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Full Length Article

Novel viscoelastic model for predicting the synthetic polymer's viscoelastic behavior in porous media using direct extensional rheological measurements

Madhar S. Azad, Japan J. Trivedi*

School of Petroleum Engineering, Department of Civil and Environmental Engineering, University of Alberta, Edmonton, Alberta T6G 1H9, Canada

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ABSTRACT

High molecular weight, flexible polymers used for heavy oil recovery exhibits viscoelasticity that causes the thickening of apparent viscosity which could not be predicted by the conventional shear thinning rheological models. Unified apparent viscosity model (UVM) developed at UT-Austin based on the postulation that the apparent viscosity of polymer solutions is the sum of shear and elongational viscosity accounts for the viscoelastic thickening in the extensional part through relaxation time, maximum elongational viscosity and strain hardening index. Although UVM addresses the other limitation of the previous viscoelastic models, its dependence on the core flood data to predict maximum elongational viscosity and strain hardening index limits its commercial independent usage for preliminary screening.

These limitations are addressed in our novel viscoelastic model named as Azad Trivedi Viscoelastic Model (AT-VEM), which could predict the apparent viscosity in the shear thickening region using the extensional parameters measured by capillary breakup extensional rheometer (CaBER) through the combination of Upper Convected Maxwell (UCM), finite extensible nonlinear elasticity (FENE) and power law theories. CaBER set up uses a step-strain to stretch the drop of polymeric liquid placed between the two plates and monitor its midpoint diameter during filament drainage. The relaxation time is determined by fitting the filament diameter from the region representing the balance between the elastic stress and surface tension into UCM. As per FENE theory, fluid relaxes at the rate two-third of its strain rate and the extensional viscosity around the critical Deborah number of 0.66 corresponds to the maximum elastic limit and would be the maximum elongational viscosity. Filament during drainage gets strained and the corresponding increment in extensional viscosity is fitted with power law to determine the strain hardening index.

A series of core flood data (performed using partially hydrolyzed polyacrylamide (HPAM) polymers) from the UT-Austin that validated the UVM model was used extensively. Other reported literature data were also used. Extensional rheology was performed on those polymers at the similar conditions to determine the relaxation time, maximum elongational viscosity, and strain hardening index. These parameters along with the shear parameters were used to match the reported apparent viscosity. All the experiments fairly match well with the average downscaling power factor of 0.35 to the maximum elongational viscosity and subtrahend of 1.2 to the strain hardening index. Downscaling and subtrahend factor is essential to scale down the pure elongation in the extensional bulk field to the combination of shear and elongation experienced in the porous media.

AT-VEM can be incorporated into commercial numerical simulators for predicting the injectivity and recovery due to viscoelastic thickening independently and thereby assist in quick screening polymers for oil recovery applications.

1. Introduction

Polymer flooding is one of the most commonly used enhanced oil recovery (EOR) methods for improving the recovery factor in depleted oil reservoirs. Polymers are also used as mobility control agent in surfactant polymer (SP) flooding, alkali polymer flooding (AP) flooding and alkali surfactant polymer (ASP) flooding [1]. A large amount of oil remains as unswept oil in the water flooded reservoir. The amount of

* Corresponding author.
E-mail address: jtrivedi@ualberta.ca (J.J. Trivedi).

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unswept oil after water flooding will be higher in the reservoirs characterized by high heterogeneity and high oil viscosity. Water is a Newtonian fluid with the unit viscosity that tends to channel/finger easily through high permeable streaks and high viscous oil. The added polymers viscosify the displacing slugs, control its mobility and thereby provide high sweep efficiency which is essential for higher overall recovery factor. The polymers solutions are non-Newtonian and the viscosity exhibited by them would be different at different shear rates. Shear rates are generally high near the wellbore. In the farthest part of the reservoirs, shear rates are generally low due to exposure of flood front to a larger area. Shear rates are also dependent on the injection rate, permeability, porosity etc. Reservoir characterized by the high oil viscosity requires high viscosity from polymer solutions for the optimal sweep. Injectivity is an issue with slugs providing high viscosity [2]. Hydrolyzed polyacrylamide (HPAM) and Xanthan gum, the two commonly used EOR polymers [1–4], exhibit different in-situ behavior. Xanthan gum is rigid, viscous biopolymer without considerable elasticity. HPAM is the synthetic viscoelastic polymer. Viscoelasticity in HPAM provides higher in-situ viscosity than xanthan gum to the displacing slugs [4]. Prior determination of the in-situ viscosity exhibited by the displacing slugs is essential for screening and simulation. Core flooding can be performed to determine the in-situ viscosity of polymer solutions. However, chemical EOR (cEOR) is an extensive process. Salinity variances in the reservoir necessitate core flooding to be done at different salinities. Different combinations of chemical EOR slugs include the different concentration of surfactant, polymer, and alkali. Performing core flooding with respect to these variables is a cumbersome process. Moreover, cores for representative reservoirs are not available in most of the cases, or obtaining the cores is an expensive process. Rheological experiments are performed to measure the viscosity at the desired shear rate and correlating them to the reservoir's shear rate by the appropriate mathematical models. Shear rheological experiments are used extensively in the oil industry for predicting the performance of polymer solutions [5–7]. Shear rheological experiments are also used for screening the chemical formulation for mobility control purpose [8]. Carreau model, developed based on shear rheology, was successful in matching the porous media behavior for viscous biopolymers that shows thinning in both the bulk shear and porous media [2,5].

Viscoelastic effects were deemed to cause the reduced mobility of synthetic HPAM solutions at high rates in porous media [9–11]. Marshall and Metzner [11] correlated the viscoelastic effects with Deborah number. They reported that the viscoelastic effects become dominant in porous media when Deborah number is in between 0.1 and 10. At higher flow rates, the Deborah number increases. Smith [12] observed that the mobility of polymer solutions decreases significantly at higher flow rates. Smith claimed that viscoelastic effects at high rates might reduce the channeling in the high permeable zone. Jennings et al. [13] also reported the viscoelastic effects were prominent with high molecular weight polymers with flexible, linear chain structures. High rates are typically encountered around the wellbore where the injectivity is a major concern. Injectivity, defined as the measurement of ease with which the fluid can be injected into the reservoir [14] will be lower for viscoelastic polymers possessing higher apparent viscosity at the higher shear rate. Higher apparent viscosity results in the higher injection pressure. The excessive pressure generated during injection will result in the mechanical degradation and formation fracturing. Both degradation and unintended fracturing are undesirable and the amount of fluid that can be injected safely becomes lower in the case of viscoelastic polymers. Viscous polymer solutions exhibiting shear thinning will have higher injectivity. Viscoelastic polymers solutions exhibit thickening after a critical flow rate in the porous media [15–21]. Thickening causes an increase in the viscosity with respect to shear rate. However, in the bulk shear field, its exhibits shear thinning. Polymer solutions that exhibit shear thinning in the shear field, exhibits thickening in the extensional field [22]. Carreau model that predicts the pure viscous biopolymer behavior fairly well, underestimated the apparent viscosity of the viscoelastic polymers in the porous media by a considerable margin [16,17]. Seright et al. [2] studied the behavior of HPAM and biopolymer in porous media. Xanthan gum exhibits shear thinning behavior both in bulk shear field and in porous media. HPAM that exhibits shear thinning in bulk field, exhibited thickening in porous media. This was attributed to viscoelastic nature of HPAM. Predictions based on the Carreau model will result in the overestimation of injectivity that may lead to undesirable consequences such as fracturing and mechanical degradation.

The critical flow rate that results in the viscoelastic thickening may occur at the relatively lower rate experienced in the reservoir for high molecular weight polymers [17,23]. Viscoelastic effects may result in poor injectivity. However, it influences the oil recovery positively [15,17,23,24]. Therefore, predicting the onset is crucial for screening or formulating the polymers solutions that could give better recovery due to viscoelasticity. Onset is not observed in the Carreau model for viscoelastic polymers solutions [17]. Thus, viscoelasticity has an influence on the injectivity and recovery. Predicting the shear thickening regime and onset is crucial for screening the polymers for optimal injectivity and recovery. Models were developed since 1970 s, to quantify the viscoelastic effects [3,15,17,25–30]. Hirasaki and Pope [25] developed the viscoelastic model based on the postulation that flow through varying cross-sectional pores is simply elongational. However, the physical meaning of the Hirasaki and Pope's model is lost when the Deborah number is greater than 1. Commonly used high molecular weight polymers exhibit Deborah number much higher than 1 [25]. Heemskerk et al. [26] performed detailed core flood studies to ascertain the viscoelastic onset. The authors quantified the viscoelastic effects through the critical flow rate causing the viscoelastic onsets. Also two power-law coefficients representing thinning and thickening effects were used. The conducted studies provided a detailed sensitivity analysis of polymer and porous media properties on the viscoelastic effects. However, it could not be used for quick screening as it relied completely on core flooding. Masuda et al. [15] developed an improved version of viscoelastic model representing the Darcy viscosity through the combination of elastic viscosity and viscous viscosity for accounting the viscoelastic effects. The developed model was used to history match the additional oil recovery caused by the viscoelastic effects. Masuda's model depends on core flooding to determine the empirical parameters and relaxation time. Another limitation is the elastic force in the elongational part increases indefinitely when Deborah number increases. Ranjbar et al. [27] developed a model based on the Maxwell-Fluid relation for accounting the additional apparent viscosity caused by the strain flow of viscoelastic polymer solutions. They reported that the model index to be important parameter for viscoelastic quantification. Model index is determined through extensive core flooding experiments by observing the changes inducted to the polymer molecules before and after the reduction of injection rate and injection pressure. Garrouch [3] highlighted the limitation of oscillatory relaxation time in 1999 in explaining the different porous media behavior of viscous polymer and viscoelastic polymer. The author introduced a new viscoelastic number. New number that explains the behavior of viscous polymer and viscoelastic polymer is determined through core flood experiments. Yin-Hongjun [28] proposed the model that requires extensive core flooding experiment to calculate the apparent viscosity. Delshad et al. [17] developed the unified apparent viscosity model (UVM) based on the postulation that the apparent viscosity of polymer solutions is the sum of shear and elongational viscosity. UVM models account for the viscoelastic thickening in the extensional part through oscillatory relaxation time, strain hardening index and maximum elongational viscosity. Deborah number is the product of the relaxation time and shear rate. UVM model addressed the limitation of previous viscoelastic models. However, UVM depends on the core flood data to predict the extensional parameters such as maximum elongational viscosity and strain hardening index. Recently, Kim et al. [29]