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Influence of Nanofluid Flooding on Oil Displacement in Porous Media

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Abstract

Hydrocarbon displacement at the pore scale is mainly controlled by the wetness properties of the porous media. Consequently, several techniques including nanofluid flooding were implemented to manipulate the wetting behavior of the pore space in oil reservoirs. This study thus focuses on monitoring the displacement of oil from artificial glass porous media, as a representative for sandstone reservoirs, before and after nanofluid flooding. Experiments were conducted at various temperatures (25 – 50° C), nanoparticles concentrations (0.001 – 0.05 wt% SiO_2 NPs), salinity (0.1 – 2 wt% NaCl), and flooding time. Images were taken via a high-resolution microscopic camera and analyzed to investigate the displacement of the oil at different conditions. In addition, contact angle measurements on quartz surfaces were also conducted at similar conditions to understand the flow behavior in the porous media. Further, zeta potential and particle size distribution measurements were conducted to examine the stability of the injected nanofluids. Results revealed that the injection of nanofluids into oil-wet pore space can significantly enhance the recovery rate of hydrocarbon by altering the wettability of the porous media. However, salinity, particularly at high nanoparticles concentration (≥ 0.005) can dramatically reduce the efficiency of nanofluid. Further, increased aging time can improve the ability of nanofluid to alter the wettability of the surface, and thus more oil can be displaced. Thus, nanofluid can efficiently enhance oil recovery if correctly formulated.

Keywords: *Nanofluid, silica, nanoparticles, porous media, wettability, EOR.*

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1- Introduction

The continuous growth of energy demand along with the decline of oil production from mature oil reservoirs has drawn attention to applying new technologies including nanotechnology in enhanced oil recovery (EOR, which is also called tertiary oil recovery) applications. Dispersions of nanoparticles (NPs) in a liquid phase are called nanofluids. Such liquid phases can be surfactant micelles, polymer, DI water, brine, or oil [1, 2]. Many underground applications such as geothermal extraction [3, 4], soil purification [5], wellbore drilling [6], carbon capture and storage (CCS) [7, 8], and EOR [9-11], which this study focused on, have shown great potentials for nanofluids. Typically, primary oil recovery can produce no more than 15-20% of the original oil in place (OOIP) [12]. EOR techniques are costly procedures used to increase oil production from depleted oil reservoirs through various thermal and/or chemical methods. Thus, when no more oil is produced, EOR is implemented to resumption oil production via the modification of the interfacial properties of the formations [13]. To facilitate the displacement of oil by water from the porous media, chemically enhanced oil recovery (CEOR) methods are utilized to shift the wettability of the subsurface formations towards a more water-wet status and reduce the interfacial tension [14, 15]. The efficiency of oil production from depleted oil reservoirs mainly depends on the wettability of surfaces in the pore space [16]. In this situation, extremely oil-saturated rocks have a strongly oil-wet state under reservoir conditions. The most challenging process in oil recovery is to change the wettability of such oil-saturated porous media to water-wet [17]. Strongly oil-wet formations may become water-wet with the flooding of surface-active chemicals including surfactants and polymers into oil reservoirs. However, in addition to the high-cost issues, there are environmental challenges associated with injecting such chemicals into the subsurface formations [18]. Dispersion of NPs in a liquid phase is an elegant alternative for that costly and harmful chemical [19]. Recently, inorganic fillers, particularly silica (silicon dioxide; SiO_2) NPs, showed a wide range of potential in science and industries, including food, cosmetics, medicine delivery, and geological applications like aquifer cleansing, CCS, and EOR [20]. Silica NPs are environment-friendly materials with no harmful effects on the ecosystem. In

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*Corresponding Author: Name: Mohammed Mahdi, Email: mohammed.suhaib1607m@coeng.uobaghdad.edu.iq most cases, silica NPs can increase hydrocarbon recovery by turning oil-wet surfaces into wet surfaces [21].

In the last decade, many studies have been conducted to understand the role of NPs in EOR. Most of these studies have concentrated on the effect of NPs on interfacial properties including wettability and interfacial tension (IFT). In this context, NPs with their unique small size can detach oil components from the oil-wet surfaces via structural disjoining pressure (SDP) of NPs at the edge point of the solid-oil-water system [17, 20, 22]. Wettability and wettability alteration are typically investigated via contact angle measurements [23]. Studies showed that compare to several NPs types, silica NPs can drastically decrease the contact water-contact angle referring to a significant shift of wettability in water-wet conditions [24] at ambient conditions. Other studies revealed that silica NPs are efficient wettability modifier agents even in reservoirs' harsh conditions including high pressure and temperature [25]. Later studies have investigated the potential of surface-modified silica NPs on oil recovery [26]. Recently, researchers have investigated the synergistic effects of NPs and other surface materials including surfactants and/or polymers on the wettability of oil-wet surfaces [2]. On the other hand, a limited number of studies have investigated the effect of NPs on oil recovery via the amount of recovered oil using a core-flooding setup [27]. In such studies, the efficiency of NPs is examined according to the access amount of recovered oil.

In this study, a glass porous media was used to monitor the fluid distribution and flow behavior in pore space and investigate the influence of silica nanofluid as a wettability modifier on the displacement of oil from oil-wet pore space. To the best of our knowledge, this work gives the first insight into the effect of NPs on oil displacement in a porous media via monitoring the altering of wettability and displacing of oil along the treatment time.

2- Experimental

2.1. Materials

Silicon dioxide (SiO_2 purity 99.5%) NPs from Sigma Aldrich were dispersed in DI water (from David Grey, conductivity 0.02 mS/cm) or brine to formulate various nanofluids. NaCl (purity 99.5 mol%, from Rowe Scientific) was used to formulate various concentrations of brine. Crude oil (from Amarah oil field, Density 0.893 g/ml, API Gravity 26.8, Salt content 28 ppm, Water content 0.065 %wt.) was used to fill the porous media.

The model porous media was made out of a glass with a specific pattern and dimensions (30x30x1 mm, Fig. 1) where the pore throat size of the glass model is (1 mm), which can be utilized to systematically carry out many tests to study the displacement of oil by a nanofluid.

The glass porous model served as a representative for a sandstone reservoir. According to an XRD analysis of a rock core taken from a sandstone oil reserve [28], the sandstone formation is typically composed primarily of quartz (84 wt% quartz). Therefore, all initial assessments of surface wettability in this investigation were made on smooth quartz crystal surfaces before and after treatments with crude oil and/or nanofluids. The sample employed in this study was extremely smooth, according to AFM measurements. Around 55 nm was the root mean square (RMS) roughness [29].

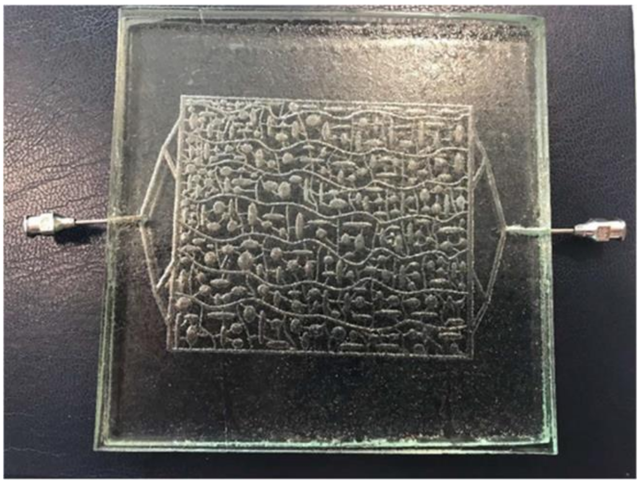

Fig. 1. Glass Porous Media

A magnetic stirrer (Table 1) and ultrasonic homogenizer (300 VT Ultrasonic Homogenizer/BIOLOGICS) were used to formulate different fluids. Further, a digital plastic syringe pump with injection speeds ranging from 0.1 to 99.9 ml/h was used to feed different fluids (DI water, brine, crude oil, nanofluid, and cleaning agents) into the porous media.

Table 1. Specifications of Magnetic Stirrer

Item	Description
Model	1.613.01.001, Digital stirrer/ hotplate, metal plate, 630 W
Heated area, mm	Diameter =130
Temp plate. °C	0-280
Stirrer speed, rpm	0-1500 rpm
Overall dimensions (w x d x h), mm	140 x 240 x50
Electrical supply	200-240V, 50/60Hz

2.2. Formulation of Nanofluid

Nanofluids with various silica NPs concentrations (0.01 to 0.05 wt% SiO_2) were studied to determine their stability, flow behavior, and oil displacement efficiency. Nanofluids were formulated via sonicating SiO_2 NPs in the base fluid. In this study, all the prepared dispersions were sonicated using the same sonication time (5 min) and power (240 V) to ensure identical formulation conditions [30, 31]. The time and power of the sonication process mostly depend on a load of dispersed NPs. To evaluate any substantial unstable behaviors of the NPs during the injection period, the nanodispersions were visually inspected.

2.3. Zeta potential, Particle size distribution, and SEM measurements

The physicochemical properties of silica NPs and their interactions with the solid substrate were investigated utilizing different approaches. A zeta sizer (ZS, Malvern Instrument, UK) was used to measure the zeta potential of silica NPs in the nanofluid at various salinity and acidity. Zeta potential is a direct scale of the surface electric charge of the surface charge of solid particles in the liquid phase [32]. Typically, the value of zeta potential determines the stability behavior of the particles in the suspension (Table 2) [33, 34]. Dynamic light scattering (DLS, Malvern Instrument, UK) was used to measure the particle size and particle size distribution of NPs in the dispersions [35-37]. In addition, the adsorption behavior of NPs on the surfaces was probed via a scanning electron microscope (SEM, Zeiss Neon).

Table 2. Zeta Potential and Stability

Zeta potential range (mV)	Stability status
(0) - (±10)	Extremely Unstable
(±11) – (±24)	Unstable
(±25) – (±35)	Critically Stable
(±36) – (± 59)	Stable
≤ (±60)	Thermodynamically Stable

2.4. Contact angle measurements

Contact angle measurement is an international standard method for assessing the wetness behavior of a specific surface in a solid/fluid/fluid system [38]. In this study, the tilted plate technique (at 14 ° inclination, Fig. 2) was used for direct measurements of advancing (θ_a) and receding (θ_r) contact angles simultaneously [23, 39]. This contact angle measurement will give preliminary advice about the optimum conditions (i.e. NPs concentration, temperature, and time of nano-treatment) that are used during flooding the porose media with nanofluid.

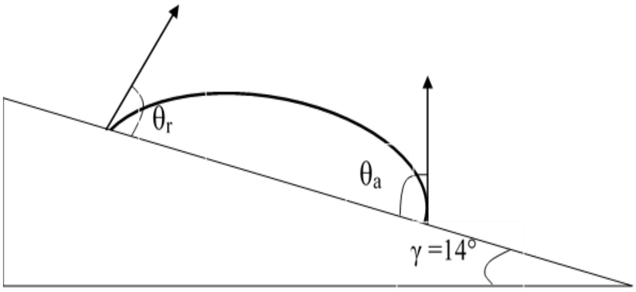

Fig. 2. Advancing and Receding Contact Angle Measured Via Tilted Plate Technique

Typically, sandstone including quartz and glass substrates are strongly water-wet surfaces that are desired for oil recovery. However, in real conditions, rocks in oil reservoirs tend to have an oil-wet and strongly oil-wet state due to immersing in crude oil for years. Such oil-wet status holds tightly to the oleic phase in the pore space which dramatically reduces the displacement of oil. Altering the wettability of such oil-wet surfaces into water-wet is the key to feasible oil recovery. Thus, to mimic the potential scenarios in sandstone oil reservoirs, pure quartz samples that are originally strongly water-wet will be immersed in crude oil to shift their wettability to an oil-wet status similar to the real condition in oil reservoirs [40, 41]. Subsequently, such oil-wet quartz samples will be treated with nanofluid to render their wettability into water-wet conditions that are favorable in EOR processes [42].

2.5. Flooding Processes and Oil Recovery

In the artificial porous media, several flooding procedures were conducted to simulate scenarios in subsurface formations and oil recovery procedures from the oil reservoir. First, DI water was used to efficiently clean the porous media from any contaminants including dust and glass off-cuts. After that, the porous media was dried with pure nitrogen. It is well agreed that the subsurface formation is a high-salinity environment. Thus, brine (0.1 wt% NaCl) was pumped into the model with a very low rate of injection (0.5 ml/h) to provide a salty condition in the place. Such a relatively low concentration of brine was used to avoid the extremely high salinity and the subsequent instability of the lately injected nanofluid [33]. Typically, a surfactant is added to the nanofluid to improve the stability of the dispersion in a high-salinity environment. However, in this work, no surfactant was added to ensure the accurate investigation of NPs role in oil recovery without the synergistic effects of other surface-active materials. Consequently, all wettability changes will be related to the influence of NPs and thus accomplish the study's goal of figuring out how NPs act as a wettability modifier in the porous medium. All fluids including brine, crude oil, and nanofluids were injected into the porous media at the same rate of injection (0.5 ml/h) via the syringe pump. Further, all these fluids were collected from the outlet of the porous media using small transparent collectors.

2.6. Monitoring of fluids

The distribution of fluids in the porous media was monitored using a microscopic video camera (Basler scA 640-70 fm, pixel size = 7.4 lm; frame rate = 71 fps; Fujinon CCTV lens: HF35HA-1B; 1:1.6/35 mm). Directly and attentively the fluid flow was watched on the monitor while it was flowing in the porous media. Images were also taken from the movie files for fluid flow behavior and oil recovery investigation. The retrieved images have a spatial magnification of 0.04 mm per pixel and a very high resolution. The crude oil's dark color makes it possible to starkly observe the displacement processes and wettability changes. Three gray shades representing solid, nanofluid, and oil showed in the extracted photos. The color code in image-j was subsequently changed to convert the images to color.

3- Result and Discussion

3.1. Zeta potential measurements

The surface charge of the NPs in the liquid phase is indicated by the zeta potential [34]. The sign and value of zeta potential are typically determined by the type of NPs, salinity, and acidity of the base fluid. As a result, nanofluids containing 0.01 wt% of silica NPs were formulated at various salinity (0 to 2 wt.% NaCl) and acidity (pH range from 2 to 9) to measure the zeta potentials of the suspensions using the zeta sizer, Fig. 3.

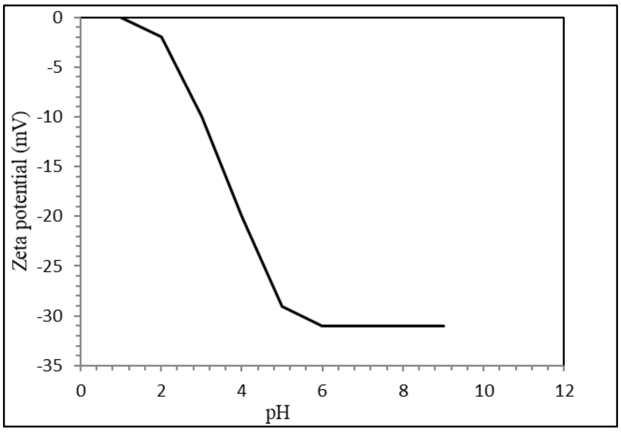

Fig. 3. Zeta Potential of Silica NPs (0.01 wt%) in DI-Water at Various pH

The results demonstrate the negatively charged nature of silica NPs, and they also demonstrate that the absolute value of the potential rose with pH until it reached a plateau (- 31 mV) at about pH = 6.25. Although these findings are slightly different from earlier studies, it has nevertheless shown that such nanofluids are only marginally stable [36, 37]. Zeta potential in this situation must be large enough to provide adequate repulsive forces between NPs in the liquid phase. These repelling forces are necessary to keep each NP separately floating in the liquid phase by preventing any adjusted NPs from colliding and coalescing [43, 44]. The dispersion is categorized as unstable when the zeta potential value is lower or equal to 25 mV. Above 35 mV, the suspension will be stable, while it will be critically stable between (25 - 35) mV [33]. Typically, salinity of oil reservoir typically exhibits significant variance within the same formation [16]. Thus, using various NaCl concentrations, the impact of salinity on the zeta potential was studied.

Fig. 4 shows that, with a salt concentration of 2 wt% NaCl in the liquid phase, zeta potential reaches very low values, around 0 mV. At such a status, the isoelectric point (IEP) is reached leading to accelerated attraction process between adjusted particles due to losses of repulsive forces that present between similarly charged particles. This phenomenon is connected to how NaCl ions balance the surface charge of NPs [35]. Consequently, the collision and coalescence processes between particles would accelerated and the size of the liquid phase particles will significantly rise [33]. Therefore, it is crucial to gauge the size of the NP particles in the salt-containing mixture.

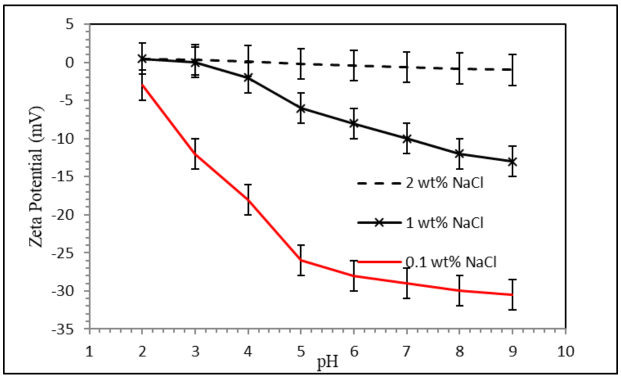

Fig. 4. The Effect of Salt Concentration on Zeta Potential of Nanofluid (0.01 wt%) Silica NPs at Different pH

3.2. Particle size and particle size distribution

The nano-size of the NPs in the suspension has a major role on the function of nanofluids in surface treatment applications. Therefore, it is important to maintain the NPs' diameters in the base fluid within the nanoscale range (100 nm). This section of the study focused on NPs load, fluid salinity, and NPs size growth with time.

Fig. 5 depicts the particle size distribution of the NPs in the fluid measured after 5 minutes from the sonication process. It’s clear that most NPs at this time at size ranged between (35 – 55) nm which indicates a limited aggregation process. Such aggregation phenomenon is mainly related to the high surface energy of NPs and the screening impact of base fluid ions on the surface charge of NPs [32].

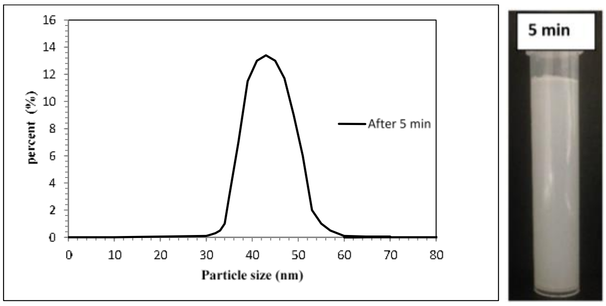

Fig. 5. Particle Size Distribution of Silica NPs (0.01 wt% SiO_2) Dispersed in DI-Water Measured 5 Minutes after Formulation

The effect of time on the particle size distribution of NPs is depicted in Fig. 6. It is obvious that the average size of NPs grows with time to eventually reaches 150 nm after 90 minutes. Such size growth is principally caused by the high surface energy of NPs and the Brownian motion that causes the adjusted NPs to collide [33, 35, 36]. Some particle collisions resulted in coalescence, which produced larger particles. Such coalescence is highly predominant when the particle's zeta potential is low (≤ ±30 mV), and it can rapidly increase with time in the presence of an electrolyte [35, 37]. Particle size and particle size distribution measurement using the dynamic light scattering (DLS) technique was used to examine such growing behavior of the particle size. Note that the DLS technique is a laser-based technique that only works accurately with transparent media [2, 45]. Thus, all systematically tested nanofluid samples were diluted samples (low NPs concentration) to avoid the opaque status of the sample.

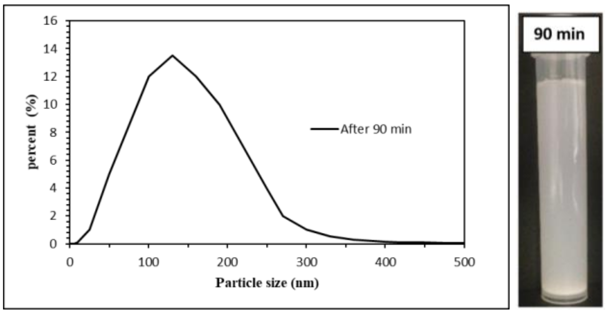

Fig. 6. Particle Size Distribution of Silica NPs (0.01 wt% SiO_2) Dispersed in DI-Water Measured 90 Minutes after Formulation

Salt has a considerable impact on particle size in the liquid phase, as shown in Fig. 7. Despite using a very low concentration of salt (0.1 wt% NaCl), the particle size distribution was drastically shifted to bigger values, indicating an accelerated rate of particle aggregation. As previously mentioned, the main reason for such an increase in NPs size is the impact of electrolyte ions on the surface charge of the particles [37, 45]. Such screening effect of salt on the surface charges will consequently eliminate the repelling forces between solid particles [32, 33]. Although it is anticipated that the salinity may reach very high concentrations (> 20 wt% NaCl) at reservoir conditions [26], this study only used a small amount of salt due to device limitations. Further, fluid injection into underground formations and the subsequent mobility of such fluids in the subsurface formations is a very low and time-consuming process. Thus, the stability and size-growing behaviors of NPs are necessary to be investigated over longer periods.

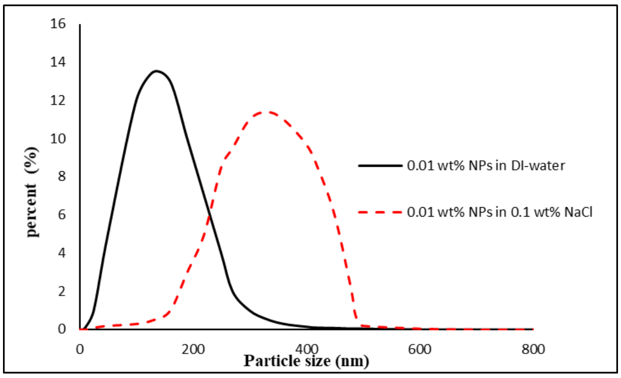

Fig. 7. Particle Size Distribution of Silica NPs (0.01 wt% SiO_2) Dispersed in DI-Water and 0.1 wt% NaCl Brine Measured 90 Minutes after Formulation

Fig. 8 shows how particle size changed over the first day of the formulation. According to the findings, the presence of salt ions will cause the particle size to rise above 100 nm within the first hour of the formulation.

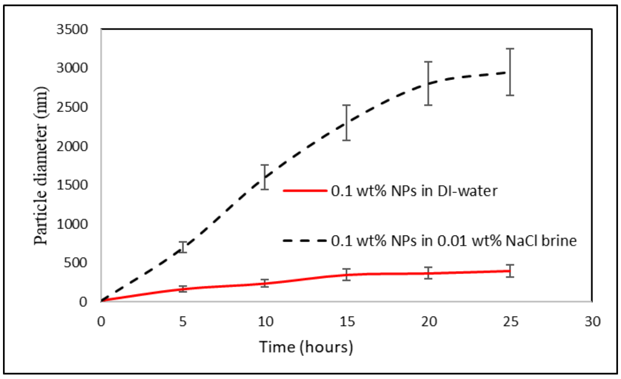

Fig. 8. The Effect of Time and Base-Fluid Salinity on Particle Size

Typically, due to the relatively low zeta potential (-31 mV) which places the dispersion in the critically sable zone (25 -35 mV), NPs dispersed in DI-water can expand in size greater than 100 nm after 30 minutes even without the presence of salt ions. It's thus necessary to add some chemicals which can supercharge the surfaces of particles and consequently stabilize NPs in the liquid phase [17]. These chemicals are mainly surfactants [46], polymers [2], and surfactant-polymer combinations [47]. Such a combination of surface active materials and NPs can synergistically produce very stable colloid dispersions for EOR applications [2, 33]. This study, however, focuses on NPs' roles in the EOR process. Thus, all measurements will be made at zero or very low salinity (0.1 wt% NaCl) and directly after the formulation of the nanofluid to prevent the need to add further additives. That's how the sole effect of NPs on the EOR is investigated.

3.3. Scanning electron microscope (SEM) measurements

Using a scanning electron microscope (SEM, Zeiss Neon 40EsB FIBSEM), the surface characteristics and modifications were examined. The SEM image in Fig. 9 demonstrates that the surface of pure quartz is smooth and flat and thus suitable for contact angle measurements which quantify the wettability of the surface and different treatment stages [23, 28, 29]. This picture was taken after being cleaned with acetone and DI water and then dried with nitrogen. Even after cleaning, certain pollutants are still visible on the surface. Such imperfections might be caused by contamination from the researcher's hand or by quartz fragments that were left on the surface. Such impurities can dramatically impact the accurate measurements of contact angle [38]. As previously mentioned, submerging solid samples in crude oil will produce surfaces that are oil-wet or strongly oil-wet [41].

Fig. 10, on the other hand, gives an image of the oil-wet substrate after nano-treatment for 30 minutes. The term nano-treatment refers to the immersing process of the oil-wet quartz sample vertically in the nanofluid. It's obvious that significant NPs clusters are distributed over the surface non-uniformly. Such relatively large silica clusters indicate the instability of nanofluid even when formulated with DI water [26].

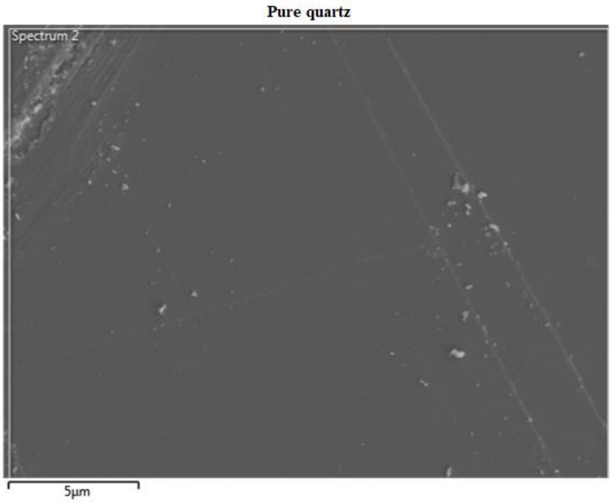

Fig. 9. SEM Image of Pure Quartz Surface

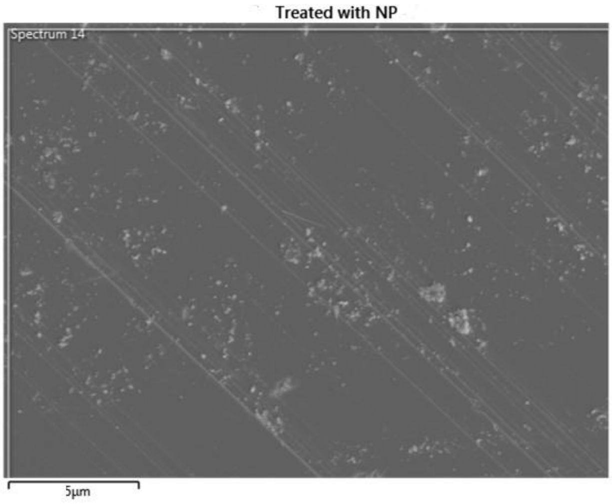

Fig. 10. SEM Image of Nano-Treated Oil-Wet Quartz Surface with 0.01 wt.% SiO_2 NPs in DI Water for 30 Minutes

Even though the surfaces are similarly charged, the placement of silica NPs on quartz surfaces can drastically modify the wetness characteristics of oil-wet surfaces into water-wet surfaces [11, 41]. Only contact angle measurements can accurately quantify such a change in wettability.

3.4. Effect of NPs Concentration on the contact angle

The effect of NPs load in the nanofluid (wt% of NPs in the base fluid) was systematically investigated (Fig. 11). In this section, a wide range of NPs concentrations, ranging from (0.001 wt%) to (0.05 wt%), at two temperatures (25 and 50° C) were examined. Further, the immersing time of quartz samples (the nano-treatment) was 60 minutes for all experiments.

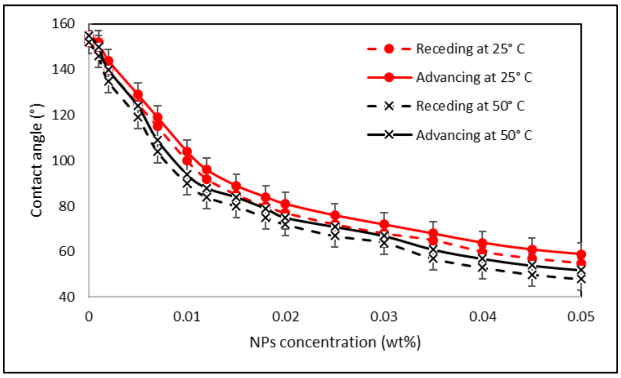

Fig. 11. The Effect of NPs Concentration (wt% Silica NPs in DI Water) at Two Different Temperatures (25, and 50°C) for One Hour of Treatment

This figure shows that the contact angle of the oil-wet surfaces decreases as NPs concentration increases at both tested temperatures. Typically, the number of NPs per unit area in the nanofluid increase with NPs concentration leading to larger numbers of NPs that are available to be attached to the treated surface. This is consonant with previous studies conducted on different surfaces including limestone [12, 42, 48, 49] and sandstone [50]. It is apparent from the results that during the first hour of treatment, treating with dilute nanofluid (0.005 wt% NPs) shows no obvious influence on contact angle reduction at both tested temperatures. However, increasing NPs concentrations (0.02, and 0.018 wt%) results in a significant reduction of contact angle (≤ 75°, which refers to the alteration of wettability into water-wet). Such reduction in contact angle refers to the gradual removal of oil components from the treated surface. Mechanistically, the removal of oil component from the treated surface is mainly related to the structural disjoining pressure of NPs of the edge of the oil-solid-liquid system [17, 20, 22]. Another interesting observation in the figure is that a further increase in nanofluid concentration (≥ 0.04 wt% NPs) has less influence on contact angle reduction. This is mainly due to reaching the adsorption capacity of the surface where the number of attached NPs into the surface is the same as the number of detached ones. Such phenomenon slightly depends on the temperature of treatment [25]. Thus it is obvious that the efficiency of NPs as a wettability modifier is slightly higher at higher temperatures (50°C). Wherefore, all the next flooding tests in this study will be at low NPs concentrations (≤0.1 wt% NPs). Such low concentrations are more reliable and feasible to be conducted in real oil- fields.

3.5. Crude Oil Flooding

The wettability of the artificial porous media is strongly water-wet since it's made out of glass. Consequently, to mimic the scenario in oil reservoirs, the wettability of the model should be switched to strongly oil-wet via aging with crude oil [42, 51, 52]. To achieve this, crude oil was injected into the artificial glass porous media and the inlet and outlet points of the model were sealed directly to avoid the penetration of air into the sample. After that, the model's temperature was raised to 50°C for the desired time of aging (2 or 7 hours, Fig. 12). After that, the two ends are opened, and the porous sample is carefully monitored to note changes in the distribution of oil via the microscopic camera.

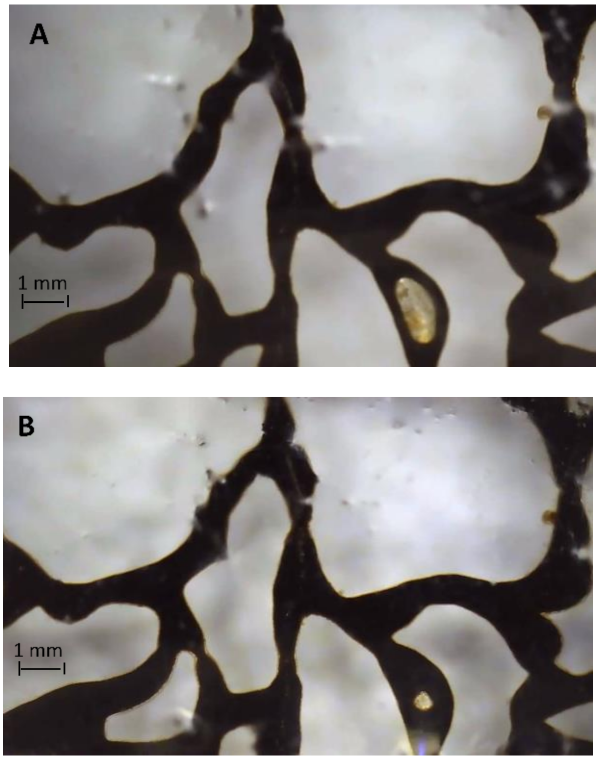

Fig. 12. A Specific Spot of the Artificial Porous Media after Aging with Crude Oil for 2 (A) and 7 (B) Hours at 50°C

Images show that the injected oil filled all the pore spaces. However, after 2 hours of aging, limited drops of oil were drained out of the sample resulting in a large air bubble in the sample (Fig. 12 A). Such phenomenon is related to the low capillary forces in the case of aging for 2 hours. In contrast, a very small air bubble was noticed at the same place of the sample after aging for 7 hours indicating stronger capillary force which tightly holds the oil phase in the pore space (Fig. 12 B). Further, no oil drop where drained out of the sample after 7 hours aging referring to strongly oil-wet status (contact angle ≥ 150°) [50]. Thus, after aging with crude oil for 6 hours, the glass artificial porous media can typically stimulate the condition in oil reservoirs.

- Water Flooding

Water flooding, also known as secondary oil recovery, is typically used when oil reservoirs stop producing oil spontaneously [13, 53]. In this section, the porous media, after aging with crude oil for 7 hours (Fig. 13 A), was flooded with an excessive amount of water to extract as much oil as possible from the porous media (Fig. 13 B). The water flooding process was conducted via a syringe pump at a very low rate of flow to mimic the scenario of water flooding in subsurface formations. In this context, water may typically displace oil from larger pore spaces and wide channels, leaving a considerable amount of oil trapped in the pore space (Fig. 13 B). Despite how much water is injected at this point; no further oil is recovered from the porous media. Mechanistically, to produce more oil, the oil film must be separated from the oil-wet surface by significantly altering the wettability of the porous media [54]. Such wettability alteration can be achieved via nanofluid flooding with an accurately formulated nanofluid.

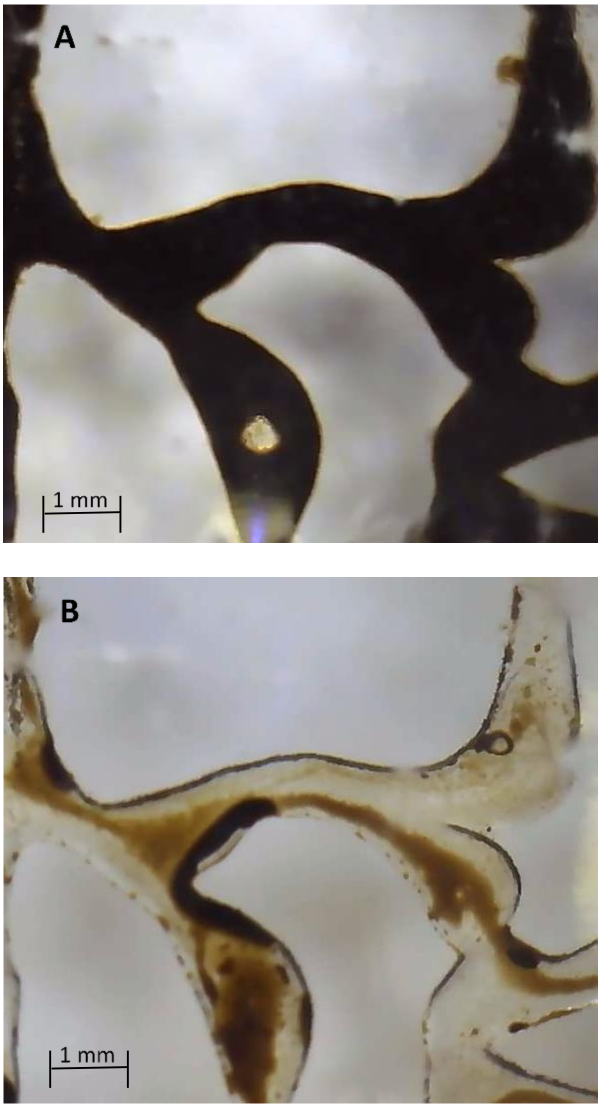

Fig. 13. Specific Spot of the Artificial Porous Media after Aging with Crude Oil for 7 Hours (A), and after Water Flooding (B) with an Excess Amount of Water at 50°C

- Nanofluid Flooding

Nanofluid flooding into glass artificial porous media will help to monitor the alteration of interfacial properties of the pore space via nano-priming (Fig. 14).

At the end of water flooding, a considerable amount of oil can be seen trapped in the pore space (Fig. 14 A). Results show that the use of nanofluid can significantly increase oil recovery by displacing more oil from porous media (Fig. 14 B). Mechanistically, the adsorption of NPs into the porous media can gradually detach oil droplets that move into the larger pores and bigger channels finding a way out of the porous media. As stated before, the structural disjoining pressure of NPs controls the detachment of the oil phase from the pore space [22].

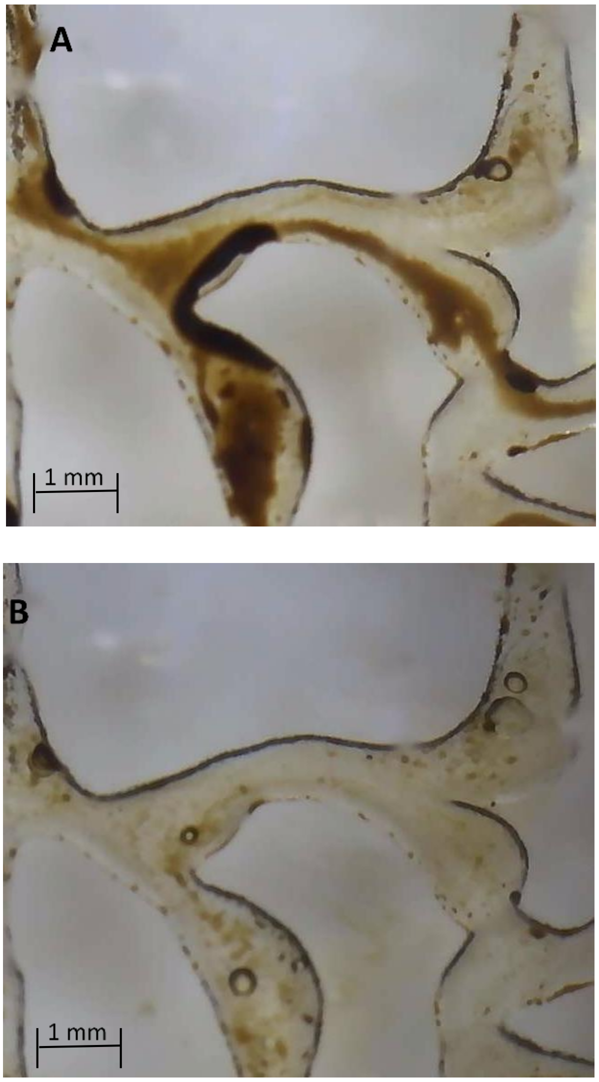

Fig. 14. Specific Spot of the Artificial Porous Media after Flooding with an Excess Amount of Water (A), and after Nanofluid Flooding (B) with 0.1 wt% Silica NPs for 3 Hours at 50°C

4- Conclusion

In this study, the fluid flow behavior of oil and water was explored before and after nanofluid flooding using a transparent glass porous media. Before conducting flooding tests, the stability and particle size distribution of NPs in the liquid phase were investigated. The results declared that the zeta potential dramatically decrease and particle size drastically increase with the presence of salt ions. Contact angle measurement of pure, oil-wet, and nano-treated quartz surfaces was conducted to find the best nanofluid composition and operating condition for nanofluid flooding. The results showed that while immersing with crude oil can switch the wettability of pure quartz into oil-wet, treatment with nanofluids can efficiently render the wettability of oil-wet surfaces water-wet and strongly water-wet. And thus enhance oil recovery. Flooding tests revealed that silica NPs can efficiently improve water flooding and a significant amount of additional oil can be recovered by injection of nanofluid into the porous media. The nano-flooding scenario including the nano-treatment period, temperature, the salinity of the porous media, and most importantly NPs concentrations in the nanofluid are the main factors that affect the recovery of additional oil from the pore spaces.

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تأثير الغمر بمحلول النانو على إزاحة النفط من الوسط المسامي

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الخلاصة

يتم التحكم في إزاحة الهيدروكربونات على نطاق المسام بشكل أساسي من خلال خصائص التبلل للوسط المسامي، وبالتالي تم تنفيذ العديد من التقنيات بما في ذلك غمر السوائل النانوية للتحكم بسلوك التبلل للوسط المسامي في المكامن النفطية. وبالتالي تركز هذه الدراسة على مراقبة إزاحة الزيت من الوسط المسامي المصنع من الزجاج، كنموذج لمكامن الساندستون، مع وبدون الغمر بالمحلول النانوي. أجريت التجارب في درجات حرارة مختلفة (٢٥–٥٠ درجة مئوية)، تراكيز الجسيمات النانوية (٠,٠٠١ – ٠٥.٠٠ بالوزن٪ SiO_2 NPs)، الملوحة (٠,١ – ٢٪ بالوزن كلوريد الصوديوم)، وزمن المعالجة. تم التقاط الصور عبر كاميرا مجهرية عالية الدقة وتحليل الصور للتحقق من إزاحة النفط في ظروف مختلفة. بالإضافة إلى ذلك، تم إجراء قياسات زاوية التماس على أسطح الكوارتز أيضًا في ظروف مماثلة لفهم سلوك الوسط المسامي. بالإضافة الى ذلك، أجريت قياسات شحنة السطح وحجم الجسيمات لفحص ثبات واستقراريه السوائل النانوية المحقونة. كشفت النتائج أن حقن السوائل النانوية في الوسط المسامي المتبلل بالزيت يمكن أن يعزز بشكل كبير إزاحة النفط بمعدل أعلى. ومع ذلك، فإن زيادة تركيز الجسيمات النانوية والملوحة بشكل كبير يمكن ان تقلل من ثبات المحلول النانوي عن طريق التكتل المتسارع للجسيمات النانوية. علاوة على ذلك، يمكن أن تؤدي زيادة وقت المعالجة إلى تحسين قدرة الموائع النانوية في تغيير قابلية السطح للتبلل، وبالتالي يمكن إزاحة المزيد من النفط. لذلك، يمكن للمحلول النانوي تعزيز استخلاص النفط بكفاءة إذا تم تركيبه بشكل صحيح.

الكلمات الدالة: المحاليل النانوية، السيليكا، الوسط المسامي، التبللية، تحسين انتاج النفط.