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Optimization of Nanofluid Systems for Enhanced Oil Recovery: Analysis of Concentration, Slug Size, and Injection Rates

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Abstract

In this study, commercial silica nanoparticles dispersions were used in standard core flooding experiments to evaluate the effect of the nanoparticles concentration, slug size and injection rate on the incremental oil recovery and provide insights on how to optimize the nanofluid systems. Picking the optimum particles size from previous work, then different concentrations of nanofluids have been used with combinations of different slug sizes and injection rates. Pre- and post-flooding fluids and rock characterization has been done to understand the transport of the nanoparticles in the porous media. The results of this study propose a theory that there is a critical concentration of the nanoparticles after which the recovered oil will decrease due to the agglomeration and retention of the particles in the pore system. This critical concentration equals the amount that will 100% cover the surface area of the rock grains. As any extra concentration will agglomerate in the pore throats and negatively affect the oil recovery and reduce the permeability. This paper conclusions are expected to have a real impact on designing the optimum set of parameters like injection rate, slug size and concentration of commercial nanofluid system that works best for the subject reservoir rock and achieves the highest ultimate oil recovery with the most economic approach. This will open the door for taking the nanotechnology from the lab to the oil field

Keywords: *Enhanced oil recovery (EOR); Nanotechnology; Nanofluids; Nanoparticles; Surface area; Porous media.*

1. Introduction

The use of nanoparticles has been investigated and established for several applications in the oil and gas industry. Using nanoparticles for enhanced oil recovery (EOR) applications underlines their small size in comparison with the size of the rock pore throats; consequently, they could easily transport into porous rocks with minimum retention effect and permeability reduction. Nanoparticles can significantly increase the oil recovery by enhancing both the fluid properties and fluid-rock interaction properties.

Nanotechnology is defined as the application of very small pieces of material(s) with dimensions between approximately 1 and 100 nanometers. Using nanoparticles can drastically increase the oil recovery by improving both the injected fluid properties and fluid-rock interaction properties. The injected fluid can have enhanced viscosity, enhanced density, reduced surface tension, and improved emulsification. The fluid-rock interaction properties mainly incorporate the wettability alteration [1].

2. Applications of nanoparticles in EOR processes

Exploiting the distinct properties and unique phenomena of nanoparticles, at that scale ranging from individual atoms or molecules to about 100 nanometers as compared to those associated with bulk behavior, novel real applications of materials, devices and systems have been available in many industries.

The nanoparticles present many advantageous characteristics such as high surface area, active surfaces, and special optical and chemical responses. The nanoparticles have a very large specific surface area, which increases exponentially with the decrease in the diameter of the particles.

A nanofluid is simply defined as a colloidal suspension of nanoparticles with an average size of 1 to 100 nm. The mechanisms of nanofluid EOR have been investigated in many previous studies, which mainly include disjoining pressure, temporary pore channels plugging (log-jamming), increased viscosity of injection fluids (decreasing the mobility ration), IFT reduction, and wettability alteration [2-5].

3. Research design and methodology

In this project, the ultimate target was to understand the mechanisms behind the additional recovered oil with using nanoparticles as an EOR method (nanofluid flooding), and to understand how to optimize the nanoparticles concentration required for the highest recovery. The experimental work of the project started with preparing the core samples to simulate the actual reservoir rock conditions. A number of 1″ and 1.5″ plugs were cut using a plugging machine then they were trimmed and had end-face grinding. After getting the core plugs into the required dimensions, a Soxhlet distillation extraction device was used to remove the liquid phases (oil and/or water) from the core. Once the samples were cleaned, the samples were left to dry in a conventional oven. After drying the samples, full measurements of weight and dimensions were taken down, then the Helium gas expansion Porosimeter was used to determine the samples grain and pore volume.

After measuring the porosity of the samples, they were fully saturated with formation water. Brine with 75,000 ppm/NaCl (average salinity of formation water in Egypt) was used to saturate the samples. After saturating the samples with 100% of the water with the designed salinity, the samples weight was taken down to double check the porosity measured with the Helium Porosimeter which is usually a bit higher than the value driven by the difference between dry and wet weight due to the disconnected pores. Then the relative flooding apparatus was used to measure the absolute permeability under reservoir-representative confining pressure. After measuring the absolute permeability, the injection fluid was switched to oil. The flooding started at 0.2 cc/min rate until no more water is getting out of the sample, then the injection rate was increased gradually while monitoring the pressure at each step until it stabilizes, and no more water gets out. This stage stays up to 8 hours to guarantee reaching the irreducible water saturation. The whole flooding process is performed with 2000 psi confining pressure to simulate the overburden pressure in the reservoir rock.

By then, using the porosity measurements and the volume of water out of the oil flooding, the S_{wi} and S_o were calculated for each sample. At this stage, the sample was ready for investigating any secondary or tertiary recovery method, which is in this project, the nanofluid flooding.

4. Results insights and discussions

Commercial SiO_2 nanofluid was used in this project that has no coating applied on the surface of the particles. A little dispersant (1-2% poly (N-vinylpyrrolidone) PVP) was applied to help disperse the nanoparticles and prevent the agglomeration. This nanofluid system could be applied economically in the oil field, given the ease of preparation, and the low cost, in comparison with most of the other nanofluids used in the literature. PVP was preferred rather than polyethylene glycol (PEG), propanediol, and propanol, due to the higher cost of the coating.

Proposing the idea of commercial nanofluid EOR method, we tried to study the effect of continuous nanofluid, 5% wt. nanoparticles concentration, after the waterflooding breakthrough. The properties of the core sample used in this step are summarized in Table 1**.**

The results of the 5% wt. nanofluid, illustrated in Fig. 1, show increased oil recovery. However, there is an increase in the pressure, which implies reduction in the permeability due to the retention of the nanoparticles and the temporary plugging of the pore throats.

Table 1. Rock properties of samples set #1.

Sample number	X2
Sample type	Sandstone
Diameter / Length (mm)	25.14 / 70.90
Surface (cm²)	4.96
Bulk volume (cc)	35.19
Grain density (g/cc)	2.67
Mdry / Mwetted (g)	68.47 / 78.69
Pore Volume (cc)	9.51
Porosity (%)	27.02%
Permeability (mD)	20.74
Swi (%)	25.34%
Experiment	Cont. 5% LS NF

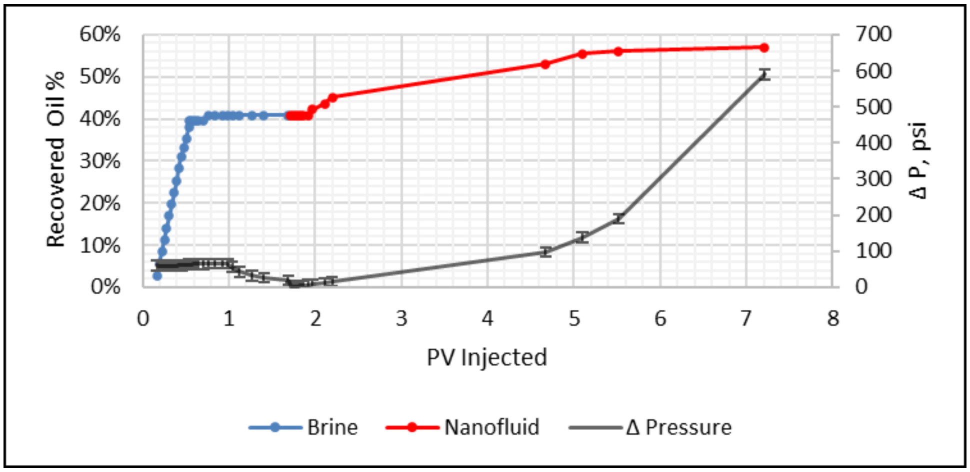


Fig. 1. LS 5% wt. nanofluid.

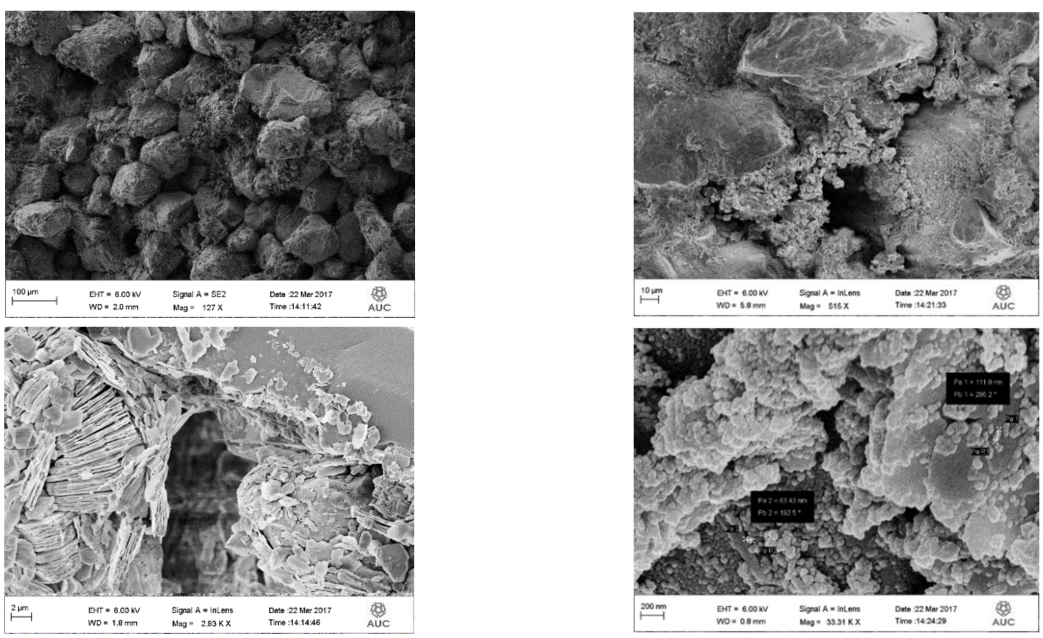


Fig. 1. (a) Clean rock sample before flooding (b) After the 5% wt. concentration nanofluid flooding.

To investigate the retention of the nanoparticles in the porous media, a clean sample of the rock before any flooding and another sample after the nanofluid flooding were scanned by SEM, as shown in Fig. 2, to compare the effect of the nanofluid flooding on the pore system.

In Fig. 2 (b), we can see the agglomeration of the nanoparticles after the 5% wt. nanofluid flooding compared with the clean structure in Fig. 2 (a). The pore throats have been blocked with these agglomerations. Hence, this system will not be applicable in the field on the reservoir scale as it will require very high injection pressure that might damage the reservoir if it exceeds the formation fracture pressure.

The next step was to investigate the nanofluid flooding but with lower concentration, 3% wt., and investigate the effect of the slug size. Properties of the rock samples used in this step are summarized in Table 2.

Table 2. Rock properties of samples set #2.

Rock Properties			
Sample number	X1	Y1	Y2
Sample type	Sandstone	Sandstone	Sandstone
Diameter / Length (mm)	25.25 / 70.88	25.30 / 62.44	25.28 / 66.84
Surface (cm²)	5.01	5.03	5.02
Bulk volume (cc)	35.49	31.39	33.55
Grain density (g/cc)	2.66	2.65	2.64
Mdry / Mwetted (g)	68.59 / 77.81	60.31 / 68.29	64.87 / 73.26
Pore Volume (cc)	8.58	7.42	7.80
Porosity (%)	24.16%	23.64%	23.26%
Permeability (mD)	23.61	85.83	81.03
Swi (%)	16.05%	24.56%	20.56%
Experiment	0.2 PV 3% LS NF	0.4 PV 3% LS NF	0.6 PV 3% LS NF

Nanofluid slug sizes of 0.2 PV, 0.4 PV, and 0.6 PV were used as per the results shown in Fig. 3, Fig. 4 and Fig. 5 respectively. The SEM scans of the rock samples before the flooding are shown in Fig. 6 (a), and the SEM scans of the rock samples after the flooding are shown in Fig. 6 (b), Fig. 6 (c), and Fig. 6 (d) respectively.

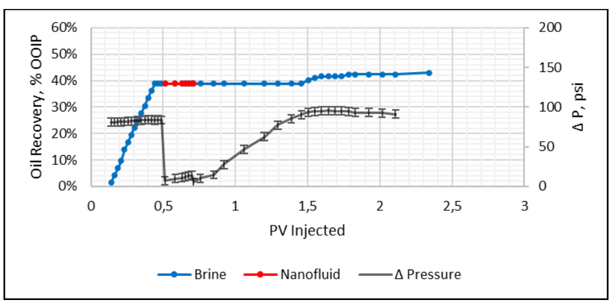


Fig. 3. LS nanofluid 3% - 0.2 PV slug size.

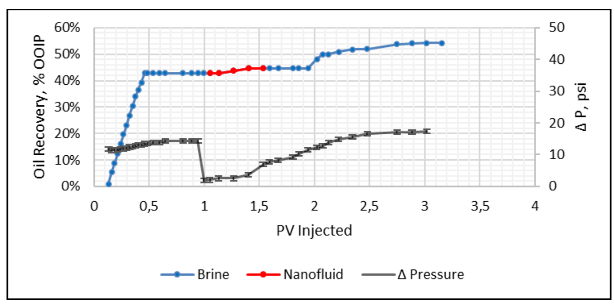


Fig. 4. LS nanofluid 3% - 0.4 PV slug size.

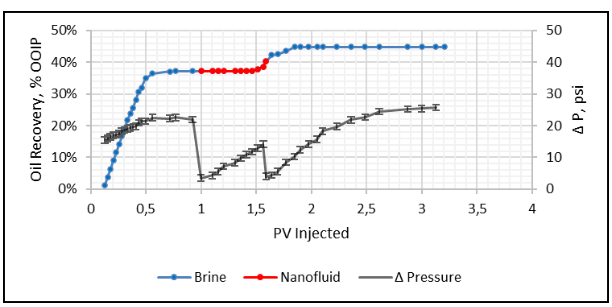


Fig. 5. LS nanofluid 3% - 0.6 PV slug size.

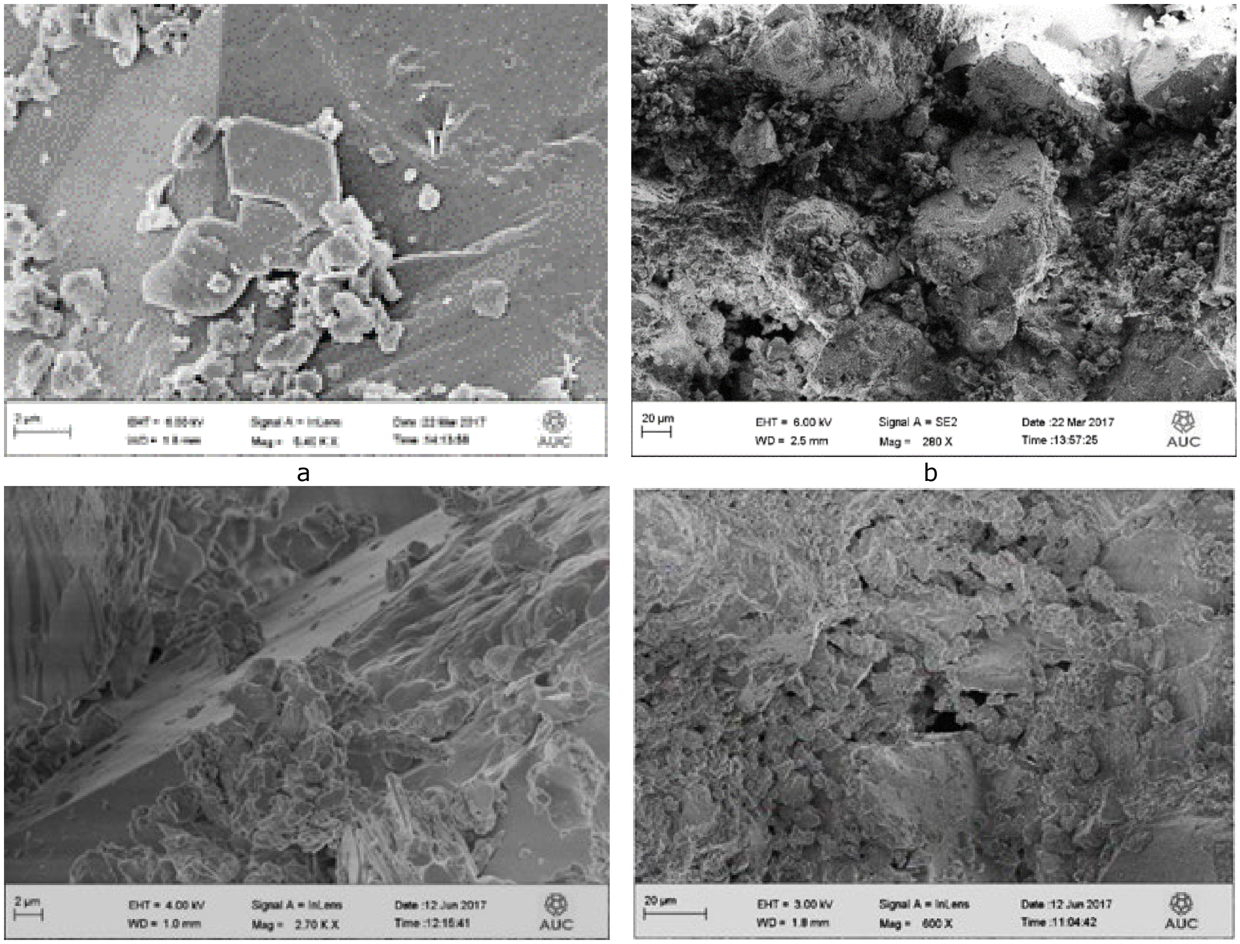


Fig. 6. (a) Clean rock sample before flooding (b) Rock sample after 0.2 PV 3% wt. concentration nanofluid (c) After 0.4 PV 3% wt. concentration nanofluid (d) After 0.6 PV 3% wt. concentration nanofluid.

We can see from the above experiments and as summarized below in Fig. 7, that the 0.4 PV slug size gives the highest recovered oil not as expected for 0.6 PV slug size considering the higher particles concentration, the higher the oil recovery. Fig. 5 and Fig. 6 (d) clarify that as for 0.6 PV slug size, the amount of the agglomerated particles blocking the pore throats and reducing the permeability is higher than the 0.4 PV slug size. Therefore, the is an optimum system of nanofluid slug size to be used, not to mention taking the other factors of concentration and injection rate into consideration.

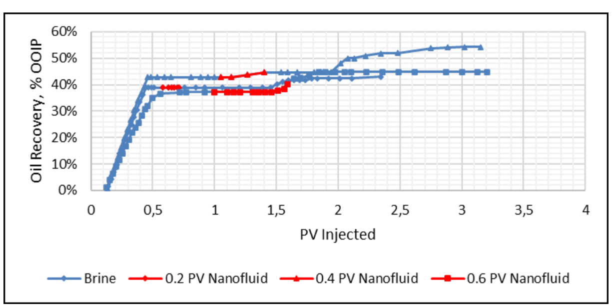


Fig. 7. LS nanofluid 3% - summary of PV slug size.

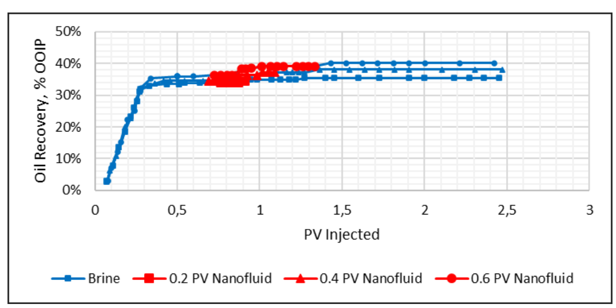
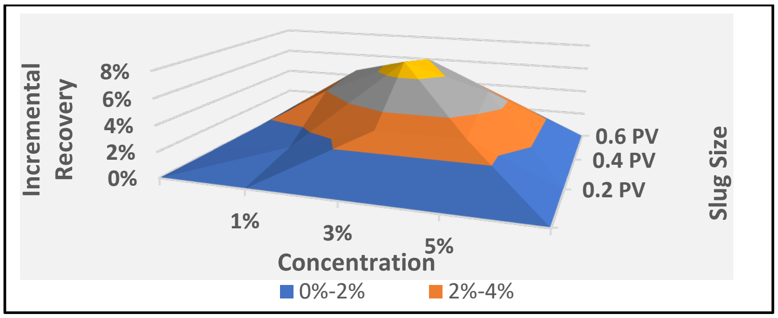


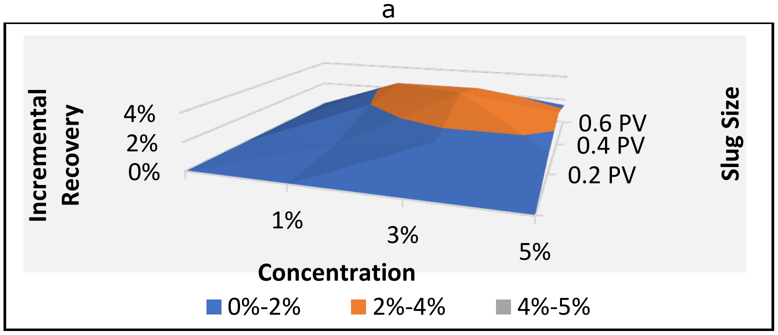
Fig. 8. LS nanofluid 1% - summary of PV slug size.

To better understand the effect of the other factors, we replicated the same experiments using nanofluid with lower concentration of 1%, and from the results, we can see that the 0.6 PV slug size shows the highest oil recovery, as summarized below in Fig. 8.

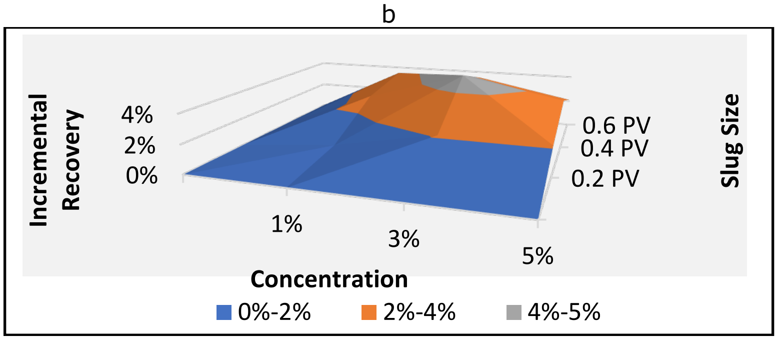
Doing the combination of the factors under investigation; slug size and nanofluid concentration, Fig. 9 (a) summarizes the effect of these factors on the oil recovery. Subject to rock properties, the optimum concentration would be 3%, along with using 0.4 PV slug size.



a



b



c

Fig. 9. Effect of nanofluid concentration and slug size (a) 0.2 CC/min (b) 0.1 CC/min (c) 0.4 CC/min.

All of the above experiments were performed with injection rate of 0.2 CC/min, which reflects the optimum "rule-of-thumb" flood front rate of 1 ft/day. In order to complete the triangle of the factors controlling the nanofluid EOR process, we replicated the experiments with different injection rates to verify the validity of the oil field practical injection rate equivalent of 0.2 CC/min. Fig. 9 (b) summarizes the results using lower 0.1 CC/min injection rate, and Fig. 9 (c) summarizes the higher injection rate of 0.4 CC/min. We can see that the optimum point of nanofluid concentration and slug size at both injection rates is showing lower recovered oil compared to the optimum point while using the 0.2 CC/min.

Therefore, we are proposing a theory that there is a critical concentration of nanoparticles after which the recovered oil will decrease due to the agglomeration and retention of the particles in the pore system. This critical concentration equals the amount that will nearly 100% cover the surface area of the rock grains. As any extra particles will agglomerate in the pore throats and negatively affect the recovery and reduce the rock permeability. Hence, the main factor in the flooding process is the nanofluid system, whose design consists of particles size, concentration, and chemical modification. The concentration "number of particles" is estimated by dividing the volume of nanoparticles in one liter by the size of one nanoparticle, assuming spherical particle with density similar to silica density of 2.66 g/cc, Equation 1.

$$C_{NP} = \frac{\frac{\rho_{dispersion} \times 1L \ \times wt.\%}{\rho_{NP}}}{\frac{4\pi}{3} r_{NP}^{3}} \quad \#/L_{Conc.} \qquad (1)$$

If volume V of nanoparticles trapped in pore space, assuming spherical particles with equal diameter touching each other at one-point, specific area can be defined as Equation 2.

$$S_b = \frac{A}{V} = \frac{d^2\,\pi}{\frac{1}{6}\,d^3\,\pi} = \frac{6}{d} \qquad (2)$$

If we further assume V is the volume of the particles that will be adsorbed on the pore walls/surfaces, then we assume that V` is the volume of particles that are going to be entrapped at pore throats, all normalized per unit bulk volume of the media. Moreover, we assume that the adsorption will happen as a single layer, then the total surface area that will be in contact with fluids, also normalized per bulk volume of porous media, is calculated by Equation 3.

$$S = \beta\,(V - V`) \times S_b \qquad (3)$$

where β is assumed to be the surface area coefficient. There are several methods to calculate the specific area of a sand core, but the most straightforward method would be by the following empirical formula [6] Equation 4.

$$S_v = 7000\,\emptyset\sqrt{\frac{\emptyset}{K}} \qquad (4)$$

As illustrated in Fig. 10, the red layer represents the specific area of the particles "S", and the black layer represents the specific area of the rock grains "Sv". At the time when S = Sv, it means that the total surface should be completely covered by particles adsorbed on the pore surfaces. At this stage, the wettability is determined by nanoparticle properties more than the rock surface itself. However, with more nanofluid injected where S > Sv, the additional deposition of particles will only negatively lead to reduction in porosity and permeability.

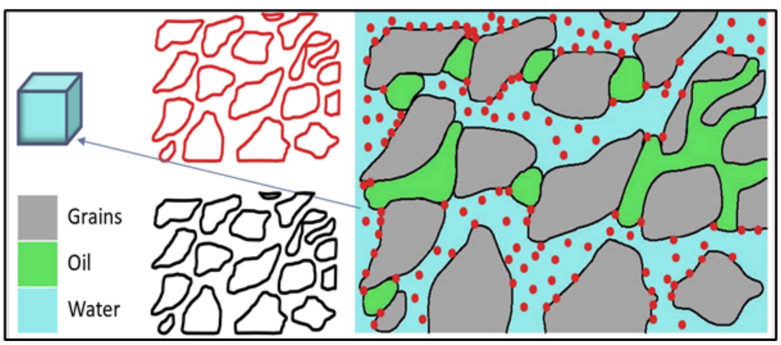


Fig. 10. Illustration of nanofluid critical volume in unit bulk volume of the pore system.

Looking at the results of 0.6 PV slug size in Fig. 5, assuming no particles entrapped at pore throats and β coefficient of 1, S value is higher than S_v, which increased the pressure difference, implying a reduction in permeability due to the agglomeration of the particles, which confirms the theory of the balance between the grains and nanoparticles surface areas.

The amount of the particles that will be adsorbed on the rock surface may change the wettability of the rock. Adhering and detaching of the particle on pore walls is mainly controlled by the Van der Waals attraction forces between the silica particle and the pore wall.

On the other side, looking at slug sizes of 0.2, and 0.4 PV in Fig. 7 and Fig. 8, higher slug sizes doesn't show the best results but quicker response in the recovery. This should follow the case where S is less than Sv, and the particles have not covered the entire rock surface yet.

5. Conclusions

The commercial nanofluid can be used as EOR method and achieve incremental recovery. There is a critical concentration of nanoparticles after which the recovered oil will decrease due to the agglomeration and retention of the particles in the pore system. The critical concentration equals the amount that will 100% cover the surface area of the rock grains. As any extra concentration will agglomerate in the pore throats and negatively affect the recovery and reduce the permeability. Optimizing the slug size and concentration of the nanofluid plays an important role in achieving the highest recovery factor.

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