An experimental investigation of inorganic sediment damage for CO$_2$ flooding reservoirs

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ABSTRACT

Carbon dioxide (CO$_2$) flooding is a technology for improving the oil recovery of low-permeability reservoirs. However, the interaction between CO$_2$-water induced by CO$_2$ injection can lead to the formation of inorganic sediments in reservoir pores, which seriously affects the effectiveness of CO$_2$ flooding. Therefore, experiments of CO$_2$-saltwater-rock reaction in a high-temperature and high-pressure reactor, and CO$_2$ flooding saltwater-saturated core samples were conducted to research the damage law of the reservoir due to the formation of inorganic sediments. We found that the inorganic precipitation formed in reservoir pores with CO$_2$ flooding is mainly siderite and kaolinite, and the amount of sediments increases with the rise of contact pressure and temperature between CO$_2$ and saltwater. However, the precipitation in reservoir pores tends to dissolve when the contact pressure exceeds 40 MPa. The peak particle size of solid particles in the formation water is 1718 nm, which indicates the small pores below this pore size in the reservoir will be blocked during CO$_2$ flooding. To prevent the blockage impact of inorganic sediments, CO$_2$ injection pressure can be appropriately increased to promote precipitation dissolution.

Keywords: CO$_2$ Flooding, reservoir damage, inorganic sediments, oil recovery

1. INTRODUCTION

CO$_2$ flooding is an exceptional technology for enhancing oil recovery from low-permeability reservoirs[1]. When injected into the reservoir, CO$_2$ has the propensity to form a miscible mixture with the crude oil[2]. This mixture subsequently lowers oil viscosity and interfacial tension between CO$_2$ and oil[3]. Additionally, the interaction of CO$_2$, water, and rock acidifies the rock matrix and removes inorganic sediments, thereby enhancing the flow capacity of multiphase fluids[4]. However, CO$_2$-water-rock interactions also lead to the formation of inorganic mineral precipitates in the saltwater, which blocks the reservoir pores and diminishes permeability[5]. Wang et al.[6] propose that the interaction between CO$_2$ and formation water can facilitate the deposition of precipitates such as calcium carbonate and magnesium carbonate within the formation water, which may subsequently block the pore structure of the reservoir. Conversely, as the amount of CO$_2$ dissolved gradually increases, the sediment formed in the formation water will dissolve again, reducing the adverse effects of sediment blockage[7-9]. Through CO$_2$-water-rock reaction experiments and numerical simulations, Zhang et al.[10] and Xu et al.[11] found that CO$_2$-water-rock reaction can cause the dissolution of minerals such as chlorite, feldspar, and calcite in the reservoir, leading to precipitation of minerals such as iron dolomite (Fe/CaMg(CO$_3$)$_2$), sodium aluminate (NaAl (CO$_3$)(OH)$_2$), siderite/magnesite, and kaolinite, and increasing the porosity of the two phases. Cui et al.[12] studied the impact of salt precipitation caused by CO$_2$ diffusion on reservoirs using GEM multiphase flow software and found that precipitation blockage occurred in the formation near the wellbore due to CO$_2$ injection.

Although many scholars have conducted research on the inorganic precipitation damage impact on the oil reservoirs during the CO$_2$ injection process, research on the comprehensive impact of different precipitation on reservoir damage during the CO$_2$ displacement process is relatively rare. However, to clarify the damage laws of the inorganic sediments formed during CO$_2$ injection into the reservoir is crucial to make a reasonable CO$_2$-EOR plan. Therefore, experiments on the formation laws of inorganic precipitation with the interaction between CO$_2$, formation water, and rock during CO$_2$ flooding were conducted to research reservoir damage law, and the results can provide technique support for damage prevention in low-permeability reservoirs developed by CO$_2$ injection.

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2. EXPERIMENTAL DESCRIPTION

2.1 Experimental materials and devices

The formation water used in the experiment come from the production well BZ25-1 oilfield. The formation water is $CaCl_2$ type. The purity of CO_2 used in the experiment is 99.99%. The physical parameters of the core sample taken from the oil-bearing layer in the BZ oilfield are shown in Table 1.

The type of NMR scanner used in the experiment is the MesoMR12-060H-I produced by Newmai Company in Jiangsu, China; The composition of precipitations generated by CO_2-water reaction is analyzed by S360 scanning electron microscopy analyzer(SEM), produced by Cambridge, UK; The CO_2 displacement experiment is completed with the devices of TES-92 CO_2 displacement system, produced by Jiangsu Tuochuang Petroleum Research Instrument Co., Ltd., China; The Omni Particle size and Zeta electric potential analyzer, Brookhaven Instruments, USA.

Table 1. The physical parameters of core for CO_2 displacement and water-rock reaction experiments.

Core number	Reservoir type	Permeability/mD	Porosity/%	Rock type
1#	Low-permeable	11.9	13	Sandstone

2.2 Experimental process

The experimental process of CO_2-saltwater mainly includes the following steps. The formation water from the BZ25 oilfield was first measured with the Zeta potential, particle size, and solid content with Omni Particle size and Zeta electric potential analyzer. The formation water of 600 mL and the experimental core sample is poured into the HT-HP dynamic reaction kettle. The temperature of the reactor was raised to the experimental temperature and then the CO_2 booster injection pump was opened to inject CO_2 into the reactor to induce the CO_2-water reaction for 10 days. After the reaction, 20 mL of the water-sediments mixture and the sediment formation water is filtered with a pore size of 0.45 μm CN-CA filter membrane and weighed. Another 20 mL of formation water is taken for the Zeta potential and the particle size analysis. The mineral composition of the sediments filtered from the formation water is analyzed by SEM.

3. RESULTS AND DISCUSSION

3.1 Inorganic precipitation components

The precipitation was filtrated from 20 mL of formation water extracted from the reactor after the CO_2-water-rock reaction experiment and observed with SEM, and the mineral in the sediments are shown in Figure 1. We found that the mineral crystals of solid precipitate formed in the formation water system were the appearance of siderite and kaolinite. The kaolinite formation in sediment mainly be due to the dissolution of feldspar minerals in oil reservoirs, while the siderite precipitation is generated by the reaction of Fe, Mg, and CO_3^{2-} ions in the formation water during the CO_2 injection process[13,14].
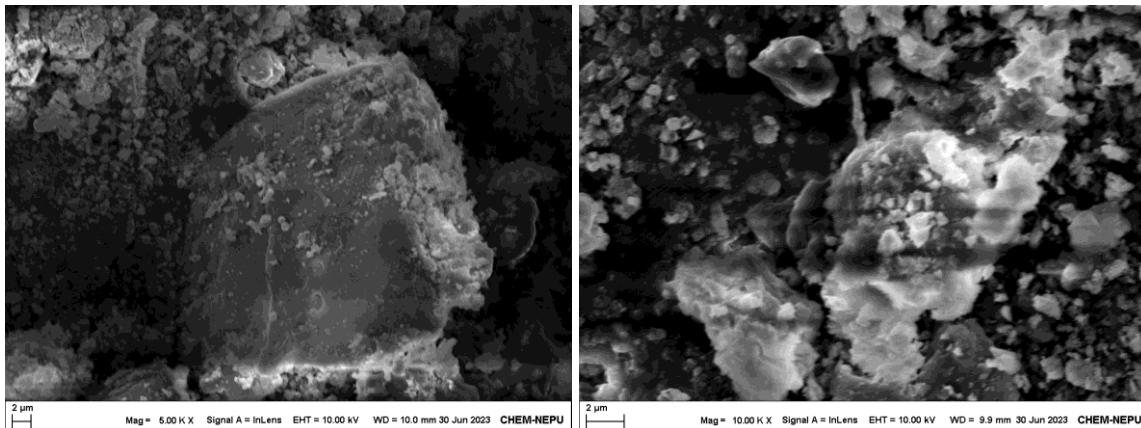

Figure 1. SEM results of inorganic precipitation in formation water.

3.2 Pressure impact

The inorganic precipitation in formation water during CO_2 displacement with different pressures is filtered through a pore size of 2 μm of CN-CA filter membrane and the precipitation amount difference is shown in Figure 2. We find that the inorganic precipitation amount at the experimental pressure range of 30 MPa-40 MPa increases with the enhances of CO_2-water pressure. But when the pressure is higher than 40 MPa, the precipitation amount in the formation water decreases with the contact pressure increase. The Zeta potential of the formation water system after CO_2 injection reaction under different pressures is listed in Table 2. Before the contact pressure in the HT-HP reactor is lower than 40 MPa, the absolute Zeta potential of formation water decreases as the pressure increases, and the amount of inorganic precipitation in formation water increases[15]. After the pressure in the HT-HP reactor exceeds 40 MPa, the absolute Zeta potential of the formation water tends to increase, which indicates that the precipitation in the formation water partially dissolved after CO_2 injection at a contact pressure higher than 40 MPa.
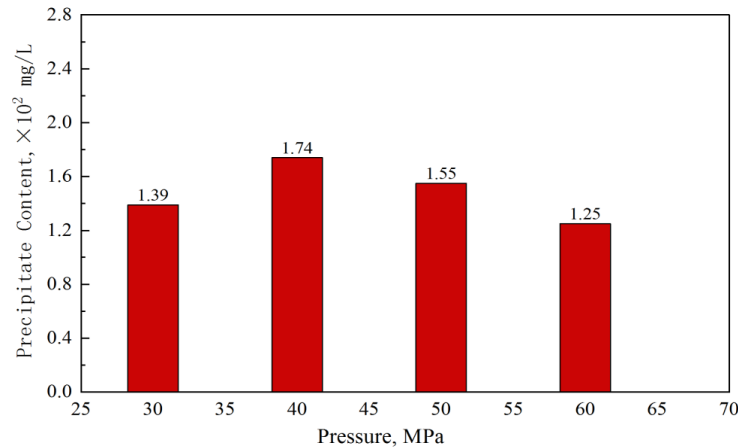

Figure 2. Effect of CO_2-water-rock contact pressure on inorganic precipitation quantity with experimental temperature 127°C.

Table 2. Zeta potential of formation water after CO_2-water reaction at different pressures.

Experimental pressure, MPa	Zeta potential, mV	Stability standards
Original formation water-30	-8.145	When the absolute of Zeta potential of the water system is between 0 mV-5 mV and 10 mV-30 mV, the solid phase in water forms rapidly and slowly.
30	-7.81	
40	-7.63	
50	-7.73	
60	-7.76	

The particle size analysis of suspended sediments in the formation water system was conducted after different CO_2-water reaction experiments, and the results are shown in Figure 3. The peak particle size of suspended solid particles in the original formation water of the BZ25 oilfield was 513.2 nm. However, with the increase of CO_2-water contact pressure, the peak particle size of sediments in the formation water increased. When the pressure rises up to 40 MPa, the peak particle size of solid particles in the formation water reaches 1718 nm. But what's interesting is that when the contact pressure in the reactor is over 50 MPa, the peak particle size of suspended solids in the formation water decreases with pressure enhancement. At 60 MPa, the peak particle size of the solid phase in the formation water decreases to 815 nm. According to the mercury flooding results of the reservoir core in the oilfield, the pore diameter range of the reservoir is between 20 nm and 109.7×10^3 nm, and the mercury saturation in the pore lower than inorganic solid precipitation diameter at 1718 nm is 38.5%, which indicates that the inorganic solid precipitation generated by CO_2-water interaction during CO_2 flooding in the reservoir may cause reservoir damage.
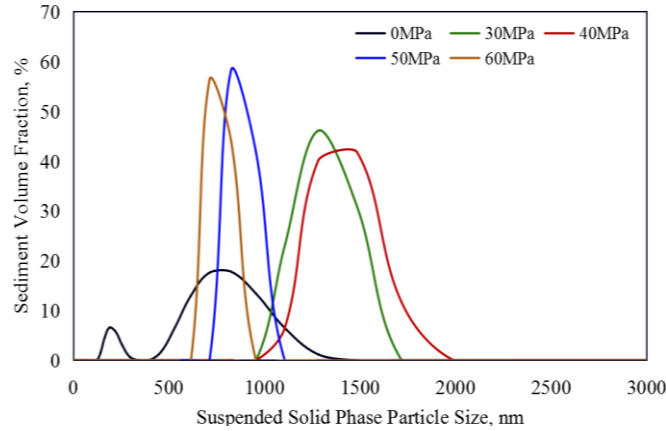
Figure 3. Sediment particle size formed in formation water after CO_2-water reaction with different pressure.

3.3 Temperature influence

The reaction temperature impact on the inorganic precipitation induced by the CO_2-water reaction is shown in Table 3 and Figure 4. When the contact pressures in the reactor change from 30 MPa to 60 MPa, the absolute value of Zeta potential and peak particle size of suspended sediments in the formation water system decreased and increased respectively with the temperature increased from 127℃ to 154℃. The analysis is that the experimental temperature increases promote the decomposition of HCO_3^- into CO_3^{2-} formation in the water system, which makes the ion more prone to precipitation.

Table 3. Zeta potential of formation water after CO_2-water reaction at different temperatures.

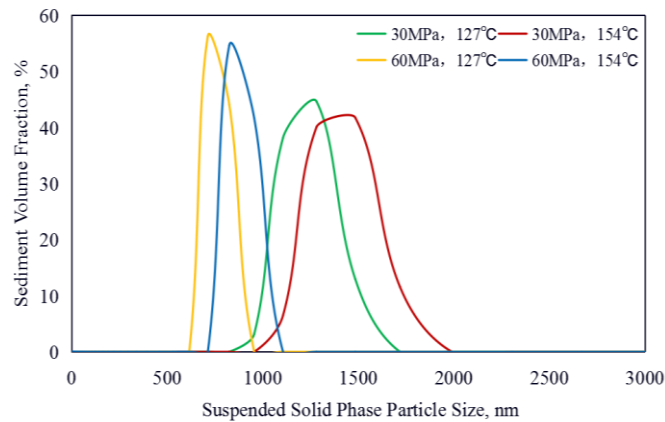| Pressure, MPa	Temperature, ℃	Zeta potential, mV
30	127	-7.81
	154	-7.65
60	127	-7.76
	154	-7.32

Figure 4. Sediment particle size in formation water after CO_2-water reaction with different temperatures.

4. CONCLUSIONS

(1) He particle size of the inorganic solid-phase precipitation formed in formation water during the CO_2-water reaction increases with experimental pressure and temperature increase, with a maximum particle size of sediment 1718 nm at this boundary pressure of 40 MPa.

(2) The solid-phase precipitation formed in the formation water began to dissolve over the boundary pressure 50 MPa. At the CO_2 flooding pressure of 60 MPa, the peak particle size of inorganic solid-phase precipitation is 815 nm. To prevent the blockage impact of inorganic sediments, CO_2 injection pressure can be appropriately increased to promote precipitation dissolution.

ACKNOWLEDGMENTS

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