Investigating the Effect of Wettability on Sand Production in the Presence of Smart Water and Smart Nanofluid: an Experimental Study

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Abstract: In recent years, research activity to increase oil recovery from hydrocarbon reservoirs by smart water (SW) injection has risen sharply. Smart water injection is one of the most efficient and low-cost methods in the improved and enhanced oil recovery (IOR/EOR) process. One of the active mechanisms of smart water to increase the oil production is wettability alteration of the rock surface from oil-wet to water-wet conditions. Recently smart water injection into unconsolidated sandstone reservoirs due to disturbance of the rock surface equilibrium causes instability of formation particles and sand production. One of the main factors disturbing the equilibrium and sand production is the sandstone surface's wettability alteration mechanism caused by disjoining pressure and stresses on the rock surface. Reduction of the reservoir permeability and closure of fluid flow paths and consequent reduction of oil production are among the main damages of sand production. In this study, a complete study on optimum smart water design based on the least sedimentation due to mixing has been done by formation water compatibility tests and analysis on divalent ions through the Taguchi design. Then the water wet sandstones were converted to oil-wet condition by model oil (stearic acid + normal heptane) in different concentrations. The wettability effect of water wet, neutral wet oil-wet on the amount of sand production in the presence of smart water in the reservoir conditions was fully investigated. To prevent sand production, a very effective chemical method of nanoparticles was used. By stabilizing silica nanoparticles (SiO$_2$) with an optimum concentration of 2000 ppm in smart water (pH = 8), according to the results of the zeta potential and Dynamic light scattering (DLS) test, the effect of wettability on sand production in the presence of smart nanofluid was fully investigated. The test results show a significant reduction in sand production and a rapid wettability alteration towards smart nanofluids’ water-wet conditions. This indicates the improvement of fluid for enhanced oil recovery processes in unconsolidated sandstone reservoirs.

Keywords: sand production; smart water (SW); smart nanofluid; silica nanoparticles (SiO$_2$); wettability alteration; zeta potential.

1. Introduction

Sandstone reservoirs are one of the most important types of oil reservoirs around the world. Sandstone mainly consists of quartz, feldspar, and clay minerals (kaolinite, illite, smectite, and chlorite) [1, 2]. The quality of sandstone reservoirs depends on their porosity and permeability, which depends on the rock's texture and cementation. The dissolution process in these reservoirs results from the leaching of cement and unstable particles such as feldspar, for which sand production is one of the reservoir’s problems [3]. This phenomenon, in which sand
particles are separated from the reservoir rock following high pressures, imposes high oil companies' costs each year. Erosion and blocking of surface and intra-well equipment and reduction of reservoir permeability, and subsequent decrease of recovery factor (RF) are some of the important problems of sand production [4-6].

The geochemical complexity causes wettability alteration in sandstones to encompass a wide range from very strong water-wet to very strong oil-wet [7]. The sandstone surface has a negative electric charge within the reservoirs' natural pH range [8]. One of the factors that significantly impact the migration of formation particles is the surface rock's wettability properties [9]. Various researchers have conducted experiments in the two-phase flow state in porous media and, it has been concluded that the movement of the surface wetting phase is necessary for the migration of formation particles [10, 11].

However, considering that most of the world's oil reservoirs have entered the secondary and tertiary recovery periods, the residual oil production in the reservoirs has been found after primary recovery. Low salinity water flooding (LSWF) or controlled salinity water flooding (CSWF), commonly known as smart water (SW), is proposed as a highly efficient method in IOR/EOR [12-14]. Smart water, having created changes in the composition and concentration of salts in water, has led the injection fluid towards more compatibility with rock and fluids reservoir. However, with low salinity water, only primary water salinity (seawater) decreased to a ratio, so low salinity water can be considered as a kind of smart water [15-17].

The use of smart water changes the reservoir rock's wettability. It brings it to the desired wettability by changing the salinity of water injection into the reservoir and using specific ions utilized in the smart water composition [18, 19]. A reservoir rock can have three types of wettability; 1- water-wet (WW): reservoir rock tends to spread water on its surface. 2- oil-wet (OW): the oil phase is spread on the rock surface. 3- neutral-wet (NW): rock has the same tendency to spread water and oil on its surface. This property is investigated by measuring the contact angle formed by the fluid and the rock surface. The classification of wettability types is given in Table 1 [20].

| Contact angle (°) | Wettability          |
|------------------|----------------------|
| 0-30             | Strongly-water wet   |
| 30-90            | Water-wet            |
| 90               | Neutral wet          |
| 90-150           | Preferentially oil-wet |
| 150-180          | Strongly oil-wet     |

Khishvand et al. performed flooding tests over the sandstone cores, and they observed that at a pressure of 1000 psi and temperature of 60°C, the reservoir rock wettability in the presence of smart water had changed from oil-wet to water-wet. However, high-salinity water injection has not significantly altered the wettability of the samples [21]. Therefore, the reservoir rock's wettability by low salinity water injection leads to more water wetting and increased oil recovery [22-25].

In the case of incompatibility with the combination of injected saltwater (smart water) and the reservoir fluids, sediments caused by the reaction between them are created in the reservoir environment, which affects the recovery efficiency and fluid flow. Therefore, smart water composition should be considered before injection into the reservoir in terms of compatibility with reservoir fluids [26].
In loose sandstone reservoirs, any change in the composition of the injected fluid, changes in the reservoir environment's pH, and the rock surface's wettability alteration leads to instability of the rock surface particles and causes sand production. In this process, the cement in the rock texture gradually dissolves over time due to water flow, resulting in the separation and movement of sand particles. The resulting sediments and sand particles can be blocked in the reservoir, causing some of the fluid pathways, affecting the reservoir permeability and fluid movement. Due to the high fluid flow with a high rate in the near-wellbore, sand production is more common than other points [27-29].

With the separation of sand particles and other particles from the rock surface, the reservoir's wettability can also change. This issue is very important in the enhanced oil recovery (EOR) of reservoirs [30].

Different methods can be used to prevent sand production, classified into two categories of mechanical and chemical methods. The mechanical methods are using gravel pack, slotted liner, wire wrapped screen, and pre-packed screen. Chemical methods, including the use of the warm air injection technique, silicon halide injection in the form of gas or solution, polymer injection, and resin injection, can be pointed out. These methods are usually uneconomical and sometimes reduce permeability (damage to the formation) and production [31-35].

Nanotechnology is one of the most effective chemical methods for sand production prevention. These particles have nanometer dimensions and are present in aqueous solutions in the form of charged particles, having both water-wetting and oil-wetting properties. On the one hand, while entering the reservoir environment, nanoparticles are absorbed onto the rock surface, and wettability alteration towards water wetting and reducing the interfacial tension (IFT) of water and oil, which increase production. On the other hand, by coating the rock cement's surface, it prevents its contact with the aqueous solution and, as a result, dissolves it, and therefore acts as a stabilizer and prevents sand production [36-41].

Due to their very small size, the high proportion of the area to volume of nanoparticles has very high reactivity. For the first time in 2008, Huang et al. used nanoparticles to stabilize formation particles in a hydraulic fracturing test. Previous research showed that the use of nanoparticles could prevent the migration of minerals separated from the rock surface due to disturbing the ionic balance in the porous media [42, 43].

Yuan et al. designed experimental smart water and nanoparticles to increase oil recovery. They examined their experiments in the simultaneous injection of nanoparticles with smart water and nanofluid injection before smart water injection as a pre-flush fluid in the porous media. In the case of simultaneous injection of nanoparticles with smart water, the nanoparticles adhere to the formation particles and reduce their surface charge, causing the formation particles to adhere to the porous media wall. When nano is injected with the pre-flush fluid into the porous media, absorption of formation particles into the porous media becomes more effective in the migration of sand particles [44].

To prevent the production of formation particles by nanoparticles, Ogolo et al. found that, in addition to a considerable decrease in formation particles' production due to using nanoparticles, increasing the step-by-step injection rate yields better nanoparticle performance in preventing the production of formation particles [45].

Hasannejad et al. used silica oxide (SiO₂) to control the production of formation particles. Using core flooding tests and injecting silica oxide as a stabilizer for formation particles, they found that the nanoparticle could reduce the formation particles production by 80 percent at a concentration of 0.1 percent mass. Also, they measured the atomic force
microscopy (AFM) and analyzed the results. It was observed that injecting silica nano-oxide increased the surface roughness, which they considered the most important mechanism in preventing the movement of formation particles [46].

In this paper, the effect of wettability alteration on the amount of sand production in the presence of smart water and smart nanofluids has been evaluated by conducting a large number of laboratory tests. Wettability alteration of the sandstone surface to water wetting with smart water disturbs the equilibrium on the rock surface and causes sand production. In addition to accelerating wettability alteration to water wetting, tests currently performed in the presence of smart nanofluid (Smart water + 2000ppmSiO$_2$) have reduced sand production. This shows the improvement and economy of this fluid for injection into sandstone reservoirs for EOR processes.

2. Experimental Procedures

2.1. Materials

2.1.1. Minerals (artificial cores and thin sections).

The unconsolidated artificial sandstone cores, which initially had sand production potential, were made with optimum composition to investigate the sand production. The artificial core is the core of the cement compound because, in addition to sand production, the made cores should resist the applied pressures. The core is composed of water, sand, cement, and kaolinite. Using kaolinite clay mineral has a shallow effect on reducing the porous media's permeability compared to other clay minerals. The combination of X-Ray Fluorescence (XRF), elemental analysis of cement and sand is given in Table 2.

| Component | SiO$_2$ | Al$_2$O$_3$ | BaO | CaO | Fe$_2$O$_3$ | K$_2$O | MgO | MnO | Na$_2$O | P$_2$O$_5$ | SO$_3$ | TiO$_2$ | LOI | Sr |
|-----------|---------|-------------|-----|-----|-------------|-------|-----|-----|--------|---------|-------|--------|-----|----|
| Sand(%)   | 78.81   | 8.95        | 0.05| 2.42| 0.55        | 3.16  | 0.21| -   | 1.74   | -       | 1.47  | 0.05   | 2.58| -  |
| Cement(%) | 20.73   | 4.12        | 0.07| 61.91| 3.25        | 0.78  | 3.26| 0.21| 0.35   | 0.08    | 2.39  | 0.31   | 2.49| 0.07|

From the artificial cores, thin sections with about 3mm thickness and about 25mm in diameter were cut using a cutting machine, as shown in Figure 1. The thin sections taken from the cores by a helium porosimeter and gas permeameter have an average porosity of 28.22% and average permeability of 34.31md.

![Image](https://biointerfaceresearch.com/)

**Figure 1.** Sandstone core and a thin section for sand production test.

2.1.2. Brines.

To obtain the optimal combination of smart water, the formation water (the composition of one of the sandstone reservoirs of southern Iran) and seawater (Persian Gulf water
composition) were initially synthesized in the laboratory by distilled water and laboratory salts (Merck). The distilled water used in the experiments is a one-time distillation type and has the characteristics of total organic contact (T.O.C < 5) and resistivity 18.2 MΩ cm. Initially, to reduce seawater's salinity, the dilution process was diluted at five ratios of 2, 5, 10, 15, and 20 times compared to its original composition. For seawater's compatibility in different proportions with formation water, the compatibility test was performed with a ratio of 50 to 50 at reservoir temperature (65°C). Water 10 times diluted, which had the lowest sediment and highest compatibility with the formation water, was selected as the base water for the final compatibility test and to obtain the optimal smart water combination.

For optimization of smart water composition, Taguchi design was carried out using Minitab software. After compatibility testing of 9 smart water compositions with formation water, a combination of number 9 was selected due to less deposition as optimum smart water composition. Taguchi design in Table 3 shows that numbers 1 to 3 represent the three variables' three levels. The numbers 1, 2, and 3 represent half the initial concentration, the concentration equal to the initial concentration, and one-half of the initial concentration.

### Table 3. Taguchi’s algorithm.

| Composition number | A→Na2SO4 | B→MgCl2 | C→CaCl2 |
|--------------------|----------|----------|----------|
| 1                  | 1        | 1        | 1        |
| 2                  | 1        | 2        | 2        |
| 3                  | 1        | 3        | 3        |
| 4                  | 2        | 1        | 2        |
| 5                  | 2        | 2        | 3        |
| 6                  | 2        | 3        | 1        |
| 7                  | 3        | 1        | 3        |
| 8                  | 3        | 2        | 1        |
| 9                  | 3        | 3        | 2        |

The composition of optimum smart water (SW) and formation water and seawater are given in Table 4.

### Table 4. Composition of formation water, seawater, and smart water.

| Component  | Formation water weight(g/l) | Seawater weight(g/l) | Diluted seawater (g/l) | Smart water weight(g/l) | Manufacturer |
|------------|-----------------------------|----------------------|------------------------|-------------------------|--------------|
| NaCl       | 150                         | 28                   | 2.8                    | 3.364                   | Merck        |
| KCl        | 0                           | 0.8                  | 0.08                   | 0.08                    | Merck        |
| CaCl2·2H2O | 49.5                        | 1.38                 | 0.138                  | 0.069                   | Merck        |
| MgCl2·6H2O | 14.5                        | 5.5                  | 0.55                   | 0.275                   | Merck        |
| NaHCO3     | 0.66                        | 0.1                  | 0.01                   | 0.01                    | Merck        |
| Na2SO4     | 0.403                       | 4.4                  | 0.44                   | 0.22                    | Merck        |

2.1.3. Other materials.

In this experiment, nano-silica (SiO2) was used to prepare smart Nanofluids (smart water + nanoparticles). The Nano SiO2 used has a purity of more than 99%, the average particle size is about 20 to 30 nm, and has a specific surface area of about 200 to 600 m²/g. For oil wetting thin sections, a combination of stearic acid (fatty acid) CH₃(CH₂)₇COOH (molecular weight 284.48 g / mol and density 0.941 g / ml) and normal heptane C₇H₁₆ (molecular weight 100.21 g/mol and density 0.684 g/ml) were used. Kerosene oil (45.5°API and 1.5 cp viscosity) was used for the contact angle test.
2.2. Methods.

2.2.1. Nanofluid preparation.

By obtaining the optimum smart water composition, SiO$_2$ nanoparticles were added to the smart water in two concentrations of 1000 and 2000 ppm to determine the most stable and optimal concentration in the tank conditions. The reason for using these two concentrations is that, essentially, the high concentrations of nanofluids are not economically efficient, and the high concentrations of nano are not used due to lack of stability [47]. By adding nanoparticles of SiO$_2$ at specific concentrations to smart water for the initial dispersion of nanoparticles, we place the fluid on a magnetic stirrer for 30 min (at a rotation speed of about 1800 rpm). To uniformly disperse the nanoparticles in the fluid for 1 hour, we place them in an ultrasonic bath (with a frequency of 24 kHz and a power of 400 W). The creation of the wave disperses the nanoparticles evenly in the solution and allows the investigation of stability or instability over time and under temperature conditions [48]. The nanofluid preparation steps are shown in Figure 2.

![Figure 2. Schematic of smart nanofluid preparation steps in this study.](image)

The manufactured nanofluids were placed in the oven at reservoir temperature (65°C) for 24 hours, and the stability was visually checked. The two main criteria for nano stability in smart water are Zeta potential and Dynamic Light Scattering (DLS). According to the isoelectric point’s (IEP) definition in which the pH of zeta potential value is equal to 0, the IEP value for silica nanoparticles is in the 2-3 range. By moving away from this pH, the value of zeta potential changes and causes nanofluid stability [49]. Nanoparticles are gradually absorbed through unequal charges to form clumps that eventually lead to nanofluid instability [50]. Due to both nano concentrations' visual stability, based on the results of Zeta potential and DLS tests, which are given in Table 5 and Figure 3, nanoparticles with a concentration of 2000 ppm in smart water (pH = 8) were selected as the optimum nanofluid.

| Nano fluid     | pH | Zeta potential (mV) | Average diameter(nm) | Stability quality |
|----------------|----|---------------------|----------------------|------------------|
| SiO$_2$ (1000ppm) | 8  | -21.4               | 277                  | good             |
| SiO$_2$ (2000ppm) | 8  | -23.9               | 344                  | Very good        |

![Figure 3. Zeta potential distribution curve (a) 1000 ppm SiO$_2$; (b) 2000 ppm SiO$_2$.](image)
2.2.2. Water-wet sandstone.

Artificial cores are made because water is used in their composition, and the obtained cores are placed in water (calcite solution) for 28 days to achieve sufficient strength. The core is initially thoroughly water wet. The contact angle of the water-wet base thin section in the presence of kerosene oil is 56.702 degrees. Also, to investigate the effect of the contact angle of water-wet sandstone, the thin base section was placed in distilled water (pH = 7 (neutral pH)) for 72 hours. Its contact angle was obtained at 49.883 degrees in the presence of kerosene oil. Distilled water does not react with rock due to its neutral pH and lack of ions, so sand production does not occur. Figure 4 shows the contact angle of the base and 72 hr. in distilled water-thin sections.

2.2.3. Oil wetting and neutral wetting procedure.

Model oil was used for wettability alteration of thin sections towards oil wetting. The oil model consists of a combination of stearic acid and normal heptane. Stearic acid (fatty acid) has a polar head and a non-polar head that adheres to the rock surface from the polar head. Their non-polar head can be dissolved in alkanes. In this case, London forces are the cause of the interconnection of fatty acid and oil molecules. Stearic acid can dissolve in normal heptane and heavier alkanes [51, 52].

To investigate the effect of different contact angles, the rock was oil wetted at two concentrations of 0.01 and 0.03 molar stearic acid in normal heptane. Thin sections were placed in a solution of acetic acid and normal heptane at 65°C in an oven (reservoir temperature) for 72 hours. Figure 5 shows solutions of 0.01 and 0.03 molar stearic acid in normal heptane and shows the thin sections within the solution. Also, by placing the rock at 0.005 molar of stearic acid and normal heptane solution similar to the two concentrations mentioned, the contact angle that the rock finds is equal to 92.121 degrees, which is almost neutral-wet, according to Table 1.

![Figure 4. Contact angle of water wet (WW) thin sections.](https://biointerfaceresearch.com/)

![Figure 5. (a) 0.01; (b) 0.03 molar stearic acid in normal heptane.](https://biointerfaceresearch.com/)
2.2.4. Contact angle measurement.

To investigate the effect of smart water and smart nanofluid (2000 ppm SiO$_2$ in smart water) on changes of contact angle and sand production, each of the thin sections of water-wet and oil-wet with concentrations of 0.01M, 0.03M, and the neutral-wet thin section of 0.005M (stearic acid + normal heptane) were placed in the beaker containing smart water and smart nanofluid. The fluid and thin section of the sample was placed in an oven at 65°C, simulating reservoir temperature. For five days every 24 hours, the rock's contact angle was measured in the presence of smart water kerosene oil. The angle created by the denser fluid (smart water) is considered as the contact angle between the rock and oil droplet. The contact angle measurement was performed in atmospheric conditions. The schematic setup of the contact angle measurement is shown in Figure 6.

![Figure 6. Contact angle apparatus schematic.](https://biointerfaceresearch.com/)

2.2.5. Weighing of sand production.

We first measure the weight of completely dry thin sections with a digital balance by an accuracy of 0.01 g. Then we put one number from each thin section in our special beaker. We place the beakers in a 65°C oven, the reservoir temperature. After 24 hours, we take out the thin section with high accuracy and sensitivity from the fluid of smart water and smart nanofluid and put it in an oven with the same temperature of 65°C for 2 hours until it dries completely. Then we weigh each of the thin sections. We transfer the thin sections to our specific beaker, place them in an oven at 65°C and repeat this process for five days (120 hr.) every 24 hours.

3. Results and Discussion

3.1. Wettability alteration effect on sand production in smart water.

One of the main active mechanisms of smart water for increasing reservoirs' oil production is the wettability alteration toward water-wet conditions [53, 55]. This wettability alteration is caused by disturbing the equilibrium conditions of the ions in the reservoir environment. For this purpose, it is possible to use different ions such as Ca$^{2+}$, Mg$^{2+}$, and SO$_4^{2-}$ in the composition of the injected water to the reservoir with low salinity and create changes in the ionic power of the injected water [56]. The competition between disjoining pressure, capillary pressure, and removal of naphthenic acids from the rock surface define the ultimate wettability after smart water injection in the IOR process. By altering the electrostatic repulsive force and removing naphthenic acids using the ion exchange mechanism, smart water alters the
disjoining pressure at the rock surface and the wettability alteration towards more water wetting [57, 58].

Due to the contact of smart water with cement and clay minerals of the rock surface, the rock cement and clay minerals are gradually separated from the surface rock. Thus, the rock’s surface charges have changed, and polar and charged particles in the oil cannot remain on the rock surface. Therefore, the wettability of the reservoir rock moves towards more water-wet conditions [56, 59].

Two layers can be considered surrounding the rock. The first layer is called the stern layer and only includes single and double capacity cations such as Na⁺, Ca²⁺, and Mg²⁺. It is absorbed in the rock due to chemical interactions, while the second layer, known as the diffuse layer, can have particles of negative charge within itself. If particles with negative charge can be absorbed into the stern layer cations, the stone has an oil wetting property.

Suppose the stern layer’s cations can absorb particles with a negative charge of oil. In that case, they give the rock surface an oil wetting property. By reducing the injectable water's salinity, the ionic strength decreases. The diffuse layer gradually thickens, resulting in a lower chance of negatively charged particles being absorbed into the stern layer’s cations. During this process, non-complex cations have replaced organic and organic-metallic compounds, and wettability has approached more water wetting, leading to increased oil recovery [60, 61].

Recently, smart water injections in sandstone reservoirs cause sand production and migration of formation particles. In these experiments, we investigated the effect of wettability alteration on sand production in sandstone reservoirs.

**Table 6. Initial weight of thin section in smart water.**

| Type of thin section | 72 hr. in Distilled water (water wet) | Base sandstone (water wet) | 0.005 M (Neutral wet) | 0.01 M (oil-wet) | 0.03 M (oil-wet) |
|---------------------|--------------------------------------|---------------------------|----------------------|-----------------|-----------------|
| Weight (g)          | 7.82                                 | 5.56                      | 6.13                 | 8.14            | 6.05            |

Initially, 50cc of optimum smart water (the composition of Table 4) was poured into a beaker. Thin sections with different wettability, the dry weight is given in Table 6, were placed in a beaker containing smart water. We placed them at a reservoir temperature of 65°C in the oven and checked the contact angle and sand production every 24 hours.

As shown in Figure 7, the maximum amount of sand production from the rock is observed in the first 24 hours. The amount of sand production decreases over time. Stress caused by wettability alteration of the rock in the presence of smart water and electrostatic force changes disturbs the equilibrium on the rock surface. It causes the sand to separate from the rock surface. Over time, wettability alteration (contact angle alters) decreases, and sand production is gradually reduced. Due to low salinity water contact with the mineral of rock surface and cement between the loose sandstone particles, the ionic balance of the environment is disturbed. As a result, the process of leaching and separation of sand particles from the rock surface occurs. Over time, as the stress on the rock surface stabilizes, sand production decreases.

In this study, water-wet, neutral-wet, and oil-wet effects have been observed. The base contact angle in the presence of smart water fluid has been taken from thin sections every 24 hours. According to Table (7), the contact angle of thin sections of 72 hrs in distilled water and base sandstone is completely water-wet. Thin sections of 0.01M and 0.03M (stearic acid + n-heptane) are completely oil-wet, and the thin section of 0.005M is close to neutral-wet.
Table 7. Base contact angle.

| Type of thin section | 72 hr. in Distilled water | Base sandstone | 0.005 M | 0.01 M | 0.03 M |
|----------------------|---------------------------|----------------|---------|--------|--------|
| Contact angle(degree) | 49.883°(WW)               | 56.702°(WW)    | 92.121°(NW) | 120.314°(OW) | 146.551°(OW) |

According to Figure 7, the highest amount of sand production is related to water-wet thin sections. A thin section 72 hr. in distilled water has the highest sand production, while the weight loss of rock is 0.23 g, and sand production is 2.941% of the total rock. Also, the water wet base thin section has sand production close to the thin section that was placed in distilled water for 72 hrs. The amount of sand produced is 0.16 g, which is about 2.877% of the thin section’s total weight. Also, the trend of decreasing the contact angle of these two water-wet thin sections is shown in Figure 8.

**Figure 7.** Sand production in smart water in different wettability.
According to Figure 7, the maximum sand production in the 0.005M thin section is similar to other thin sections in the first 24 hours. The amount of sand production decreases. The sand production of the NW thin section is lower than that of WW thin sections, and the amount of sand production is 0.14 g, which is 2.284% of the thin section's total weight. The contact angle alteration process of this thin section is shown in Figure 8.

![Figure 8](https://biointerfaceresearch.com/)

**Figure 8.** Contact angle measurement in smart water.

As can be seen in Figure 7, the lowest sand production is related to OW thin sections. The wettability goes towards more oil-wetting. Sand production decreases due to gradual wettability alteration towards water wetting, and the stresses and equilibrium on the rock
surface change more slowly. Also, due to the strong molecular bonds of fatty acids (petroleum) on the surface of the oil wetting rocks and the adhesion created, less sand is produced from the rock’s surface. In the 0.01M thin section, the amount of sand production is 0.011 g, which is 1.351% of the total weight of the rock, and in the 0.03M thin section, the amount of sand production is 0.07 g, which is 1.157% of the total weight of the rock. The trend of changes in the OW thin sections’ contact angle from oil-wet toward water-wet is shown in Figure 8.

3.2. Wettability alteration effect on sand production in smart nanofluid.

In the process of smart water injection into the reservoir, due to the very low salinity of the injected water compared to formation water, the ionic balance in the reservoir environment is disturbed. There is an interaction between the minerals forming the rock surface. Mainly the cement between the particles and available ions occurs in the environment. As a result, the cement on the rock surface in the presence of smart water tends to separate from the rock surface. This creates a problem for separating sand particles from the rock surface and migration along with the fluid flow.

One way to prevent sand particles from migrating due to rock surface contact with low salinity water is to cover the rock surface and mostly the cement between the particles using nanoparticles. It is one of the most widely used nanoparticles in IOR silica (SiO$_2$) nanoparticles and metal oxides [62]. In this experiment, by stabilizing Nano SiO$_2$ in smart water with optimum concentration, in addition to increasing production caused by a faster shift to water wetting and reducing interfacial tension (IFT), it also reduces sand production [63, 65]. Based on the Zeta potential and DLS test results related to Table 5, nanofluid concentration of 2000 was selected.

To see the wettability alteration from water wetting to oil wetting by (stearic acid + n-heptane) and the effect of nanoparticles on the rock surface, Field Emission Scanning Electron Microscopy (FESEM) images have been taken. They show that the presence of smart nanofluid (2000 ppm SiO$_2$) can completely cover the rock’s surface and act as a barrier, reducing stress on the rock surface and preventing sand production. Figure 9 shows the wettability alteration from water wetting to oil wetting and rock surface before contact with the nanofluid. As you can see, there is no cover or barrier on the rock surface, and all the rock grains can be in direct contact with the smart water.

![Figure 9. Rock surface before submerging in Nano fluid. (a) base (WW); (b) 0.01M (OW); (c) 0.03M (OW).](https://biointerfaceresearch.com/13443)

Now we put the thin section in the smart nanofluid for 24 hours. After 24 hours, the nanofluid is given a soaking time to affect the rock. The nanoparticles settle on the rock surface.
Figure 10 shows the spherical silica nanoparticles that the rock surface has absorbed cover the rock surface like a coating. It is also helping the oil production process by reducing interfacial tension and improving the wettability alteration towards more water-wet conditions. It prevents smart water contact with rock cement and thus leaching the rock, leading to preventing sand production.

![Figure 10. rock surface after submerging in a smart nanofluid. (a) surface absorption of nanoparticles on rock surface; (b) particle size absorbed on the rock surface.](image)

The pressure applied to the solid surface in the face of the fluid adhesion force, which tends to disjoin the fluid from the surface, is called the disjoining pressure. As shown in Figure 11, nanoparticles are absorbed into the rock surface during the surface adsorption process. Similar to a protective layer, nanoparticles prevent fluid from reaching the surface of the rock. On the other hand, by applying disjoining pressure to the oil phase, they separate oil droplets attached to the rock surface. As a result, the wettability of the reservoir rock leads to more water-wet conditions. This pressure is the result of Brownian forces and electrostatic repulsion between nanoparticles. The smaller the nanoparticle size and the higher the nanoparticle concentration, the higher the pressure. Nanoparticles alter disjoining pressure by structurally disjoining pressure at the wedge film. The excess pressure due to the accumulation of nanoparticles in the wedge film leads to overcoming the Van der Waals forces and changing the wettability [66-68].

![Figure 11. Process of wettability alteration by applying disjoining pressure from silica (SiO₂) nanoparticles to the oil droplets attached to the rock surface.](image)

Nanoparticles have a very high ability for wettability alteration of the rock surface. Depending on the nature of the oil-wet or water-wet nanoparticles, the surface can become oil-
wet or water-wet. As the silica nanofluid is absorbed into the rock surface, the surface wettability moves toward being more water-wet [69].

Similar to previous experiments, initially in smart water, the 2000 ppm silica Nanoparticles (SiO$_2$) are stabilized and poured into a 50 cc volume within its special beakers. Then, the thin sections' weight becomes completely dry, which can be seen in Table 8. We put the thin sections in our special beaker, including the smart nanofluid, and place them in an oven with a temperature of 65°C, which is the reservoir temperature. We investigate the sand production, and the contact angle changes every 24 hours for five days.

Table 8. The initial weight of thin section in a smart nanofluid.

| Type of thin section | 72 hr. in Distilled water (water wet) | Base sandstone (water wet) | 0.005 M (Neutral wet) | 0.01 M (oil-wet) | 0.03 M (oil-wet) |
|----------------------|--------------------------------------|-----------------------------|----------------------|------------------|------------------|
| Weight(g)            | 6.34                                 | 7.99                        | 6.83                 | 6.19             | 6.94             |

The experiments performed in the presence of nanoparticles show that the amount of sand production is significantly reduced. After the soaking time and sedimentation of nanoparticles on the rock surface, sand production is almost stopped. Similar to the experiments conducted on smart water, the results of these experiments show that the lowest sand production is related to the more oil-wet thin section (0.03M). The highest sand production is related to the more water-wet thin section (72hr. in distilled water).

The water-wet thin sections (base and 72hr. in distilled thin sections) had the highest sand production. According to Figure 12, the highest sand production in all thin sections is related to the first 24 hours, and after the settlement of SiO$_2$ nanoparticles on the rock surface and creating a coating on the rock surface, the amount of sand production is greatly reduced and ultimately comes to an end.

The amount of sand production in the (72 hr. in distilled water) thin section is 0.15 g, which is about 2.366% of the thin section's total weight. Also, the amount of sand production in the thin base section is 0.12, which is 1.502% of the rock's total weight. According to Figure (12), the maximum sand production in the 0.005M thin section is similar to other thin sections in the first 24 hours. The amount of sand production decreases. The sand production of the NW thin section is lower than the WW thin sections, and the amount of sand production is 0.09 g, which is 1.317% of the thin section's total weight.

According to Figure 12, the lowest amount of sand production is related to oil-wet thin sections. The amount of sand production in the 0.01M thin section is 0.07g, which is 0.987% of the total weight of the thin section, and in the 0.03M thin section, which has the lowest amount of sand production is 0.02g, which is 0.288% of the total weight of the thin section. In the 0.03 M thin section, the amount of sand production from the second day is completely stopped.

According to Figure 13, as expected, a decrease in contact angle occurred faster in all wettability than in smart water without nano, which indicates a fluid improvement.

According to Figure (12) and the factors mentioned, the lowest amount of sand production is related to oil-wet thin sections. The amount of sand production in the 0.01M thin section is 0.07g, which is 0.987% of the total weight of the thin section, and in the 0.03M thin section, which has the lowest amount of sand production is 0.02g, which is 0.288% of the total weight of the thin section. In the 0.03 M thin section, the amount of sand production from the second day is completely stopped.
Figure 12. Sand production in smart water with nano (Smart Nanofluid) in different wettability.

According to Figure 13, as expected, a decrease in contact angle occurred faster in all wettability than in smart water without nano, which indicates a fluid improvement.

According to the results, as much as the sandstone has strong oil wetting, a smaller amount of sand is produced. Based on the experiment results, it was observed that smart water with nanoparticles significantly reduces sand production, and after a while, the amount of sand production comes to an end. A comparison between the percentage of sand produced by different types of thin sections during five days in the presence of smart water and smart nanofluid is given in Figure (14).
4. Conclusions

With smart water injection into unconsolidated sandstone reservoirs, the competition between disjoining pressure and capillary pressure and removing naphthenic acids result in wettability alteration of the rock surface to water-wet conditions. Wettability alteration of the unconsolidated sandstone surface is one of the main factors disturbing the equilibrium in the rock surface and sand production.

Enhanced oil recovery processes, such as smart water injections, usually take place in reservoirs where the natural production life is over. Most of these reservoirs have oil-wet conditions because of the asphaltene deposition and adhesion of oil droplets on the rock surface. Due to the strong bonding of oil molecules (fatty acids) with the rock surface, the 0.01M and 0.03M (stearic acid + n-Heptane) thin sections had lower sand production in the presence of smart water and smart nanofluids.
Figure 14. Sand production of different thin sections in the smart water and smart nanofluid (smart water +2000ppm SiO₂).

The amount of sand production from the rock was significantly reduced by dispersing silica nanoparticles in smart water at stable and optimum concentrations based on the zeta potential and dynamic light scattering (DLS) test results. According to FESEM images, due to the settling and covering of the rock surface by spherical silica nanoparticles after soaking time, in addition to helping wettability alteration come closer to water-wet conditions, it prevents smart water from contact with grains and cement, thus preventing the sand production.

With regard to experimental results, the highest stress and chemical activity arising from wettability alteration of the rock surface by smart water are related to the initial phases of the experiment. With the passage of time and obtaining equilibrium at the rock surface, the amount of sand production is reduced. Besides, the results of smart nanofluid tests show that the highest sand production rate is related to the initial phases of the experiment. With the settling of silica nanoparticles on the rock surface, sand production would eventually come to an end.

Smart water containing nanoparticles (smart nanofluid) have reduced the amount of sand production by 30% compared to smart water in the water-wet thin section, 36% in the neutral-wet thin section, and 54% in the oil-wet thin section. According to the results of a contact angle test, the smart nanofluid has caused greater water-wettability of the rock surface due to the disjoining pressure at wedge film, the accumulation of nanoparticles at the rock surface overcoming Van der Waals forces. This indicates the improvement of the injection fluid in the IOR / EOR process.

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Conflicts of Interest

The authors declare no conflict of interest.
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