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A Simulation Study of Nanoparticle Transport in Porous Media: Effects of Salinity and Reservoir Parameters

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Highlights

- Transport and retention of nanoparticles determine the performance of EOR processes;
- The effect of the main subsurface factors on the nanofluid-assisted EOR is examined;
- The effect of the salinity of the injected fluid on the amount of nanoparticles deposition on rock surface is studied;
- The degree of wettability alteration is related to the concentration of nanoparticles on the rock surface.

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Abstract

Although experimental studies confirmed the effectiveness of nanoparticles in enhanced oil recovery applications, no comprehensive investigation has been carried out to reveal the effect of different subsurface factors on this improvement. Proper application of nanoparticles mainly depends on their ability to travel long distances within a reservoir without agglomeration, retention, and blocking the pore throats. This study strengthens our understanding of the effect of the main subsurface factors on the nanofluid-assisted enhanced oil recovery. To this end, a transport approach utilizing the kinetic Langmuir model is developed and validated using experimental data. After that, the effects of reservoir rock type and its properties (clay content and grain size), the salinity of injected fluid, and the reservoir temperature on the transport and retention of nanoparticles in porous media concerning enhanced oil recovery methods are investigated. Since the concentration of nanoparticles in the injected fluid and on the rock surface (as deposited) control the mobility and wettability alteration, the effect of subsurface factors and salinity of injected fluid on this deposition is also analyzed. The results showed that the rock type and its properties significantly affect the transport and retention of nanoparticles in porous media. Brine salinity also has the most significant impact on the amount of nanoparticles deposited on the rock surface. The surface covered by nanoparticles increased from 10% to 82% after changing salinity from 3 wt % NaCl to the API brine.

Keywords: Enhanced oil recovery, Nanofluid flooding, Mobility control, transport and retention of nanoparticles, Wettability alteration

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1. Introduction

Nanotechnology has found high popularity in different applications such as petroleum engineering (Rashidi et al., 2018), petrochemical processes (Khalil et al., 2017), wastewater treatment, food industry (Cushen et al., 2012), textile (Paosangthong et al., 2019), and drug delivery (Pu et al., 2018) during the last decade. Modification and improving recovery efficiency of water-flooding operation using nanomaterial is an emerging research topic in academic studies and an objective of some real field applications (Tajmiri et al., 2015). Several studies have been performed to investigate the effects of different parameters such as nanoparticles type, size, concentration, and surface properties on the performance of a nano-assisted enhanced oil recovery (EOR) process (Rashidi et al., 2018).

Salem Ragab and Hannora (2015) compared the impact of SiO_2 and Al_2O_3 nanofluids on improving oil recovery efficiency through several experiments. They observed that the silica-based nanofluids (with varying sizes from 72 to 102 nm) could effectively increase the oil recovery from sandstone core samples taken from an Egyptian oil field. In addition, Hendraningrat (2015) compared the effect of Al_2O_3, TiO_2, and SiO_2 nanofluids on the ultimate recovery factor for Berea sandstone samples. It was observed that the TiO_2-based nanofluid had the highest total oil recovery (74%) among the considered nanofluids. Haroun et al. (2012) studied the performances of FeO, CuO, and NiO nanofluid flooding. Their results justified a better performance of CuO-based nanofluid than FeO and NiO.

The influence of nanomaterial size on the oil recovery factor was studied (Ragab and Hannora, 2015). Their results showed that the ultimate recovery factor increased by decreasing nanoparticle size. The same results were obtained by El-Diasty (2015) and Hendraningrat et al. (2013b) for SiO_2-based nanofluid flooding on an Egyptian sandstone sample. Li et al. (2015) studied the effect of hydrophilic and hydrophobic silica-based nanofluids on the oil recovery on a core scale. Both hydrophilic and hydrophobic nanofluids could improve the oil recovery factor.

The potential application of nanofluid slugs for continuous injection to porous media and its economic attractiveness was highlighted by Tarek and El-Banbi (2015). Although a high dosage of nanomaterial in an injected fluid can improve the oil recovery efficiency, it increases the operation cost and may reduce the ultimate oil recovery thorough blocking the pore throats, which is the main reason behind extensive studies conducted to determine the optimum concentration of nanoparticles in an injected fluid (Zargartalebi et al., 2014). Moreover, the concentration of nanoparticles in an injected fluid influences displacement efficiency, wettability alteration, and interfacial tension (IFT) between reservoir fluids. Increasing the dosage of nanoparticles in an injected fluid up to a critical level improves the displacement efficiency, wettability alteration, and IFT reduction. However, when the nanomaterial concentration is higher than a critical level, they will aggregate and accumulate near the injection point and reduce the displacement efficiency. Hendraningrat and Torsæter (2014) reported that both porosity and permeability of a Berea core decreased after the injection of nanofluids containing 0.5 wt % of silica.

During the injection of nanofluids into hydrocarbon reservoirs, several phenomena, including adsorption, desorption, blocking, transportation, and aggregation of nanoparticles, often occur. Adsorption of nanoparticles on the rock surface is responsible for wettability alteration (Ali et al., 2018; Giraldo et al., 2013; Hendraningrat and Torsæter, 2015; Karimi et al., 2012; Li et al., 2015). Wettability is the main factor controlling the capillary pressure and relative permeability curves in reservoir modeling and simulation. Moreover, nanoparticles can change both rheological (Maghzi et al., 2013) and transport properties of nanofluids (Li et al., 2019). Nanoparticles can also improve the sweep efficiency of an injected fluid by increasing its viscosity (Metin et al., 2013; Song et al., 2005). It is well established that the fraction of rock surface covered by deposited nanoparticles is the main factor in wettability alteration (Karimi et al., 2012). Therefore, the main objective of this study is to establish a link between the reservoir properties and nanoparticles distribution on porous media concerning enhanced oil recovery performance. To this end, the distribution of nanoparticles on the rock surface and injected fluid through different subsurface conditions, their effect on the viscosity of injected nanofluid, and interfacial tension between the reservoir and injected fluids are investigated.

As mentioned earlier, almost all previous research studies have focused on the effects of the type, size, surface properties, and concentration of nanoparticles in nanofluids on the oil recovery efficiency. However, the key factors that govern the interactions between nanoparticles and their surrounding medium inside porous media have received less attention in previous works (Caldelas, 2010; Murphy, 2012; Salejova et al., 2011; Zhang, 2012). Indeed, the effects of the main subsurface factors, including rock type and its clay content, and salinity of an injected fluid on nanoparticle transport and retention in porous media have not been systematically investigated. Since the characterization of transport and retention of nanoparticles in porous media is necessary for selecting an efficient nanofluid-assisted EOR scenario, the distribution of nanoparticles in different subsurface conditions should be analyzed comprehensively. The present study tries to construct a new bridge for modeling and understanding the transport and retention of nanoparticles in oil reservoirs concerning enhanced oil recovery.

2. Model development

The advection–dispersion equation is a mathematical formula extensively used to describe the solid particle movement in porous media. Several attempts have been made to modify this model so that it can be used to predict nanomaterial transport in porous media (Irfan et al., 2019). To simulate transportation of nanoparticles and colloidal particles in lab-scale porous media and numerically match the effluent concentration, a mathematical model based on the modified filtration theory is often employed (Abdelfatah et al., 2017a). As Equation (1) clearly expresses, a filtration term $R = (\frac{\rho_b}{\varphi}\frac{\partial S}{\partial t})$ is inserted into the advection–dispersion equation for particle mass balance during transportation (Abdelfatah et al., 2017b; El-Amin et al., 2015; Wang et al., 2008).

$$\frac{\partial(\varphi C_w)}{\partial t} + \boldsymbol{u_w} \cdot \nabla C_w = \nabla \cdot (\phi D_w \nabla C_w) + \mathrm{R} \tag{1}$$

where $\nabla \cdot (\phi D_w \nabla C_w)$ and $\boldsymbol{u_w} \cdot \nabla C_w$ indicate the dispersion and advection terms, respectively. The concentration of the particle is expressed by C; D stands for the dispersion coefficient, and φ is the porosity of the porous medium.

By considering both adsorption capacity and reversible adsorption, Wang et al. (2008) defined the filtration term, R, by Equation (2):

$$\frac{\rho_b}{\varphi}\frac{\partial S}{\partial t} = k_{dep}\left(1 - \frac{S}{S_{max}}\right)C - \frac{\rho_b}{\varphi} k_{det}\, S \tag{2}$$

where ρ_b is the bulk density of the porous medium, S indicates the retention capacity and defined as the mass of nanoparticles adsorbed on the unit mass of solids, S_{max} represents the maximum retention capacity with the same unit as S, and k_{dep} and k_{det} are deposition and detachment rates, respectively. The following boundary and initial conditions are used to solve Equations (1) and (2), as shown in Figure 1.

$$C(x,0) = 0 \qquad C(0,\mathrm{t}) = C_{Inj} \qquad \frac{\partial C(\mathrm{L},\mathrm{t})}{\partial x} = 0 \tag{3}$$

$$S(x,0) = 0$$

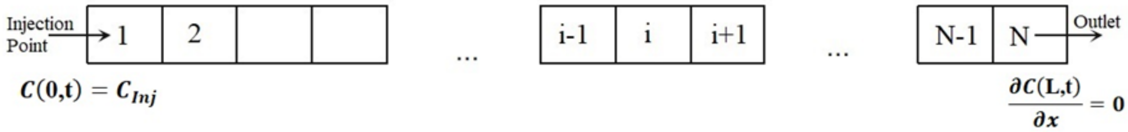


Figure 1
A schematic representation of solution nodes and applied boundary conditions.

The equation is discretized on finite mesh points.

$$\frac{C_i^{n+1}-C_i^n}{\Delta t}+\frac{u}{\varphi}\frac{C_{i+1}^n-C_{i-1}^n}{2\Delta x}=D\frac{C_{i+1}^n-2C_i^n+C_{i-1}^n}{(\Delta x)^2}+R^n+o(\Delta t.\Delta x^2) \tag{4}$$

Employing a finite difference scheme on the boundary conditions results in Equation (5).

$$\frac{C_N^{n+1}-C_N^n}{\Delta t}+\frac{u}{\varphi}\frac{3C_N^n-4C_{N-1}^n+C_{N-2}^n}{2\Delta x}=D\frac{2C_N^n-5C_{N-1}^n+4C_{N-2}^n-C_{N-3}^n}{(\Delta x)^2}+R^n+o(\Delta t.\Delta x^2) \tag{5}$$

Neumann stability analysis is implemented to ensure that temporal discretization obtains long-lasting results, where the time and space steps can be expressed by (Agista, 2017):

$$\boldsymbol{\Delta t}=\frac{\boldsymbol{\Delta x^2}}{\boldsymbol{u_w}\,\Delta x+2\boldsymbol{D_w}} \tag{6}$$

2.1. Validation of the proposed model

A transport model is developed based on the above-mentioned advection–dispersion equation to simulate the behavior of nanoparticles in porous media. Since the derived transport models are partial differential equations, the finite difference method is employed for their solution. Since this solution method often has the convergence problem, the Neumann stability analysis was applied to obtain a stable result from the solution. At first, it is tried to check the reliability of the solution using some experimental datasets (Table 1) at different injection rates and concentrations of nanoparticles (Caldelas, 2010; Zhang, 2012).

Table 1
The experimental datasets of Caldelas (2010).

Exp #	Core type	Length (ft)	Flow rate (cc/min)	Pore diameter (1/cm)	Surface-to-volume ratio (1/cm)	Salinity	Temperature (°C)
25	**Sandstone**	1	1	297–420	15016	3 wt % Brine	22
28	**Sandstone**	1	1	150–177	17082	3 wt % Brine	22
32	**Boise sandstone + 10 wt % Clay**	1	1	250–297	57768	3 wt % Brine	22
45	**Boise sandstone**	1	1	297–420	14978	API Brine	22
46	**Texas Cream**	1	1	297–420	15286	3 wt % Brine	22
52	**Boise sandstone**	1	1	105–125	17729	API Brine	56
54	**Boise sandstone**	1	1	105–125	17777	API Brine	80

Figure 2 illustrates the normalized concentration of nanoparticles at an effluent stream for both experimental and mathematical studies. It is evident that our proposed model not only correctly predicts the trend of experimental datasets but it can also estimate nearly all distinct data points.

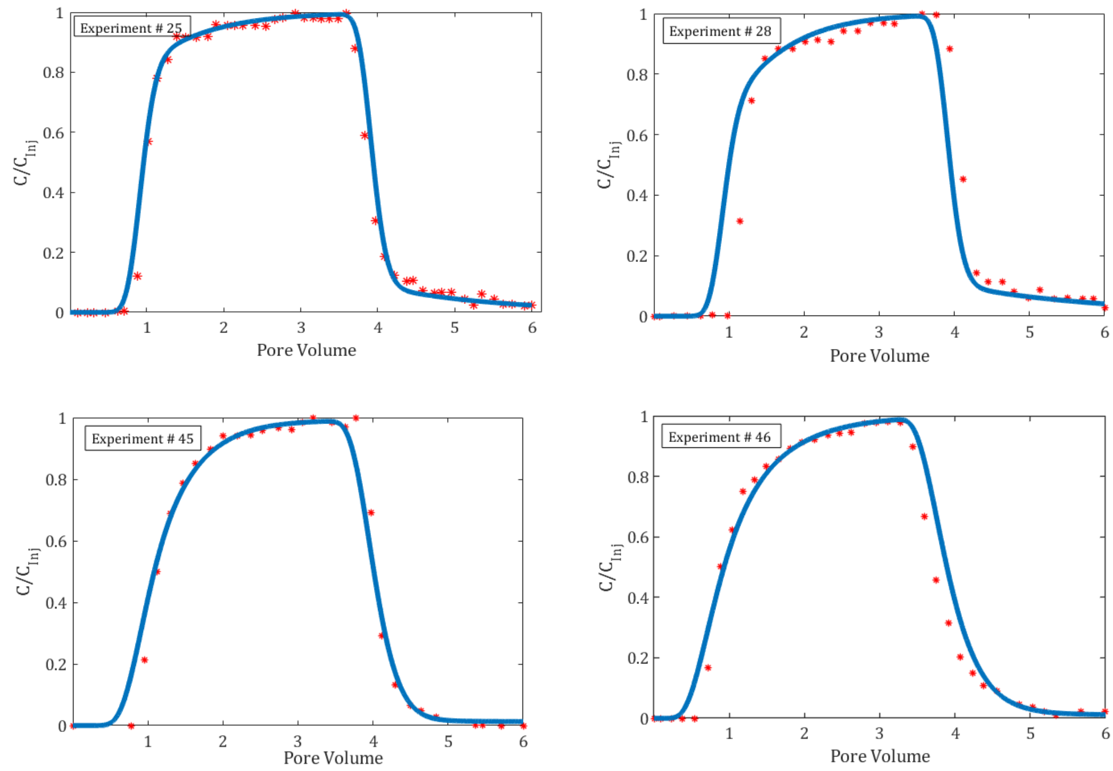


Figure 2
Comparison of the results of the mathematical model (this study) and experiments #25, 28, 45, and 46 of Caldelas (2010).

2.2. Evaluation of relative permeability, mobility, and IFT

The deposition of nanoparticles on the rock surface may cause wettability alteration and change the relative permeability curves. When $S = S_{\max}$, the total surfaces per unit bulk volume of the porous media are entirely occupied by the nanoparticles adsorbed on the pore surfaces or entrapped in core throats; when $S < S_{\max}$, the nanoparticles partially cover the surfaces of the porous medium. Therefore, the relative permeability of water ($k_{rw,m}$) and oil ($k_{ro,m}$) phases can be linearly related to a fraction of the surface covered by the nanoparticles, i.e., $0 < S < S_{\max}$ (El-Amin et al., 2013; Parvazdavani et al., 2014). Equations (7) and (8) express the mathematical formulation of this statement.

$$k_{rw.m} = k_{rw} + \frac{S}{S_{max}}(k_{rw.NP} - k_{rw}) \tag{9}$$

$$k_{ro.m} = k_{ro} + \frac{S}{S_{max}}(k_{ro.NP} - k_{ro}) \tag{10}$$

where $k_{rw.NP}$ and $k_{ro.NP}$ respectively indicate the relative permeability of water and oil phases when S is equal to S_{max}. $k_{rw,m}$ and $k_{ro,m}$ denote the relative permeability of water and oil phases, respectively when the surface nanoparticles partially occupy the surfaces per unit bulk volume of the porous media.

In this study, two experimental relative permeability datasets for $S = 0$ and $S = S_{max}$ are used (Parvazdavani et al., 2014). These experimental datasets for the relative permeability of water and oil phases are depicted in Figure 3. The reported result shows that the relative permeability of oil and water for nanofluid flooding is a value between surfaces fully covered by nanoparticles ($S = S_{max}$) and higher than their associated values for $S = 0$.

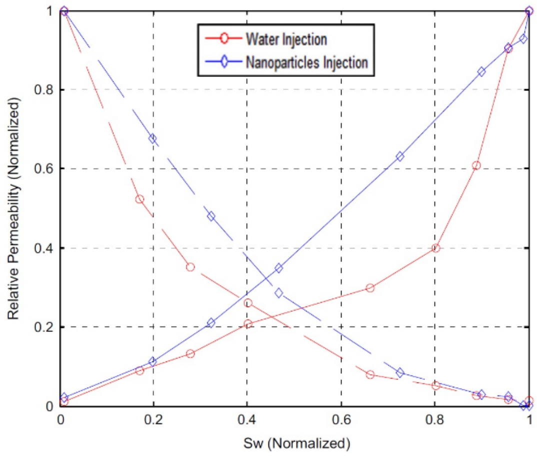


Figure 3
The effect of retention capacity on the relative permeability of oil and water phases replotted from Parvazdavani et al. (2014).

Moreover, it is necessary to determine the mobility of the injected fluid with acceptable accuracy to achieve better sweep efficiency for higher oil recovery. As mathematically expressed by Equation (11) , the mobility is a function of permeability and viscosity of the displacing and reservoir fluids (Denney, 2001):

$$M = \frac{k_{rw.m}\ \mu_o}{k_{ro.m}\mu_w} \tag{12}$$

where M shows the mobility ratio, $k_{rw.m}$ and $k_{ro.m}$ are the relative permeabilities of the injected fluid and oil, respectively, μ_w and μ_o represent the viscosity of injected fluid and oil, respectively. The reports of Song et al. (2005) clearly show that the viscosity of nanofluid continuously increases by increasing the concentration of nanoparticles and salinity.

Increasing the capillary number by reducing the interfacial tension of oil–water systems is the primary role of a nanofluid flooding operation to improve recovery efficiency. Therefore, the magnitude of interfacial tension reduction is an essential issue in any nanofluid-assisted EOR operation. Several research groups confirmed that the lowest value of IFT can only be achieved at a specific concentration of nanoparticles in an injected fluid. For instance, Hendraningrat et al. (2013b) stated that the IFT is directly related to nanoparticle concentration. This study employs modeling results to determine the effect of different factors on the distribution of nanoparticles concentration and IFT and mobility of injected fluid. The variation of IFT and viscosity of injected fluid versus nanoparticles concentration has been done using the experimental results of Song et al. (2005) and Roustaei and Bagherzadeh (2015).

3. Results and discussion

3.1. The effect of injection volume

The concentration of nanomaterials injected into porous media is one of the most influential parameters on the ultimate oil recovery factor. Increasing the dosage of nanoparticles in a base fluid increases its viscosity, and the interfacial tension between the reservoir and injected fluids significantly decreases. A higher concentration of nanoparticles also increases the final recovery by making the rock surface more water-wet. On the other hand, increasing the concentration increases the project cost and may reduce displacement efficiency by porosity and permeability impairment (Hendraningrat, 2015; Hendraningrat and Torsæter, 2014). Figure 4 illustrates the variation of nanoparticle concentration in an injecting fluid as a function of distance from the injecting point after three pore volumes of nanoparticle injections followed by three pore volumes of brine post flush (Experiment #25 as in Table 1). The decrease in nanoparticle concentration along the core indicates the deposition of nanoparticles on the rock surface. The results confirm that the concentration of nanoparticles in porous media (and consequently the IFT, mobility, and wettability of reservoir rock) is not constant during the whole injection process. It is worth noting that the three lower profiles in Figure 4 show the detachment of the deposited nanomaterial from rock surface during brine flooding. The results are in accordance with the experimental observations of Caldelas (2010), in which 96% of nanoparticles were recovered after three pore volumes of brine post flush. Simulation results in Figure 5 present the average amount of nanoparticles deposited on rock surface during the injection of three pore volumes of silica nanoparticles, followed by three pore volumes of brine flooding into Boise sandstone core (Experiment #25 of Caldelas (2010)). It can be concluded that the injection of more than two pore volumes of nanofluids (with the initial concentration of 5 wt% in Boise sandstone) has a negligible effect on the amount of deposited nanoparticles on the rock surface. Indeed, it only increases the process cost and has no remarkable effect on wettability alteration and oil recovery.

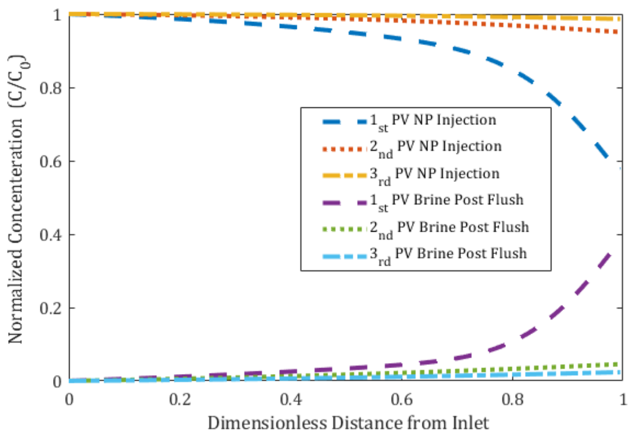


Figure 4
The profile of nanoparticle concentration in an injecting fluid as a function of distance from the inlet for Boise sandstone.

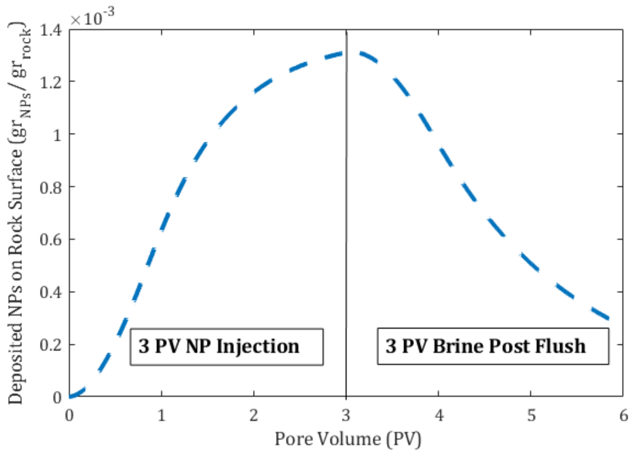


Figure 5
The simulation of the average amount of deposited nanoparticles in Boise sandstone.

3.2. The effect of rock type

The effect of Boise sandstone and Texas Cream limestone on the transport behavior of silica nanoparticles is presented in Figures 6 and 7. The grain size, specific surface area, porosity, and permeability of two cores are equal (as presented in Table 1 and the report of Caldelas (2010)). The results show that the amounts of deposited nanoparticles on the surface (after three pore volumes of injection) vary in two cases. It can be observed that the amount of deposited nanoparticles and surface coverage for the Texas Cream limestone is higher than the Boise sandstone. The negligible adsorption of nanosilica particles on the sandstone core could be attributed to the high surface energy of particles. The higher adsorption density of the limestone could be related to its electrostatic force with the silica nanoparticle (Yu et al., 2012).

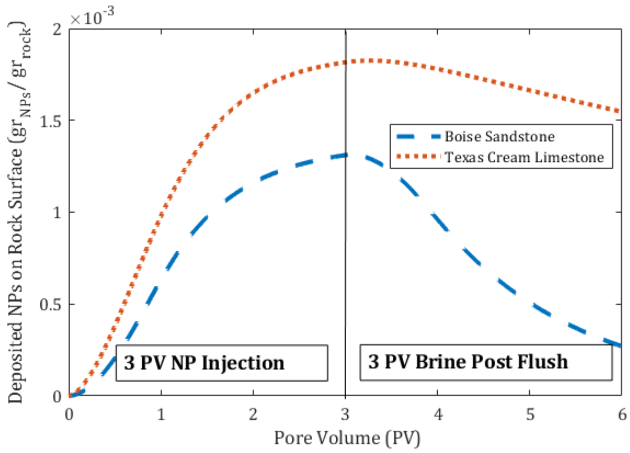


Figure 6
The effect of rock type on the amount of deposited nanoparticles on the rock surface.

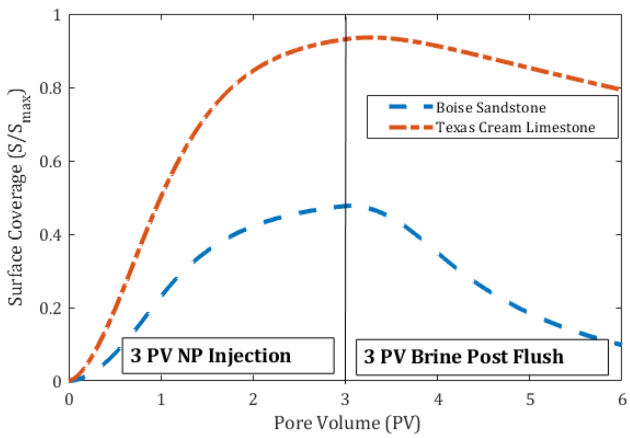


Figure 7
The variation of normalized surface coverage with rock type.

The variation of both interfacial tensions between reservoir fluids and injection fluid to the porous medium and viscosity of nanofluids as a function of distance from the inlet for two different rock types are illustrated in Figure 8. The results show that the IFT between reservoir fluids and nanofluid for the Texas Cream limestone is lower than the Boise sandstone. This observation can be explained by the amount of nanoparticles deposition on the former rock being higher than the latter. Indicating that the Texas Cream limestone separates more nanoparticles from the base fluid than the Boise sandstone. This higher separation reduces nanoparticle concentration in the injected fluids and increases interfacial surface tension. Furthermore, it can be observed that the mobility of nanofluid in contact with the Texas Cream limestone is lower than the one in contact with the Boise sandstone. Decreasing the dosage of nanoparticles in the fluids injected into the porous medium reduces its viscosity.

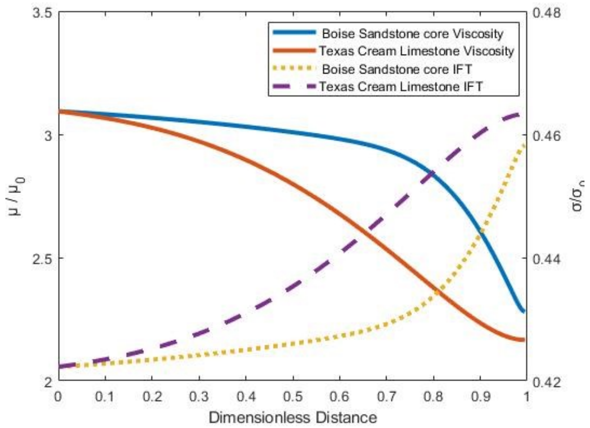


Figure 8
The effect of rock type on the viscosity and IFT of displacing fluid after injecting one pore volume of nanoparticles.

3.3. The effect of rock grain size

The variation of the amount of nanoparticle deposition on the rock surface and surface coverage as a function of the grain diameter is shown in Figures 9 and 10, respectively. Decreasing the grain diameter of the sandstone results in increasing both depositions of nanoparticles and surface coverage. This result agrees with those obtained by Caldelas (2010), who reported a decrease in the amount of recovered nanoparticles by decreasing the grain diameter. On the other hand, small grains may create smaller pores inside the porous medium and increase the possibility of a physical straining mechanism. The results show that micromodels and sand columns, even with the same porosity and permeability, may not be good models for studying the transport of nanoparticles in an actual reservoir.

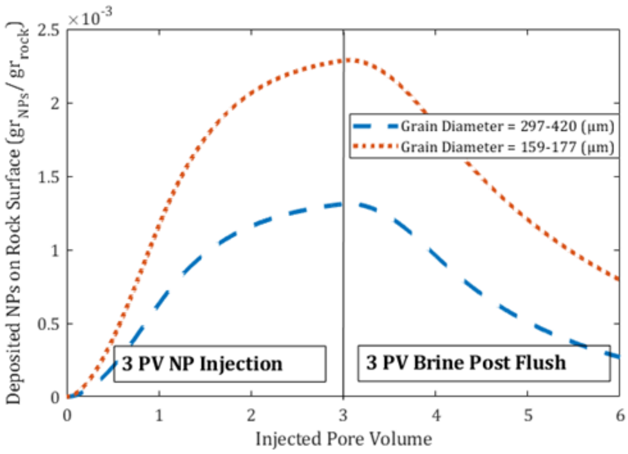
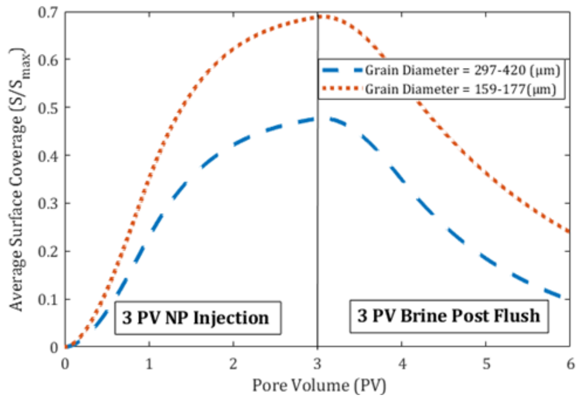


Figure 9
The effect of grain diameter on the amount of deposited nanoparticles on the rock surface.



Figures 10
The variation of normalized surface coverage with the grain diameter of the rock.

3.4. The effect of clay content

The profile of deposited nanoparticles and surface coverage as a function of distance from the wellbore for the Boise sandstone with and without the clay content is shown in Figures 11 and 12, respectively. Figure 11 demonstrates that the deposition of nanoparticles on the Boise sandstone increases in the presence of clay particles. This observation may be explained by the work of Fang et al. (2013), which claimed that porous media with a higher clay content had more small pores to retain the nanoparticles.

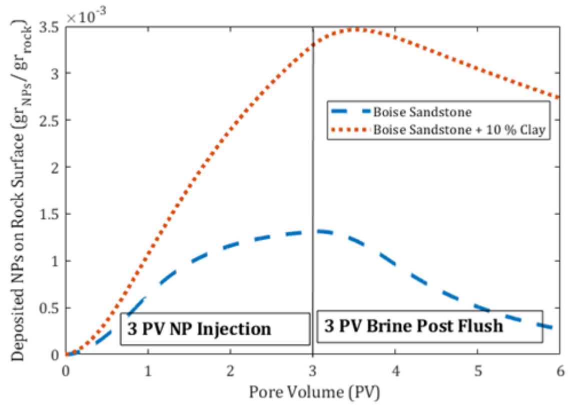


Figure 11
The effect of the clay content of rock on the amount of deposited nanoparticles.

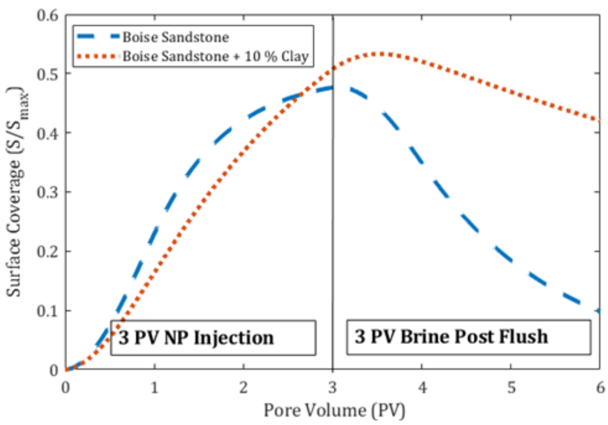


Figure 12
The variation of the normalized surface coverage with the clay content of the rock.

Although the Boise sandstone with a higher clay content shows a higher amount of deposited nanoparticles, it cannot be extended to the surface coverage. As shown in Figures 11 and 12, the surface coverage of the Boise sandstone increases by decreasing its clay content. Increasing the value of S_{max} by increasing the clay content may contribute to this result. Consequently, for nano flooding operations, the presence of clay is a negative factor. The effect of the clay content of the porous media on the viscosity of the injected fluid and the IFT between the reservoir and injected fluids is presented in Figure 13. It can be seen that the presence of clay in the Boise sandstone negatively affects both viscosity and IFT of nanofluid/oil. Similar to our previous reasoning line, these observations can also be related to the amount of nanoparticles separated from the base fluids. In conclusion, it should be mentioned that despite the previous results for rock type and grain size, in this case, a higher amount of deposited nanoparticles does not lead to higher surface coverage. Therefore, clays have an undesirable effect on front concentration and surface coverage.

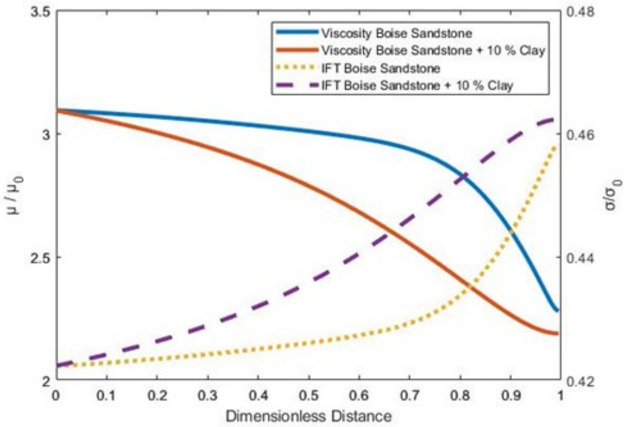


Figure 13
The effect of clay content on the viscosity and IFT of displacing fluid after injecting one pore volume of nanoparticles.

3.5. The effect of salinity

The salinity of both displacing nanofluid and reservoir fluid significantly affects the stability of the dispersion. An effect of the salinity of the system on both the amount of deposition of nanoparticles on the rock surface and surface coverage is presented in Figures 14 and 15, respectively. Increasing the salinity from 3 wt % NaCl to API brine causes surface deposition. Since the surface coverage is a positive factor, the API brine performs better than 3 wt % brine. Higher ionic strengths will result in lower repulsion forces, thus allowing van der Waals attractive forces to dominate (Saleh et al., 2008). Increasing salinity appears to increase the adsorption of nanoparticles and improve the surface coverage. However, the stability of nanoparticles may be reduced in a high-salinity system. Therefore, the appropriate salinity level and surface modification are essential issues that should be considered to prevent the agglomeration of nanoparticles.

3.6. The effect of reservoir temperature

Since the reservoir temperature is always higher than the surface temperature, the propagation of nanofluids used for nano-based EOR application at relatively high temperatures should be recognized. The effect of reservoir temperature on the amount of deposition of nanoparticles on the rock surface and surface coverage is presented in Figures 16 and 17, respectively. Since reservoir temperature involves several variables, the mechanism of variation of the nanoparticle behavior with temperature is complex and difficult to be explained. For instance, increasing the temperature that often decreases the zeta potential of the particles and stability of the nanofluid (McElfresh et al., 2012) will likely reduce oil recovery due to agglomeration. On the other hand, increasing the temperature may increase the oil recovery by decreasing viscosity and IFT, weakening molecular interaction, and increasing the Brownian motion (Hendraningrat et al., 2013a). In order to emphasize the effect of temperature change on transport and retention kinetics, nanoparticles transport in three porous media with precisely the same reservoir rock and fluid properties (Experiments #45, 52, and 54 of Caldelas (2010)), different transport kinetics were modeled. The simulation results in Figures 16 show that by increasing the temperature to 80 °C, the amount of deposited particles increases substantially.

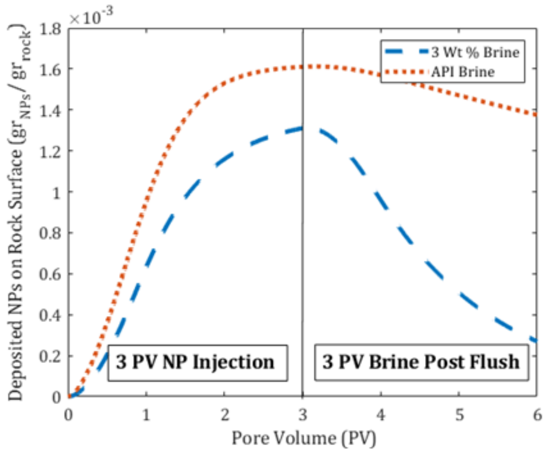


Figure 14
The effect of salinity of the injecting fluid on the amount of deposited nanoparticles on the rock surface.

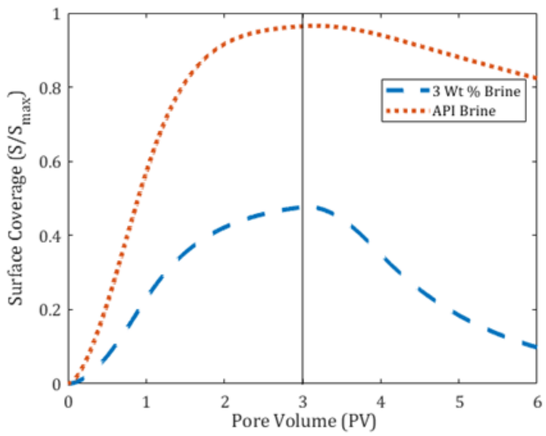


Figure 15
The variation of normalized surface coverage with the salinity of the injecting fluid.

In contrast, the surface coverage does not follow the same trend as in Figure 17 because increasing temperature results in increasing the maximum surface capacity. Consequently, it could be seen that even at a higher amount of deposited nanoparticles on the sand surface, the surface coverage remains constant in flooding at 80 °C. Since temperature will affect both nanofluids and the reservoir fluid properties, the effect of temperature on oil recovery cannot be generalized. Therefore, further study on the temperature effect should be performed to better understand its role in a nano-assisted EOR process.

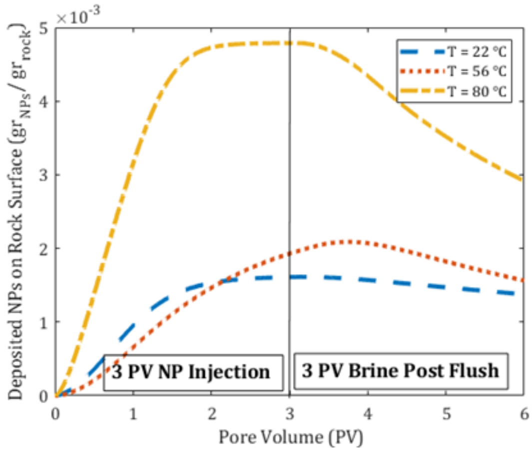


Figure 16
The effect of the reservoir temperature on the amount of deposited nanoparticles on the rock surface.

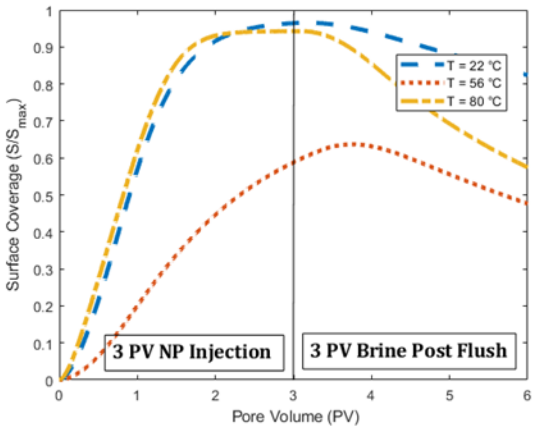


Figure 17
The variation of normalized surface coverage with the reservoir temperature.

4. Conclusions

The transport and retention of nanoparticles in porous media concerning enhanced oil recovery were theoretically investigated in this study. A new transport approach was developed and validated using experimental data from the literature based on a modified kinetic Langmuir model. The effects of different subsurface conditions, including rock type and its characteristics, the volume of injected nanomaterials, the salinity of injected fluid, and the reservoir temperature on wettability alteration, interfacial tension, and mobility were analyzed systematically. The key findings of this study can be summarized as follows:

- There is an optimum concentration of nanoparticles to be injected into a porous medium. The injection of nanoparticles at higher than maximum retention capacity results in no more adsorption of nanoparticles on the surface, and the effluent concentration will be the same as injected. Indeed, the amount of nanoparticles deposited on the rock surface equals detached ones. Therefore, proper determination of deposition and detachment kinetics is necessary.
- Interactions between nanoparticles and reservoir rock determine the efficiency of the nanofluid flooding process. Different surface charges and properties of sandstone and limestone lead to different behaviors of the deposition of silica nanoparticles. The amount of deposited silica nanoparticles (i.e., surface coverage) on limestone rock is relatively higher than sandstone.

- Rocks with smaller grain sizes have higher surface area and consequently more available sites for deposition of nanoparticles. A higher amount of nanoparticles deposits on reservoir rock with finer grains. However, the wettability alteration depends on the deposited particles divided by the surface area. Therefore, the characterization of reservoir rock is essential for determining the efficiency of a nano-assisted EOR method. In the case of relatively narrow pore throats, the porosity and permeability reduction should be considered.
- The salinity of the reservoir and injected fluids significantly affects the transport and retention of nanoparticles. Increasing the salinity increases the amount of deposited nanoparticles on the rock surface and makes the surface more water-wet. Conversely, the instability and agglomeration of nanoparticles at higher salinity result in lower efficiency.
- Reservoir temperature substantially affects the kinetics of transport and retention of nanoparticles. The kinetic rate of deposition and detachment is significantly impacted by temperature. Higher reservoir temperatures result in a higher rate of deposition. Further investigation is needed to clarify the mutual effects of the temperature on reservoir wettability, IFT, and viscosity.

This study improves the basic understanding of the impact of reservoir parameters on nanoparticles transport by identifying a direct link with surface coverage, wettability alteration, and mobility of injected fluid. Nevertheless, the significant impact of subsurface factors on nanoparticles transport in reservoirs suggests that future investigation on this subject will be fruitful.

Nomenclature

API	American Petroleum Institute
EOR	Enhanced oil recovery
IFT	Interfacial tension
PV	Pore volume

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