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Research Article

Pressure Modification or Barrier Issues during Polymer Flooding Enhanced Oil Recovery

Wang Dongmei, [1] **Shane Namie**, [1] **and Randall Seright** [2]

[1] *Harold Hamm School of Geology & Geological Engineering, University of North Dakota, Grand Forks, ND 58202, USA*
[2] *Petroleum Recovery Research Center, New Mexico Institute of Mining & Technology, NM 87801, USA*

Correspondence should be addressed to Wang Dongmei; dongmei.wang@und.edu

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Effective oil displacement from a reservoir requires adequate and properly directed pressure gradients in areas of high oil saturation. If the polymer bank is too large or too viscous during a polymer flood, the pressure drops from the injection well to the polymer front may act as a pressure modification or barrier by usurping most of the downstream driving force for oil displacement. Polymer injection pressures must be limited. The maximum allowable injection pressure is commonly constrained by caprock integrity, injection equipment, and/or regulations, even though fractures can be beneficial to polymer injectivity. This paper examines when the pressure-barrier concept limits the size and viscosity of the polymer bank during a polymer flood. Analytical and numerical methods are used to address this issue. We examine the relevance of the pressure modification concept for a wide variety of circumstances, including oil viscosities ranging from 10 cp to 1650 cp, vertical wells versus horizontal wells, single versus multiple layered reservoirs, permeability contrast, and crossflow between layers. We also examine the relation between the pressure-barrier concept and fractures and fracture extension during polymer injection. We demonstrate that in reservoirs with single layers, the pressure-barrier concept only limits the optimum viscosity of the injected polymer if the mobility of the polymer bank is less than the mobility of the displaced oil bank. The same is true for multizoned reservoirs with no crossflow between layers. Thus, for these cases, the optimum polymer viscosity is likely to be dictated by the mobility of the oil bank, unless other factors intervene. For multizoned reservoirs with free crossflow between layers, the situation is different. A compromise must be reached between injected polymer viscosity and the efficiency of oil recovery. This work is particularly relevant to viscous oil reservoirs where polymer viscosities are substantially lower than the oil viscosity.

1. Introduction

Regardless of economic effects, oil displacement requires a sufficient pressure gradient or driving force to push the oil to a production well. Many different pressure sources are often available for this function (Figure 1). For example, water from a nearby injection well often provides this driving force. However, if the oil is viscous, fingers can develop that causes the water to bypass the oil. A bottom water drive can also provide pressure support, but water coning (along with viscous fingering) can allow the water to short-circuit to the producer. Solution gas can provide some pressure support, but in viscous oil reservoirs, the oil is often depleted of gas so that little drive pressure remains. A gas cap could provide some drive energy, but like the case with water, the unfavorable mobility ratio commonly leads to viscous fingering, coning, and inefficient oil displacement. Also, during a polymer flood, much of the injected polymer may be wasted by entering the gas cap or aquifer. Compaction has provided a drive energy in rare cases (e.g., Tambaredjo oil field in Suriname, [1]) but has a small effect in most reservoirs. For most polymer floods, the injected polymer bank is intended to provide the drive energy to efficiently displace the oil.

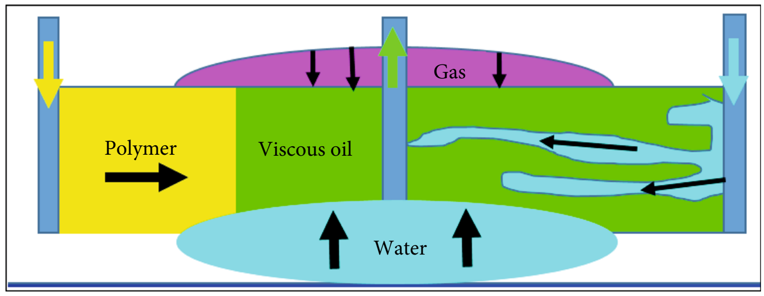


Figure 1: Illustration of sources of pressure to push oil toward a production well.

Effective oil displacement from a reservoir requires adequate and properly directed pressure gradients in areas of high oil saturation. If the polymer bank is too large or too viscous during a polymer flood, the pressure drop from the injection well to the polymer front may act as a pressure barrier by usurping most of the downstream driving force for oil displacement. In this paper, we define a "pressure modification" or "pressure barrier" as a viscous polymer bank (e.g., the yellow polymer bank in Figure 1) that substantially reduces the pressure available to drive oil toward the production well (as in the green oil bank in Figure 1). Intuitively, one can appreciate that whether or not a pressure modification develops depends on the length and viscosity of the polymer bank.

Polymer injection pressures must be limited. The maximum allowable injection pressure is commonly constrained by caprock integrity, injection equipment, and/or regulations, even though fractures can be beneficial to polymer injectivity (and even sweep efficiency in some cases). This paper examines when the pressure-barrier concept limits the size and viscosity of the polymer bank during a polymer flood.

Basic college textbooks in reservoir engineering teach the importance of the mobility ratio to sweep efficiency during injection of various fluids to displace oil [2]. A water/oil mobility ratio of one is taught as the balance point between a stable and unstable fluid displacement [3]. A novice might assume that a unit-mobility displacement is necessarily the optimum for all conditions. However, a mobility ratio of unity is not necessarily the optimum value to maximize sweep efficiency during a polymer flood [4, 5]. To explain, if a reservoir contains multiple layers and shale or other barriers do not isolate those layers, fluids can crossflow between adjacent layers. As explained in [4], if polymer injection provides a unit-mobility ratio (between the polymer bank and the oil bank), viscous fingering will be prevented in any given zone. However, the polymer front will sweep high-permeability zones faster than low-permeability zones. When the polymer front arrives at a production well from a high-permeability layer, the polymer front in adjacent low-permeability layer may only have traveled a small fraction of the distance between the injection well and production well—thus potentially stranding a large amount of oil. In contrast, Sorbie and Seright [5] and Seright [4] demonstrated that oil displacement from the adjacent low-permeability layer will increase in direct proportion to the reduction in polymer mobility (to a specific point)—even for polymer/oil mobility ratios significantly less than one. As a consequence, in layered reservoirs with free crossflow, the optimum sweep efficiency may require injecting polymer solutions that reduce the water/oil mobility ratio by a value equivalent to the permeability contrast between adjacent layers [4]. For example, for the original commercial-scale polymer flood at Daqing [6], the injected polymer solution (~45 cp) provided a mobility ratio of about 0.25—for displacing the 10 cp Daqing oil. The average permeability contrast of the reservoir was ~4 [6]. So as suggested by Sorbie and Seright [5] and Seright [4]), for a permeability contrast of 4 in a reservoir with free crossflow between layers, the optimum sweep efficiency is achieved using a polymer/oil mobility ratio of 0.25 (i.e., 1/4)—and NOT a polymer/oil mobility ratio of one.

However, a concern with this approach is that the injectivity losses (associated with injecting very viscous polymer solutions) could conceivably compromise economic fluid injection rates. This concern is mitigated to some extent by the presence of fractures around injection wells (that significantly enhance injectivity). Several persuasive studies demonstrate that most (perhaps all) polymer injection wells intersect fractures (either natural or induced) [6–10].

A large number of simulation studies of polymer flooding have been published. Many of these studies have struggled with or simply ignored realities about polymer injectivity [11, 12]. A basic problem with assuming radial flow around vertical polymer injection wells is that simple Darcy calculations reveal that injectivity of EOR polymer solutions will reduce injectivity to economically unacceptable values [9]. Some have circumvented this problem during simulations by artificially assuming an unrealistically large wellbore in the injection grid-block [13]. Others have "predicted" observed field injectivities by assuming that HPAM polymer solutions exhibit a falsely optimistic shear thinning behavior in porous media [12], where in reality, these polymer solutions show strong shear thickening behavior (i.e., the opposite of shear thinning). (If radial flow exists around an unfractured injection wells, shear thickening and high resistance to flow might be expected near the well, while shear thinning and low resistance to flow would be found far from the wellbore [9]. Still others have utilized obscurity and treated simulators as a black box to history match and "predict" injectivity and polymer flood performance in a way that blatantly violates Darcy's law [11]. Recently, some studies have properly incorporated fractures into their simulations—this more correctly predicting injectivity and polymer flood performance [14].

The inability of conventional simulations to properly account for polymer injectivity can substantially compromise their utility in predicting whether a polymer bank will be too viscous or too large—so that the polymer bank acts as a pressure barrier and reduces the driving force for effective oil displacement. In this paper, we start by performing simple, transparent calculations to allow the reader to appreciate when a polymer pressure modification is not expected to materialize. Subsequently, we add simulations of various field applications to demonstrate the utility of the basic concepts. Ultimately, this work will predict that a unit-mobility displacement is beneficial both from the viewpoint of maximizing polymer injectivity and maximizing pressure gradients within the oil bank. The novelty of this work is in visualization of why this finding is valid for various polymer flooding conditions.

This work will also point out concerns and possible avenues for improvement for certain important existing polymer floods. Although a novice might think that design of a polymer flood is well established, notable differences of opinion exist about how large and how viscous the polymer bank should be in a field application [4]. For example, at Milne Point (North Slope of Alaska, ~300 cp oil), the design targeted simply achieving a unit-mobility displacement (REF). At Pelican Lake (Alberta, Canada, ~1000-3000 cp oil), the mobility of designed polymer bank was substantially greater than the oil mobility—for a number of reasons that have been hotly debated [4]. Questions have long been raised about whether the Pelican Lake flood might perform better if more viscous polymer solutions were injected [4]. At Daqing (northeast China, ~10 cp oil), the initial polymer bank design provided a mobility ratio around 0.25, in order to effectively sweep zones with permeability contrasts up to four [6]. A later design (targeting capillary-trapped residual oil with the polymer) provided water/oil mobility ratios as low as 0.04 [15]. Ironically, no issues associated with reduced polymer injectivity or excessive fracture extension (leading to channeling) were noted at Daqing [4]. At Tambaredjo (Suriname, ~600 cp oil), field tests injecting polymer viscosities up to 165-cp did not appear to improve displacement efficiency (over 45 cp polymer)—for reasons that are still being debated [1, 16, 17]. Concerns about the impact of a pressure modification (associated with the polymer bank) have influenced the decisions made during most of these field applications. Thus, analysis of the pressure modification concept might lead to improvements in operation and understanding for the performance of these and other field applications of polymer floods.

Another factor considered in this paper is whether waterflooding before polymer flooding influences the performance of a polymer flood (and in particular, the waterfloods relation to a potential pressure modification). A few previous studies considered the effects of waterflooding before a polymer flood [18–22]. Using fractional flow analysis, Kamaraj et al. [20] noted that waterflooding for any time period (before the start of a polymer flood) had no significant impact on the ultimate volume of oil that could be recovered by a polymer flood.

The fractional flow calculations of Kamaraj et al. [20] made no allowance for viscous fingering with unfavorable mobility ratios. Skauge et al. [22] used X-ray tomography to demonstrate the impact of viscous fingers during waterflooding and polymer flooding of viscous oils in a 2-D laboratory setting. Viscous fingers from a waterflood have been argued as a means to improve injectivity for viscous oil reservoirs and provide the primary pathway for production of displaced viscous oil during a polymer flood [22].

Observations associated with the Pelican Lake polymer flood [18, 23, 24] indicate that viscous oil was displaced more efficiently when polymer flooding was implemented directly after primary production than when waterflooding was conducted before the start of the polymer flood. Although statistical analysis of a significant number of polymer flooding patterns supports this conclusion, a physical explanation is not yet evident. We also note the arguments of [21], indicating that polymer flooding immediately after primary production may be more likely to maintain connected oil drops—thus allowing the residual oil saturation to be decreased to a lower value than when polymer flooding after a waterflood. This issue is related to both theoretical and practical problems. One issue is the injection timing which may not be well understood. Another issue is whether light oil and viscous heavy oil exhibit fundamental differences in behavior beyond mobility considerations (e.g., wettability and capillarity).

On the other hand, radial flow around unfractured injection wells and production wells has long been recognized as accentuating pressure losses [25, 26] between wells. From a practical viewpoint, it has been effectively argued that all vertical injection wells have open fractures during polymer injection [7–10]. In contrast, pressure gradients around production wells are such that no fractures are present or any fractures are closed unless held open by proppant or frac-packs. From this information, we may anticipate that flow is basically linear from the injection well until the polymer approaches a vertical production well. Near the production well, flow will become radial and pressure gradients will become substantial.

We also note the work of Zhong et al. [27], Azad and Trivedi [28], and many others (referenced in these two papers) who examined the effects of HPAM viscoelasticity on reductions of residual oil saturation. These viscoelastic effects have been shown to primarily impact injectivity in the vicinity of unfractured injection wells and are of lesser significance for oil displacement deep within reservoirs where velocities and viscoelastic effects are small [28]. Although HPAM viscoelasticity can have an important effect on injectivity in vertical unfractured polymer injections wells, it does not alter our analyses of the relations between mobility ratio, injectivity, and pressure gradient within the oil bank, as discussed in this paper.

The primary novelty of this paper (for polymer flooding) is in examining mechanistic relations between mobility ratio, injectivity, and the driving force for oil displacement (i.e., the pressure gradient within the oil bank). A particularly unique feature of this work is its focus on relating the pressure gradient in the oil bank to mobility ratio and injectivity. We are aware of no previous literature with this emphasis. The pressure gradient within the oil bank is the single most important parameter affecting effective oil displacement. In contrast to most prior literature, the importance of fractures in polymer flooding is prominently considered, with an emphasis on promoting a mechanistic understanding of how polymer-induced injectivity losses may impact the pressure gradient within the oil bank. As mentioned in the discussion above, a substantial fraction of the previous polymer flooding simulations (where fractures were not incorporated) essentially acted as black boxes that provided little to no understanding of the simulator predictions. Commonly, these previous efforts imposed unrealistic or incorrect assumptions about polymer properties [11, 12]—in order to match field-observed injectivities. Another new feature of this work is a reconsideration of the ideal polymer viscosity/mobility ratio for a polymer flood. Our previous work [4] demonstrated that the highest oil displacement efficiencies can be achieved in heterogeneous viscous oil reservoirs with free crossflow between layers using mobility ratios less significantly below one (i.e., using a mobility ratio equal to the reciprocal of the permeability contrast). This paper demonstrates why, for certain cases, achieving the optimum sweep improvement may cause unacceptable losses in both injectivity and driving force for oil displacement. Finally, another new feature is in providing understanding of the performance of certain field polymer floods (Daqing, Pelican Lake, Milne Point, and Tambaredjo) and in some cases recommending improvements.

Some of the original analysis associated with this work can be found in a proceeding paper of Wang et al. [29].

2. Methodology

In this paper, both analytical and numerical methods are used to address this issue. We examined the relevance of the pressure modification concept for a wide variety of circumstances, including oil viscosities ranging from 10 cp (like at Daqing, China) to 1650 cp (like at Pelican Lake, Alberta), vertical wells (like at Tambaredjo, Suriname) versus horizontal wells (like at Milne Point, Alaska), single versus multiple layered reservoirs, permeability contrast, and crossflow between layers. We also examined the relation between the pressure-barrier concept and fractures and fracture extension during polymer injection.

2.1. Analytical Models. Consider the pressure losses across a polymer bank, assuming a single-layer, incompressible reservoir where the injected polymer provides the only source of drive pressure and oil displacement is linear and piston-like (Figure 2). Assume that a fixed total pressure difference (Δp_t) exists between the injection well and production well. The pressure drops across the polymer bank and oil bank are Δp_p and Δp_o, respectively; the lengths of the polymer and oil banks are L_p and L_o, respectively; and the polymer/oil mobility ratio is M (that is, polymer mobility divided by oil mobility).

For this simple case, Darcy's law for flow in series can readily be used to calculate the injection rate relative to the initial rate (q/q_i) as a function of mobility ratio (M) and relative length of the polymer bank $[L_p/(L_p + L_o)$ or $L_p/L_t]$:

$$\frac{Q}{q_i} = \frac{M}{\left[\left(L_p/L_t\right) + M\left(1 - \left(L_p/L_t\right)\right)\right]}. \quad (1)$$

Similarly, the pressure gradient in the oil bank relative to the initial pressure gradient within the oil bank $[(\Delta p_o/L_o)/(\Delta p_t/L_t)i]$ can be calculated using

$$[(\Delta p_o/L_o)/(\Delta p_t/L_t)i] = \frac{M}{\left[\left(L_p/L_t\right) + M\left(1 - \left(L_p/L_t\right)\right)\right]}. \quad (2)$$

Note that the left side of Equations (1) and (2) are the same. (This assumes that the ratio, M, in these equations is polymer mobility in the polymer bank divided by mobility of the oil bank.) Figure 3 plots predictions from these equations, as a function of mobility ratio and fractional polymer distance of penetration (L_p/L_t).

The mobility ratio used in Equations (1) and (2) is suggested to be the endpoint mobility ratio. Seright [4] provides an explanation for why this choice is superior to choosing the mobility ratio at the polymer/oil shock front. For some viscous oil reservoirs, we understand that some operators have not made the effort to properly determine the true endpoint permeability to water. For those cases, as explained by [4, 30], it may be acceptable to either use the observed permeability to water at the given high water cut or to match relative permeability curves to the observed data and extrapolate an endpoint.

For mobility ratios less than one (i.e., the two red curves in Figure 3), a substantial loss of injectivity occurs—because of the sizeable pressure drop across the polymer bank (i.e., a pressure barrier). As indicated by Equations (1) and (2), the pressure gradient across the oil bank follows the same trend as for injectivity. Thus, polymer banks that provide a mobility ratio less than one also create a pressure modification that significantly decreases the pressure gradient within the oil bank. Thus, for two important reasons (loss of injectivity and pressure gradient in the oil bank), mobility ratios less than one appear undesirable. Of course, sweep efficiency decreases continuously with decreasing mobility ratio [4]. However, the point raised here is that for mobility ratios less than one, the benefits of sweep improvement may be offset by reduced injectivity and reduced pressure gradient in the oil bank.

The two black curves in Figure 3 show that for mobility ratios greater than one, injectivity and pressure gradient within the oil bank gradually improve (with polymer throughput), but the effects do not become substantial until after 0.5 PV of polymer is injected. Even after 0.5 PV, it may be unrealistic to expect pressure gradients across the oil bank to increase significantly. The reason is that polymer solutions with an unfavorable mobility ratio will viscous finger

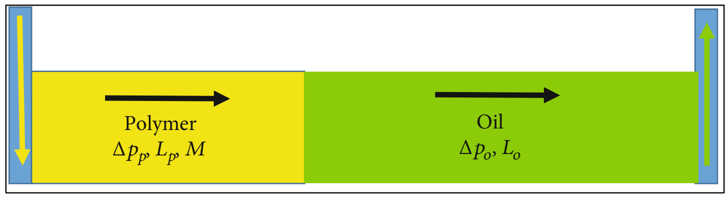


FIGURE 2: Simple linear, piston-like displacement of oil in a single layer.

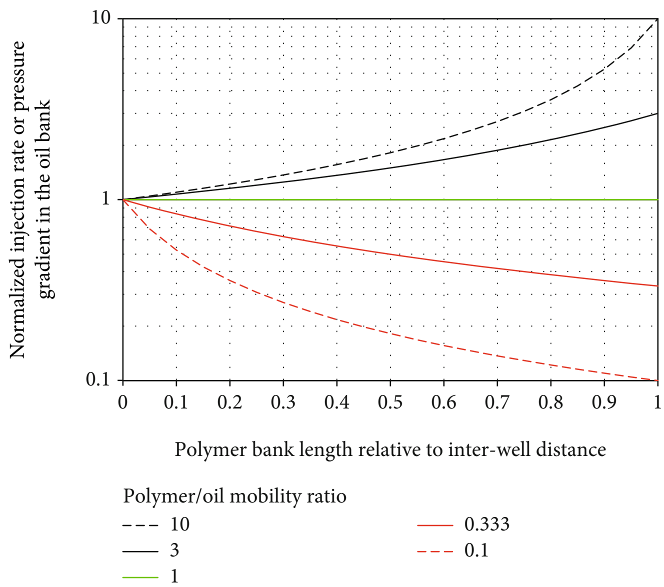


FIGURE 3: Normalized injection rate or pressure gradient in the oil bank versus polymer/oil mobility ratio and polymer bank length.

through the oil bank. The vertical equilibrium concept [5, 31] will force the pressure gradient within the oil bank to match that within the polymer fingers.

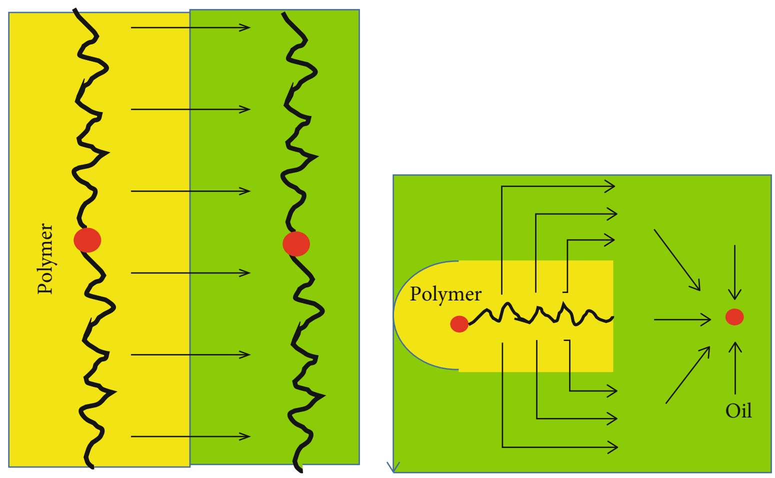
The overall message from this analysis is that it is most desirable to maintain a polymer/oil mobility ratio close to one. Mobility ratios less than one will create a pressure modification that harms both injectivity and pressure gradient within the oil bank. Mobility ratios greater than one may slightly improve injectivity but will not increase pressure gradient within the oil bank.

2.1.1. Multiple Layers with No Crossflow. If fluids cannot crossflow between adjacent layers, then each layer performs independent of the others. In that case, the conclusions that we reached above for one layer will also apply to multiple layers, so long as no crossflow can occur. Consequently, for a multilayer reservoir with no crossflow, a polymer/oil mobility ratio of one will also be most desirable. This conclusion is consistent with that reached based on fractional flow calculations in [32].

2.1.2. Multiple Layers with Crossflow. If fluids can crossflow between adjacent layers of different permeability, fractional flow analysis suggests that the optimum oil displacement will occur when the polymer mobility is lower than one by a factor that is equivalent to the permeability contrast [4, 32]. So if one layer has twice the permeability of the other (in a two-layer reservoir with free crossflow), the optimum polymer/oil mobility ratio would be 0.5. If the permeability contrast was 4 : 1, Seright [4, 32] predicts that the most efficient displacement would occur with a polymer/oil mobility ratio of 0.25. Will a similar conclusion be appropriate when considering the pressure modification concept?

With free crossflow, vertical equilibrium should exist—meaning that for any given horizontal position between and injector-producer pair, the horizontal pressure gradient is the same for all layers [31]. Also, if the polymer/oil mobility ratio is less than or equal to the reciprocal of the permeability contrast, the polymer will propagate in the less-permeable layer at the same rate as in the most-permeable layer [4, 5]. For that case, the injectivity and pressure gradient behavior mimic that for the red curves shown in Figure 3. Thus, for the case of free crossflow between layers, lower injectivity and pressure gradient within the oil bank will occur if the polymer/oil mobility ratio is low enough to give the most efficient sweep.

If free crossflow can occur between adjacent layers, we recognize that gravity and/or capillary forces can influence the displacement, in addition to viscous effects [2]. If the high-permeability layer is on the bottom, the greater density of water (over oil) could diminish polymer displacement into the upper oil zone, while capillary effects could enhance



(a) (b)

Figure 4: Illustration of effect of fracture orientation.

water/polymer penetration into the oil zones (if the oil zones have a significant water-wet character). However, other considerations tend to mitigate the impact of gravity and capillary effects. In particular, capillary forces are thought to be minimal for most viscous oil reservoirs [30]. Also, the high viscosity of polymer solutions will diminish the rate of gravity segregation, in direct proportion to the polymer viscosity value.

In summary, for the case of free crossflow, a polymer/oil mobility ratio near one will give the optimum injectivity and pressure gradient within the oil bank. This is in spite of the fact that a greater sweep efficiency will result from injecting a more viscous polymer bank. Thus, for all three cases of (1) a single layer, (2) multiple layers with no crossflow, or (3) multiple layers with free crossflow, a polymer/oil mobility ratio of one should provide the optimum injectivity and pressure gradient within the oil bank.

2.1.3. Effect of Vertical Fractures. For our purposes, fractures in injection wells can be put in one of two basic categories: (1) those oriented perpendicular to the desired direction of flow (between and injector and producer, as in Figures 4(a)) and (2) those oriented parallel to the desired direction of flow (as in Figure 4(b)).

For the situation illustrated in Figure 4(a), the case is the same as that shown in Figure 2—i.e., linear flow between two wells. Recall for that case, a polymer/oil mobility ratio of one provides the optimum injectivity and pressure gradient in the oil bank and absence of a pressure barrier associated with the polymer bank.

For the situation illustrated in Figure 4(b) (with the fracture pointing directly at the production well but leading only part way there), previous work [4, 33, 34] demonstrated that sweep efficiency will not be compromised so long as the fracture extends less than one-third of the distance between the injector and producer. The streamlines from the fracture toward the production well are not linear. Still, the polymer bank will create a pressure barrier if the polymer/oil mobility ratio is significantly less than one. That pressure modification would force fracture extension toward the production well with continued polymer injection. In contrast, if the polymer/oil mobility ratio is one or greater, fracture extension is much less likely (although viscous fingering will certainly occur for high mobility ratios). Consequently, a polymer/oil mobility ratio of one appears optimum in this situation as well.

2.1.4. Effect of Horizontal Fractures. At the Daqing (China) and Tambaredjo (Suriname) fields, induced fractures have been argued to be horizontal [15, 35]. As illustrated in Figure 5, injection could continually extend a horizontal fracture as polymer leaks off along the fracture faces—efficiently sweeping the oil. To explain, high pressure gradients along the polymer bank and high pressures within the fracture are likely to promote fracture extension (just as it does with vertical fractures). Figure 5(a) illustrates horizontal fracture initiation and development near the start of polymer injection, while Figure 5(b) illustrates fracture extension during prolonged polymer injection. Presumably, the pressure at the fracture tip is only moderately less than in the injection well (because of the fractures' high conductivity). A significant pressure drop is expected between the fracture and the edge of the polymer bank. Near the fracture tip, polymer can extensively leakoff through the fracture faces into the reservoir—thus pushing oil toward the production well. Far upstream of the fracture tip (toward the injection well), polymer that leaked off into the rock previously probably is stagnant—so that injected polymer exclusively propagates down the open fracture until it reaches the vicinity of the fracture tip. If the distance of polymer leakoff is too high, the polymer bank could act as a pressure barrier when displacing some oils (as suggested by Figures 3 and 4). For that reason, the mechanism shown in Figure 5 will be most effective in thin formations.

The mechanism illustrated in Figure 5 may be particularly relevant to the Daqing polymer flood. At Daqing, the layers are relatively thin, and few problems have been observed with either injectivity or early polymer breakthrough in production wells [6, 36–43]. These observations

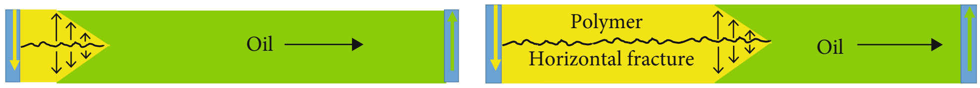


FIGURE 5: Illustration of propagation of a horizontal fracture during polymer injection.

are difficult to rationalize using conventional simulations without fractures, particularly for the Daqing cases where 150-300 cp polymer solutions were injected to recover ~10 cp oil. The mechanism illustrated in Figure 5 is the only viable mechanism proposed to date to explain the injectivity and lack of early polymer breakthrough observations at Daqing.

2.2. Numerical Simulation Models. In this section, we consider several important field applications of polymer flooding, including Pelican Lake (Alberta, Canada), Milne Point (Alaska, USA), Tambaredjo (Suriname), and Daqing (China). Our focus is on describing characteristics of the field that are relevant to the polymer pressure-barrier issue, followed by numerical simulations that examine whether a polymer pressure barrier might be expected under the specific conditions of that field. The simulations were performed for single patterns with one actual injector well and actual production well within existing polymer flood field projects using CMG IMEX. In contrast to the simple models used in the previous section, these simulations used geologic characteristics (including permeability, porosity, layering), PVT and wetting properties (including relative permeabilities), and polymer properties (including rheology in porous media and field-specific retention properties), and average injection and production rates during polymer injection that are relevant to the particular field. The goal was to determine whether the complications associated with the field application might alter the basic conclusions from the previous section. Figure 6 and Table 1 show oil (k_{ro}) and water (k_{rw}) relative permeability curves that were calculated using endpoints and Corey exponents reported in the literature, as well other major parameters used in the simulation (for the area of paired wells) for the four field cases. Details used to establish the simulation models will be introduced in following individual sections.

In order to examine the polymer front between an injector and a producer, 3D models were established based on the description for each field. For vertical wells, the length of the polymer bank was presented in the x-direction in the model, and for horizontal wells, it was presented in the y-direction, as illustrated by Figure 7.

3. Results and Discussion

3.1. Results. Some important predictions from our simulation efforts are included in Figure 8. One option was to normalize the y-axis by dividing the pressure gradient in the oil bank by the initial value (as was done in Figure 3). However, because the pressure gradients were reasonably close around 0.1 PV, we decided to report the values without normalization. The reader should focus primarily on the trends associated with a given curve—not the magnitude of the values.

3.1.1. Pelican Lake: Parallel Horizontal Wells. 800-3000 cp Oil. The Pelican Lake field (sometimes called Brintnell) in northern Alberta, Canada, covers an area of approximately 51 km by 42 km. The reservoir was discovered in 1978 and contains about 6.4 billion bbl OOIP. Oil viscosities range from 800 to 80,000 cp, but the bulk of the polymer flooded area has a viscosity of 3000 cp or less. Up to 900 horizontal wells have injected up to 300,000 bbl of HPAM solution, resulting in up to 67,000 BOPD (attributed to polymer flooding) from ~1400 horizontal production wells [19]. Typical injector-producer spacing is either 100 or 200 meters, and horizontal well lengths are typically 1500-2500 meters. Porosity and permeability of this unconsolidated sand averages roughly 30% and 1 Darcy, respectively, and formation thickness typically ranges from 3 to 6 meters. Recovery factors are projected to be 6% due to primary and 15% due to waterflooding after primary [23, 44]. Polymer flooding directly after primary provides an average recovery factor of 28%, while polymer flooding in a tertiary mode (i.e., after waterflooding) provides a projected average of 22% (CNRL website). Produced water cuts are typically between 57% and 69% [24]. No explanation was given for why polymer flooding directly after primary performed better than polymer flooding after waterflooding. Voidage replacement ratios targeted a value of one, but substantial variations occurred [19].

Typically, the viscosities of the injected polymer solutions at Pelican Lake were 15-30 cp (measured at 7.3 s^{-1} and 25°C). Given the high oil viscosity, an important question is whether the project would have seen improved performance by injecting a more viscous polymer solution. A number of rationalizations have been used to justify injecting such a low-viscosity polymer solution to displace a very viscous oil. First, losses of injectivity were feared. However, the weak Wabiskaw Formation at Pelican Lake has consistently shown few injectivity losses, regardless of injectant. Second, high polymer costs were argued to limit the economics of injecting more viscous polymer solutions. In contradiction, this concern is mitigated because (above 10 cp) polymer viscosity increases with the 1.9 power of polymer concentration [4]. So, doubling the viscosity only requires a 1.4X increase in polymer viscosity. Third, the relative permeability to water (k_{rw}) may be very low (e.g., 0.03), thereby requiring a low-viscosity polymer solution to achieve a favorable mobility ratio [30]. This is a legitimate reason, but an effort must be made to establish that the relative permeability to water actually is low. In fact, extensive studies associated with the Cactus Lake viscous oilfield, k_{rw} values around 0.03, were reported [30].

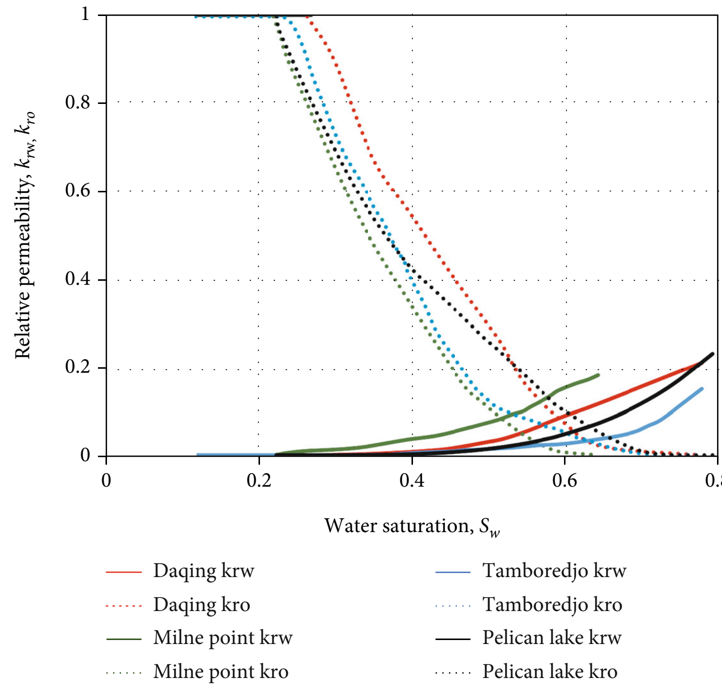


Figure 6: Relative permeability curves used in simulations after smoothing.

Table 1: General property of simulation area for the four oil fields.

Reservoir property	Oil field			
	Daqing	Milne point	Tambaredjo	Pelican Lake
Well geometry	Vertical	Horizontal	Vertical	Horizontal
Well spacing (ft)	820	1179	443	574
Oil viscosity (cp)	10	300	600	1650
Injection layers	4	8	5	2
Ave permeability (md)	512	1032	4066	3030
Ave. thickness (ft)	8.00	1.70	24.06	4.4
Max. permeability contrast	5.76	1.86	22.32	1.22
Ave. porosity	0.21	0.35	0.19	0.30
Polymer viscosity (cP)	45	45	45~85	22
S_{wi}	0.265	0.220	0.120	0.224
k_{rw} at S_{or}	0.210	0.18	0.15	0.216
Bubble point pressure (psi)	1395	1382	290	305
Reservoir pressure (psi)	1591	1600	485	420

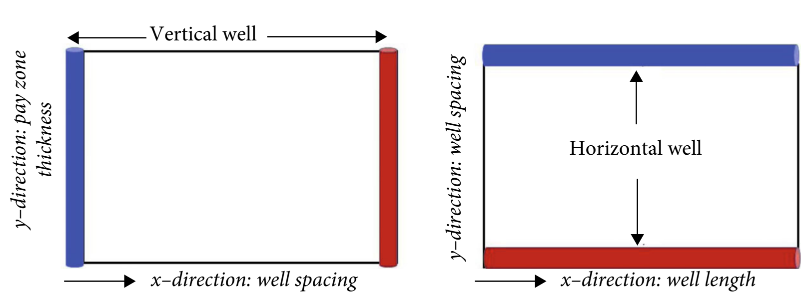


Figure 7: Illustration of polymer advancing direction in simulation models.

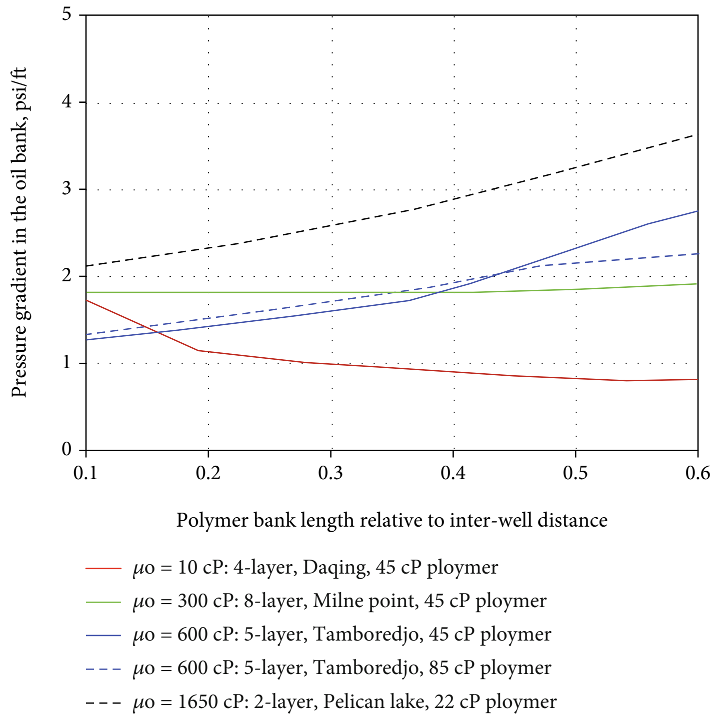


Figure 8: Simulation predicted pressure gradients in the oil bank at various oil field conditions.

Public information about oil-water relative permeability curves for Pelican Lake is scarce. Delaplace et al. [45, 46] reported endpoint relative permeabilities of water from 0.1 to 0.15, with Corey exponents of ~3.8 for water and~1.9 for oil. Delamaide et al. [47] reported that injection of 20 cp polymer solutions provided a mobility ratio of ~16 at Pelican Lake. Injected polymer viscosities have typically been from 15-30 cp [19], indicating that the flood has generally operated with a substantially unfavorable mobility ratio even during polymer injection.

Delamaide [18, 19] noted that higher recovery factors were associated with injecting polymer directly after primary production, compared with waterflooding before the polymer flood. Polymer injection directly after primary production was most likely to cause a definitive increase in oil production rate, in addition to reducing the produced water cut. In contrast, polymer injection after waterflooding might reduce water cut but generally did not increase the oil production rate. As expected, better oil-recovery responses to ~20-30 cp polymer flooding occurred in parts of the field with lower oil viscosities—i.e., less unfavorable mobility ratios.

When waterflooding before polymer flooding a viscous oil, Skauge et al. [22] demonstrated that viscous fingers form pathways to the production well, and these fingers, in turn, serve as pathways for much of the incremental oil flow during subsequent polymer injection. Oil response to polymer injection is expected fairly quickly for this situation [22]. Consistent with this suggestion, the response to polymer injection typically occurred after 9-12 months [23]. If the mobility ratio remains unfavorable (as at Pelican Lake), the domination of flow through the fingers means that pressure gradients in the oil bank will not increase significantly. So, although the water cut should decrease during polymer injection, the oil production rate may not increase significantly—just as observed at Pelican Lake.

(1) Simulation Results. Simulations were performed to estimate the pressure gradient in the oil bank during polymer injection under Pelican Lake conditions. Simulations were performed using CMG IMEX and properties listed by Delaplace et al. [45, 46] and Delamaide et al. [47]. The relative permeability curves for these Pelican Lake simulations are shown by the black curves in Figure 6.

The predicted pressure gradients in the oil bank are shown by the dashed black curve in Figure 8. This curve is qualitatively consistent with the black curves in Figure 3 (i.e., for unfavorable polymer/oil mobility ratios). The implication here is that increased injected polymer viscosity will decrease mobility ratio and improve recovery efficiency. However, we must point out that these simulations do not incorporate viscous fingering associated with the unfavorable mobility ratio at Pelican Lake. As mentioned in the discussion associated with Figure 3, in reality, viscous fingering and the vertical equilibrium phenomenon will inhibit or prevent increases in pressure gradient in the oil bank. Thus, as predicted by the green curve in Figure 3, one would expect water cut and sweep efficiency at Pelican Lake to benefit from increasing injected polymer viscosity to achieve a polymer/oil mobility ratio closer to one.

Perhaps, the main consideration that inhibits injection of higher polymer viscosities at Pelican Lake is the government-mandated maximum injection pressure of 7 MPa. Delamaide [19] plotted wellhead injection pressures for various parts of the Pelican Lake field. In the western part of the field, the average injection pressure averaged about 10% below the government-mandated maximum (7 MPa), so little room is available there to increase injected polymer viscosity (if the same rate is to be maintained). However, in the eastern part of the field, injection pressures averaged over 40% below the maximum pressure mandate. Thus, it appears that improvements in sweep could be made by increasing injection viscosities in that part of the field.

Delamaide [23] noted that no correlation existed between well spacing and oil recovery. However, by using tighter spacing and the same injection pressure constraints, our analysis suggests that Pelican Lake could benefit by injecting more viscous polymer solutions—i.e., achieving a polymer/oil mobility ratio closer to unity and increasing pressure gradients in the oil bank.

3.1.2. Milne Point: Parallel Horizontal Wells. 300 cp Oil. The Milne Point field is a large, viscous oil reservoir on the North Slope of Alaska. A polymer flood pilot project has been underway since August 2018. Oil viscosity at reservoir conditions is about 300 cp. Formation thickness is 15-30 ft. A number of publications describe details of this project [48–58]. The pilot is at the J-pad of the Milne Point Unit and consists of two horizontal injectors (J-23A and J-24A) and producers (J-27, J-28) drilled into the Schrader Bluff NB-sand. The horizontal wells range from 4,200 to 5,500 ft in length, and the interwell distance varies from 1,100 to 1,500 ft. Before the polymer pilot, this pattern was waterflooded, which was terminated when the oil recovery was only 7.6% OOIP and water cut reached 70%. The initial polymer concentration was 1,750 ppm (45-cp at 7.3 s^{-1}, 25°C), which was reduced to 1,500 and later to 1,200 ppm (30 cp at 7.3 s^{-1}, 25°C). A low-salinity water (2,600 mg/l total dissolved solids, TDS) was used to prepare the polymer solution. The target for the injected polymer solution viscosity was to achieve a unit polymer/oil mobility ratio. At the start of the project, 1750 ppm HPAM was injected that provided a viscosity of ~45 cp at 7.3 s^{-1}. However, after recognizing that the actual effective average shear rate in the reservoir was about 1 s^{-1} (because of the horizontal wells), the target polymer concentration was reduced to 1200 ppm. Extensive measurements of relative permeabilities (green curves in Figure 6) and other properties relevant to the Milne Point project suggest that the current operation is providing a near unit-mobility displacement of the oil. In apparent contradiction, polymer breakthrough in Production wells J-27 and J-28 occurred after only 10% PV of polymer injection. However, extensive studies and the available evidence indicated that this early breakthrough was due to polymer channeling through fracture-like features—and not due to viscous fingering associated with an unfavorable mobility ratio.

(1) Simulation Results. Extensive simulation efforts to describe the behavior during the Milne Point polymer flood can be found in [56]. In the current work, we focus on the pressure gradients anticipated within the oil bank during the polymer flood. In the model which generated the green curve in Figure 8, eight vertical layers were used in the simulation model to represent the NB sand in the Milne Point field. This green curve is qualitatively consistent with the green curve in Figure 3—where the predicted pressure gradient within the oil bank remains fairly constant for most of the polymer flood.

In addition, in order to compare the pressure modification development in viscous oil reservoirs, an eight-layer model with same reservoir conditions (of the Milne Point field) was used during simulations with various oil viscosities. In the base case, 45 cp polymer was injected to displace the viscous oil. The base case was anticipated to provide a near unit-mobility displacement. Consistent with the green curve in Figure 3, the predicted pressure gradient within the oil bank remains fairly constant for most of the polymer flood.

The other curves in Figure 9 show predictions, assuming the oil in the reservoir was more viscous than 300 cp. Consistent with the black curves in Figure 3, the predicted pressure gradients within the oil bank become greater as the polymer flood progresses and as the reservoir oil becomes more viscous (because of the increased polymer/oil mobility ratio as the oil viscosity is raised while keeping the polymer viscosity fixed at 45 cp) at a certain polymer injection volume (0.67 PV). We suspect that the increase in pressure gradient will not actually materialize within the oil bank because of viscous fingering and vertical equilibrium effects.

3.1.3. Daqing: Vertical Wells. 10 cp Oil. Daqing has been the largest polymer flood in the world since 1996. Many papers are available that describe this project [6, 36–43]. The oil viscosity associated with the main polymer flood was about 10 cp at 45°C. Five-spot patterns of vertical wells were used, typically with 250-meter well spacing. Multiple strata are present—some with free crossflow between layers and some without crossflow. Total net pay averages around 18 m. Polymer injection wells have been proven to have open fractures during polymer injection [6]. Interestingly, the Daqing experts felt that these fractures were oriented horizontally, despite the formation depth around 1000 meters subsurface [6]. Much of the polymer flood involved injection of 45 cp HPAM. Endpoint relative permeability to water was 0.21. The relative permeability curve for polymer flooding in the Daqing oil field was established based on laboratory experiments using unsteady-state (USS) techniques [59]. One might be surprised at the high endpoint permeability to water. However, very extensive experiments have confirmed these curves and the oil-wet nature of the Daqing reservoir.

In another important part of the Daqing polymer flood, 150-300 cp polymer was injected in attempt to reduce the capillary-trapped residual oil saturation below that obtainable by extended waterflooding [15, 36, 39, 40, 42, 43, 60]. Interestingly, evidence of injectivity problems was not usually seen, even during injection of 150-300 cp polymer. Injectivity was reported to be only about 10% less for 200-300 cp polymer than for 40-50 cp polymer [15]. Fracture extension seems the most likely explanation for this observation. Interestingly, no evidence of severe polymer channeling was reported either. Of the field cases considered, this is the case

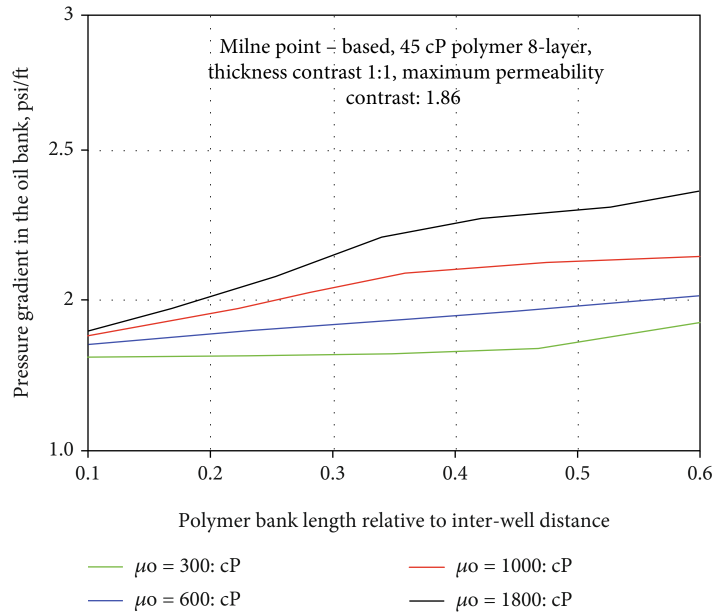


Figure 9: Simulation predicted pressure gradients in the oil bank at Milne Point—based (eight-layer).

where a polymer pressure barrier is most expected (based on the arguments associated with Figures 3 and 4). Also, this is the case where severe fracture extension and development of severe channeling would have been expected. In speculating a reason why these phenomena were not seen, fortuitous fracture extension seems a possible explanation. Perhaps, the key is horizontal fractures. As illustrated in Figure 5, polymer injection could continually extend the fracture as it leaks off along the fracture faces—efficiently sweeping the oil (assuming the zone is not too thick).

Many simulators focus on manipulation of relative permeability curves to match observed results. We tried this approach and found it incapable of matching the key observations noted above. For vertical injection wells with no fractures, it is apparent that no credible relative permeability manipulation could explain how injection of 300 cp polymer could result in little or no injectivity reduction when displacing a 10 cp oil [4, 9]. Fractures are required to explain the results [6].

It is worth noting that many hydraulic fracturing measures have been actually employed during polymer injection in Daqing. This at least partly accounted for the observations concerning injectivity. Another important point for Daqing is that significant injectivity reductions where observed during polymer injection into some wells—suggesting that perhaps not all wells were fractured or that if fractures were present, they did not extend sufficiently to accommodate polymer injection at the desired rate.

(1) Simulation Results. Reservoir properties and polymer properties for numerical simulation associated with this simulation effort can be found in [15, 36, 38–40, 42, 43, 60, 61]. Four vertical layers were used in the simulation model to represent the major pay zone of Pu I-II strata in Daqing field. The red curve in Figure 8 shows the prediction from the simulation effort for Daqing. Qualitatively consistent with the red curves in Figure 3, the simulation predicted a decline in injectivity and in pressure gradient within the oil bank as the polymer progresses through the reservoir (except for the artifact where pressure gradients increase as polymer approaches the production well). As mentioned above, this behavior and a polymer-induced pressure barrier did not appear to materialize in the actual Daqing field application. We suggest that the discrepancy can be explained by fracture extension during polymer injection—as illustrated in Figure 5.

3.1.4. Tambaredjo: Vertical Wells. ~600 cp Oil. The Tambaredjo reservoir (Suriname) is a 12-Darcy reservoir containing ~600 cp oil. During primary production, ~20% OOIP was recovered, by solution-gas and compaction drive. Polymer pilots were developed using vertical wells in 5-spot patterns with ~135-meter spacing [1, 16, 17, 35, 62, 63]. The pilot area was described by permeability of 4-12 Darcies and two beds (T1 and T2) with a 12: 1 permeability contrast (free crossflow, 20 ft thickness for the most-permeable layer and 15 ft thickness for the second layer). Initially, the project injected ~45 cp HPAM solutions into vertical wells that were proven to have open horizontally oriented fractures or fracture-like features. Based on arguments raised in Seright [4], injected polymer viscosities were increased in stages to as high as 165 cp (at 7.3 s^{-1}, 25°C). Unfortunately, injection of the more viscous polymer solutions did not improve performance of the polymer flood. The reasons for this have been debated [1, 16, 17], but one possibility raised was that pressure barriers may have been created during injection of the more viscous polymer solutions.

Although the oil-displacement mechanism illustrated in Figure 5 could explain the viscous polymer injection at Daqing, why did it not appear to work at Tambaredjo in Suriname? Tambaredjo was a shallower field (~300-meter depth) with a single, thin formation, so horizontal fractures and the above mechanism are more easily justified there than at Daqing.

(1) Simulation Results. Reservoir and polymer properties associated with this simulation effort can be found in [1, 16, 64]. Five vertical layers were used in the simulation model to represent the T1 and T2 strata in the Tambaredjo field. The two blue curves in Figure 8 show the predicted results (from simulation), assuming 45 cp and 85 cp polymer, respectively. Both of these cases involved polymer/oil mobility ratios greater than one. So, consistent with the black curves of Figure 3, pressure gradients within the oil bank (and injectivity) were predicted to increase with increased polymer throughput. Since higher injected polymer viscosities did not increase oil recovery performance at Tambaredjo [1, 17], an explanation is needed. One possibility is that the assumed relative permeability curves for this case may have been incorrect—so that the injected 45 cp polymer actually provided a polymer/oil mobility ratio near unity. In that case, a pressure barrier could have developed during injection of the more viscous polymer solutions. This observation emphasizes the importance of measuring relative permeability characteristics for these polymer floods. However, we note that other explanations have been proposed for the lack of improved performance at Tambaredjo, including (1) unconfined patterns during the polymer pilots, (2) viscous polymer injection countering a significant compaction drive, and (3) formation damage at production wells inhibiting collection of displaced oil [1].

3.2. Discussion of Additional Ideas and Findings. This paper noted that if the polymer bank is too large or too viscous during a polymer flood, the pressure drop from the injection well to the polymer front may act as a pressure barrier by usurping most of the downstream driving force for oil displacement. Some possible improvements for polymer floods design are suggested:

(a) For the successful polymer floods in the Grimbeek oil field in Argentina or Nuraly in [65, 66], the injected polymer viscosity ranged from 50 to 135 cP. The polymer/oil mobility ratios appeared to be less than 0.1. In Grimbeek, for instance, we suspect that pressure modifications might exist as the polymer advanced deeper into the reservoir. However, fractures probably opened during polymer flooding to aid injectivity as we discussed in Daqing example. In addition to fractures, the voidage replacement ratio (VRR) and the confining pressure of the well patterns should be considered in the future

(b) Based on the analysis, we believe for most current polymer flooding cases, the polymer viscosity designed was acceptable. However, considering injectivity, for the later stage of polymer injection ($L_p/L_T > 0.5$), lower polymer viscosity is suggested

(c) For multiple layers with free crossflow circumstances, only one set of relative permeability curve was considered for one pair of wells in the numerical simulation model. For some field cases, multiple relative permeability curves have been applied during history matching (the Milne Point field, for instance). In this case, the endpoint mobility ratio could be floated up or down to match the average mobility ratio. Consequently, the shape of the pressure gradient in the oil bank maybe different than the green curve in Figure 3. However, the curve trends will be similar to the green curve in Figure 3 (where the target mobility ratio was 1)

(d) Compared with the simple analytical model, other factors in the field may complicate the observed performance, but more sophisticated numerical simulation could compensate for these effects

4. Conclusions

(1) During polymer flooding, this work suggests that under most circumstances, the optimum injectivity (i.e., least likelihood of developing a polymer-induced pressure barrier) and the greatest pressure gradient within the oil bank will be achieved with a polymer/oil mobility ratio near one

(2) Our current work suggests that a previous analysis [4] may have overpredicted the most desirable polymer viscosity for polymer flooding a heterogeneous reservoir with free crossflow between layers. That previous analysis correctly predicted that the optimum sweep efficiency would result from a polymer viscosity (relative to water) that was the waterflood endpoint mobility ratio times the permeability contrast. However, the current work reveals that excessive pressure barriers could develop with that approach

(3) Because the polymer/oil mobility ratio is generally unity or greater, a pressure barrier due to the injected polymer bank is not likely to materialize for viscous oil reservoirs such as Pelican Lake or Milne Point

(4) At Milne Point, where the target polymer/oil mobility ratio is near one, analytical and simulation results support achievement of the optimum injectivity and greatest pressure gradient within the oil bank

(5) At Pelican Lake where polymer/oil mobility ratio is currently substantially greater than unity, by using tighter spacing, our analysis suggests that Pelican Lake could benefit by injecting more viscous polymer solutions. Also, in the eastern part of the field (where the government-mandated injection pressure is generally not limiting), recovery efficiency might benefit from injection of higher polymer concentrations—i.e., achieving a polymer/oil mobility ratio closer to unity

(6) Although injection of viscous polymer solutions (up to 165 cp) clearly did not improve sweep (over 45 cp

polymer) at the Tambaredjo field, the observed injectivity reductions seem unlikely to be due to development of a polymer pressure barrier (because the current polymer/oil mobility ratio is thought to be notably greater than unity), unless the true end-point permeability to water was much lower than the value assumed during simulations

(7) Although a severe pressure barrier was anticipated for the Daqing polymer flood (where the polymer/oil mobility ratio was significantly less than unity), it clearly did not materialize, even with injection of 150-300 cp HPAM solutions. During polymer injection, fortuitous extension of (horizontal) fractures may explain why problems did not develop with injectivity reduction, pressure modifications, and channeling associated with excessive fracture extension

Nomenclature

k: Permeability, Darcy [μm^2]
k_{ro}: Relative permeability to oil
k_{rw}: Relative permeability to water
L_o: Length of the oil bank, ft [m]
L_p: Length of the polymer bank, ft [m]
L_t: Total distance from injector to producer, ft [m]
M: Polymer/oil mobility ratio
Δp_o: Pressure drop across the oil bank, psi [Pa]
Δp_p: Pressure drop across the polymer bank, psi [Pa]
Δp_t: Pressure drop from injector to producer, psi [Pa]
PV: Pore volumes of fluid injected
ΔPV: Pore volumes difference
S_{or}: Residual oil saturation
Δt: Incremental time, hr
v: Velocity, ft/d [m/d]
v_i: Initial velocity, ft/d [m/d]
ϕ: Porosity
ρ_{rock}: Rock density, g/cm^3.

SI Metric Conversion Factors

cp $\times$ 1.0 $*$:	E $-$ 03 = Pa $\cdot$ s
ft $\times$ 3.048 $*$:	E $-$ 01 = m
in.$\times$ 2.54 $*$:	E + 00 = cm
mD $\times$ 9.869 233:	E $-$ 04 = μm^2
psi $\times$ 6.894 757:	E + 00 = kPa
$*$:	Conversion is exact.

Data Availability

Data associated with this paper can be accessed at http://www.prrc.nmt.edu/groups/res-sweep/ and https://netl.doe.gov/node/6842.

Additional Points

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Conflicts of Interest

The authors declare that there is no conflict of interest regarding the publication of this paper.

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