

Effect of Alkalinity on Sand Production Due to Optimized Smart Water Based on the Scale Minimization: Impact of Silica Nanoparticles

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Abstract: Smart water injection in oil and gas reservoirs is one of the most popular and low-cost methods to increase the recovery factor of reservoirs. However, due to the abundance of sandstone reservoirs in the world and the necessity to increase recovery in these types of reservoirs, injection of smart water will disturb the distribution of intergranular stresses in the porous media which results in sand production that causes many problems in many parts of the petroleum industry. For this reason, the necessity to investigate possible parameters affecting sand production was increased. Also, according to the relative researches, the injection of smart water changes the reservoir pH, which could change the sand production rate. In this paper, a comprehensive study on the effect of pH or alkalinity on sand production, as well as the effect and mechanism of silica nanoparticles, has been performed to control the grains separated from the rock. The effect and mechanism of silica nanoparticles with economic concerns have also been analyzed, which can significantly reduce and control the amount of sand production. In this paper, we can determine the effectiveness and the most effective parameters in an acidic or basic environment.

Keywords: Nanoparticles; Sand production; Smart water injection; Alkalinity; Composition optimization.

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1. Introduction

1.1. Sand production.

Sand production is one of the costly problems of the oil and gas industry in sandstone reservoirs, which cost millions of dollars annually to predict and reduce its production. Its effects include corrosion and erosion of pipelines, plugging the wells, reducing productivity index, and decreasing the stability of open-hole completed wells [1]. Sand production also presents many problems associated with HSE and operational aspects. Also, mixing oil with sand requires a very costly separation process [2-3], so knowing all the factors affecting sand production such as formation properties, clay content [4-5], and effective stress [6]. Also, operating conditions such as injection pressure is necessary to prevent and predict sand production. In recent years, numerous studies have been performed on the geological factors and properties of cementation materials and the initial drag force on sand production [7]. Ranjith et al.; experimentally concluded that the rate of sand production increased with increasing drag force and decreased with increasing clay content [8]. A mathematical study of

sand production) also showed that sand production was highly dependent on the compressive strength of the sand grains, which can either decrease or increase the amount of sand production [9].

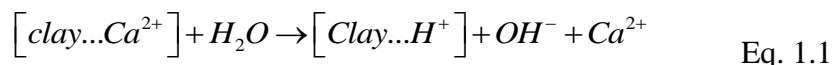
At the beginning of production from a well, some solid particles with oil come to the surface. This phenomenon depends on the type and age of the reservoir, which is usually seen in younger reservoirs because they are less robust, and their cement materials are usually clay, which any production of sand would impose an additional cost on the oil industry. The other reasons for sand production include in-situ stresses, fluid viscosity, capillary forces, etc. [9]. However, generally, sand production is controlled by the frictional force between grains, capillary force, and cement materials. For example, when the bit is drilling the reservoir, the hydrostatic pressure of the drilling mud replaces the forces applied to the sand grains which stress distribution will be different from before in the reservoir, which can be decomposed into horizontal or vertical stresses that usually they are not equals [10]. Stress changes can be due to a variety of reasons, such as smart water injection to increase reservoir recovery[10,26,27]. If the new stress distribution system in the near-wellbore or reservoir exceeds the rock resistance, instability will form in the reservoir, which can lead to the separation of sand grains from the rock surface and their production due to pressure difference. However, in the Mohr-Coulomb model, failure occurs when the stress of the rock exceeds the resistance of the formation. This stress can be caused by many factors such as water injection into the reservoirs. Finally, sand production usually results from grains that are not solidified or separated by external stresses.

1.2. Smart water injection.

The average pressure of reservoirs will be depleted during the primary production period. This reduction will destroy a large amount of the reservoir OOIP, in which many methods for pressure maintenance have been proposed [12]. Due to the enormous water resources and ease of water injection in depleted reservoirs, smart water injection is one of the most popular ways to increase reservoir recovery, which does not require expensive chemical and operation [10-11-12]. In this case, Kokal and Al-kaabi [13] stated the advantages of smart water injection compare to other EOR methods: 1) It has the cheapest way to increase oil production from the reservoirs. 2) It has the highest final recovery coefficient with the least investment. Tang and Morrow also showed with experimental tests that changing the salinity of the brine will change the reservoir recovery factor [14]. Zhou et al. also reported that a little change in brine composition in the reservoir had a significant effect on the recovery factor [15]. However with the injection of smart water, the pH value of the environment will change due to the ion exchange between the clay and the injected water [16], so the final value of pH depends on the pH of the injected water and the amount of ion exchange with the porous medium, also change in pH value is one of the mechanisms which can increase the recovery factor of the reservoir [17].

Due to the influence of several factors on sand production, environmental alkalinity can also affect the rate and amount of change in forces exerted on the sand grains. But another phenomenon caused by water injection into the sandstone reservoirs is leaching, which will often lead to sand production in the sandstone reservoirs due to the balance disturbance of forces and stresses. Therefore, due to the numerous problems caused by sand production and the necessity of using smart water, it is essential to consider all the factors affecting sand production due to smart water injection. As mentioned above, with the injection of smart water

into the reservoirs, the pH of the environment will change due to the interactions between the clay and the salts (Ca^{2+}) in injected water [16], which can affect the rate and amount of sand production. The mechanism of pH changes due to the injection of smart water by Austad et al. was shown in Equation 1-1 [18]



As shown in Eq. 1.1, the pH value will be increased due to smart water injection, which may affect the sand production. However, controlling and reducing the sand production began in the 1950s with the use of chemical methods (resin, polymers, plastics, etc.) [32] and mechanical methods (gravel pack, slotted liner, etc.). Past researches have shown that the presence of nanoparticles can reduce the movement of minerals [21,29,31,34,39,40] and fines from the rock surface and porous media and also can prevent the ionic change in reservoirs. [18,19,20,22,23].

On the other hand, due to smart water injection into the reservoirs, the pH value will be changed, which can cause formation damage [42] or change the value of the recovery factor [18]. Bagci also concluded that the change of pH will reduce permeability in sandstone reservoirs [22-32-41]. Thus, careful study of pH change and its effect on sand production can reduce and control the rate and amount of sand production, which was studied in this paper. Also, due to concerns and applications of various technologies in the petroleum industry, nanoparticles should be tested to prevent sand production, as the use of nanoparticles in other petroleum industry applications has yielded excellent results [23-24].

So Due to the lack of investigation of the effect of alkalinity on sand production in previous studies, also due to the change in pH during the injection of smart water and its effect on the balance of intergranular forces, in this paper, with a large number of laboratory tests, a comprehensive study of sand production due to the smart water presence under different conditions such as different pH values has been carried out. Also, the effect and mechanism of nanoparticles on various laboratory tests have been analyzed. The alkalinity of the environment in the presence and absence of nanoparticles has been studied, which can clearly show the effect of each parameter individually and together. In addition, laboratory experiments for smart water composition optimization and the stability of nanoparticles in each case were carried out. Moreover, finally, a novel method for sand production measurement without core flooding was concluded, and the detailed data were reported.

2. Materials and Methods

2.1. Smart water.

Deionized water, which was used for the brine preparation, having total organic content T.O.C <5 ppb and resistivity of 18.2MΩ cm, and it was one-time evaporation. To produce smart water, different diluted seawater was used, and NaCl salt was used to compensate for the TDS. The Persian Gulf water was used as seawater, and the ions contained in it were used to obtain the various composition of low salinity water. The composition of smart water used in laboratory tests after optimizing the type and amount of salt dissolved in it, with the Taguchi algorithm (MINITAB software-shown in table 5) and performing water compatibility tests with formation water at one of the sandstone reservoir temperature in Iran (150°F) was conducted which shown in Table 1.

Table 1. Composition of smart water, seawater, and formation water.

Component (made by Merck)	Formation Water (gr/L)	Seawater (gr/L)	Smart Water (gr/L)
NaCl	150	28.00	3.364
KCl	0	0.80	0.080
CaCl ₂ .2H ₂ O	49.50	1.38	0.069
MgCl ₂ .6H ₂ O	14.50	5.50	0.275
NaHCO ₃	0.66	0.10	0.010
Na ₂ SO ₄	0.403	0.44	0.220

Also, the formation water composition used is related to one of the sandstone reservoirs in the southwest of Iran that was shown in Table 1. (Some ions with very low concentrations and economic concern were ignored). After seawater dilution, they were mixed in equal proportions to the formation of water and kept static at reservoir temperature (150F) for 24 h in the oven. After 24 hours the samples were removed from the oven and allowed to cool to ambient temperature, the fluid was then passed through a 4-7 microns’ filter paper, and the optimized composition based on the minimum scale deposition due to the interaction of ions were selected table 4 [37].

Table 2. Zeta potential and DLS for 1000ppm SiO₂ in optimized smart water.

	Zeta potential (mv)	Average diameter (nm)	Stability index
1000ppm SiO ₂ at PH=5	-21.4	246	Very good
1000ppm SiO ₂ PH=8	-23.9	227	Very good
2000ppm SiO ₂ at pH=5	Reject visually due to Nano precipitation	Reject visually due to Nano precipitation	Unstable
2000ppm SiO ₂ at pH=8	-15.9	316	Moderate

After the smart water composition optimization, SiO₂ nanoparticles with an average particle diameter of 20-50nm was added at various concentrations(500,750,1000,1500 and 2000 ppm) in smart water and placed in magnetic stirrer (at a speed of 1000RPM for 15min) and sonicated (at 250W for 30min) to obtain the most stable concentration in the reservoir conditions based on two criteria which are zeta potential (ZP) and Dynamic Light Scattering (DLS) to measure the size of nanoparticles dispersed in smart water at different pH values. The obtained concentration was also corrected according to the IEP (iso-electric point: is the pH at which a molecule carries no net electrical charge or is electrically neutral in the statistical mean) point introduced for SiO₂ nanoparticles and the effect of smart water pH (near and far from IEP point) for all pH.

Table 3. X-ray fluorescence (XRF) analysis of thin sections.

Component	Sand (%)	Cement (%)
SiO ₂	78.81	20.73
Al ₂ O ₃	8.95	4.12
BaO	0.05	0.07
CaO	2.42	61.91
Fe ₂ O ₃	0.55	3.25
K ₂ O	3.16	0.78
MgO	0.21	3.26
MnO	Negligible	0.21
Na ₂ O	1.74	0.35
P ₂ O ₅	Negligible	0.08
SO ₃	1.47	2.39
TiO ₂	0.05	0.31
Cr ₂ O ₃	Negligible	Negligible
LOI	2.58	2.49
Sr	Negligible	0.07

So the optimum concentration value of SiO₂ nanoparticles in the most stable condition for all pH values based on the zeta potential and DLS test (table 2) was 1000ppm. According to Table 2, the zeta potential and average diameter of dispersed particles at a concentration of 1000 ppm is better and indicates very good stability 18.

Table 4. Various diluted water composition from seawater.

Component	0.D SW	2.D SW	5.D SW	10.D SW	15.D SW	20.D SW
NaCl	28	14	5.6	2.80	1.860	1.4
KCl	0.8	0.4	0.16	0.080	0.053	0.04
CaCl ₂ .2H ₂ O	1.38	0.69	0.276	0.138	0.092	0.069
MgCl ₂ .6H ₂ O	5.5	2.75	1.1	0.550	0.366	0.275
NaHCO ₃	0.1	0.05	0.02	0.010	0.006	0.005
Na ₂ SO ₄	4.4	2.2	0.88	0.440	0.293	0.220
pH	8.1	7.8	7.9	8.3	8.1	8.2
TDS(grL)	40.18	20.09	8.036	4.018	2.67	2.009

Table 5. Taguchi table, made by MINITAB software.

Composition name	SW.1	SW.2	SW.3	SW.4	SW.5	SW.6	SW.7	SW.8	SW.9
Na ₂ SO ₄	1 ^a	1	1	2 ^b	2	2	3 ^c	3	3
MgCl ₂ .6H ₂ O	1	2	3	1	2	2	1	2	3
CaCl ₂ .H ₂ O	1	2	3	2	3	1	3	1	2
Weight of scale	0.001	0.0102	0.0148	0.0094	0.0154	0.0096	0.0110	0.0091	0.0080

^a number 1 means that the concentration multiplying by 0.5

^b number 2 means that the concentration multiplying by 1

^c number 3 means that the concentration multiplying by 1.5

2.2. Sandstone cores, thin sections, and pH adjustment.

Thin slices were made of sandstone cores, which the size and shape of that were shown in figure 1. The composition of rock was reported by the XRF test is shown in Table 3.

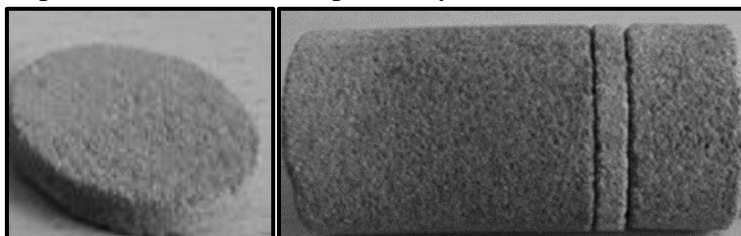


Figure 1. Sandstone core and the thin section with a diameter of 2.54 and thickness equal to 3mm.

This core had the permeability of 70 md and the porosity of about 35%. Since the pH value for smart water will be different based on the designed composition [25,35], the amount of sand produced from these thin sections that fully oil wetted (with 0.03 Molar stearic acid and n-heptane) was measured at 5 pH ranging from 4.5 to 8.5 in the presence of optimized smart water with/without nanoparticles at 120 hours at the temperature of one of the sandstone reservoir in Iran (150°F).

The samples were weighed every 24 hours by a digital scaler with an accuracy of 0.01mg after drying the samples and ensuring that no fluid is in the porous media (thin sections were washed with deionized water before drying to ensure that scales do not settle on the rock surface and make sure that the thin section weighting and sand production calculation will be accurate). The difference between the weight of the thin section and the weight took the day before, after drying the sample and ensuring that fluid is not present, is the amount of sand produced (which may be due to wettability alteration [33,43], viscous and capillary forces,

erosion, etc.) which the sand grains were observed at the bottom of a glass. To adjust the pH of the smart water, the solution of HCl was used to decrease, and the NaOH powder was used to increase pH.

3. Results and Discussion

3.1. Effect of alkalinity on sand production due to smart water injection.

When the pH was in the acidic range, the amount and intensity of sand production during the first days were much higher than conditions similar to the higher pH in the alkaline intervals. As can be seen, the amount of sand produced during the first days is higher, and the amount of sand removed from the sample decreases with time. The reason for these results may be that the loose grains were initially separated, and the more consolidated grains have remained in place. According to Carlson et al. (1992) results, loosely and unconsolidated grains will be separated at first. If the stress (induced by any parameter) is greater than the grain adhesion force, the other grains will also be separated from the rock. But in figure 2(a), which shows the process of thin section weight loss at pH = 5.5, the rate of sand production from the rock decreased compared to similar conditions at pH = 4.5 (fig.2(b)). At pH = 5.5, it was also observed that the rate of sand production during the first days was greater than the days after. Similarly, the rate of weight loss caused by sand production at pH values of 6.5, 7.5 and 8.5 can be seen in Figures 3(a), 3(b) and 4(a), respectively.

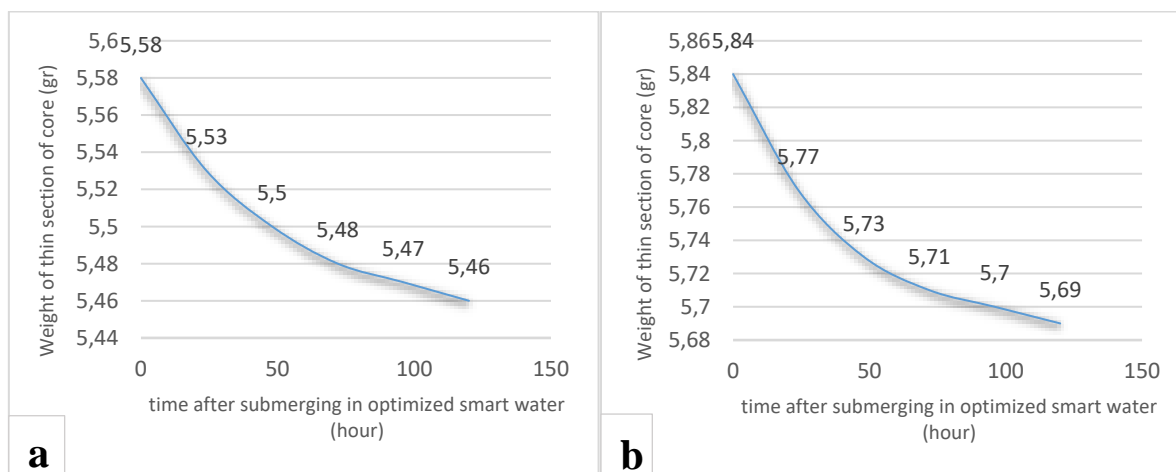


Figure 2. Thin section weight vs time for:(a) pH=5.5 and (b) pH=4.5.

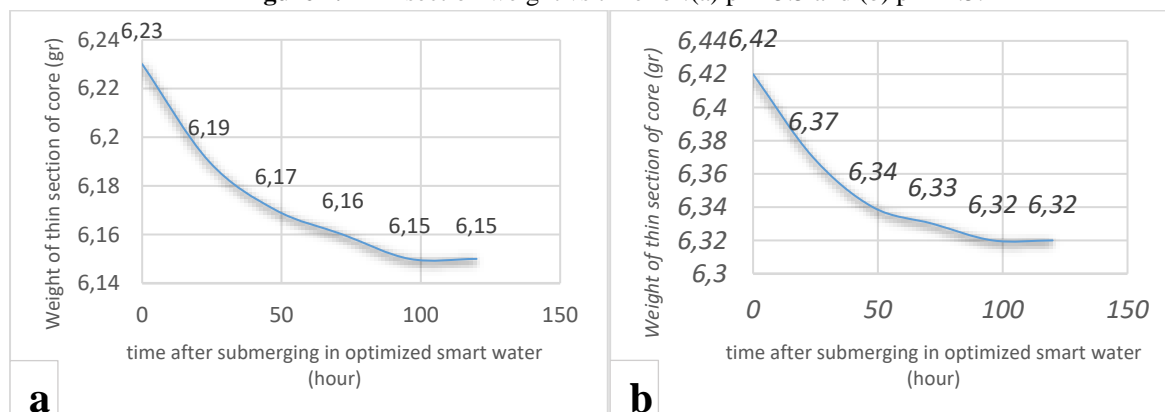


Figure 3. Sand produced in smart water without nanoparticles at (a) ph=7.5 and (b) ph=6.5.

However, in Figure 2(a), which shows the amount of sand produced at pH=5.5 during 120 hours, it is observed that they had less sand production than pH=4.5. So that smart water

with pH = 4.5 and pH=5.5 during 120 hours, 2.5%, and 1.5% of thin section weight were produced respectively. On the other hand, at pH = 6.5 after 96 hours, the weight of the thin section has not diminished; this means that no sand is produced from the rock. The same thing can be seen at pH = 7.5 in Figure 3(b). The reason for the results may be that as the pH increases, the stress on the sand grains will decrease, which can lead to stop or decrease the sand production rate over time. Because according to the results of the previous studies 38, sand is produced when the applied stresses are higher than the cement material adhesion stresses.

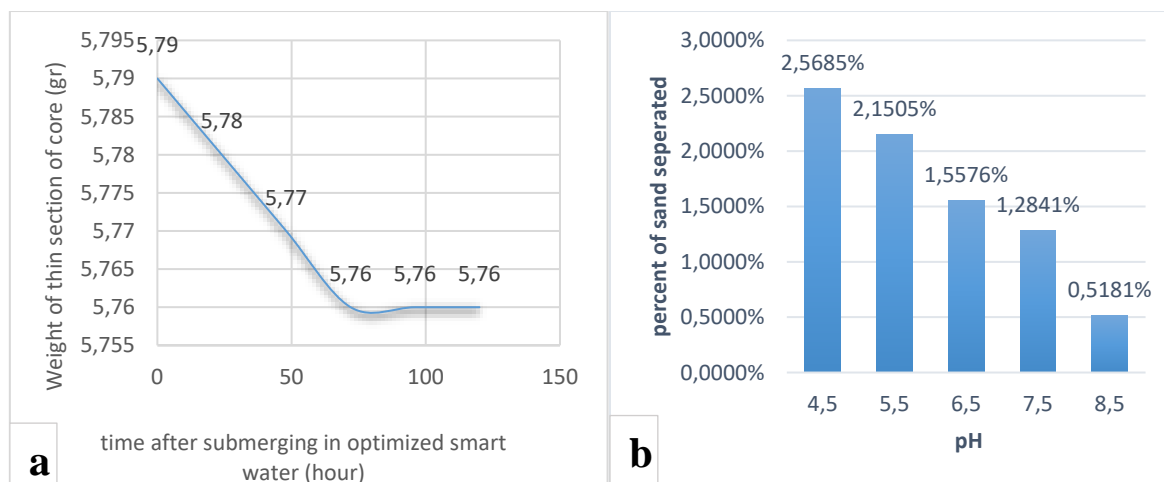


Figure 4. (a) sand produced at Ph=8.5 (b) sand produced percent for each pH without nanoparticles.

It is also clear from Figure 4(b) that the amount of sand produced was decreased significantly with increasing the alkalinity of smart water. So that at pH = 8.5, which is almost the maximum pH of smart water [35], it will lead to the lowest amount of sand production. As mentioned, in the high pH values, the sand production stops earlier because it is likely to bring less stress to the grains, as can be seen in Figure 4(a), the sand production was stopped after 72 hours.

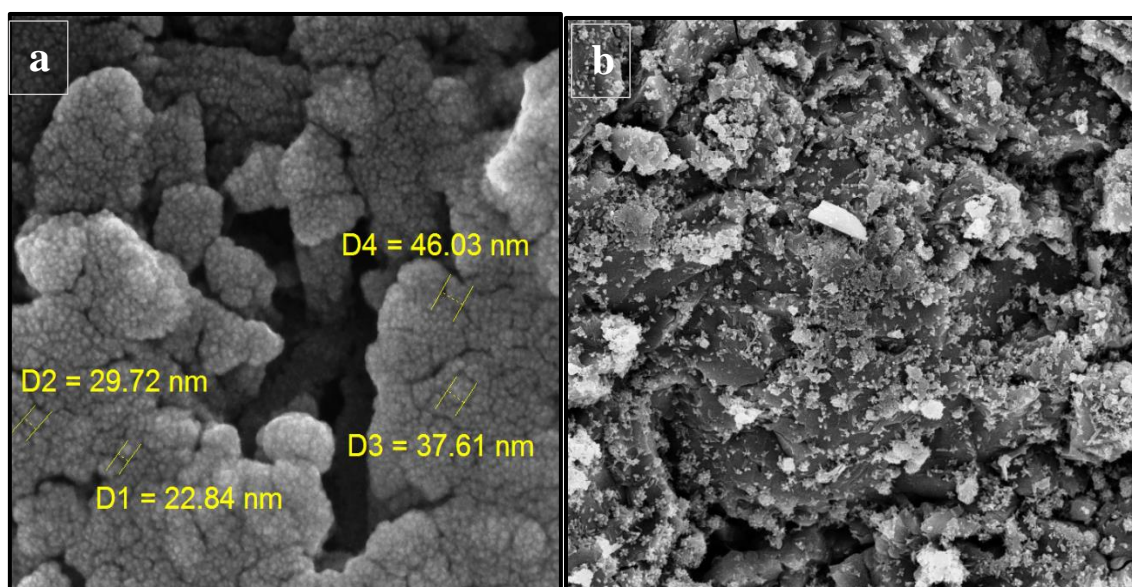


Figure 5. FESEM image of rock surface before contacting with nanofluid (a) 200nm and (b) 1µ.

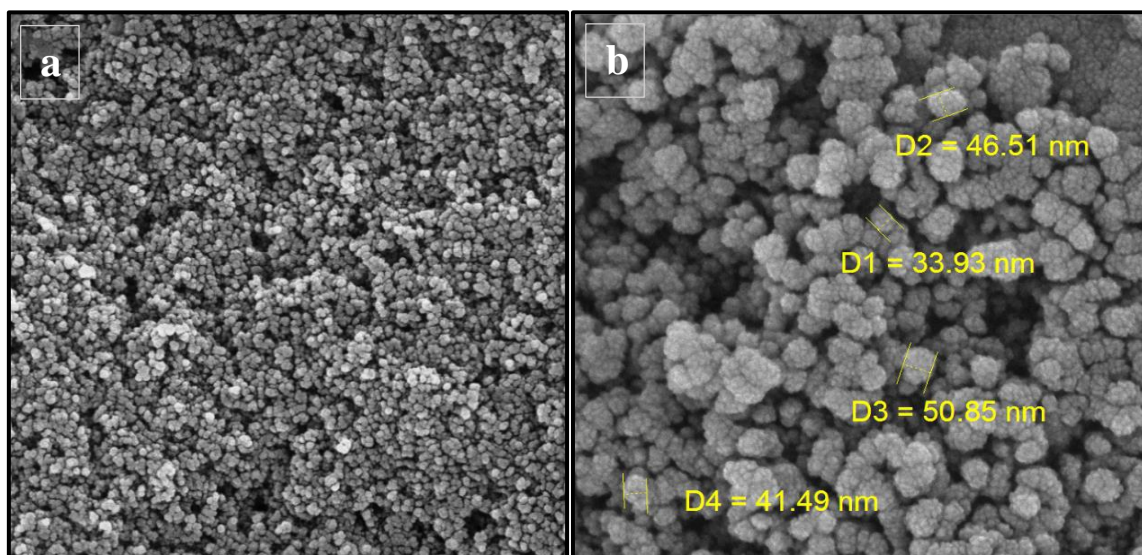


Figure 6. FESEM image of rock surface after contacting with nanofluid (a) 200nm and (b) 1µm.

3.2. Effect of Nanoparticles on sand production at different pH.

In the previous section, the effect of alkalinity was investigated, and its results reported and also discussed. However, another factor that will alter the rate of sand production is the presence of nanoparticles in the smart water injection. The optimum and stable concentration of nanoparticles was 1000ppm, which was the optimum and stable concentration according to the Zeta potential and DLS tests, which were shown in Table 2. To illustrate the effect of nanoparticles on the rock surface, FESEM images shown that the presence of 1000 ppm of SiO₂ nanoparticles in smart water can cover the entire rock surface, which will probably act as a barrier and reduce the stresses on the sand grains[36]. Figure 5 shows the surface of the rock before contacting the nanofluid. As can be seen, there is no cover on the rock surface. All sand grains are directly in contact with the smart water or any fluid that can enter the reservoir (such as drilling mud, completion fluid, etc.). The mechanism and reaction associated with the pH change reported by Austad et al. will also be intensified in this case. Because of the large contact of sand grains with smart water, all the grains on the surface and the grains inside the porous media are involved in the reaction described in Equation 1-1 [20].

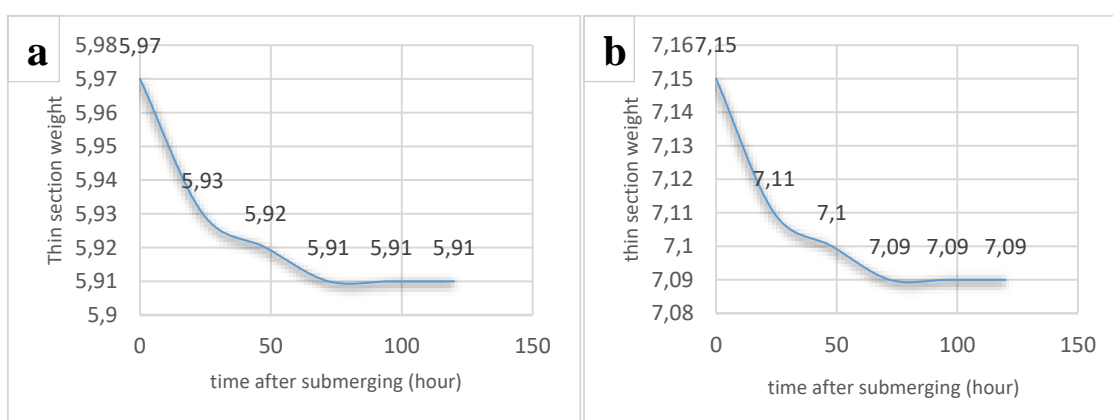


Figure 7. sand produced with nanoparticles at (a) PH=4.5 and (b) pH=5.5.

The rock was exposed to the nanofluid for 24 hours 42 (optimized smart water +1000 ppm SiO₂ nanoparticles), where the effect of the nanoparticles on the rock surface and thin sections are shown in Figure 6. As can be seen, rock surfaces covered with a layer of

nanoparticles that is likely to reduce sand production. But the results of experiments in the presence of nanoparticles has shown that the rate of sand production was significantly reduced and after the short time has stopped. As can be seen in Figure 7, the amount of sand produced in the presence of nanoparticles decreased by 39% compared to the results when there were no nanoparticles in smart water, and also, after 72 hours the sand production has stopped (also figure 8(a), (b) and (c)). Also, in Figures 7(a) and (b) similarly, it is observed that the amount of sand produced in the presence of nanoparticles decreased by 44% and 49% compared to the absence of nanoparticles [34,36].

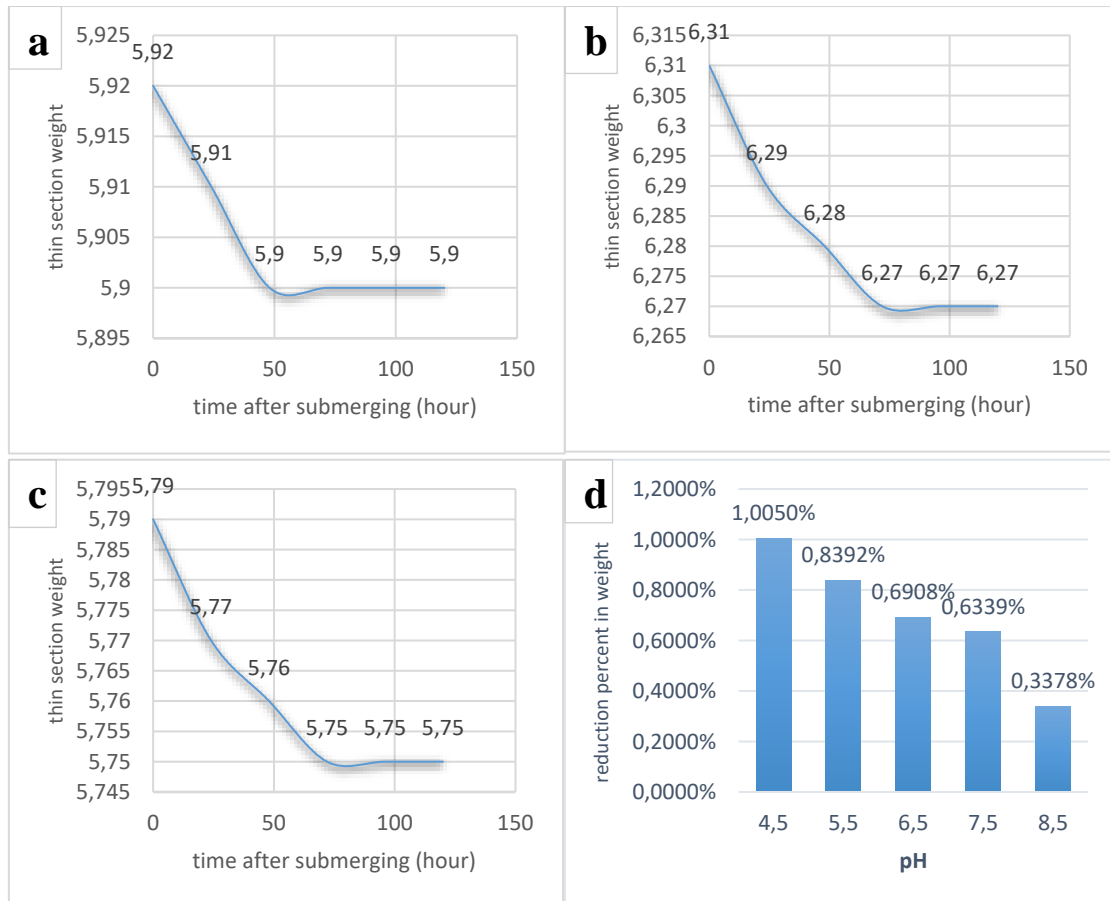


Figure 8. Sand produced with nanoparticles at (a) pH=8.5, (b) pH=7.5, (c) PH=6.5, and (d) reduction percent in weight of samples for each PH at reservoir temperature.

Therefore, according to the results reported in this paper, the amount of sand production decreased with increasing alkalinity, and the presence of nanoparticles also reduced sand production[39]. Figure 8(d) is shown that how much weight of the samples decreased after 120 hours in the presence and absence of nanoparticles at different pH values. It can also be concluded that the rate of decrease in sand production due to the presence of nanoparticles in acidic environmental is more than the basic environmental. In summary, as can be seen in Figure 9 and 10, the presence of nanoparticles in the water at concentrations of 0.001gr / liter or 1000ppm can significantly reduce the amount of sand production; also the amount of sand production can be compared simultaneously in two modes (with Nano and without Nano) and different pH values.

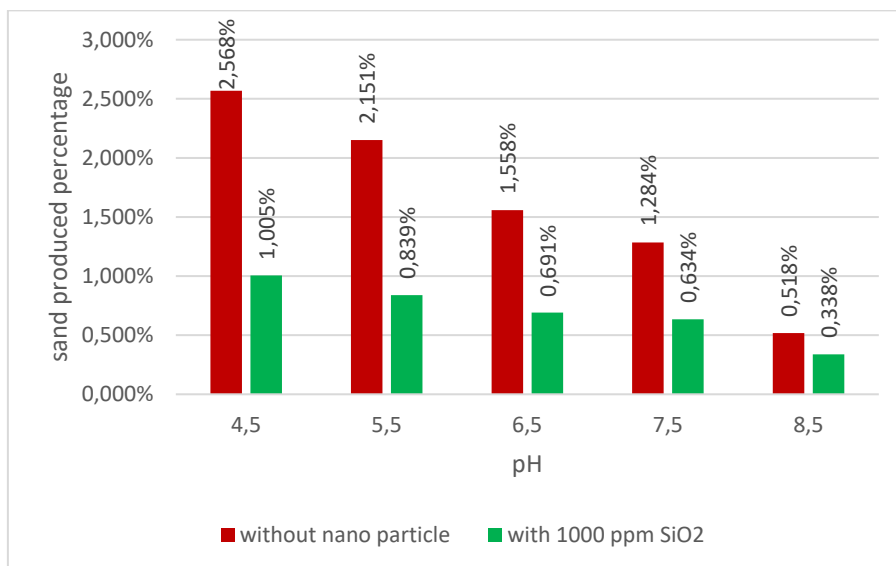


Figure 9. Comparison of sand production with and without Nanoparticles.

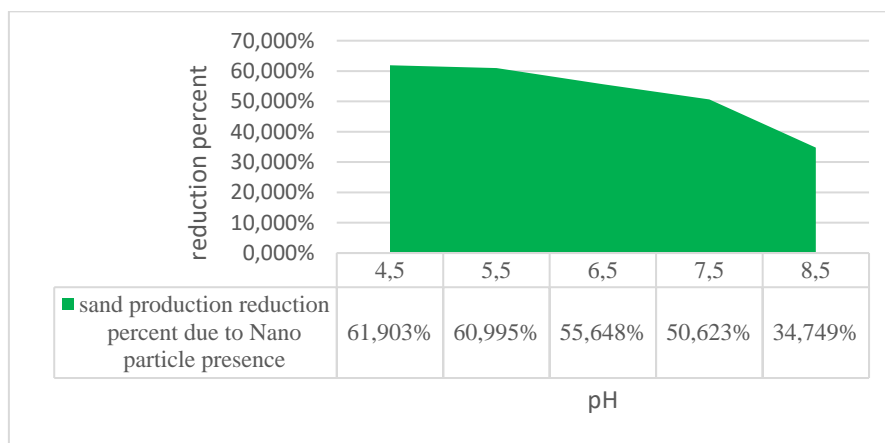


Figure 10. Sand production reduction percent due to Nanoparticle presence.

4. Conclusions

By increasing the alkalinity of optimized smart water (increasing pH), the rate of sand production was decreased; this is probably may be due to a reduction in stresses and the attraction and repulsion forces between the ions.

After drying and washing the thin sections, the amount of weight reduced will be the amount of sand production because nothing has been added to it and nothing has been removed from thin sections, so only the produced sand grains that were visible at the bottom of the glass were the cause of the reduced weight of the thin sections. So this is a novel method for sand production measurement. The source of error of the thin section method is the accuracy of the weighting, drying and washing process, low, stable time of Nanoparticles dispersed in smart water. With decreasing the errors, we can determine the amount of sand production (based on the conservation of mass law).

In the presence of Nanoparticles, the amount of sand produced from the rock was significantly reduced. This reduction may be due to the coating of rock surfaces with nanoparticles. The rock coated surface prevents water from entering into the porous media. So the lower wettability alteration and higher equilibrium (between grains) have occurred.

In the experiments that were mentioned in two modes (with and without Nanoparticles), both confirmed that increasing pH and sand production are inversely related.

As the pH increased, the effect of the nanoparticles on the reduction of sand production decreased. The reason may be the overcoming of the decrease in sand production due to the increase in pH over the decrease in sand production by the nanoparticles.

At high pH values, the amount of sand production is reduced, and the time required to reach a stable point (stopping sand production) was reduced, which can reduce the effect of nanoparticles at high pH values.

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Conflicts of Interest

The authors declare no conflict of interest.

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