Research Article

Experimental Investigation of Chemical Flooding Using Nanoparticles and Polymer on Displacement of Crude Oil for Enhanced Oil Recovery

Imran Akbar , Hongtao Zhou , Wei Liu, Muhammad Usman Tahir, Asadullah Memon, Ubedullah Ansari, and Fengzhang Lv

School of Petroleum Engineering, China University of Petroleum, Huangdao District, Qingdao, Shandong 266580, China

Correspondence should be addressed to Imran Akbar; imran_sixes@yahoo.com and Hongtao Zhou; zhouht@upc.edu.cn

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In the petroleum industry, the researchers have developed a new technique called enhanced oil recovery to recover the remaining oil in reservoirs. Some reservoirs are very complex and require advanced enhanced oil recovery (EOR) techniques containing new materials and additives in order to produce maximum oil in economic and environmental friendly manners. In this work, the effects of nanosuspensions (KY-200) and polymer gel HPAM (854) on oil recovery and water cut were studied in the view of EOR techniques and their results were compared. The mechanism of nanosuspensions transportation through the sand pack was also discussed. The adopted methodology involved the preparation of gel, viscosity test, and core flooding experiments. The optimum concentration of nanosuspensions after viscosity tests was used for displacement experiments and 3 wt % concentration of nanosuspensions amplified the oil recovery. In addition, high concentration leads to more agglomeration; thus, high core plugging takes place and diverts the fluid flow towards unswept zones to push more oil to produce and decrease the water cut. Experimental results indicate that nanosuspensions have the ability to plug the thief zones of water channeling and can divert the fluid flow towards unswept zones to recover the remaining oil from the reservoir excessively rather than the normal polymer gel flooding. The injection pressure was observed higher during nanosuspension injection than polymer gel injection. The oil recovery was achieved by about 41.04% from nanosuspensions, that is, 14.09% higher than polymer gel. Further investigations are required in the field of nanoparticles applications in enhanced oil recovery to meet the world's energy demands.

1. Introduction

Conventional technologies cannot recover 2/3 of oil in place approximately. Thus, to recover a sizable portion of the remaining oil, there is a desperate need for enhanced oil recovery (EOR) [1]. In mature wells, due to the low rate of oil production and the high rate of water production, these wells are abandoned. In recent years, two new EOR technologies: preformed particle gel and low salinity water flooding, have been widely used in recent years to recover the residual oil [2]. Within the past two decades, the use of PPG has been increased to enhance the sweep efficiency of water flooding. PPG size ranges between a few nanometers to several millimeters [3]. PPGs can solve the inherent

problems of in situ gelation systems like dilution by water formation, chromatographic fractionation, and lack of gelation time control [4–6]. Initially described the effect of low salinity water flow (LSWF) on oil recovery. Since then, LSWF due to its ability to reduce the residual oil saturation in swept areas has been researched extensively [7].

In an attempt to increase hydrocarbon production and mitigate excess water production, chemically composed gels are widely used to preferentially seal fractures or higher permeability zones [8–13]. In situ gel systems were initially applied by industries in which 3D gel bulks were formed downhole by crosslinking of gelling solution. However, due to some inherent drawbacks of this technology such as possible damage to low permeability zones, selective

injectivity syneresis, dehydration, inadequate control of gelation time and dispersion, and dilution of gelant, this technology was quickly dropped [14–17].

Polymer flooding is a chemical EOR technique which uses polymer solutions to increase the viscosity of the injected water by decreasing the mobility ratio between the fluids, i.e., water and oil. A decrease of the oil/water mobility ratio improves the microscopic and volumetric sweep efficiencies of oil through controlling viscous fingering [18]. The polymer flooding is commonly used nowadays in three effective ways: (1) through the effects of polymers on fractional flow, (2) by decreasing the water/oil mobility ratio, and (3) by diverting injected water from zones that have been swept [19]. The hydrolyzed polyacrylamide (HPAM) is the most common polymer used for EOR. The polymer retention, hydrodynamic retention, adsorption phenomenon, mechanical entrapment, and inaccessible pore volume are the important parameters that influence the flow of polymers through porous media [20]. The retention delays the propagation of the polymer front through the reservoir, which retards the oil-bank displacement and recovery [21–23]. Among them, polymer retention is significant influence by the rate of polymer propagation during flooding, and reasons might be some factors that affect the polymer retention which includes polymer type, molecular weight, polymer concentration, rock surface, salinity, hydrolysis, permeability, wetting phase, and temperature [24].

Many research investigations in recent years have revealed that nanoparticles (NPs) offer a promising opportunity for researchers in the field of enhanced oil recovery (EOR) regarding silica-based nanoparticles. The oil displacement mechanism by nanoparticles treatment is still not studied effectively, although a new method to extract the remaining oil is adopted by nanotechnology in the last few decades [25, 26]. The use of nanoparticle in enhanced oil recovery technology is now a common option available across the market [27]. The application of nanoparticles has gained more importance because it has a direct impact on interfacial tension reduction, wettability modification, creating nanoemulsion, plugging of pore throat, swelling of high viscosity oil, and viscosity reduction or expansion depending on producing or injection fluid, respectively [28]. Often, the useful effect of nanosuspensions can also be achieved by dispersion of nanoparticle into the subsurface fluid which can lead to profitable results [29]. For instance, disjoining the pressure in the reservoir to feed enhanced oil recovery mechanism and lead to improvement of productivity from the reservoir by affecting other properties of reservoir fluid [30].

Additionally, the influence of nanoparticles on reservoir fluid and enhancing the oil recovery is important, but it also matters how these fluids flow in porous media. The answer is it depends on what concentration it is being injected [31]. However, some of the studies suggest that besides the ability of nanoparticles to pass easily through the pore throats in the porous media as they possess small sizes, they still can also remain dispersed within the solutions due to their active surface and high stability [32]. Furthermore, the applicable sizes of nanoparticles that are feasible to be transported

through the porous media are up to $200\text{ }\mu\text{m}$ which can be easily transported with high dispersion stability [33]. Indeed, it has also been observed that the adsorption efficiency and recovery performance of nanofluids with the use of fumed silica nanoparticles are better than with colloidal silica nanoparticles [34].

The nanoparticles have many advantages over micro/macroparticles in EOR, such as (a) large surface area, (b) smaller size, (c) strong tendency to make bonds with functional groups, and (d) easily move into tiny pores of rock [35]. In addition, it has a great ability to control mobility using nanoparticles solutions along with altering rock wettability and interfacial tension (IFT) to increase the oil recovery by decreasing the viscosity of displacing fluid. Few studies focused on the transport of nanoparticles in porous media and their application to EOR processes [36]. However, the importance of nanoparticles in the industry is increasing day by day due to their special properties in the last decade [27, 37–39]. Silicon dioxide (SiO_2) nanoparticles are very effective materials for increasing oil recovery in the coming era. Pore-scale displacement efficiency can be increased effectively by these particles [40, 41]. Literature has well documented the applications of NPs dealing with oil recovery improvement in water-wet sandstone [42, 43].

In this study, nanosuspensions are used as a diverting agent rather than the commercial preformed particles gel (PPG) and compared their results with polymer gel flooding. For polymer gel flooding, 0.6 PV slug was used in the sand pack model having a permeability of 1.71 Darcy, while for nanosuspensions (KY-200), 0.5 PV slug was used in the sand pack model having a permeability of 2.00 Darcy. Nanoparticles (KY-200) can enhance the viscosity of the suspensions. The aim of this research work is to investigate the transport behaviour of nanosuspensions (KY-200) and polymer gel HPAM (854) propagating through the sand pack and study the performance of nanosuspensions (KY-200) and polymer gel HPAM (854) in the enhanced oil recovery and to investigate how much effective nanosuspensions are regarding plugging and sweep efficiency as compared to polymer gel flooding at approximately same conditions, such as permeability, flow rate, and temperature to improve and enhance oil recovery. The method used to conduct this study was as follows (Figure 1): (a) nanosuspensions and polymer gel were prepared in water; (b) the viscosity of prepared nanosuspensions and polymer gel solutions was tested; (c) the core flooding experiments using sand pack equipment at 70°C were performed and the flow performance parameters were investigated; (d) the oil recovery and water cut curves of nanosuspensions and polymer gel were compared.

2. Materials and Methods

The materials, methods, and equipment used in this study are described as follows.

2.1. Materials. Polymer HPAM (854) molecular weight 3400×10^4 was purchased from Dongying Baomo Biology

FIGURE 1: Work flow chart of current study.

Chemical Co., Ltd (China). Nanoparticles (KY-200) manufactured by Shanghai Sinopharm Chemical Reagent Co., Ltd (China) were purchased; an oil sample from a Shengli oil field (China) having the viscosity of 68 mPa s and with density of 0.8300 g/cm³ having boiling point of 255~285°C was used; sand with size of 120 mesh and De ionized (DI) water was used.

2.2. Methods. Nanosuspensions were prepared in the water with different concentrations under the room temperature. The solution was mixed homogeneously with a mechanical stirrer (IKA stirring machine) at the speed of 400 rpm and aged for a few hours to remove the air bubbles. The apparent viscosities were measured by a DV3T rheometer while density was measured by hydrometers. The same process was repeated for polymer viscosity measurements.

2.2.1. Viscosity Measurements for Nanosuspensions (KY-200) and Polymer Gel (HPAM 854). The viscosities for nanosuspensions at different concentrations are measured, and it was found that after 2.5 wt % concentration nanosuspensions viscosity dramatically increased due to which at 3 wt % the viscosity of nanosuspensions was recorded to be 2727 mPa s. This concentration of nanosuspensions was chosen for displacement experiments. Viscosity values for nanosuspensions (KY-200) and polymer gel (HPAM 854) are shown in Tables 1 and 2, respectively.

After viscosity measurements, sand pack core flooding experiments were conducted. In flooding tests, polymer gel and nanosuspensions were injected in the form of slugs separately to study their impact on oil recovery.

2.2.2. Sand Pack Core Flooding Experiment. Using sand pack equipment, all the experiments were done at 70°C. The

schematic diagram illustrates the necessary components used for the experiments, i.e., four fluid injection cylinders, one sand pack tube, syringe pump, five pressure sensors (P_0 , P_1 , P_2 , P_3 and P_4), and effluent tube. The sand pack tube has a length of 60 cm and a diameter of 5 cm. The tube was filled with the sand size of mesh 120 to meet the required permeability. The sand pack tube had five pressure sensors fixed with it to record the pressure change across each pressure sensor. All the chemicals, nanosuspensions, polymer gel, water, and oil from the accumulators were injected into the sand pack model using a syringe pump. The produced oil and water were accumulated at effluent by using a test tube (Figure 2).

2.3. Experimental Procedure

2.3.1. Water Saturation

- (i) First of all, we measured the weight of the empty sand pack model (M_1), then measured the weight of the sand (sand + vessel) together with the vessel containing sand (M_2). Then we poured the sand (size 120 mesh) into the sand pack model. Then we weighted the remaining sand in the vessel and recorded the weight (M_3). Then we calculated M_4 by taking the difference of M_2 and (M_3). This M_4 is actually the amount of sand that we poured into the sand pack tube.

$$M_4 = M_2 - M_3. \quad (1)$$

- (ii) Before starting water saturation, we adjusted the flow rate at 2 ml/min and also noted the initial pressure, $P_{0_{\text{initial}}}$ and then started water saturation. When water saturation completed, we noted the final pressure, $P_{0_{\text{final}}}$ and calculated ΔP :

TABLE 1: Nanoparticle (KY-200) viscosity measurements.

Concentration (%)	Viscosity (MPa s)	Spindle	Torque (%)	Speed (rpm)	Temperature T (°C)	Shear stress (dyne/cm ²)	Shear rate (1/s)
0.5	7.44	SC4-31 (31)	6.2	250	25.7	6.32	85
1.0	14.04	SC4-31 (31)	11.7	250	25.6	11.93	85
1.5	39.96	SC4-31 (31)	33.3	250	25.4	33.97	85
2.0	92.64	SC4-31 (31)	77.2	250	25.3	78.74	85
2.5	464.4	SC4-31 (31)	77.4	50	25.1	78.95	17
3.0	2727	SC4-31 (31)	90.9	10	25.2	92.72	3.4

TABLE 2: Polymer gel (HPAM 854) viscosity measurements.

Polymer	Concentration (wt %)	Viscosity (MPa s)	Spindle	Torque (%)	Speed (rpm)	Temperature T (°C)
HPAM 854	0.5	10.25	SC4-31 (31)	4.1	120	25

FIGURE 2: Sand pack schematic diagram.

$$\Delta P = P_{0_{\text{final}}} - P_{0_{\text{initial}}} \quad (2)$$

- (iii) After water saturation, again we measured the weight of the sand pack model (M_5) and calculated the water volume (Mw/ρ).

$$Mw = M_5 - M_4 - M_1. \quad (3)$$

- (iv) Then we calculated the permeability by using Darcy's Law.

$$K = \frac{Q\mu L}{A\Delta P}, \quad (4)$$

where K is permeability in Darcy, Q is flow rate in ml/min, L (cm) is the length of the sand pack tube, μ is the viscosity of water, A is the cross-sectional area (cm²) of the tube, and ΔP (atmosphere) is the pressure difference.

2.3.2. Oil Saturation

- (i) We started the oil saturation at the same flow rate as that of water saturation. When the oil drops came out in the effluent tube, and no more water was produced in the outlet, then we stopped oil saturation.

2.3.3. First Water Flooding

- (i) When oil saturation was achieved, then first water flooding was started at an injection rate of 2 ml/min to recover the primary oil recovery conditions. The water injection was continued into the sand packs until the water cut reached more than 95%, and the water injection pressure became stable.

2.3.4. Gel Slug Injection

- (i) Polymer gel slug and nanosuspensions slugs were injected into the sand pack at the injection rate of 2 ml/min after the first water flooding processes were completed. Total 0.5 PV slug was injected in the nanosuspensions case and 0.6 PV slug was injected in polymer gel injection case at the same injection rate of 2 ml/min to study the effect of gel resistance to water flow.

2.3.5. Second Water Flooding

- (i) As the gel injection process was finished, second water flooding was carried out with the same flow rate as that of first water flooding to study the performance of nanosuspensions and polymer gel to displace the remaining oil and water shutoff.

3. Results and Discussion

3.1. First Water Flooding Injection Pressure. After attaining the oil saturation conditions, first water flooding was carried out to displace oil. The pressure behaviour during the first water flooding is shown in the form of pressure curves in (Figure 3), and primary oil recovery was calculated, as shown in Table 3.

3.2. Gel Injection Pressure Performance. Polymer gel and nanosuspensions (KY-200), when fully dissolved in water during stirring, were injected into low permeability sand pack models to test their behaviour. For nanosuspension 0.5 PV slug was injected and for polymer gel, 0.6 PV slug was injected, as shown in Table 3.

An obvious difference in injection pressure was observed for nanosuspensions injection as compared to that of polymer gel injection. It was observed that when nanosuspensions of (KY-200) of 0.5 PV slug were injected, the injection pressure increased up to 1.813 MPa which was higher than the pressure of polymer gel injection which was 0.269 MPa at pressure sensors P_0 , respectively (Figure 4). It was observed from Figure 4 that at point P_0 , which is outside the core (Figure 2), pressure increased gradually and fluctuated during the injection process, but this increase in pressure is much higher in nanosuspensions injection case as compared to polymer gel injection. The results also indicated that the pressure changes took place at all the sections (P_0 , P_1 , P_2 , P_3 and P_4), which shows that the nanosuspensions propagated deeply across the core. Moreover, the high concentration leads to more agglomeration; thus, high core plugging takes place and diverts the fluid flow towards unswept zones to push more oil to produce and decrease the water cut. Since the nanosuspension was injected, the injection pressure increment at pressure sensor P_0 was much higher than at other pressure sensors, which implies that most of the gel particles had been caught in the front part of the core by retention or trap mechanism. The nanosuspensions particle retention is defined as the number of gel particles that captured, remained, or trapped in the pore throat at the injection inlet side and did not propagate deep into sand pack core. When the slug entered the core, the injection pressure was recorded at P_1 for both polymer gel and nanosuspension injection, which was remarkably reduced as compared to the pressure recorded at pressure sensor P_0 for both polymer gel and nanosuspension injection (Figure 4). This happened due to the propagation of the slug across the core deeply. But it was observed that at pressure sensors P_1 , P_2 , P_3 , and P_4 , for nanosuspensions the injection pressure is still higher as compared to the polymer gel injection pressure. The reason for this was that the core plugging occurred because nanoparticles blocked the seepage channels and nanoparticles were trapped in pore throats causing increase in pressure [44].

3.3. Second Water Flooding Injection Pressure Performance for Nanosuspensions and Polymer Gel. After the placement of polymer gel and nanosuspensions, secondary water

flooding was carried out. A big difference in injection pressures was observed. In the case of nanosuspensions, the injection pressure at each pressure sensor (P_0 , P_1 , P_2 , P_3 , and P_4) was much higher than the polymer gel's pressure curves. This rise in pressure in the case of nanosuspensions flooding is due to the high viscosity of nanosuspensions and also due to the trap mechanism of nanoparticles. As the nanosuspensions were prepared in the water, the nanoparticles have the ability to swell by absorbing water and increasing the particle size. Due to an increase in size these particles were trapped in pore throats causing an increase in pressure [45].

From the results of secondary water flooding, it was found that the nanosuspensions prepared in water did a very good job of blocking the thief zones by trapping into pores as compared to polymer gel. For polymer flooding during the 1st and 2nd water flooding maximum pressure increase at P_0 was 0.311 MPa and 0.180 MPa, respectively, while for nanosuspensions flooding during 1st and 2nd water flooding maximum pressure increase at P_0 was 4.030 MPa and 1.287 MPa, respectively (Figures 3 and 5). This is solid evidence for the trapping of nanoparticles into pores. During the second water flooding, most of the nanoparticles were flushed out from the outlet due to which pressure drop occurred during 2nd water flooding after nanosuspensions injection, but from 2nd water flooding results, it is very clear that few nanoparticles retained into pore throats and did not flush out completely, and these particles still created resistance to water flow [44]. Due to this reason in nanosuspensions, flooding pressure was much higher than the polymer gel flooding during 2nd phase of water flooding.

3.4. Enhanced Oil Recovery by Polymer Gel and Nanosuspension Injection in Sand Pack Model. The cumulative oil recoveries of polymer gel and nanosuspensions in sand pack displacement tests are plotted in Figure 6. In Figure 6, the upper curve, lower curve, and middle curve are representing nanosuspension's oil recovery, polymer gel's oil recovery, and average oil recovery, respectively. The cumulative oil recovery comprises all three displacement stages: first water flooding, slug injection, and second water flooding. During the first water flooding stage, oil recovery of high permeability sand pack was higher than those of the low permeability sand pack. This was due to differences in permeability ratio as shown in Table 3. The incremental oil recoveries for polymer gel injection and nanosuspensions injection are 26.95% and 41.04%, respectively (Figure 7). From these results, it is very clear that nanosuspensions injection effectively increased the sweep efficiency as compared to polymer gel injection by plugging the thief zones of the sand pack and diverted the fluid flow towards unswept zones to recover more oil. As a whole, it can be seen from Figure 7 that the oil left behind in the reservoir after polymer gel injection and nanosuspensions injection is 32.21% and 12.21%, respectively. These results indicate that nanosuspensions had increased the sweep efficiency of injected fluid and also diverted the fluid flow towards low permeability zones by plugging the thief zones very effectively and

FIGURE 3: First water flooding pressure curves before the placement of polymer gel and nanosuspensions.

TABLE 3: Results of polymer gels and nanosuspensions injections.

Permeability (Darcy)	Chemical solution	Slug (PV)	Concentration wt (%)	Primary oil recovery (%)	Secondary oil recovery (%)	Total oil recovery (%)	Remaining oil (%)
1.71	Polymer gel HPAM (854)	0.6	0.5	40.84	26.95	67.79	32.21
2.00	Nanosuspensions (KY-200)	0.5	3	46.75	41.04	87.79	12.21

FIGURE 4: Polymer gel and nanosuspension injection pressure vs. PV.

FIGURE 5: Second water flooding pressure curves of polymer gel and nanosuspensions.

FIGURE 6: Cumulative oil recovery of polymer gel and nanosuspensions flooding.

recovered more residual oil in the low permeability zones. The sweep efficiency effect was much improved by nanosuspensions in more heterogeneous reservoirs. This is because of the dual property of nanosuspensions to increase the viscosity of the water phase and divert the fluid flow towards unswept low permeability zones [46].

3.5. Water Cut Curves for Polymer Gels and Nanosuspensions.

The experimental results for polymer gel flooding and nanosuspensions flooding are expressed in Figures 6 and 8.

From the data, water cut during nanosuspensions flooding was smaller than that of polymer gel flooding during total 3.2 injected pore volume (PV) of fluid injection, which is clear indication that water mobility is effectively reduced by nanosuspensions injection and may extend the duration of water flooding. It was also observed that from Figure 8, as slug injection starts in both cases, water cut starts to decrease, in the case of polymer gel slug, water cut fell down very sharply, but in the same way, it increases within no time, while on the other hand in the case of nanosuspensions slug injection, water cut starts to decrease gradually and it

FIGURE 7: Cumulative performance of polymer gel and nanosuspensions flooding, (a) polymer gel injection, and (b) nanosuspensions injection.

FIGURE 8: Water cut % vs. injected pore volume, PV.

also increases slowly. Due to this reason, the water flooding was enhanced by the injection of nanosuspensions injection which in turn enhances oil recovery.

4. Conclusion

The following conclusions are drawn from this experimental study:

- (1) Nanosuspension particles transported deeply into the sand pack core. However, in the case of nanosuspension, high injection pressure was measured in the front part of the sand pack core as a result of gel particle retention as compared to polymer gel injection.
- (2) This incremental pressure in case of nanosuspension flooding is because of high viscosity of nanoparticles; therefore the nanosuspensions are supposed to be prepared in the water. Besides, the nanosuspension has the ability to swell by absorption of water and to increase the particle size,

whereas, with the size increase, these particles tend to trap in pore throats, causing pressure rise in the system.

- (3) As the nanoparticles propagated deeply through sand pack core. As a result, these particles blocked the seepage channels within the core and diverted the fluid flow towards unswept area to displace the oil due to which oil recovery was remarkably high for nanosuspensions injection as compared to polymer gel injection. Further, water mobility was effectively reduced, and sweep efficiency was increased by nanosuspensions injection.
- (4) More than 3 PV of brine injection was carried out; water cut % was remarkably reduced from the effluent due to plugging of the thief zones by nanosuspension particles and increased the oil recovery %.

Data Availability

The data used to support the findings of this study are available from the corresponding author upon request.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

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