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Research article

Laboratory study of polymer injection into heavy oil unconventional reservoirs to enhance oil recovery and determination of optimal injection concentration

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Abstract: Polymers have been used for many years to control the mobility of injected water and increase the rate of oil extraction from unconventional reservoirs. Polymer flossing improves the volume of the broom, reduces the finger effect, creates channels, and delays water breakage. The combination of these processes has the potential to increase oil production and reduce production costs. To carry out this process, various polymers are used alone or in combination with surfactants and alkalis. In this study, a new type of polymer called FLOPPAM 3630 has been used to investigate the overload of very heavy oil reservoirs. For this purpose, six polymer solutions with different concentrations were made, and stability tests on shear rate, time, and temperature were performed. The polymer's stability results indicate that it is stable under other shear rate, temperature, and time passage conditions. As a result, this polymer is a suitable candidate for conducting silicification tests in reservoir temperature conditions. Then three more suitable polymer solutions were selected, and the polymer was polished. The results showed that the solution with a concentration of 1000 ppm has the best yield of about 40%. The reason for the good efficiency of this concentration is that the surface and vertical sweepers are higher than the other concentrations. Also, the difference in efficiency between less than 1000 and 2000 ppm is greater because it is more economical, and its injectability is easier to use with less concentration. Furthermore, the oil efficiency of this type of polymer in sandblasting is higher than that of other polymers tested under these conditions, making its use more economical.

Keywords: injection; polymer; fluidizing; viscosity; shear stress; unconventional reservoir

1. Introduction

Polymers have been used in recent decades to control the mobility of injected water and increase the rate of oil extraction from unconventional reservoirs. [1–6]. Unconventional reservoirs, which differ significantly from conventional reservoirs, have received increased attention in recent years and are causing a significant revolution in the oil and gas industry. These reservoirs are of the source rock type, which contains rich organic material and has reached thermal maturity without migration. Horizontal drilling and multi-stage hydraulic fracturing are used to develop these fastest-growing hydrocarbon resources [7,8].

Many extraction methods have been developed in recent decades to increase oil recovery, including chemical injection, carbon dioxide injection, nanoparticle technology, and thermal recovery. The polymer flossing process is one of the common types of chemical extraction methods. This operation is an effective method for controlling the oil recovery process of the highly dynamic and heterogeneous reservoirs [9]. This improves the sweeping drive and allows the oil to move more quickly in the swept area [2]. After chemical and/or water flooding, there is always some oil left in the reservoir that can no longer be produced by water injection. There are two reasons for oil remaining in a reservoir. Oil is trapped in the reservoir by capillary forces (residual oil) or remains behind the injected waterfront [10].

In order to drive this oil, the surface tension between water and oil must be reduced. This is done by adding the surfactant to the water. Some researchers believe that polymers have the ability to reduce residual oil due to their elastic properties [11]. More details in this regard are given in the following sections [10,12]. However, even assuming that the polymer lubrication is not capable of reducing residual oil, this method is a very effective and economical way to achieve a shortage of oil [13].

According to other researchers, the reason for the higher recovery in the polymer flossing process compared to the flossing area is due to the effect of polymer 1 on the polymer to water ratio on the partial flow of the partial flow to the partial flow. Kumar et al, have performed various experiments to investigate the undesirable dynamic ratios. They concluded that the finger effect strongly influences the displacement of oil. They suggested that relative dynamics improvements (for example, by adding polymer) resulted in improved reservoir sweeping and recovery [14].

Sweeping, along with the dynamic ratio, is a critical evaluation criterion for a watering project and rock properties [15–18]. The total drive coefficient, E, is defined as the fraction of the total oil at the initial of the polishing process that this process can displace.

Many researchers have investigated the polymer using different methods, among these methods, the following can be mentioned: surfactant-polymer [19], chemical EOR for heavy oil [20], Chemical EOR [21]. And some reserchers work on the tight and unconventional reservoir that includes: EOR performance and CO2 storage in tight reservoir [22], CO2 EOR performance evaluation in tight reservoir [23], unconventional hydrocarbon resources [24].

Many factors influence chemical processes, the most important of which are reservoir temperature, salinity, and nucleus content. In the operation of permeable polymer polishing, another important factor is considered (viscous properties) [25–28]. A suitable polymer must have no oxygen in its structure (carbon chain), be thermally stable, and have viscous properties for good chemical stability and relative permeability [29]. Laboratory studies in this field were started in 1977 by Knight and Rudy. In their experiments, they used a polymer solution with different concentrations. They examined two samples of heavy oil. The dynamic ratio was initially reported to be around 30 for water and oil, while after the polymer injection, this amount was 0.34 and 3.2, respectively. The oil recovery results also showed an increase in recovery between 19 and 31% [30]. For example, Vasmus et al, injected polymer at a concentration of 1500 ppm into three oil samples with different viscosities, and observed an average recovery increase of 20% [31].

Another sandbox study with HPAM polymer on heavy oil shows an increase in recovery of 4 to 20%. Several researchers have also investigated the injection of HPAM polymer into cores saturated with heavy oil [12,13,32]. Also, the relative permeability of water and oil changed after the injection of the polymer, and in some cases, the high viscosity of the polymer caused injection molding problems and forced coercion to inject the polymer [33].

Other polymers other than HPAM are also common for heavy oil extraction. For example, blasting experiments were performed by researchers and they indicated good piston-to-piston oil displacement, with a wide range of concentrations and no finger formation [34–36]. The viscosity of the polymer solution, as well as the adsorption of the polymer on the surface, are reduced by adding nanoparticles to the polymer solution [37].

The three effective parameters in increasing polymer removal are viscosity, polymer concentration, and permeability. Considering the work done over the past years, it can be found that the behavior of polymers on very heavy sediments has also deteriorated [14,38–42]. For example, choosing the right type of polymer for this type of reservoir and choosing the right concentration of polymer for injection are both ambiguous. Furthermore, because polymer injection is expensive, increasing final recovery as much as possible will result in greater economic savings in such projects [43].

For this reason, in this study, the feasibility of injecting a new type of polymer into this type of reservoir has been investigated by conducting a series of polymers on the surface of the tube. The polymer used is very stable in terms of temperature, salinity, and shear stress, and its viscosity is quite high. For this reason, this polymer was selected for testing and has been tested in various experiments. In addition, the increase in the final oil recovery for this polymer has been calculated, and the economics of this method will be investigated. The workflow diagram for material methods shows in Figure 1.

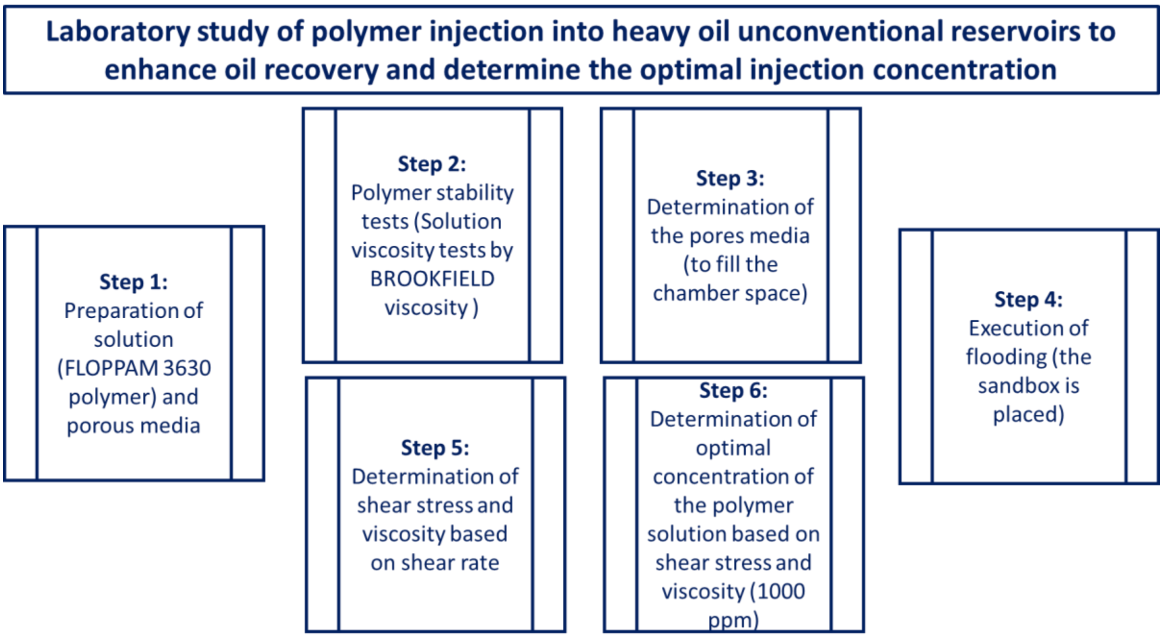

Figure 1. The polymer injection workflow diagram in laboratory testing.

2. Materials and methods

2.1. Material

For the experiments, the French company SNF's FLOPPAM 3630 polymer was used. The water used in the experiments is deionized distilled water. A German company manufactures all of the salts used. The toluene and alcohol used to wash and clean the porous medium were also made in Germany and had a purity of 99%. The sand used to make the porous medium is 99% silica. The used oil for conducting flooding experiments is heavy oil, coming from one of the reservoirs in southwestern Iran with an environmental viscosity of 2100 cp and an API grade of 20. Table 1, shows the properties of pores media and fluid used in this study.

Table 1. Properties of core and fluid used in this study.

Properties	Value
Polymer type	FLOPPAM 3630
Molecular weight (10^6 g/mol)	18
Polymer concentration (mg/L)	500–4000
Core type	Silica
L × H (cm)	3.675 × 12
Porosity (%)	40%
Permeability (D)	3

2.2. Preparation of solutions and porous media

In order to prepare the polymer solution, the polymer weight proportionally to the intended concentration is slowly added to 100 cc of distilled water. The solution was placed on the magnetic agitator, and after the polymer was completely added, it was left on the agitator for 24 hours. The reason for this is to achieve physical and chemical homogeneity in all parts of the polymer solution. The porous medium was indeed salinity saturated at around 200,000 ppm. The percentage composition of the salts used in the constructor is the actual composition of the constructor and is given in Table 2. Due to the formation of some sediment after filtration, it was filtered, and the filtered water without sediment was used as a constructor in all experiments. The conductivity of the composite water after the filter is 265600 cm/μs, which is due to the existing relationships for conversion to a solid concentration of solid (Tpd) of 170000 (ppm).

Table 2. The composition of the formulation water percentage used in the experiments.

Type of salt	Concentration (ppm)
NaCl	140314
CaCO3	1628
MgCl2	2854
CaCl2	40286
Na2 SO4	2586
NaHCO3	2014
TDS (ppm)	189682
Ionic strength (mol/L)	3.6747

3. Experimental procedures

3.1. Polymer stability tests

As mentioned, FLOPPAM 3630 polymer was used for the experiments. In order to ensure the possibility of conducting watering tests, it is necessary to perform a series of stability tests in different conditions. To conduct stability tests, 6 concentrations of polymer were selected according to Table 2. The reason for selecting these concentrations is the extensive study of concentrations to evaluate the feasibility of their use in the polymer injection process. Also, due to the difficulty in measuring the properties and lack of injectability of concentrations above 4000 ppm, only concentrations above this value have been tested. Solution viscosity tests were performed by the BROOKFIELD viscosity measuring device. In the first part of the stability tests, the amount of shear stress and viscosity changes in 15 different shear rates were measured. In the second part, the polymer solution stability with both time and salinity is fixed at a shear rate, and in the final part, the effect of heat transfer on the surface is observed.

3.2. Porous media

To fill the chamber space, sand grains of silica with a purity of 99% with a particle size of between 0.1 and 0.3 mm have been used. Water absorption by these particles was very low. The average permeability and porosity of the porous medium were measured as 30 mD and 40%, respectively. Figures 2 and 3 show the sandbox used in the experiments. The sandbox body is made of stainless steel to withstand high temperatures. The dimensions of this chamber are 675/3 cm 675 cm. The diffuser was installed in both heads of this chamber. On top of them, a steel mesh with a diameter of

180 was placed. To prevent wall impact, rings with a distance of 1 mm were machined perpendicular to the inner wall of the chamber on the inner wall of the chamber. This prevents the liquid from slipping off the wall to an adequate extent. After preparation of the porous medium, its permeability was measured, fixed with stabilized pressure drop values and plotted injection flow rate and right line slope by drawing a graph using the D-ratio for absolute current.

Figure 2. View of the sandbox lids.

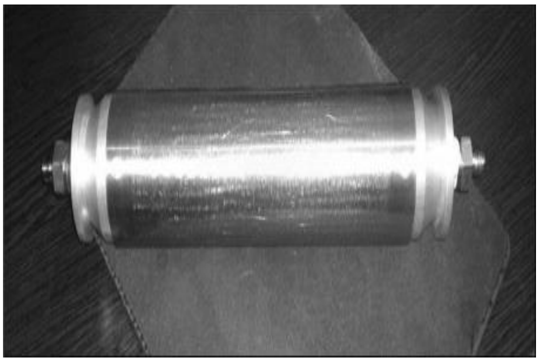

Figure 3. Sand chamber made of steel.

3.3. Execution of flooding

The sandbox is placed inside the 40° watering machine, the machine is turned on and the temperature is set to C degree. For a period of 3 h, the device was monitored at the desired temperature until the liquids reached equilibrium temperature. The injection rate was considered to be 0.5 min/cc in all cases. First, the chamber was saturated with water and its absolute permeability was measured. The oil is then injected into the chamber and the outlet water is carefully calculated. As long as the oil injection continues, it will be possible to ensure that there is no outflow of water. For some reason, after observing 10 cc of heavy oil, ordinary oil is no longer discharged into the water outlet. After saturation of the oil chamber, flooding took place. Injection of water into the chamber continues until the outlet oil is less than 5%. An empty volume of water is injected into the chamber. After the water flooding was completed, an empty volume of the polymer solution was continuously injected. Due to the heavy oil and the uncertainty of the exact amount of water and oil outlet, the outlet fluid is separated into containers of 10 cc, and their lids are closed and placed in a furnace at a temperature of 2° C for two days.

Following the abdomen of the density of water and water, it is completely beneficial to the water, and in the upper part of the abdomen, it can be included in the water and can be read from the water. In each experiment, an average of 3 empty volumes of water and polymer were injected into the porous medium. Table 3 below lists the conditions governing sealing tests. The only variable in this section was the concentration of the injected polymer. It should be noted that all polymers are prepared in distilled water.

Table 3. Properties of fluids and porous media used for flooding.

Test number	Polymer concentration	Permeability	oil saturation	Porosity
Units	PPM	D	%	%
1	500	3.2	82.5	39.3
2	1000	2.8	82	39.3
3	2000	3.1	83.1	38.5

4. Results and discussion

4.1. Polymer stability tests

For this part of the tests, FLOPPAM polymer was used for the purpose of multiplication and feasibility testing, and a complete series of stability tests have been performed to date. In the first part of the experiments, 6 solutions of 4000, 3000, 2000, 1500, 1000, 500 concentrations with 3000 and 4000 ppm polymer were prepared. The stability test of polymer with different concentrations was performed at 15 different shear rates. The shear stress and viscosity results are given by changing the shear rate in Figures 4 and 5. Due to the shapes, the polymer used at the shear rates exhibits different Newtonian behavior similar to other polymers with increasing shear rate stress.

Also, the viscosity reduction process is quite similar for all concentrations and follows the same relationship. This behavior is a positive sign that FLOPPAM polymer injection into the reservoir is useful as a high oil efficiency product. The viscosity of the polymer solution is determined by the shear rate of fluid movement in the reservoir. The linear velocity of oil movement in the reservoir, as per standard, is approximately one foot per day.

Now, if the injection rate of the polymer is assumed to be 100 times the velocity of the oil in the reservoir, which is not the case (we reach a rotational velocity of about 0.14 rpm), and we want it to reach pp 1000 at the viscous polymer.

As a result of the experiments, the phenomenon of fingering will not occur, and complete control of water mobility has occurred, allowing us to produce remaining oil.

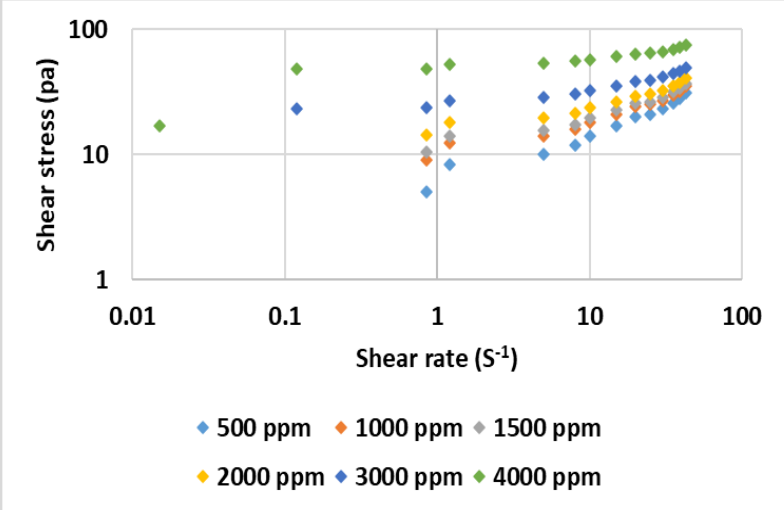

Figure 4. Shear stress - Shear rate of polymer solutions.

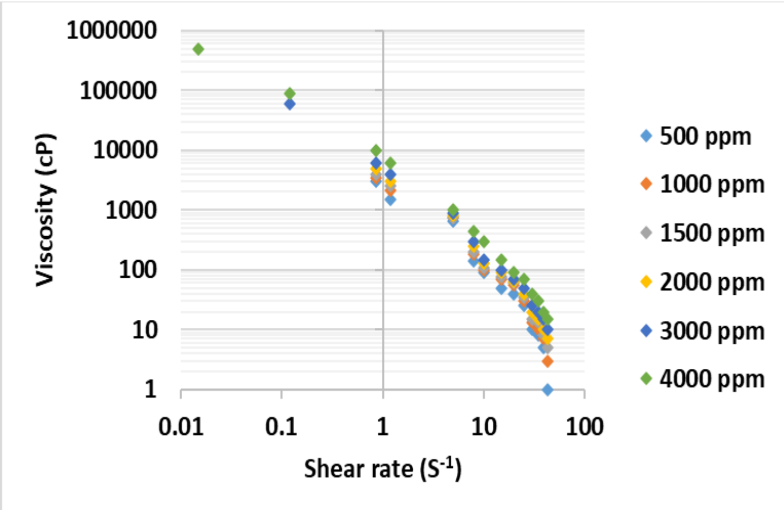

Figure 5. Viscosity - Shear rate of polymer solutions.

In the second part of the stability experiments, the effect of time on the shear stress changes of polymer solutions at a constant shear rate was measured. The results, according to Figure 6, showed that the shear stress remained constant and, consequently, the viscosity of the solutions remained the same after one week. As a result of these findings, the polymer used retained its rheological properties after one week and remained relatively stable. This test, however, was conducted at room temperature, and polymer chains may become broken and unstable at higher temperatures. Therefore, the stability of this polymer at different temperatures has been investigated, the results of which will be continued. Two experiments were performed to investigate the effect of water salinity on the stability of the polymer. First, a solution of 1000 ppm in distilled water was made, and then the same solution was made in water. Then, the viscosity of these two solutions was measured at a constant shear rate of 6.12 s. The two solutions viscosity results for distilled water and reconstituted water showed 346.9 and 303.8 cP, respectively. All polymers experience a decrease in viscosity as salinity increases, but this polymer does not experience a significant decrease. It can also be claimed that this polymer has been stable in high salinity, has not been broken, and has retained its properties. The proximity of the water to the exterior reduces the exposure of this location of the Vermeulen research on the effects of water on the effect of polymers. In the final part of the polymer stability tests, the effect of temperature changes on the rheological properties of the polymer used was investigated. Thus, the 70 °C viscosity of the 6 solutions at 3 polymer temperatures of 20, 50 and 70 °C was measured and the results are shown in Figure 7. As shown in Figure 7, this type of polymer has relatively good stability in comparison to 70° C, though this decreases slightly with increasing temperature due to the viscosity of the polymer solution. This behavior indicates that polymer chains do not break under temperature, which justifies injecting the same behavior for polymer lubrication tests.

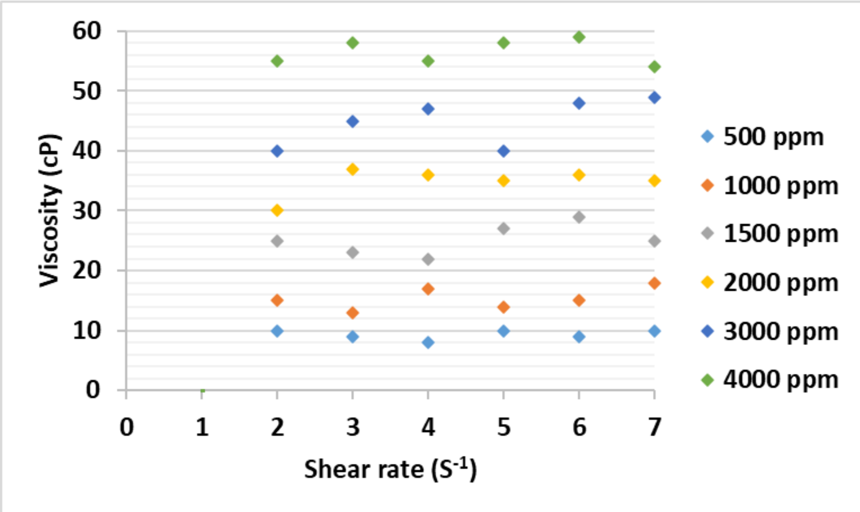

Figure 6. Shear stress changes of polymer solutions over time.

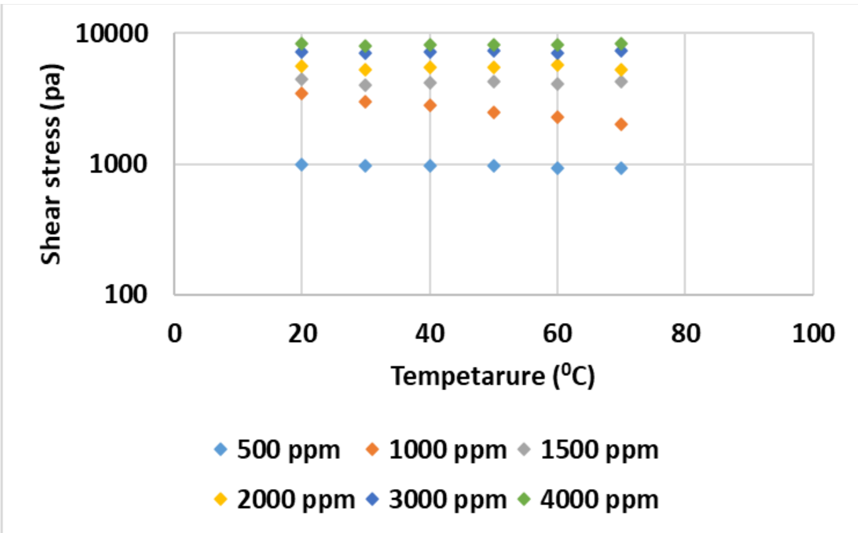

Figure 7. Changes in the viscosity of polymer solutions with temperature changes.

4.2. Fluid testing

After a complete series of stability tests, it was concluded that it is not possible to use high concentrations of this type of polymer for injection into the reservoir. The reason for the high cost of higher concentrations of this type of polymer is that it is very difficult and even impossible to inject it with a pump.

However, for the feasibility of this method, three solutions with concentrations lower than 500, 1000, and 2000 ppm can be polished with polymer fibrillation and increase the amount of carbon monoxide caused by them. The oil used for conducting sealing tests has a viscosity of 2100 cP and an API grade of 20. The results of watering in these three concentrations are shown in Figure 8.

The first part of each of the three samples (approximately 1.5 volumes of empty water injection volume) is related to the increase in water-glass recovery. The rate of this recovery is between 30% and 40% of the oil in the initial stage, and after that, by continuing to inject water alone, it is seen that water does not come out, and no oil is produced. After the secondary recovery phase, the tertiary phase or polymer injection begins. As can be seen from Figure 8, the final recovery rate increased with the increasing concentration of the injected polymer. In fact, with increasing concentration, the viscosity increases and the polymer's ability to vacuum the porous medium is increased. For this reason, less residual oil is left behind on the polymer residue front and, as a result, the final oil recovery rate shows a considerable increase.

As can be seen from Figure 9, the increase in the recovery rate relative to water polymerization for the polymer at concentrations of 500, 1000, and 2000 ppm is 29%, 40%, and 43%, respectively. Higher recovery can be achieved by increasing the concentration of the polymer solution, but the problem is that the solution is injectable. In fact, a pump with very high injection potential is either unavailable or its cost is so high that it is not economically viable. The important point in these experiments is that the oil is heavy. With the presence of heavy oil, we have witnessed that the polymer used was able to sweep the oil efficiently, releasing a high percentage of the oil. In fact, not every polymer is capable of producing such remaining oil and these results indicate the applicability of this polymer should not be used in some cases. In continuation of the above explanation, the rate of increase in oil recovery in these three experiments is shown in Figure 8. Due to the aforementioned limitations and the excellent results of the 1000 ppm solution, the optimal concentration of the polymer solution for injection into the oil reservoir is the 1000 ppm concentration.

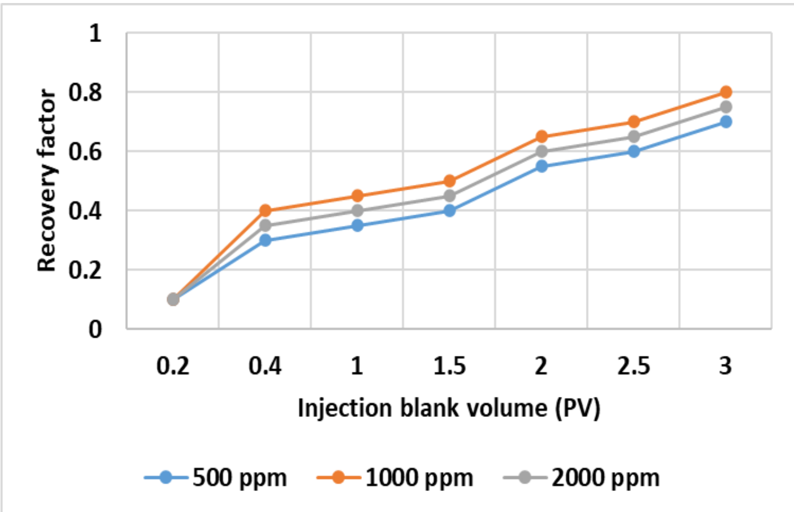

Figure 8. Results of polymer injection experiments with different concentrations.

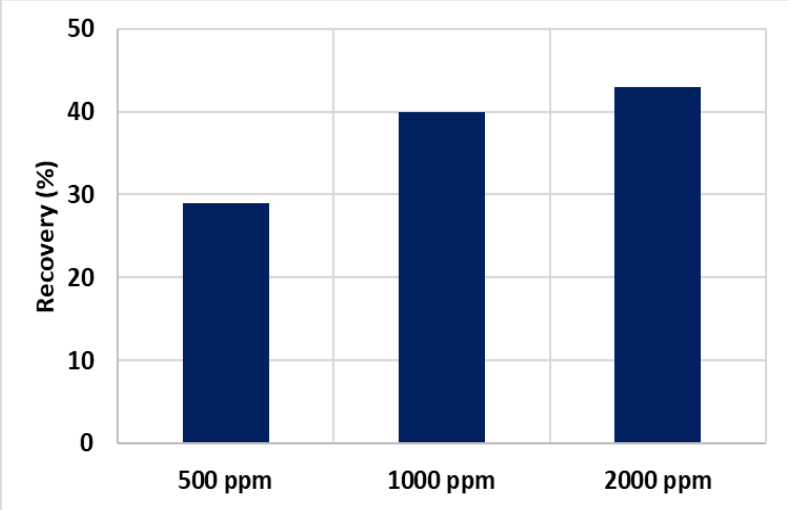

Figure 9. Increase recovery factor due to injection of different concentrations of polymer.

5. Conclusions and recommendations

Based on the results of the performed experiments, it can be concluded that the stability of this type of polymer with changes in shear rate and time is more suitable for the polymer. Also, with increasing temperature, its viscosity does not change, and this feature will make it possible to use it in oil reservoirs that have different temperatures. Stress can also affect the stability or non-stability of the polymer, but its effect is very small in comparison to the other factors studied. The results of polishing show that the efficiency of this type of polymer is very good. In such a way, up to about 45% of the oil yield has occurred at some point due to the polymerization of the polymer. This efficiency is also used for very heavy oil, indicating the high performance of this type of polymer on heavy oils. The reason for the good performance of this type of polymer in the first place is its stability in different test conditions, as well as its ability to increase the viscosity more than other polymers. As a result, the finger phenomenon is eliminated and the amount of surface scouring of the polymer increases significantly. The polymer flossing results also show a concentration of 1000 ppm as the optimum concentration for injection into the reservoir. Economic comparisons show that this type of polymer yields higher yields than other polymers, resulting in more cost-effective production. Because the cost of purchasing polymer is a significant part of the cost of polymer injection operations. The increase in efficiency caused by using a lower concentration of polymer is the reason for using this type of polymer more economically. The viscosity of this polymer is higher in constant concentration compared to other polymers. Also, its performance is better in high temperature and salinity conditions, and its stability is acceptable. The polishing results of this polymer also showed that, compared to other works, it was able to achieve significant efficiency at a lower concentration and showed very good performance. As a result, this polymer is an excellent candidate for injection operations to improve oil recovery and is highly recommended for heavy oil reservoirs.

Data availability

Since the data used in the study are confidential, the authors do not have permission to share data.

Conflict of interest

The authors declare no conflict of interest.

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