HPG fracturing fluid, which can better meet the needs of fracturing technology.

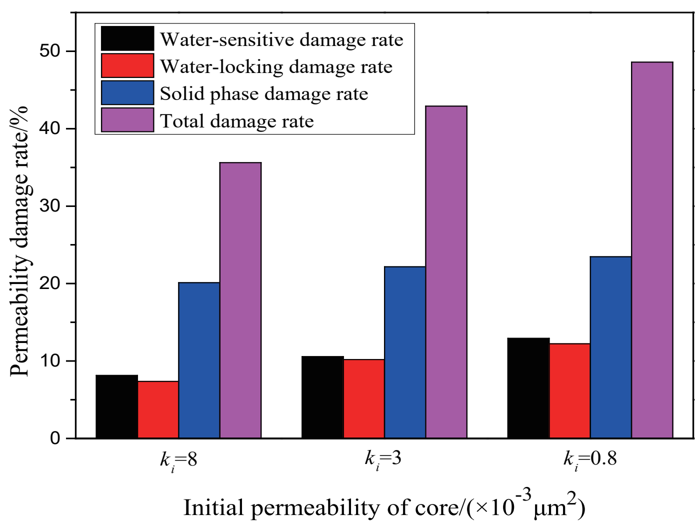
2.2 Damage to the Permeability of the Matrix

In the process of hydraulic fracturing, the damage to matrix caused by water-based fracturing fluid includes water-sensitive damage, water-locking damage, and solid phase damage. In order to quantify the damage rate of each type, six groups of experiments were conducted, and three tests were in each group. The parameters of the cores used in the three tests of each group were supposed to be the same, because the cores used in the three tests of each group were taken from the same conditions. The core numbers and parameters used in each test are shown in Table 2. The specific steps to determine the damage rate of the three types are as follows. For water-sensitive damage, firstly 10PV of simulated formation water was injected to determine the permeability k_0, then 2PV of simulated exogenous water was injected through the reverse direction, and finally 10PV of simulated formation water was injected to determine the permeability k_1. For the water-locking damage, firstly simulated formation water was injected to saturate the core, then simulated oil was injected to establish the state of oil saturation, and the oil phase permeability of k_0 can be obtained. 2PV of simulated exogenous water was injected through the reverse direction, and finally 10PV of simulated oil was injected to determine the oil phase permeability of k_1. For solid phase damage, firstly 10PV of simulated formation water was injected to determine the permeability k_0, then 2PV of the solution of gel breaking fluid obtained after filtration was injected through the reverse direction, and finally 10PV of simulated formation water was injected to determine the permeability k_1. The damage rate of each test can be calculated according to the initial permeability k_0 and final permeability k_1, as shown in Figure 1.

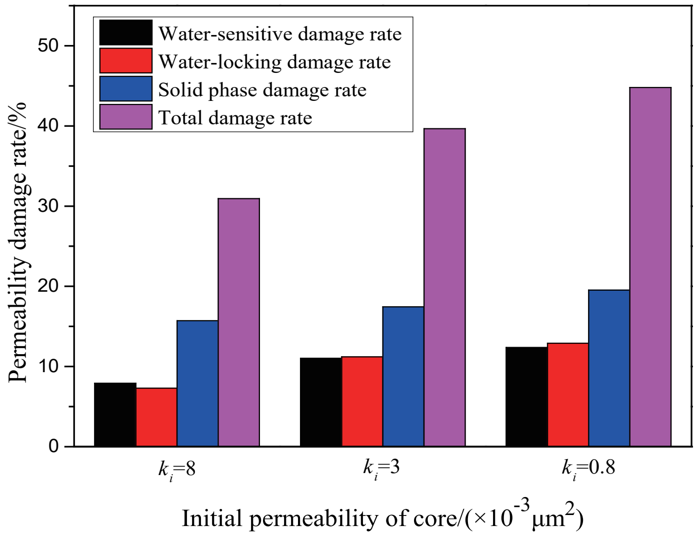
Table 2
Core Parameters and the Corresponding Experimental Program

Thicker	Core number	Length/cm	Diameter/cm	Porosity	Permeability/$10^{-3}\mu m^2$	Type of damage	Injected liquid
	1-A	4.95	2.51	13.06	7.96	Water-sensitive damage	(b)
	1-B	4.93	2.51	15.15	8.11	Water-locking damage	(c)
	1-C	4.96	2.51	14.59	8.03	Solid phase damage	(d)
	2-A	4.92	2.53	10.76	3.11	Water-sensitive damage	(b)
HPG	2-B	4.98	2.53	10.99	3.15	Water-locking damage	(c)
	2-C	4.93	2.53	10.02	3.09	Solid phase damage	(d)
	3-A	5.01	2.52	5.36	0.78	Water-sensitive damage	(b)
	3-B	4.96	2.52	5.92	0.86	Water-locking damage	(c)
	3-C	4.97	2.52	6.19	0.88	Solid phase damage	(d)
	4-A	4.98	2.52	16.32	8.72	Water-sensitive damage	(b)
	4-B	4.96	2.52	15.08	8.05	Water-locking damage	(c)
	4-C	4.99	2.52	15.97	8.32	Solid phase damage	(d)
	5-A	4.93	2.52	11.13	3.26	Water-sensitive damage	(b)
CMHPG	5-B	4.97	2.52	9.86	3.05	Water-locking damage	(c)
	5-C	4.96	2.52	11.83	4.02	Solid phase damage	(d)
	6-A	4.92	2.51	4.98	0.65	Water-sensitive damage	(b)
	6-B	4.95	2.51	5.25	0.72	Water-locking damage	(c)
	6-C	4.93	2.51	5.12	0.69	Solid phase damage	(d)

Three conclusions can be drawn from Figure 1. Comparing the permeability damage rates of cores with different permeability shows that as the initial permeability decreases, the damage rate under the same conditions increases. In the three damage types, the damage caused by the adsorption and retention in the reservoir of macromolecules in the fracturing fluid residue is the largest, which is the main factor of damage caused by fracturing fluid, while water-sensitive damage and water-locking damage are less and with little difference between them. Comparing the damage rate caused by HPG and CMHPG, the former is obviously bigger than the other. The reason lies in that the solid phase damage is the main factor. The gel-breaking performance of CMHPG is better than that of HPG, and with little residue in the gel broken solution.



(a) HPG fracturing fluid



(b) CMHPG fracturing fluid

Figure 1
Relationship of Permeability Damage Rates With the Initial Permeability of Cores

2.3 Damage to the Conductivity of the Proppant Pack

In the conductivity tests, the closure pressure was set at 10MPa to prevent the influence caused by proppant crushing. The liquids were injected according to the order: Firstly 10PV of the KCl solution was injected and the initial conductivity was calculated; secondly the gel borken solution of HPG or CMHPG with different volume was injected from the reverse direction; finally 10PV of the KCl solution was injected and the final conductivity was calculated. The relationship of fracturing conductivity with the injection volume of gel broken solution is shown in Figure 2.

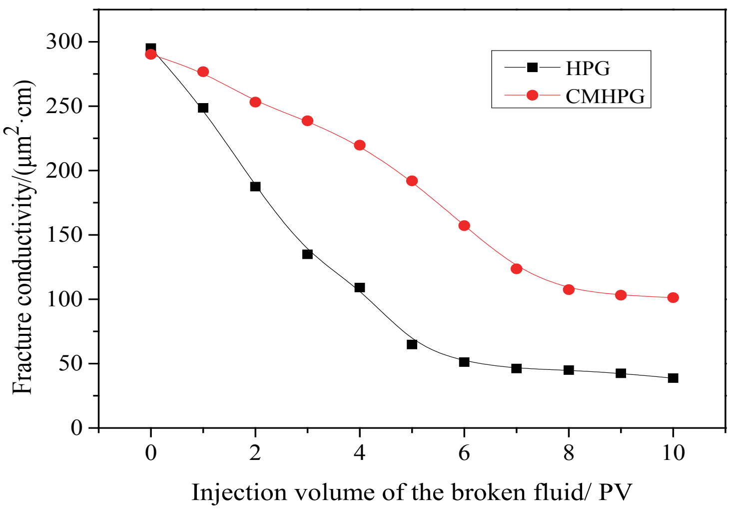


Figure 2
Relationship of Fracturing Conductivity With the Injection Volume of Gel Broken Solution

It can be seen from Figure 2 that with the increase in the volume of the gel broken solution injected, the conductivity of the proppant pack decreases. When 1PV of the solution was injected, the conductivity of the sample treated by HPG was 248.61μm^2·cm, and the damage rate was 15.74%, while 4.63% when comes to CMHPG. With the further increase of the volume to 4PV, the damage rate of HPG and CMHPG was 63.03% and 24.3%, respectively, indicating the gap became widening. When the injection volume was 8PV, the slopes of the two curves tended to be stable. The damage rates changed to 86.88% and 65.11%, accordingly, meaning that the CMHPG fracturing fluid resulted in lower damage than HPG. The results were corresponding with the mass of fracturing fluid residue, which were 405.3 mg·L^{-1} and 168.9 mg·L^{-1}. It shows that the gel-breaking performance of guar based fracturing fluid is the main reason that causes the damage to the conductivity of the proppant pack. Therefore, the fracturing fluid with excellent gel-breaking performance should be selected in field application to reduce the damage to conductivity of proppant pack.

CONCLUSION

(a) The gel-breaking performance of CMHPG fracturing fluid is better than that of HPG fracturing fluid. The content of the residue in the gel broken solution is less than that of MPG fracturing fluid, as well as the damage to matrix and proppant pack.

(b) Under the same conditions, the smaller the reservoir permeability, the greater the damage caused by the fracturing fluid. For guar gum fracturing fluid, solid damage is the main reason for the decrease of reservoir permeability, and that is the main factor of fracturing fluid damage to the reservoir.

(c) The content of residue in gel broken solution is the main factor that affects the conductivity of proppant pack. The higher the dosage of thicker is, the larger the damage will be.

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