A Comparison of Polymer Flooding With In-Depth Profile Modification

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Summary

For stratified reservoirs with free crossflow and where fractures do not cause severe channeling, improved sweep is often needed after water breakthrough. For moderately viscous oils, polymer flooding is an option for this type of reservoir. However, in recent years, an in-depth profile-modification method has been commercialized in which a block is placed in the high-permeability zone(s). This sophisticated idea requires that (1) the blocking agent have a low viscosity (ideally a unit-mobility displacement) during placement, that (2) the rear of the blocking-agent bank in the high-permeability zone(s) outrun the front of the blocking-agent bank in adjacent less-permeable zones, and that (3) an effective block to flow form at the appropriate location in the high-permeability zone(s). Achieving these objectives is challenging but has been accomplished in at least one field test. This paper investigates when this in-depth profile-modification process is a superior choice over conventional polymer flooding.

Using simulation and analytical studies, we examined oil-recovery efficiency for the two processes as a function of (1) permeability contrast, (2) relative zone thickness, (3) oil viscosity, (4) polymer-solution viscosity, (5) polymer- or blocking-agent-bank size, and (6) relative costs for polymer vs. blocking agent. The results reveal that in-depth profile modification is most appropriate for high permeability contrasts (e.g., 10:1), high thickness ratios (e.g., less-permeable zones being 10 times thicker than high-permeability zones), and relatively low oil viscosities. Because of the high cost of the blocking agent relative to conventional polymers, economics favours small blocking-agent-bank sizes (e.g., 5% of the pore volume in the high-permeability layer). Even though short-term economics may favour in-depth profile modification, ultimate recovery may be considerably less than from a traditional polymer flood.

Introduction

Heterogeneity is well known to reduce sweep efficiency during waterflooding and other flooding processes. Depending on the nature of the heterogeneities, a number of methods are available to improve sweep efficiency. For example, if continuous impermeable barriers separate high-permeability watered-out strata from less-permeable oil-productive strata, one can use cement, mechanical methods, or certain chemical plugging agents to block off the offending high-permeability zones at the wellbore so that injected water only enters and displaces oil from the less-permeable zones. As another example, if a fracture or fracture system causes direct channeling between wells, gels can be extruded deep into the fractures to allow subsequently injected fluid to be diverted to displace oil from the rock matrix (Sydansk and Romero-Zeron 2011). This paper is directed at a third scenario, in which fluids can crossflow between strata but fractures do not contribute significantly to channeling. Improving sweep efficiency for this case is generally acknowledged as considerably more challenging than doing so for the first two cases (Seright et al. 2003).

Polymer Flooding. Polymer flooding is one method to attack this difficult problem (Willhite and Seright 2011). **Fig. 1** illustrates the benefits of a polymer flood in a two-layered system with free crossflow. This figure shows five displacements of water by red-dyed polymer solutions, with xanthan solutions ranging in concentration from 0 to 2,000 ppm and viscosities (at 11 s^{-1}, 25°C) ranging from 1 to 75 cp. In each case, the plexiglass-encased beadpack had dimensions of $238\times11.6\times1.3$ cm. A 5.8-cm-high layer of 150-μm glass beads comprised the bottom layer, while a 5.8-cm-high layer of 500-μm glass beads acted as the top layer. The top layer was 11.2 times more permeable than the bottom layer. No flow barrier existed between the layers. Fig. 1 shows the position of the polymer fronts in the bottom layer at the time when the polymer reached a fixed position in the top layer. The figure clearly shows the benefit of a polymer flood. As the viscosity of the injected fluid increases, sweep efficiency in the less-permeable layer increases. [Details of these experiments can be found in Sorbie and Seright (1992). Videos of these laboratory experiments may be viewed at http://baervan.nmt.edu/randy/.]

Gels for In-Depth Profile Modification. When gels and other blocking agents were proposed to improve sweep in stratified reservoirs with crossflow, it was commonly stated or implied that the material exclusively entered and reduced permeability in high-permeability strata, thereby diverting subsequently injected water into less-permeable oil-bearing strata (Needham and Doe 1987; Chang et al. 2006; Choi et al. 2010). Unfortunately, this view ignores penetration into and permeability reductions in less-permeable strata (Seright 1988; Sorbie and Seright 1992; Sydansk and Romero-Zeron 2011). In Fig. 1, one can easily envision that if the polymer solution suddenly gelled, the reduction in flow capacity in the low-permeability layer may be greater than in the high-permeability layer. This expectation is confirmed experimentally in **Fig. 2** and in additional videos of experiments at http://baervan.nmt.edu/randy/. After polymer placement, injected water forms severe viscous fingers that channel exclusively through the high-permeability layer.

Water Post-Flush Following Placement of a Water-Like Gelant. To get around the problem illustrated in Fig. 2, an idea was conceived that used a water post-flush following placement of a water-like gelant (Fletcher et al. 1992; Sorbie and Seright 1992). **Fig. 3** illustrates the idea. During waterflood operations, assume that injected water has reached a production well by following a high-permeability pathway. Presumably, considerable mobile oil remains in less-permeable strata. For the first step of the gel treatment, a gelant with a water-like viscosity is injected (Fig. 3a). Because of the low viscosity of the gelant, penetration into the less-permeable zones is minimized (Seright 1988; Sorbie and Seright 1992). Second, water is injected to displace the water-like gelant away from the wellbore (Fig. 3b). Enough water must be injected so that the rear of the gelant bank in the most-permeable zone outruns the front of the gelant bank in an adjacent less-permeable zone. In the third step of the process, the gelation or permeability reduction occurs (Fig. 3c). Finally, if the gel treatment is applied in a waterflood injection well, water injection is resumed (Fig. 3d). It is hoped that a pathway will be available for water to crossflow from the high-permeability zone into the less-permeable zone(s) so that sweep efficiency can be improved.
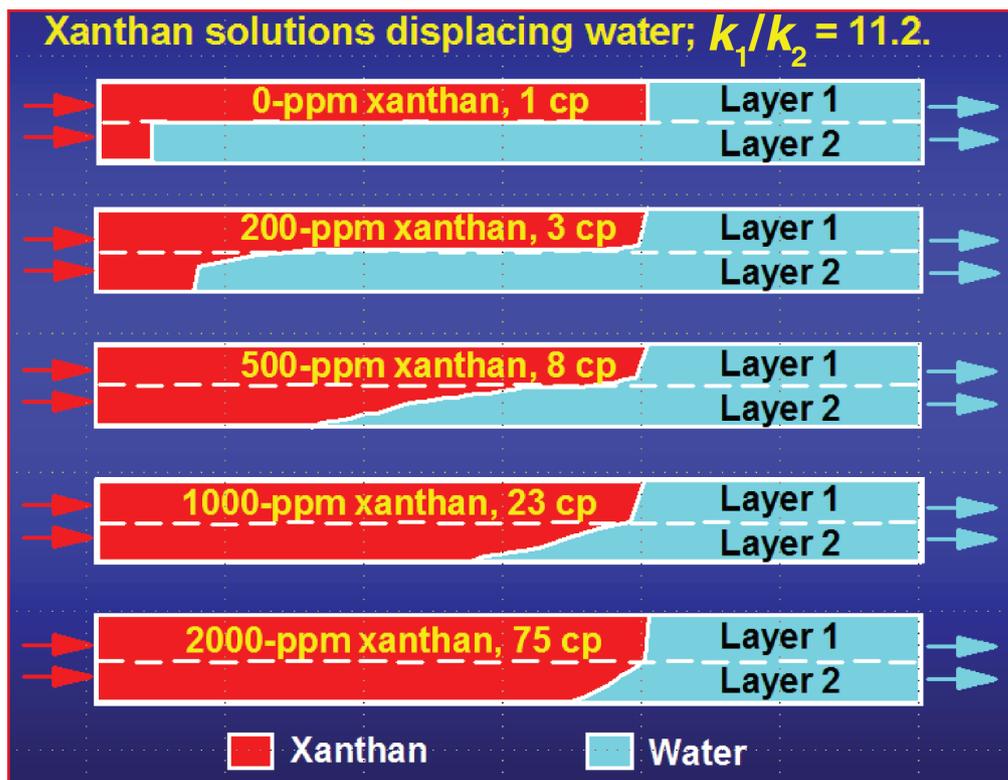
Fig. 1—Polymer flood improving sweep in a two-layer system with free crossflow.

If this scheme is feasible, it could provide favourable injectivity. During water injection after gelation, much of the water leaving the wellbore should enter the most-permeable zone. If the cross-sectional area is relatively large in the region where water cross-flows from the high-permeability zone into the low-permeability zone, injectivity losses from the gel treatment could be minimized. In contrast, conventional gel treatments (i.e., those with no post-flush before gelation) in unfractured injection wells should cause significant injectivity losses. The "incremental" oil from this scheme could be recovered relatively quickly. Oil displaced from the less-permeable zones can crossflow into the most-permeable zone, where it can flow more rapidly to the production well.

A number of limitations should be recognized for this scheme. First, the gel treatment will not improve sweep efficiency beyond the greatest depth of gelant penetration in the reservoir. Once beyond the gel bank in the most-permeable zone, fluids can cross-

flow back into the high-permeability channel. This provides an incentive to maximize the depth of gelant penetration in the high-permeability channels.

Gelation time can be an important factor that limits the depth of gelant penetration in a reservoir. If the offending channel consists of a permeable rock matrix, then long gelation delays (many months) may be needed in order to achieve large depths of gelant penetration.

The applicability of this scheme depends on the sweep efficiency in the reservoir before the gel treatment. In injection wells, the scheme is expected to work best if sweep efficiency was poor before the gel treatment. Then, the water that is diverted into the less-permeable strata should primarily displace oil. In contrast, if sweep efficiency was high before the gel treatment or if gelant penetration is insufficient in the high-permeability channel, there may be little or no oil to displace in the less-permeable zones.
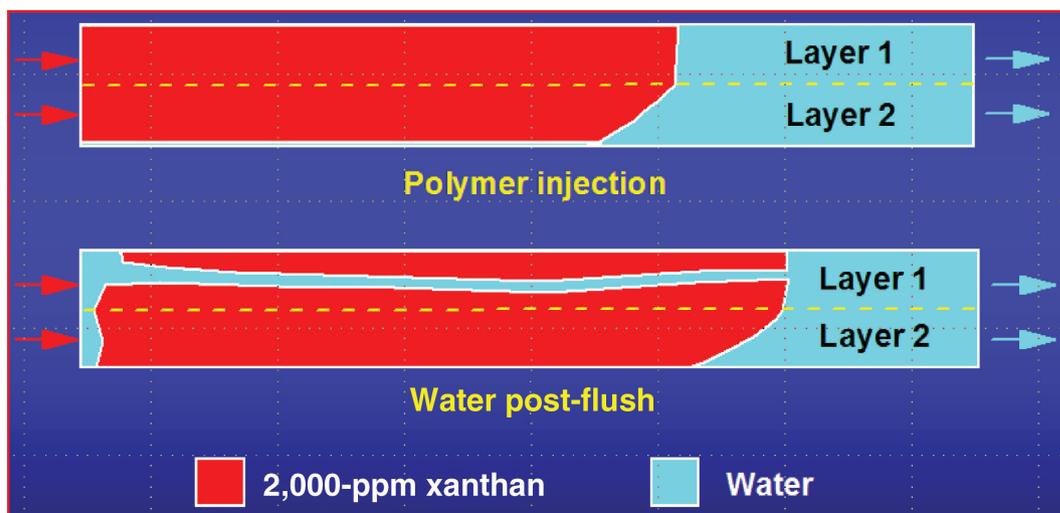

Fig. 2—Water injection following polymer injection for the bottom case in Fig. 1.
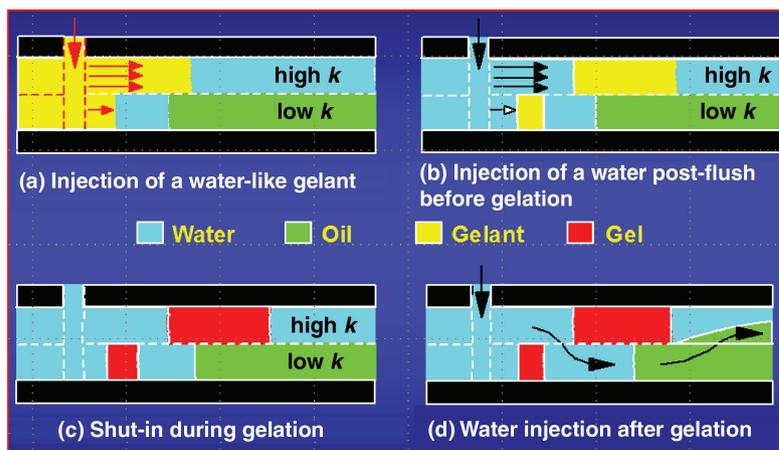
Fig. 3—Use of a water post-flush with a water-like gelant.

In light-oil reservoirs, one important limitation is that the viscosity and resistance factor of the gelant must not be too large. Viscous gelants will penetrate to a greater degree into the less-permeable zones (see Fig. 1). Furthermore, before gelation, viscous gelants will crossflow continuously from the high-permeability channel into the adjacent less-permeable zones. This creates a barrier of viscous gelant in the less-permeable zones all along the interface with the high-permeability channel. When a water post-flush is injected, the barrier hinders crossflow of water from the high-permeability channel into the lower-permeability zones. Thus, viscous fingers from a water post-flush will break through the viscous gelant bank in the high-permeability channel before breakthrough in less-permeable zones. This can render the process ineffective. In viscous-oil reservoirs, it is conceivable that this limitation could be relaxed. In addition, the viscosity and resistance factor of the gelant should not increase much during injection of either the gelant or the water post-flush. Any increase in gelant resistance factor during this time will drive additional gelant into the less-permeable zones and thereby, jeopardize the process.

Use of a Thermal Front. A variation of the idea in Fig. 3 is illustrated in **Fig. 4.** Cold water is sometimes injected into hot reservoirs, creating a thermal front that moves through the reservoir more slowly and evenly than the displacement front (Fletcher et al. 1992). If a gelant is injected that is activated by heat, a plug might form in the high-permeability layer after the formulation passes the thermal front (Fig. 4). With proper planning, no plug will form in the less-permeable layer because the gelant never reaches the thermal front (so the gelant never experiences a high enough temperature to react and form a gel). The reader should recognize that the scheme in Fig. 4 is subject to all the advantages and limitations that were mentioned previously for Fig. 3. The concept in Fig. 4

was field tested in the Kuparuk field on the North Slope of Alaska in the early 1990s. Aluminum-crosslinked HPAM was the gelant. Although world-class engineering was used during project design and implementation, permeability reduction was felt to have been confined to the region of the injection well because of aluminum retention (Pritchett et al. 2003).

In recent years, a variation of this concept has been commercialized (Chang et al. 2002; Frampton et al. 2004). We will refer to this as in-depth "popping" technology, because it uses polymer particles that "pop" or swell when activated. The material consists of crosslinked sulfonate-containing microparticles (0.1–3 μm in diameter) with both labile and stable internal crosslinks (Frampton et al. 2004). The kernel particles are manufactured as a 30% dispersion in light mineral oil. This dispersion is diluted along with a surfactant (surfactant/polymer ratio of 1:2 to 1:3) to prepare polymer concentrations from 3,000 to 4,500 ppm (Pritchett et al. 2003; Ghaddab et al. 2010). Cost for the polymer was indicated to be USD5.71/lbm in 2003 (Pritchett et al. 2003). The activation is typically accomplished by exposure to elevated temperature. Consequently, this technology has been advocated and applied in cases where cold water has been injected into a warm/hot reservoir (i.e., where a thermal front exists in the reservoir). The polymer particles are injected with the intention that they will pass the thermal front and "pop" first in the high-permeability watered-out zones, thus diverting subsequently injected water/fluids into the less-permeable oil zones. Resistance factors estimated for the "popped" polymer ranged from 11 to 350 (Frampton et al. 2004; Ohms et al. 2009; Husband et al. 2010). The reader should realize that from a reservoir-engineering viewpoint, this concept has the same advantages/limitations as the post-flush concept described in Fig. 3. Field applications of the process have occurred in Indonesia (Pritchett et al. 2003), Argentina (Yañez et al. 2007), Alaska (Ohms et al. 2009; Husband et al. 2010), and
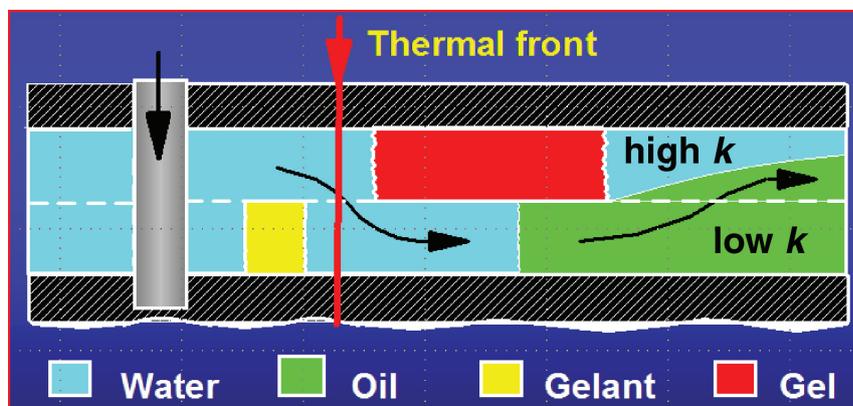

Fig. 4—Modified idea, exploiting a thermal front.

Tunisia (Ghaddab et al. 2010). Ohms et al. (2009) reported injecting ~40,000 lbm of polymer (38,000 bbl with 3,300 ppm polymer), and recovering ~60,000 bbl of oil. Husband et al. (2010) reported injecting ~200,000 lbm of polymer (190,000 bbl with 3,000 ppm polymer) into three wells, and recovering ~500,000 bbl of oil.

Methods and Assumptions

The question raised in this paper concerns when the in-depth profile-modification process is a superior choice over conventional polymer flooding. We made several attempts to address this question using both analytical and simulation methods (Akanni 2010; Zhang 2011). This paper presents our most refined effort. All three of our efforts assumed that the in-depth popping material had the same viscosity as water before activation. This assumption is optimistic, and will push our analysis results in favour of in-depth profile modification (compared with traditional polymer flooding). In reality, before activation, the popping material exhibits viscosities/resistance factors two to seven times higher than those for water (Chang et al. 2002; Pritchett et al. 2003). As demonstrated in Fig. 1, increased viscosity promotes crossflow of the gelant into the less-permeable layers and diminishes or eliminates the ability of post-flush water to be diverted into the less-permeable layer (Fig. 2). For the in-depth profile-modification process, Sorbie and Seright (1992) suggested that the maximum allowable viscosity/resistance factor during placement is ~0.3 times the permeability contrast.

All three of our efforts assumed that the popping material caused no permeability reduction in the less-permeable zone. Again, this is an optimistic assumption that will favour in-depth profile modification over traditional polymer flooding. All of our efforts also assumed that (1) activation of the popping material occurred instantaneously, (2) permeability was reduced to zero in the high-permeability path where the popping material was activated, and (3) the permeability reduction was permanent. In reality, the popping material reduces permeability by factors from 11 to 350 (Frampton et al. 2004; Ohms et al. 2009; Husband et al. 2010). Also, the resistance associated with the popped-polymer bank goes through a peak (with time and throughput), and the bank shows some degree of movement through porous media (Chang et al. 2002; Frampton et al. 2004). This behavior is what might be expected. If the particles pop to become hydrated polymer molecules in solution, the resistance factors reflect the viscosity of 3,000 to 4,500-ppm polymer solutions. For a time, this viscous polymer bank in the high-permeability zone will (it is hoped) allow much of the subsequently injected brine to be diverted into less-permeable zones. However, eventually, the brine will finger through this viscous polymer bank (as in Fig. 2). Thus, our assumption of a permanent block in the high-permeability layer is optimistic and will favour in-depth profile modification over traditional polymer flooding. Capillary pressure and gravity were also neglected during all of our efforts. Also, no dispersion was allowed at the boundaries of the popping-agent bank. Furthermore, in all our analyses, polymer rheology was Newtonian; polymer retention balanced inaccessible pore volume; and polymer did not reduce residual-oil saturation below that for water flooding. Flow was generally linear between one injection well and one production well. (However, during the two simulation efforts, radial flow was assumed in the two well gridblocks.) The relative permeability characteristics that we used were as follows:

$$k_{rw} = k_{rwo}\left[(S_w - S_{wr})/(1 - S_{or} - S_{wr})\right]^{nw} \quad \ldots\ldots\ldots\ldots (1)$$

$$k_{ro} = k_{roo}\left[(1 - S_{or} - S_w)/(1 - S_{or} - S_{wr})\right]^{no} \quad \ldots\ldots\ldots (2)$$

$$k_{rwo} = 0.1, \ k_{roo} = 1, \ S_{or} = 0.3, \ S_{wr} = 0.3, \ nw = 2, \ no = 2$$
$$\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (3)$$

Using the ECLIPSE simulator, Akanni (2010) examined a two-layer reservoir with permeability contrasts ranging from 2:1 to 20:1 and with oil-/water-viscosity ratios ranging from 1 to 10,000. He assumed relatively large popping-agent-bank sizes and examined the effect of popping-agent-bank positioning on recovery. He concluded that in-depth profile modification would have its greatest opportunity to compete with polymer flooding if the permeability contrast between layers was high. As expected, he concluded that placement of larger popping-agent banks in the high-permeability layer would enhance oil recovery, but economics would likely favour use of small popping-agent banks. He also concluded that higher recovery values favoured positioning the popped bank in the middle of the high-permeability layer or somewhat toward the producer (i.e., not near the injector). Some concerns were raised about the simulations during the benchmarking process. Akanni (2010) was unable to match accepted expectations during waterflooding (i.e., before application of polymer flooding or in-depth profile modification). In particular, as the water/oil mobility ratio increases, accepted reservoir engineering predicts that recovery efficiency in a stratified reservoir should become progressively worse for the case of free crossflow than for the case of no crossflow (Craig 1971). Instead, the simulation predicted that waterflood recoveries for the crossflow and no-crossflow cases were similar, even at high mobility ratios. We presume that this deficiency was attributable to our inexperience with simulation (at the PRRC). However, we noted this same behavior with two other simulators involving other personnel.

Consequently, an effort was made to attack our problem using strictly analytical means (i.e., no simulator). In that analysis, Zhang (2011) confirmed that in-depth profile modification had the best opportunity to compete with polymer flooding when the permeability contrast between layers was high. In-depth profile modification also benefited when the high-permeability layer was much thinner than the less-permeable layer. The study also indicated that use of small popping-agent banks would be most desirable (economically) when displacing low-viscosity oils. More-viscous oils are expected to require larger popping-agent banks.

For both of the previous approaches, at the start of polymer injection or popping-agent placement, we assumed that the high-permeability layer was at residual-oil saturation and the low-permeability layer was at connate-water saturation. We also assumed that the popping agent was placed instantaneously. Both of these assumptions are unrealistic. Consequently, a new analysis was performed by an expert in simulation of chemical-flooding processes. This analysis assumed that (1) the reservoir was initially at connate-water saturation, and (2) one pore volume (PV) of water was injected before beginning either polymer or popping-agent injection. For the in-depth profile-modification cases in the new analysis, the popping-agent material acted simply as a continued waterflood until the popping-agent bank reached its desired location. For example, if a small bank of popping agent was to be placed in the centre of the high-permeability layer, (1) the reservoir (i.e., both layers) were at connate-water saturation initially, (2) one PV of water was injected, (3) an additional amount of fluid (1-cp popping-agent pregel material followed by water) was injected to allow the popping-agent bank to reach the centre 5% of the high-permeability layer, (4) the popping-agent bank was then instantaneously set into place to reduce permeability in the centre 5% of the high-permeability layer to zero, and (5) finally, the waterflood was continued with the new block in place.

In order to verify the correctness of our previous efforts, we used a simulator from Computer Modelling Group. Our experienced simulation person was able to confirm credible behavior during benchmarking waterflood simulations. Subsequently, we examined oil-recovery efficiency for the two processes (in-depth profile modification vs. polymer flooding) as a function of (1) permeability contrast (up to 10-fold), (2) relative zone thickness, (3) oil viscosity (up to 1,000 cp), (4) polymer-solution viscosity, (5) polymer- or blocking-agent-bank size, and (6) relative costs for polymer vs. blocking agent. Our reservoir had an injection well and a production well that were 400 m apart. Two layers were present, with the combined thickness of the layers being 10 m. Our reservoir grid typically consisted of 20 gridblocks in the x-direction, one gridblock in the y-direction, and two gridblocks in
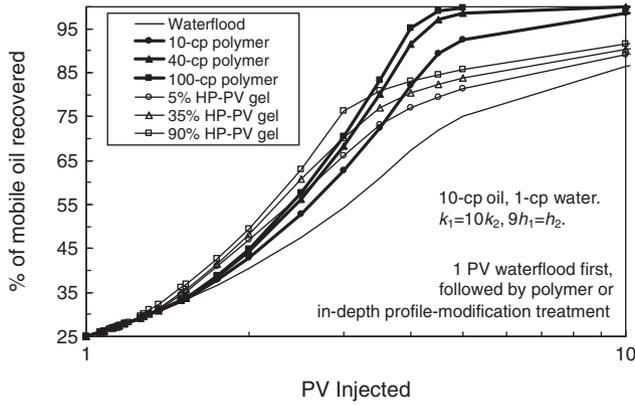
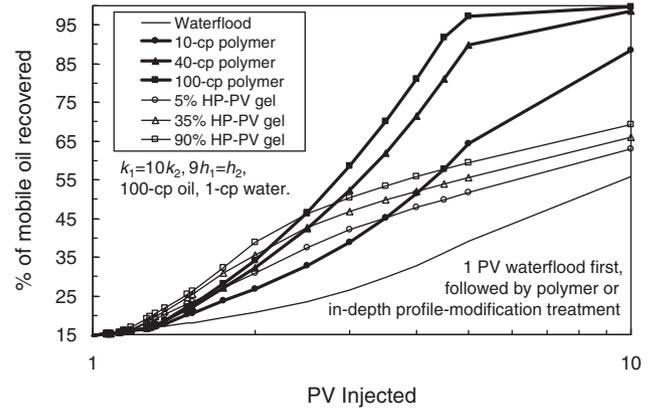**Fig. 5—Recovery with $k_1/k_2 = 10$ and $h_2/h_1 = 9$. 10-cp oil.**

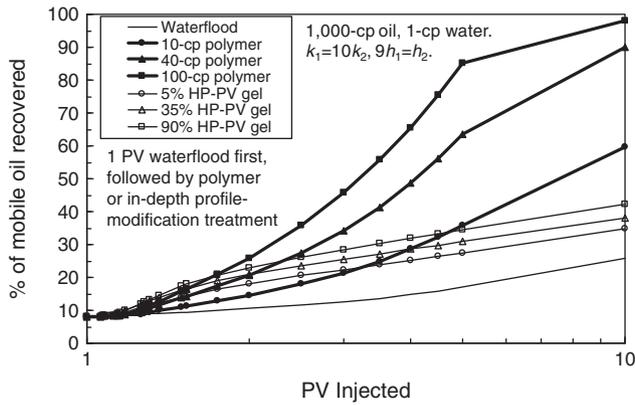**Fig. 6—Recovery with $k_1/k_2 = 10$ and $h_2/h_1 = 9$. 100-cp oil.**

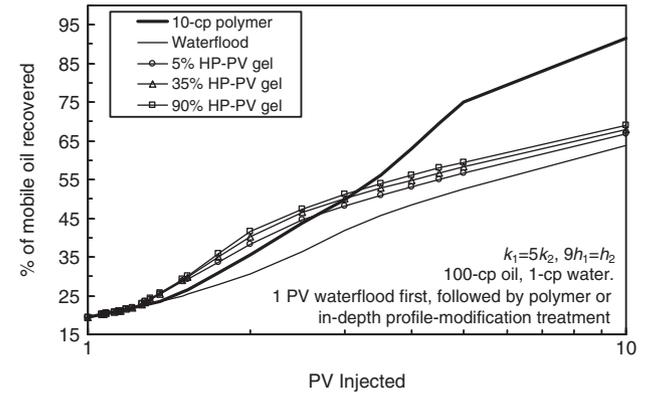**Fig. 7—Recovery with $k_1/k_2 = 10$ and $h_2/h_1 = 9$. 1,000-cp oil.**

Fig. 8—Recovery with $k_1/k_2 = 5$ and $h_2/h_1 = 9$. 100-cp oil.

the z-direction. Therefore, flow was generally linear between the two wells. We performed sensitivity studies with less and more (5 to 100) gridblocks in the x-direction and with up to 10 gridblocks in the z-direction to confirm that our results were independent of our grid system. In **Figs. 5 through 11,** we plot the percent of original mobile oil in place that was recovered as a function of PV injected. Results from the first PV of injection were not included because they were all the same for a given figure (because 1 PV of water was injected at the start of all cases). In each figure, the thin solid curve (with no symbols) represents the waterflood-only curve, and the thick solid curves represent the case where polymer solutions (10, 40, or 100 cp) were injected beginning after 1 PV of waterflood. The other three curves in each figure show cases where 5, 35, or 90% of the high-permeability

layer (HP-PV) was blocked with popping-agent gel (after the initial waterflood).

Effect of Oil Viscosity

We first examine the effects of oil viscosity. Our initial interest in this topic was motivated by a question as to whether in-depth profile modification would be preferred over polymer flooding for reservoirs on Alaska's North Slope that contained somewhat viscous oils (100–1,000 cp). Figs. 5 through 7 show recovery projections (expressed as the percent of the original mobile oil that was in place) vs. PV injected for oil viscosities of 10, 100, and 1,000 cp, respectively. For each case in these figures, the high-permeability layer (Layer 1) was 10 times more permeable than the low-
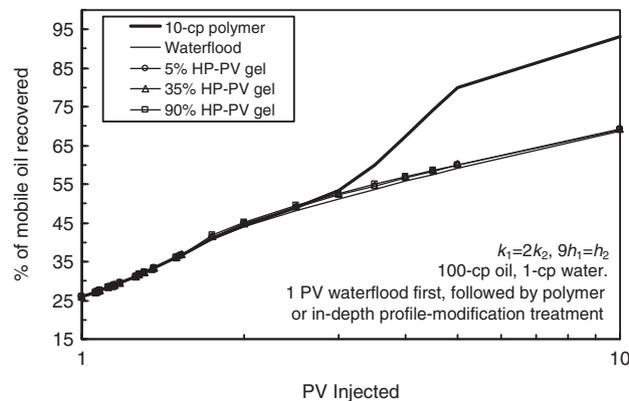

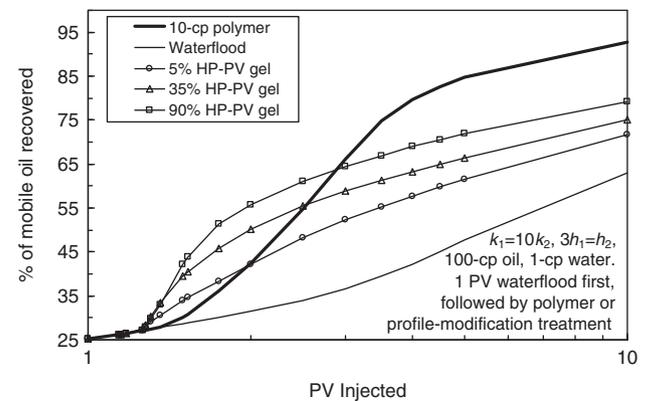**Fig. 9—Recovery with $k_1/k_2 = 2$ and $h_2/h_1 = 9$. 100-cp oil.**

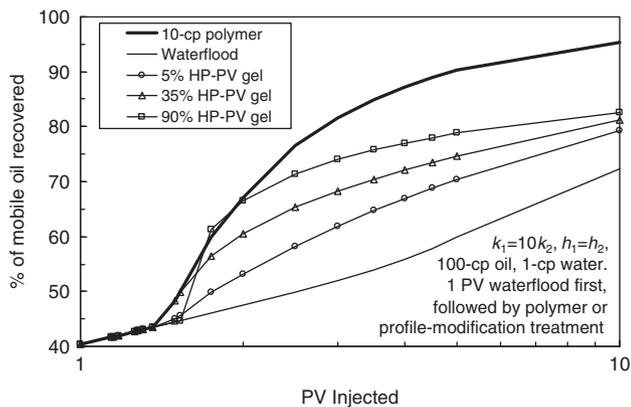**Fig. 10—Recovery with $k_1/k_2 = 10$ and $h_2/h_1 = 3$. 100-cp oil.**

Fig. 11—Recovery with $k_1/k_2 = 10$ and $h_2/h_1 = 1$. 100-cp oil.

permeability layer ($k_1/k_2 = 10$), the low-permeability layer (Layer 2) was nine times thicker than the high-permeability layer ($h_2/h_1 = 9$), and water viscosity was 1 cp. In all cases, waterflooding occurred between 0 and 1 PV—then, the alternative process was implemented. In each of the following figures, the thin black curve shows the results for continued waterflooding, which provided the lowest recovery in all cases.

The thick black curves in Figs. 5 through 7 show results from polymer floods with 10-, 40-, or 100-cp polymer. These results are quite in line with expectations (Seright 2010). When displacing 10-cp oil (Fig. 5), injecting a 10-cp polymer solution provides a noticeable improvement over waterflooding. Additional recovery is seen using 40 or 100-cp polymer, but the incremental benefit diminishes substantially with increased polymer viscosity. In contrast, for the 100 and 1,000-cp oils (Figs. 6 and 7, respectively), substantially greater recovery is seen with the more-viscous polymer solutions.

In Figs. 5 through 7, the thin lines with open symbols show results for various bank sizes (5–90% in the high-permeability layer) for the in-depth profile-modification process. Interestingly, in all three figures, a 90% popping-agent bank only recovered modestly more oil than a 5% bank. There are several reasons for this. First, for the more-viscous oils, during water injection after placement of the popping agent, sweep efficiency is poor in the thick less-permeable zone. Viscous fingering within the less-permeable layer strongly affects the incremental recovery. Second, because we assumed that permeability dropped to zero when the popping agent activated, oil reserves in the blocked portions of the high-permeability layer were lost. The magnitude of the loss is directly proportional to the size of the popping-agent bank. One can argue that this loss of reserves is unrealistically pessimistic because water can actually finger viscously into the popping-agent bank and displace some of that trapped oil. However, this error is offset by our overly optimistic assumption that the blocking action is permanent in the high-permeability layer. As will be seen, the relatively modest effect of popping-agent-bank size on recovery will result in economics favouring the use of small banks. This observation is consistent with what is currently advocated by the vendor of this in-depth profile-modification technology.

Note that in-depth profile modification provides higher oil-recovery values (for a given PV) than polymer flooding between 1 and 3 PV. Even for this PV range, the recovery values are, at best, only modestly greater than for polymer flooding. At high PV values (>4 PV), polymer flooding always provides higher recovery values.

Effect of Permeability Contrast
Along with Figs. 5 through 7, Figs. 8 and 9 demonstrate the effect of permeability contrast on the performance of in-depth profile modification vs. polymer flooding. Permeability contrast was 10:1 in Fig. 6, 5:1 in Fig. 8, and 2:1 in Fig. 9. For all three cases, oil

viscosity was 100 cp, and the low-permeability layer was nine times thicker than the high-permeability layer. A comparison of Figs. 6 and 8 reveals that the enhanced recovery using in-depth profile modification (over 10-cp polymer flooding) diminishes significantly as the permeability contrast drops from 10:1 to 5:1. Fig. 9 (2:1 permeability contrast) shows no benefit of in-depth profile modification over 10-cp polymer flooding, for any popping-agent-bank size. These results are qualitatively consistent with the results from our earlier analytical effort (Zhang 2011) and with the results from the first simulation effort using ECLIPSE (Akanni 2010).

Effect of Layer Thickness
Along with Figs. 5 through 7, Figs. 10 and 11 demonstrate the effect of layer thickness on the performance of in-depth profile modification vs. polymer flooding. The thickness ratio (low-permeability layer to high-permeability layer) was 9:1 in Fig. 6, 3:1 in Fig. 10, and 1:1 in Fig. 11. For all three cases, oil viscosity was 100 cp, and the high-permeability layer was 10 times more permeable than the low-permeability layer. For large popping-agent-bank sizes (e.g., 35 or 90%), in-depth profile modification showed enhanced recovery (over 10-cp-polymer flooding) for thickness ratios of 9:1 and 3:1 (Figs. 6 and 10, respectively). However, the benefit occurred over a narrower range of PV for a 3:1 thickness ratio (1.3–2.5 PV in Fig. 10) than for a 9:1 thickness ratio (1.2–4 PV in Fig. 6). For a 1:1 thickness ratio, Fig. 11 shows that 10-cp polymer flooding was superior to in-depth profile modification. The results reveal that in-depth profile modification is most appropriate for high permeability contrast (e.g., 10:1) and high thickness ratios (e.g., less-permeable zones being 10 times thicker than high-permeability zones). These results are qualitatively consistent with the results from our earlier analytical effort (Zhang 2011).

Cost Considerations
The popping-agent process usually requires high concentrations of polymers (e.g., 0.3–0.45%) and surfactants (e.g., 0.1–0.2%), resulting in a cost (per weight of chemical) that is several times higher than that for conventional polymer flooding (Pritchett et al. 2003; Ghaddab et al. 2010). The polymer used in the popping-agent process (an internally crosslinked HPAM) is a specialty polymer and is therefore more expensive (on a per-weight basis) than HPAM. In the following analysis, we will focus on the most-favourable case for in-depth profile modification, with a permeability contrast (k_1/k_2) of 10:1 and a thickness ratio (h_2/h_1) of 9:1. Oil was assumed to have a value of USD50/bbl; water was assumed to cost USD0.25/bbl; HPAM was assumed to cost USD1.50/lbm; a 10-cp HPAM solution required 0.1% polymer; a 40-cp HPAM solution required 0.2% polymer; a 100-cp HPAM solution required 0.3% polymer; and the popping-agent block was assumed to require a 0.3% concentration of popping-agent polymer. Our assumptions about viscosity vs. HPAM concentration are conservative in favour of the in-depth profile-modification process. This level of viscosification by HPAM would be valid if the injection water were saline (e.g., as with seawater). If less-saline water were used, a higher viscosity would be achieved with less polymer. For example, at Daqing oil field, 0.1% HPAM yields solution viscosities from 40 to 50 cp (Wang et al. 2008b). For a given PV of fluid injected, a relative profit was calculated as the total value of the oil produced minus the total cost of fluid injected (water, polymer, popping-agent material). In these figures, we assumed that the cost of the popping-agent material was expended immediately at the start of popping-agent injection—explaining the sudden drop in relative profit at 1 PV for the popping-agent cases.

The cost comparisons are shown in **Figs. 12 through 14.** These figures assume that the popping-agent material costs USD5.71/lbm [per Pritchett et al. (2003)] and 0.3% popping polymer was used in the popping bank. For an oil viscosity of 10 cp (Fig. 12), small popping-agent treatments appeared modestly more profitable than polymer flooding in the range of 2–4 PV.
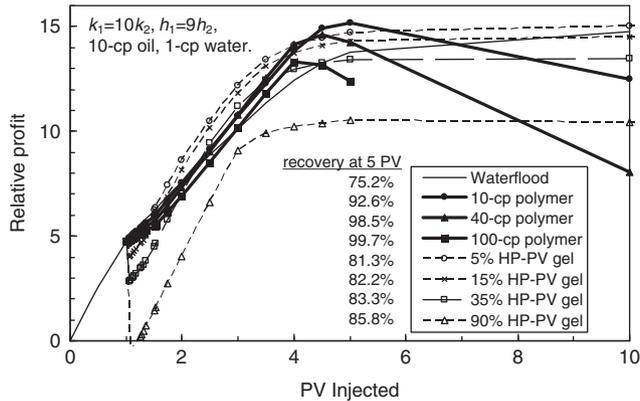
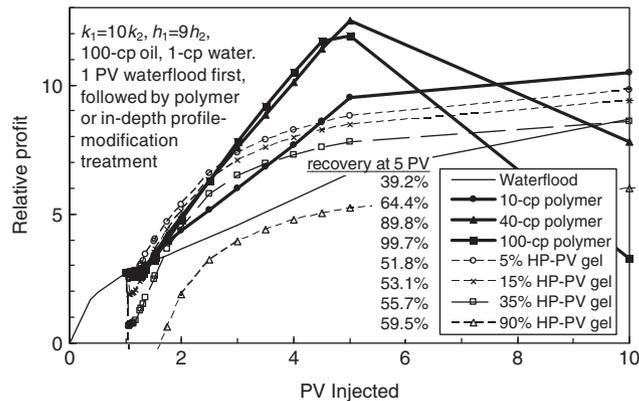**Fig. 12—Relative profit for various cases: 10-cp oil.**

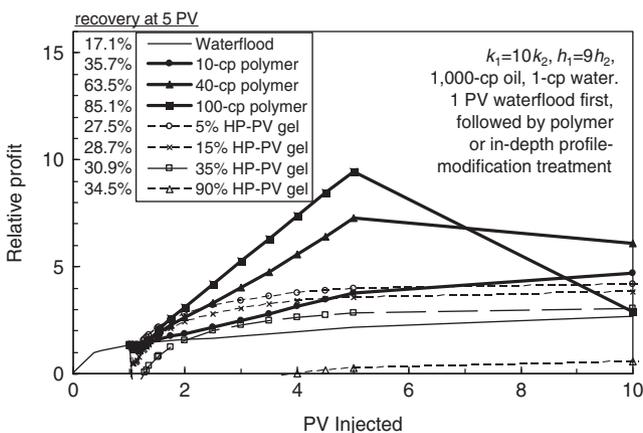**Fig. 13—Relative profit for various cases: 100-cp oil.**

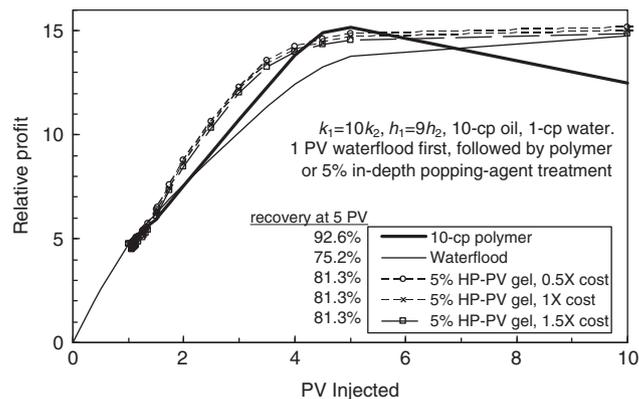**Fig. 14—Relative profit for various cases: 1,000-cp oil.**

Fig. 15—Relative profit assuming various popping-agent material costs.

Note that the smallest popping-agent bank was always more profitable than the larger banks. Although large popping-agent banks result in higher oil recoveries (Figs. 5 through 7), their high cost negates that benefit (open triangles in Fig. 12). This result is consistent with the current advocacy of the popping-agent vendor. A table in the centre of Fig. 12 compares the percent of the original mobile oil that was recovered after 5 PV for various cases. Note that the ultimate recoveries for polymer flooding were higher than for in-depth profile modification. Although the smallest popping-agent bank (5% of the PV in the high-permeability layer) provided a higher profitability (i.e., at 3 PV), its ultimate recovery factor was significantly less than for 10-cp-polymer flooding. Also note that 10-cp-polymer flooding provided a higher profitability than any of the other cases at 5 PV—where the profitability peak occurred. After 5 PV, profitability for polymer flooding decreased because the value of the oil produced was less than the value of the polymer injected. For the popping-agent cases, profitability did not decrease after 5 PV because no additional popping-agent material was purchased or injected. As mentioned earlier, this projection is overly optimistic because the blocking effect from the popping material will deteriorate with time (Chang et al. 2002; Frampton et al. 2004).

For 100-cp oil (Fig. 13), the economics for a 5% PV popping-agent treatment appears slightly better than for a 40-cp-polymer flood for a short range between 1 and 2.5 PV. However, recovery efficiencies are dramatically lower for the popping-agent treatment (51.8% vs. 89.8% in the centre table of Fig. 13). For 1,000-cp oil, a 40-cp-polymer solution appears superior to in-depth profile modification for virtually all cases (Fig. 14).

Fig. 15 compares cases in which the popping-agent material costs differing amounts. In all cases, Layer 1 was 10 times more permeable and nine times thinner than Layer 2, and oil viscosity was 10 cp. For the cases with in-depth profile modification, the

bank size was 5% PV (in the high-permeability layer). The "x" symbols with the dashed curve (labelled "1X cost") show the case where the popping-agent concentration was 0.3% and the popping-agent cost was USD5.71/lbm. The "1.5X cost" case in Fig. 15 assumes that the total popping-agent cost was 1.5 times more expensive [e.g., as in Pritchett et al. (2003), where 0.45% popping-agent concentration was used]. The "0.5X cost" case in Fig. 15 assumes that the total popping-agent cost was half as expensive (e.g., if a breakthrough in price reduction can be accomplished). All other assumptions were the same as in Fig. 12, with a small popping-agent bank (5% of the PV in the high-permeability layer). The primary message from Fig. 15 is that popping-agent performance was not highly sensitive to popping-agent cost, presumably because the bank size was so small. However, even though short-term economics (i.e., before 4 PV in Fig. 15) may favour small in-depth profile modification, a longer view (i.e., at 5 PV, where the peak of profitability occurred) favoured polymer flooding. Also, the relative simplicity of the polymer-flooding process favours it over in-depth profile modification.

Seyidov and Lane (2010) performed a relevant simulation study of "deep diverting gels."[*] This study assumed that the blocking agent could be effectively placed in a multilayered reservoir with crossflow. They observed a number of results that were consistent with our findings. Their study concluded that "although higher ultimate recovery was achieved with a polymer flood, the combination of delayed production response and large polymer amounts used adversely impacted polymer flood economics." They also found that treatment size and oil viscosity were important variables in determining the effectiveness of these treatments.

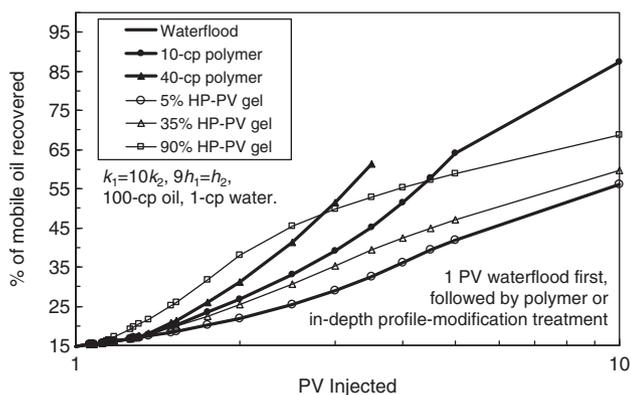[*]Personal communication with R.H. Lane (16 June 2011).

Fig. 16—Effect of radial flow (five-spot pattern), investigating parameters from Fig. 6.

Injectivity Considerations

Concern about injectivity losses was a key motivation that was given for choosing in-depth profile modification over polymer flooding. The concern is that injectivity losses associated with injection of viscous polymer solutions will result in prohibitive losses in oil-production rate. However, most waterflood and polymer-flood injectors are thought to be fractured (van den Hoek et al. 2009; Khodaverdian et al. 2009; Wang et al. 2008a; Seright et al. 2009). Fractures are especially likely to be present in hot reservoirs with cold-water injectors (Fletcher et al. 1992). Even when injecting concentrated, viscous polymer solutions (i.e., 200–300 cp), injectivity has not been a problem in field applications (Wang et al. 2011) because fractures extend to accommodate the viscosity and rate of fluid injected. Of course, the key concerns when injecting above the parting pressure are to not allow fractures to extend so far and in a direction that causes severe channeling, and to not allow them to extend out of zone. If these concerns can be mitigated, under the proper circumstances, injection above the parting pressure can significantly (1) increase polymer-solution injectivity and fluid throughput for the reservoir pattern, (2) reduce the risk of mechanical degradation for polyacrylamide solutions, and (3) increase pattern sweep efficiency (Trantham et al. 1980; Wang et al. 2008a; Seright et al. 2009). Using both field data and theoretical analyses, these facts have been demonstrated at the Daqing oil field in China, where the world's largest polymer flood is in operation (Wang et al. 2008a).

Additional Considerations

Dispersion. If small banks of popping agent are injected (e.g., ~5% PV in the high-permeability layer), a significant amount of mixing and dispersion may occur as that bank is placed deep within the reservoir (Lake 1989)—thus, diluting the bank and potentially compromising the effectiveness of the blocking agent. Also, as mentioned earlier, because the popping material provides a limited permeability reduction (i.e., 11 to 350) and the popped-material has some mobility, the blocking bank eventually will be diluted and compromised by viscous fingering (Chang et al. 2002; Frampton et al. 2004).

Retreatment. Another consideration is the possibility of retreatment for the in-depth profile-modification process. During a second or subsequent treatment, the presence of a block or partial block in the high-permeability layer will (1) divert new popping-agent into less-permeable zones during the placement process and (2) inhibit placement of a new block that is located deeper in the reservoir than the first block. These factors may compromise any retreatment using in-depth profile modification.

Proper Problem Diagnosis. A third additional consideration concerns the initial diagnosis of the problem. The assumption in

this paper and with some of the previous treatments is that fractures or fracture-like features were not responsible for significant channeling in the reservoir. However, if the mobility ratio is favourable during waterflooding (i.e., low-viscosity oil) and the maximum permeability contrast is modest (e.g., 4:1), one has to wonder why the water/oil ratio is high (e.g., <20) if the oil-recovery factor is low. For this type of case, one may want to reconsider whether fractures are important to channeling. If so, traditional gel treatments (Sydansk and Romero-Zeron 2011) may warrant consideration.

Capillary Forces. In our work, capillary forces were neglected. If the reservoir is water-wet and if the permeability of the low-permeability layer is sufficiently small, flood water will be drawn into the less-permeable layer by capillary action. Thus, waterfloods may be more efficient than shown in our work. During placement of the popping-agent bank during in-depth profile modification, capillary forces might draw the popping agent into the less-permeable layer, potentially creating a flow barrier in the less-permeable layer that could compromise the treatment. In contrast with polymer flooding, capillary action that draws more water or polymer into the less-permeable layer will only help flood efficiency.

Gravity. Our work also neglected gravity. If the high-permeability layer is above the less-permeable layer, the water, polymer solution, and popping agent will tend to slump into the the less-permeable layer. This action will aid sweep for waterflooding and polymer flooding. However, for in-depth profile modification, slumping of the popping agent could create a barrier in the less-permeable zone that could compromise the treatment. If the high-permeability layer is below the less-permeable layer, gravity effects should be less important.

Effect of Polymer-Bank Size. Figs. 5 through 11 show results from continuous polymer injection (after first injecting 1 PV of brine). Of course, field applications will inject a limited bank of polymer. Following the polymer bank, presumably, brine injection will resume. Uncertainties exist concerning oil-recovery behavior after polymer injection stops, because subsequently injected water will form viscous fingers through the polymer bank. Current simulation methods typically do a poor job of simulating this fingering behavior. The most conservative approach would simply assume that oil recovery ceases shortly after stopping polymer injection. With this approach, our figures can be used to make a conservative comparison of polymer-bank sizes. For example, in Fig. 11, injection of 1 PV of water, followed by 1 PV of 10-cp polymer solution, would recover 68% of the mobile oil—and in the worst case, no more oil would be recovered during subsequent water injection.

Effect of Radial Flow. Our primary simulation effort to this point used essentially linear flow, with gridblock dimensions: $\Delta x = 20$ m (the direction directly between the injector and producer), $\Delta z = 5$ m (vertical direction), and $\Delta y = 400$ m (the horizontal direction perpendicular to flow). To investigate the effect of radial flow on our results, simulations were performed using a one-quarter five-spot pattern, with the injector and producer in opposite corners. For these cases, gridblock dimensions were $\Delta x = 20$ m, $\Delta z = 5$ m, and $\Delta y = 20$ m. Results are shown in **Fig. 16,** and the differences between linear and radial flow can be appreciated by comparing Figs. 6 (linear flow) and 16 (radial flow).

Note in Fig. 6 (i.e., for linear flow) that all in-depth-profile-modification cases provided higher recovery values than the waterflood. In contrast for radial flow, the case with the 5% HP-PV bank of popping agent (open circles in Fig. 16) provided no benefit over waterflooding (thick solid curve without symbols in Fig. 16). Also, the benefit from a 35% HP-PV bank of popping agent was not as great for radial flow (open triangles in Fig. 16) as for linear flow (open triangles in Fig. 6). Furthermore, in radial

flow, recovery for the 10-cp-polymer flood (solid circles with the thick solid curve in Fig. 16) was always greater than for the 5% and 35% HP-PV banks of popping agents. This was not the case for linear flow (see Fig. 6). Thus, from an oil-recovery/sweep-improvement viewpoint, polymer flooding appears to gain an advantage over in-depth profile modification. Of course, we must remember that polymer flooding will suffer substantial injectivity disadvantages for radial-flow applications (Seright et al. 2009).

Summary of Model Biases. As mentioned throughout the course of our paper, a number of assumptions were made during our analysis. The following assumptions bias our results in favour of in-depth profile modification: (1) no gravity, (2) no capillary forces, (3) no dispersion of chemical banks, (4) the popping agent had the same viscosity as water during placement, (5) no popping agent sets up in the less-permeable zone, and (6) the popping agent becomes immobile after activation. The following assumption biases our results against in-depth profile modification: The mobile oil that remains within the popping-agent bank becomes immobile when the popping agent sets (i.e., the permeability in the popped bank permanently is reduced to zero).

Conclusions

Our analyses revealed that in-depth profile modification is most appropriate for high permeability contrasts (e.g., 10:1), high thickness ratios (e.g., less-permeable zones being 10 times thicker than high-permeability zones), and relatively low oil viscosities. Because of the high cost of the blocking agent (relative to conventional polymers), economics favours small blocking-agent-bank sizes (e.g., 5% of the PV in the high-permeability layer). Even though short-term economics may favour in-depth profile modification, ultimate recovery may be considerably less than that from a traditional polymer flood. A longer view may favour polymer flooding both from a recovery viewpoint and an economic viewpoint.

Nomenclature

h_1 = height of Layer 1, ft [m]
h_2 = height of Layer 2, ft [m]
k_1 = permeability of Layer 1, md [μm^2]
k_2 = permeability of Layer 2, md [μm^2]
k_{ro} = relative permeability to oil
k_{roo} = endpoint relative permeability to oil
k_{rw} = relative permeability to water
k_{rwo} = endpoint relative permeability to water
no = oil-saturation exponent in Eq. 2
nw = water-saturation exponent in Eq. 1
S_{or} = residual-oil saturation
S_w = water saturation
S_{wr} = residual-water saturation

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SI Metric Conversion Factors

cp $\times$ 1.0*	E−03 = Pa·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 factor is exact.

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