Petroleum Science 20 (2023) 910–921

Contents lists available at ScienceDirect

Petroleum Science

journal homepage: www.keaipublishing.com/en/journals/petroleum-science

Review Paper

Polymer flooding: Current status and future directions

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ARTICLE INFO

Article history:
Received 16 January 2023
Accepted 1 February 2023
Available online 7 February 2023

Handling Editor: Baojun Bai
Edited by Yan-Hua Sun

Keywords:
Polymer flooding
Reservoir sweep improvement

ABSTRACT

This review presents our perspective on the factors that have brought polymer flooding to its current state. Insights are provided on why HPAM is the dominant polymer used as well as what is needed to make alternative polymers and mobility-control methods viable. Explanation is given for why large polymer banks are needed for polymer flooding, and design of the injected polymer viscosity is detailed for cases with/without crossflow. The role of fractures and horizontal wells are discussed for improving injectivity and extending polymer flooding to recover oils with viscosities as high as 10,000 cP. Operational improvements are described to minimize mechanical and oxidative stability to allow HPAM polymers to be viable to 70 °C and ATBS polymers to 120 °C. Key factors affecting polymer retention are summarized. The paper points out unresolved issues and future directions for polymer flooding.

1. Introduction

Polymer flooding is an enhanced oil recovery (EOR) method that utilizes high molecular weight (Mw) polymers to increase viscosity of injected water (i.e., reduce water mobility)—thereby improving reservoir sweep efficiency when displacing viscous oil. Several previous reviews of polymer flooding have been published (Needham and Doe, 1987; Littman, 1988; Sorbie, 1991; Green and Willhite, 1998; Saleh et al., 2014; Sheng et al., 2015; Thomas, 2019). Polymer flooding has enjoyed substantial economic and technical improvements over the past decade that have encouraged more large-scale field applications. This paper presents our perspective on the factors that have brought polymer flooding to its current state—as of 2023. Our intent here is NOT to dictate how/when/where a polymer flood must be performed. We understand that petroleum producers are extremely independent and always want to try new things. We also understand that every reservoir has its unique conditions and that improvements are aways changing our understanding to how best overcome an obstacle. So, we actively encourage innovation. Our goal is to point out the best practices for polymer flooding at this time, and provide insights that help polymer flooders avoid mistakes made previously. Although a given statement made in this paper may seem counter-intuitive to some readers (even to some "experts"), the given references document in much more detail why we see the suggestion as the best current way forward. We encourage you to read the references if you doubt what we say.

2. HPAM polymer prices remain low

HPAM (an abbreviation for partially hydrolyzed polyacrylamide or acrylamide-acrylate copolymer) has been, by far, the dominant polymer used in enhanced oil recovery. HPAM prices are actually lower now than in 1980—in spite of a 3.8X rise in the consumer price index since 1980. A substantial fraction of the credit for low HPAM prices must go to the polymer suppliers for their advances in manufacturing the polymer. Credit must also go to several large-scale polymer floods (e.g., Daqing in northeast China, Mangala in western India, and Pelican Lake in Alberta, Canada) for increasing the market for HPAM (Wang et al., 1995, 2008a, 2008b, 2009, 2010, 2011a, 2011b ; Guo et al., 2021; Prasad et al., 2014, 2022; Delamaide, 2018, 2021).

Since polymer is usually the largest single expenditure in a polymer flood, there will always be a high interest in lower-cost or more cost-effective polymers. Of the many alternative polymers proposed in recent years, poly(ATBS) and acrylamide-ATBS copolymers are the most promising (Gaillard et al., 2015; Rodriguez et al., 2018). As will be discussed later, depending on the ATBS content, these polymers can exhibit impressive thermal stability and low retention in reservoir rock (Seright et al., 2021; Seright and Wang, 2023). Fig. 1 illustrates the compositions of HPAM versus poly(ATBS) polymers.

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https://doi.org/10.1016/j.petsci.2023.02.002

Abbreviations

ATBS	Acrylamido-t-butyl-sulfonate
EOR	Enhanced oil recovery
HPAM	Hydrolyzed polyacrylamide or acrylamide-acrylate copolymer
IAPV	Inaccessible pore volume
k	Permeability, mD (μm^2)
k_i	Permeability in Layer i, mD (μm^2)
k_{rwo}	Relative permeability to water at residual oil saturation
L_{pi}	Distance of polymer penetration into Layer i, ft (m)
M	Mobility ratio (water or polymer mobility divided by oil mobility)
Mw	Molecular weight, g/mol
PAG	Polymer alternating gas
PAW	Polymer alternating water
PV	Pore volume, cm^3
S_{or}	Residual oil saturation
WAG	Water alternating gas
μ	Viscosity, cP (mPa s)
μ_o	Oil viscosity, cP (mPa s)
μ_p	Polymer solution viscosity, cP (mPa s)

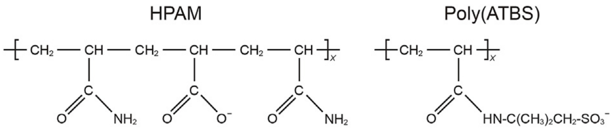

Fig. 1. HPAM versus poly(ATBS) polymers.

Because of its salt tolerance, impressive resistance to mechanical degradation, and relatively low retention in rock, xanthan (a polysaccharide) enjoyed significant interest in the 1970s and 1980s (Cannella et al., 1988; Taber et al., 1997). However, high prices, insufficient availability, and abandoned efforts to reduce manufacturing costs have not allowed xanthan to become competitive with HPAM. Other polymers [(scleroglucan, schizophyllan, diutan, poly(N-vinyl pyrrolidone)] have suffered a similar fate (Doe et al., 1987; Rivenq et al., 1992; Seright et al., 2009; Leonhardt et al., 2014; Gaillard et al., 2014; Jensen et al., 2018; Muhammed et al., 2020; Elhossary et al., 2022). Microbial degradation of biopolymers is a common concern, but has been proven to be controllable by proper treatment of microbial populations—either with biocides or controlled nutrient environment (O'Leary et al., 1987). Hydrophobic associative polymers have been of interest since 1975 (Reichenbach-Klinke et al., 2011; Seright et al., 2011a). However, concerns with predictability, control of performance, and ability to propagate through reservoir rock have limited their application (Seright et al., 2011a; Dupuis et al., 2012; Xie et al., 2016). The results of Seright et al. (2011a) suggest that associative polymers might perform better with reduced hydrophobe content and higher molecular weights. Associative polymers have been proposed as "thermally activated polymers" (L'Alloret et al., 1997; Reichenbach-Klinke et al., 2018; Thomas, 2019; Hryc et al., 2022) that provide low viscosity at low temperatures (i.e., near injection wells) and higher viscosity beyond a thermal front in a reservoir (closer to the polymer-oil displacement front). This exciting idea has considerable potential, but the basic concerns about hydrophobic associative polymers must be overcome first (especially, the inability to propagate through reservoir rock with a practical pressure gradient when the polymer is in the associated form). Recently, polyethylene oxide has been re-introduced for polymer flooding carbonate reservoirs (Mejía et al., 2022), although it is too early to assess the viability of this polymer.

3. Large polymer banks (> 50% pore volume) are required

General agreement exists that polymer banks greater than 50% pore volume (PV) are needed for successful polymer flooding (Seright, 2017; Keith et al., 2022; Prasad et al., 2022). The primary technical reason is illustrated in Fig. 2. When injecting water after a polymer bank, brine forms viscous fingers that will propagate almost exclusively in the most-permeable pathway (middle part of Fig. 2) (Sorbie and Seright, 1992; Doorwar and Mohanty, 2017; Seright, 2017; Seright et al., 2018). After water breaks through, the polymer bank will stop moving in the reservoir, and water cuts will rise to very high levels. This view contrasts with an incorrect view of polymer flooding (bottom part of Fig. 2), which was used to justify the many small-volume polymer banks of floods before 1990 (Needham and Doe, 1987; Sorbie, 1991; Seright, 2017). Of course, polymer injection must stop once the costs of polymer injection exceed the value of the oil produced.

4. Strive for a polymer/oil mobility ratio of one or lower

The first priority in selecting the injected polymer viscosity is to strive for a polymer/oil mobility ratio of one or less (Craig, 1971; Green and Willhite, 1998). If the mobility ratio is greater than one, the aqueous phase will form viscous fingers through the oil. Reviews of the viscous-fingering literature (Peters and Flock, 1981; Doorwar and Mohanty, 2017; Seright et al., 2018) reveal several critical findings that emphasize the severity of damage to sweep efficiency caused by viscous fingers and the necessity of eliminating them by achieving a mobility ratio of one or less. First, as the mobility ratio increases, fingering becomes worse—with longer, narrower fingers and fewer fingers. Second, fingering makes sweep efficiency worse than predicted by Buckley-Leverett and by most simulators. Since simulators and fractional flow calculations are rarely capable of accounting for viscous fingering, they will overestimate sweep efficiency in a reservoir if the mobility ratio is

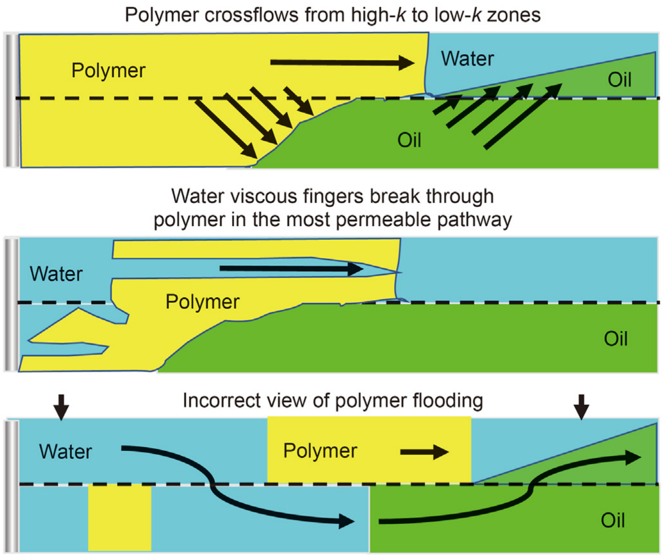

Fig. 2. Viscous fingering: Why large polymer banks are needed.

greater than one. Third, fingering in wide paths (e.g., a reservoir layer) is worse than in a narrow path (e.g., a laboratory core or slim tube). Fourth, fingering is generally worse for immiscible displacements than miscible displacements. To a first approximation, for water displacing oil, the growth of a water finger is proportional to the square of mobility ratio (Doorwar and Mohanty, 2017). In contrast, for a miscible displacement (e.g., water displacing polymer solution), the growth of water fingers is roughly proportional to mobility ratio (Koval, 1963; Seright, 1991a). Of course, for a given unfavorable mobility ratio "fingering" or channeling will become more severe with increased permeability contrast in layered systems (Sorbie and Seright, 1992). Thus, reducing the water-oil mobility ratio to one or less is very important. We realize that those who have read about or worked on Canadian polymer floods (as we did for 14 years) may doubt the practicality of achieving a mobility ratio of one or lower for heavy oils. For those skeptics, the discussion within Seright (2017) and Seright et al. (2018) may be of value. Sometimes, relative permeability to water is remarkably low—allowing relatively low viscosity polymer solutions to displace quite viscous oils. But you must measure at least the endpoint relative permeability to determine this.

4.1. Need k_{rwo} to select the proper polymer viscosity

Mobility is defined as permeability to a given phase divided by the viscosity of that phase (Craig, 1971). Thus, identifying the polymer solution viscosity needed to achieve a unit mobility ratio requires knowledge of the relative permeabilities—notably the endpoint relative permeability to water (k_{rwo}). For a polymer flood targeting a 1600-cP oil, an endpoint mobility ratio of one could be achieved using a polymer viscosity of 480 cP if $k_{rwo} = 0.3$; 160 cP if $k_{rwo} = 0.1$; and 48 cP if $k_{rwo} = 0.03$. The case of $k_{rwo} = 0.3$ was reported for the Daqing polymer flood (Wang et al., 2011b), while the case of $k_{rwo} = 0.03$ was reported for the Cactus Lake polymer flood (Seright et al., 2018). This highlights the need to determine the relative permeability curves (or at least the endpoint for water) when planning a polymer flood. Without this knowledge, a substantial uncertainty becomes evident in projecting the effectiveness of a polymer flood. Ironically, some large-scale polymer floods (e.g., Pelican Lake) do not appear to have measured relative permeabilities. Although there is value in reducing the mobility ratio by any amount, these floods may be a long way from optimum operation because of a possible inappropriate choice of polymer viscosity (e.g., 25–30-cP polymer to displace 1000–10000-cP oil). There is also value in knowing whether polymer changes the relative permeabilities (Zaitoun and Kohler, 1987, 1988; Seright et al., 2018; AlSofi et al., 2017; Li et al., 2020; Zhao et al., 2021; Souayeh et al., 2022).

4.2. Use low-shear rate viscosity to design the polymer viscosity

The low-shear rate viscosity provides the most reliable estimate of viscosity performance for a polymer solution in porous media (Delshad et al., 2008; Seright et al., 2011b; Jouenne et al., 2019; Dean et al., 2022; Zeynalli et al., 2022). The most important shear-rate or velocity for a polymer flood is that experienced by the polymer deep within a reservoir where the vast majority of the oil is to be displaced. For conventional EOR polymers, the apparent viscosity at low velocities in porous media (i.e., the resistance factor) should match or be consistent with the viscosity observed in a viscometer at an appropriate shear rate. The reader should be suspicious of low-rate resistance factors that are significantly greater than expectations from viscosity measurements. Higher-than-expected resistance factors usually are an experimental artefact associated with using short cores, filtration of undissolved or very high Mw polymers, or rock that is too low in permeability for a given Mw of polymer (Seright et al., 2011b). For the same reasons, permeability reduction (residual resistance factor) values should conservatively be assumed as one unless convincing evidence to the contrary is available (Seright, 2010; Thomas, 2019; Dean et al., 2022). The reader should be suspicious of residual resistance factors greater than two.

On the other hand, advocates of the "depletion-layer" concept have claimed that polymer viscosity in porous media is actually lower than measured in a viscometer (Sorbie, 1991). Their argument assumes that the polymer concentration near a pore wall is lower than in a bulk solution, and therefore has a lower viscosity than near the center of a pore. Although excluded volume effects are relevant to chromatography, the depletion-layer concept has been used in misleading ways in the petroleum literature and should not be accepted in most cases. See Seright et al. (2011a), Manichand and Seright (2014), and Seright and Wang (2023) for more details on this critique.

The choice of shear rate at which to make the viscosity measurement is important. By convention, 7.3 s^{-1} has been commonly used to allow direct comparisons of various polymer solutions in the laboratory. This shear rate may be representative of fluid velocities or effective shear rates for 5-spot patterns of vertical wells with moderate spacing. However, 7.3 s^{-1} is typically much too high to properly represent velocities between parallel horizontal wells (Dandekar et al., 2021). The shear rate at which the viscosity is measured should be consistent with the median fluid velocity expected deep within the reservoir. The shear-thinning character of most polymers can mean that less polymer will be needed to achieve a given viscosity or mobility ratio if the average reservoir velocity is reduced.

If multiple layers of different permeability are present (with no vertical communication or crossflow), the effective shear rate (and polymer solution viscosity) is largely unaffected by the fact that velocities are lower in less-permeable zones (Seright, 1991b, 2010).

4.3. Polymer/oil mobility ratios < 1 may aid free crossflow cases

If only one homogeneous layer is present, achieving a mobility ratio of one is sufficient for an efficient polymer flood. However, if two or more layers are present, further improvements in sweep efficiency can be achieved by reducing the mobility ratio below one (Seright, 2010, 2017). The second illustration of Fig. 3 depicts that with a mobility ratio of one, the polymer front in the most-

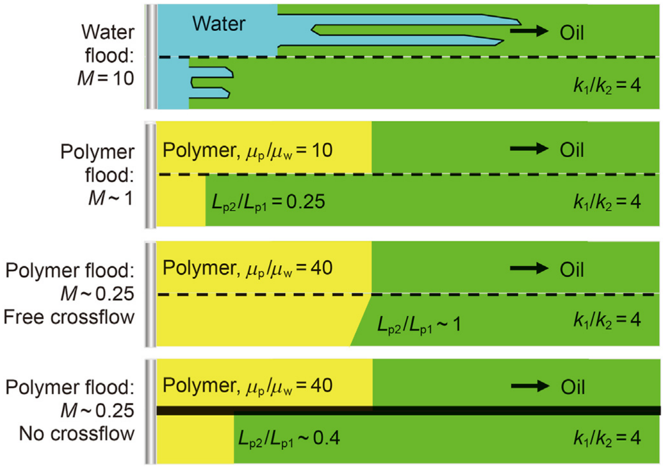

Fig. 3. Various mobility ratio (M) scenarios in polymer flooding.

permeable layer will advance faster than in a less-permeable layer—in proportion to the permeability contrast. If fluids can freely crossflow between layers, the polymer front in the less-permeable layer can be made to advance as rapidly as in the adjacent high-permeability layer by reducing the mobility ratio to the reciprocal of the permeability contrast (e.g., ¼), as depicted in the third illustration of Fig. 3. Results of fractional flow calculations (in Fig. 4) highlight the possible sweep improvements for a polymer flood in a two-layer system with free crossflow (Seright, 2010). For recovery efficiency at one pore volume of injection when displacing 1000-cP oil, the incremental oil displaced is larger when increasing the injected polymer viscosity from 10 cP to 100 cP than when increasing from 1 cP to 10 cP. An even larger incremental jump in oil recovery results when using 1000-cP polymer instead of 100-cP polymer. In contrast, Fig. 5 illustrates analogous fractional flow projections for exactly the same conditions, but with no crossflow between the two layers. Here, the largest improvement in oil recovery comes from increasing the injected polymer viscosity from 1 cP to 10 cP. Further increases in polymer viscosity provide diminishing returns. Thus, the incentive to reduce the polymer/oil mobility ratio below one is notably greater for the free-crossflow case than for the no-crossflow case. This is an important consideration when selecting the injected polymer viscosity and concentration.

4.4. If polymer/oil mobility ratio is < 1, the polymer bank could cause a pressure barrier for oil displacement

If the mobility ratio is one or less, the oil is driven to the production wells by the pressure difference between the polymer front and a given production well (Wang et al., 2022). Normally, concerns about the integrity of formation seals or surface equipment limit the maximum pressure allowed in polymer injection wells. So, if the pressure difference from the injection well to the polymer front is too great (either because the polymer bank is too long or too viscous), insufficient pressure will remain to adequately drive the oil towards a producer. This phenomenon may explain field cases where injectivity gradually diminishes as more polymer is injected. This "pressure barrier" is only a concern if the polymer/oil mobility ratio is less than one (Wang et al., 2022). Means to mitigate this problem are (1) reduce well spacing, (2) stimulate injection and/or production wells, (3) tolerate fracture extension in polymer injectors, and (4) reduce the viscosity of the polymer bank.

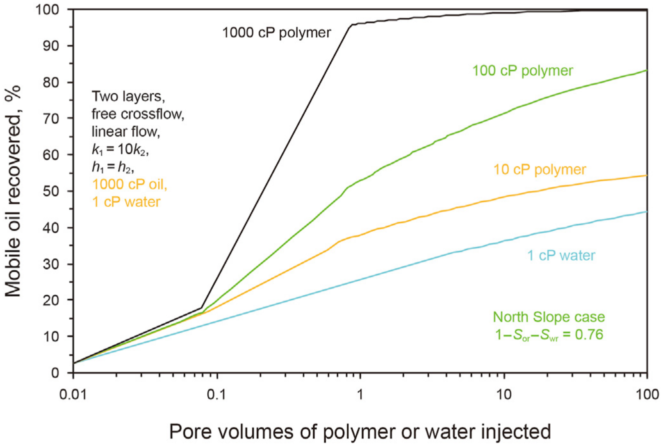

Fig. 4. Crossflow promotes injection of more viscous polymer solutions (from Seright, 2010).

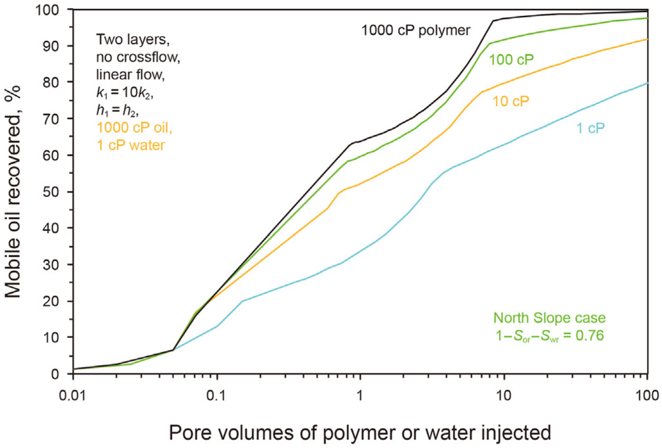

Fig. 5. With no crossflow, the benefit of reducing mobility ratio below one is limited.

4.5. Make sure the polymer is dissolved!

Although this point seems obvious, undissolved polymer has been a notable problem with some field projects. If polymer gel is found during well-cleanout or back-production of injectors, undissolved polymer was probably injected at some point. If the polymer is not in solution, it is not enhancing viscosity, is wasting money, and creates unnecessary injectivity losses or fracture extension. Filter tests have been strongly advocated to monitor solution quality (Dean et al., 2022). However, over-reliance on filter tests alone can cause operators to overlook important dissolution problems (Dandekar et al., 2020, 2021; Edwards et al., 2022)—because they only sample an extremely small fraction of the fluid volume injected and because they have no convincing quantitative relation to polymer injectivity (Seright et al., 2009). Filter tests should be complemented with wellhead low-shear-rate (e.g., 7.3 s^{-1}) viscosity measurements that are consistent (i.e., small variations around the target viscosity) and lack of plugging of facility filters (e.g., sock filters) that all injected polymer must pass through (Edwards et al., 2022; Prasad et al., 2022).

5. Need fractures for acceptable injectivity in vertical injectors

Injectivity (volumetric rate divided by pressure difference between the wellbore and the average reservoir pressure) is crucial to a successful polymer flood. Most oilfield reservoir engineers and managers recognize that the rate of oil production is directly tied to the rate of fluid injection during flooding processes. Consequently, they will not accept a polymer flood that suffers injectivity reductions that are significantly below injectivity of water. One might think that would present a dilemma for polymer flooding, since polymer solutions are necessarily much more viscous than water. If it takes ten times longer to inject a 10-cP polymer solution (than water), few field engineers and managers will accept a polymer flood. Fortunately, the vast majority of polymer floods have experienced injectivities that were not much lower than that for water. Contrived explanations have been proposed to explain this behavior—typically involving the non-Newtonian rheology of polymer solutions (Sagyndikov et al., 2022a). However, the only viable explanation (especially for vertical polymer injection wells) is that fractures are open during polymer injection and these extend to accommodate whatever viscosity, rate, or level of suspended particulates are associated with the fluid (Seright et al., 2009; van den Hoek, 2009; Khodaverdian et al., 2010; Ma and McClure, 2017; Sagyndikov et al., 2022a).

5.1. Determine fracture growth direction before the polymer flood

Since open fractures are essential for achieving acceptable injectivity for all vertical polymer injection wells, the orientation (horizontal or vertical), direction of extension and distance of fracture extension can be critical for polymer flooding. Fig. 6 illustrates this point. Fractures that are perpendicular to the desired direction of fluid flow in a reservoir are beneficial, both for enhancing injectivity and sweep efficiency. In effect, these fractures can act like parallel horizontal wells. Of course, fractures that extend all the way from an injection well to a production well can substantially harm sweep efficiency. Interestingly, fractures that point directly at a production well are not detrimental to sweep, so long as they do not extend more than one-third of the distance between the two wells (Crawford et al., 1954; Dyes et al., 1958; Khodaverdian et al., 2010; Seright, 2017).

Ideally, the direction of fracture growth should be established before implementing the polymer flood. Rather than focus on idealized 5-spot or other pattern configurations that are common during waterflooding, polymer floods require greater emphasis on placing injection and production wells in an attempt to take advantage of the natural "line drive" afforded by fracture extension. As an example, the L-Pad in the Milne Point polymer flood (North Slope of Alaska) used north-south oriented parallel horizontal injection and production wells (Edwards et al., 2022). After over four years, this flood has injected 0.3 PV of polymer solution to displace an 850-cP oil (polymer/oil mobility ratio near one), with no water or polymer breakthrough to date. In contrast, during polymer injection over the same timeframe, the J-Pad in the same field used east-west oriented parallel horizontal wells (Dandekar et al., 2021), and experienced polymer breakthrough through a north-south-directed fracture or fracture-like feature after only 0.1 PV of polymer injection (even though oil viscosity was only 300-cP). If fractures naturally tend to grow in the north-south direction in this field, polymer flooding will be more effective if the horizontal wells are oriented in the same direction as the fractures. Predicting the extent of fracture extension is an important need for polymer flooding.

5.2. Fractures eliminate HPAM mechanical degradation and reduced injectivity due to shear-thickening behavior

If vertical polymer injection wells truly contained no open fractures, a wide range of fluid velocities would be experienced as the polymer flows radially away from an injection well (Fig. 7). HPAM polymers would exhibit a dramatic shear-thickening (apparent viscosity in porous media decreasing with decreasing Darcy or superficial velocity) and severe mechanical degradation as the polymer exited the well into the porous rock (Maerker, 1975; Seright et al., 1981; Seright, 1983). The shear thickening would radically reduce HPAM injectivity and the mechanical degradation would severely degrade the effectiveness (mobility reduction) provided by the polymer deep within the reservoir (Seright et al., 2009, 2011b; Manichand et al., 2013; Sagyndikov et al., 2022a). Fortunately, open fractures in vertical polymer injectors always reduce the velocity at which the polymer solutions enter the rock, thereby eliminating both the shear-thickening and the mechanical degradation of HPAM. These expectations were demonstrated quite convincingly during a field application in the Kalamkas field in Kazakhstan (Sagyndikov et al., 2022a) and in the Mangala field in India (Shankar and Sharma, 2022). Methods and equipment are available to minimize mechanical degradation in surface facilities (Flavien et al., 2020, 2022). Mechanical degradation of HPAM has been shown to be minimal (even over long distances) in properly designed pipes (Jouenne et al., 2015).

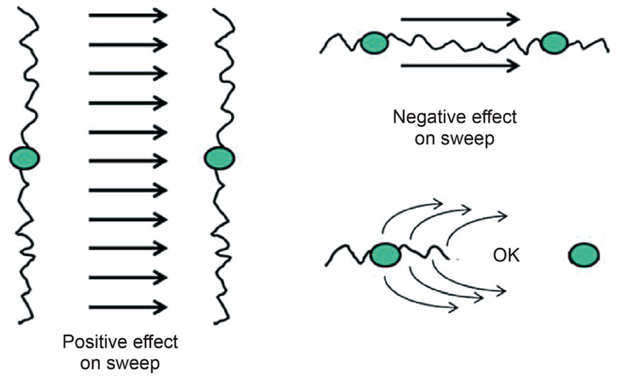

Fig. 6. Impact of fracture direction on sweep with vertical wells.

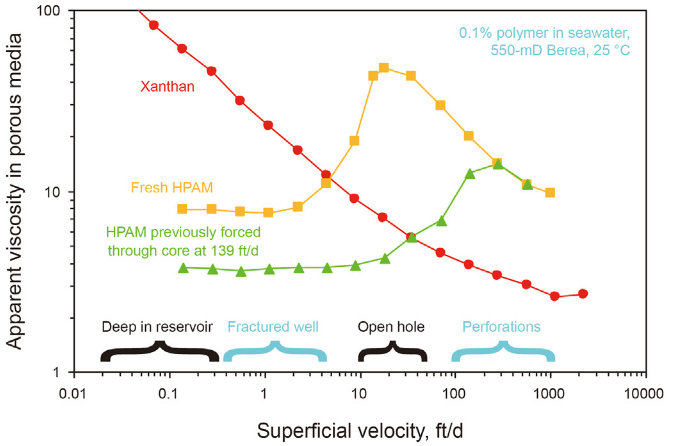

Fig. 7. Rheology in porous media.

5.3. Fractures must not cut reservoir seals

Care must also be exercised to make sure that fractures do not compromise the reservoir seals and allow flow "out of zone" (de Pater, 2015). Thus, in polymer flooding, a compromise must be reached between using the highest practical injection pressure and not extending fractures too far or cutting the reservoir seals. Sometimes, the maximum injection pressure is set by pressure limitations associated with the injection flow lines and pumps.

5.4. Remediation if fractures cause channeling

Fortunately, many cases exist where polymers have been injected into vertical wells above the formation parting pressure without compromising sweep efficiency (Wang et al. 2011a, 2011b; Manichand et al., 2013; Zechner et al., 2015; Seright, 2017). Of course, some cases have also been observed where fractures caused early polymer breakthrough in production wells (Zornes et al., 1986; Dandekar et al., 2021; Sagyndikov et al., 2022a). Separate remedial action can be taken for these cases. Some possible remedies include (1) reducing the injected polymer viscosity or rate in hopes that the fracture will close naturally, (2) shutting in the offending production well or converting it to an injector (in effect making the connecting fracture a horizontal polymer injector), (3) applying a remedial treatment to plug the fracture (Seright and Brattekas, 2021), or (4) tolerating the polymer channeling (and excess polymer production).

5.5. Production wells must have sufficient flow capacity to collect the oil

Our focus to this point has been on establishing good injectivity to ensure high fluid throughput during the polymer flood. However, it is critical to keep oil productivity high as well (Edwards et al., 2022; Prasad et al., 2022). With fractures in injection wells, high pressures associated with high injectivity may push oil away from producers if the production wells don't have sufficient flow capacity. Several approaches can be employed: Pump off production wells as much as possible. Make sure that production wells have minimum formation damage. Stimulate production wells if that is viable. Add more production wells if necessary. Use horizontal production wells if that is viable.

6. Horizontal wells allow polymer floods to target up to 10,000-cP oil

Use of horizontal injection and production wells has allowed polymer flooding to be extended to recover oils as viscous as 10,000 cP (Seright, 2010; Delamaide, 2018, 2021; Seright et al., 2018; Dandekar et al., 2021; Sagyndikov et al., 2022b). The example of the L-pad at Milne Point highlights the utility of parallel horizontal wells for polymer flooding—no water or polymer have arrived at production wells even after 0.3 PV of polymer was injected to displace 850-cP oil (Edwards et al., 2022). Also, the Pelican Lake polymer flood has shown impressive results for 25–30-cP polymer displacing 1000–10,000-cP oil (Delamaide, 2018, 2021).

Properly oriented vertical fractures in vertical wells can act like horizontal wells, but they are usually not long in high-permeability formations. For example, at the Tambaredjo polymer flood (Suriname), the estimated fracture length was less than 30 ft (Manichand et al., 2013), and at the Matzen polymer flood (Austria), the estimated fracture length was 43 ft (Zechner et al., 2015). Further, the fracture growth direction is dictated by local tectonic stresses and may not be as desired. In contrast, horizontal wells in polymer floods have been as long as 10,000 ft, and their direction was well-controlled (Delamaide, 2018, 2021; Edwards et al., 2022).

An important issue with horizontal wells is monitoring of flow profiles along the wells. Effective assessment and control of a polymer flood would be greatly enhanced if the flow profiles along the well were known. This would allow timely identification and remediation of fractures and fracture-like features that allow polymer to channel directly between wells. However, because of their substantial length and horizontal orientation, it is quite challenging to obtain profiles along the entire length, and they are rarely applied (Dandekar et al., 2021; Edwards et al., 2022). Identification and application of effective profiling tools in horizontal wells is a key need.

7. Minimize dissolved oxygen/prevent oxygen leaks!

7.1. Approaches to eliminate dissolved oxygen

All polymers are susceptible to oxidative degradation (Seright et al., 2021). Fortunately, oil reservoirs contain no dissolved oxygen (Seright et al., 2010). Most reservoirs contain sufficient iron minerals (e.g., pyrite, siderite) to quickly (within hours or days) deoxygenate any normal volume of water that contained dissolved oxygen. Thus, the primary concern about potential oxidative degradation exists in surface facilities and flow lines until the reservoir minerals can remove any residual oxygen. If the temperature is over 50 °C, laboratory work (Shupe, 1981; Seright and Skevrak, 2015; Jouenne et al., 2017) and field work (Mittal et al., 2018; Prasad et al., 2022) reveal that the dissolved oxygen level must be kept near zero (e.g., <10 parts per billion). If the temperature is less than 50 °C, HPAM degradation may not be a major concern if the water source has low salinity and especially low dissolved iron content (Wang et al., 1995; Manichand et al., 2013). However, if water salinity is elevated and/or the water contains dissolved iron, oxygen leakage into the flow stream can cause significant degradation (Shupe, 1981; Seright and Skevrak, 2015; Jouenne et al., 2017; Sagyndikov et al., 2022a). Several approaches have been taken towards dissolved oxygen in the flow stream, including (1) taking no action if the temperature is below 50 °C, water salinity is low, and no dissolved iron is present (Wang et al., 1995; Manichand et al., 2013), (2) adding a chemical oxygen scavenger or antioxidant package (Wellington, 1983), (3) adjusting oxidation-reduction potential, pH, impurities (Levitt et al., 2011), (4) removing all dissolved iron present (Irvine et al., 2012), and (5) plugging all oxygen leakage into the flow stream and using physical methods or minimal use of chemical methods to remove oxygen (Prasad et al., 2022). We advocate the last method because it is usually the most cost-effective and easiest method to implement (Seright and Skevrak, 2015).

7.2. Effective methods to eliminate oxygen leaks

A number of relatively easy and low-cost actions can be taken to minimize dissolved oxygen in the surface flow stream. First, most water that originates from the subsurface contains no dissolved oxygen (Seright et al., 2010). Consequently, simply preventing air leakage into the system will dramatically help. A common occurrence in water flooding is that liquid is pumped into the top of a storage tank and drops through air before reaching the stored fluid—thus, extensively oxygenating the liquid. This situation can be mitigated by installing a pipe (with a check valve) inside the tank that deposits the water below the liquid surface. This adaptation can be made to dramatically reduce dissolved oxygen in all tanks associated with the polymer project—even without any other oxygen-mitigation measures. Further reduction in dissolved oxygen can be made using a gas (e.g., nitrogen) blanket on the tanks. Concerns about gas losses can be reduced by transferring gas from a tank that is filling with liquid into a tank that is emptying its liquid (Flavien et al., 2022). Another common spot where oxygen leaks into the system is from polymer powder as it is introduced into the eductor or polymer slicing unit. It is often not practical to gas-blanket the entire powder hopper. However, a small stream of gas can be introduced at the bottom of the hopper that pushes oxygen away from the eductor or polymer slicing unit (Flavien et al., 2022; Prasad et al., 2022). Of course, the eductor or polymer or slicing unit must be enclosed to prevent air from entering the flow stream. In place of powder-form polymers, polymer supplied as liquids have utility for offshore applications (Flavien et al., 2020; Alexis et al., 2022).

8. HPAM can be stable to 70 °C; ATBS polymers to 120 °C

8.1. Stability limits of existing polymers

In the absence of dissolved oxygen, the stability of a given polymer depends on both temperature and time of exposure. The time required for polymer stability in a given application depends on temperature and transit time between injectors and producers. This transit time, in turn depends on well spacing and injection rate. Fig. 8 illustrates the time-temperature-stability relations for several EOR polymers (Seright and Henrici, 1990; Seright et al., 2010, 2021; Sandengen et al., 2017, 2018). Under the proper circumstances these relations (i.e., Arrhenius relations) can allow

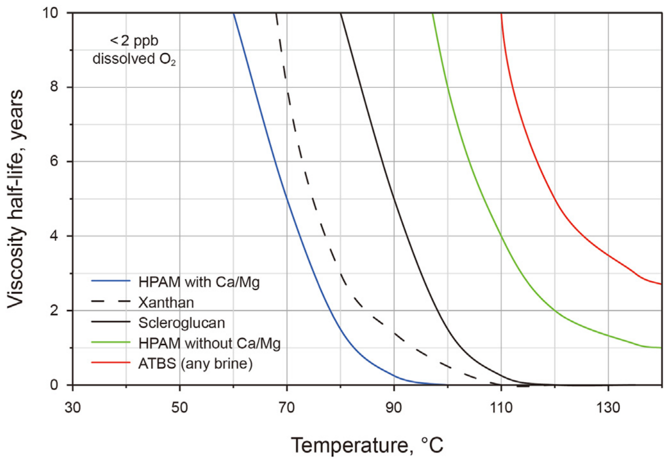

Fig. 8. Time-temperature stability relations for EOR polymers.

relatively rapid experiments at multiple high temperatures to project long-term stability at lower temperatures. This method can be particularly useful because inter-well polymer transit times are often many years at the reservoir temperature. In contrast, laboratory stability studies rarely last more than two years (Seright et al., 2021). If laboratory stability tests are confined to the reservoir temperature, they may not properly assess whether the polymer has sufficient stability for the intended application. Fig. 8 indicates that HPAM could exhibit a five-year viscosity half-life at 70 °C if typical levels of divalent cations are present in the brine. That half-life is raised to 107 °C if no divalent cations are present. Xanthan and scleroglucan could exhibit five-year viscosity half-lives at 75 and 90 °C, respectively. A recently commercialized ATBS polymer could exhibit a five-year viscosity half-life at 120 °C (Gaillard et al., 2015; Rodriguez et al., 2018; Seright et al., 2021). The latter development could substantially increase the number of reservoirs where polymer flooding could be applied.

8.2. Precipitation after hydrolysis and contact with divalent cations

Many publications describe the chemistry around hydrolysis and precipitation of HPAM and ATBS polymers (Zaitoun and Potie, 1983; Doe et al., 1987; Swiecinski et al., 2016; Sandengen et al., 2017, 2018; Beteta et al., 2021). Fig. 1 provides a comparison of the chemistry of HPAM versus poly(ATBS). An excellent recent set of laboratory and field tests have confirmed some of these concepts in the Mangala field (Mittal et al., 2018; Shankar et al., 2022a; Shankar and Sharma, 2022). HPAM with 20%–30% degree of hydrolysis was exposed to 65–74 °C for a prolonged period while transiting the Mangala reservoir. This exposure significantly increased the degree of hydrolysis (up to 50%) and deteriorated polymer in situ performance—presumably because of precipitation with divalent cations in the formation brine (Shankar et al., 2022a). Replacement of HPAM with polymers containing ATBS is underway to mitigate this problem (Shankar et al., 2022b).

8.3. Hot surfaces in heater-treaters and pumps accentuate HPAM precipitation

After HPAM breakthrough in production wells, several authors noted severe fouling of heater-treaters (heat exchanges) during efforts to break produced oil/water emulsions by application of heat (Zheng et al., 2011; Mittal et al., 2018; Prasad et al., 2022). Research revealed that these problems were caused by the hot surfaces hydrolyzing HPAM to a high degree, which gelled when significant concentrations of divalent cations were present (Mittal et al., 2018; Zagitov et al., 2020; Dhaliwal et al., 2022). For typical residence times in the heater-treater, Dhaliwal et al. (2022) demonstrated that the HPAM hydrolysis/precipitation problem can be avoided by keeping the skin temperature (of the heater-treater) below 120 °C. Pinnawala et al. (2022) demonstrated that this temperature could be raised to 163 °C if a copolymer with 25% ATBS was used.

Certain pumps (notably jet pumps and electrical submersible pumps) have points which can get hot enough to hydrolyze and precipitate HPAM to form an intractable gel scale (Mittal et al., 2018; Agrawal et al., 2019; Zagitov et al., 2020; Dandekar et al., 2020; Prasad et al., 2022). For cases where desired production rates are not high, this problem can be mitigated by using cooler pumps—in particular, progressive cavity pumps and sucker-rod pumps. Another advantage of progressive cavity and sucker-rod pumps is that they cause minimal mechanical degradation to HPAM polymers, whereas jet pumps and electrical submersible pumps can substantially degrade HPAM (Manichand et al., 2013; Hoy et al., 2020; Shankar et al., 2022a).

9. Polymer retention

9.1. Impact of polymer retention depends on the assumed form of the retention function

The projected impact of polymer retention (adsorption, mechanical entrapment, etc.) on the efficiency of oil displacement depends greatly on the form assumed for the polymer retention function (Wang et al., 2020; Seright and Wang, 2023). Fig. 9 plots predictions for several different polymer retention functions, where the total retention is fixed at 240 μg/g and the injected HPAM concentration was 1750 parts per million (ppm). For each case, Fig. 9 plots the predicted effluent polymer concentration (relative to the injected concentration) versus pore volumes of polymer injected. In fractional-flow calculations (black curve in Fig. 9), a concentration-independent value for polymer retention is assumed (Green and Willhite, 1998). For this assumption (with 240 μg/g), effluent polymer concentration remains at zero until 1.44 PV; then the effluent concentration jumps abruptly to the injected value. Thus, retention delays propagation of the polymer bank (and the displaced oil bank), but after polymer breakthrough, the effluent has the full concentration and viscosity as was injected. Others assume that polymer retention causes no delay in polymer propagation, but immediately reduces the polymer concentration and

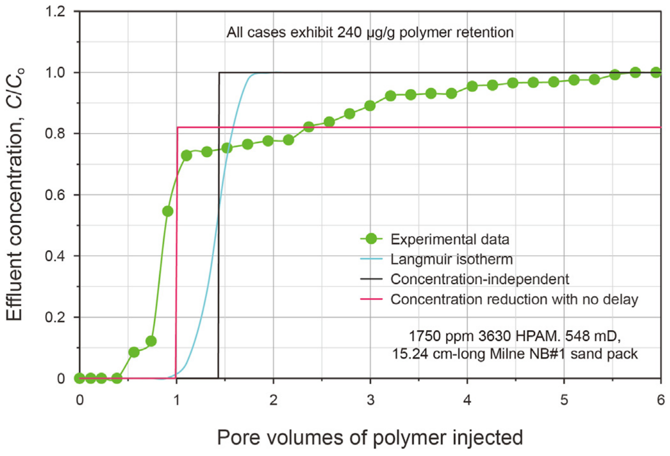

Fig. 9. Various forms of the polymer retention function.

viscosity (Seright and Wang, 2023)—as depicted by the red curve in Fig. 9. In this case, no delay is predicted in the development and movement of an oil bank from polymer flooding, but the polymer is less efficient in displacing the oil (because the polymer viscosity is reduced). Most chemical flooding simulators use the Langmuir isotherm (Wang et al., 2020), which assumes that retention is zero at zero polymer concentration, but rises linearly with concentration until achieving the maximum value. This case is illustrated by the blue curve in Fig. 9. As with the assumption of concentration-independent retention (i.e., for fractional flow calculations), the Langmuir isotherm predicts a delay in propagation of the polymer bank (in proportion to the retention value), but once breakthrough occurs, effluent polymer concentration rises rapidly to the injected value. As can be seen, the Langmuir isotherm predicts a more dispersed polymer front than is predicted by the concentration-independent case. For comparison, the green curve in Fig. 9 shows actual effluent polymer concentrations from a dynamic retention experiment in Milne Point cores, from the north slope of Alaska (Wang et al., 2020; Seright and Wang, 2022).

9.2. *Retention depends greatly on clay content, divalent cations and ATBS content of the polymer*

Literature reviews of polymer retention reveal several key points (Manichand and Seright, 2014; Seright and Wang, 2023): First, clays (high-surface-area materials) in the rock commonly dominate polymer retention. Monovalent cations have little effect on polymer retention, but increased divalent cations have a large effect. HPAM degree of hydrolysis has little effect, but a small amount of ATBS (Fig. 1) can greatly reduce retention. The vast majority of the existing polymer floods have high-permeability rock (average > 500 mD). Nevertheless, there is high current interest in polymer flooding carbonates and other less-permeable rock (Ghosh et al., 2021; Mejía et al., 2022; Song et al., 2022). Polymer retention can increase dramatically with decreasing permeability, especially below 100 mD. Mechanical entrapment/hydrodynamic retention is important in low-permeability rock (< 100 mD) but not in high-permeability rock (> 500 mD). Retention of xanthan is usually less than that of HPAM. Over a very broad range of polymer concentration, retention can have a modest fixed value (e.g., ~20 μg/g) at low concentrations, a notably higher fixed (e.g., ~200 μg/g) at high concentrations and a transition in between. Contrary to expectations (and some unsupported literature claims), most researchers reported only a modest effect of oil presence on polymer retention—sometimes modestly lower (e.g., as much as half) than with no oil (Szabo, 1975; Kolodziej, 1988; Chiappa et al., 1999; Masalmeh et al., 2019; Wang et al., 2020, 2021; Seright and Wang, 2022; Song et al., 2022; Alfazazi et al., 2021; Sebastian et al., 2022), sometimes about the same (Huh et al., 1990; Wang et al., 2020; Seright and Wang, 2022; Song et al., 2022), sometimes higher (Broseta et al., 1995; Huh et al., 1990; Wang et al., 2021; Seright and Wang, 2022; Song et al., 2022). A more detailed analysis of this unexpected observation can be found in Seright and Wang (2023) and Manichand and Seright (2014). Also contrary to expectations, wettability has not been established as a key factor in polymer retention—possibly because polymer adsorption can make surfaces more water wet (Zaitoun and Kohler, 1987, 1988; AlSofi et al., 2017; Li et al., 2020; Souayeh et al., 2022).

9.3. *Assume inaccessible pore volume (IAPV) is zero if permeability > 200 mD*

Literature reviews of the topic of inaccessible pore volume reveal several key points (Manichand and Seright, 2014; Seright and Wang, 2023): Reported IAPV values were VERY inconsistent, especially with respect to permeability and Mw dependence. Most previous IAPV reports either did not report PV of brine injected between the polymer banks or only injected 5–10 PV of brine. 100+ PV may be needed (Wang et al., 2020) to obtain a valid IAPV. If insufficient brine is injected between the polymer banks, a misleadingly high IAPV will appear (Wang et al., 2020). 0.1–0.5 μm polymers should readily access > 98% of pores in 500+ mD rock (Seright et al., 2006). A conservative approach to designing polymer flood assumes that inaccessible pore volume is zero, especially in rock/sand with > 500 mD (i.e., virtually all existing large-scale polymer floods).

10. Staged/modular application of polymer flooding can improve economics

The high upfront investment for facilities and injectants and uncertainties about projected performance often present major hurdles for initiation of an EOR project. Juri et al. (2020) advocated a distributed polymer injection concept to mitigate these concerns. Rather than convert the field to polymer flooding with one massive investment, the process is implemented in stages over time. Areas of the field are prioritized to identify the most favorable locations. Given a number of location options, a number of smaller polymer floods are implemented that are optimized for the current economic conditions. Skid or container mounted polymer injection units are used instead of a central facility (Flavien et al., 2022). Over time, these injection units can be moved to apply polymer flooding in different areas of the field when conditions become appropriate. This approach has been successfully applied in a number of fields throughout the world (Juri et al., 2020; Delamaide, 2021; Flavien et al., 2022; Sagyndikov et al., 2022b).

11. Alternatives to polymer flooding are not viable yet

11.1. *Foams*

Brief mention will be made of alternative attempts at mobility control. Foam flooding represents the most promising alternative (Wang et al., 2001; Alcorn et al., 2020), although substantial improvements are needed before they can be competitive with polymer flooding. The primary potential for foams lies in their conceptual ability to form in high-permeability porous rock, but collapse in a less-permeable zone. In theory, if this limiting capillary pressure effect could be predicted and controlled, the vertical sweep in a layered reservoir with no crossflow could be superior to that for a polymer flood (Zhang and Seright, 2007). This advantage over polymer flooding is not available if fluids can crossflow between zones. Further, there are currently major limitations associated with the use of foams, including (1) undesired foam collapse due to surfactant partitioning into the oil phase or adsorption onto rock, (2) insufficient foam stability for the desired timeframe of the flood, (3) viscous fingering of gas and surfactant after foam collapse in the less-permeable zone, and (4) lack of control over foam mobility. In a polymer flood, any desired viscosity/mobility ratio can be achieved simply by adjusting the injected polymer concentration. In contrast, foams allow limited/no control over the level of mobility reduction. Foam mobilities are typically either greatly higher ("weak foam") or greatly lower ("strong foam") than the optimum mobility required for a given situation (Shah et al., 2020; Yu et al., 2020).

11.2. *Other materials*

Most other proposed alternatives to polymer flooding (i.e., colloidal dispersion gels, emulsions, specifically sized particulates, and precipitates) exhibit a number of serious technical flaws (Seright and Liang, 1995; Zhang and Seright, 2007; Seright et al., 2012; Wang and Seright, 2021). Chief among these flaws is an inability to propagate a significant distance into a porous medium while still maintaining a desirable level of mobility reduction (Wang and Seright, 2021). Perhaps, an easy way to appreciate this deficiency is to realize that humans have purified water for thousands of years by flowing contaminated water through porous media—to remove particulates and emulsions by either filtration or adsorption. Polymer flooding fares much better in providing a sustained mobility reduction in porous media because polymers enhance viscosity by the friction created as intertwined polymer molecules slide over each other in attempt to disentangle during flow (de Gennes, 1979).

12. Unresolved issues and future directions

12.1. How does a prior waterflood impact polymer flooding?

It is not yet clear whether or when it is desirable to water flood a reservoir prior to a polymer flood. Fractional flow calculations suggest that prior water flooding should not affect the ultimate quantity of oil recovery from polymer flooding (Kamaraj et al., 2011). In contrast, Skauge et al. (2014) provided convincing evidence that fingers from a prior water flood can be instrumental in improving injectivity and providing a pathway for recovering oil that is mobilized by viscous polymer. On the other hand, Huh and Pope (2008) argued that polymer flooding directly after primary production maintains more connected flowing oil ganglia and leads to higher oil recovery levels than if a prior waterflood was applied. Further, field experience at Pelican Lake reveals that polymer flooding with no prior water flooding clearly recovers oil more effectively than polymer flooding after a waterflood (Delamaide, 2021). The mechanistic reasons for this result are not understood.

12.2. Can polymer reduce residual oil saturation (S_{or})?

Many authors have noted that HPAM injection at high velocities can reduce the capillary-trapped residual oil saturation significantly below that for water flooding (Wang et al. 2010, 2011a, 2011b; Vermolen et al., 2014; Erincik et al., 2017; Azad and Trivedi, 2020). However, it is not clear that this effect is workable at the low velocities associated with reservoirs with horizontal wells or fractured vertical injectors (i.e., most/all existing polymer floods). Exploration of other mechanisms for S_{or} reduction (e.g., wettability change) may have value (Zaitoun and Kohler, 1987, 1988; AlSofi et al., 2017; Li et al., 2020; Souayeh et al., 2022).

12.3. Should polymer banks be graded at the end of polymer injection?

Claridge (1978) proposed a method for grading polymer viscosities to minimize viscous fingering during the final stages of a polymer flood. He recognized that grading (i.e., reducing injected polymer concentration in stages) was most appropriate for homogeneous reservoirs, and that viscous fingering is accentuated in heterogeneous reservoirs. In contrast, Cyr et al. (1988) argued that grading would not be of practical benefit for polymer flooding under practical circumstances. Although graded banks are often used or planned in field applications, there is no consensus about whether it works or the optimum method for grading (Prasad et al., 2014; Seright, 2017).

12.4. Polymer flooding in low-permeability reservoirs

Interest has recently increased in applying polymer flooding in less-permeable reservoirs, especially carbonates (Ghosh et al., 2021; Mejia et al., 2022; Song et al., 2022). Because of the large-volume of oil target, this topic has substantial potential. The primary concerns for these applications are (1) ability of the polymer to propagate effectively through low-permeability rock and (2) cost-effectiveness of the lower-Mw polymers that must be used in these applications.

12.5. Recycling produced polymer

Since large polymer banks are needed for successful polymer flooding, polymer will eventually be produced in production wells. A growing question is whether this produced polymer can be recycled to reduce the cost of injected polymer. In addition to cost reductions, polymer recycling could reduce the carbon footprint associated with enhanced oil recovery (Ghosh et al., 2022). This is a new area with exciting possibilities. Obviously, recycling polymer will require that the polymer be effectively produced and separated from the oil with minimum degradation. To accomplish this, mechanical degradation must be minimized by proper choices of pumps (i.e., progressive cavity pumps or rod pumps instead of jet or electrical submersible pumps) and other surface equipment, and oxidative degradation must be minimized by prevention of air leaks.

12.6. Polymer-alternative-water and polymer-alternating-gas processes

In gas flooding processes, a limited/modest improvement in sweep can sometimes be realized by water-alternating-gas (WAG) injection (Green and Willhite, 1998). By extension, interest has been expressed in applying polymer-alternating-gas (PAG) and polymer-alternating-water (PAW) processes (Pan et al., 2020; Pang and Mohanty, 2022). Substantial questions about the viability of these processes remain to be addressed. In particular, do these processes offer any benefit beyond injecting a fixed bank of the less mobile fluid after injecting a fixed bank of the more mobile fluid?

12.7. Polymer flooding in the presence of aquifers and gas caps

Polymer flooding in the presence of aquifers and gas caps is challenging. Even if the aquifers and gas caps are inactive, polymer that enters these features is largely lost and can significantly diminish the overall ratio of oil recovered per mass of polymer injected. Even so, interest has occurred in using polymer injection as a means to inhibit water influx from an active aquifer using strategically placed horizontal wells and balanced polymer injection rates and pressures (Mjeni et al., 2022). Substantial challenges are presented by viscous fingering of aquifer water through viscous oils and polymer solutions.

13. Final comments

Despite having been declared a “mature” technology, successful polymer flooding requires a notably different mindset than water flooding. For the reservoir engineer, standard flooding patterns (e.g., 5-spot) often make sense for water flooding. However, in polymer flooding, prior awareness of the naturally preferred fracture directions can and has made the difference between early polymer breakthrough and a field performance that closely mimics an idealized Buckley-Leverett displacement. Prior measurement of at least the endpoint relative permeability to water can and has made the difference between choosing the optimum polymer injection viscosity and either insufficient polymer viscosity (leading to viscous fingering and early polymer breakthrough) or overly viscous polymer (leading to unnecessary injectivity losses and excessive fracture extension). With a water flood, the facilities or production engineer may view poor water quality or air leakage into the system as nuisances not worth correcting. In contrast, in a polymer flood, modest viscosity losses due to oxidative or mechanical degradation can and have cost tens of millions of dollars per year. Undissolved polymer can and has unnecessarily clogged wells, reduced injectivity, over-extended fractures, and wasted valuable polymer. Awareness of the stability limits of polymers can and has made the difference between trouble-free production operations and wells and surface facilities that become clogged with gelled polymers after exposure to excessively hot pumps or heater-treaters. As was mentioned in the introduction, we encourage innovation, even if it deviates from the suggestions made in this paper. However, if you try a "new" idea, please be objective in reporting the results in the literature—i.e., resist the natural temptation to report a "success" if it really wasn't. Everyone benefits from objective reporting of failures.

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