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An improved correlation to investigate the effect of chemical additives on the mobility ratio of two-phase flow

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ABSTRACT

World energy demand continues to increase, as they evolve, and developing countries consume more energy to keep their rising factories going. A significant portion of the energy demand is supplied by fossil fuels, especially crude oil. Therefore, in order to satisfy the world's energy demand, oil reserves and oil production capability must be increased. This objective can be accomplished by enhancing the recovery efficiency of the existing generating or mature reservoirs through the application of increased oil recovery. The injection of fluids into oil reservoirs has the purpose of supplementing natural energy and is used in some cases to engage with the reservoir's rock/oil system, standardizing for oil recovery, such as lower interfacial stress, oil swelling, reduction of oil viscosity and adjustment of wettability.

Subject to comprehensive studies, in heavy oil reservoirs, polymer injection is not dependent on large technological instruments, requiring only mixing and filtration equipment, except for those already used for traditional water injections. In addition, polymers are non-toxic and corrosive and can produce desirable mobility ratios. The implementation of this approach decreases the output ratio of water to oil, thus decreasing operating.

In the present work, thirty-five data points from experimental work had been investigated to develop a new correlation for viscosity of water by using the suitable program. It was analyzed the influence of the polymer additives on the mobility ratio, temperature and concentration effect on mobility ratio, and viscosity altering with the additives have been investigated. The results of the correlation showed acceptable agreement between the observed and predicted viscosity values. As a contrast to the polymer additives approach, pure water was proposed.

Keywords: Enhanced Oil Recovery, Fluid Flow, Mobility Ratio, Polymer Additives, Production

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1. Introduction

In the early 1960s, in secondary or tertiary oil recovery tasks, a technique using polymer solutions to improve oil recovery was first implemented. Since this form of chemical Improved Oil Recovery (IOR) has achieved widespread commercial implementation, it has been possible to find huge publications for various reservoir cases [1]. The primary aim of EOR processes is to increase the overall efficiency of oil displacement, which is a microscopic displacement efficiency variable. Microscopic performance refers to the pore-scale displacement or mobilization of oil. The strength of the displacing fluid in moving oil at certain positions in the rock is evaluated, according to microscopic efficiency [2].

In any enhanced oil recovery process, mobility control is one of the fundamental concepts. It can be accomplished by adding chemicals to adjust the displacement of fluid viscosity or to preferentially minimize particular fluid relative permeability. The widely used mobility control agent is a polymer so the apparent viscosity of the injected fluid can be greatly increased [3]. In order to minimize the mobility, polymer flooding consists of adding polymer to a water. A lower mobility ratio is caused by the resulting viscosity rise, as well as a decrease in aqueous phase permeability. This reduction increases the efficiency of the volumetric sweep and reduces the saturation of oil in the swept field. Only if the waterflood mobility ratio is high, the reservoir heterogeneity is extreme, or a combination of these two occurs, can the polymer flooding be economical and useful.

The main objective of present work is studying the effect of polymeric additives on EOR by obtaining experimental results of applied parameters such as polymer concentration and temperature on EOR then correlating experimental data and comparing the results with the theoretical part.

2. Theoretical background

Most available EOR is based on the principles of depressing the mobility ratio to increase the hydrocarbon recovery. Mobility ratio (*M*) is defined as the mobility of the displacing fluid divided by the mobility of the displaced fluid [4].

$$M = \frac{\lambda\, displasing}{\lambda\, displased} = \frac{\mu o\ *\ krw}{\mu w\ *\ kro} \tag{1}$$

Where: λ = mobility; krw = relative permeability of water; kro = relative permeability of oil; μo = oil viscosity; μw =viscosity of water Relative permeability as described by the ratio of effective permeability of the fluid to absolute permeability of the rock [5]. The dynamic property of reservoir rock is efficient permeability and tests the ease with which a fluid will flow through the rock [6-8]. M should however be ≤ 1 for maximum displacement efficiency, typically denoted as a satisfactory mobility ratio. If M >1 (unwanted), then it means that the displacing fluid, e.g., water in a water flood, flows more quickly than the displaced liquid, i.e., oil. This is not beneficial since, given a phenomenon called 'viscous fingering' where much of the oil is bypassed, the displacement fluid can flow past the displaced fluid. However, one of the most favorable method to reduce the mobility ratio is increasing the viscosity of displacing fluid (i.e., water), or depressing the viscosity of the displaced fluid, (i.e., oil). There are two manners for estimating the viscosity of the oil. The first approach is to use oilfield data, such as oil API gravity produced by reservoir temperature, solution gas-oil ratio, [9, 10]. The second approach uses the empirical correlations used for viscosity prediction by other data, such as the composition of the reservoir fluid, temperature of the pour point, normal boiling point and critical temperature [11,12].

Beal (1946) developed a graphical correlation for determining the viscosity of the oil as a function of temperature and the API gravity of the crude [13].

$$\mu_o = \left(0.32 + \frac{1.8 \times 10^7}{\mathrm{API}^{4.53}}\right)\left(\frac{360}{\mathrm{T} + 200}\right)^{10^{\left(0.43+\frac{8.33}{\mathrm{API}}\right)}} \tag{2}$$

Where, μ_0 is the oil viscosity at 1 atm pressure and temperature, T in °F.

An empirical correlation for determining the viscosity of crude oil was established by Beggs and Robinson [14]. It is based on 460 measurements of oil viscosity and can be expressed as;

$$\mu_o = 10^{\frac{10^{(3.0324-0.02023^{\circ} API)}}{T^{1.163}}-1} \tag{3}$$

Egbogah-Jacks correlation [15], proposed the following empirical equation to determine the viscosity of oil;

$$\mu_o = 10^{10^{[2.06492-\ 0.0179\ \times\ API - 0.70226\ \times\ log(T)]}} - 1 \tag{4}$$

All these scientists used crude from different locations and of other characteristics. Each study claimed that the resulting correlations could apply to the different regions of the world. However, these correlations are of limited accuracy because of the variation in the geological, lithological and petrophysical conditions of the operating environment.

3. Methodology

Distillate water and Brine water had been used in this work, while Poly-electrolyte was acquired from one Iraqi oil company to be used as additives for experimental purposes. The method of solution preparation adapted in this study was to make 3.5% for 1000m.lit by weight concentration in an aspirant. Thus, a gram of the corresponding surfactant was placed in a one-litre conical flask of three samples in different salinity**,** ranged **as** 10,110 and 1140 Total Dissolved Salt (TDS) mixed with polymer under laboratory temperature.

The container was placed in an electrical shaker, at (80-160) rpm. The shaker was used instead of stirring device to avoid polymer molecular degradation; hence the shaker has no sharp edge that could expose the polymers to high shear force**.** The shaker was started from 80 rpm and increased by 40 rpm after every 2 hours. The solution was allowed to stand at least 24 hours at room temperature before its use as drag reducer, in a re-circulation closed-loop system. Viscosity measurements at different temperatures were performed by using a u-tube capillary viscometer. The selection of type and size of viscometer depend on the prepared solution. The u-tube capillary viscometer was placed in a water bath, which was capable of maintaining the temperature with ±0.5℃. The viscosity measurement apparatus consisting of the following part: **A)** Two gm of polymer (Poly-electrolyte). **B)** U -tube Viscometer. **C)** Pycnometer Density 50 ml. **D) Water** Bath at a different temperature range from (30-60°C) for the full range of viscosity application. **E)** Shaker for dissolving surfactant in the water at suitable wr. p **F) Sensitive** balance. **G)** Stand for holding the viscometer. **H)** Different Size of Flask and Beaker. **I)** Stopwatch, Cone, Pipette and thermometer ..., etc., for completing the experimental purpose. At the first time, we will weigh the pycnometer (with 50 mil volume) as empty at the sensitive balance. Second, we will fill the pycnometer with the solution until the liquid pour from the above hole of the pycnometer. Put the pycnometer filled with the solution into the water bath. At the time we reach the selected temperature, we will weigh the pycnometer again in the sensitive balance. Repeat step 4 for different temperature (ranged from 30 to 60 C^o). Repeat step (2 until step 5) for each change in the concentration of the solution (varied from 20 to 100 ppm). The density calculated using the following equation:

$$\rho = m/v \tag{5}$$

Where: - ρ: density, m: mass, v: volume.

A certain amount of each prepared solution previously was poured into a beaker then transferred to a suitable viscometer. The viscometer, filled with the above solution, has been inserted into the water bath at the appropriate temperature. The level of the solution in the viscometer was raised to the starting mark on the left-hand limp of the viscometer; another finger used to close the other limp to avoid the flow of the solution due to air. The finger removed to allow flow of solution down the capillary at that point, the time at which the solution flows down is taken and recorded. This process is repeated for the various solution and at different temperature. Then viscosity is obtained by multiplying the constant of the viscometer by the time acquired. The viscosity of all solution was measured at five different temperature, namely: 30,40,50,55 and 60 C^o. The dynamic viscosity was calculated experimentally from the measured flow time by the equation:

$$\frac{d1t1}{d2t2} = \frac{\mu 1}{\mu 2} \tag{6}$$

Where: d1= density of fluid, d2= density of water, t1 = time of fluid flow, t2 = time of water flow; µ1= dynamic viscosity of fluid, µ2= dynamic viscosity of water.

The following data has been obtained experimentally for different temperature ranged (30 – 60 ºC) by variation the polymer concentration from (20-100ppm).

Table 1. Viscosity of solution at different temperature and concentration

Temperature, ⁰C	Pure water	20 ppm	40 ppm	60 ppm	80 ppm	100 ppm
30	0.000801	0.000818	0.000831	0.000856	0.000896	0.000923
40	0.000656	0.000671	0.000684	0.000696	0.000721	0.000782
50	0.000549	0.000576	0.000588	0.000599	0.000610	0.000669
55	0.000506	0.000521	0.000531	0.000554	0.000566	0.000624
60	0.000469	0.000486	0.000496	0.000532	0.000542	0.000602

As it's seen from Fig. 1 and Fig.2 below, as temperature decreases the viscosity decrease at a constant concentration, and the viscosity will be increase by increasing the concentration of surfactant up to 100ppm at a constant temperature which it's well known previously.

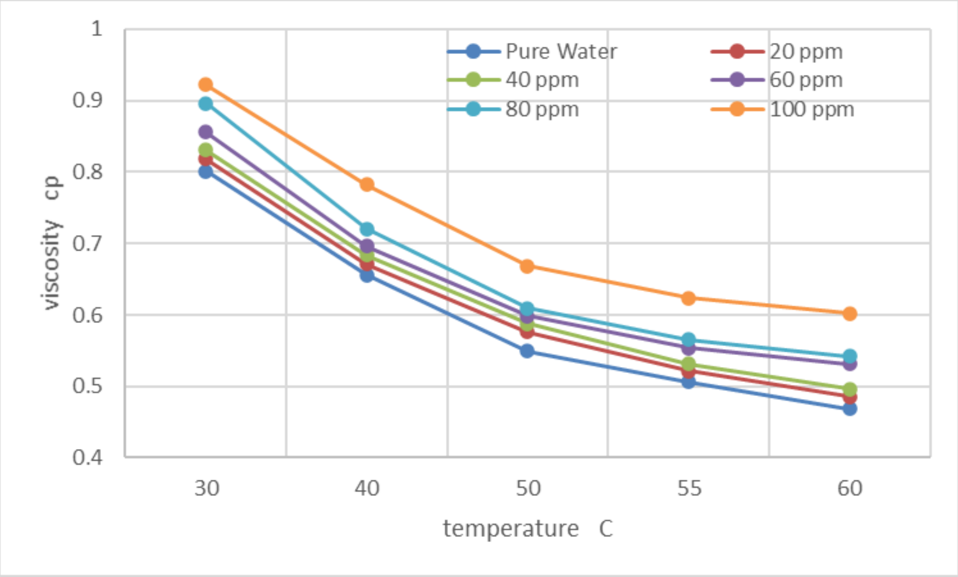

Figure 1. Effect of temperature and polymer concentration on viscosity

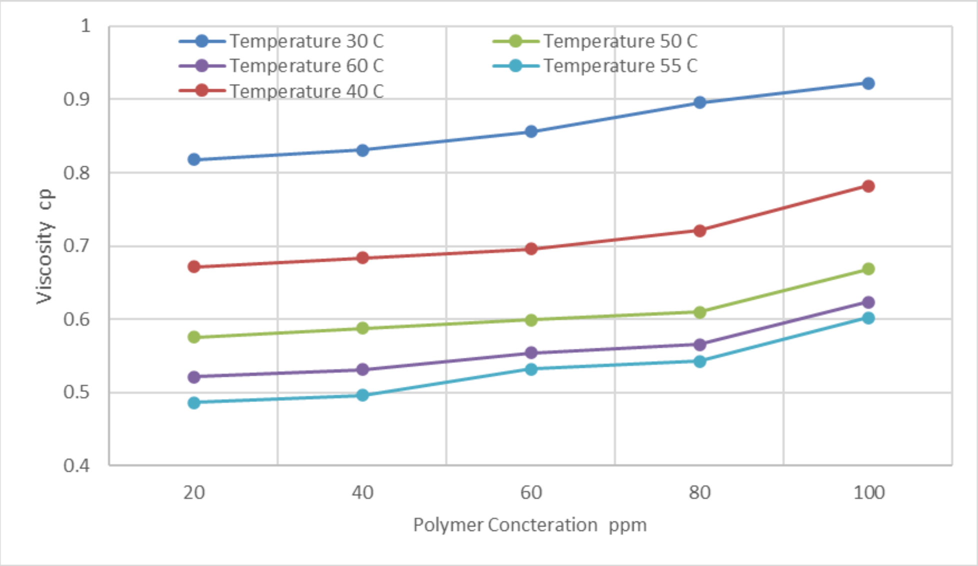

Figure 2. Effect of polymer concentration on viscosity for each temperature

4. Results and discussion

The most popular analytical models currently used in petroleum engineering viscosity prediction calculations are those developed by Beal, Beggs and Robinson, and Egbogah-Jacks. In this study, thirty-five data points from experimental work were available on which to develop a new correlation for μ_{wp}, the data is fairly well spread, covering Five different samples at different temperatures ranged from 30 up to 60 ºC for each sample. During the comparison the available correlations in the present work by calculating the average percent errors, the best correlations for μ_{wp} had been found and attributed by three correlations. An Excel program by using solver was used to analyze the values of the appropriate constants for each empirical equation to produce the best fit measured data. Beal equation had been modified to be applicable in calculating the viscosity of water with polymer instead of the viscosity of oil as the following equation.

$$\mu wp = \left(d + \frac{e}{ppm^{f}}\right)\left(\frac{g}{T+h}\right)^{10^{\left(b+\frac{c}{ppm}\right)}} \tag{7}$$

Where: - *μwp:* viscosity of water with polymer additives. The equation constants (b, c, d, e, f, g and f) are found using the Excel solver package, as shown in Table 2.

Table 2. Estimated Constants of Improved Beal equation

b	c	d	e	f	g	h
-4.548130167	8.08613997	0.000598879	1.85E+07	10.8185347	359.95889	200.047677

The modification of Beggs and Robinson Correlation was modified as follows:

$$\mu_{wp} = 10^{\frac{10^{(a-b*ppm)}}{T^{c}}} - d \tag{8}$$

The equation constants (a, c, b, d) found using the Excel solver package, as shown in Table (3).

Table 3. Estimated Constants for Improved Beggs and Robinson Correlation

a	c	b	d
0.129134	1.987919	-0.0013702	0.999671

The modification of Egbogah-Jacks correlation was written below for polymer concentration appearance:

$$\mu_{wp} = 10^{10^{[a-(b\times ppm)-(c\times log(T))]}} - d \tag{9}$$

Again, the equation constants (a, b, c, d) found using the Excel solver package, as shown in Table (4).

Table 4. Estimated Constants for Improved Egbogah-Jacks correlation

a	b	c	d
0.427026	-0.00149	2.154137	0.999648

All of these models have modified and improved to expressed water viscosity as a function of both polymer concentration in ppm and reservoir temperature (T) in ^{o}F. The accuracy of each correlation for Water viscosity calculation was checked with the comparison with experimental data. The error percentage for these improved models are measured using absolute average relative error (AARE); the results shown in Table (5).

Table 5. AARE for each Improved Model

Improved Model	AARE %
Beal equation	14.47
Beggs and Robinson Correlation	2.18
Egbogah-Jacks correlation	6.32

The performance of the tuned correlations found to predict the data better where the AAPE decreases. The selected formula was Beggs & Robinson correlation because it has minimum AAE (2.18 %). By the comparison of experimental values of viscosity with predicted ones, it is obvious that the new correlation provides results in good agreement with experimental values. Based on water viscosity data and relative permeability, the mobility ratio can be determined at each temperature by applying mobility formula as in (1). To illustrate the effect of additives on mobility ratio for each concentration, a typical value of saturation equal to 0.19 has been chosen with a relative permeability of water equal to 0.008 and relative permeability of oil equal to 0.925 and API equal to 37^{o}. Also, differing temperature from 30 ^{o}C up to 60 ^{o}C for each additive beginning with pure water up to 100 ppm considered. The results of the effect of polymer additives on the mobility ratio presented in Fig. 3. It can be noticed from this figure; there was a low mobility ratio at the highest values of concentrations such as 100 ppm. In case of fixing the value of viscosity to 0.75 cp, the pure water mobility ratio is equal to 0.053, and for 60 ppm, the mobility ratio is equal to 0.04. In contrast, the mobility ratio is 0.035 approximately 100 ppm. The reason for the lower value of M in the increasing the concentration attributed to at time concentration increases the viscosity will also increase and this because of the monomer of Poly-electrolyte will be a propagated with increasing ppm. The inversely proportional

relationship between the additives and the mobility ration cause of the denominator will be greater than the nominator representative by the viscosity of water. As a result, the value of M will be decreased according to (1). The effect of temperature on mobility ratio also investigated as shown in Figure 4 which demonstrated the effect of temperature with five temperature values (30, 40, 50, 55, 60 ºC) for different values of concentration of additives up to 100 ppm. It shown from the Figure 4, the mobility ratio decreases as temperature increases, this phenomenon had been interpreted to more rapidly decreasing in the oil viscosity with little reduction in water viscosity; as a result, the mobility ratio will be reduced.
The application of a mathematical formula to approximate the behavior of temperature and concentration effect together on mobility ratio have been encountered by curve fitting examination as shown in Figure 5. Determining the equations of the quadratic regression function data have been listed in Table (6). Showing that the curve of temperature at 60 º C has the best fit data according to maximum value of coefficient of determination (R^2) approximately equal to 0.98. However, this outcome is emphasized with experimental data as presented in Figure 2.

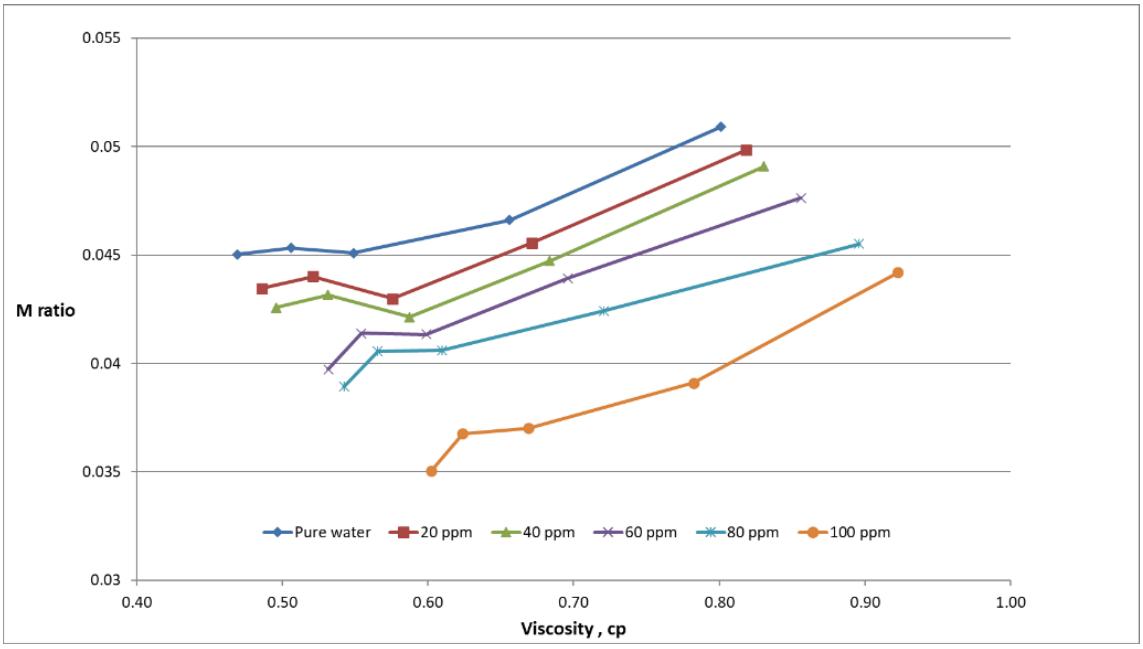

Figure 3. Effect of viscosity of pure water and different concentration of polymer on mobility ratio

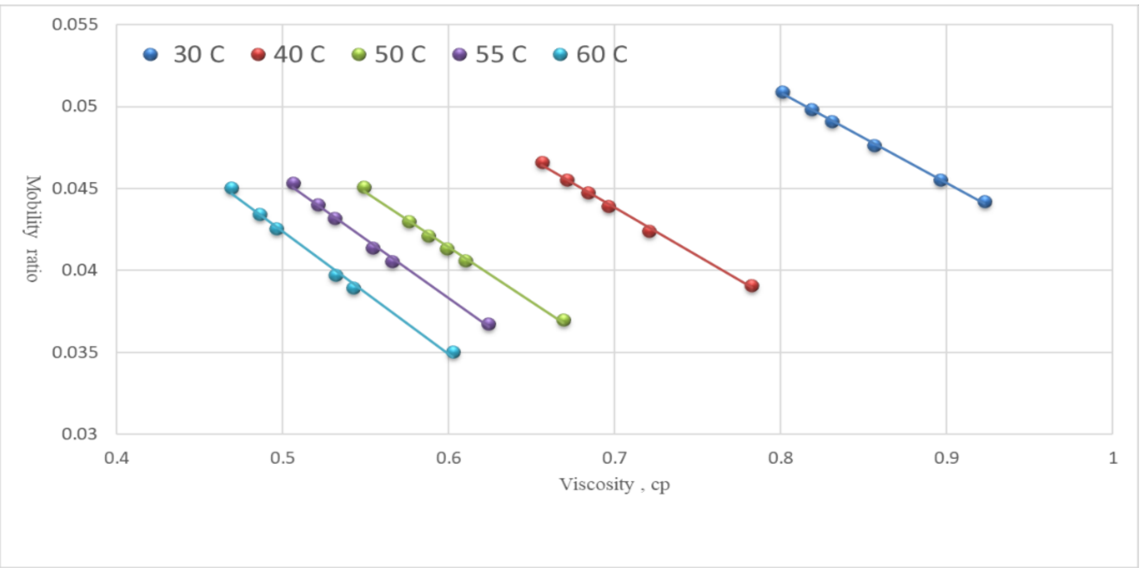

Figure 4. Effect of temperature on mobility ratio for different concentrations of additives

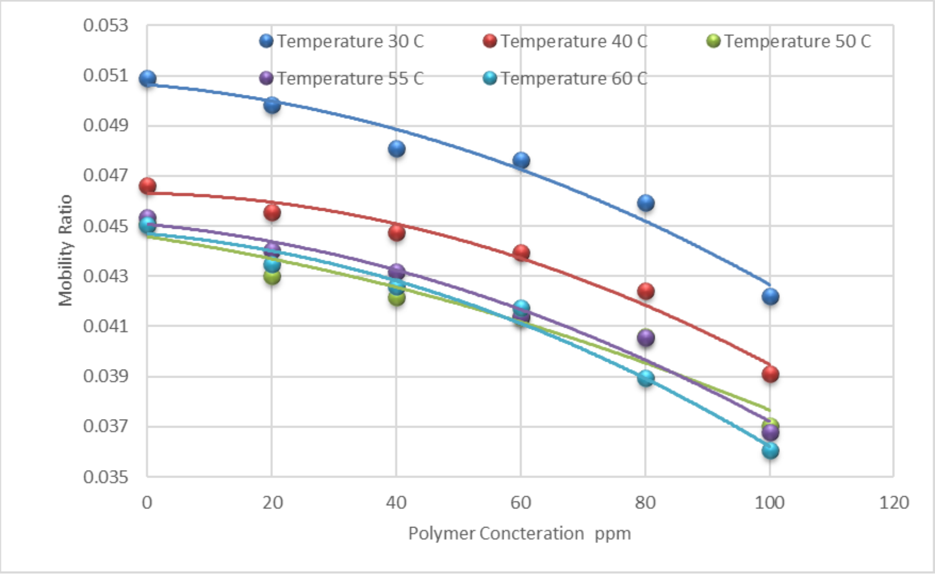

Figure 5. Effect of polymer concentration on mobility ratio for different temperatures.

Table 6. Quadratic regression equations of polymer concentrations versus mobility ratio

Temperature,C	**Quadratic Regression Eq.**	**Coefficient of Determination, R^2**
30	M = -6E-07x2 - 2E-05(ppm) + 0.0506	0.9678
40	M = -6E-07x2 - 5E-06(ppm) + 0.0463	0.9748
50	M = -3E-07x2 - 4E-05(ppm) + 0.0446	0.9315
55	M = -5E-07x2 - 2E-05(ppm) + 0.0451	0.9723
60	M = -6E-07x2 - 2E-05(ppm) + 0.0447	0.9841

5. Conclusions

Three correlation have been used to express the effect of changing the viscosity with temperature for water. The experimental data ranged from (30 - 60°C) has been used to find constant of the present correlation by modification the equations attributed to (Beal, Beggs & Robenson and Egbogah -Jacks,). The predicted correlation with different constant has an absolute per cent error (2.18) which it's has an acceptable value, if it's compared with the previous one. As it's seen from the result in the appropriate program at time concentration increases the viscosity will also increase, and this attributed to the monomer of Poly-electrolyte will be a propagated with increasing ppm. The Mobility ratio will be decreased by increasing concentration and increasing the temperature; that's mean the injection of the polymer at high temperature will be suitable for EOR. The mobility ratio decreases as temperature increases; at temperature 60^o C the regression analysis presented a best fit value with 0.98 coefficient of determination; this phenomenon had been interpreted to more rapidly declining in the oil viscosity with a small decrease in water viscosity; as a result, the mobility ratio will be decreased. For future work, it is recommended to complete the remaining experimental part and obtaining the results from built-up rig to study the effect of Polymer and Surfactant on injection to water for EOR needs to be investigated. Also, studying the effect of water saturation and salinity of water on to mobility ratio has been recommended.

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