



Synchronous impact of divalent ions on formation damage and wettability alteration during smart water injection: static and dynamic assessment

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Abstract

Smart water injection into oil fields is an efficient EOR method but has significant challenges due to incompatibility between the formation brine and the injecting water. The presence of reactive ions in smart water can change the wettability of reservoir rock to increase oil production. However, the possibility of formation damage due to inorganic scales may increase. In this research, static and dynamic experiments were conducted to investigate the competition between rock wettability alteration and formation damage due to smart water injection. The experiments were performed in two parts including waters compatibility tests and rock wettability measurements for various concentrations of potential-determining ions in smart water. The crystal size and morphology of the sulfate scales were inspected visually using scanning electron microscopy images. In static compatibility tests, the maximum amount of sulfate scales was detected in the mixture containing 40% injection water. The experimental data indicated that the simultaneous increase in the concentration of sulfate and magnesium ions improves the carbonate rock wettability 18% more compared to increasing sulfate concentration alone. As a result, SW_1Ca.2 Mg.1.5S revealed the highest effect on rock wettability changes from oil-wet to water-wet conditions in both static and dynamic tests. The formation damage analysis through core-flooding experiments showed that increasing the concentration of sulfate ions twice the sea water causes an 88% reduction in core permeability. However, doubling the magnesium concentration in the presence of sulfate ions reduces the permeability decline to 77%. The maximum recovery factor (i.e., 35%) was attained by injecting SW_1Ca.2 Mg.1.5S into the carbonate core, and core permeability was enhanced twofold. The findings show that simultaneous changes in the concentration of potential-determining ions in smart water, in addition to increasing oil production, also prevent formation damage, which is often neglected in previous studies.

Keywords Formation damage · Brines incompatibility · Inorganic scale · Carbonate reservoir · Wettability alteration

List of symbols

A Cross sectional area, m²
K Permeability, m²
K₀ Initial permeability, m²
L Length, m
P Pressure, Pa

Q Flow rate, m³/s
 ν Volume of fluid, m³
 μ Viscosity, Pa.s

Abbreviations

DP Differential pressure
EOR Enhanced oil recovery
FW Formation water
IW Undiluted injection water
PDIs Potential-Determining Ions
PV Pore volume
RF Recovery factor
SEM Scanning electron microscopy
WAI Wettability alteration index

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XRD X-ray diffraction

Introduction

Formation damage is a general term used to describe the permeability impairment of the reservoir rock, especially in near-wellbore regions. As an operational and economic challenge, formation damage may occur in different stages of oil and gas recovery, including drilling, production, workover, and enhanced oil/ gas recovery operations (Vasheghani et al. 2019; Veisi et al. 2020; Hajipour 2020; Movahedi and Jamshidi 2021; Movahedi et al. 2021; Khodaei et al. 2021; Cheraghi et al. 2022). Water injection is a widely used method in the oil fields to increase oil production. It involves injecting water into oil reservoirs to increase the oil recovery and maintain pressure in the aquifer. The ultimate goal of water injection is to improve the oil recovery factor. However, due to the great volume of water required for injection, seawater is often considered a suitable option. Formation damage due to incompatibility of injection water with reservoir rock or fluid is the main challenge in water injection operations (Abbasi et al. 2020; Al-Shalabi et al. 2016; Kianersi et al. 2023). Therefore, conducting waters compatibility studies and simulations before water injection operation can greatly assist in the design and improving the efficiency of the process. Researchers have proposed modifying the composition of injected water to enhance the interaction with the reservoir rock. This modification aims to improve the overall effectiveness of the water injection operation by increasing the detachment of oil from the rock surface (Jackson et al 2016). In addition to dissolution, mineral precipitation occurs in porous media due to the incompatibility between injected water and formation brine (Abbasi et al. 2020; Valadbeygjan et al. 2023).

In recent years, it has been shown that smart water injection effectively increases the oil recovery factor. This method has shown promise in both sandstone and carbonate reservoirs, with different mechanisms in play. Experimental data has demonstrated that low salinity water injection can lead to a positive response in oil recovery from carbonate reservoirs. Both spontaneous imbibition and core flooding studies have been conducted to explore the impact of engineered water injection on the oil recovery factor from carbonate reservoirs (Darvish Sarvestani et al 2019; Manzari et al. 2018). Although various researchers have studied the crystallization process of calcium sulfate over the past 30 years, there remains a lack of consensus regarding the formation temperature of calcium sulfate dehydrate and anhydrate. Calcium sulfate anhydrate is known to be the most stable form, being harder, more adherent, and consequently more challenging to remove (Nikoo et al 2020;

Lashkarbolooki et al. 2016). Calcium carbonate is commonly found in association with dolomite in carbonate reservoirs. At lower temperatures, magnesium ions can play a significant role in determining the solubility of dolomite. However, at higher temperatures, an increase in the concentration of dissolved magnesium leads to an accelerated rate of dolomite solubility (Qazvini et al.2021; Shabani et al. 2019a, b; Hiorth et al. 2010). Furthermore, rock dissolution plays a vital role in enhancing oil recovery during the engineered water injection operation. Conversely, alterations in injection water composition disturb the balance between the rock, oil, and brine, resulting in the removal of oil from the rock surface (Austad et al 2012; Movahedi et al 2022). Carbonate rocks exhibit more complexity regarding rock-fluid interactions, as well as their wettability characteristics (often a combination of mixed-wet). Additionally, their response to engineered water operation is also more intricate. Numerous research studies have indicated that the alteration of wettability is the primary mechanism responsible for the effectiveness of engineered water flooding (Shabani et al. 2019a, b; Bijani et al. 2019; Zamanpour et al. 2020). In carbonate reservoirs, the connate water is typically saturated with Ca^{2+} , Sr^{2+} , and Ba^{2+} ions, which can potentially cause scaling. Among various potential-determining ions (PDIs), SO_4^{2-} is essential for smart water flooding. However, it is important to note that a high concentration of SO_4^{2-} ions can lead to scaling issues, such as pore blockage and flow restrictions in the reservoir. Previous studies have demonstrated the synergistic effects between SO_4^{2-} and Ca^{2+} ions, as well as SO_4^{2-} and Mg^{2+} ions, in enhancing oil recovery from chalk formations (Aminian et al. 2019; Mokhtari et al. 2019; Shahrabadi et al. 2022). Permeability impairment caused by mineral scale formation is a significant issue in water flooding projects. The efficiency of low salinity water injection in carbonate reservoirs is not well understood, particularly about brine/rock/oil interactions. Therefore, further investigation is needed to understand the role of important mechanisms i.e., ion exchange, dissolution, and precipitation (Gachuz-Muro et al. 2017; Hasankhani et al. 2018; Amiri et al. 2019). Previous studies have primarily focused on the deposition/precipitation of calcium sulfate scales, as the concentration of calcium ions in the formation water is usually higher than that of strontium ions. However, it is important to note that even a small amount of strontium cations can react strongly with sulfate ions, resulting in the formation of strontium sulfate deposits. These deposits are resistant to acid treatment operation and have low solubility (Park et al. 2018; Naseri et al. 2015) The rarity of vaterite can be attributed to its higher solubility compared to the other two calcium carbonate polymorphs. Calcite, on the other hand, is the most thermodynamically stable crystal with fewer crystal defects. Vaterite, being an unstable

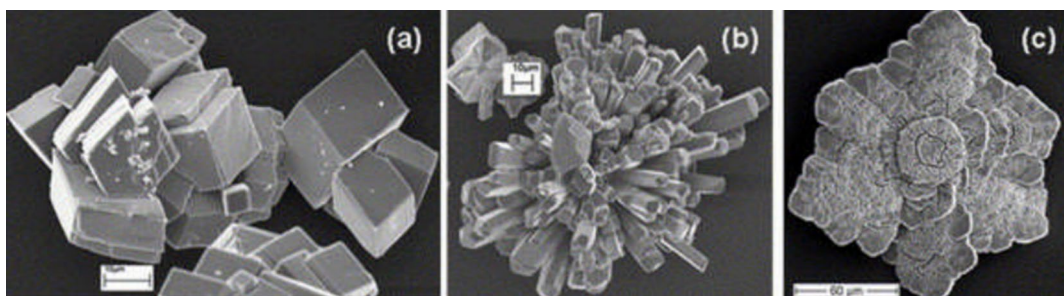


Fig. 1 SEM images **a** calcite, **b** aragonite, and **c** vaterite (Mukkamala et al. 2006)

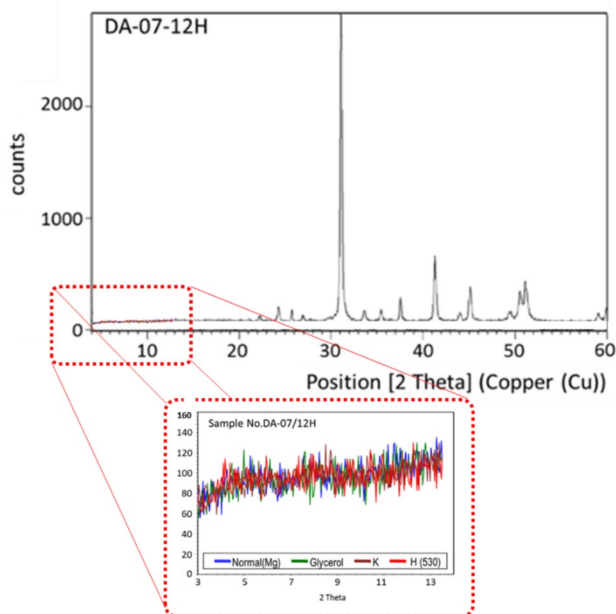


Fig. 2 XRD pattern of core plug

Table 1 Mineralogy of the core plug used in this study

Compound	Calcite	Dolomite	Anhydrite	Quartz	Muscovite
Weight percent	1.5	93	2.5	1.5	1.5

crystal, forms a porous structure due to its agglomeration of vaterite crystals together. The SEM images in Fig. 1 reveal distinct characteristics of different scale types. The calcite scales appear rhombic in shape, while the aragonite scales have a needle-like structure. Interestingly, the vaterite scales can be observed in both spherical and irregular shapes (Esmailinasab et al. 2023; Rezaeidoust et al. 2009).

Numerous studies have been carried out to ascertain the mechanisms of smart water injection technique for improved oil recovery. Focus was often on the injected fluid-rock interactions and, specifically, the wetting behavior of the rock surface. Given the importance of the ionic composition of the smart water, modification of active ions responsible for the fluid-rock equilibrium will bring into effect numerous mechanisms of displacement that have been extensively discussed. In many previous studies, only the impact of

smart water on the wettability of the reservoir rock was examined, and possible damages due to changes in ions concentration have been neglected (Bazhanova et al. 2020; Al-Otaibi et al. 2020; Hosseini et al. 2021; Bovard et al. 2023). This experimental study, however, aimed to explore the simultaneous impact of potential-determining ions in smart water on oil recovery and formation damage in carbonate reservoirs. To carry this out, both static and dynamic experiments were conducted for the investigation of brines compatibility and wettability alteration of reservoir rock. To understand the wetting behavior of the rock surface and how it interacts with brine mixtures, the contact angle was measured over time. To this end, images of the oil droplet on the rock surface at regular intervals were captured and the changes in contact angle were analyzed using ImageJ software. Moreover, dynamic imbibition experiments were carried out to calculate and compare the Amott wettability index. The scaling potential of sulfate precipitates was examined by conducting static jar tests and dynamic core flooding experiments. SEM images were applied to analyze the size and shape of scale crystals. By comparing the results of brines compatibility and rock wettability tests, the ion content of smart water can be optimized for both, more wettability alteration toward water-wet and lower risk of formation damage.

Materials and methods

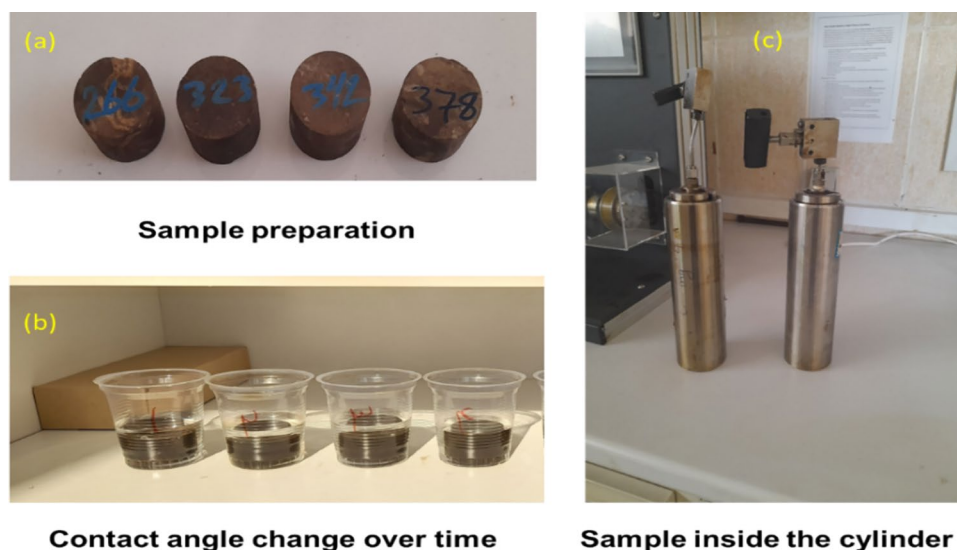
Brine and core samples

The core plugs used in this study were obtained from a carbonate formation with low clay content in the south of Iran. In order to understand the mineral composition of cores, an X-ray diffraction (XRD) test was conducted. The results, illustrated in Fig. 2 and detailed in Table 1, confirmed that the core plug primarily consists of dolomite.

Synthetic brine samples were prepared using strontium chloride (SrCl_2), magnesium chloride (MgCl_2), sodium chloride (NaCl), calcium chloride (CaCl_2), sodium sulfate (Na_2SO_4), magnesium sulfate (MgSO_4), and potassium

Table 2 Ions concentration (mg/l) in brine samples

Brines	Sr ²⁺	Mg ²⁺	Ca ²⁺	Na ⁺	Cl ⁻	SO ₄ ²⁻	K ⁺
Formation water	890	1800	7000	70,000	121,000	1000	980
Sea water	25	1640	500	14,735	24,108	3579	520
SW_2Ca.1 Mg.1S	25	1640	1000	14,735	24,108	3579	520
SW_1Ca.2 Mg.1S	25	3280	500	14,735	24,108	3579	520
SW_1Ca.2 Mg.1.5S	25	3280	500	14,735	24,108	5219	520
SW_1Ca.1 Mg.2S	25	1640	500	14,735	24,108	7158	520

Fig. 3 Process of static measurement of contact angle

chloride (KCl) from Merck Chemicals. The ionic composition of the injection water and formation brine were based on the composition of real samples for the water injection process in the investigated oil field. Table 2 displays the ionic composition of brines that were used in static and dynamic experiments. After the preparation of synthetic brine samples, each solution was filtered using a Millipore vacuum filter. As shown in Table 2, SW_2Ca.1 Mg.1S means the concentrations of Ca²⁺, Mg²⁺, and SO₄²⁻ ions of the modified brine are 2, 1, and 1 times those of sea water, and so on.

Static experiments

Static compatibility experiments were conducted to examine the interactions of seawater with smart water samples using a jar test. First, the formation and injection water samples were filtered to remove any solid particles and then mixed in different volume ratios in separate glass tubes. After complete mixing at a constant temperature, the scale crystals were separated by passing each solution through a 0.45 μm filter paper with the help of a vacuum pump. The filter papers were dried in an oven at 80 °C, cooled in a desiccator, and then the weight of solid scales was measured. Preliminary measurements were performed for the equilibration time and no change in the mixture properties was observed after 24 h. Therefore, all static compatibility

tests were performed after 24 h of mixing the brines. SEM images were used to explore the morphology of the precipitates found on the filter papers. Each test was repeated at least three times, and the mean values of the obtained results were reported.

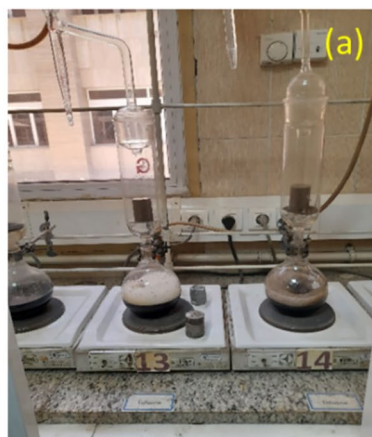
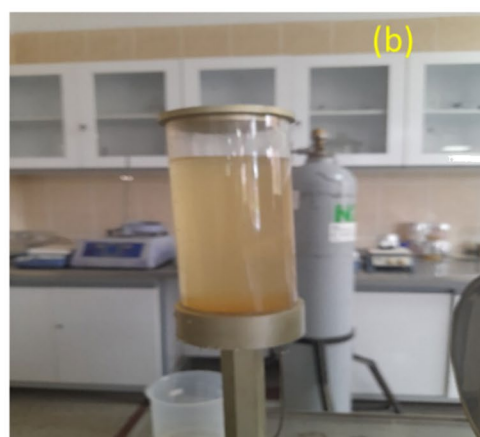
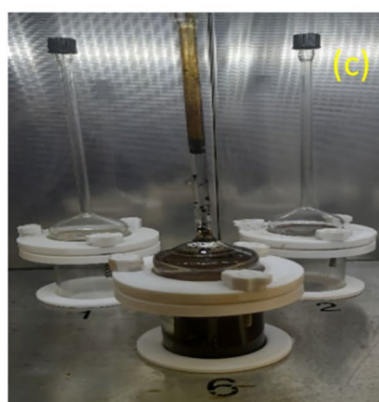
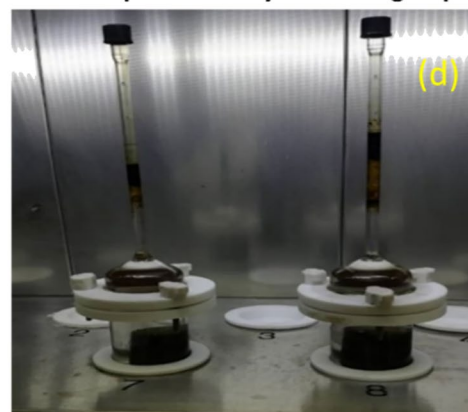
To investigate the impact of smart water samples on rock wettability alteration, thin pieces of rock were aged in the oil sample for 30 days to make the rock samples completely oil-wet. Then, the rock wettability was determined by measuring the contact angle of the oil drop on the carbonate rock surface in the presence of a mixture of the formation brine and smart water. This measurement was repeated for all smart water samples. To understand the wetting behavior of the rock surface and how it interacts with brine mixtures, the contact angle was detected over time by capturing images of the oil droplet on the rock surface at regular intervals and analyzing the changes in the contact angle using ImageJ software. Figure 3 displays the process of static measurement of contact angle.

Dynamic experiments

In this study, Soxhlet and core flooding techniques were used to clean the core plug samples. The dimensions and petrophysical properties of core samples are shown in Table 3. First, each core plug underwent a flooding process

Table 3 Dimension and petrophysical properties of core samples

Core No	L (cm)	A (cm ²)	K (md)	Dry Weight	Wet Weight	PV
1	4.780	11.335	2.096	135.950	144.200	7.373
2	4.440	11.039	3.307	114.100	123.230	8.160
3	4.86	10.980	4.85	117.950	130.320	11.056

Fig. 4 Dynamic spontaneous imbibition experiment**Cleaning of plug with soxhlet****check water permeability & Cleaning of plug****Spontaneous imbibition With Amott cell**

using toluene. A minimum of 10 pore volumes (P.V.) of toluene was injected into each plug at a high injection rate ranging from 18 to 54 ml/min. Then, the core plugs were cleaned using methanol in the same way as toluene. Continuing the experiment, a Soxhlet apparatus was used to clean each core plug. Toluene was circulated through the Soxhlet for at least 3 days, and methanol was circulated for at least 2 days. These cleaning steps are depicted in Fig. 4a.

To saturate the core sample with formation water, the core sample was first cleaned. It was then placed in a rubber sleeve and inserted into the core holder. This sleeve served as a connection to apply the overburden pressure of approximately 1000 psi on the rock. After placing each core plug in the core holder, they were vacuumed using a vacuum pump for a minimum of 4 h. Subsequently, the core plugs were saturated with formation brine through core flooding. Core flooding continued until at least four pore volumes of

formation brine were injected. Once the saturation of the core with formation water was completed, flooding at different rates was conducted to re-check the water permeability of each plug as shown in Fig. 4b.

Dynamic spontaneous imbibition experiments were conducted to examine the potential impact of smart water on the wettability alteration of rock samples. These experiments served as a secondary recovery factor process, using three aged carbonate core plugs in separate Amott cells. The cells were then subjected to spontaneous imbibition tests at 80 °C. The first test involved filling one cell with smart water, while the other cell was filled with formation water. The oil recoveries through spontaneous imbibition in the Amott cells were measured over time and compared to analyze the influence of ions in engineered water on rock wettability. Figures 4c and d illustrate the results of this analysis.

The Amott method is a technique that involves measuring spontaneous imbibition with Amott cells and forced imbibition with core flood (oil-saturated cores). During the experiment, the displacement (both spontaneous and forced) of water by oil and the displacement of oil by water are measured. The Amott Index for each fluid phase is calculated by the following equations (Civan 2023).

$$I_w = \frac{vw1}{vw1 + vw2} \quad (1)$$

$$I_o = \frac{vo1}{vo1 + vo2} \quad (2)$$

where $vw1$ ($vo1$) is the volume of brine (oil) spontaneously imbibed, and $vw2$ ($vo2$) is the volume of brine (oil) forcibly imbibed. The wettability alteration index (WAI) is the difference between the Amott index of water and oil and varies from +1 (i.e., strongly water-wet) to -1 (i.e., strongly oil-wet).

$$WAI = I_w - I_o \quad (3)$$

To conduct the core flood experiment, the rock sample was first placed in a core holder within a heating chamber and then saturated with formation water. The temperature of the chamber was set to 80 °C. After a waiting period of 3–4 h, as shown in Fig. 5a, the core plugs samples were flooded with crude oil samples at a rate of 0.1–0.15 cc/min. The flooding process continued until no water production was observed. To facilitate the wettability alteration process, four pore volumes of selected smart water were injected into the core plug sample. Throughout this step, pressure differences (DP) along the core and the production rates of water and oil were recorded, as shown in Figs. 5b–d. These recordings allowed for the determination of permeability changes.

The permeability of the core sample was calculated using Darcy's law i.e., Eq. 4 (Rostami et al. 2019; Purswani et al. 2017; Tale F et al. 2020)

$$K = \frac{q \cdot \mu \cdot l}{A \cdot DP} \quad (4)$$

Results and discussions

This study aimed to determine the effect of ions in smart water samples on formation damage due to scale formation and wettability alteration. This was done through both static and dynamic experiments by measuring the amount of inorganic scale and rock wettability alteration at various concentrations of active ions.

Results of static experiments

The results of static compatibility tests at ambient and reservoir temperatures are shown in Fig. 6. The highest scale was formed at 40% formation water at both ambient and reservoir temperatures. Therefore, the mixing ratio of 1.5 IW/FW was selected in the experiments. As can be seen, the amount of precipitated scale is higher at elevated temperatures. In fact, the increase in temperature disrupts the chemical equilibrium between soluble ions and solid phase toward the formation of more scale. The increased scale formation with temperature can be justified by the endothermic nature of the precipitation reaction. According to Le Chatelier's principle, the increase in temperature causes the reaction to proceed in a direction that consumes further heat and decreases temperature.

Figure 7 displays the amount of scale after mixing different samples of injection water with formation brine at a constant volume ratio i.e., 1.5 IW/FW. The maximum amount

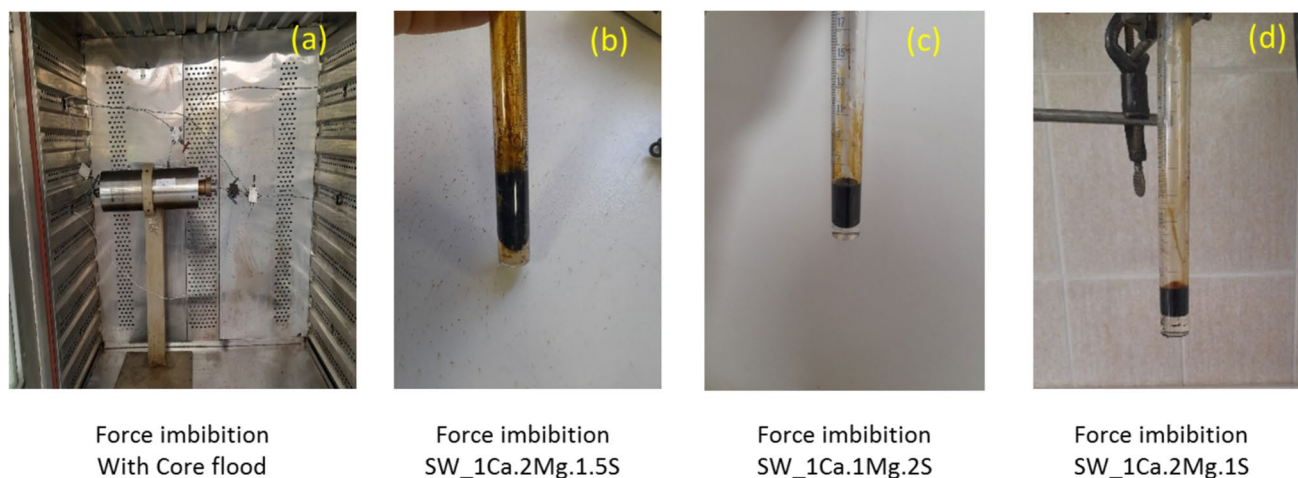
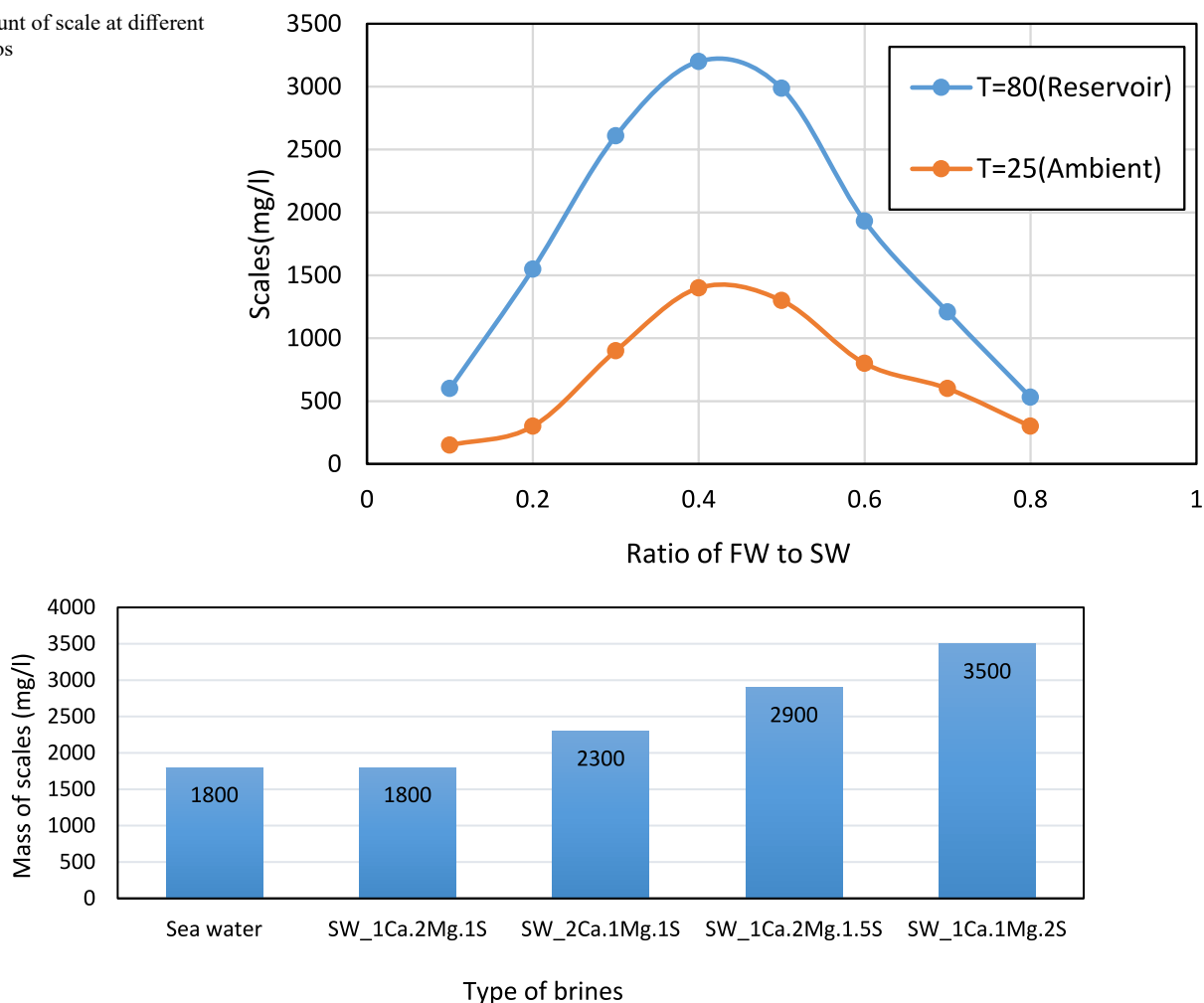


Fig. 5 Dynamic experiments, force imbibition process

Fig. 6 Amount of scale at different mixing ratios**Fig. 7** Effect of different injection water on the amount of scale

of scale was detected in the mixture containing formation brine and SW_1Ca.1 Mg.2S. In fact, by increasing the concentration of sulfate ions twice the sea water, the risk of formation damage due to inorganic scales increases.

The variations of contact angle over time are demonstrated in Fig. 8. As can be seen, the increase of divalent ions concentration in smart water alters the rock wettability from oil-wet to water-wet. The increase of sulfate ions twice the sea water improves the rock wettability toward water-wet and results in a decrease in the contact angle from 120° to 95° . However, the best improvement in rock wettability (i.e., 39%) was attained when the concentration of sulfate and magnesium ions increased simultaneously. In fact, magnesium cations can modify wettability by attaching to carboxylic acid groups on the rock surface. This reduces the repulsive forces on the surface, allowing the magnesium cations to come closer to the rock surface and react with the pre-adsorbed carboxylic acid groups, ultimately leading to improved oil recovery. However, the presence of sulfate ions has a greater effect due to their higher ionic strength

and reactivity. Therefore, increasing the concentration of both magnesium and sulfate ions near the rock surface can contribute to improved oil recovery.

Figure 9 displays the changes in wettability of the rock surface in the mixture of FW with SW_1Ca.2 Mg.1.5S sample over a period of 5 h. It can be observed that the decrease in contact angle and wettability alteration occur slowly over time.

Results of dynamic experiments

The dynamic experiments were conducted based on the findings of static tests. By injecting the smart water into the carbonate core, the variations of the pressure drop and the oil recovery factor were measured and illustrated in Figs. 10, 11, 12. As can be seen in Fig. 10, throughout injecting four pore volumes of SW_1Ca.2 Mg.1S, the pressure drop across the core first increased at the breakthrough and then decreased and stabilized. The recovery factor reached 25% and remains constant. Figure 11 displays the pressure

Fig. 8 Contact angle for different mixtures of FW with smart water samples

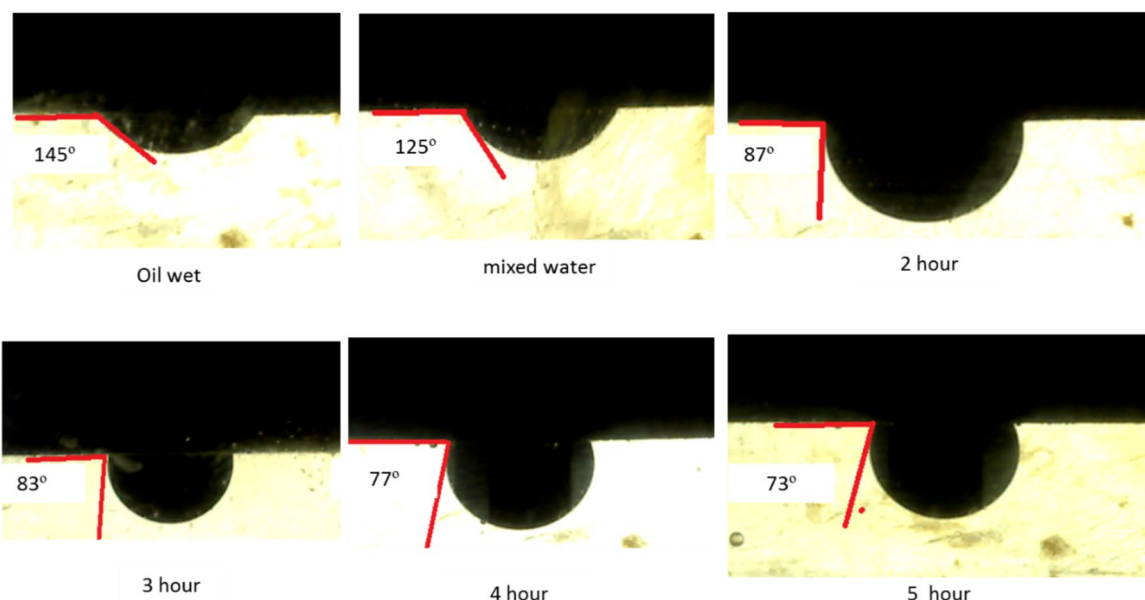
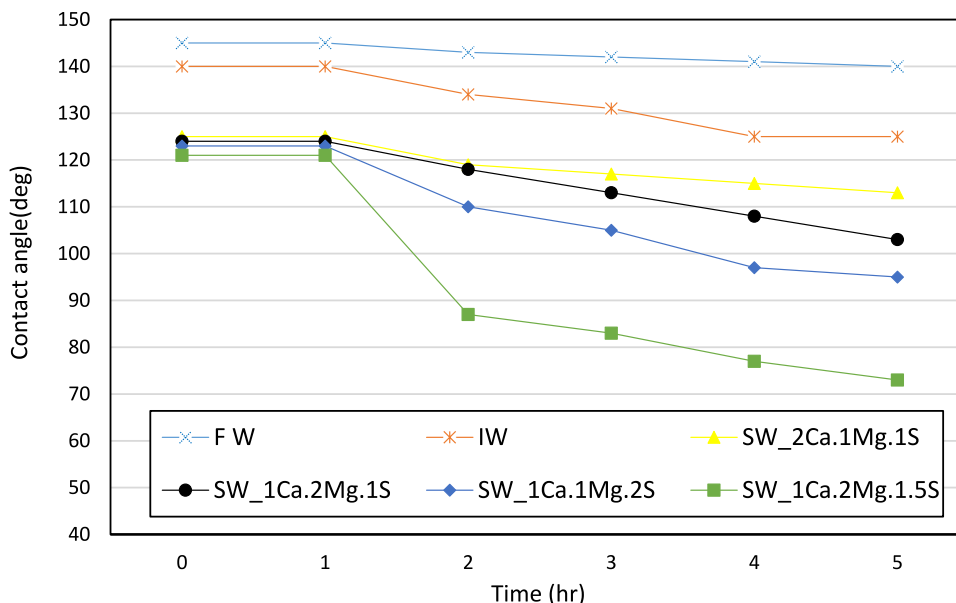


Fig. 9 Contact angle change over time for the mixture of FW and SW_1Ca.2 Mg.1.5S

drop changes during the injection of SW_1Ca.1 Mg.2S. As shown, the pressure drop increases due to the increased sulfate scale precipitation. By injecting the smart water containing an increased concentration of sulfate ions, scale nucleation occurs rapidly. This leads to a severe decrease in the core permeability, followed by a slower crystal growth process. The oil recovery factor of SW_1Ca.1 Mg.2S is 28% which is 3% higher than the previous case (i.e., SW_1Ca.2 Mg.1S).

Figure 12 displays the pressure drop and the oil recovery factor of SW_1Ca.2 Mg.1.5S. With the simultaneous increase of magnesium and sulfate ions concentration, the recovery factor increased significantly and reached 35%.

Compared to the injection of SW_1Ca.1 Mg.2S, the pressure drop decreases by increasing the magnesium ions. In fact, by increasing the magnesium cation in the solution, the concentration of sulfate ions decreases due to ion pairing and making complex with magnesium ions. Therefore, less sulfate scale is formed and a lower pressure drop is observed.

From the relation between the core permeability and the pressure drop, the final core permeability was calculated and the results are reported in Table 4. As shown, the highest reduction in core permeability i.e., 0.11 of the initial permeability was recorded for the injection of SW_1Ca.1 Mg.2S. In fact, increasing the concentration of sulfate ions in the

Fig. 10 Oil recovery factor and differential pressure by injecting SW_1Ca.2Mg.1S

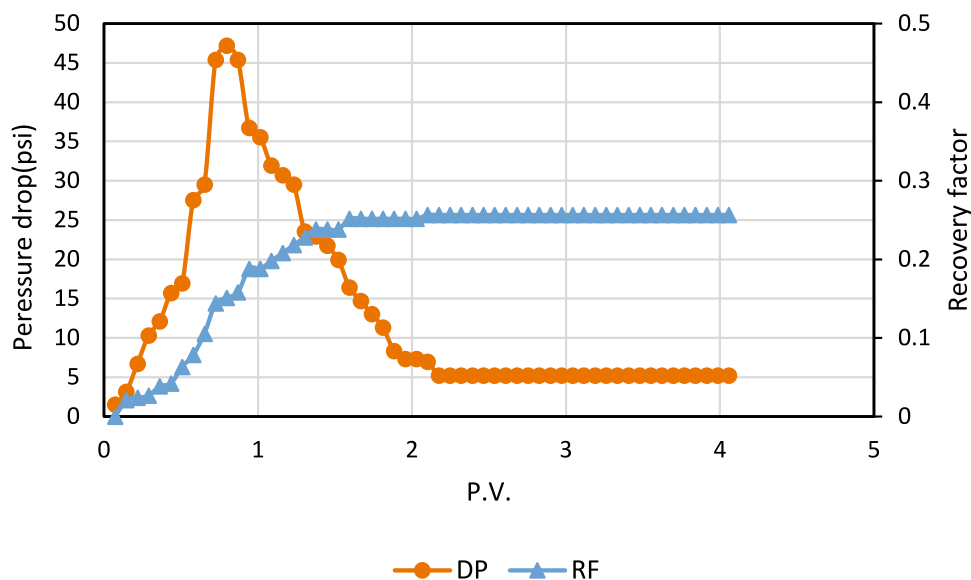
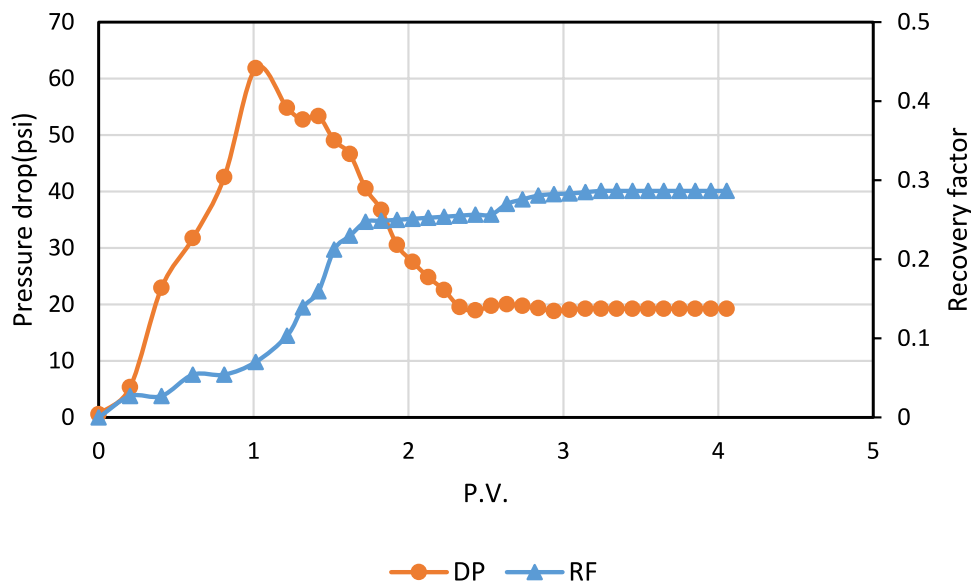


Fig. 11 Oil recovery factor and differential pressure by injecting SW_1Ca.1Mg.2S



smart water, rises the reactivity speed of sulfate ions with free cations in the solution and the amount of sulfate scale, leading to severe reservoir damage and permeability decline.

On the other hand, increasing the magnesium concentration in smart water has a positive effect on the core permeability due to the reduction in scale formation. By injecting SW_1Ca.2 Mg.1.5S, the ratio of final permeability to initial permeability reached 0.22. The results of dynamic experiments demonstrate that a simultaneous increase in the concentration of magnesium and sulfate ions leads to permeability enhancement.

To evaluate the effect of the smart water samples on the improvement in the oil recovery factor, the recovery factor curves obtained from the core flood tests are compared in Fig. 13. It is clear that the simultaneous increase in the concentration of magnesium and sulfate ions has a noticeable

impact on improving the oil recovery factor. It can be seen that injection of SW_1Ca.2 Mg.1.5S leads to the highest increase in incremental oil recovery. In the presence of sulfate ions, the positive charge of the carbonate rock surface is decreased, so magnesium cations can reach the surface easier and detach carboxylic groups from the rock. Therefore, increasing the magnesium ions in smart water containing sulfate ions intensifies the wettability alteration and facilitates further displacement of oil from the porous rock.

The values of the WAI in the injection of smart water samples are reported in Table 5. The closer the index to unity, the stronger the wettability tendency toward water-wet. The highest WAI was detected for injection of SW_1Ca.2 Mg.1.5S, which is in agreement with static measurements.

Fig. 12 Oil recovery factor and differential pressure by injecting SW_1Ca.2Mg.1.5S

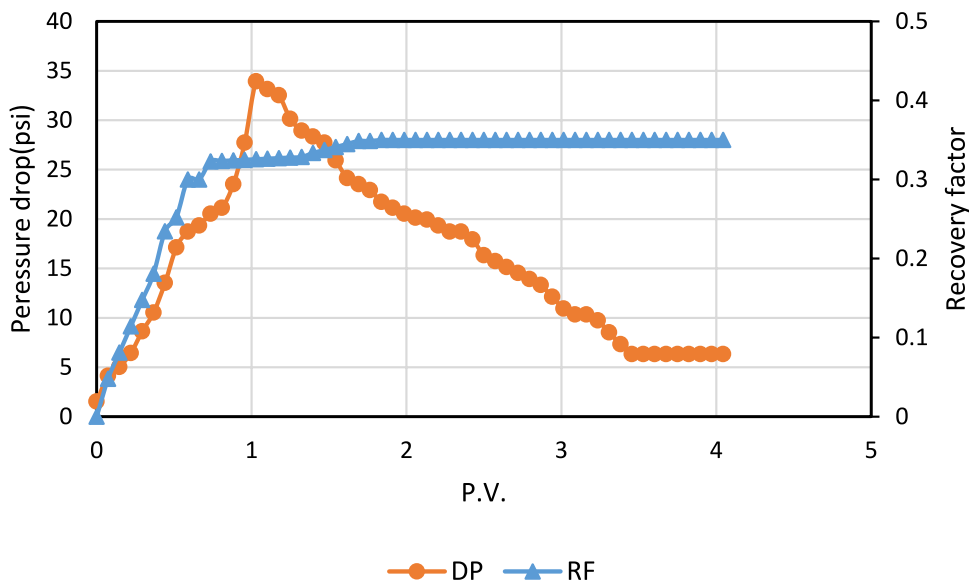


Table 4 Permeability ratio for different injection water

Injection water	K/K ₀
SW_1Ca.2 Mg.1S	0.27
SW_1Ca.1 Mg.2S	0.11
SW_1Ca.2 Mg.1.5S	0.22

Table 5 Wettability alteration index

Injec- tion water	SW_1Ca.2 Mg.1S	SW_1Ca.1 Mg.2S	SW_1Ca.2 Mg.1.5S
Amott index (I _w)	0.07	0.10	0.12
Amott index (I _o)	0.02	0.02	0.02
WAI	0.05 (Neutrally Wet)	0.08 (Neutrally Wet)	0.1 (water Wet)

The results of rock wettability alteration in static and dynamic tests are compared in Fig. 14. The results of static experiments (i.e., contact angle measurement) can be found from the left y-axis and the results of dynamic tests (i.e., wettability alteration index) can be interpreted from the right y-axis. It can be seen that the results of static and dynamic wettability alteration experiments are similar and SW_1Ca.2 Mg.1.5S has the most positive effect on rock wettability changes toward a more water-wet state.

SEM images of scales

Figure 15 displays SEM images of scales obtained from

Fig. 13 Recovery factor vs. smart water injected pore volume

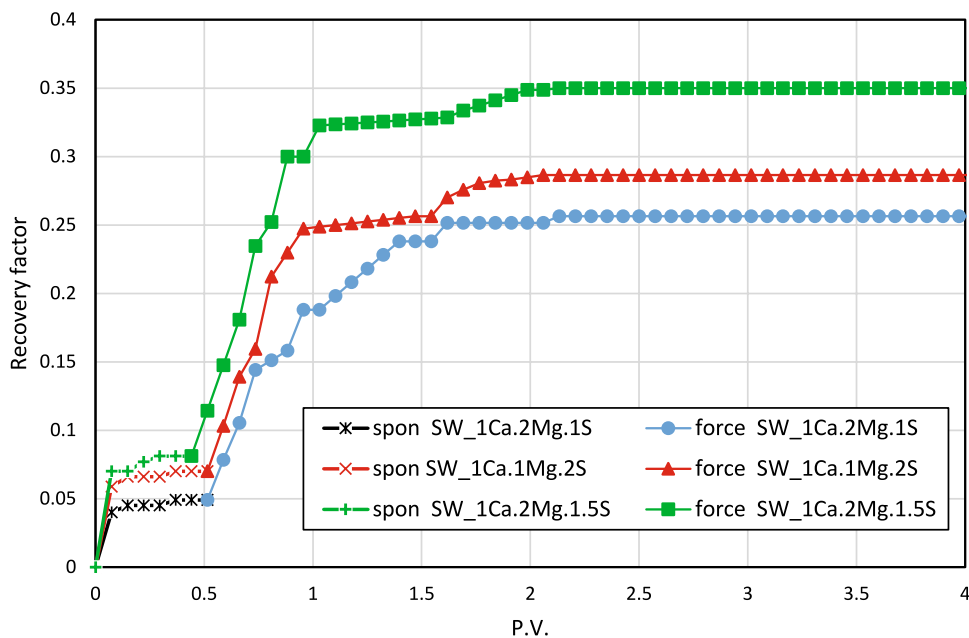


Fig. 14 Comparing the results of static and dynamic wettability measurements

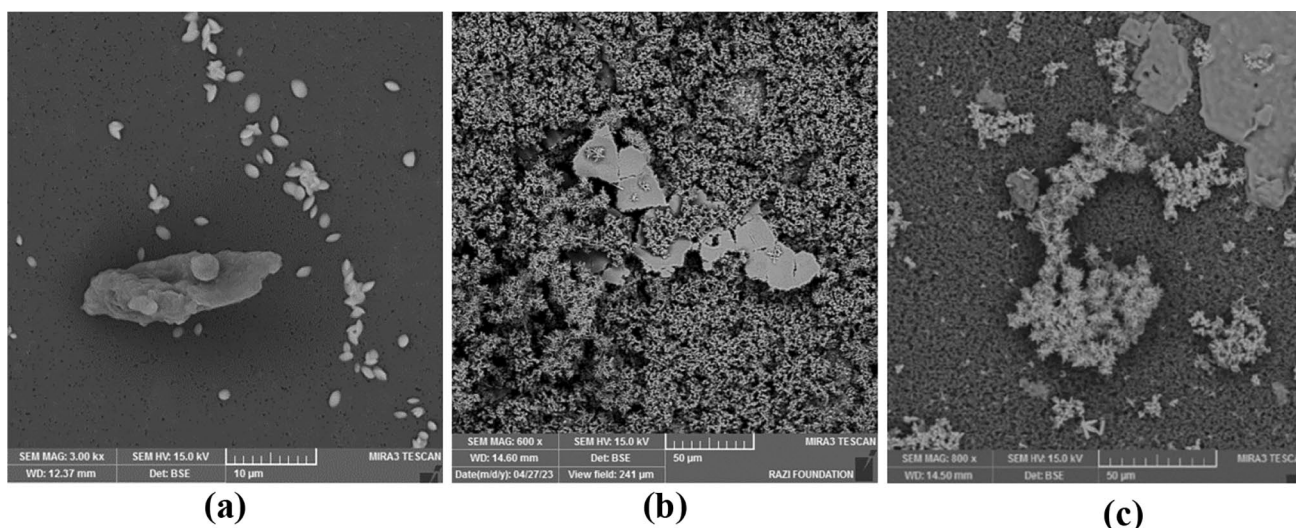
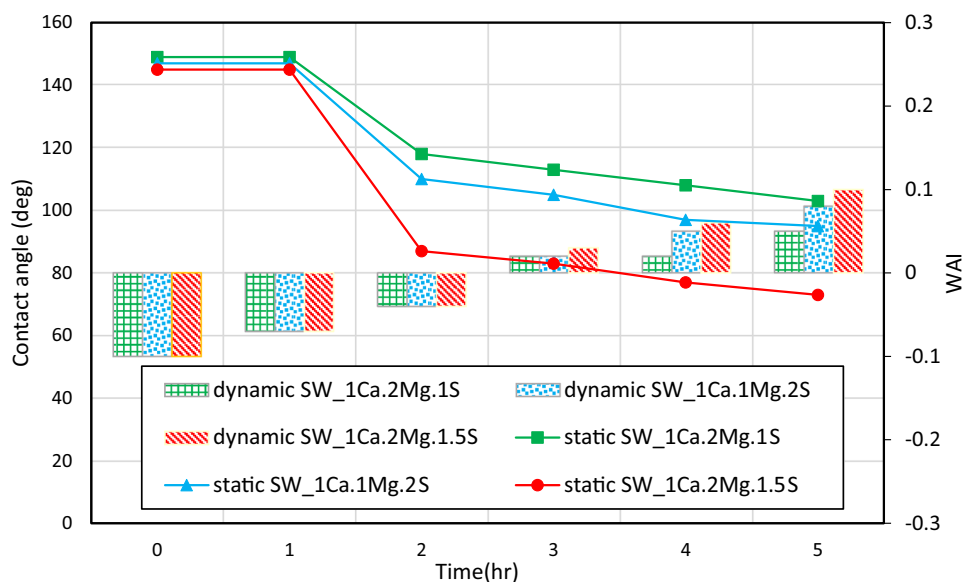


Fig. 15 SEM images of scales in the mixture containing FW and **a** SW_1Ca.2 Mg.1S, **b** SW_1Ca.1 Mg.2S, **c** SW_1Ca.2 Mg.1.5S

static compatibility tests. In this figure, the size and shape of the scale crystals can be found. By analyzing the pore size distribution of the porous rock sample, the critical size at which sulfate scales plug the pores can be determined.

The mixture of SW_1Ca.2 Mg.1S and formation brine has various effects on solid inorganic scales and crystal morphology. Magnesium ions in the solution can act as a stabilizing agent for unstable crystals. It can also affect the kinetics of crystal growth, leading to changes in crystal size of less than 2 microns (Fig. 15(a)) and the morphology of unstable crystals by affecting the growth rates of different crystal faces. Increasing the concentration of magnesium cations will generally increase the ionic strength of the solution and can affect the dissolution of other compounds. The higher ionic strength can potentially lead to changes in the

solubility of different substances, as well as the formation of complexes or precipitates.

The mixing of SW_1Ca.1 Mg.2S with the formation brine can potentially accelerate the precipitation of calcium sulfate salts and the formation of insoluble strontium sulfate crystals. In general, high concentrations of sulfate ions in the brines mixture may influence the size of precipitated crystals between 2 and 10 microns (Fig. 15(b)). The presence of both magnesium and sulfate ions in concentrations more than sea water leads to various effects on the nucleation and growth of inorganic scales, crystal size and morphology. As can be seen in Fig. 15(c) the final size of the crystals varies between 2 and 10 microns. The elevated concentration of magnesium and sulfate ions can also affect the formation of different crystalline phases or polymorphs which can lead to variations in the structure and properties of the solid scale.

Conclusions

In the present study, static and dynamic experiments were conducted to investigate the impact of PDIs in smart water on rock wettability alteration and formation damage due to inorganic scales. In static assessments, the brines compatibility jar tests and contact angle measurements were carried out. In dynamic experiments, forced and spontaneous imbibition and core flood analysis were performed. The experimental data revealed that although high concentrations of sulfate ions in injection water improve the wettability of reservoir rock, increases the potential of formation damage due to sulfate scales, simultaneously. Therefore, the concentration of sulfate anions should be adjusted at an optimum value in the presence of other ions in smart water. The main findings are as follows.

- The maximum amount of sulfate scale was found at 3500 mg/l in the mixture containing 60% smart water with sulfate ions concentration twice the sea water.
- Doubling the concentration of sulfate ions in smart water results in rock wettability alteration from oil-wet to neutrally-wet and changes the contact angle value from 145° to 95°, but causes an increase in the amount of sulfate scales.
- Both static brines compatibility and dynamic core flood tests indicated that a simultaneous increase in the concentration of magnesium and sulfate ions in smart water can diminish the potential of reservoir damage due to sulfate scale formation.
- The wettability measurements showed that SW_1Ca.2 Mg.1.5S has the most significant effect on rock wettability alteration toward water-wet and changes the contact angle value from 145° to 73°.
- The results of core flood tests displayed that the injection of SW_1Ca.2 Mg.1.5S into the carbonate core leads to the maximum recovery factor (i.e., 35%) and doubles the permeability.
- Two distinct morphologies were observed in SEM images, which indicates the formation of calcium sulfate and strontium sulfate scales.

Declarations

Conflict of interest The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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