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Research Article

Formation Damage due to Drilling and Fracturing Fluids and Its Solution for Tight Naturally Fractured Sandstone Reservoirs

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Drilling and fracturing fluids can interact with reservoir rock and cause formation damage that impedes hydrocarbon production. Tight sandstone reservoir with well-developed natural fractures has a complex pore structure where pores and pore throats have a wide range of diameters; formation damage in such type of reservoir can be complicated and severe. Reservoir rock samples with a wide range of fracture widths are tested through a multistep coreflood platform, where formation damage caused by the drilling and/or fracturing fluid is quantitatively evaluated and systematically studied. To further mitigate this damage, an acidic treating fluid is screened and evaluated using the same coreflood platform. Experimental results indicate that the drilling fluid causes the major damage, and the chosen treating fluid can enhance rock permeability both effectively and efficiently at least at the room temperature with the overburden pressure.

1. Introduction

Drilling fluid is typical water-based or oil-based depending on the needs of field operations [1, 2]. Compared to water-based drilling fluids, oil-based drilling fluids can provide excellent lubrication, stabilize water-sensitive clays, reduce leak-off, and form thinner filter cakes; besides, they can be applied in deep reservoirs with characteristics of high pressure and extreme temperature [2–5].

Among different types of oil-based drilling fluids, water-in-oil emulsion (i.e., inverted emulsion) is mainly used in the field because of its outstanding properties [3, 6]. However, depending on their droplet sizes, emulsions therein can invade reservoir rock and plug pores/pore throats, resulting in diminished hydrocarbon production [7–9]; moreover, surfactants which are added for generating emulsions can be adsorbed on rock surface and alter the wettability, which may also cause formation damage [7, 10]. Besides the emulsions, suspended solids in the inverted emulsion, which is added for hindering leak-off, may also plug pores/pore throats; and this can make the formation damage even worse [8, 11]. Furthermore, drilling fluid may also affect the quality of cementation [12, 13] or hydrocarbon production through multiphase flow [14]. Therefore, it is imperative to evaluate the formation damage due to drilling fluid and explore the corresponding solutions.

Once the drilling process is accomplished, hydraulic fracturing is commonly used to stimulate the reservoir; this process can also cause formation damage. During the fracturing, a large volume of proppants is carried into the reservoir by the fracturing fluid, and this is aimed at creating a complex and highly conductive fracture network [15, 16]. Gel is typically used as the fracturing fluid to maximize the proppant-carrying capacity because of its excellent viscosity and elasticity [17–22]. However, gel residuals can block fractures and pores at fracture faces, thus impeding the flow of hydrocarbon [23–25]. Besides gel residuals, water can imbibe rock matrix and cause phase trapping, which reduces hydrocarbon permeability due to multiphase flow [26–29].

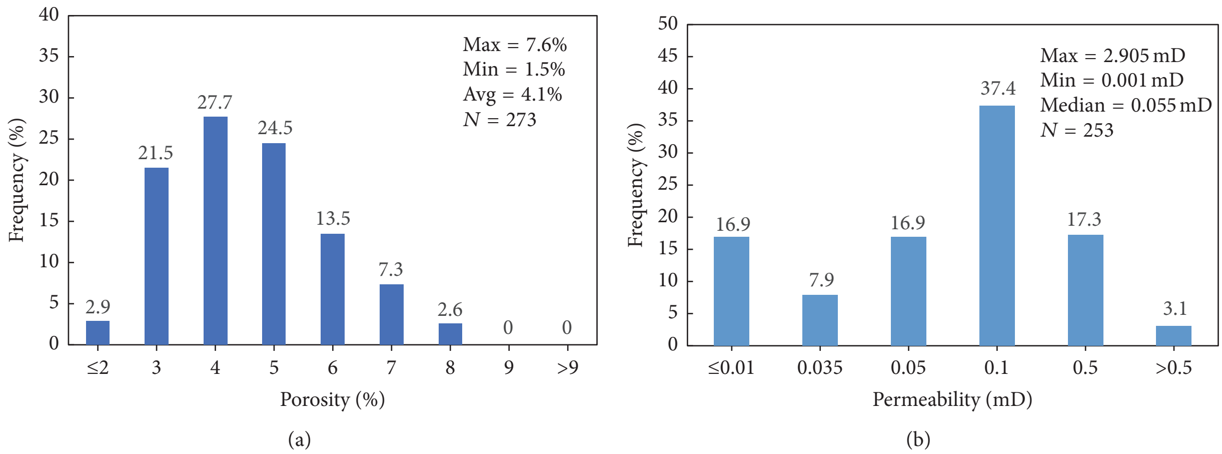


Figure 1: Core analysis results of porosity (a) and permeability (b) from over 250 reservoir rock samples.

Formation damage due to drilling and fracturing fluids is likely different in the low-permeability sandstone with well-developed natural fractures. For such a type of rock matrix, natural fractures may serve as the primary pathway for hydrocarbon to flow into the hydraulic fractures and then the wellbore. It has been found that formation damage in fractures can be difficult to be cleaned up and detrimental to the production [30, 31]. However, for this type of reservoir rocks, it remains unknown that the proportion of permeability damage due to either the drilling fluid or the fracturing fluid and its change with the width of natural fractures. Specifically, for reservoir rock far away from the wellbore, fracturing fluid likely dominates the formation damage, while, for reservoir rock near the wellbore, both drilling and fracturing fluid can dominate the formation damage.

To mitigate formation damage due to the water-in-oil drilling mud, it has been found that lowering pH value can invert the emulsions into the oil-in-water form, which can aid in the removal of emulsion blockage [3, 5], while choosing nonionic surfactants can reduce the adsorption on rock surface and thus prevent the wettability alteration [13]. To mitigate formation damage due to the fracturing gel, it has been found that lowering pH value can also remove gel residuals and clean up such damage [32, 33]. Meanwhile, using acid can also create new flow paths, dissolve suspended fines, and clean up the plugged pores [34–36]; in the field, using acid (i.e., acidizing) has already been successfully applied in sandstone reservoirs to enhance the production [37]. Low-permeability sandstone with well-developed natural fractures has a complex pore structure, where pores and pore throats have a wide range of diameters. In such type of porous media, impact of the acidic treating fluid can be complicated and thus needs to be evaluated for further modification.

In this study, rock samples are directly cored from a deep reservoir in Tarim Basin; fractures with well-controlled widths are reconstructed in the samples so that the impacts of working fluids can be systematically studied in the lab. A multistep coreflood platform is designed to quantitatively evaluate the formation damage caused by drilling and/or fracturing fluids, as well as the effectiveness of the well-screened acidic treating fluid on mitigating such damage and enhancing the production.

2. Target Reservoir

The target reservoir locates in the northwest of Tarim Basin in China. Buried in a depth of over 6000 m, this reservoir is characteristic of high pressure and extreme temperature, where oil-based drilling fluid with weighting agents is required for drilling. The reservoir rock is mainly composed of low-permeability sandstone with well-developed natural fractures. Within a total thickness of about 300 m, core analysis results of over 250 samples show the porosity of the reservoir rock ranges from 1.5% to 7.6% with an average of 4.1% (Figure 1(a)), while the permeability ranges from less than 0.001 mD to 2.905 mD with a median of 0.055 mD (Figure 1(b)). Results indicate this reservoir has a low porosity and moderate heterogeneity in permeability, which is likely attributed to the natural fractures within rock matrix.

Pore system typically consists of intergranular pores, intragranular pores, basis pores, and natural fractures. Their percentages in the reservoir rock are measured from 6 wells through imaging logs and core analyses, as shown in Figure 2(a). Results indicate intergranular pores account for the largest proportion of the total pore spaces, and natural fractures are well-developed in the reservoir rock. Considering relatively high permeability/conductive of natural fractures, it is very likely that they contribute more to the total production, especially during the early time. Among all the natural fractures, approximately 68% is uncemented or partially cemented (Figure 2(b)), which can serve as high-speed pathways for hydrocarbon to flow.

3. Materials and Methods

3.1. Core Samples from Reservoir. 27 core samples are drilled from the reservoir and tested in this study. Table 1 lists the dimensions, matrix permeability, and the mimicked fracture

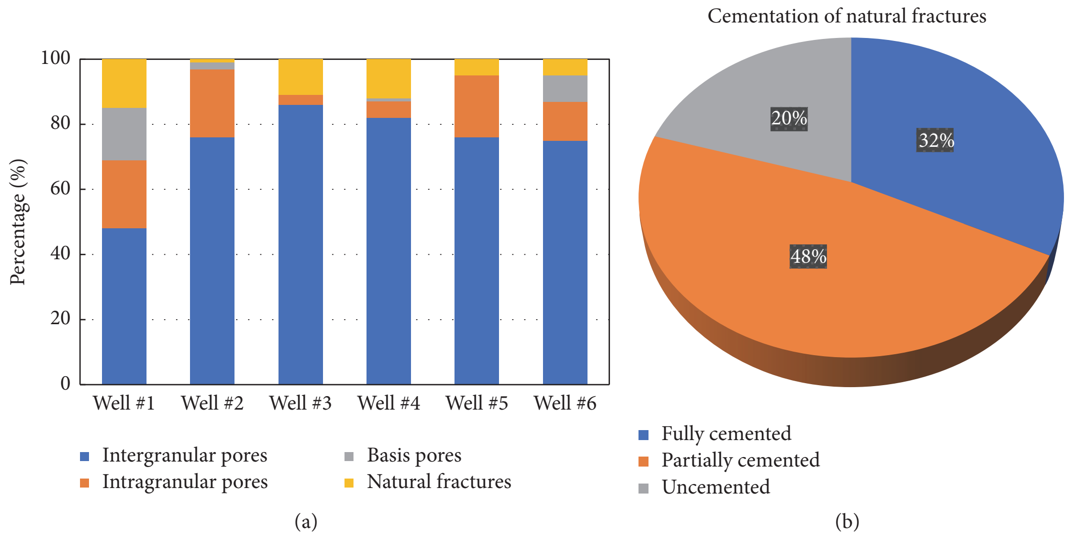


FIGURE 2: Percentages of different types of pores (a) and cementation of natural fractures (b) in the reservoir rock.

TABLE 1: Information about core samples used in this study.

Sample name	Length (cm)	Diameter (cm)	Matrix permeability (mD)	Fracture width (μm)	Fluid damage or treatment tests
#1	4.70	2.47	0.0077	10	Fracturing fluid
#2	4.53	2.47	0.0047	57	Fracturing fluid
#3	3.92	2.46	0.0027	89	Fracturing fluid
#4	37.5	2.46	0.0027	112	Fracturing fluid
#5	56.8	2.48	0.0056	123	Fracturing fluid
#6	51.9	2.45	0.0087	139	Fracturing fluid
#7	3.75	2.46	0.0027	20	Drilling fluid + fracturing fluid
#8	4.45	2.44	0.0137	53	Drilling fluid + fracturing fluid
#9	4.34	2.44	0.0137	76	Drilling fluid + fracturing fluid
#10	4.27	2.46	0.0012	98	Drilling fluid + fracturing fluid
#11	4.27	2.46	0.0012	116	Drilling fluid + fracturing fluid
#12	4.38	2.45	0.0910	127	Drilling fluid + fracturing fluid
#13	4.30	2.45	0.0910	139	Drilling fluid + fracturing fluid
#14	4.17	2.45	0.0140	42	Acid treatment
#15	4.27	2.44	0.0010	68	Acid treatment
#16	4.18	2.47	0.0019	91	Acid treatment
#17	4.15	2.47	0.0019	103	Acid treatment
#18	4.36	2.44	0.0010	117	Acid treatment
#19	4.40	2.44	0.0010	127	Acid treatment
#20	4.52	2.45	0.0015	139	Acid treatment
#21	4.07	2.44	0.0045	17	Drilling fluid + acid treatment
#22	4.49	2.44	0.0010	53	Drilling fluid+ acid treatment
#23	4.49	2.45	0.0015	75	Drilling fluid+ acid treatment
#24	4.09	2.45	0.0140	97	Drilling fluid+ acid treatment
#25	4.58	2.45	0.0038	115	Drilling fluid + acid treatment
#26	4.55	2.45	0.0009	127	Drilling fluid+ acid treatment
#27	4.59	2.45	0.0002	140	Drilling fluid+ acid treatment

Figure 3: Setup to measure permeability of tight rock through pressure-pulse-decay method.

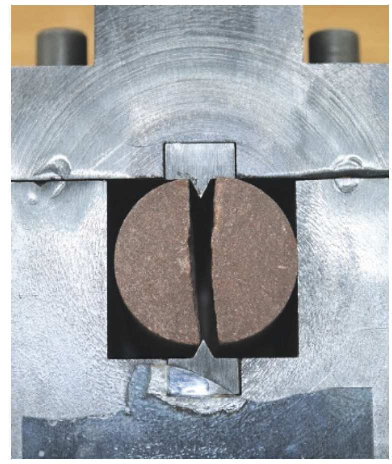


Figure 4: Device for splitting core sample to generate a fracture.

width of each core sample, as well as the damage-evaluation test conducted on each sample. To measure the matrix permeability, pressure-pulse-decay method is applied using a setup as shown in Figure 3. After loading a core sample in the coreholder, a pressure-pulse is generated at the core upstream using nitrogen; core permeability can be calculated from the measured pressure-decay curve from the upstream and/or the pressure response from the downstream [38, 39]. For different damage-evaluation tests, their detailed procedures are delineated in the section of *evaluation of permeability damage due to different working fluids*.

4. Working and Treating Fluids in the Lab

4.1. Formation Brine. In this study, the mimicked formation brine is used as the base fluid to measure the permeability of the fractured reservoir rock. It contains 2 wt.% potassium chloride, 5.5 wt.% sodium chloride, 0.45 wt.% magnesium chloride, and 0.55 wt.% calcium chloride.

4.2. Drilling Fluid. Oil-based emulsion (i.e., inverted emulsion) is used in the field as the drilling fluid. In the lab, the identical formulation is tested to evaluate its damage on the reservoir rock. To synthesize this fluid, 20 wt.% calcium chloride brine is emulsified in #0 diesel oil with a water-to-oil ratio of 20 : 80. It also contains 2 wt.% bentonite to improve the fluid rheology, 3 wt.% asphalt to reduce the leak-off, and an appropriate amount of barite to tune the fluid density for balancing the reservoir pressure.

4.3. Fracturing Fluid. The fracturing fluid applied in the field contains approximately 0.5 wt.% high-molecular-weight guar, 1 wt.% temperature stabilizing agent (i.e., antioxidant), 1 wt.% flow-back surfactant, 0.1 wt.% bactericide, and traces of other additives. In the lab, this formulation is also tested to evaluate the damage from the fracturing fluid on the reservoir rock.

4.4. Acidic Treating Fluid. Mud acid is commonly used to mitigate the formation damage in sandstone reservoirs, and it is a mixture of hydrofluoric acid (HF) and hydrochloric acid (HCl) [35, 40]. However, it has drawbacks including clay sensitivity, high corrosion rate and thus high acid-consumption rate for the target reservoir rock. To overcome such drawbacks, an organic acid (i.e., formic acid) is mixed with mud acid because of its retarded nature, low corrosion rate and thermal stability [41]; other additives are also applied for multiple purposes as their names suggested, such as preventing the wellbore corrosion, minimizing the potential formation of sludge and emulsions, and stabilizing the clay minerals [42, 43]. In this study, the optimized formulation of the acidic treating fluid contains 9 wt.% hydrochloric acid, 3 wt.% formic acid, 2 wt.% hydrofluoric acid, 2 wt.% clay stabilizer, 4 wt.% corrosion inhibitor, 1 wt.% flow-back surfactant, 0.3 wt.% friction reducer, and 1 wt.% demulsifier. Its effectiveness on reducing the damage from working fluids is also evaluated using the same coreflood platform.

5. Mimicked Naturally Fractured Core Samples with Different Fracture Widths

Imaging logs have shown that the widths of natural fractures in this reservoir typically range from 20 μm to 160 μm. Since the stress-change from the deep reservoir to the surface during the coring operation can easily affect the widths of fractures within the cores or even break the integrities of cores with wide fractures, core samples with few natural fractures are chosen in this study; in all chosen samples, no uncemented or partially cemented fractures are observed. To mimic a naturally fractured rock, a cylindrical core sample is split in half using the fracture-generating device as shown in Figure 4; after two identical copper wires with certain thicknesses are placed parallel between two halves, the core sample is wrapped by a heat-shrink tubing and dried in an oven for later usage. After each coreflood test, the wrapped core sample is open, and the thicknesses of two copper wires are measured and recorded as the fracture width of this core. To quantitatively study the influence of fracture width on permeability damage due to different working and treating fluids, core samples with copper wires with different

Figure 5: Multistep coreflood platform in the Lab.

thicknesses are prepared and compared using the identical experimental setup as introduced in the following section.

6. Laboratory Evaluation of Permeability Damage due to Different Working and Treating Fluids

To evaluate the permeability damage due to the drilling and fracturing fluids as well as the effectiveness of the acidic treating fluid on mitigating the damage, a multistep coreflood platform is designed in the lab as shown in Figure 5. Before conducting the coreflood experiments, artificial fractures with different fracture widths are generated within 27 core samples as shown in Table 1. Although a separate experiment has been conducted beforehand to explore the relationship between the fracture width and the effective permeability of the fractured rock, both parameters are still acquired for each core samples during its multistep coreflood; details are shown as follows.

Step 1 (saturate the core with the mimicked formation brine). Once the fractured core sample is completely dried in an oven, it is loaded vertically in the core holder with a confining pressure of 5 MPa (center in Figure 5). After vacuuming the core sample, brine is injected at a constant flow rate from the top to the bottom till this core is fully saturated. Then, it is rested for 12 hr to minimize the impact of stress-change on its fracture width. In the end of this step, brine is injected again into the core at a constant flow rate; from the pressure-drop across the core measured by a pressure transducer (left in Figure 5), the initial effective permeability of this fractured core can be determined before it experiences any damage from the working fluids.

Step 2 (damage the core with the working fluids). In this step, the drilling fluid or fracturing fluid is injected through a piston accumulator into the core sample from the bottom to the top. Due to the high viscosity of the drilling fluid, it is injected at a constant pressure of 3.5 MPa for 2 hr, while the fracturing fluid is injected at a constant flow rate of 4 mL/min for 15 min. For the reservoir rock near wellbore, it is successively damaged by both drilling fluid and fracturing fluid; to mimic this damage in the lab, the drilling fluid and the fracturing fluid are injected into the core in sequence during this step, both at a constant pressure of 3.5 MPa for 2 hr.

Step 3 (evaluate the permeability damage of the core). The mimicked formation brine is injected again into the core sample from the top to the bottom as in Step 1. After the pressure-drop across the sample is stabilized, the effective permeability is calculated to evaluate the damage caused by working fluids. In the end of this step, the core sample is taken out of the core holder, and the thicknesses of two copper wires therein are averaged, which is recorded as the fracture width of this core.

6.1. Treatment: Evaluate the Effectiveness of Acidic Treating Fluid on Mitigating the Damage. To evaluate the selected acidic treating fluid, it is injected into the core sample at a constant flow rate of 4 mL/min for 15 min after the drilling fluid injection at Step 2. The permeability recovery is then measured through a normal Step 3 using the mimicked formation brine. Results are further compared to a group of corefloods without any working fluid damage; that is, only the acid treating fluid is injected into the core during Step 2.

In this study, formation damage and its mitigation are evaluated using "permeability recovery rate," which is defined as the ratio of rock permeability after the damage to rock permeability before the damage. All experiments are conducted at room temperature, and it is focused on the changes of rock permeability after the damage and the treatment. Although it has been reported that a strong correlation may exist between formation damage at low and high temperatures [44], future studies are still needed to fully understand the performance of the chosen acidic treating fluid on mitigating the damage at the reservoir temperature (130°C). Nevertheless, all working and treating fluids are aged overnight at 130°C before they are tested on 27 core samples in this study, as detailed in Table 1.

7. Results and Discussion

7.1. Fracture Width versus Effective Permeability of Fractured Core. Before testing the damage from working fluids on the artificially fractured core samples, a separate experiment is conducted to explore the correlation between the width of the generated fracture using copper wires and the effective permeability of the sample. Figure 6 shows the results of this separate experiment, as well as all data points measured in 27 corefloods as listed in Table 1. Results show a good consistency and all data points fall on a curve where effective permeability (k) is proportional to the third power of fracture width (W). This agrees on the classic formula on estimating fracture permeability in the laminar flow regime [45, 46].

7.2. Permeability Damage due to Fracturing Fluid (Mimicking Formation Away from Wellbore). Reservoir rock away from wellbore is more likely to be damaged by fracturing fluid. To evaluate this damage, the mimicked fracturing fluid is injected into the core sample during Step 2 of the multistep coreflood experiment. Figure 7 shows the permeability recovery rates of core samples with different fracture widths after Step 3 reaching an equilibrium. With increasing in fracture width and thus the initial effective permeability, permeability recovery rate increases until it achieves a plateau above 97%. In general, permeability damage due to the fracturing fluid on the fractured reservoir rock is low (i.e., less than 50%); this is likely attributed to the low viscosity of this fracturing fluid.

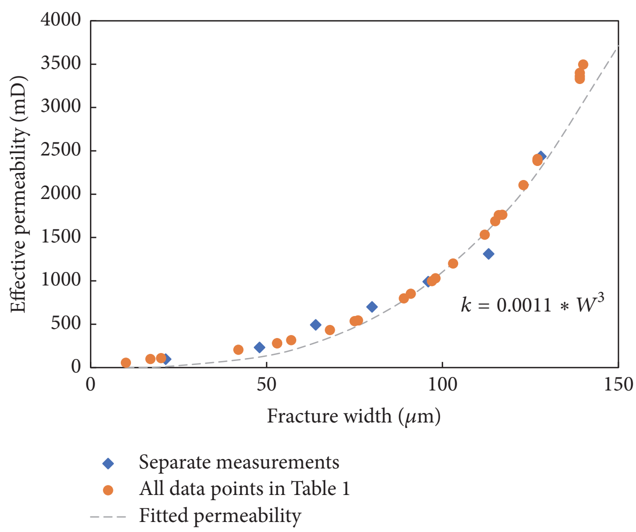


Figure 6: Change of effective permeability of fractured core with change of fracture width.

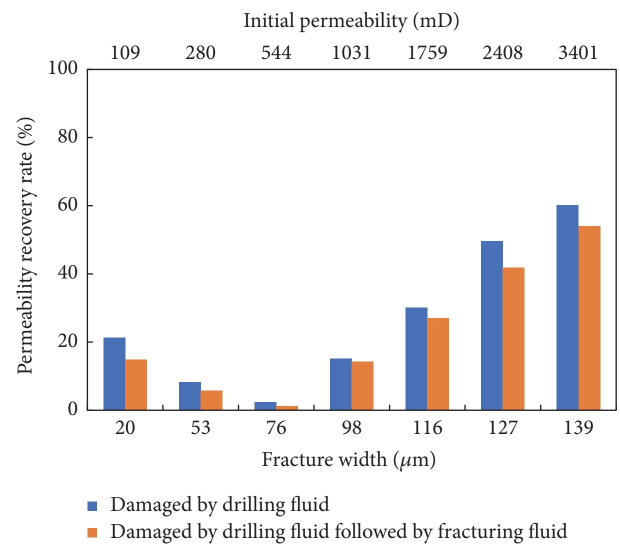


Figure 8: Permeability damage due to drilling and fracturing fluids (core samples #7–#13).

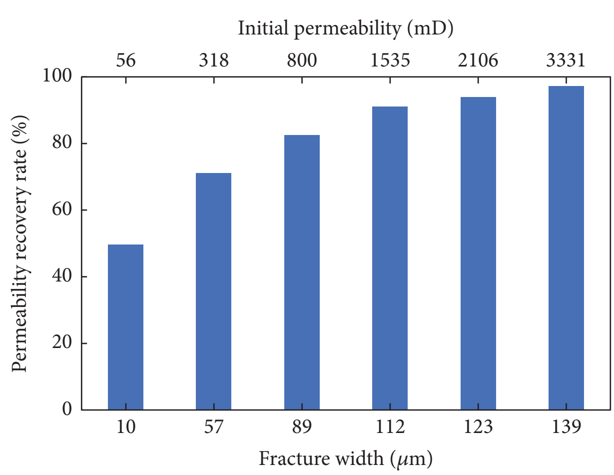


Figure 7: Permeability damage due to fracturing fluid (core samples #1–#6).

7.3. Permeability Damage due to Drilling and Fracturing Fluids (Mimicking Formation Near Wellbore). Reservoir rock near wellbore is damaged by both drilling fluid and fracturing fluid. To mimic the damaging process and evaluate this damage, the mimicked drilling fluid and fracturing fluid are injected in sequence into the core sample during Step 2 of the multistep coreflood experiment. Figure 8 shows the permeability recovery rates of core samples with different fracture widths after core samples are damaged by only the drilling fluid or both fluids. For core samples with fractures thinner than 100 μm, permeability recovery rate is only about 20% or less; for core samples with thicker fractures, although rare in the reservoir, permeability recovery rate can achieve 55–60%. In general, permeability damage due to the drilling fluid is much more serious than that due to the fracturing fluid; this is likely attributed to the suspended solid particles in the drilling fluid, including barite and bentonite. Particle-size distribution tests show that the size of barite in this drilling fluid ranges from 12.72 μm to 381.58 μm with an average of 76.11 μm, and the size of bentonite in this drilling fluid ranges from 1.54 μm to 41.27 μm with an average of 11.11 μm. This leads to the lowest permeability recovery rate for the core sample with a fracture width of 76 μm. When the suspended solid particles have similar sizes as the fracture width, they can bridge and plug the fracture, instead of being screened out at the core inlet or being carried out by the fluid [47, 48].

7.4. Mitigation of Fluid Damage Using Acidic Treating Fluid. An acidic treating fluid has been developed for mitigating formation damage in the target reservoir as introduced already. Its effectiveness is evaluated through the same multistep coreflood experiment in the lab. Since the drilling fluid contributes more to the total permeability damage caused by the working fluids, each core sample is only exposed to the drilling fluid before it contacts with the acidic treating fluid. Effective permeability of the sample is then determined and compared to its initial effective permeability measured in Step 1. To establish a baseline, a control group is conducted on the undamaged core samples for obtaining the permeability recovery/enhancement after the treatment. As shown in Figure 9, the effective permeabilities of core samples with different fracture widths are all increased by 30–50%; the smaller the initial fracture width, the larger the increment. Unlike acidizing in carbonates, acidizing in sandstones is slow and thus fracture width may not obviously change under the confining/overburden pressure; thus, the increase of rock permeability is likely attributed to the increase of the roughness of fracture faces. Figure 10 compares the topography of fracture face before and after a core sample is treated by the chosen treating fluid. It can be observed that most of chemical reactions occur in the open region

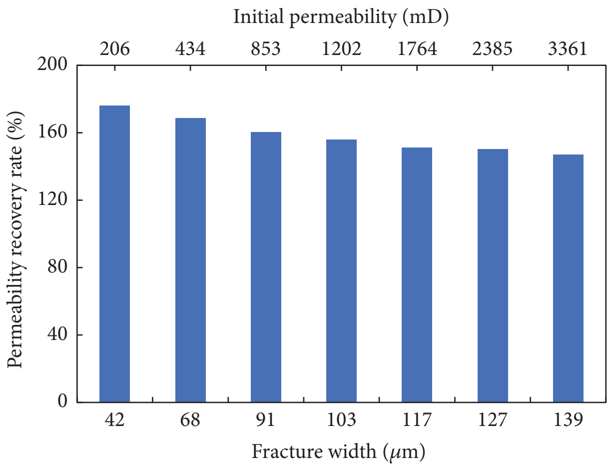


FIGURE 9: Permeability enhancement after acidizing treatment in undamaged core samples (core samples #14–#20).

supported by two copper wires, where rock turns into white and rough after the treatment.

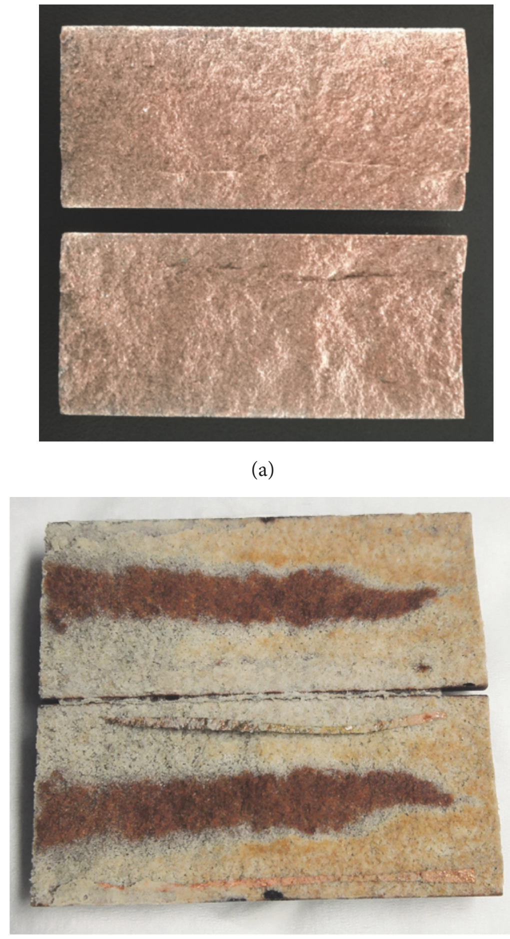
When this acidic treating fluid is applied on core samples damaged by the drilling fluid, the similar trend of enhancement is observed as shown in Figure 11. Core samples with smaller fracture widths tend to obtain higher permeability recovery rates, while this enhancement eventually reaches a plateau. However, the existence of drilling fluid seems to slow down the chemical reaction between acid and the rock and thus reduce the degree of permeability enhancement. Nevertheless, this is out of the scope of this study; further studies are needed to fully understand the impact of acidic treating fluid on fracture face in the presence of drilling and fracturing fluids and thus maximize its efficiency on mitigating the damage.

In summary, using acidic treating fluid can effectively mitigate the formation damage caused by the working fluids and enhance the permeability of the fractured reservoir rock at an overburden condition.

8. Conclusions

Naturally fractured rock is reconstructed in the lab so that the impacts of working fluids can be systematically studied. A multistep coreflood platform is designed to quantitatively evaluate the formation damage caused by the drilling and/or fracturing fluids, as well as the effectiveness of a well-screened acidic treating fluid on mitigating such damage. Thereby interactions between various working fluids and the reservoir rock, either away from or near the wellbore, can be understood.

Experimental results indicate that thinner fractures are more sensitive to the fluid damage, where the drilling fluid contributes much more than the fracturing fluid. This is likely attributed to the suspended solid particles in the drilling fluid, including barite and bentonite, which are originally designed to reduce the leak-off. Developing low-damage drilling fluid system is a difficult task for deep reservoirs, but screening an acidic treating fluid may easily solve the problem. It can effectively and efficiently mitigate the formation damage caused by the working fluids and enhance the permeability of the fractured reservoir rock at the overburden conditions.



(a)

(b)

FIGURE 10: Topography of fracture face before (a) and after (b) acidizing treatment.

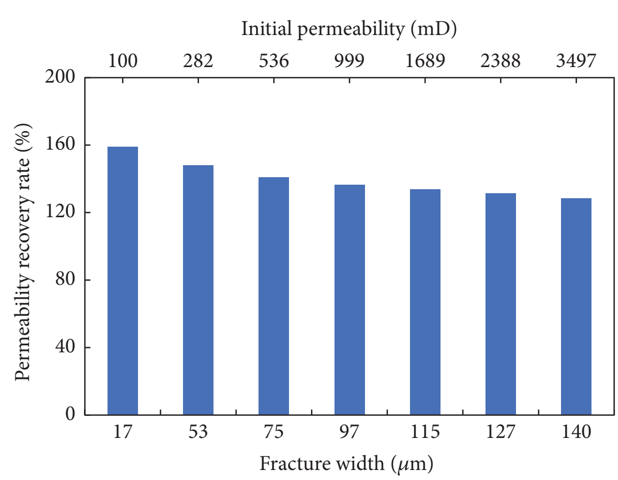


FIGURE 11: Permeability enhancement after acidizing treatment in drilling-fluid-damaged core samples (core samples #21–#27).

Conflicts of Interest

The authors declare that they have no conflicts of interest.

Acknowledgments

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