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Original article

Numerical investigation of oil recovery due to nanofluid injection into the oil reservoirs

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Abstract

In the process of oil recovery, after the initial oil recovery process, a considerable amount of oil remains in oil reservoirs. Enhanced oil recovery methods are used to extract residual oil of reservoirs. Various methods are used to improve oil recovery, one of which is the injection of nanofluids instead of water injection. In this study, a numerical study has been considered to determine the effect of various nanomaterials on the improvement of oil recovery. Various nanoparticles have been included, and their major impacts on the factors affecting oil extraction are also presented. The black oil model has been used to study the numerical effect of the nanoparticles on oil extraction. A mixture of different metal oxides nanoparticles such as Al_2O_3, TiO_2 and SiO_2, and water as nanofluids is used as an aqueous phase in solving problems. Mass balance and momentum balance equations of nanofluids are solved numerically. In this study, the effect of temperature changes, nanoparticle concentration, nanofluid density, size and density of solid particles of nanoparticles on oil recovery, interfacial tension, and pore pressure variations have been examined. According to the results presented in this study, the addition of nanoparticles reduces the amount of suction and interfacial tension and also increases the amount of oil extraction. By increasing the concentration of nanomaterials in the base solution, the amount of oil extraction increases. The effect of the size and density of solid particles of nanoparticles on the amount of oil extraction is considerable, and the variations of these parameters also result in a change in oil extraction.

1. Introduction

During the oil exploration, usually after the initial recovery, a large amount of oil is still in place. After oil recovery from the reservoir, various recovery processes such as water flood, gas injection, thermal recovery, chemical flood, etc. are used. The main purpose of these different recovery methods is to increase the final production of reservoirs. The water flood process, in which, water is injected to extract the remaining oil, is a simple and inexpensive secondary recovery process that is widely used for oil recovery after the initial recovery process.

Nanotechnology has recently attracted lots of attentions; there have been many studies which have conducted on the applications of nanotechnology in enhanced oil recovery (EOR). Today scientists are using other solutions to inject into oil reservoirs to improve oil recovery, instead of using water. One of these solutions is the nanofluid solution.

Different nanomaterials, combined with water, alter the physical water properties, such as density and viscosity, and the resulting solution known as a nanofluid, can be injected to improve the oil recovery in the secondary recovery process. In this study, a numerical model for determining the effect of nanomaterials on oil recovery is used. Some factors affect oil recovery are viscosity, density, temperature, contact angle and interfacial tension. Enhanced oil recovery methods are such methods in which various nanoparticles, including

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metallic and non-metallic nanoparticles used as injection fluid. In this case, many studies are done by different scientists to figure out the importance of EOR.

In the course of studies in 2012 and 2013, the Hendraningrat group [1-4], studied on enhanced oil recovery, especially about injection of silica dioxide nanoparticles. They worked on enhanced oil recovery process by examining issues such as nanofluid flood (December 2012), core-flood (April 2013), Optimum concentration of nanomaterials (July 2013). According to their study, incremental oil recovery and displacement efficiency increased as decreased nanoparticle size, meanwhile contact angle of aqueous phase also decreased as nanoparticle size decreased, the greatest value of incremental oil recovery and displacement efficiency was achieved from intermediate-wet condition. As a result of their experiments, nanofluids will be more effective in the intermediate-wet rocks. Increasing nanofluids injection rate will decrease incremental oil recovery and increasing temperature will increase incremental oil recovery and displacement efficiency. Significant reduction of interfacial tension has been observed by introducing nanoparticles into the brine. The higher concentration of nanofluids will give the lower IFT. This IFT reduction indicates potential candidates for EOR.

H. Ehtesabi et al., [5] also studied enhanced oil recovery in 2013 by injecting titanium dioxide nanoparticles. By examining the effective parameters such as nanofluid viscosity, nanofluid absorption and rock wettability, and the amount of nanoparticle accumulation in solution, the effect of each of these parameters on the enhanced oil recovery process investigated. The results showed that the recovery factor improved by using anatase nanoparticles. Although, when the concentration of nanoparticles was about 1%, the extraction coefficient decreased for both anatase and amorphous particles. According to the results of viscosity measurement, it can be understood that the dispersion of various nanoparticle did not affect the viscosity of water. On the other hand, due to the results of contact angle measurements, deposition of nanoparticle changed the wettability of the surface.

In 2014, L. Hendraningrat and O. Torsæter expressed some metal nanoparticles, including aluminum oxide, magnesium oxide, zirconium dioxide, cerium dioxide, titanium dioxide, zinc oxide and iron oxide, and pointed out that injection of these nanoparticles into the base solution should guarantee the stability of the nanofluid [6]. It was concluded that due to nanoparticles injection in water, it ensures an increase in oil recovery. It is visually understood that the main methods that consider nanoparticles to be EOR agents are the reduction of IFT and variation of porous media wettability. Although increasing the nanoparticles concentration improves the final oil recovery, achieving the optimum concentration is always desirable. By injecting aluminum oxide, titanium dioxide and silica dioxide, they evaluated the effect of injection of each of these nanoparticles on rock wettability variation, contact angle and interfacial tension of the oil, and ultimately evaluated enhanced oil recovery and stability of formed nanofluid.

The issue of enhanced oil recovery by injecting silicon dioxide nanoparticles in 2014 by Maghzai et al., was further investigated [7]. The effect of silicon nanoparticles on polymer density and oil extraction, the effect of salt on the polymer viscosity and oil extraction by using nanoparticles, the relationship between oil extraction and injection viscosities, the relationship between pore-to-pore displacement of oil in the porous media and the concentrations of nanoparticles were investigated in their study. According to the results of this research, the ion-dipole interaction between cations and SiO_2 increases the viscosity of the nanofluid by increasing the concentration of these nanoparticles. Also, by increasing concentrations of nanoparticles, during the flood test, oil recovery will increase. At the same salinity, oil recovery obtained by nanofluid flooding is about 10% higher than the polymer flooding in the absence of SiO_2 nanoparticles in a polymer solution. By increasing the concentration of nanoparticles, oil recovery increases slightly. In the absence of SiO_2 nanoparticles, when the minimum salinity decreases, the oil recovery rate will increase due to the increasing of the concentration of polymer.

Effects of temperature and silica nanoparticles on variations of oil-wet calcite wettability were investigated in 2017 by Al-Ansari et al., [8]. According to the research, the efficiency of nanoparticles was higher at high temperatures, while nanoparticle size did not effect. The size of the nanoparticles (5 or 25 nm) did not affect the wettability variations of nanofluid. It was also concluded that the temperature increase would reduce the time needed to achieve the same contact angle reduction. However, in relatively long immersion periods, the contact angle converges to a minimum, without and dependence on temperature. This was due to increased absorption of SiO_2 nanoparticles on the surface of calcite by increasing the temperature, consistent with measurement for the ZrO nanoparticles.

Enhanced oil recovery was investigated using surface functionalization of silica nanoparticles, as an agent to enhance the efficiency of water flooding in oil wet reservoirs, in 2017 by Azarshin et al., [9]. In their study, these nanoparticles created in the laboratory to enhance the efficiency of water flooding and it was found that these nanoparticles in comparison with the typical nanoparticles were more effective.

Results conducted from experimental studies showed that both interfacial tension and contact angle were decreased in the presence of these nanoparticles. These results were obtained by performing core-flood tests. Also, it was found that an optimum concentration for the contact angle and interfacial tension that were decreased due to nanoparticles exists, and at a concentration above this threshold, the interfacial tension increases slightly. It was also emphasized that nanoparticles productivity is strongly dependent on the specific composition of crude oil and the type and concentration of nanoparticles. Therefore, the appropriate nanoparticle type should be selected based on the test of the reservoir oil samples.

In 2017, Salehi et al., [10] studied on the variations of salinity of injection water and its effects on the amount of oil extraction, absolute permeability, residual oil saturation, interfacial tension and capillary pressure. This study was based on laboratory investigation. The results of this study showed that increasing salinity of injected water up to 200,000 ppm and determining the optimum salinity, the oil recovery would increase. This increase seems to be supported by the reduction of IFT. This effect reduced the capillary pressure which increases the tendency to reduce the residual saturation of the oil.

The impacts of nanoparticles on the wetting behavior of fractured limestone formation were investigated by Nwidee et al., [11] in 2017. Due to their research, the effect of zirconium (IV) oxide nanoparticles (ZrO_2) and nickel (II) oxide (NiO) nanoparticles on the preferences of fractured limestone formations (oil-wet) were investigated. Wettability was checked through SEM, AFM, and contact angle. The nanoparticle potential to change the oil-wet calcite substrate water-wet has been tested experimentally at low concentrations of nanoparticles (0.004 to 0.05% by weight). It was shown that at the same particle concentrations, behavior of both nanoparticles was similar. While ZrO_2 shows a better efficiency by changing the oil-wet (water contact angle θ=152 °) calcite substrates to a strongly water-wet state (θ=44°), NiO changes wettability to an intermediate condition (θ = 86 °) at 0.05 wt% concentration of nanoparticles.

H. Pei et al., [12] in 2018, considered the issue of enhanced oil recovery by an experimental study on nanoparticles and surfactant stabilized emulsion flooding. According to their research, with increasing volume of injectable emulsion, incremental oil recovery gradually increased, but it was concluded that there is an optimal economic value of injectable volume. The lower injection rate had a better impact than the higher injection rate, and continuous injection pattern in comparison with the cyclic injection pattern indicated that the oil recovery was higher in the continuous injection pattern. The nanoparticle-surfactant stabilized emulsion flooding had great potential for improving oil recovery in oil reservoirs, with the permeabilities of 500-2000 mD and a viscosity of crude oil less than 1000 mPa.s.

The carbon nanotubes have been used in the variety of issues [13], but in the enhanced oil recovery category, in 2018, Chen et al., [14] investigated the using of carbonaceous nanoparticles multi-walled carbon nanotubes (MWNTs) and carbon blacks (CBs) as surfactant carrier in enhanced oil recovery by a laboratory study. As the result of their study, surfactants carried by nanoparticles to obtain an equilibrium between the aqueous phase and excess oil similar to the amount of surfactant formulation only (0.007-0.009 mN/m). By performing the tests, it was concluded that the injection of MWNT-surfactant mixtures contributed to fast and higher tertiary recovery than surfactant-only formulation. When the surfactant released, destabilization has occurred in the dispersion of the nanoparticles, and therefore their retention in the porous medium increases.

Chunkai Fu et al., [15] investigated the enhanced oil recovery by using the nanoparticle-stabilized carbon dioxide foam for waterflooded residual oil recovery. They have mentioned that CO_2 foam produced as a dispersion of CO_2/nanosilica through a porous medium. This foam can reduce carbon dioxide mobility and improve its sweep efficiency in the carbon dioxide flooding. This foam has shown the ability to enhance the residual oil recovery after waterflooding process. They also examined the effects of pressure and temperature on the efficiency of carbon dioxide foam in extracting residual oils. The results showed that the residual oil recovery rate (carbon dioxide/nanosilica flood) changed increasingly from 64.9 to 75.8% when pressure changed from 1200 psi to 2500 psi. As the temperature rises from 25 °C to 60 °C, residual oil recovery obtained by carbon dioxide/nanosilica flooding decreased from 62.6% to 52.1%.

Gharibashi et al., [16] used computational fluid dynamics to study simulated thermal enhanced oil recovery in 2018. To have a better perception of the fluid flow in the reservoir, a 2D micromodel was generated. Type of nanoparticle, volume fraction of nanoparticles, diameter of nanoparticles and temperature of the injected fluid, as four important factors which had a great effect on the process, were studied by Taguchi method. The results of their study showed that factors such as reducing the nanoparticles diameter, increasing their percentage volume in the base fluid and the temperature of the injected fluid improved the rate of oil production from the porous medium, considerably increased. By injecting the nanofluid at an optimum level, the heavy oil viscosity changed and decreased from 35 to 25 Pa.s.

Synthesized citric acid-coated magnetite nanoparticles were used as an agent in the process of enhanced oil recovery by Divandari et al., [17] in 2018. In their study, nanoparticles coated with magnetite citric acid were synthesized in a cost-effective, facile and one-step process, and then by using different methods were characterized. Subsequently, oil recovery efficiency was investigated by using the 2D micromodels which were heterogeneous and homogeneous and were in a magnetic field. According to the results, the oil extraction factor for nanoparticles coated with magnetite citric acid was higher than hematite nanoparticles, due to decreased interfacial tension (IFT) between oil and injection fluid, change in level of surface wettability from oil-wet to water-wet, promote the distribution of nanoparticles in porous media and create a pillar structure in the presence of a magnetic field. Actually, magnetic nanoparticles play the role of a piston against a magnetic field by creating columns that sweep the oil and increase production. Also, these nanoparticles flooding increases the extraction factor over the flood of polymer and hematite.

From the existing literatures, it can be concluded that the addition of nanoparticles affects factors such as fluid stability, interfacial tension, contact angle, viscosity, density, and thermal conductivity. According to the experimental results of different scientists, by adding the nanoparticles to the base fluid (water) the amount of oil recovery increases. Due to the experimental studies, scientists achieved some results, such as reducing interfacial tension, reducing fluid viscosity, and similar results in terms of enhanced oil recovery by conducting core-flood tests, flooding of various types of surfactants, flooding of various types of polymers, and flooding of various types of nanoparticles.

Ghasemzadeh presented a heat and mass transfer model in an unsaturated porous medium [18]. This model was developed for simulating a two-phase model and attained the high-orders of accuracy at a reasonable computational cost [19-21], and also to increase the model accuracy and calculation speed, the model was developed further [22-24].

In 2019, Ghasemzadeh et al., [25-26] Conducted studies to improve the modeling of hydrocarbon and deformable reservoirs. According to these studies, cases such as the effect of capillary between fluid phases as well as forces due to mechanical stresses, thermal stresses and fluid pressure in the reservoir were investigated and according to the results of their research, by adding capillary parameters, the amount of oil extracted increased. And the effects of temperature and mechanical stresses affected the production flow rate.

Recent studies in 2021 and 2022 have also been conducted on the effects of nanoparticles on enhanced oil recovery. Sircar et al. [28] discussed the applications of nanoparticles in chemical, miscible, thermal and microbial floodings. Their study mainly focused on various mechanisms involved by adding nanoparticles such as wettability alteration, IFT reduction, rheology improvement, mobility control etc. and also addresses new green nanomaterials and nanocomposites, which includes injecting specialized green chemicals (surfactants, alcohols, and polymers) that successfully displace oil. The IFT between the displacing fluid and the oil was reduced due to phase-behavior properties. Chemical nanoparticles such as SiO_2 and TiO_2 have shown great potential in recovery.

The parameters that influence and affect the application of nanoparticle-EOR were highlighted and discussed by Tinuola [29]. Elaboration on the potential of hybrid EOR processes in which nanoparticles were combined with other proven EOR methods were also reviewed in his study. The mechanisms attributed to efficient nanoparticle-EOR process were then presented.

Bai et al, [30] studied and researched on A clay-intercalated polymer which is a novel chemical flooding agent with application prospect for enhanced oil recovery, and its flooding performance is closely connected with its microstructure and dispersion characteristics in liquid phase. Due to their research, the intercalated polymer showed an obviously better enhanced oil recovery performance compared with conventional polymers under same conditions, and favorable incremental oil recovery could be achieved with optimal injection concentration, slug size, and injection rate.

Zhao et al, [31] focused on the interaction between naphthenic aryl sulfonate (NAS) solution and petroleum components at micron- and nano-scale. Their findings help understanding of the interaction between surfactant solution and crude oil before the formation of microemulsion, revealing the role of micellar solubilization and in-situ emulsification on oil displacement at low surfactant concentration and presenting a new strategy for designing surfactant based displacing system for EOR process.

The main objective of this paper is to investigate the effects of various nanomaterials (Al_2O_3, TiO_2, SiO_2) on the factors affecting oil recovery and on the improvement of oil recovery by using the black oil model. Although other studies were investigated experimental methods, this study is based on numerical methods and so far, enhanced oil recovery has not been numerically studied. Also, this study neglects the interaction between fluid and rock at the atomic scale [32-34]. Due to the results of solving the numerical model for each of nanoparticles, the value of oil extraction is increased by adding nanoparticles to the base fluid (water).

2. Government of equations

The governing equations of the numerical model, include porous medium equations, including three fluid phases (nanofluid, oil and gas), which after extracting the equations governing the system, a suitable numerical solution for converting differential equations to algebraic equations was presented.

The differential equations governing the system have a highly nonlinear behavior. To achieve an efficient and stable model, the simultaneous solution of the equations is considered. After completing the system of equations and solving methods, a computer program has developed to implement the aforementioned modelling.

The general form of the equations used in the numerical model based on [24], is as follows.

2.1 Momentum Balance

The final forms of momentum equations in fluid phases are as follows:

$$n_{nf} w_{nf} = K_{nf} \left[\rho_{nf} g - \nabla p_{nf} \right] \tag{1}$$

$$n_o w_o = K_o \left[\rho_o g - \nabla p_o \right] \tag{2}$$

$$n_g w_g = K_g \left[\rho_g g - \nabla p_g \right] \tag{3}$$

which in above relations, wα and nα respectively represents the relative velocity and volume percentage of the α phase. K_α is the degree of permeability of the α phase. Density and pressure of the α phase are also ρ_α and p_α. In the above relations, g is the gravitational acceleration vector. (1), (2) and (3) equations are the momentum equations for nanofluid, oil and gas phases, respectively.

In above relations, density and K_α are based on a viscosity function which for each fluid, the function is as follows:

$$Vis_{nf} = (Exp(1.003 - 0.01479 \times T_F + 0.00001982 \times T_F^{\,2})) \times 10^{-6} \tag{4}$$

$$Vis_o = \frac{0.0000736317 \times (Exp\left[\dfrac{797.7122}{T_K - 177.3562}\right])}{1000} \tag{5}$$

$$Density_{nf} = \left[\frac{0.14395}{0.0112^{(1+(1-((\frac{T_K}{649.727})))^{0.05107})}} \right] \times 10^{-3} \tag{6}$$

$$Density_o = 0.879 \times (1 - 0.0007 \times (T_C - 15)) \quad (7)$$

which in above relations, T_K, T_C and T_F are temperatures in degree of Kelvin, Centigrade and Fahrenheit. equations (4) and (5) represent viscosity functions for nanofluid and oil, respectively. Also, the relations (6) and (7) are density functions for nanofluid and oil, respectively.

2.2 Mass Balance

The final form of the mass balance equations for three phases of nanofluid, oil and gas are in accordance with relations (8), (9) and (10), respectively:

$$n_{nf}\left[\frac{\partial \rho_{nf}}{\partial p_{nf}}\frac{D^s p_{nf}}{Dt}\right] + \rho_{nf}\left[n'_w\left(\frac{D^s p_o}{Dt} - \frac{D^s p_{nf}}{Dt}\right)\right] + \nabla.\{\rho_{nf} K_{nf}\left[\rho_{nf}\, g - \nabla p_{nf}\right]\} : I = \dot{M}_{nf} \quad (8)$$

$$n_o\left[\frac{\partial \rho_o}{\partial p_o}\frac{D^s p_o}{Dt}\right] + \rho_o\left[n'_l\left(\frac{D^s p_g}{Dt} - \frac{D^s p_o}{Dt}\right) - n'_{nf}\left(\frac{D^s p_o}{Dt} - \frac{D^s p_{nf}}{Dt}\right)\right] + \nabla.\{\rho_o K_o\left[\rho_o\, g - \nabla p_o\right]\} : I = \frac{\partial m_{og}}{\partial p_o}\frac{D^s p_o}{Dt} + \dot{M}_o \quad (9)$$

$$n_g\left[\frac{\partial \rho_g}{\partial p_g}\frac{D^s p_g}{Dt} + \frac{\partial \rho_g}{\partial T}\frac{D^s T}{Dt}\right] + \rho_g\left[-n'_l\left(\frac{D^s p_g}{Dt} - \frac{D^s p_o}{Dt}\right)\right] : I + \nabla.\{\rho_g K_g\left[\rho_g\, g - \nabla p_g\right]\} = -\left(\frac{\partial m_{og}}{\partial p_o}\frac{D^s p_o}{Dt}\right) + \dot{M}_g \quad (10)$$

In the above equations, n'_{nf} represents a partial derivative of the volume of nanofluid to the capillary pressure. m_{og} represents the exchange of crude oil and gas phase. $\dot{M}_\alpha$ shows the fountain and well of the mass of the α phase, and I is the unit matrix. Other parameters were presented in the momentum equilibrium relations.

3. Problem Statement

In this study, a computer program has been designed to study the numerical impact of nanomaterials on oil extraction in the secondary extraction process. The addition of nanomaterials to water leads to a change in the density and viscosity of the solution, resulting in changes in suction and surface tension between the two phases of water and oil, which ultimately changes the amount of oil extraction. Also, temperature variations have changed the solution properties can, therefore, be considered as an effective factor in oil extraction.

To determine the effect of different nanoparticles on oil recovery, a one-dimensional model is defined. Solving this model is based on the mathematical relations presented.

The basic conditions and assumptions for solving the problem for the defined model are given in Table 1.

Table 1. The basic conditions and assumptions for solving the problem

Temperature	25˚C
Pressure	1 atm
Rock porosity	0.385
Rock permeability	1584 mD

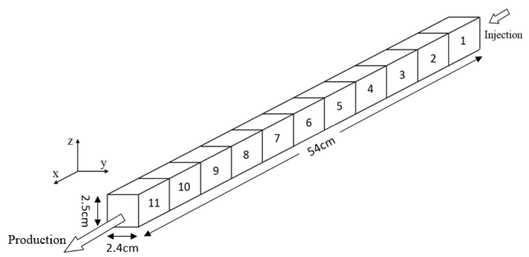

Fig. 1. One dimensional problem element

Reservoir rock type is sandstone with dimensions of 2.4×2.5×54 cm^3, saturated with heavy paraffinic oil. To extract oil from this reservoir, the nanofluid is injected from one side of the core and from the other side of the core the fluid inside of the reservoir is extracted.

4. Nanoparticles Addition

In recent years, scientists have used many nano-materials to improve oil recovery. Of the nanomaterials, in most research and experiments were carried out to improve the oil recovery, titanium dioxide and silicon dioxide nanomaterials were used.

According to what mentioned, the problem has been solved numerically, using the various nanomaterials used in the index papers.

4.1 Using nanoparticles to solve the problem

To use nanofluids, the viscosity and density functions of nanofluid have been replaced with the viscosity and density functions of the aqueous phase.

$$\rho_{nf} = (1-\varphi)\rho_{bf} + \varphi\rho_s \qquad (11)$$

$$\mu_{nf} = \mu_f/(1+34.87(\frac{d_p}{d_f})^{-0.3}\varphi^{1.03}) \qquad (12)$$

The equation (11) represents the nanofluid density function in which ρ_{nf}, ρ_{bf}, ρ_s and φ are respectively the nanofluid density, base fluid density, solids density and nanomaterials concentration. The equation (12) also describes the nanofluid viscosity, μ_{nf}, μ_f, d_p, d_f and φ, are respectively nanofluid viscosity, base fluid viscosity, nanoparticle dimension, base fluid molecule dimension, and nanomaterial concentration [35].

In order to investigate the effect of nanoparticles on interfacial tension (surface tension) and consequently its effect on the amount of oil extraction, the relations of interfacial tension in the system of equations should be presented. The n_{nf} equation (nanofluid volume fraction) related to the calculation of the capillary pressure used in the original model is given below. In order to investigate the effect of nanomaterials on the interfacial tension of the aqueous phase and oil, *b* and *d* parameters of this relationship are changed and the results of the changes are presented (*b* and *d* parameters are the parameters used to calibrate the model) [24].

$$n_{nf} = (\frac{n_{nfsat}+n_{nfres}\times(\frac{p_{conf}}{b})^d}{1+(\frac{p_{conf}}{b})^d}) \qquad (13)$$

In the above equation, n_{nf},n_{nfsat}, n_{nfres} and p_{conf}, present the value of nanofluid content, saturation of nanofluid, residual saturation of nanofluid and capillary pressure.

By changing the b and d parameters, in the above relation, the range of oil extraction changes after the implementation of the numerical model and solving the problem are obtained and with the help of the results presented in the index articles, the practical range for *b* and *d* parameters is obtained. The following results are obtained by putting the values of Table 2, in related relationships and solving the problem. Comparison of the results obtained from the model and the reported results are shown in Fig. 2 This graph displays the recovery performance of original oil in place versus the injection volume ratio to the total porosity of media.

Table 2. Specifications of used nanomaterials [36], [37]

Nano-particles	Density (ρ_s)(kg/m^3)	Nanomaterial dimension (d_p)(nm)	Nanomaterial's concentration in solution
Al_2O_3	3900	40	1 and 5 %
SiO_2	2400	25	1 and 5 %
TiO_2	4100	10	1 and 5 %

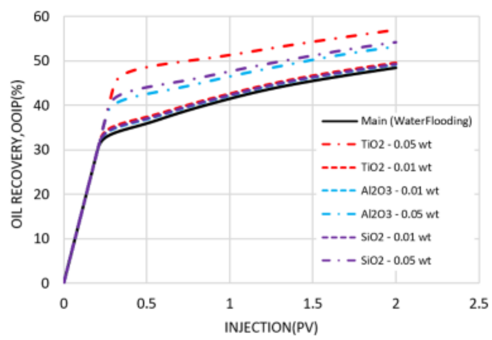

Fig. 2. The amount of oil extraction for nanofluids injection and comparison of them with water injection

Table 3. The value of n_{nf} and p_{conf} for different nanofluids

Nanofluids	n_{nf}	p_{conf}(kN/m^2)
TiO_2	0.1587	1.154
SiO_2	0.1575	1.158
Al_2O_3	0.1572	1.159

According to Fig. 2, the amount of oil recovery increases with the addition of nanomaterials to water, which varies with the variables of dimension and the concentration of nanomaterials.

4.2 Effect of Nanomaterial Concentration on Oil Extraction

To investigate the effect of nanomaterials concentration on oil extraction, aluminum oxide

nanomaterials were used in various concentrations in the solving problem.
As can be seen from Fig. 3, increasing the concentration of nanomaterials leads to an increase in oil extraction. After the injection of nanofluid, the amount of oil extraction has been rising initially, but over time, due to reasons such as reduced reservoir pressure, the amount of oil extraction is reduced. Increasing the concentration of nanoparticles leads to changes such as increasing the viscosity, which leads the amount of oil extraction increasingly continue after nanofluid injection.

Table 4. Results of software implementation for different nanomaterials injection

Solution	Viscosity (kPa.s)	Density (ton/m^3)	Oil Recovery, OOIP%
Al_2O_3, 1 wt%	1.05493E-06	1.02805	49.18
Al_2O_3, 5 wt%	1.54255E-06	1.18405	53.23
SiO_2, 1 wt%	1.06695E-06	1.01305	49.29
SiO_2, 5 wt%	1.68857E-06	1.10905	54.22
TiO_2, 1 wt%	1.09703E-06	1.03005	49.57
TiO_2, 5 wt%	2.18649E-06	1.19405	57.00
Water	9.8185E-07	0.99904	49.23

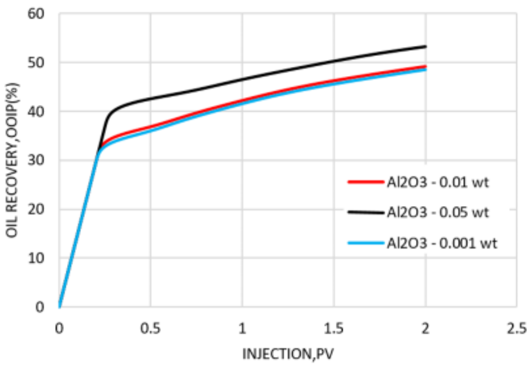

Fig. 3. Amount of oil extraction for nanomaterials concentration changes

4.3 Temperature effect on oil extraction in nanofluid injection

As noted earlier, the increase in temperature leads to an increase in the amount of oil extraction, but in this section the rate of changings in oil extraction for different temperature in nanofluid injection were examined.

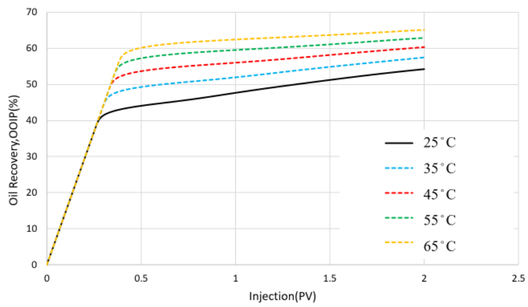

Fig. 4. Amount of oil extraction for temperature variations in nanofluid injection state

Fig. 4 shows the amount of oil extraction changes for adding silicon dioxide nanomaterials to the aqueous phase at different temperatures. According to this figure, the oil extraction rate increases with increasing temperature.
According to Fig. 5 and Table 4, the viscosity increases with the addition of nanoparticles to water, and as the temperature rises, the viscosity of the fluid decreases.

4.4 The effect of nanomaterials on the suction between the aqueous phase and oil

Fig. 6 shows the suction variations between the two phases of nanofluid and oil for various nanomaterials. Fig. 7 also describes the effect of the concentration of nanomaterials on the suction variations between the aqueous phase and oil. According to Fig. 7, the higher the concentration of nanomaterials in water, the amount of suction between the aqueous phase and oil decreases and corresponding to what was mentioned above, the amount of oil extraction also increases.
Increasing the temperature will reduce the suction between the aqueous phase and oil, this is also true in the model. In the model, with increasing temperature, the suction variations have been calculated and the results are presented in Fig. 8.
In order to investigate the effect of pressure changes and subsequent suction changes between the aqueous phase and oil in different areas of the model, the pressure of nanofluid and oil is calculated in the nodes 13 (on the face between the elements 1 and 2), 20 (on the face between the elements 6 and 7) and 36 (on the face between elements 10 and 11) of the model over the defined time ranges and the results of the pressure changes are presented in the Fig. 9. The reason for this change is the progression of the injected fluid in the model.

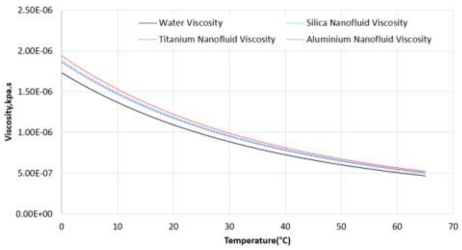

Fig. 5. Viscosity variations with temperature changes

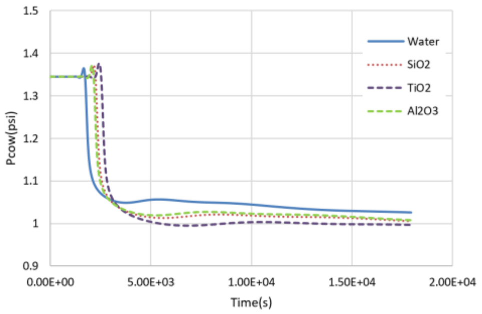

Fig. 6. Suction variation for different nanomaterials in node number 36

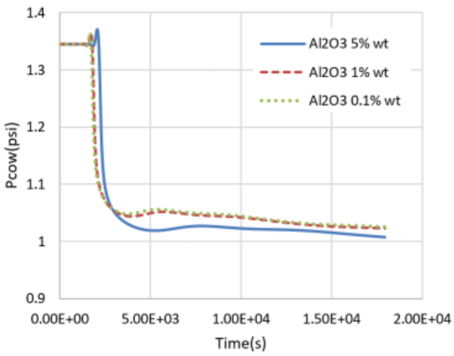

Fig. 7. Suction variations according to the concentration of nanomaterials in the node 36

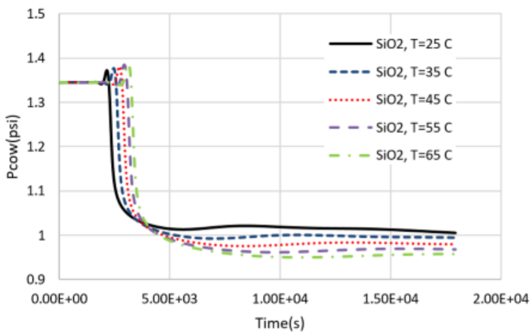

Fig. 8. Suction variations according to temperature in the node 36

4.5 The effect of nanomaterials on capillary relationships and aqueous phase volume fraction

Before examining nanomaterials directly on the surface tensile strength, we investigate n_{nf} for the injection of different nanoparticles.

According to Fig. 10, with increasing oil extraction rates, n_{nf} levels have also increased and p_{conf} levels have decreased accordingly. According to equation (14), the capillary pressure and surface tension are directly related and, as a result, reducing the pressure of the capillary leads to a reduction in surface tension, which is similar to the injection of nanomaterials.

$$p_{conf} = \frac{2\sigma_{onf} \cos\theta_{onf}}{r} \tag{14}$$

where σ_{onf} represents the interfacial tension between oil and nanofluid, θ_{onf} is the contact angle, r is pore radius and p_{conf} is capillary pressure between oil and nanofluid.

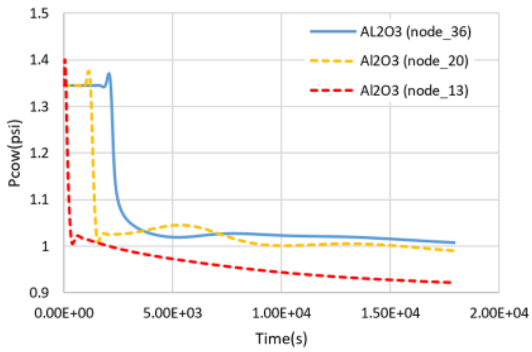

Fig. 9. The suction variations in the primary node (node 13), the middle node (node 20) and the end node (node 36)

Nanofluid Injection ⇨ Increase in oil extraction rate (increase in linear part of Fig 2.) ⇨

$$\left[\begin{array}{l} TiO_2 > SiO_2 > Al_2O_3 \\ n_{nf}^{TiO_2} > n_{nf}^{SiO_2} > n_{nf}^{Al_2O_3} \\ p_{conf}^{TiO_2} < p_{conf}^{SiO_2} < p_{conf}^{Al_2O_3} \end{array}\right.$$

Fig. 10. Comparison of n_{nf} and capillary pressure of different nanofluids injection (according to the results of Fig. 2 and Table 3)

Now, according to the above, we use the results of Hendraningrat's experimental study to directly investigate the effect of nanomaterials on surface tension in this study. Therefore, according to equation (14) and the Hendraningrat results, p_{conf}

is calculated. Then, using the equation (13) and by p_{conf} insertion, the value of n_{nf} is calculated.

Table 5. Comparison of n_{nf} and n_w

Nanomaterial	Hendraningrat study results*	n_{nf}	n_w
SiO_2	θ = 31˚ σ = 7.9 mN/m r = 11.7 μm	0.157	0.155

* θ: *Contact angle*; σ: *Interfacial Tension*; r: *Radii of curvature*

According to Table 5, the n_{nf} is greater than n_w, and according to the what mentioned at the first of this section, the increase of n_{nf} has a correlation with the reduction of the IFT and, consequently, according to the Hendraningrat study, the IFT rate for the addition of nanomaterials to the base fluid decreases.

Therefore, equation (13) can be used to directly investigate the effect of nanoparticles on surface tension, assuming that the addition of nanoparticles to the base fluid leads to a change in the parameters of this relationship. By changing the parameters *b* and *d*, the amount of oil extraction is obtained and then, considering that the addition of nanoparticles increases the amount of oil extraction, we consider the acceptable ranges for changes *b* and *d*.

The oil extraction rate is considered to be increasing in this range of variations of *b* and *d*, resulting in an increase in the n_{nf} content and, as a result, the IFT decreases.

The results obtained from Fig. 11 and Fig. 12 are shown in Table 6. The results of the experiments conducted by Hendraningrat [2] were examined in order to compare with the results of the implementation of the numerical model. Hendraningerat et al., In order to investigate the effect of nanomaterials on the interfacial tension, injected various nanofluids with different weight percentages of nanomaterials in the flood test at room temperature into Berea sandstone samples. The nanofluid injection rate was constant and the following equation is used to calculate the interfacial tension.

According to equation (13) and Table 6, by adding nanoparticles (Al_2O_3, TiO_2 and SiO_2) to the base fluid, the practical range for *b* and *d* parameters are [0.9-1] and [12-18], respectively.

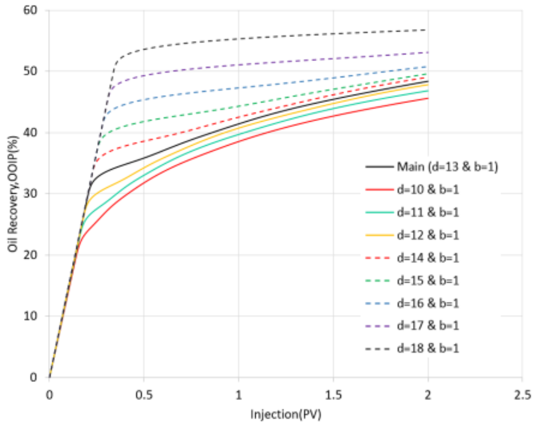

Fig. 11. The rate of oil extraction changes for the variations of d

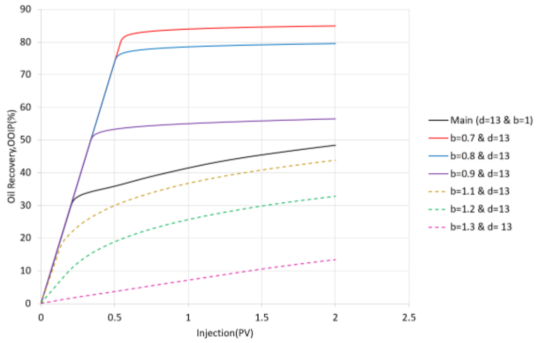

Fig. 12. The rate of oil extraction changes for the variations of b

Table 6. The rate of oil extraction changes for the variations of b and d

Nanofluid volume fraction parameters		OOIP (%)	Nanofluid volume fraction parameters		OOIP (%)
b	*d*		*b*	*d*	
0.7	13	84.90	1	10	45.62
0.8	13	79.50	1	11	46.84
0.9	13	56.48	1	12	47.84
1.1	13	43.80	1	14	49.06
1.2	13	32.78	1	15	49.63
1.3	13	13.39	1	16	50.80

5. 3D Simulation

A 3D modeling is proposed to show the capability of the numerical model employed in this study. In this simulation, the amount of oil extraction has been investigated due to the addition of various nanomaterials to the base fluid. The assumptions and conditions of the problem are given in Table 7.

Table 7. Parameters and assumptions considered in 3D injection problem

Rock Type	Sandstone
Porosity	0.208
Absolute permeability	1500 mD
Temperature	25 ˚C
Pressure	1 atm

In this simulation, nanofluid injects from a vertical well and oil extract from a similar horizontal well. This simulation is briefly represented by HP-VI.

Solving the numerical model for the HP-VI status, it is concluded that by adding nanomaterials to water and injecting the resulting nanofluids, the amount of oil extraction has changed and the results are shown in Fig. 14. According to this figure, the addition of nanoparticles to water leads to an increase in the amount of oil extraction. The concentration of nanomaterials in water is considered to be the same, and the reason for the variability of oil extraction rates for injection of these nanofluids can be attributed to the dimension and density of solid particles of nanoparticles.

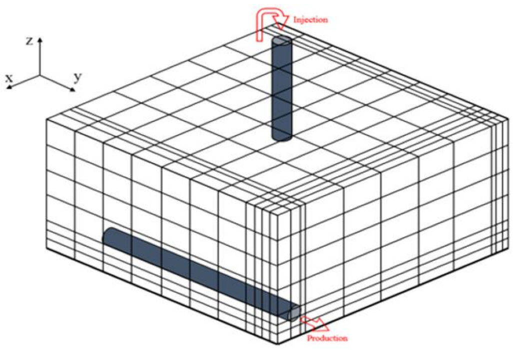

Fig. 13. 3D simulation with vertical injection well and horizontal extraction well

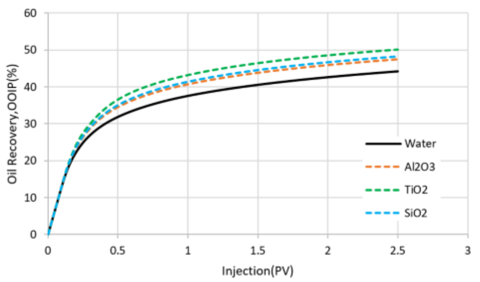

Fig. 14. Oil extraction rate for different nanofluids injection in 3D simulation

Table 8. Oil extraction rate for different nanofluids injection with 5% of nanoparticles in 3D simulation

Aqueous phase	Oil Recovery,OOIP(%)
Al_2O_3 Nanofluid	47.43
SiO_2 Nanofluid	48.31
TiO_2 Nanofluid	50.16
Water	44.24

6. Conclusions

In this study the impact of adding nanoparticles to the water (nanofluids) on oil extraction was investigated. Black oil model was used to simulate the oil and nanofluids displacement and extraction.

Concerning the effect of nanoparticles on interfacial tension between aqueous and oil phases and according to the concepts of nanofluid volume fraction and capillary pressure, it was shown that the addition of nanoparticles leads to an increase in oil extraction and the amount of interfacial tension was reduced accordingly. Using the numerical model, the range of variations of the variables used in the nanofluid volume fraction relation was determined in order to consider the effect of nanomaterials on interfacial tension.

According to the results, rising temperature will increase oil extraction. Nanofluid injection increased oil extraction, and the amount of oil extraction varies with the dimension and concentration of nanomaterials in the base solution (water). For example, by adding about 0.05 wt% (weight percent) of TiO_2 nanoparticles to the water, the amount of oil extraction was increased about 8% OOIP (Original Oil in Place) more than water injection process. Increasing the concentration of nanomaterials in water increases the amount of oil extraction. Of course, one should pay attention to the phenomenon of accumulation of nanoparticles at high concentrations. By adding about 0.01 wt% of Al_2O_3 nanoparticles to water, oil extraction was increased about 2% OOIP. The suction between nanofluid and oil is also reduced by adding nanomaterials.

In the end, it should be noted that, due to reservoir results deficiency, the results of this study did not compare with reservoir results, so it is better to control them with the real reservoirs results.

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