

Viscosity Measurements of Different Fluids Used for Mobility Control in Mature Reservoirs

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Abstract

In the oil industry, it is important to increase the mobility of hydrocarbon fluids (oil and/or gas) and decrease the mobility of water. Doing so results in an increase in oil production and a decrease in unwanted water production. Polymers have been widely used to increase water viscosity, causing a decrease in water mobility. Surfactants have been used to change reservoir wettability and to clean the rock surface. The use of surfactants changes the formation wettability from oil wet to water wet. This results in an increase in oil production from various water wet sandstone and carbonate formations. Low water salinity has also been used to enhance oil recovery. The mobility of the oil should be more than the mobility of the water to ensure maximum extraction efficiency. As a result, viscosity measurements are very important in determining the impact of a viscous fluid in enhanced oil recovery (EOR). We measured the viscosity of mixed fluids used in the oil industry such as brines of varying concentration (Sodium Chloride and Calcium Chloride solutions) and various polymer solutions at different temperatures.

1. Introduction

Enhanced oil recovery (EOR), also known as tertiary recovery, is a process used to extract oil remaining in a reservoir after water flooding [1]. This can be done using mechanical methods or chemical methods, generally targeting particular permeability zones or viscosity issues. The goal is to reduce reservoir heterogeneity and increase recovery [2]. Properly adjusting the viscosity of the displacing phase, the interfacial tension, or the interfacial viscosity can increase sweep efficiency [3]. It was seen that the interfacial tension and interfacial viscosity are equally important factors when considering displacement pressure [4, 5]. The use of polymers and surfactants are common not only for changing the permeability and wetting phase respectively, but also for changing the viscosity of a phase. It should be noted that in some cases for polymers, the resulting in-reservoir fluid will become non-Newtonian due to resistance from polymer coil elongation [6]. When this occurs, polymer solutions can greatly increase pressure losses at medium to high strain rates and require proper application [3].

Water flooding of high viscosity oil results in a poor displacement efficiency due to fingering. This is caused by the lower capillary resistance experienced by the lower viscosity displacing fluid and can be seen in the Invasion-Percolation Model [7]. Eventually, the fingers break through and the water cut begins to climb. It becomes far more difficult for the displacing solution to force much of the remaining oil out, as the pressure required to overcome capillary forces is larger than the pressure required to flow through the breakthrough zones [2, 8]. As a result, capillary bypassing takes place, causing oil to be surrounded by displacing fluid and trapped [9, 10]. Capillary forces are typically neglected in heavy oil reservoirs; however, they are of importance [11]. Typically, heavy oil water flooding is avoided. However, experience has shown that heavy oil reservoirs can provide around half of their cumulative output with a water cut of 90% and above, but the operator must be able to financially handle the large amounts of excess water produced for extended periods of time. In heavy oil reservoirs, viscosity differences are the primary cause of residual oil [11]. The viscosity ratio, defined as

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$$M_{\mu} = \frac{\mu_{\text{Injected}}}{\mu_{\text{Displaced}}} \dots\dots (1)$$

where μ_{Injected} is the displacing fluid viscosity and $\mu_{\text{Displaced}}$ is the displaced fluid viscosity, helps determine the in-reservoir flow pattern, which becomes fractal as M_{μ} approaches 0 [12, 13]. The time dependence of the flow is proportional to a power of the viscosity ratio [14].

The viscosity ratio is similar to the inverse of the traditional mobility ratio that is commonly used in industry. The mobility ratio is also of use when considering the effectivity of a water flood. It can be used to calculate flood front stability in a 1D system. The instability number I_{sr} is proportional to the mobility ratio minus 1. Transition from stability to instability of the front begins around π^2 and completes around 1.000, progressively increasing in severity [15]. The equation is below.

$$I_{sr} = \frac{(M-1)vD^2\mu_w}{C^*\sigma k_{wor}} (2)$$

where I_{sr} is the instability number, M is the mobility ratio, v is the injection rate, μ_w is the water viscosity, D is the core diameter, C^* is the wettability constant, σ is the interfacial tension, and K_{wor} is the permeability to water at the irreducible oil saturation.

In mature wells, water production can reach 98% of total fluid recovery [16]. Greater water production translates to higher production costs [17] and such wells are typically no longer economically viable. As wells mature, it is imperative that recovery efficiency is maximized [18]. During a water flooding study of heavy oil reservoirs in Canada, it was seen that halting water flooding operations decreased the water cut by 40% and increased oil recovery slightly [19]. Such issues can be solved through a reduction of fingering, improving sweep efficiency. Fingering can be reduced by increasing the viscosity of the displacing phase [12, 13]. This results in a more uniform sweep pattern and therefore greater recovery. Left unaccounted for however, this viscosity change can be detrimental to existing centrifugal pumps and other equipment [20]. These equipment modifications could increase the cost of the EOR operation.

The viscosity of the displacing phase is affected by the salinity of the solution, the temperature, and the presence of surfactant, polymer, alcohols, glycerin, or sugars [2]. Generally, higher salinities and concentrations of polymers, alcohols, glycerin,

and sugars will result in higher viscosities, while higher temperatures and surfactant concentrations will result in the decline of solution viscosity [2]. The viscosity of oil can also be modified. The presence of sulfates at high temperatures and pressures or surfactant can cause a reduction in oil viscosity, and therefore an increase in the viscosity ratio. Interfacial tension is also decreased [21]. Emulsifiers are quite effective at reducing the viscosity of oil, which was decreased by 97%.

Increasing recovery by reducing the viscosity ratio in a cost-effective way is an objective for many in the oil industry. With the recent drop in oil prices, cost effectivity has been of concern for many tertiary recovery projects. The modification of displacing fluid viscosity is cheaper than many other EOR methods and is an effective way of increasing well life and production. Especially since as wells age, the average viscosity of the residual oil increases due to the extraction of the lower viscosity product 70% of residual oil worldwide is heavy, high viscosity oil [22]. This contributes to a decrease in reservoir productivity.

It is critical to understand the viscosity of both the displacing and displaced fluids and how surfactants and other additives or conditions will affect the viscosity. The viscosity can be measured by a rheometer, and if the fluid is Newtonian, Eq. (3) below holds.

$$\mu = \tau \frac{b}{u_0} (3)$$

where τ is the shear stress induced on the fluid, μ is the dynamic viscosity, u_0 is the maximum velocity (in the case of the rheometer the bob), and b is the distance between zero velocity and maximum [23]. The presence of polymer can result in Non-Newtonian performance under certain conditions, and this was avoided in this work.

2. Experimental

2.1. Materials

Brine Preparation: To manufacture the brines, deionized (DI) water from was used. Sodium Chloride, a popular salt in SAP kinetics studies, was mixed with the DI water by percent weight. Calcium Chloride is another common reservoir salt that was employed in this work.

Oil: Different oils were employed. The types were mineral oil and Real oil from Oklahoman fields. Pictures of the samples can be seen in Fig. 1.



Fig. 1. Oil types used. (a) – type 1 is mineral oil, and (b) – type 2 is real oil.

The properties of these oils are presented in Table (oil density, oil specific gravity, API gravity, and viscosity). The mineral oil is a lighter oil compare with the real oil. Table shows the properties which was measured in the laboratory. The API gravity of the real oil is lower than API gravity of the mineral oil which mean that the real oil is heavier than the mineral oil.

Surfactant: 233 Schaeffer WET-SOL Concentrate Surfactant was used in the work. It was mixed with other solutions to measure the effect on solution viscosity. It has a pH of 7 to 8, and a solution viscosity of 14.678 cP/mP as at a temperature of 25 °C.

Polymer: Polymer solutions were also made. The primary polymer used was Liquiblock 40F, a Potassium salt of crosslinked polyacrylic acid. The particle sizes of the polymer ranged from 35 to 60 mesh or 250 to 500 μm . The typical solution pH of this material is in the range of 5 to 6 pH according to the manufacturer. The polyacrylamide polymer used in this project was incompatible with Calcium brines above extremely low salinities at standard pH values, limiting the polymer's applicability [24]. An image of a brine and polymer solution can be seen in Fig. 2 below.

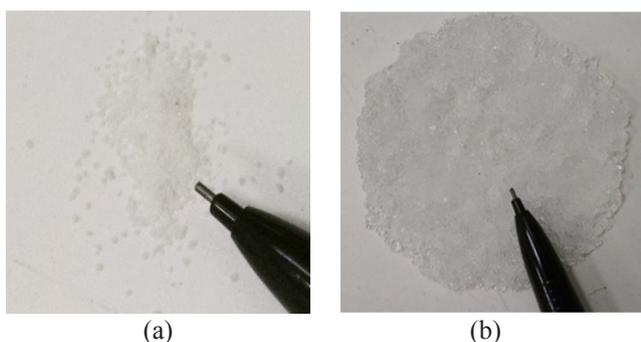


Fig. 2. (a) – unswollen polymer; (b) – swollen polymer solution

Table
Measured Oil Sample Properties

Oil Sample	Density (g/cm ³)	Specific Gravity	API Gravity (°API)	Viscosity (MPas or cP)
Type 1 (Mineral)	0.7791	0.7791	50.12	1.988
Type 2 (Real Oil)	0.8667	0.8667	31.76	2.281

An electronic precision balance, a Tree® HRB103, was used to weigh out all components used in this work. Agitation of the solutions was performed to ensure uniformity, especially if polymers were present. A VWR® Lab Dancer S41 was utilized to perform this task. Rheometer was used to measure the viscosity of various fluids used in oil industry. Heat Water Bath was used to provide a viscosity measurements at different temperatures.

2.2. Rheometer and heat water bath setup

Testing the viscosity required the use of a Brookfield R/S Plus Rheometer with a cylindrical bob. Studying the effects of temperature required the use of a Julabo® F25 MC bath heater and circulator. This device has the capability to both cool and heat samples inserted into the rheometer by circulating bath fluid around the sample sleeve via hose connections. Figure 3 shows the setup. To mix solutions, a magnetic stirring machine was also used.



Fig. 3. Rheometer and Heat Bath Setup.

2.3. Experimental Procedure

Initially, samples of the various mixtures were prepared. These mixtures included deionized water with sodium chloride, deionized water with calcium chloride, deionized water with sodium chloride and calcium chloride, deionized water with

super-absorbent polymer and sodium chloride, surfactant concentrate with mineral oil, and surfactant concentrate with real oil. The samples were then mixed at different concentrations with polymer and surfactant percentages varying from 0–20%. The samples were then agitated and allowed to stand before measuring their viscosities. Viscosity measurements were performed after allowing the solution to equilibrate for 2–5 min at a constant temperature of 25 °C (77 °F) controlled and maintained by the water bath. Viscosity readings were taken at a speed of 1000 revolutions per minute (rpm) for a duration of 60 sec before addition to oil. The temperature was then varied between 77 °F and 300 °F.

3. Results and Discussion

The viscosity tests started with brine solutions. The Sodium Chloride and Calcium Chloride solution results showed a relatively linear relationship between viscosity and salinity. Figure 4a and b show the data. It appears that Calcium Chloride actually results in a higher solution viscosity compared to Sodium Chloride. This may be due to greater intermolecular forces between the Ca^{+2} , Cl^- , and the polar H_2O during solution shearing. Figure 5 gives a comparison displaying the difference between the NaCl brines and CaCl_2 brines. The presence of polymer in various NaCl brine solutions was also investigated. It can be seen, when comparing Figs. 4a and 6, that there is, surprisingly, a decrease in the viscosity of the brine solutions overall. The true nature of polymer solutions would require further work, as has been previously mentioned the reaction of polymer solutions to shear forces can be non Newtonian.

The next trials conducted were on the effects of surfactant and temperature on solution viscosity. Figure 7 clearly shows a trend of viscosity drop with increasing surfactant concentration. In addition, temperature increases also reduced the solution viscosity. When modifying the temperature of NaCl solutions with polymer (Fig. 8), it was seen that the viscosity increased significantly. This could be due to the polymer's tendency to 'uncoil' as temperature increases. This may allow the brine to shear at forces similar to those of brines containing no polymer. It was seen that the viscosity of the medium oil was originally lower than that of the mineral oil (Fig. 9). The effects of temperature were far more impressive, although surfactant was not as effective at reducing solution viscosity.

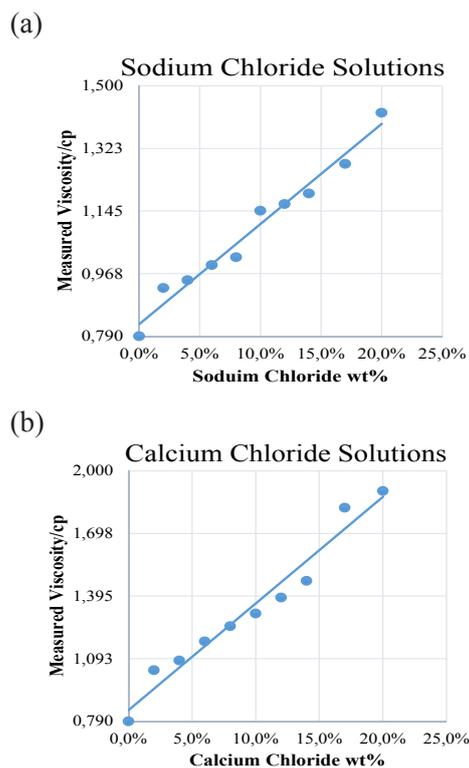


Fig. 4. (a) – viscosity of sodium chloride solutions; (b) – viscosity of calcium chloride solutions.

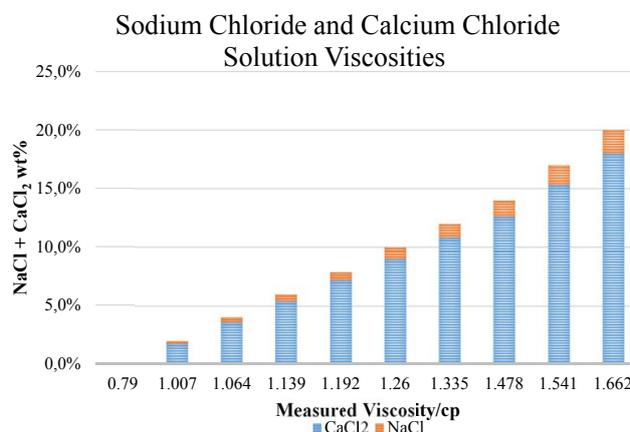


Fig. 5. Viscosity of the mixed of sodium chloride and calcium chloride solutions compared.

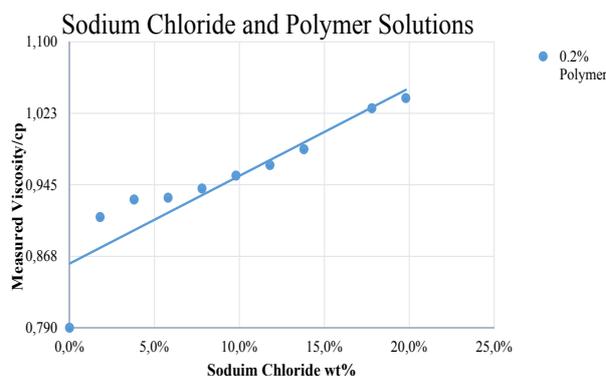


Fig. 6. Viscosity of the mixed of sodium chloride and polymer solutions.

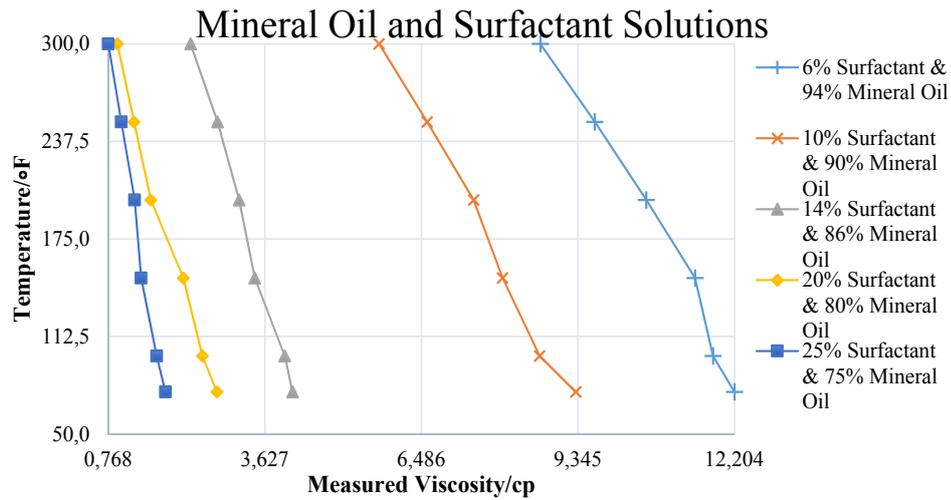


Fig. 7. Effect of temperature on viscosity the mixed of mineral oil and surfactant solutions.

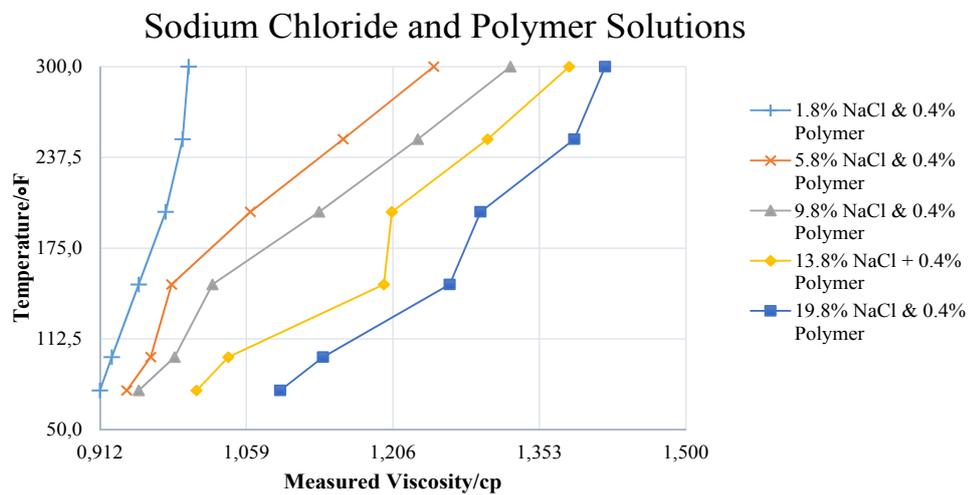


Fig. 8. Effect of temperature on viscosity the mixed of sodium chloride and polymer solutions.

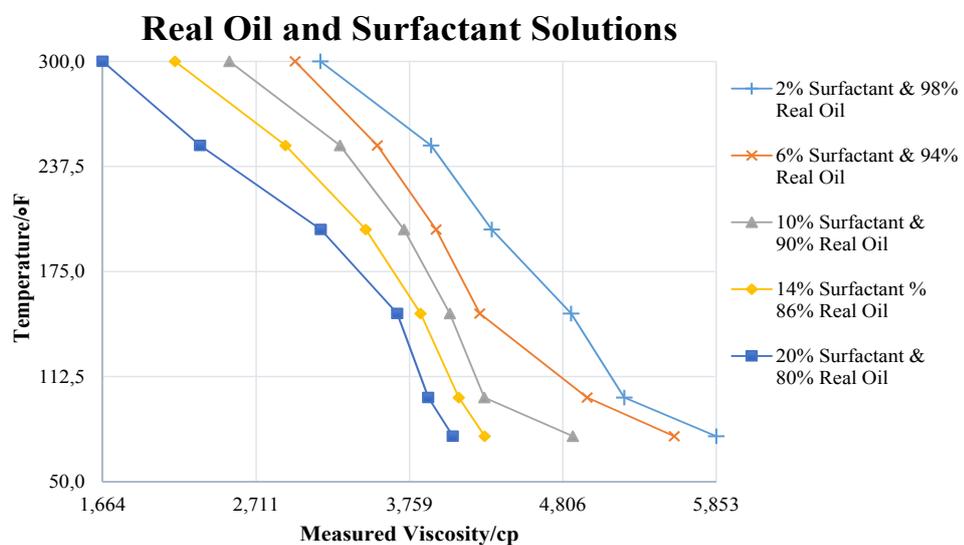


Fig. 9. Effect of temperature on viscosity of mixed real oil and surfactant solutions.

4. Conclusions

Calcium Chloride tends to increase solution viscosity much more than Sodium Chloride with or without polymer. In fact, polymer in this work actually decreased solution viscosity except at elevated temperatures. When investigating the polymer's properties, it is evident that higher temperatures and higher salinities increased the shear strength of the polymer solution. This implies that high salinity waterfloods may benefit from polymer treatments, as it will provide a thickening mechanism in the displacing phase that operators will have some control over. Further study is needed, since the concentration of polymer in the solution will undoubtedly have an effect on viscosity.

The mineral oil was quite sensitive to the concentration of surfactant, and less so to deviations in temperature. In comparison, the light oil was far more sensitive to temperature than to the concentration of surfactant in the solution. Surfactant appears to be quite effective at modifying the viscosity of heavy oil, but less so when faced with lighter oils. This should not be a big problem in practice, since the majority of residual oil in waterflooded reservoirs is considered heavy.

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