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Comparison Between Cold/Hot Smart Water Flooding in Sandstone Reservoirs

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Abstract

The incremental oil recovery has been investigated and approved by many laboratory and field projects using water flooding in tertiary stage. The salinity of the injected water is an important factor observed by many researchers. The more salinity decreases the more oil recovery obtained. The investigations on the hot low salinity water flooding have been conducted by many researchers and they found out that it is useful for increasing oil recovery especially heavy oil due to reducing oil viscosity and make it easy to produce to the surface. The thermal expansion of water plays an important role in the incremental oil recovery mechanism, reducing the density of the injected water relative to the aquifer water. This reduces mixing; minimizing thermal losses to the aquifer. Hot water flooding may also increase the economic life of individual wells by as much as a factor of two. Smart water was also used to alter the reservoir wettability and increase oil recovery by manipulating the divalent cations in the injected water. In this study, we used hot and cold smart water and injected both into the sandstone saturated with crude oil in order to investigate the important role of smart water itself and hot smart water. The systematic results showed that changing some cations in the injected brines was better than to spend more money to heat the smart water. The divalent cations Ca^{2+} and Mg^{2+} were the most effective component in the smart water. In this study, we also studied the pH effect of the cold/hot smart water effluent smart water EOR.

Keywords: Smart water flooding; Enhanced oil recovery; Thermal enhanced oil recovery

Introduction

Eastern Kansas oil field contains heavy oil that is produced via rod sucker pumps. The daily production from Bartlesville Sandstone reservoir is around 500 bbl/day with a higher water cut. Such reservoirs have a low temperature and the oil viscosity of several hundreds of centipoise. The mobility ratio is quite different between the water and the heavy oil and if a conventional water flooding would be conducted, the oil recovery could be low. A higher temperature of water flooding, prompt to reduce the oil viscosity. The hot injected water also could reduce the unequal viscosity of the water and the oil in the heated zone, and in turn, the sweep efficiency could be improved.

In this work, we injected smart water because of its results in increasing oil recovery according to many labs works and pilot based on the mechanisms that propose and qualify the effectiveness of smart water flooding such as: (i) Multicomponent ion exchange [1], (ii) Double-layer expansion [2], (iii) Reduction in interfacial tension and increased pH [3] (iv) Fines mobilization [4], (v) Mineral dissolution [5] (vi) Organic material desorption from the clay surface [6], (vii) Cation exchange on quartz surface [7] (viii) Desorption of organic materials from quartz surface [8].

In the case of using thermal EOR techniques, the heat provided to the reservoir could absolutely reduce the oil viscosity and increase oil recovery. The economic overview, on the other hand, the least expensive thermally technique is hot water flooding based on oil recovery [9]. In this work, a combined chemical and thermal technology was applied on Bartlesville Sandstone cores to find a feasible, cost-effective EOR solution to increase oil recovery from heavy oil reservoirs without using high energy methods such as thermal techniques.

Experimental Section

Porous media

Core samples were taken from the Bartlesville Sandstone reservoir located in east Kansas. The cores description is listed in Tables 1 and 2.

Brines and crude oil

Reagent-grade salts were prepared with deionized water to make FW and smart water. The compositions of brines are listed in Table 1. A reservoir crude oil was delivered by Colt Energy from Bartlesville Sandstone reservoir. The oil viscosity is ~600 cp and density 0.83 at 20°C.

Core preparation and flooding

The experimental setup is shown in Figure 1. The cores first cleaned with toluene. The cores were then evacuated and saturated under vacuum in the FW. The same FW was used to measure the permeability. The cores were pre-aged in heavy crude oil for three weeks at 90°C. The water flooding was conducted at reservoir temperature 90°C. FW was injected into the cores until residual oil saturation was reached. After that, smart water was injected until no more oil was produced and injection pressure stabilized. The cores were saturated with the same

Elements	FW	Smart Water
Na^+	1.50	0.015
Cl^-	1.675	0.01675
Ca^{2+}	0.089	Table 2
Mg^{2+}	0.089	Table 2
TDS	97.5	~1.0
Salinity	97500	~1000

Table 1: Brines composition (mol/L).

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FW and smart water was injected as follows:

RC1: The smart water contains 45 mmol of Ca^{2+} , and the experiment temperature was 25°C.

RC2: The smart water contains 90 mmol of Ca^{2+} , and the experiment temperature was 85°C.

RC3: The smart water contains 45 mmol of Mg^{2+} , and the experiment temperature was 25°C.

RC4: The smart water contains 90 mmol of Mg^{2+} , and the experiment temperature was 85°C.

Results and Discussion

Reservoir core (RC1) and RC2 were flooded with smart water containing 45 and 90 mmol Mg^{2+} at 25°C and 85°C, respectively as described in Table 2, while both RC3 and RC4 were flooded with smart water containing 45 and 90 mmol Ca^{2+} at 25°C and 85°C, respectively.

RC1: The temperature of this experiment was set on 25°C. The core successively flooded with FW and smart water. The volume of the produced oil was collected and logged at the room temperature. The pressure readings were also recorded. The ultimate oil recovery was 54%

of original oil in place (OOIP) after the core flooded with FW (Figure 2). The injection pressure started with 50 psi and rose up to 180 psi and dropped until stabilizing at 41 psi after injecting 2 PV of FW (Figure 3). The incremental oil recovery after switching the injected brine to smart water was 5% of OOIP (Figure 2). The injection pressure rose up to 64 psi and stabilized at 49 psi (Figure 3).

RC2: This core was flooded the same way as RC1 except the smart water containing 90 mmol of Mg^{2+} . The temperature was 85°C for both FW and smart water flooding. The oil recovery during secondary water flooding with FW was 57% (Figure 2), the flooding was stopped after injecting 2 PV of FW. The water injection stopped until no more oil was produced and until the pressure stabilized. During the FW flooding, the pressure started 52 psi. The pressure increased quickly until reaching the maximum reading at 151 psi. After the crude oil began to flow out the core, the pressure decreased slowly until stabilizing at 31 psi (Figure 3). Upon switching to smart water, the incremental oil recovery was 2% of OOIP. The injection pressure increased dramatically until reaching the highest point which was 51 psi and stabilized at that point (Figure 3).

RC3: This core and the following one (RC4) were flooded with smart water containing 45 and 90 mmol of Ca^{2+} at 25 and 85°C, respectively.

Core	Diameter (cm)	Length (cm)	K (md)	Porosity (%)	Ca^{2+} in the smart water	Mg^{2+} in the smart water	T (°C)
RC1	2.54	14.50 cm	77 md	20%	0	45	25°C
RC2		14.44 cm	71 md	18%	0	90	85°C
RC3		14.47 cm	82 md	21%	45	0	25°C
RC3		14.45 cm	75 md	20.3%	90	0	85°C

Table 2: Petrophysical properties.

Core	FW	Smart	Total	T (°C)	Ca^{2+} in the smart water	Mg^{2+} in the smart water
RC1	54	5	59	25°C	0	45
RC2	57	2	2	85°C	0	90
RC3	51	9	9	25°C	45	0
RC4	53	1	1	85°C	90	0

Table 3: Oil recovery results.

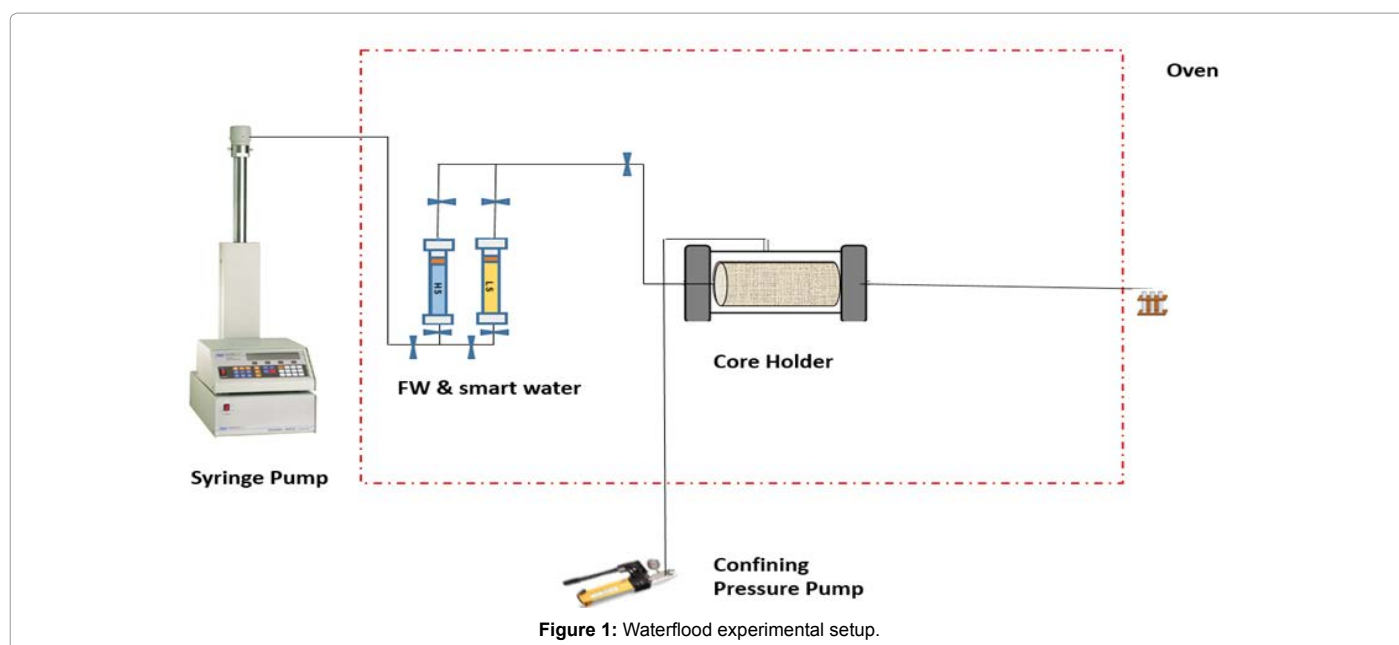


Figure 1: Waterflood experimental setup.

The experiment temperature is 25°C for RC3. The oil recovery with FW was 51% of OOIP (Figure 4). The injection pressure started with 66 psi and rose up to 160 psi and then stabilized at 52 psi (Figure 5). Upon switching to smart water the improved oil recovery was 9% of OOIP (Figure 4). The injection pressure stabilized at 59 psi (Figure 5).

RC4: The experiment temperature was set at 85°C. The same procedure was followed as in previous cores. After injecting 2 PV of FW the oil recovery was 53% of OOIP (Figure 4). The recovery was improved to 54% after the injected brine switched to smart water, resulting in a 1% incremental recovery of OOIP (Figure 4). The injection pressure stabilized at 43 psi (Figure 5).

All Cores were similar in FW but different in the experiment temperatures and the injected smart water. Both RC1 and RC2 were flooded using 45 and 90 mmol of Mg^{2+} in the smart water but at 25°C and 85°C.

Increasing concentration of Mg^{2+} in smart water has the effect on

reducing oil recovery during smart water flooding. Comparing RC1 and RC2, the oil recovery from RC1 by FW was 54% of OOIP, while it was 57% of OOIP from RC2. The ultimate oil recovery in RC2 was higher than in RC1 because the higher temperature.

The incremental oil recovery from RC1 using smart water was 5% of OOIP, while it was 2% of OOIP from RC2; i.e., the improved oil recovery decreased by a factor of 2.5 when doubling the concentration of the Mg^{2+} in the injected smart water even though the temperature was higher for RC2. Similarly, comparing RC3 with RC4, the oil recovery was 51% of OOIP for RC3 with FW flooding, while it was 53% for RC4 also due to extra heat. The incremental oil recovery using smart water flooding was 9% of OOIP for RC3, while it was only 1% of OOIP for RC4; i.e., the improved oil recovery increased by a factor of 9 if we reduced the concentration of the Ca^{2+} in the injected smart water although the temperature was ambient temperature. Increasing the divalent cations in the injected smart water led to decrease the adsorption of the organic

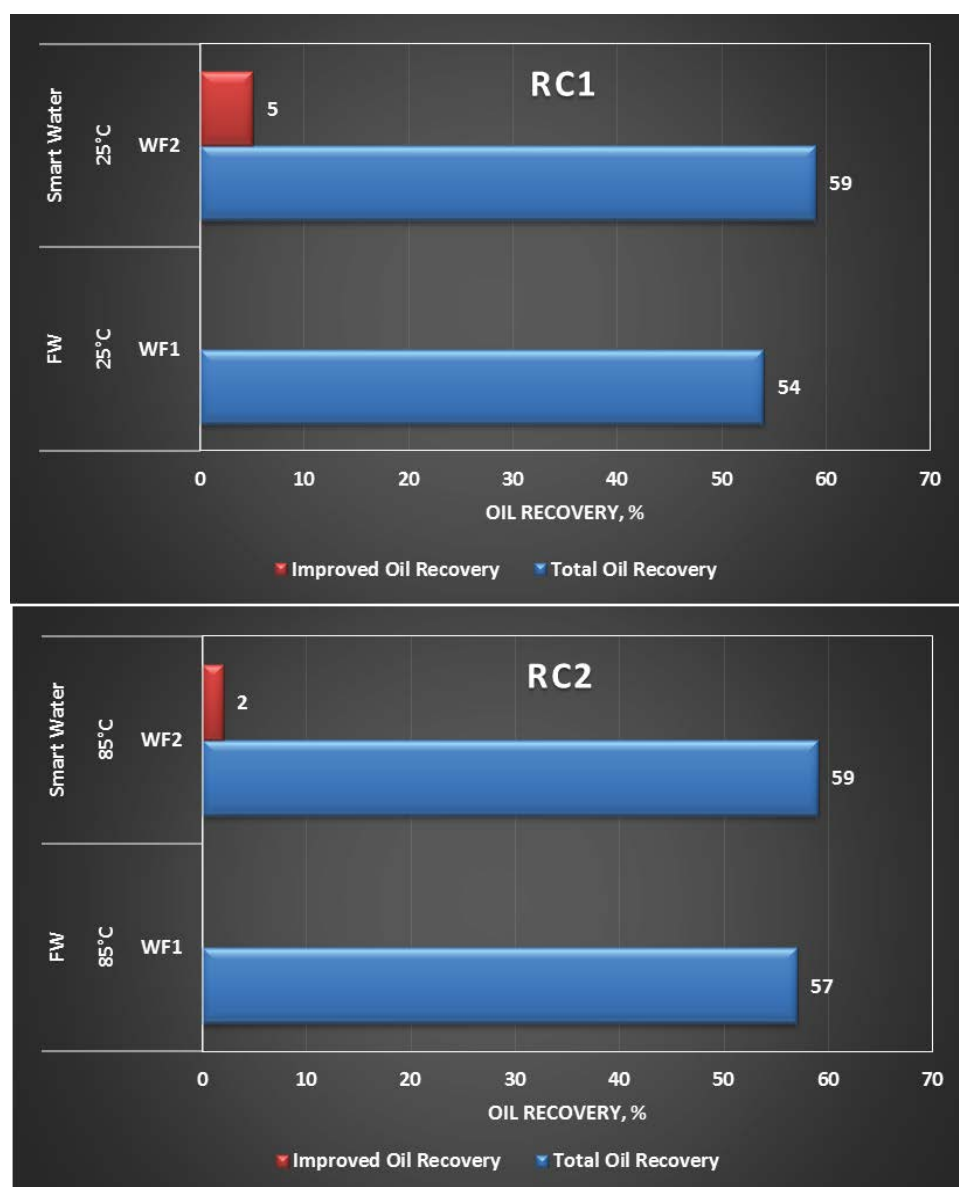


Figure 2: Total and incremental oil recovery for RC1 and RC2.

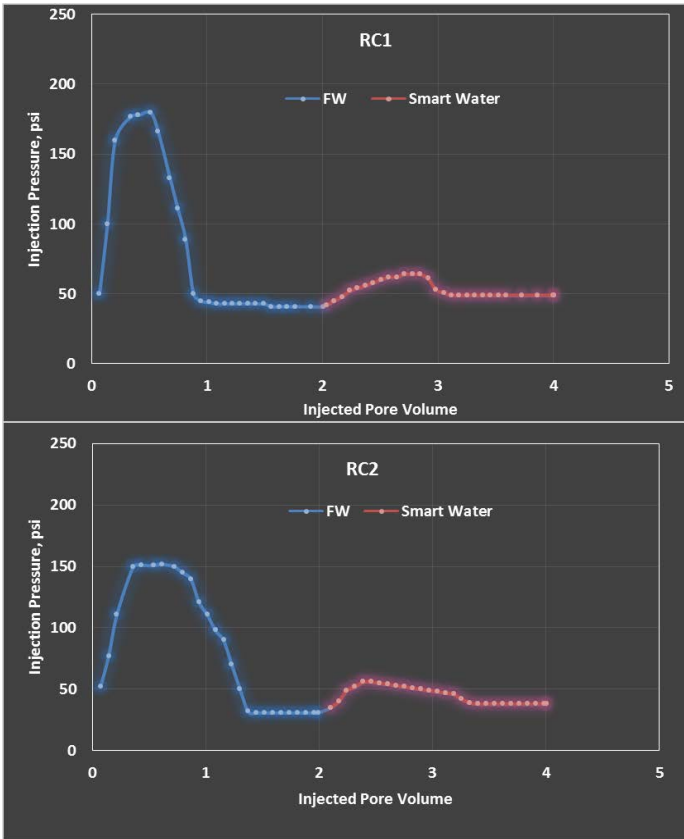


Figure 3: FW and smart water Injection pressure for RC1 and RC2.

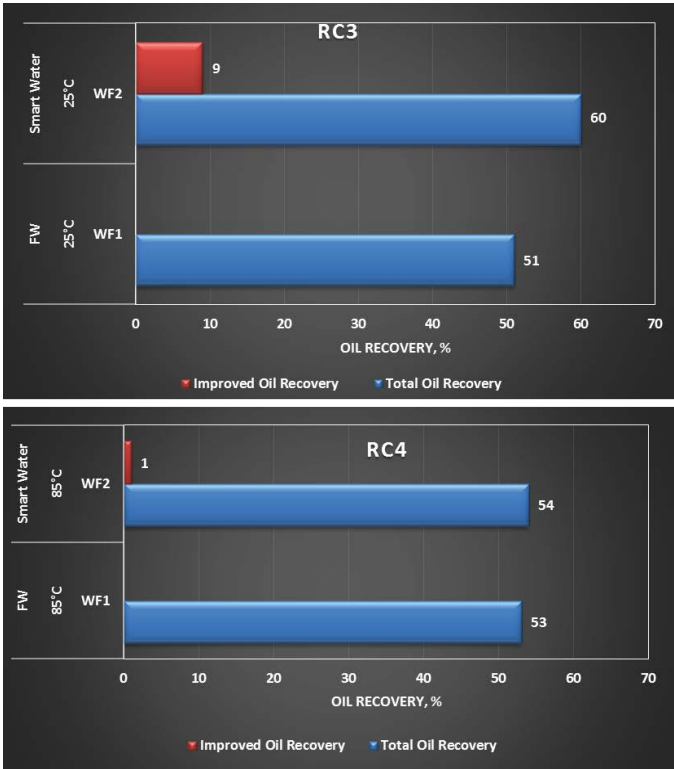


Figure 4: Total and incremental oil recovery for RC3 and RC4.

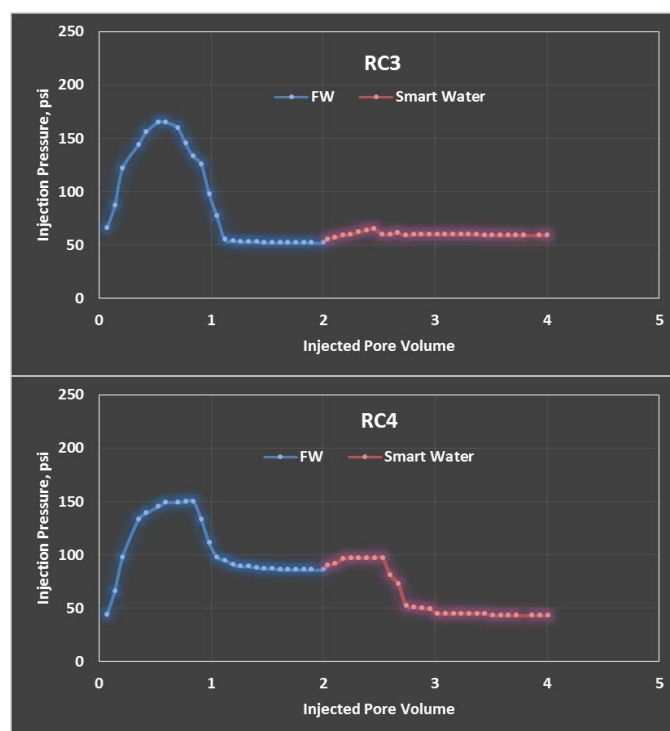


Figure 5: FW and smart water Injection pressure for RC3 and RC4.

material, and in turn, the rock became too water-wet for observing smart water effect. During FW flooding, comparing all the cores in this work the higher the temperature, the higher the oil recovery. Using hot water improves the mobility ratio due to reducing the oil phase viscosity compared with cold water. Thermal expansion of water plays an important role in injecting hot water, the lower density of hot water reduces thermal losses to the aquifer and speeds up the propagation of the temperature front through the reservoir.

The effect of increasing the temperature to 85°C with a double Mg^{2+} concentration in smart water (RC2) is the same as applying 25°C with a smart water containing a half concentration of Mg^{2+} (RC1).

Increasing temperature to 85°C when smart water has double Ca^{2+} concentration (RC4) is a worse scenario than using 25°C with a smart water contains a half concentration of Ca^{2+} (RC3). The fuel consumption using high temperature could be replaced chemically by controlling the divalent cations concentration. The fuel consumption could be more feasible when controlling the water chemistry. The good example for that is RC3 when lowering the Ca^{2+} to the half and also (RC1) when lowering the Mg^{2+} to the half. Applying ambient temperature with reducing Ca^{2+} concentration to a half provided a higher oil recovery among all the other scenarios (60% of OOIP). Table 3 shows the summary of the results.

Conclusion

Increasing the temperature of the injected water reduces the viscosity contrast between oil and water in the heated region. This can improve the sweep efficiency. Heating the oil using hot water could reduce the oil viscosity and in turn increase oil recovery.

Hot water flooding may also increase the economic life of individual wells by as much as a factor of two. Controlling the chemistry of water could provide a better solution for increased heavy oil recovery instead

of increasing the injected water temperature, that could lower the energy required to move the heavy oil from the heavy oil reservoirs in general and in this work for the eastern Kansas oil reservoirs. The conclusions can be drawn as follows:

1. The adsorption of the organic material in heavy crude oil on the sandstone decreased because of the rock became too water-wet for observing smart water flooding effect when the divalent cations presented in a higher concentration.
2. Heating could reduce the oil viscosity, interfacial tension, and residual oil saturation which lead to potentially higher recovery factor. Yet, controlling the chemistry of water (especially divalent cations) could improve oil recovery instead of increasing the injected water temperature. Increasing temperature with tune water concentration provide a greater heavy crude oil recovery.

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