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Review Paper

A comprehensive review of in-situ polymer gel simulation for conformance control

Baojun Bai*, Jianqiao Leng, Mingzhen Wei

Missouri University of Science and Technology, Rolla, 65409, USA

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ABSTRACT

Gel treatment has been widely applied in mature oilfields to improve sweep efficiency and control water production. Correct numerical simulation is of major importance to the optimization design and prediction of a successful gel treatment. However, there exist many problems in current simulation studies in published literature. This paper first presents a comprehensive review on the major factors that have been considered at different gelation stages during gel treatment, the models used in the commercial/in-house simulators, and current numerical simulation studies on both laboratory and field scales. Then we classify the current in-situ gel numerical simulation problems as 1, deficient model problem that has published numerical model but has not been applied in simulator and application studies; 2, missing model problem that does not have published quantitative model; and 3, inaccurate application problem that does not consider the major factors of gel performance, based on the reasons from some questionable results of current simulation studies. Finally, we point out the major research efforts that should be made in the future to better simulate in-situ gel treatment process. The review indicates that numerous simulation studies using commercial software packages intend to predigest the gel treatment, many of which, however, ignore important mechanisms and mislead the operation of gel treatment. In fact, a full assessment of simulating in-situ gels cannot be achieved unless the quantitative models can be qualified in terms of transport and plugging mechanisms based on the experimental results.

1. Introduction

Excessive water production is a common problem as reservoirs mature due to reservoir heterogeneity and low sweep efficiency. For heterogeneous reservoirs, after thief zones (or water channels) are formed by extensive water floods, improved sweep is commonly needed immediately. Gel has been widely applied in oil industry including sealant for wellbore leakage (Zhu et al., 2021), fluid (Wu et al., 2021), and plugging agent for enhanced oil recovery (Zhao et al., 2021). Conformance control using gel treatment is a technique to encourage displacing movable oil in an un-swept zone and to improve water drive closer to optimal conformance condition (Bai et al., 2015). With proper application, gel treatment is proved to be an effective and economic solution to control the conformance and reduce water production from oil and gas fields.

In-situ gel treatment was developed in 1970s (Needham et al., 1974) for conformance control. The concept of gel treatment is to improve the sweep efficiency of water flooding by placing a blocking slug of gel at water channel to seal the thief zone. Many types of gels have been tested in the past decades, the success experience favors the polymer-based gel system proposed by Sydansk (1988, 1990) that used partially hydrolyzed polyacrylamides (HPAM) and Chromium III (Cr(III)) acetate for conformance control due to its relatively long and stable gelation time. Thus, this review will mainly focus on the HPAM/Cr(III) acetate type of gel. The basic operation for this technology is to pump the polymer solution (e.g., 0.5 wt%) and crosslinker system (e.g., 1/40 of polymer) as a mixture solution, called gelant, into the formation with a relatively low flow rate to reduce gelant invasion in matrix. Then, shut-in the well for certain time ensuring in-situ gelation taking place sufficiently. The gelation process refers to the transition from polymer/crosslinker to crosslinked polymer gel. During this period, the slug of three-dimension gel as a permeability modifier or barrier in the preferential water channel is formed.

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* Corresponding author.
E-mail addresses: baib@mst.edu (B. Bai), jl3kf@umsystem.edu (J. Leng), weim@mst.edu (M. Wei).

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Finally, open the well and the water drive can be diverted to the unswept zone. Based on the location of gel placement, the treatment can be categorized by injection profile control, in-depth flow path diversion, and producer water shutoff.

Based on experiences, Sydansk and Southwell (2000), Sydansk et al. (2005) and Seright et al. (2011a) stated that the conformance control using in-situ gel treatment is a very complicated concept that strongly depends on the gel-, reservoir-, well-, and formation-properties. On the other hand, based on their compositions and application conditions, effect of in-situ gel treatment also depends on the gel properties. To ensure a successful treatment and to optimize the performance of in-situ gel, numerous experiments have been carried out to study the mechanisms. However, due to limitation of budgets, instruments and research scale of lab experiments, the accurate critical conditions and optimization for gel treatments are commonly difficult to obtain. Thus, numerical simulation studies are vitally important to study the laboratory results and to optimize the field applications. However, due to complex physiochemical properties of polymer gel, quantitative studies of in-situ gel treatment are very challenging. Qualified simulation of gel treatment requires the consideration of major mechanisms, principal physio-chemical phenomena, and important influence factors; the consistency between laboratory and simulation results; and the capability of computational efficiency.

Therefore, the purposes of this review are to summarize the mechanisms, to examine the capability of commercial/in-house simulators and to critically investigate the simulation studies. With this review, the researchers interested in gel treatment simulation can improve the simulators and simulation methods to meet current needs of mature oilfields.

2. Mechanisms discussion of in-situ gel treatment for numerical simulation

Simulation of in-situ gel is quite complicated because the system contains great change in viscosity and flow regime before and after gelation. Moreover, the system has both fluid and solid properties during crosslinking process and after gel is formed. It is necessary to categorize in-situ gel treatment as three stages based on the gelation process, including gelant stages, gelation stage and gel stage, separately.

2.1. Gelant stage

Gelant is a mixture of polymer, crosslinker and perhaps some additives. Before gelation, the gelant has quite the same flow behavior as polymer solution alone (Seright, 1991a, 1991b, 1991b). The gelant properties and parameters to be considered for a numerical simulation include polymer rheology, polymer and crosslinker adsorption/retention, and inaccessible pore volume.

Polymer rheology. Resistance factor (F_r) is a critical parameter to quantify the rheology of polymer in laboratory experiment. It is measured by pressure drop ratio of waterflooding to polymer injection at the same flow rate (Eq. (1)). Assuming no reduction of permeability caused by polymer, we can estimate F_r by viscosity ratio due to the same effective permeability to gelant and water. If we assume water viscosity is unit, we can further estimate F_r by the apparent viscosity of gelant.

$$F_{\mathrm{r}} = \frac{\Delta \boldsymbol{P}_{\mathrm{p}}}{\Delta \boldsymbol{P}_{\mathrm{w}}} = \frac{\lambda_{\mathrm{w}}}{\lambda_{\mathrm{p}}} = \frac{\frac{k_{\mathrm{w}}}{\mu_{\mathrm{w}}}}{\frac{k_{\mathrm{p}}}{\mu_{\mathrm{p}}}} \sim \frac{\mu_{\mathrm{p,app}}}{\mu_{\mathrm{w}}} \sim \mu_{\mathrm{p,app}} \quad (1)$$

where $\Delta \boldsymbol{P}$ is pressure drop, λ is mobility , k is effective permeability, $\mu_{\mathrm{p,\ app}}$ is polymer apparent viscosity, subscript w refers to water and p refers to polymer.

The rheology of polymer, as a non-Newtonian fluid, has been studied for decades by many researchers (Gogarty, 1967; Graessley, 1974; Gleasure, 1990; Seright et al., 2008; Smith, 1970; Zhang and Seright, 2015). Seright et al. (2011b) summarized the rheology responses of polymers and concluded that the resistance factor could be a function of polymer concentration, salinity, shear rate (velocity), which depended on the type of polymer and formation properties. Their studies reported that Xanthan polymer only behaved a shear thinning rheology that the resistance factor decreases with increasing shear rate. HPAM polymer behaved a Newtonian flow regime at low shear rate, a shear thinning rheology at low to medium shear rate and a shear thickening rheology at medium to high shear rate. Shear thickening means that the resistance factor increases with increasing shear rate. Their studies also showed that the critical condition for the onsets of shear thinning and shear thickening depended on the polymer concentration, salinity, and porous media permeability. Besides, Seright et al. (2011b), Zechner et al. (2013) and Ma and McClure (2017) stated that if the formation contained open fractures, such as the natural fractures, extension of hydraulic fractures and wormholes, HPAM polymer would perform only shear thinning rheology, because the polymer elongations in small pores were not observed in large pores or fractures.

Seright et al. (2011b) studied the impact of polymer concentration and salinity on polymer rheology. The results showed that with increasing polymer concentration from 200 to 1600 ppm, the onset of shear thickening (the velocity required to let polymer start to behave shear thickening) decreased by a factor of two. The results also showed that polymer tended to have a higher shear thickening coefficient (greater shear thickening slope) in high salinity water than in low salinity water.

Polymer and crosslinker retention. During injection of gelant, polymer and crosslinker retention can have a major impact on gelant penetration into a reservoir and the gelant composition in different locations due to chromatographic effect. Adsorption was reported as the major mechanism for polymer and crosslinker retention that might occur via physical and chemical adsorption. The adsorption process can be characterized by determining the number of molecules adsorbed per surface area. μg polymer per g contaminant is the commonly used unit for polymer and crosslinker adsorption. Green and Whillhite (1998) reported the retention of polymer ranged from 9 to 700 μg/g for polymer concentration 500–3000 ppm, which greatly influenced the transport of polymer during placement. Langmuir adsorption isotherm is commonly suggested for the fitting of retention result of polymer. Polymer has a large molecule composed of repeating subunits bound together by covalent bonds. Thus, besides adsorption, Ferreira (2019), Zhang and Seright (2014) stated that retention data suggested the bridging, clogging and entrapment could also be the main mechanisms of polymer retention as a function of polymer hydraulic dynamic radius and pore throat size. The recent study (Dandekar et al., 2021) also indicated the polymer solution retention data was not fitted well with Langmuir adsorption isotherm. Stavland et al. (1993) studied the retention of crosslinker and stated that different retention mechanisms such as ion exchange and precipitation could be observed having alone or combination effect on crosslinker retention, which was related to pH value, carbonate concentration and core types.

Inaccessible pore volume (IAPV). Dawson and Lantz (1972) observed the IAPV of polymer that some pore volume is accessible to small molecule water but inaccessible large molecule polymer. Since then several mechanisms conducting IAPV have been reported and summarized by Leng (2021): (1) Molecule sizes restricted polymer from penetrating into some pore space (Shah et al., 1978); (2) Existence of depletion effect of large molecules built up a depletion layer at pore walls and prevented the mass centers of polymer molecules from reaching pore walls (Chauveteau, 1981; Omari et al., 1989; Sorbie, 1989); (3) Unfavored entropic effect pushed polymers away from solid boundaries (Liauh et al., 1979); (4) In-situ rheology behavior of polymer was different from intrinsic rheology, which made polymer flow in-situ faster than expected (Chauveteau et al., 1984; Ferreira, 2019; Stavland et al., 2010). Though the value and explanation of IAPV concept were not consensus, the existence of IAPV that influenced the transport of polymer was commonly acknowledged. Zhang and Seright (2014) summarized the IAPV data from the laboratory results reported in literatures and concluded that the IAPV value had a wide range from 0% to 48%. Their results showed that the IAPV was positively related to the S_{or} and mole weight, negatively related to the resistance factor and retention. However, due to inconsistency of the IAPV results, no quantitative models were reported for IAPV model.

2.2. Gelation stage

The process of gelation contains inner crosslinking and outer crosslinking. Inner crosslinking refers to that single crosslinker connects itself to two adjacent polymer chains and forms two dimensional (2D) structures. Outer crosslinking refers to that these 2D crosslinker-polymer structures continue connecting themselves to adjacent 2D structures and form 3D structure gel. Commonly, the inner crosslinking takes much longer time than outer crosslinking. The crosslinking process is governed by gelation kinetics. Gelation kinetics has been studied by many researchers and many types of explanations have been proposed. Baylocq et al. (1998) explained the HPAM/Cr(III) acetate gelation by three steps' reaction, which separate inner crosslinking into two steps including single crosslinker to one adjacent polymer chain and single to two adjacent polymer chains. They suggested that the triangular structured Cr(III) should hydrolyze in three steps. Jain et al. (2005) stated that the gelation process included two step-by-step reactions: uptake and crosslink.

Gelation time is a fundamental parameter in oilfield applications that quantifies the total time for gel to form. However, due to different structures, the gelant resistance factor or dynamic viscosity will keep at low level at the stage of inner crosslinking but increase sharply at the stage of outer crosslinking. Thus, the transition from inner to outer crosslinking stage could be more important for field application and simulation studies. Sydansk (1988) used bottle test and defined gel-strength code to represent the stage of gelation. Winter and Mours (1997) applied Tung and Dynes method to define the starting time of outer crosslinking as the gel point. The method measured the elastic modulus (G') and loss modulus (G'') and used the time when the ratio of G'' to G' is equal to 1 as the gel point. Romero-Zerón et al. (2008) implemented nuclear magnetic resonance (NMR) to investigate the bulk relaxation rate during gelation and proposed the interception point of two stages of crosslinking could be more feasible and accurate to represent the gel point.

Commonly, it takes a few hours for HPAM/Cr(III) type gel to reach gel point and another one or couple hours to reach gelation time (Sydansk et al., 2005). However, the recent publication stated the delayed technology of crosslinking so that the gel point could take up to one month (Cordova et al., 2008; Sun et al., 2016).

The other key mechanism of gelation is the reaction rate of each crosslinking stage. Prud'homme et al. (1983) studied the HPAM/Cr(III) gel gelation process using rheological monitoring and proposed Arrhenius equation for the reaction rate. The reaction kinetics has polymer reaction order of 2.7 and crosslinker reaction order of 2 for the outer crosslinking stage. Scott et al. (1987) simplified the reaction kinetics by first order reaction for each reactant (second order in overall) so that the model could be generalized to more complex mixture of polymer and crosslinker. Romero-Zerón et al. (2008) found that the reaction kinetics were not same for inner and outer crosslinking processes and the inner crosslinking was much slower than outer crosslinking. Their results proposed that only the outer crosslinking stage of gelation follows a second order overall reaction (first order on polymer and first order on crosslinker).

2.3. Gel stage

After a gel is formed, it is very difficult to transport through common porous media, but it might be able to propagate through fractures or fracture-like channels. The primary mechanisms in this process contain propagation and retention. Residual resistance factor is a key factor to evaluate the permeability reduction caused by retained gel.

Propagation. Formed gel propagation through fractures or fracture-like channels has different transport behavior from gelant solution. Seright (1999, 2001) studied bulk gel propagation through fractures and concluded that the pressure gradients required to propagate gels were greater than those for flow of gelants and a threshold pressure was required to mobilize the gel.

Retention. Gel can retain during propagation through porous media or fractures. Gel retention may result from many mechanisms including size exclusion of large molecule, chemical adsorption or attachment by the rock surface, gravity segregation, diffusion to the pinch-out pores, and bridging (Chauveteau et al., 1998; You et al., 2013; Zhang and Seright, 2014). Wang et al. (1981) considered a Langmuir adsorption model as a function of aqueous phase polymer concentration and salinity to quantify the retention concentration of gel. Seright (2009) studied the mechanism of gel retention and shown that additional to the monolayer adsorbed on rock surface, gel could aggregate at the pore throat and accumulate in the pore space, which indicated a pore filling behavior. Charoenwongsa et al. (2012) also suggested that the retention of in-situ gel should include both adsorption layer and solid entrapment layer.

Dehydration. In fact, during gel propagation in fracture, the retention of formed gel is very complex. Formed gel can retain on surface of fracture to matrix. Moreover, due to superabsorbent property, the water molecules in gel structure can be squeezed out and flow through the fracture or to the matrix, which as a result increases the concentration of gel retained in fractures and forms a filter cake. This process is denoted as fluid leak-off in studies of bulk gel that has been reported by experimental researchers (Seright, 1998, 2001, 2001; Brattekås et al., 2018).

Residual resistance factor. Due to gel retention in pore network, the permeability of the porous media can be reduced. Residual resistance factor (F_{rr}) is commonly applied in laboratory to characterize the plugging efficiency, which is the permeability ratio before and after gel treatment shown in Eq. (2).

$$F_{\mathrm{rr}} = \frac{k_{\mathrm{b}}}{k_{\mathrm{a}}} \tag{2}$$

where k_{b} is permeability before gel treatment and k_{a} is permeability after gel treatment.

As measured in laboratory, F_{rr} is commonly a constant value that refers to the final result after gel is fully placed. However, in upscaled field application, the gel treatment requires the dynamic result with varied concentration and time. Thus, a function to relate F_{rr} with polymer concentration is necessary. Yuan (1991) studied the gel retention and used a tablet model to quantify the relationship between dynamic F_{rr} and polymer concentration and the result was reported consistent with the exponential result. Stavland et al. (1994) proposed the permeability reduction as a linear function of F_{rr} and adsorbed polymer concentration. Cheng (2012) studied the retention of gel and stated that the retention of gel could cause higher permeability reduction than prediction of linear model. Their results employed an exponential function of retention concentration to fit the permeability reduction, which showed a better fitting.

After gel is placed, several factors can reduce the F_{rr} including chemical degradations, shear stress, and oil throughput. Seright (1988) studied the degradation of formed gel and found that unlike the erosion or desorption of polymer, after treatment of strong gel, the permeability reduction to water was stabilized rapidly and remained stable for more than six months. However, for long-term consideration, the chemical degradation that can gradually reduce F_{rr} cannot be neglectable. Seright (2009) stated that shear degradation caused by the chasing water can be attributed by several aspects including the desorption of retained pore-filling gel due to increased pressure gradient. Brattekås et al. (2016) applied visualization of bulk gel in fracture and observed the wormhole created in the gel slug due to higher shear stress in the center of fracture. Ganguly et al. (2002) applied coreflooding in tube model and reported that the rupture pressure gradient of gel structure was related to the tube size, length, salinity, gel composition and aging time.

Besides, disproportionate permeability reduction (DPR) effect, or relative permeability modifier (RPM) effect, is also an important mechanism for gel treatment that most gel system can provide much higher permeability reduction to water than to oil. Thus, F_{rr} is different for water (F_{rrw}) and for oil (F_{rro}). Seright (2005) found that the oil throughput from 1 to 100 PV decreased the gel strength and increased the oil effective permeability gradually by factors from 5 to 10 times, which explained, as part of the reason, for the DPR effect. In fact, the proposed mechanisms for RPM are numerous. One of the most agreed is the segregated pathways for water and oil proposed by White et al. (1973) and Nilsson et al. (1998).

3. Models for numerical simulation

In this section, we will discuss the numerical models for in-situ gel simulation. The models include quantitative models that were published in literatures and models that were reported as build-in functions in commercial/in-house simulators including UTCHEM, SCORPIO, CMG STARS, POL-GEL, IORCoreSim and Eclipse 300.

3.1. Gelant simulation

Rheology: Polymer rheology is influenced by many factors including polymer concentration, shear rate, polymer plateau viscosity. The shear rate is influenced by flow velocity, rock phase porosity and permeability. Polymer plateau viscosity is influenced by polymer type and polymer concentration.

In laboratory, polymer plateau viscosity is commonly measured using viscometer at 7.33 s^{-1}. To fit the laboratory result, Thurston et al. (1987) proposed a linear regression function to fit the polymer plateau viscosity using polymer concentration and water viscosity (Eq. (3)). Stavland et al. (1994) added a F factor that was a function of active polymer and crosslinked polymer. Delshad et al. (1996) added a salinity factor to consider the effect of effective salt concentration.

$$\mu_p^0=\mu_w\left[1+\left(A_{p,1}C_p+A_{p,2}C_p^2\right)\right] \tag{3}$$

where μ_p^0 is polymer plateau viscosity; μ_w is water viscosity; C_p is polymer concentration; $A_{g,1}$ and $A_{g,2}$ are tunning parameters.

CMG STARS defines $F(x)$ function by Eq. (4) to modify the basic viscosity mixing rule and describes the change of viscosity that depends on mole fraction X of component i. The modified model can quantify large scale non-linear viscosity change, which favors gel simulation. The $F(x)$ function is the input, and the simulator will calculate plateau viscosity using user-input.

$$F(x)=\frac{\left((1-x_i)^*\ln\left(\mu_p^0\right)-\sum_{j\neq i}^{n_c}x_j^*\ln\left(\mu_j\right)\right)}{(1-x_i)^*\ln(\mu_i)-\sum_{j\neq i}^{n_c}x_j^*\ln\left(\mu_j\right)} \tag{4}$$

where x is mole fraction; i, j are components in the water phase; p is polymer component; n_c is the number of components in water.

Polymer rheology can depend on the permeability and porosity of the porous media because the effective shear rate varies with pore size. To quantify the effective shear rate in porous media, Chauveteau and Zaitoun (1981) proposed shear rate as a function of $\boldsymbol{u}(1-\phi)/(\phi\boldsymbol{k})^{0.5}$. Hirasaki and Pope (1974) proposed a function of $\boldsymbol{u}\sqrt{\phi\boldsymbol{k}}$. Cannella et al. (1998) reported in two phase flow (oil and water) the effective shear rate (γ_e) as a function of shear coefficient, water phase velocity, water phase saturation, water phase effective permeability and porosity (Eq. (5)). Since then, though varied coefficients were reported, the general derivation of the Cannella model has not been changed and widely applied in each simulator.

$$\gamma_e=C\left(\frac{3n+1}{4n}\right)^{\frac{n}{n-1}}\left(\frac{\boldsymbol{u}_w}{\sqrt{Kk_{rw}S_w\phi}}\right) \tag{5}$$

where n is shear coefficient; C is Cannella constant; $\boldsymbol{u}_w$ is water velocity; K is absolute permeability; k_{rw} is water relative permeability; S_w water saturation; ϕ is porosity.

For rheology model, Camilleri et al. (1987) proposed Meter's equation (Meter and Bird, 1964) to quantify the non-Newtonian behavior of polymer solution (Eq. (6)). Due to its simplicity and feasibility, the model is widely used in most simulators to simulate the shear thinning response of polymer rheology.

$$\mu_{app}=\mu_w+\frac{\mu_{p0}-\mu_w}{1+\left(\frac{\gamma_{eq}}{\gamma_s}\right)^{P_\alpha-1}} \tag{6}$$

where μ_{app} is apparent viscosity; γ_{eq} is equivalent shear rate; γ_s and P_α are tunning parameters.

Besides, Seright (1991a) summarized the rheology model of Xanthan and HPAM polymer including five shear thinning models which are power law (Bird et al., 1960), Carreau model (Bird et al., 1977), Chauveteau model (Chauveteau and Zaitoun, 1981), Cannella model (Cannella et al., 1988), and Willhite empirical models (Willhite and Uhl, 1988) and three shear thickening models which are Heemskerk dual power law model (Heemskerk et al., 1984), Hirasaki-Pope model (Hirasaki and Pope, 1974), and Durst-Bird models (Durst et al., 1982). Delshad et al. (2008) combined the experimental results of Hirasaki and Pope (1974) and Masuda et al. (1992) with Carreau model and derived a dual power law model for HPAM polymer rheology (Eq. (7)). The model could quantify both shear thinning and shear thickening of polymer solution. The model also quantified the relationship between polymer viscosity at critical point (μ_p^0 initial viscosity and μ_{max} maximum viscosity) and polymer concentration, salinity.

$$\mu_{\mathrm{app}} = \mu_{\infty} + \left(\mu_{\mathrm{p}}^{0} - \mu_{\infty}\right) * \left(1 + (\lambda \boldsymbol{\gamma})^{\alpha}\right)^{\frac{n-1}{\alpha}} + \mu_{\max}\left[1 - \exp\left(-(\lambda_2 \boldsymbol{\tau}_{\mathrm{r}} \boldsymbol{\gamma})^{n_2 - 1}\right)\right] \tag{7}$$

where μ_{∞} is viscosity without polymer; $\mu_{\max}$ is maximum viscosity of polymer solution under shear; $\boldsymbol{\gamma}$ is effective shear rate; $\lambda, \lambda_2, \alpha$ are tunning parameters; $\boldsymbol{\tau}_{\mathrm{r}}$ is shear stress; n is shear thinning coefficient and n_2 is shear thickening coefficient.

Lohne et al. (2017) studied the effect of polymer elongation on shear thickening behavior and conducted a power-law scaling model for both shear thinning and shear thickening rheology (Eq. (8)). The different point between their model and Delshad et al. (2008) model is that their model considered shear thickening term as a multiplier of the shear thinning term. The shear thinning model is based on Carreau-Yasuda model. The shear thickening model is fitted using power-law model.

$$\mu_{\mathrm{app}} = \mu_{\mathrm{p}}^{0} + \left(\mu_{\mathrm{thin}} - \mu_{\mathrm{p}}^{0}\right) * \mu_{\mathrm{thick}} \tag{8}$$

where $\mu_{\mathrm{thin}} = \mu_{\mathrm{p}}^{0} * \left(1 + (\lambda \boldsymbol{\gamma})^{x}\right)^{-\frac{n}{x}}$, $\mu_{\mathrm{thick}} = \left(1 + (\lambda_2 \boldsymbol{\gamma})^{x_2}\right)^{\frac{m+n}{x_2}}$, $x,\ x_2,\ n,\ m$ are tunning parameters.

For the IAPV model, the commercial simulators have their different aspects. Eclipse 300 (Eclipse 300 Manual, 2014) assumes that the IAPV decreases the effective water saturation; POL-GEL (Yuan et al., 2000a) assumes that the IAPV reduces the polymer effective volume, which decreases the effective concentration of polymer; CMG STARS (Manual, 2016) assumes that the IAPV decreases the effective porosity occupied by polymer. Although on different point of view, all simulators applied the constant value for IAPV of user input.

For polymer and crosslinker retention, the most widely used is the Langmuir adsorption model that is a function of aqueous phase concentration and salinity (Langmuir, 1918; Yuan et al., 2000a; Manual, 2016) (Eq. (9)).

$$C_{\mathrm{adsp}}{}^{\mathrm{w}} = \left(tad1 + tad2 * C_{\mathrm{sep,\,p}}\right) * \frac{C_{\mathrm{p}}^{\mathrm{w}}}{1 + tad3 * C_{\mathrm{p}}^{\mathrm{w}}} \tag{9}$$

where $C_{\mathrm{adsp}}{}^{\mathrm{w}}$ is polymer adsorption concentration; $C_{\mathrm{sep,\,p}}$ is effective salinity; $C_{\mathrm{p}}^{\mathrm{w}}$ is aqueous polymer concentration; $tad1$, $tad2$ and $tad3$ are model input.

Stavland et al. (1994) proposed more complex retention model for crosslinker that included ion exchange and precipitation (Eq. (10)). The model was later equipped in UTCHEM (Goudarzi, 2015).

$$\frac{\partial C_{\mathrm{Cr}}}{\partial t} = R_{\mathrm{Cr}}\left(C_{\mathrm{H^+}} + H_{\mathrm{Cr0}}\right)^{\beta}\left\{1 - \left(\frac{C_{\mathrm{Cr}} * C_{\mathrm{OH}}{}^{3}}{K_{\mathrm{Crsp}}}\right)^{\alpha}\right\} \tag{10}$$

where $\frac{\partial C_{\mathrm{Cr}}}{\partial t}$ is crosslinker precipitation rate; R_{Cr} is reaction constant; α, β are tunning parameters; $C_{\mathrm{H^+}},\ C_{\mathrm{Cr}},\ C_{\mathrm{OH}}$ are concentration of $\mathrm{H^+}$, crosslinker and OH ions; K_{Crsp} is reaction equilibrium. H_{Cr0} is constant input parameter.

3.2. Gelation simulation

The simulation of gelation contains the transition from polymer/crosslinker to small aggregates (inner crosslinking) and to large 3D structural crosslinked gel (outer crosslinking). Scott et al. (1987) applied Arrhenius reaction rate ($\frac{\partial C_{\mathrm{g}}}{\partial t}$ in Eq. (11)) to quantify the gelation kinetics. The method assumed 1 mol of polymer and 1 mol of crosslinker forms 1 mol of gel ($m = n = 1$). With their method, the laboratory measured gelation time was converted to the reaction frequency (K) as an input and a function of temperature, activation function, gas constant and Arrhenius constant. The analytical solution provides the gelation time using Eq. (12). The method has been applied in CMG STARS and were used in many simulation studies.

$$\frac{\partial C_{\mathrm{g}}}{\partial t} = \left(K_{\mathrm{g}} C_{\mathrm{p}}^{m} C_{\mathrm{Cr}}^{n}\right) \tag{11}$$

$$t_{\mathrm{g}} = \frac{1}{K C_{\mathrm{p}} C_{\mathrm{Cr}}} \tag{12}$$

where $\frac{\partial C_{\mathrm{g}}}{\partial t}$ is gel formation rate; C_{p}, C_{Cr} are polymer and crosslinker concentrations; m, n are reaction orders, reaction frequency factor $K_{\mathrm{g}} = A \exp\left(\frac{Ea}{R}\left(\frac{1}{T_0} - \frac{1}{T}\right)\right)$, and A is Arrhenius constant.

Stavland et al. (1994) considered this transition process as the changes in polymer properties that contained fraction of polymer following gel properties instead of using another component ‘gel’ (Eq. (13)). Thus, in their model, the component number was reduced.

$$\frac{\partial F_{\mathrm{g}}}{\partial t} = a\left(C_{\mathrm{p}}\left(1 - F_{\mathrm{g}}\right)\right)^{expp} C_{\mathrm{CrOH}}^{expx} C_{\mathrm{H}}^{exph} \exp\left(\frac{E_{\mathrm{a}}}{R}\left(\frac{1}{T_0} - \frac{1}{T}\right)\right) \tag{13}$$

where F_{g} is fraction of polymer that has changed to gel properties; C is concentration; $expp$, $expx$, $exph$ are tunning parameters; E_{a} is activation function; R is gas constant; T_0 is standard temperature and T is temperature in Kelvin.

3.3. Gel simulation

For gel propagation in fractures, Seright (1998) found that after a certain pressure was reached, the F_{r} of formed gel kept constant which indicates a Bingham type fluid. The flow rate was calculated using Eq. (14).

$$\boldsymbol{q} = \frac{h_{\mathrm{f}} w_{\mathrm{f}}^{3} \Delta \boldsymbol{p}}{12 \mu_{\mathrm{g}} L}\left(1 - \frac{3 y_0}{w_{\mathrm{f}}} + \frac{4 y_0^{3}}{w_{\mathrm{f}}^{3}}\right) \tag{14}$$

where $\boldsymbol{q}$ is flow rate; h_{f} is fracture half length; w_{f} is fracture width; μ_{g} is gel viscosity; L is model length; $\Delta \boldsymbol{p}$ is pressure drop; y_0 is gel cake thickness.

Wang and Seright (2006) applied a power law model to fit the relationship of flow rate and F_{r} for three different concentrations of polymer. The pressure drop was calculated using Eq. (15).

$$\frac{\Delta \boldsymbol{p}}{L} = a\left(\frac{\boldsymbol{q}}{h_{\mathrm{f}}}\right)^{n_1} \frac{1}{w_{\mathrm{f}}^{n_2}} \tag{15}$$

where a , n_1, and n_2 are tunning parameters that are equal to 156, 0.26 and 1.52 for 0.5%/0.0417% ratio of HPAM/Cr(III) gel.

Ouyang et al. (2013) suggested Herschel-Bulkley rheology model for formed gel propagation with a better fitting result. The flow rate was calculated using Eq. (16).

$$\boldsymbol{q} = 2 h_{\mathrm{f}} A\left(\frac{w_{\mathrm{f}}}{2} - y_0\right) - 2 h_{\mathrm{f}} \frac{A}{-\frac{\Delta \boldsymbol{p}}{\mu_0 L} * \left(1 + \frac{1}{n}\right)\left(2 + \frac{1}{n}\right)} + 2 h_{\mathrm{f}} y_0 A \tag{16}$$

where $A = \left(-\frac{\Delta \boldsymbol{p}}{\mu_{\mathrm{g}} L} \frac{w_{\mathrm{f}}}{2} - \frac{\tau_0}{\mu_{\mathrm{g}}}\right)^{1+\frac{1}{n}} / \left[-\Delta\left(\frac{1}{n} + 1\right)\right]$, τ_0 is yield stress; n is

Table 1
Summary of mechanisms, simulation models and concerned factors for in-situ gel simulation.

Gelation stages	Major mechanisms	Minor mechanisms	Simulation models	Considered factors	Reference	Simulator eligibility
Gelant	Fluid flow dynamics	Plateau viscosity	Flory-Huggins model	• Polymer concentration • Salinity • Water viscosity	Flory (1953) Meter and Bird (1964) Thurston et al. (1987)	Y
			Non-linear viscosity model	• Component mole fraction • Component pure viscosity	Manual (2016)	Y
		Effective shear rate	Cannella model	• Permeability • Porosity • Flow rate • Shear coefficient	Cannella et al. (1998)	Y
		Rheology	Meter's shear thinning model	• Effective shear rate • Initial viscosity • Shear coefficient	Camilleri et al. (1987)	Y
			Dual power law model	• Effective shear rate • Initial viscosity • Maximum viscosity • Shear coefficient	Heemskerk et al. (1984) Delshad et al. (2008) Lohne et al. (2017)	Y
			Depletion layer model	• Plateau viscosity • Water viscosity • IAPV	Stavland et al. (2010)	N
		IAPV	NA	• Constant input	Eclipse 300 Manual (2014) Manual (2016) Yuan et al. (2000a)	N
	Retention	Adsorption	Langmuir adsorption model	• Polymer/crosslinker concentration • Salinity	Langmuir (1918)	Y
		Ion exchange and precipitation	Precipitation model	• pH value • Ion concentration • Reaction equilibrium	Stavland et al. (1994)	N
		Permeability reduction	Linear model	• F_{rr} • Adsorption concentration • Adsorption capacity	Scott et al. (1987)	Y
			Elongation entrapment model	• Adsorption capacity • Water phase effective porosity • Shear rate • IAPV	Lohne et al. (2017)	N
		Degradation	Power law model	• Polymer mole weight • Degradation rate • Shear stress • Polymer hydrodynamic radius	Lohne et al. (2017)	N
Gelation	Gelation kinetics	Gel point	NA	NA	NA	N
		Gelation time	Second order Arrhenius reaction kinetics model	• Polymer/crosslinker concentration • Temperature • Activation energy • Gas constant	Scott et al. (1987)	Y
			Polymer model	• Polymer concentration • Temperature • Activation energy • Gas constant • Ion concentration	Stavland et al. (1994)	N
Formed gel	Transport in porous media	NA	NA	NA	NA	N
	Fracture propagation	Resistance factor	Bingham model	• Yield stress • Flow velocity	Seright (1998)	N
			Power law model	• Flow rate	Wang and Seright (2006)	N
			Herschel-Bulkley model	• Yield stress • Shear rate	Ouyang et al. (2013)	N
		Selective penetration	NA	NA	NA	N
	Dehydration	Permeability reduction	Empirical model	• Gel concentration	Seright (1998)	N
		Fluid leak-off	Carter's model	• Leak-off time	Howard and Fast (1970)	N
			Seright's model	• Leak-off rate • Fracture width	Seright (2003)	N
			Porous media model	• Porosity • Water saturation	Andersen et al. (2018)	N
	Retention	Adsorption	Langmuir adsorption model	• Polymer/crosslinker concentration • Salinity	Langmuir (1918)	Y

Table 1 (*continued*)

Gelation stages	Major mechanisms	Minor mechanisms	Simulation models	Considered factors	Reference	Simulator eligibility
		Solid entrapment	Exponential empirical model	• Adsorbed polymer concentration	Cheng (2012)	N
		Permeability reduction	Linear model	• F_{rr} • Adsorption concentration • Adsorption capacity	Scott et al. (1987)	N
		DPR	NA	NA	NA	N
		Shear degradation	Linear model	• Pressure gradient	Stavland et al. (1994)	N
		Chemical degradation	First order Arrhenius reaction kinetics model	• Polymer concentration • Degradation rate	Manual (2016)	Y

shear coefficient.

For gel retention, Stavland et al. (1994) stated that gel retention could be quantified by Langmuir type equation (Eq. (17)). Their model considered a multiplier (Q_m) that was related to fraction of polymer crosslinked. The model was claimed not fully correct in mechanisms due to particle clogging and entrapment but was reported capable of fitting several sets of experimental results. The model considered the constant rate of filtration.

$$C_{g,ads} = \frac{Q_m b C_{p,aq} C_{ads_m}}{b C_{p,aq} + 1} \tag{17}$$

where $Q_m = Q_p + C_{pt}\left[A_{ga}(F_{gs} - A_{g0}) + B_{ga}(F_{gs} - B_{g0})^2\right]\sqrt{\phi/k}$; F_{gs} is aqueous fraction of gel; A_{g0} is minimum level of F_{gs}; A_{ga} and B_{ga} are tunning parameters for adsorbed gel and filtrated gel; B_{g0} represents the onset of more rigid gel formation (rapid increase in adsorption) when filtration occurs; C_{ads_m} is adsorption capacity; b is model input depend on salinity; $C_{p,aq}$ is aqueous polymer; C_{pt} is total amount of polymer present; ϕ, k are porosity and permeability, respectively.

Unfortunately, no published simulation research studied the more sophisticate situation of retention. For reference, Lohne et al. (2010) studied the pore-throat trapping model and pore-lining retention model of drilling polymer fluid and derived Eq. (18) and Eq. (19), respectively, to quantify the trapping rate R_{trap} and lining retention rate R_{line} (unit in PV).

$$R_{trap} = \frac{\boldsymbol{u}_w}{\varphi S_w}(\lambda_1 C_t - \lambda_2 \sigma) \tag{18}$$

$$R_{line} = \lambda_3 C_g \left(C_{ads_m} - C_{g,ads}\right) - \lambda_4 C_{g,ads} \tag{19}$$

where C_t is polymer gel concentration at time t, σ is statistical result of trapping PV of polymer, $\boldsymbol{u}_w$ is flow velocity, ϕ is porosity, S_w is water saturation, λ_1 is trapping parameter, λ_2 is dragging parameter, λ_3 is adsorption parameter and λ_4 is desorption parameter, all parameters are in fraction of polymer retained per travel length unit.

For fluid leak-off model, several simulation models are available. The conventional Carter's model (Eq. (20)) was proposed by Howard and Fast (1970). The model assumed the filter cake forms uniformly on the fracture surface when fluid leak-off.

$$\boldsymbol{u}_l = 0.05 t^{-0.55} \tag{20}$$

where u_l is leak-off rate and t is leak-off time.

Seright (2003) modified Carter's model and assumed that filter cake forms non-uniformly, which can better fit the experimental results. Brattekas et al. (2015) proved the Seright's model by the MRI observation of the gel cake formation. The leak-off rate is calculated using Eq. (21).

$$\boldsymbol{u}_l = \frac{\boldsymbol{u}_m}{1 + \dfrac{\int \boldsymbol{u}_l dt}{w_f}} \tag{21}$$

where $\boldsymbol{u}_m$ is leak-off rate from mobile gel; w_f is fracture width.

Permeability reduction is contributed by the combination effect of the gel retention and dehydration. Based on the laboratory measured F_{rr}, the permeability reduction has been modeled as a mobility divider by many researchers. The most widely used model in publications is the linear function of F_{rr} (Eq. (22)) (Manual, 2016; Eclipse 300 Manual, 2014; Lashgari, 2018; Yuan et al., 2000a). The model only considered one phase permeability reduction.

$$RKW = 1 + (F_{rr} - 1) * \frac{C_{ad}}{C_{ad,m}} \tag{22}$$

where C_{ad} is adsorption concentration of gel; $C_{ad,m}$ is adsorption capacity.

Stavland et al. (1994) has proposed a more complex permeability reduction model that considered porosity, permeability and the fraction of gel formed (F_g) (Eq. (23)).

$$RKW = \frac{a_{F_{rr}}\left(C_{g,ads} - C_{p,ads}\right) F_g * b_{F_{rr}} * \boldsymbol{k}^{\frac{1}{2}} \phi^{-\frac{3}{2}}}{1 + b_{F_{rr}} * \boldsymbol{k}^{\frac{1}{2}} \phi^{-\frac{3}{2}}} \tag{23}$$

where $a_{F_{rr}}$, $b_{F_{rr}}$ are tunning parameters; $C_{g,ads}$, $C_{p,ads}$ are adsorption concentration of gel and polymer.

IORCoreSim simulator considers the permeability reduction as a function of effective water porosity and IAPV and the shear factor. The equation is shown in Eq. (24).

$$RKW = \left[1 - f_{rkw} * \frac{C_{g,ads}}{1 - IAPV}((\varphi_{sw} - 1) f_{sh} + 1)\right]^{-2} \tag{24}$$

where f_{sh} is shear factor that is a function of shear rate based on Carreau-Yasuda model; f_{rkw} is tunning factor; φ_{sw} is swelling factor of gel.

For degradation of formed gel as a plugging agent, the mechanism contains chemical degradation and shear degradation. The chemical degradation rate (R_{cd}) is commonly simulated using first order ($m = 1$) Arrhenius type kinetics (Eq. (25)). Due to low rate of chemical degradation, this model is capable of simulating the time dependent F_{rr} reduction.

$$R_{cd} = \left(K_{cd} C_g^m\right) \tag{25}$$

where K_{cd} is reaction frequency of chemical degradation.

The shear degradation has been studied by several researchers.

Table 2
Application studies review of in-situ gel simulation.

Researcher	Year	Zonal isolation	Treatment location	Influencing factors	Objective Functions	Simulator
Helleren	2011	Laboratory scale	Placement in core model	• pH • Temperature • Polymer concentration • Residence time • Gel volume	• Gel retention • F_r • F_{rr}	CMG
Hatzignatiou et al.	2014	Laboratory scale	Placement in core model	• Gel composition • Gelation time • Gel residence time • F_{rr}	• F_r • Injection rate • Effluent concentration	CMG
Hadi Mosleh et al.	2016	Laboratory scale	Placement in core model	• Polymer/crosslinker concentration ratio • pH • Polymer concentration	• Gelation kinetics • Gelant penetration	UTCHEM
Hughes et al.	1990	Both	Producer WSO	• Zonal isolation • Vertical crossflow • Placement strategy • Gel volume • Gel concentration • Gelant viscosity	• Production profile • Water cut • Cumulative oil recovery	SCORPIO
Gao et al.	1993	No	Both	• Gel initiation time • Crossflow • Treatment location	• Oil production rate • Cumulative oil recovery • Water cut	BOAST
Hwan	1993	No	Producer WSO	• Production rate • Perforation intervals • Oil water viscosity ratio • Horizontal permeability • Vertical crossflow • Oil zone thickness	• Production profile • Water cut	Vectorized Implicit Program (VIP)
Menzies et al.	1999	No	Horizontal injector water diversion	• Crossflow • Fluid viscosity • Wellbore friction • Injection rate	• Injection profile • Gel distribution	Commercial Coding Software
Yuan et al.	2000b	No	In-depth fluid diversion	• Gelant concentration • Gel amount	• Cumulative oil recovery • Gel/oil ratio	POL-GEL
Herbas et al.	2004a, b	No	Both	• Treatment location (injector/producer/both) • Gelation kinetics • Maximum F_{rr} • Grid size	• Water cut • Oil rate • Cumulative oil recovery	CMG
Seright et al.	2012	Yes	In-depth fluid diversion	• Permeability ratio • Thickness ratio • Gel volume • Gel concentration • Oil viscosity	• Mobile oil recovered • Produced oil/consumed gel ratio	CMG
Lee and Lee	2013	No	Injector in-depth water diversion	• Mean of permeability • DP coefficient • Pre-flush Time	• Water cut • Cumulative oil recovery	IGW UTCHEM
Shen et al.	2013, 2014a, b	No	Injector treatment	• Reservoir wettability • Reservoir temperature • Capillary pressure • Gel composition	• Permeability reduction • Sweep efficiency • Water cut • Cumulative oil recovery	UTCHEM
Choi et al.	2015	No	In-depth fluid diversion	• Gelant dynamic viscosity	• Cumulative oil recovery • GOR • Water cut • Bottom-hole pressure	CMG
Ghahfarokhi et al.	2016	No	In-depth fluid diversion	• Gelation time • Gel composition • Maximum F_{rr} • Crossflow • Initiation time • Gelant volume	• Water cut • F_{rr} distribution • Cumulative oil recovery	CMG
Temizel et al. Putra and Temizel	2016 2018	No	In-depth fluid diversion	• Injection rate • Permeability ratio • Maximum F_{rr} • Adsorption capacity	• Cumulative oil • Gel distribution	CMG
Xiao et al.	2016	No	Injector treatment	• Gel initiation time • Gel volume • WAG cycle sequence	• Cumulative oil recovery	CMG
Sheshdeh et al.	2016	No	Producer WSO	• Well type (vertical/deviated) • Gel volume • Relative permeability end point • K_{rw} @ S_{or} and K_{ro} @ S_{wi}	• Cumulative oil recovery • History match quality	Commercial Black Oil Simulator
Alfarge et al.	2017; 2018	No	Producer WSO	• K ratio	• Water cut	CMG

Table 2 (*continued*)

Researcher	Year	Zonal isolation	Treatment location	Influencing factors	Objective Functions	Simulator
				• Crossflow • Maximum F_{rrw}/F_{rro} • Reservoir thickness • Oil density • Oil viscosity • Production rate • Gel penetration depth	• Cumulative oil recovery	
Riazi et al.	2017	No	Producer WSO	• Reservoir type (conventional/tight) • Average permeability • Gel injection interval (vertical depth) • Gel injection frequency (period)	• Water cut	Eclipse
Khamees et al. Khamees and Flori	2017; 2018 2018; 2019	No	Injector treatment	• Rheology model • Permeability ratio • Oil viscosity • Thickness ratio • Salinity • Polymer concentration • Gel volume • Sequence of injection • Cation exchange capacity • Wettability • Gravity segregation and dip angle • Mobility ratio • Skin factor	• Cumulative oil recovery • Water cut • F_{rr} distribution	UTGEL/CMG

Scott et al. (1987) considered the shear degradation as the mass reduction of formed gel using a constant rate for user input. Stavland et al. (1994) considered the effect of shear degradation by a multiplier on F_{rr} (F_{rrf}) (Eq. (26)).

$$F_{rr_f} = 1 - (\boldsymbol{\Phi} - \boldsymbol{\Phi}_0)*\Phi_f \tag{26}$$

where $\boldsymbol{\Phi}_0$ is minimum pressure gradient to initiate shear degradation; $\boldsymbol{\Phi}$ is effective pressure gradient; and Φ_f is tunning parameter.

Lohne et al. (2017) considered the degradation as the mole weight reduction that was a function of effective shear stress ($\boldsymbol{\tau}$), degradation rate (r_{deg}), current mole weight (M_g), polymer hydraulic radius (R_p) (Eq. (27)).

$$\frac{\partial M_g}{\partial t} = -M_w * \left(r_{deg}\boldsymbol{\tau}\right)^{\alpha_d} * \frac{2M_g}{R_p} \tag{27}$$

where α_d is the tuning parameter.

As a summary, Table 1 show the models that should be considered during gel treatment process. The major mechanisms refer to macroscopic mechanisms that commonly can be observed in laboratory as phenomena. The minor mechanisms refer to mechanisms behind these phenomena that need interpretation in quantitative models. All the simulation models are listed in column four and five, with considered factors and corresponding mechanisms. The 'NA' means no models are reported in the simulators. The last column describes the eligibility of the models in commercial simulators. The eligible models marked by 'Y' mean the simulation models in current simulators can provide effective estimation of the corresponding mechanisms. On the other hand, the ineligible models marked by 'N' mean either the models are not available in simulators, or the quantitative models have not been studied.

4. Application studies of in-situ gel simulation

We summarized the published application studies of in-situ gel simulation as shown in Table 2. The first three literatures conducted the sensitivity studies on gelation kinetics and gelant injection dynamics using simulation models in laboratory scale. The influencing factors included pH value, temperature, polymer/crosslinker concentration, residence time, gelation time, F_{rr} and gel volume. The gelation process determines the amount of gel that has been formed and retained. The gelant viscosity and rock permeability can be influenced by the fraction of formed gel. The process is quite complicated and is very difficult to be examined using laboratory experiments but has been studied using simulation. Helleren (2011) studied the gelant injection F_r, gel retention and post-flush F_{rr} as a function of the factors influencing gelation kinetics. If the gel formed during the injection of gelant, the F_{rr} due to gel retention will greatly influence the dynamics of gelant injection. Hatzignatiou et al. (2014) studied this effect using a simulation core model. They studied the injection F_r using constant flow rate and injection rate variation using constant pressure, respectively. The gelation time also influences the loss of gel and further the placement depth. Hadi Mosleh et al. (2016) studied the effect of gelant composition and pH value on gelation kinetics and its effect on the gelant penetration.

The other literatures listed in Table 2 stated field scale applications. For objective function, cumulative oil recovery is considered in every simulation study as the key result of gel treatment. However, as a short-term conformance control method, in-situ gel treatment may not influence cumulative oil recovery as much as other method such as polymer flooding. Thus, the result of cumulative oil recovery may reduce the significance of in-situ gel treatment. Compared with cumulative oil recovery, oil rate and water cut may reflect the short-term result of gel treatment more accurately. Most of the literatures included water cut as one of the major results but only Herbas et al. (2004a, b) considered the oil rate as an objective function to evaluate gel treatment. On the other hand, water (injection/production) profile is a critical and concise method to evaluate the efficiency of in-situ gel treatment. Unfortunately, only three literatures including Hughes et al. (1990), Hwan (1993) and Menzies et al. (1999) considered the profile change due to gel treatment. For injection operation, Hughes et al. (1990) and

Seright et al. (2012) considered the zonal isolation injection, while the others applied 'bullhead' injection of gelants.

For influencing factors, many factors have been discussed in the sensitivity analysis parts of these application studies. However, the methods to apply these factors might not reflect the mechanisms that have been discussed earlier in this paper. For example, F_{rr} was considered in all the literatures, but the F_{rr} was only related to retained gel concentration. Moreover, the F_{rr} distribution results showed that most of the literatures reported very low F_{rr} value in each grid (e.g., lower than 100) after treatment, though some claimed maximum F_{rr} over 10^4 as input. As one of the explanations, Lee and Lee (2013) discussed the significance of using refined local grids and heterogeneities at treatment zone especially for the near-wellbore treatment and concluded that the F_{rr} could be unexpected low due to dilution of formation water without local grids refinement. Another example is the consideration of DPR effect. Both Sheshdeh et al. (2016) and Alfarge et al. (2018) considered the effect of DPR in simulation, however, the methods they applied did not consider the practical F_{rro} measured from labs. Alfarge et al. (2018) investigated the RPM effect on gel plugging efficiency by using different permeability reduction to water (RKW)/permeability reduction to oil (RKO) ratio. However, the RKO was assumed to be one for the study which underestimated the formation damage caused by retained gel. Sheshdeh et al. (2016) applied permeability reduction by an interpolation method that two different relative permeability curves were set for water flooding before gel placement and after gel placement, respectively. This method could quantify the different permeability reduction to water and oil by retained gel after placement by assuming the constant permeability reduction in each grid. Thus, it inevitably ignored the transient period between two sets of relative permeability curves. This is critical because the permeability reduction in each grid was also a function of gel concentration.

5. Discussion and suggestions

As reviewed above, the simulation studies of in-situ gel treatment have been conducted for decades. Plenty of models have been proposed by researchers to quantify the transport and plugging performance of in-situ gel from gelant to formed gel. Based on these fundamental studies, numerous sensitivity analysis and optimization articles have been reported for the guidance of field scale application of in-situ gel treatment (Gao et al., 1993; Ghahfarokhi, 2016; Goudarzi, 2015; Herbas et al., 2004a, b; Khamees and Flori, 2018; Khamees, 2020; Lee and Lee, 2013; Temizel et al., 2016; Yuan et al., 2000b). However, all of the simulations provided optimistic results, more or less, in terms of oil recovery and water cut. Meanwhile, several theoretical studies suggested the fastidious reservoir environment required for effective gel treatment (Sydansk and Seright, 2007). Seright et al. (2011a) stated the challenging operations for in-situ gel treatment and limited situations that in-situ gel treatment could be favored than polymer flooding. Besides, the field applications also not always reported the successful results (Aldhaheri et al., 2016).

Based on the comprehensive review, we found the results of many numerical simulation studies were not quite convincible. As shown in Table 1, many key mechanisms do not have proper models in commercial simulators, such as IAPV of polymer flow, gel point in gelation stage, gel transport in porous media, gel retention, gel propagation, dehydration, and DPR effect in gel stage, etc. Some of these mechanisms have numerical simulation models published but have not been applied in simulators, the others do not have eligible quantitative models for numerical simulation. Besides, some mechanisms are not considered in application studies. Thus, we categorize the reasons for questionable results of application studies as the deficient model problems, the missing model problems, and the application problems.

Deficient model: Deficient models refer to those that related mechanisms have been considered and are available in current commercial/in-house simulators; however, the models are not eligible to quantify the mechanisms properly or thoroughly. These models include gelation process, gel retention, and F_{rr} models.

The gelation process is considered in simulators using Arrhenius reaction model. However, the model of gel point has never been considered in the gelation process, which may greatly influence the gel placement. As mentioned in gelation stages section, the gel point marks the time the outer reaction takes place and the resistance factor starts to rise significantly. For current gelation models in simulator (Polymer + Crosslinker > Gel), the main problem is that once gelant is injected, the gel starts to form at highest reaction rate based on Arrhenius reaction kinetics. Simultaneously the early injected gelant can form gel and retain in the pathway. Therefore, the later injected gel will be diverted from the gel pathway (most likely the high permeability water channel). Consequently, the early injected and retained gel inevitably would increase the injection pressure due to permeability reduction. As a result, without consideration of gel point, the gel placement cannot be properly estimated, and the injection pressure cannot be properly matched. Many researchers discussed methods to determine the gel point; however, no publication indicates the numerical modeling of gel point.

For retention of formed gel, the conventional Langmuir adsorption as shown in Eq. (17) was reported not accurate by several researchers (Seright, 2000; Cheng, 2012; Charoenwongsa et al., 2012). This is because beside the adsorption, gel can be trapped by pore throat, retained, and fill the pore. Therefore, the retention volume and plugging efficiency can be higher than estimated using monolayer Langmuir model and linear retention model in commercial simulators. Many simulation models were proposed; however, the models were derived theoretically and only considered single or limited mechanisms. Thus, no retention models could history match the amount of gel retained considering the adsorption, solid entrapment, and dehydration mechanisms. In field of polymeric drilling fluid, the retention model proposed by Lohne et al. (2010) may be partially qualified in terms of factors concerned. However, the application of their model still needs consideration of dehydration and needs more experimental results for validation.

Correspondingly, the F_{rr} model as a function of retention is also not eligible. Without consideration of gel entrapment and dehydration effect on gel retention, the simulation model of F_{rr} may very possibly overestimate the damage in matrix and underestimate the plugging efficiency in channels. The general model to quantify F_{rr} in simulation studies is Eq. (22), which shows a linear relationship with retention. In fact, the F_{rr} is very sensitive to the gel strength and formation properties, such as permeability and porosity. Weak gel restricts flow in low permeability rocks by a factor that is the same or greater than that in high permeability rock; while strong gel reduces permeability of all rocks to the same low value (e.g., micro-Darcy level) (Seright, 2002). Thus, F_{rr} model should be a function of gel strength, retention, velocity, channel types and permeability, and the other formation properties.

Missing model. Some mechanisms do not have quantitative models such as IAPV model of gelant flow and formed gel transport models. As stated in mechanism section, IAPV is influenced by many factors. The constant input setting in the commercial simulators cannot properly estimate the effect of IAPV on gel penetration in low permeability strata. Thus, the simulation result may underestimate the damage of gel in oil bearing zone. However, though many researchers reported the IAPV effect, the studies were only qualitative. Based on our review, only one article discussed the derivation of IAPV that was reported by Ferreira and Moreno (2019). Their equation was based on the Stavland et al. (2010)'s rheology model with some assumptions. However, the model can hardly simulate the effect of IAPV on polymer flow because the model only fit the situation of shear thinning and assumes low viscosity of polymer that is close to water (RF~1).

When gel is formed, researchers only discussed the transport regime in open fractures. The gel is commonly considered not capable of penetrating into the porous media with complex pore networks (Bai et al., 2015), so that gel will selectively flow to the fractures or fracture-like channels. However, in relative high permeability matrix, such as high permeable unconsolidated-sand porous media, weak gel might still be movable when the threshold pressure gradient is achieved. Thus, more research is necessary for transport regimes and models of formed gel in relative high permeability porous media and critical conditions for selective penetration as a function of pore size, velocity/shear rate, and gel strength. For gel propagation in fractures, several numerical simulation models have been proposed in literatures, but the simulators do not have capable models to quantify the gel transport. In high permeability fractures or fracture-like channels, formed gel can propagate with a much higher resistance factor and dehydrate on fracture-matrix contact to form a filter cake. The gel cake can decrease the crossflow of mobile gel from fracture to matrix. Therefore, without consideration of these transport mechanisms, the simulation result may erroneously estimate the placement of gel in terms of gel consumption and penetration.

As discussed above and listed in Table 1, the problems of simulators include the ineligibility of models for gelation kinetics, gel retention and F_{rr}; and the lack of models for IAPV and gel transport.

Problems and suggestions for application studies of in-situ gel simulation. Based on the previous review and discusses, it seems that the simulation models in simulators most likely have underestimated the effect of gel for conformance control. The question is why the application studies of in-situ gel simulation always provided more optimistic results than analytical and field results, but the results were not very convincible. We concluded several problems that widely exist in the application studies.

One of the problems is the lack of correct consideration of DPR effect. As discussed in mechanism section, many polymer gels can reduce permeability to water more than that to oil or gas (Alfarge et al., 2018; Liang et al., 1995; Seright, 2009; Willhite et al., 2002); however, the permeability reduction to oil or gas cannot be neglected. Seright (2009) summarized the F_{rro} results from experiments and found that the F_{rro} ranged from 2.7 to 59 in Berea sandstone. Though the F_{rro} is smaller than F_{rrw}, considering the irreversible retention of formed gel in porous media, the damage to oil bearing zone, with F_{rro} up to 59, is severe.

Theoretically, DPR effect was reported only of value for gel treatment at production well for water shutoff (Sydansk and Seright, 2007), because only for production well treatment, the remaining oil would flow through the gel zone. However, in simulation studies, the DPR effect might also have influenced the mobile oil flow for in-depth treatment. This is because numerous literature applied excessive large volume of gel treatment (over one month gelant injection) for in-depth fluid diversion, which caused the gelant flowing in-depth through channels and invading the oil-bearing matrices from channels. In these simulation studies, F_{rro} were ignored. Thus, even though a large amount of gel had been erroneously placed in oil-bearing strata, the DPR effect on oil effective permeability was not considered and damage was neglected. Thus, the simulation results were not convincible.

Another problem is the lack of consideration of the matrix fracking or fracture propagation (or extension). Due to pressure rise caused by low mobility of gelant and gel retention, the injection pressure required for gelant placement can easily overcome the formation fracking pressure and cause the creation of new fractures in matrices or extension of existing fractures to the matrices (Khodaverdian et al., 2009). Consequently, the simulation of gel treatment needs consideration of geomechanics. With our review, we found that in most current simulation studies, the injection pressure was commonly set to be unlimited to ensure a good match of injection rate. Without consideration of fracking model during gelant placement, the injection pressure will increase much higher than practical result in field and cannot guide applications. Moreover, the simulated injection pressure will very likely be higher than pump limitation. Thus, although the simulation studies showed optimistic oil recovery and water cut reduction, the results could hardly provide reasonable estimations to the field operations.

The third problem is the misconception of gelation kinetics. As discussed in previous section, the gelation contains an inner crosslinking (low viscosity period) and an outer crosslinking (high viscosity period). Current application studies did not consider the gel point and applied an Arrhenius equation to quantify the gelation process. The problem with this model is that highest reaction rate occurs at the beginning because the rate is positively dependent on the remaining reactants' concentration. Thus, the gel will be quickly formed from the beginning of gelant injection, and the fluid viscosity will be increased. When a large amount of gelant was injected, in most application studies, the gelant were erroneously like a super-polymer-flooding agent instead of a plugging agent, which would greatly mislead the field operations (Seright and Brattekas, 2021). Because improper low values of F_{rr} were applied in these application studies, the oil recovery and water cut results seemed very optimistic. However, if retention model and F_{rr} were considered properly, the later injected gelant would be diverted to the low permeability matrices and damaged the formation due to early retention of formed gel. Because in laboratory experiments, the injection time is commonly shorter than the gel point, the measured F_{r} result does not include F_{rr} , however, in field application, the injection time could be much longer. Thus, for gelation kinetics, we suggest applying simulations case-by-case considering field scale gelant placement time. For placement duration much shorter than gel point (small treatment amount), F_{rr} model should not be included in gelant placement stage. F_{r} model could be applied for rheology model of gelant directly and F_{rr} model should be applied for permeability reduction model for post flsh, respectively. For gelant placement duration close to or smaller than gel point (obvious viscosity rise and retention will happen during gelant injection), both F_{r} model and F_{rr} model should be applied in gelant placement and F_{rr} model should be applied in post flush as well.

Last but not least, for severe channeling (e.g., super-permeability channel, fracture-like channel, or fractures), the fluid flow in channels should not be considered as Darcy flow. The high flow velocity in severe channels commonly exceed the Reynolds number (*Re*) for laminar or Darcy flow. Non-Darcy behavior is important for describing fluid flow in situations where super-high velocity occurs. Although the critical *Re* for non-Darcy flow is very inconsistent that ranges from 0.1 to 1000 depending on the rock and fluid properties (Chilton and Colburn, 1931; Ergun and Orning, 1949; Fancher and Lewis, 1933; Ma and Ruth, 1993), a typical value of $Re=10$ may be applied for gelant flow in severe channels. Hassanizadeh and Gray (1987) explained this value for non-Darcy flow as the result from the increase in the microscopic viscous force at high velocity. We suggest future studies to consider the non-Darcy flow in simulation of gelant flow in severe channels and implement appropriate models in simulators.

6. Conclusion

Simulation of in-situ gel treatment is a comprehensive work due to the complex physiochemical properties of gel and the interactions between gel and formation. In this review, we classified the process of in-situ gel treatment as three stages and summarized the major factors to be considered during each stage, the mechanisms for in-situ gel treatment and the published numerical simulation models.

A comprehensive table of simulation models is provided to compare the essential mechanisms with the published simulation models and the eligibility in simulators. The results show that the mechanisms including plateau viscosity, effective shear rate, rheology, polymer/crosslinker retention, gelation time, and chemical degradation of formed gel, have eligible models in integrated commercial/in-house simulators. The mechanisms including gelation kinetics, gel retention and F_{rr} model have corresponding models in simulators, but the models cannot fulfill the needs required by the mechanisms. The mechanisms including IAPV of gelant, formed gel transport model, do not have eligible models in simulators. The gel propagation in fractures has several published empirical models (as shown in Table 1) but has not been incorporated in simulators, while the critical condition for gel selective penetration still needs more studies on quantitative models.

A critical review of the published application studies using commercial/in-house simulators shows that the results of these application studies are questionable because (a) the simulators lack the essential models for in-situ gel treatment and (b) the problems existing in simulations include incorrect consideration of DPR effect for in-depth fluid flow diversion treatment and water shutoff treatment, the lack of consideration on the matrix fracking or fracture propagation, the misconception of gelation kinetics, and the non-Darcy flow in severe channels.

Simulation of in-situ gel has been studied by many researchers for decades, however, major improvements are still in need to properly quantify the process of gelant placement, gelation kinetics, and formed gel mechanisms for conformance control.

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