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Full Length Article

Experimental study on disproportionate permeability reduction caused by non-recovered fracturing fluids in tight oil reservoirs[☆]

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ABSTRACT

Inefficient recovery of fracturing fluid leaves much chemical residual (containing polymer friction reducer) in microfractures, which is closely related to relative permeability near fracture, flowback of fracturing fluid, production rate, etc. This work was to investigate rock damage associated with fracturing fluid filtration and its effect on subsequent oil and water flow behavior. First, fracturing fluid filtration test was performed under different core permeability and polymer friction reducer concentration conditions. Second, fractured tight sandstone models were fabricated with different fracture widths. Oil or brine was injected at various velocities before and after fractured tight sandstone models were fluxed with fracturing fluid, and residual resistance factors to oil ($F_{rr,oil}$) and brine ($F_{rr,brine}$) were specified with different fracture widths and polymer friction reducer concentrations. Experimental results showed that core damage occurred and polymer chains were trapped or adsorbed in rock matrix. Higher polymer friction reducer concentration would aggravate core damage in a lower permeability core sample. Residual resistance factor to brine and oil decreased as shear rate increased, and their relationship could be well fitted with a power-law equation. $F_{rr,brine}$ was always larger than $F_{rr,oil}$, which revealed non-recovered fracturing fluid could selectively reduce the permeability to water more than to oil in microfractures. The reason behind it was elucidated by polymer wall effect. At the same shear rates, smaller fractures presented larger residual resistance factors. Besides, chemical residual grew with an increase in friction reducer concentration, resulting in a higher resistance to fluid flow. This study could provide a constructive guide for flowback after fracturing operations and the development of fracturing fluid.

1. Introduction

The exploitation of unconventional hydrocarbon resources including tight reservoirs and gas shale has raised widespread attention from all around the world [1–4]. Field tests were successfully carried out in tight reservoirs in Daqing Oilfield and Tuha Oilfield [5,6], which provided good theoretical guidance for the development of tight reservoirs in China. Horizontal well technology and multistage hydraulic fracturing were introduced in unblocking production potential of unconventional formation. Usually water base fluid with crosslinked gel and slickwater were used together for hydraulic fracturing in tight oil reservoirs [7,8]. The injection of water base fluid with crosslinked gel was to generate the main fractures perpendicular to horizontal wellbore. And the chase injection of slickwater was to induce complex microfracture network. As operators continued to apply fracturing in the field case, the engineers began to discover there are large amount of slickwater fracturing liquids residual in widely developed microfracture network due to the inefficient recovery during flowback [9–11]. The inefficient recovery of fracturing water could be attributed to water imbibition into the clay-rich rock. Additionally, for tight gas or shale gas reservoirs, inefficient displacement of fracture water by gas was also an important factor to affect flowback ratio. Serving as the primary additive in the slickwater fracturing fluid [12,13], polyacrylamide-based friction reducer might be trapped or adsorbed in the microfractures and pore throats during hydraulic operations, and resulted in a significant impact on subsequent water and oil flow behavior [14]. Some field cases also presented better production performance under the circumstance of lower recovery of fracturing fluid. However, most of former studies were focused on production increment of tight oil due to multistage hydraulic fracturing; while very few results were reported in the literature on how non-recovered fracturing fluid impacts fluid flow behavior in microfractures.

Polymer or polymer gel exhibits the function of preferentially reducing water permeability in conventional reservoirs, which is known

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Nomenclature

F_{rr}	residual resistance factor
$F_{rr,oil}$	residual resistance factor to oil
$F_{rr,brine}$	residual resistance factor to brine
Q	oil or bine injection rate, mL/min
P_{before}	stabilized brine/oil injection pressure before fracturing fluid injection, kPa
P_{after}	stabilized brine/oil injection pressure after fracturing fluid injection, kPa
C_p	polymer friction reducer concentration in fracturing fluid, wt%
k	permeability of core sample, md
γ	shear rate, s^{-1}
W_f	fracture width, mm
DPR	disproportionate permeability reduction
C, b	experimental-related coefficients in the power-law equation between residual resistance factor and shear rate

as disproportionate permeability reduction (DPR) [15–17]. White et al. [18] reported nearly 200 producing oil wells with polymer treatment for water control and provided a guide for selecting candidate wells. Theoretically, DPR was explained as the result of a competition between the cross-sectional area of reductions to water and oil, and increasing water-wet condition during polymer adsorption process [19–21]. The experiments conducted by Barreau et al. discussed that an adsorbed-polymer layer could change the capillary pressure in addition to flow sectional area reduction at pore level and thus significantly reduce residual oil saturation for oil-wet cores [22]. And his team also revealed the wall effect of fully water-saturated polymer could account for the change in relative permeabilities and capillary pressure via numerical modeling [23]. Zaitoun et al. conducted in-laboratory experiments and computed capillary pressure, and also presented that the change of relative permeability and capillary pressure could be explained in terms of wall effect [24]. Al-Sharji et al. performed a cationic polyacrylamide injection experiment in glass micromodels [25]. Polymer layer was observed to build up on the crevices between the grains under water wet condition, resulting in a remarkable permeability reduction to water and no significant permeability reduction to oil. While no polymer layer was observed under oil-wet condition and oil/water permeability remained unchanged before and after polymer injection. Stavland and Nilsson pointed that segregated flow of oil and water at pore level was also a dominating factor to DPR fluids (gel or a single polymer system) and oil continuity was achieved much easier for single polymer system than crosslinked gels [26]. Several experimental studies demonstrated that polymer adsorption could also selectively reduce permeability to water more than to gas, and the DPR effect was more significant as compared to oil/water system [27–29]. Our previous studies that focused on tight gas and shale gas revealed that gas permeability could be even enhanced due to fracturing fluid residual in microfractures [30]. This effect was more significant in tight sandstone than in gas shale because the adsorbed polymer could lubricate the tight sandstone surface more [31]. In all, polymer treatment could present DPR effect to water and oil at pore level, but whether this effect is presented in microfractures and the extent to which water permeability is reduced more than oil permeability are still unknown.

With the focus on non-recovered fracturing fluid that was residual in tight geological formation, the objectives of this study were to investigate fracturing fluid filtration into tight sandstone, and to study the extent to which chemical residual in microfractures could reduce permeability to water more than to oil. The workflow of this study could be divided into two sections: 1) we conducted fracturing fluid filtration test under different pressure drop, rock permeability and polymer friction reducer concentration conditions to study their effect on the damage of core samples. 2) We fabricated fractured tight sandstone models with different fracture widths, and performed oil/brine injection experiments at various velocities before and after the models were fluxed with fracturing fluid. And residual resistance factors due to fracturing fluid residual were specified with different fracture widths and friction reducer concentrations. It was expected to introduce the DPR effect due to chemical residual (polymer adsorption) in porous media of conventional reservoirs to fracture system of tight oil reservoirs.

2. Experiments

2.1. Materials

Tight sandstone core slices with a diameter of 2.5 cm and a length of 1 cm were used in the fracturing fluid filtration test to model fracturing fluid leakoff during hydraulic fracturing. Cylindrical tight sandstone core samples with a diameter of 2.5 cm and a length of 30 cm were used to fabricate fractured tight sandstone models. Each core sample was cut in half from the center, and stainless steel sheets with different thicknesses were inserted between the two halves to model fractures, as depicted in Fig. 1. Tight sandstone cores were used in the experiments because they could better model the adsorption-entanglement effect of polymer in real fracture system. All the core samples were artificially fabricated with outcrop sand to make sure that the wettability of the core was consistent with that at reservoir conditions.

In this study, brine was made with distilled water and the salinity was 64,622 mg/L. The injected oil was made of paraffin oil and kerosene with a viscosity of 0.97 mPa·s that was consistent with oil viscosity in Chang 7 layer of Ordos Basin. The fracturing fluid, provided by CNPC Chuanqing Drilling Engineering Company Limited, was consist of polyacrylamide with a molecular weight of 10 million Daltons as friction reducer, surfactant with a concentration of 0.2 wt% as cleanup additive, and potassium chloride with a concentration of 1 wt% as clay stabilizer. The polyacrylamide was prepared in liquid phase with an effective content of 30% and a great solubility in water. Considering the concentration range of polymer friction reducer in slickwater fracturing fluid, the polyacrylamide concentrations in fracturing fluid were designed as 0.05, 0.1 and 0.2 wt%.

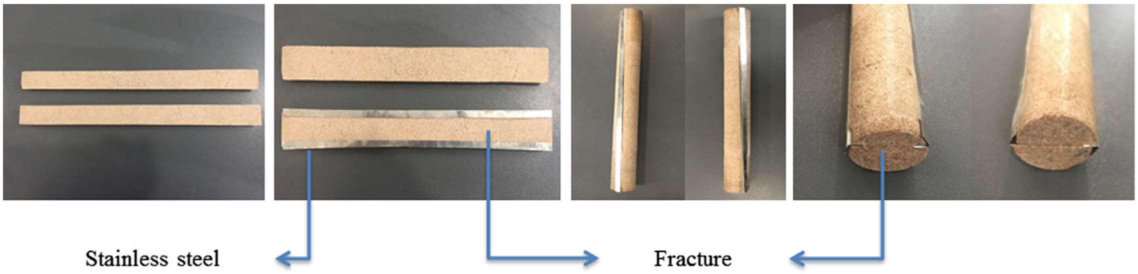

Fig. 1. Fractured tight sandstone model used in the experiments.