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Measurement and Impact Factors of Polymer Rheology in Porous Media

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1. Introduction

Crude oil is found in underground porous sandstone or carbonate rock formations. In the first (primary) stage of oil recovery, oil is displaced from the reservoir into the wellbore and up to the surface under its own reservoir energy, such as gas drive, water drive, or gravity drainage. In the second stage, an external fluid such as water or gas is injected into the reservoir through injection wells located in the formation that have fluid communication with production wells. The purpose of secondary oil recovery is to maintain reservoir pressure and displace hydrocarbons towards the wellbore. The most common secondary recovery technique is waterflooding. Once the secondary oil recovery process has been exhausted, about two thirds of the original oil in place (OOIP) is left behind. Enhanced oil recovery (EOR) methods aim to recover the remaining OOIP. Enhanced oil production is critical today when many analysts are predicting that world oil peak production is either imminent or has already passed while demand for oil is growing faster than supply. For example, the United States has a total of 649 billion barrels original oil in place, and only about 220 billion barrels are recoverable by primary and secondary recovery methods. EOR methods offer the prospect of recovering as much as 200 billion barrels of more oil from existing U.S. reservoirs, a quantity of oil equivalent to the cumulative oil production to date.

Polymer flooding is one of the most successfully methods to enhance oil recovery. The polymers that are mainly used in oilfields are water soluble polyacrylamide (HPAM), Xanthan gum (Xc), and associative polymer (AP). Polymer solutions, in contrast to water, exhibit non-Newtonian rheological behaviors, such as shear thinning and shear thickening effects, which lead to different viscosity properties in a reservoir, as compared with those in water flooding. The results from labs, numerical simulations and fields all demonstrate that the rheology of a polymer solution not only impacts the polymer injectivity but also dominates the oil production rate and final recovery of a polymer flooding project. However, the rheological properties of polymer solutions measured by conventional rheological instruments which strive to produce pure shear flow could not be used directly to predict the pressure-to-flow relationship in porous media.

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When a polymer solution is injected into a reservoir from an injection well, the flow velocity, which is related to shear rate, will change from wellbore to in-depth of a reservoir; therefore, the polymer solution viscosity will also change from near wellbore to in-depth of a reservoir correspondingly. Polymer rheology in a porous media is also affected by polymer type, molecular weight, concentration, water salinity in the reservoir, and reservoir permeability. The flow of polymer solutions through a porous media is a complex topic, governed by polymer rheology and retention behavior, and is still not understood very well.

This chapter presents the fundamental terms/concepts used to characterize polymer rheology behaviors, the mathematical models that are used to calculate shear rate, the experimental procedures to measure polymer rheology in porous media, and the factors that impact the in situ rheology of polymers.

2. Definition of terms

2.1 Apparent viscosity

Darcy's law is one of the most well-known theories that describe fluid flow through a porous media as shown as follow:

$$Q = k\frac{A\Delta P}{\mu L} \tag{1}$$

Where Q is the liquid volume at a certain time interval in cm^3/s; A is the cross-sectional area in cm^2; L is the length of the sample in the macroscopic flow direction in cm; μ is the viscosity of a fluid flowing through a porous media in $mPa\cdot s$; ΔP is the pressure drop across the porous media in atm; k is the absolute permeability in $Darcy$ for the porous media, and a measure of the conductivity of the porous media.

A polymer solution used in EOR is a non-Newtonian fluid; therefore, the viscosity term μ in Equation 1 is usually not constant. A macroscopic in situ 'apparent viscosity', $\eta_{app,}$ is often used in polymer flooding, and is defined as follow:

$$\eta_{app} = k\frac{A\Delta P}{QL} \tag{2}$$

During a polymer flooding process, a polymer solution itself is a non-Newtonian fluid. A polymer is also retained in pore surfaces and reduces the permeability of the porous media. Thus, in Equation 2, $\eta_{app,}$ is not constant and is affected by flow rate and rock permeability.

2.2 Effective viscosity

The apparent viscosity mentioned above is from Darcy's law, used to describe macroscopic rheology of a polymer fluid flow in a porous media. Effective viscosity η_{eff} is another term which is also often used in polymer flooding. It is from Poiseuille's law, refers to the observed effective viscosity in a single capillary channel, which is in microscopic. The effective viscosity is expressed as follows:

$$\mu_{eff} = \frac{\tau}{\gamma} \tag{3}$$

Where τ is the shear stress, N/m^2; γ is the shear rate, s^{-1};

Shear stress is the force per unit area required to sustain a constant rate of fluid movement. It can be defined as:

$$\tau = \frac{F}{A} \qquad (4)$$

Where F is the force applied, N; A is the cross-sectional area of material in the area parallel to the applied force vector, m^{-2}.

Shear rate is defined as the velocity change through the thickness:

$$\gamma = \frac{v}{h} \qquad (5)$$

Where v is the velocity, m/s; h is the thickness, m.

The distinction between effective and apparent viscosity should be clearly maintained, especially when considering mathematical porous media models based on capillary bundles, which as discussed below. The overall viscosity in macroscopic of the polymer fluid in the capillary bundles is η_{app}, whereas the viscosity in each of the capillaries may be different and is η_{eff}. In the latter case, η_{app} is like an 'average' value of the η_{eff} in the individual capillaries (Sorbie 1991).

2.3 Resistance factor

In order to characterize the behavior of different polymer solutions in response to pressure build-up during polymer injection, the resistance factor F_r is often used. A resistance factor is defined as the ratio of mobility of water to the mobility of a polymer solution (Littmann 1988):

$$F_r = \frac{M_w}{M_p} = \frac{\dfrac{k_w}{\mu_w}}{\dfrac{k_p}{\mu_p}} \qquad (6)$$

Where M_w and M_p are the mobility of water and polymer, respectively; k_w and k_p are the water and polymer permeability in μm^2, respectively; μ_w and μ_p are the viscosity of water and polymer in $mPa \cdot s$, respectively.

The resistance factor describes the effective viscosity of a polymer solution in porous media.

3. Calculation of shear rate in porous media

Since most polymer solutions are non-Newtonian fluids, their shear rate vs. viscosity is not a linear relationship. For a given viscosity, a shear rate should be defined in advance. An average shear rate in a porous media is related to its permeability, porosity and fluid actual velocity. This leads to an expression of an apparent shear rate, γ_{app}, to describe the interstitial

shear rate in the porous media. Table 1 provides some representative models which can be used to calculate the shear rate in a porous media. The application conditions and assumptions for each model have been listed in the Table.

No.	Equations	Prerequisite conditions and Assumptions	Source
1	$$\gamma_{app} = \frac{4u}{\phi r} \cdot \frac{L_e}{L} \qquad (7)$$ where u is the superficial flow rate, *cm/s*; ϕ is porosity; r is the average pore radius, *cm*; L_e is length of tortuous flow path, *cm*; L is the porous media length, *cm*;	1. Porous media is considered as a bundle of capillary tubes with a length that is greater than the porous media by a tortuous factor; 2. Bundle of straight capillaries; 3. Capillaries are of uniform sized; 4. Capillaries are not interconnected; 5. Flow rate in capillary is constant (at constant pressure drop).	(Kozeny 1927) (Carman 1937)
2	$$\gamma_{app} = \left(\frac{3n+1}{4n}\right)\frac{12G}{\rho\sqrt{150k\phi}} \qquad (8)$$ where n is the Power law parameter; ρ is fluid density, *g/cm³*; k is permeability, *cm²*; ϕ is porosity; G is mass velocity, *g/(cm² ·sec)* $$G = \rho(\frac{k}{H}\frac{\Delta P}{L})^{1/n} \qquad (9)$$ where ΔP is the pressure drop, *dyne/cm²*; k is permeability measured by a Newtonian fluid, *cm²*; L is the unit length, *cm*; H is the non-Newtonian bed factor, *dyne ·secⁿ ·cm⁻¹⁻ⁿ* $$H = \frac{K}{12}(9+3/n)^n(150k\varphi)^{(1-n)/2} \quad (10)$$ where K is the Power law parameter, *dyne ·secⁿ ·cm⁻²*	The permeability of the porous media is the same for all identical packed bed configurations, independent of flow conditions in the bed.	(Christopher and Middleman 1965)
3	$$\gamma_{app} = \left(\frac{3n+1}{4n}\right)^{n/(n-1)}\frac{12u}{\sqrt{150k_p\phi_w}} \qquad (11)$$ where n is the bulk power law index; u is the	1. Based on capillary bundle model for non-Newtonian fluid flow; 2. The polymers such as partially hydrolyzed	(Hirasaki and Pope 1974)

	Darcy velocity, cm/s; k_p is polymer permeability, cm^2; Φ is porosity; Φ_w is the pore space occupied by water, $\Phi_w = \Phi S_w$	polyacrylamides, the permeability reduction due to the adsorption of the polymer is considered; 3. When applied to Xanthan biopolymer through rock cores (at residual oil), very good agreement was obtained between calculated and experimental values; 4. A tortuosity of 25/12 has been assumed.	
4	$$\gamma_{app} = C\left(\frac{3n+1}{4n}\right)^{n/(n-1)}\frac{u}{\sqrt{k_w S_w \phi}} \quad (12)$$ where k_w is water permeability, cm^2; S_w is water saturation; n is the bulk power law index; C is shear rate coefficient, not constant, but a function of the network parameters; ϕ is porosity; u is Darcy velocity, $u=Q/A$, cm/s;	Equation is developed to relate the flow of Xanthan solutions in cores having different permeabilities, lithologies, and oil saturations.	(Cannella, Huh et al. 1988)
5	The average pore radius in the pack is estimated from the capillary bundle model of the porous medium. The equation: $$r = \left(\frac{8k}{\varphi}\right)^{1/2} \quad (13)$$ is shown to give a good estimate of the average hydrodynamic pore radius in homogeneous unconsolidated porous media. The equation for the shear rate at the pore wall in such media is taken as: $$\dot{\gamma} = \alpha\frac{4v}{r} \quad (14)$$ Where k is permeability, cm^2; ϕ is porosity; a is a shape parameter characteristic of the pore structure, $a=1.7$ for packs of large spheres having same diameter, $a=2.5$ for packed beds of angular grains; v is the superficial velocity, cm/s; r is the average pore radius, cm;	1. Calibrated glass beads having different diameters are packed to conduct experiments; 2. The porous media is assumed to have similar pore shapes but different pore sizes. 3. The shear rate is a maximum wall shear rate in the average pore throat diameter.	(Chauveteau and Zaitoun 1981) (Zitha, Chauveteau et al. 1995)

Table 1. Representative mathematical models to calculate apparent shear rate

4. Experimental apparatus and procedures

4.1 Apparatus

The polymer rheology in porous media is often measured by coreflooding experiments. Figure 1 shows a typical coreflooding apparatus. It is mainly composed of a pump used for pumping distilled water, piston accumulator used for polymer storage, core holder or sandpack, and pressure gauge or transducer to record injection pressure.
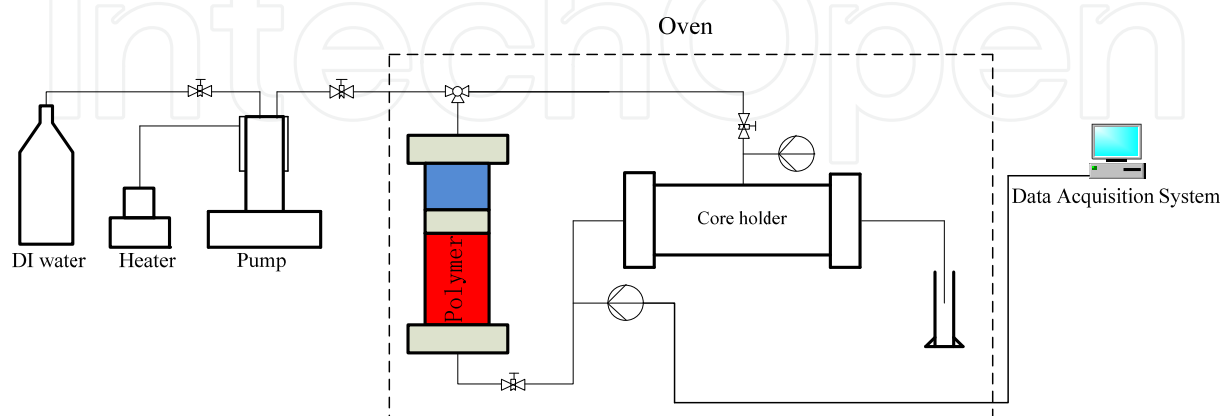

Fig. 1. Schematic of polymer flooding experiment.

4.2 Experimental procedures

1. Prepare a core or sandpack, and measure their weight;
2. Vacuum the core/sandpack for half an hour to one day, depending on permeability;
3. Saturate core with 4% KCl solution or a synthesized formation water;
4. Measure the weight of saturated core and calculate the effective porosity of the core;
5. Inject same brine to measure the core/sandpack permeability;
6. Saturate oil for the core, and calculate original oil saturation;
7. Inject same brine to displace oil until no oil comes out, and calculate residual oil saturation;
8. Inject polymer solution until a stabilized pressure can be seen at a given flow rate;
9. Continue injecting polymer solution at different flow rates and stabilized pressures as a function of injection rate are recorded.

Steps 6 and 7 can be ignored if the purpose of an experiment is only to test the rheology behavior of a polymer solution in porous media.

5. Factors impact the flow behaviors of polymers in porous media

5.1 Polymer type

Hydrolyzed Polyacrylamide (HPAM), Xanthan gum and associative polymers are the most frequently used EOR polymers, and they are all water soluble rather than hydrocarbon soluble.

5.1.1 Hydrolyzed Polyacrylamide (HPAM)

A HPAM solution is the most widely used polymer in oil field application. HPAM is a synthetic linear copolymer of acrylic acid and acrylamide (nonionic) monomers, with

negative charges in the carboxylate groups. Some amide groups ($CONH_2$) would be replaced by carboxyl groups (COO^-) during the hydrolysis process and, thus, have strong interactions with cations. Through reacting polyacrylamide with a base, such as sodium, potassium, etc., the adsorption on a solid surface can be reduced. The degree of hydrolysis is the mole fraction of amide groups that are converted by hydrolysis. It ranges from 15% to 35% in commercial products. The chemical structure of HPAM is demonstrated in Figure 2.
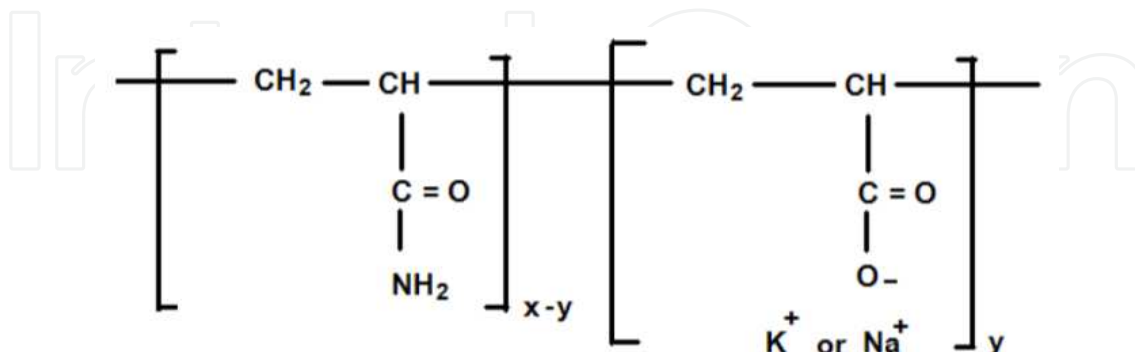
Fig. 2. Chemical structure of HPAM (Aluhwal and Kalifa 2008)

Hydrolysis of polyacrylamide introduces negative charges on the backbones of polymer chains that have a large effect on the rheological properties of a polymer solution (Sheng 2010). When HPAM is dissolved in distilled water or low salinity water, unshielded electrostatic repulsion exists between the anionic groups along the polymer chains, and the polymer molecules expand extensively. Therefore, the polymer chain and molecules are easy to stretch. This also explains that when HPAM solution is prepared in distilled water and flux at moderate to high shear rate, little or no shear thickening is seen (Seright, Fan et al. 2011). Once the HPAM molecular encounters the electrolyte solution, such as NaCl, the electrostatic repulsion is shielded by a double layer of electrolytes. Therefore, the stretch between the polymer chain and the molecules is decreased and a low viscosity is exhibited at a high salt concentration.

5.1.2 Xanthan gum

Xanthan gum, usually shortened to Xanthan, is another widely used polymer in oil fields. Xanthan is a microbial biopolymer, produced by the fermentation of glucose, sucrose, or lactose by the Xanthomonas campestris bacterium that are present in Xanthan in D-glucose, D-mannose, and D-glucuronic acid, as shown in Figure 3.

Xanthan exhibits high viscosity at a low shear force. Its shear thinning recovers rapidly once the shearing force is removed, and has a high resistance to mechanical shear degradation. Its good shear stability and thickening power at high salinity are major advantages of Xanthan over HPAM. The major disadvantages of this biopolymer are its high cost, the difficulty to prepare a uniform solutions and make it do not plug the porous media, and the viscosity loss during possible biochemical or chemical reactions (Wellington 1983).

5.1.3 Hydrophobically associative polymer

Water soluble hydrophobically associative polymers have developed very quickly in recent years, in order to possibly substitute them for HPAM and Xanthan polymers in oil field

applications (Taylor and Nasr-El-Din 2007). Associative polymers have very similar structure with the conventional polymers used in the oil industry, which is usually water soluble, except that they have a small number of hydrophobic groups attached directly into the polymer backbone (carbon chain) as shown in Figure 4. These hydrophobic groups can significantly change polymer performance, even at levels of incorporation of less than 1 mol%. During polymer flooding, the associative polymers show more stable fronts, as compared with conventional polymer solutions.
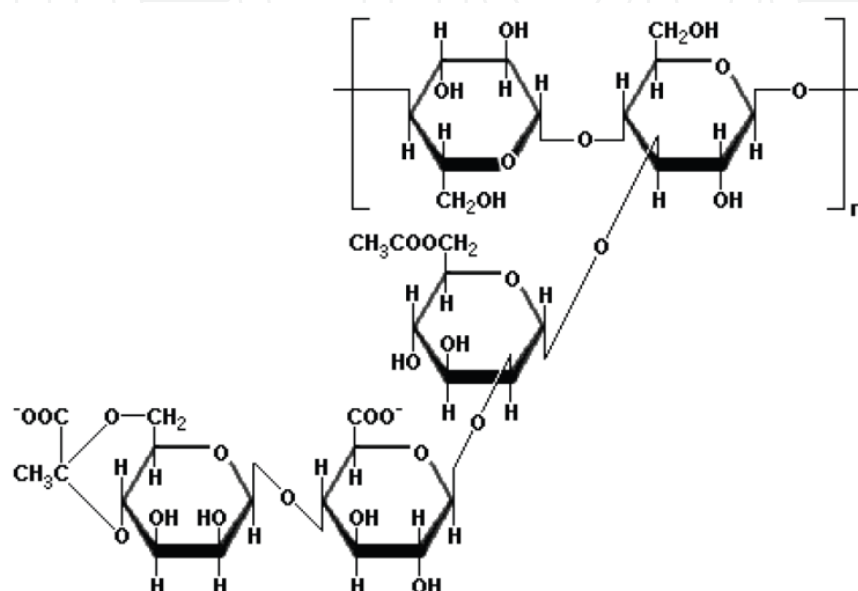
Fig. 3. Chemical structure of Xanthan Gum (Zaitoun, Makakou et al. 2011).
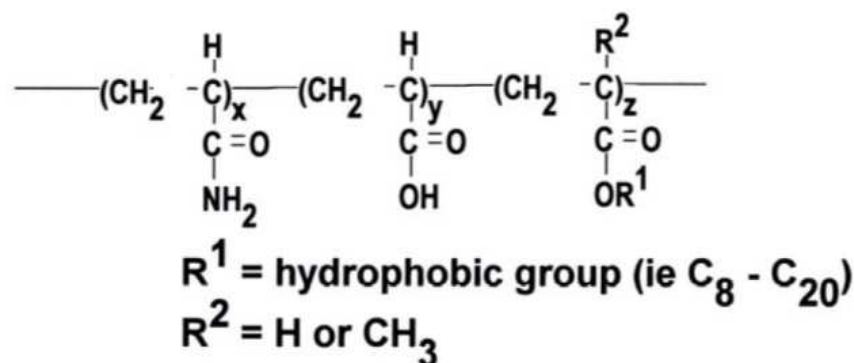
Fig. 4. Associating Acrylamide Copolymer (Taylor and Nasr-El-Din 2007)

Many hydrophobically associative polymers have been developed: SNF Floerger-S255, C1205; I-20; HMpolyDMAEMA; AP-P3; AP-P4, and etc. Different polymers have diverse characteristics. Lab tests and field applications show that one specific associative polymer may have one or two special characteristics that are better than those of HPAM or Xanthan gum. Take SNF Floerger-C1205 for instance, C1205 is an anionic-polyacrylamide-based tetra-polymer which has associative properties (Gaillard and Favero 2010). Typically, it has a hydrophobic monomer content range from 0.025 to 0.25 mol%, a 12 to 17 million g/mol

Molecular weights (Mw) and a 15 to 25 mol% total anionic content. Sulfonic monomer is present with less than 8 mol%. HPAM and C1205 (called AP in the Figure) are prepared with concentrations of 500, 900, 1,500, and 2,500 ppm in 2.52 % of the total dissolved solid (TSD) brine. Experiments are conducted in porous polyethylene cores. As shown in Figure 5, the resistance factors of the associative polymer (at a given flux) are substantially greater than those of HPAM. The associative polymer displays a similar trend with that of HPAM, with shear thinning at a low shear rate, and then changes to shear thickening at a high shear rate. The low flux resistance factors for associative polymer are around twice those of HPAM. Specifically, 500 ppm of the associative polymer (solid circles) behaves in a manner like that of 900 ppm of HPAM (open triangles). 900 ppm of the associative polymer (solid triangles) conducts like that of 1,600 ppm of HPAM (open squares) (Seright, Fan et al. 2011).
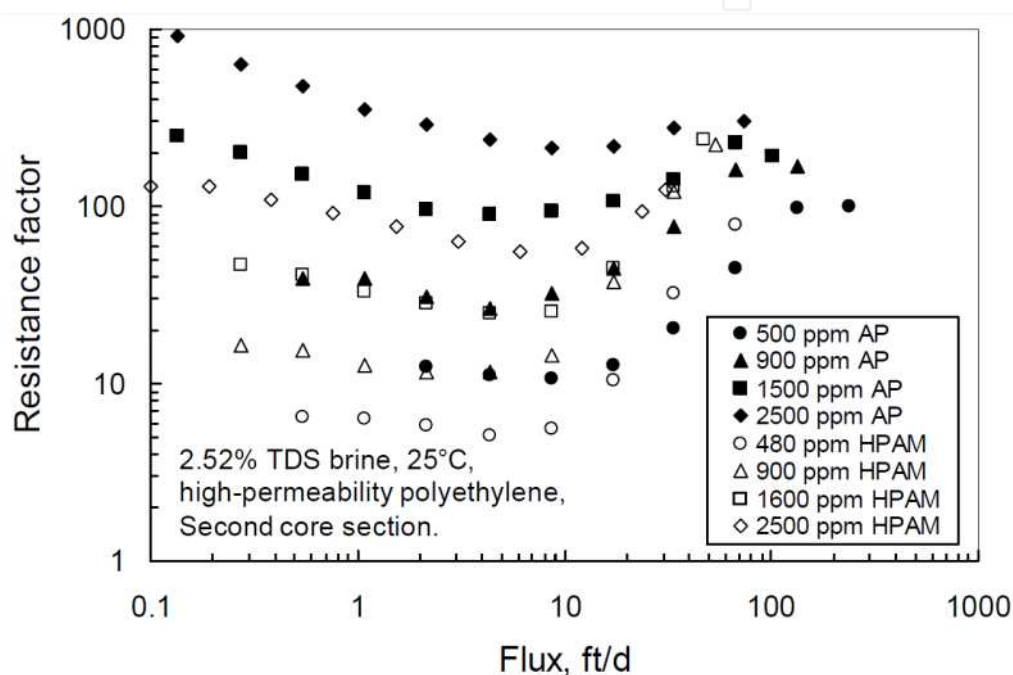

Fig. 5. Resistance factors in polyethylene: Associative polymer C1205 vs. HPAM (Seright, Fan et al. 2011).

However, when exposed to 235 psi/ft, the resistance factor losses for the associative polymer are significant—from 31 to 45%, while it is modest for HPAM—from 0 to 15%. This tells us that this associative polymer could behave in a manner similar to that of the HPAM with half concentration, but the resistance factor losses are relatively higher, as compared with those of HPAM.

Therefore, the polymer should be selected with consideration being given to its in situ geological and fluid properties, in order to make it fit and be cost effective.

5.2 Shear rate

When a polymer solution is injected into a reservoir from an injection well, the flow rate, which is related to shear rate, will change from wellbore to in-depth of a reservoir; therefore, the solution viscosity will also change from near wellbore to the in-depth of a reservoir correspondingly.

Masuda, Tang et al. (1992) conducted a series of experiments using 2.8 cm diameter, 47 cm long, unconsolidated cores packed with glass beads (70/100 mesh). Porosity and permeability are tested to be 37% and 25 μm², respectively. Two white mineral oils with viscosities of 25, 60 mPa·s, and a 200 ppm HPAM solution were employed as working fluids. In each experiment, polymer flooding was carried out after water flooding. Initial water saturation was controlled to be almost the same level at the start of each polymer flooding. The relationship of HPAM solution viscosity vs. shear rate measured in porous media and by viscometer is plotted in Figure 6.
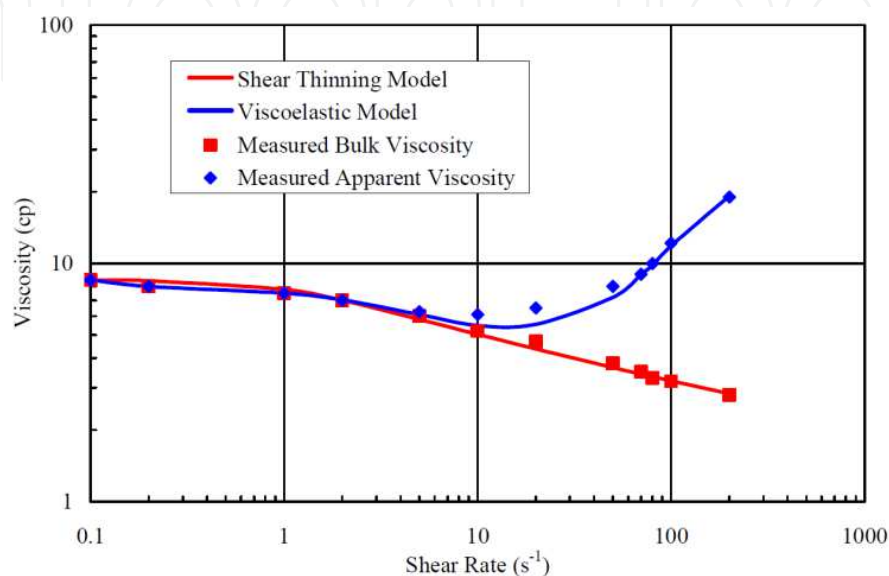
Fig. 6. Viscosity vs. shear rate of HPAM measured in porous media and by viscometer (Delshad, Kim et al. 2008).

The red box and blue diamond are bulk viscosity and apparent viscosity, acquired by viscometer and coreflooding experiments, respectively. Delshad, Kim et al. (2008) successfully matched their results with the shear thinning model and viscoelastic model as given in Figure 6.

At low velocities in a porous media, a Newtonian, near-Newtonian or mild shear thinning is observed, and the bulk viscosity has the same trend, as measured by a capillary viscometer. With the shear rate increasing, the bulk viscosity curve starts to decline, displaying an obvious shear thinning, while the apparent viscosity in the porous media starts to deviate from the declining bulk viscosity. When the shear rate continues extending, the bulk viscosity follows the same decreasing slope, but the apparent viscosity in porous media starts increasing and displays a shear thickening (Masuda, Tang et al. 1992). This behavior of HPAM solution is also confirmed by other authors (PYE 1964; Smith 1970; Jennings, Rogers et al. 1971; Hirasaki and Pope 1974; Seright 1983; Heemskerk, Rosmalen et al. 1984; Delshad, Kim et al. 2008; Seright, Seheult et al. 2008; Seright, Fan et al. 2011).

However, there is no consensus formula which could give the best prediction on the relationship of in situ viscosity and in situ shear rate. Generally, we need data both from viscometer and coreflooding experiments. Viscometer data is easy to obtain. If we do not have coreflooding data, we will need to match other available data by adjusting the shear rate coefficient: C in Equation 12. Gogarty (1967) stated that the shear rate coefficient is

related to velocity, permeability, and porosity. Teeuw and Hesselink (1980) found that the shear rate coefficient is a function of the power law coefficient and exponent in the viscometer, or the geometry of the porous medium. Cannella, Huh et al. (1988) stated that the shear rate coefficient is directly related to the ratios of the effective capillary tube radii which used to model the non-Newtonian fluid in porous media. From their findings, it is still not clear which variables keep a major impact on the shear rate coefficient (Wreath, Pope et al. 1990).

5.3 Molecular weight

Molecular weight is the ratio of the mass of the polymer molecular to $1/12^{th}$ of the mass of carbon-12 (Elias 2008), used to describe the constitutional size of a macromolecule substance. Its unit is Dalton, symbol: Da, g/mol is also used, 1 Da = 1 g/mol. Molecular weight can be determined using mass spectrometry.

Molecular weight is the main factor that affects the flow behavior of a polymer. The molecular weight of a polymer is directly related to its molecule size, which means the polymer with higher molecular weight has a larger molecular size. The polymer solutions with higher molecular weight usually have higher adsorption, higher resistance, and higher viscosity, as shown in Figure 7 (Dong, Fang et al. 2008).
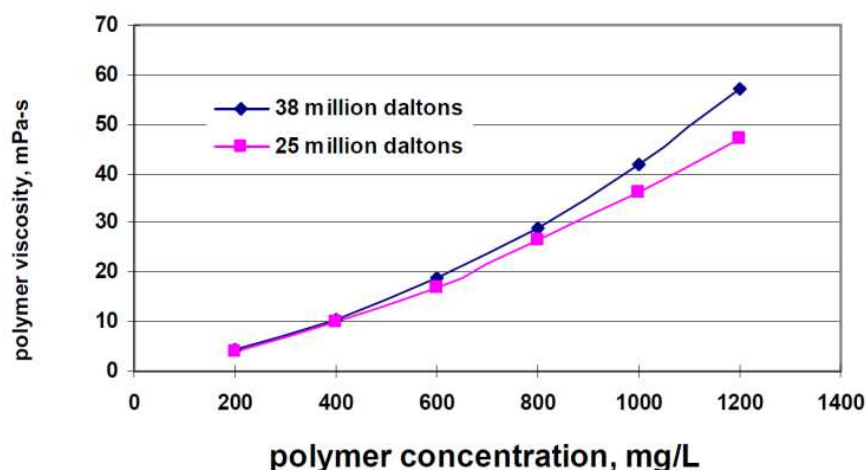

Fig. 7. A polymer's apparent viscosity as a function of molecular weight and concentration (Dong, Fang et al. 2008).

In many circumstances, a larger polymer Mw also leads to higher oil recovery. Dong et al (2008)'s coreflooding experiments shown in Table 2 verify this expectation. In these experiments, water flooding was first used, and their recoveries were almost the same (32 to 33%). Then different molecular weight polymers were applied to improve oil recovery. Total injected polymer mass was 570 mg/L·PV. Polymer concentration was 1,000 mg/L. Each core had three zones with a heterogeneity coefficient of 0.72. As shown in Table 2, the polymer with the molecular weight of 18.6 million Daltons had the highest ultimate recovery.

But for the reservoirs with middle to low permeability, higher molecular weight needs high injection pressure and also might cause more unswept pore volume, and thus resulting in lower recover factor shown as Figure 8 (Zhang, Pan et al. 2011).

Mw, 10⁶ Daltons	Water flooding recovery, %	Polymer flooding recovery %	Ultimate recovery, %
5.5	32.7	10.6	43.3
11	32.9	17.9	51.8
18.6	32.2	22.6	54.8

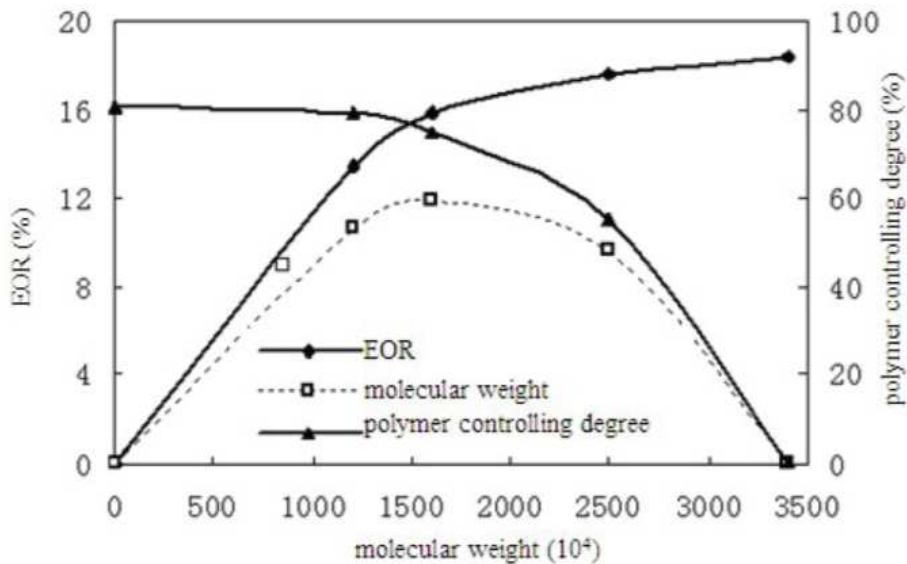Table 2. Effect of polymer molecular weight (Mw) on oil recovery (Dong, Fang et al. 2008)

Fig. 8. Molecular weight as a function of enhanced recovery rate and controlling degree (Zhang, Pan et al. 2011).

Other previous studies have shown that the high Mw polymer solutions are known to be shear sensitive (Maerker 1976; Martin 1986). Due to the breakage of macromolecule chain, shear degradation is irreversible. Zaitoun (2011) tested six polymers and co-polymers with different Mw from 2 to 18.5 million Daltons through a 5 cm long stainless steel capillary tube with a 125 μm internal diameter. The results are shown that an increase in Mw induces higher shear sensitivity. Since a large coiled macromolecule is stretched more under the same deformation regime.

However, some factors should be taking into account when choosing the polymer molecular weight. Firstly, polymer with highest Mw could minimize the amount of polymer. Secondly, the relationship between Mw and permeability should be taken in account. Thirdly, the Mw must be small enough so that the polymer can enter and propagate effectively through the pore throat and channels (Dong, Fang et al. 2008), moreover the lower Mw may be a better option for field application because very high Mw polymers may lose most of their viscosifying power when submitted to shear degradation (Zaitoun, 2011).

5.4 Polymer concentration

The concentration of a polymer can either be expressed as parts per million (ppm), pound per thousand gallon (pptg), or mg/L, although ppm is the most frequently used term.

Aluhwal and Kalifa (2008) conducted series of experiments with various concentrations of HPAM solution through sandpack at 77 °C. Results are shown in Figure 9. They measured the pressure and calculated the apparent viscosity. In porous media, for a HPAM solution at low concentration (<1,000 ppm), the apparent viscosity slightly increases with the polymer concentration increasing. While at a high concentration (>1,500 ppm), however, the apparent viscosity is increasing at a faster rate.
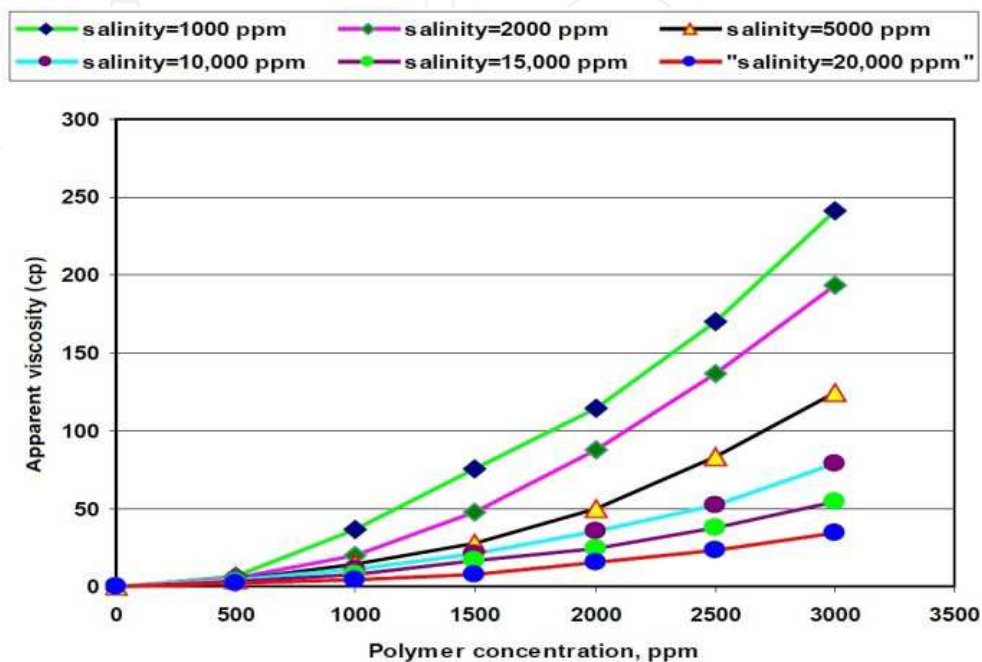

Fig. 9. A polymers' apparent viscosity as a function of concentration and salinity (Aluhwal and Kalifa 2008).

However, the rheological behaviors of associative polymers can be divided into a dilute region and a semi-dilute region by a critical concentration: c*. At concentrations below c*, it is in a dilute region where intramolecular hydrophobic associations within the polymer dominate the behavior of the polymer, and the viscosity decreases with the solution concentration increase. At a concentration above c*, it is in a semi-dilute region where intermolecular associations between polymers control the polymer rheology and the viscosity increases with the solution concentration increases (Taylor and Nasr-El-Din 2007).

Generally, the polymer concentration has a direct relationship with the apparent viscosity where an increase in the polymer concentration results in an apparent viscosity increase.

5.5 Salinity

Beside concentration, the salinity of water used to prepare a polymer solution also has a major impact on apparent viscosity. A change in the quantity of water directly affects the polymer solution's viscosity. As mentioned above, when a polymer, like HPAM, is exposed to different salinity water, its anionic and cationic in the water would have attraction/repulsion to the polymer chain, and make it compressed or stretched. When it exhibits to the distilled or low salinity water, the electrostatic repulsion between anionic groups along the polymer chains would be unshielded, make the polymer molecules

expand extensively. Then it is relative hard to pass through a porous medium and generate a relative high viscosity. When it encounters the higher salinity water, electrostatic repulsion is shielded by a double layer of electrolytes. Therefore, the stretch between the polymer chain and the molecules is decreased and a low viscosity is produced at a high salt concentration.

The electrostatic interaction between the charged groups plays an important role in adsorption as well as the permeability reduction phenomena (Aluhwal and Kalifa 2008). Figure 9 above also illustrates that salinity has a relatively strong effect on the polymer's apparent viscosity. A higher salinity would generate a lower apparent viscosity and with an increase in polymer concentration, this effect is strengthened.

5.6 Permeability

Using two Berea sandstone cores (55 and 269 md permeability) and one porous polyethylene core (5120 md permeability with a pore structure similar to Berea sandstone), Seright (2011) conducted experiments with 600 ppm Xanthan in 2.52% TDS solution with a wide injection rate range (0.0174 to 1111 ft/D). Results are shown in Figure 10, which indicates that cores with high permeability have a higher resistance factor, and it continuously decrease with the extension of velocity, while the resistance factor difference between the high permeable cores and low permeable cores is narrowing. At a flux above 100 ft/D, the resistance factors of 55 md and 269 md sandstone cores show almost no difference.
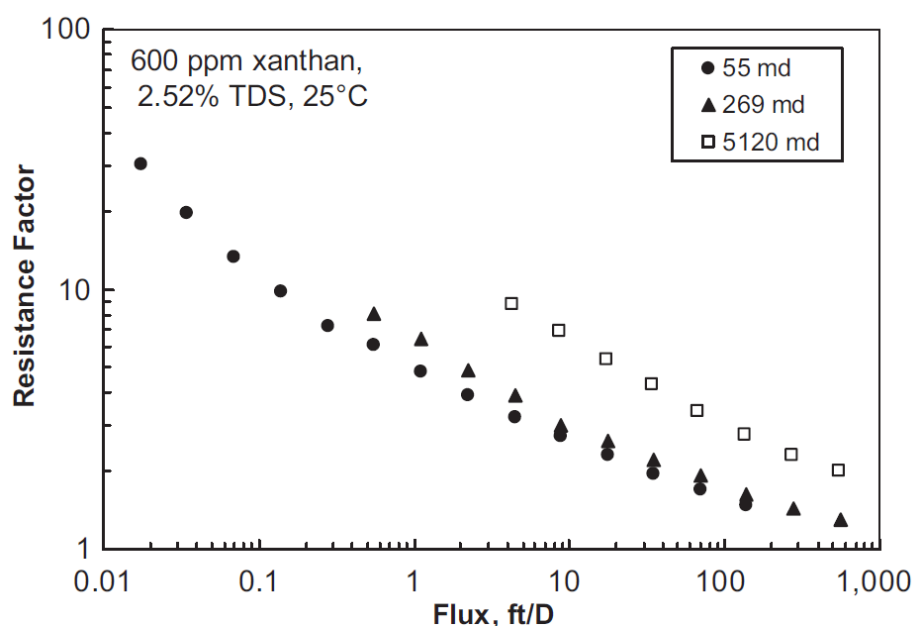

Fig. 10. Resistance factor vs. flux for 600 ppm of Xanthan with different permeability cores (Seright, Fan et al. 2011).

6. Summary

In this chapter, we have discussed some basic rheological properties of polymer solution flow in porous media, such as rheological terms, shear rate models, experiment

measurement and impact factors. Apparent viscosity, effective viscosity and resistance factor are the basic terms that can be used to estimate the polymer flow behavior in a porous media. Based on capillary bundle model, five mathematical shear rate models are presented with their prerequisite conditions and assumptions. Then experimental method and flow chart are detailed. The factors that impact polymer solution rheology in porous media were reviewed, including polymer types, shear rate, molecular weight, concentration, salinity, and formation permeability.

7. Acknowledgement

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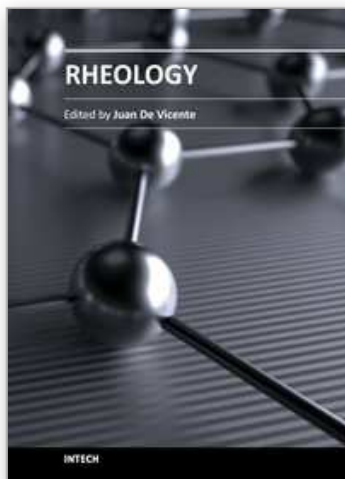
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