Polymer Floods Move Into Viscous Oil

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SOCORRO, N.M.–Strong crude oil prices are leading the domestic industry to shift drilling activity from unconventional natural gas to unconventional oil reservoirs, which often contain heavier oils. At the same time, higher prices are driving renewed interest in all types of enhanced recovery projects, including waterfloods, carbon dioxide floods and polymer floods.

Going forward, the increased development of more unconventional oil reservoirs will place increased emphasis on the need to maximize recovery in reservoirs with viscous oils. The combination of higher oil prices, modest polymer costs, increased horizontal drilling, and the ability to control polymer injection above the formation's parting pressure are helping extend polymer flooding applications to viscous oil reservoirs.

Research conducted by the Petroleum Recovery Research Center of New Mexico Tech and the National Energy Technology Laboratory under an award from the U.S. Department of Energy examined whether polymer flooding could provide a feasible means to recover heavier crude oil, especially in reservoirs where thermal methods couldn't be applied. This three-year research project assessed conventional screening criteria for applying polymer flooding, and used fractional flow calculations to illustrate improvements in displacement efficiency that could be achieved by polymer flooding viscous oils.

Using data from Alaskan North Slope reservoirs as the target, the fractional flow calculations demonstrate that high mobile oil saturation, the degree of heterogeneity, and the potential for reservoir cross-flow (no impermeable barriers between zones) promote the effectiveness of polymer flooding. For existing EOR polymers, viscosity increases roughly with the square of polymer concentration–a fact that aids the economics of polymer flooding viscous oil reservoirs.

A simple benefit analysis comparing polymer flooding with waterflooding suggests that reduced injectivity may be a greater limitation for polymer flooding of viscous oils than chemical cost. For practical conditions during polymer floods, the vertical sweep efficiency using shear-thinning fluids is not expected to be dramatically different from that for Newtonian or shear-thickening fluids. The overall viscosity (resistance factor) of the polymer solution is of far greater importance than rheology.

New Screening Criteria

The North Slope contains a vast unconventional oil resource of some 20 billion barrels of viscous reserves. Thermal recovery methods typically are deployed to recover heavier oils, but a number of operational, economic and environmental factors can complicate the viability of thermal recovery–from the impact of cold weather on steam generation, to air and water quality issues, to the cost of the input energy and infrastructure needed to generate steam.

Under appropriate circumstances, waterflooding viscous oil reservoirs can achieve ultimate recoveries of 20-40 percent of original oil in place, but 50 percent or more of the oil tends to be recovered at high (90+ percent) water cuts. Because mobile water can significantly reduce oil recovery and overall waterflood performance, enhancing the mobility ratio with polymer flooding can noticeably improve reservoir sweep and recovery efficiencies.

Conventional screening criteria indicate that polymer flooding is economically applicable in reservoirs with oil viscosities ranging between 10 and 150 centipoise (cp). For oil viscosities below 10 cp, the mobility ratio during waterflooding is generally favorable enough that polymer is not needed to achieve efficient reservoir sweep. For viscosities above 150 cp, the fear has been that the viscosity requirements to achieve a favorable mobility ratio reduce polymer solution injectivity to prohibitively low values (i.e., slowing fluid throughput in the reservoir to the point that oil production becomes uneconomically low).

However, several important changes have occurred that make conventional screening criteria obsolete. The criteria were developed at a time when oil was $20 a barrel and polymer prices were $2.00 a pound for moderate molecular weight polyacrylamide or partially hydrolyzed polyacrylamide (HPAM). With oil prices trading at $80-$90/bbl, polymer prices have remained essentially the same. In fact, with today's oil prices, operators are investigating if improved sweep from polymer injection is economically attractive even if a unit mobility ratio is not achieved.

In addition, the viscosities of commercial polymers have improved by achieving higher polymer molecular weights as well as incorporating specialty monomers within the polymers. Another important change has been the dramatic increase in horizontal drilling. In wells that are not fractured, injecting viscous polymer solutions will necessarily decrease injectivity. To maintain waterflood injection rates, the selected polymer-injection wells must allow higher injection pressures. Horizontal wells significantly reduce the injectivity restrictions associated with vertical wells, and pairs of horizontal injector/producer wells can improve areal sweep and reduce polymer requirements.

Open fractures (either natural or induced) also have a substantial impact on polymer flooding. Waterflooding occurs mostly under induced fracturing conditions. Particularly in low-mobility reservoirs, large fractures can be induced over a field's life cycle. Because polymer solutions are more viscous than water, injection above the formation parting pressure will be even more likely during a polymer flood than a waterflood. The viscoelastic nature (apparent shear-thickening or "pseudo-dilatancy") for synthetic EOR polymers such as HPAM makes injection above the formation parting pressure even more likely.

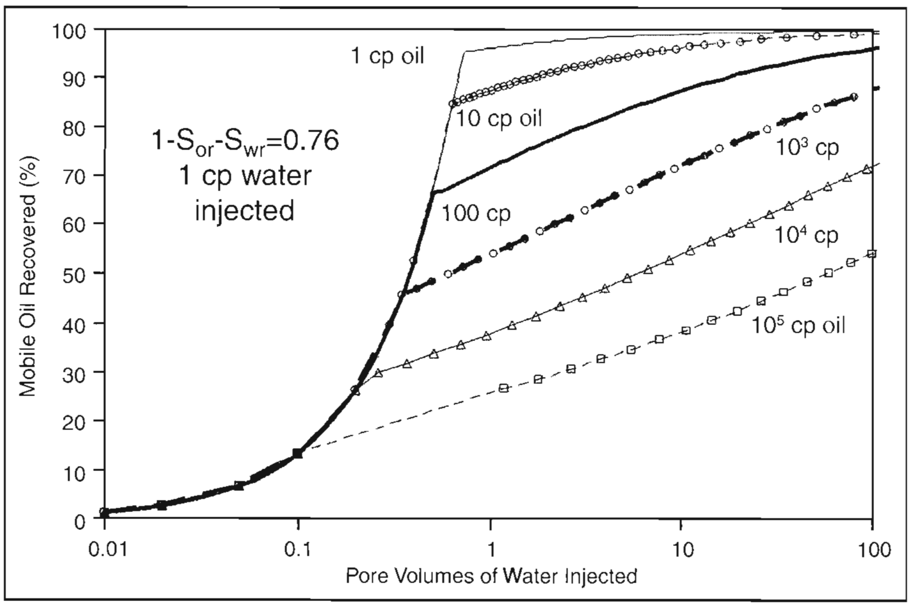
Injection above the parting pressure can significantly increase polymer solution injectivity and fluid throughput for the reservoir pattern, reduce the risk of mechanical degradation for polyacrylamide solutions, and increase pattern sweep efficiency. This has been demonstrated at the Daqing Field in China, the world's largest polymer flood.

Critical Factors

Many factors are important during polymer flooding. When designing a polymer flood, critical reservoir factors include lithology, stratigraphy, heterogeneities (such as fractures), the distribution of remaining oil, and well patterns and distances. Critical polymer properties include the cost-effectiveness per unit of viscosity, resistance to degradation (mechanical/shear,

FIGURE 1

Fractional Flow Calculations for Water Displacing Oil



oxidative, thermal and microbial), reservoir salinity and hardness tolerance, retention by rock, inaccessible pore volume, permeability dependence of performance, rheology, and compatibility with other chemicals. Issues important for polymer bank design include bank size (volume), polymer concentration, and salinity and its impact on bank viscosity and mobility, and whether to grade polymer concentrations in the chase water.

Concern about polymer rheology must be tempered in view of injectivity realities. Achieving economic injectivities and fluid throughputs with polymer solutions (especially when displacing viscous oil) requires using either horizontal wells or fractured vertical wells. With vertical fractures in vertical wells, fluid flows linearly away from the fracture. For horizontal wells, flow is radial for a short time, but soon becomes linear. For both horizontal wells and fractured vertical wells, the fluid flux is quite low as the polymer enters the porous rock.

For the target North Slope reservoirs, we estimated flux values of 0.01 to 0.2 feet/day for a vertically fractured injector (0.2 feet/day as the fluid first enters the formation from a horizontal well, and 0.01 feet/day for most of the distance between two parallel horizontal wells). For this range of flux values, HPAM polymer solutions show Newtonian or near-Newtonian behavior. Over the practical range of permeabilities and velocities anticipated for the target fractured or horizontal wells, HPAM polymer solutions exhibit nearly constant resistance factors (effective viscosity in porous rock relative to water). These observations simplify the analysis of the potential for HPAM polymer flooding.

Beyond this rheological effect, polymers of a given type and molecular weight are known to exhibit a permeability value, below which they experience difficulty in propagating through porous rock. As permeability decreases below this critical value, resistance factors, residual resistance factors, and polymer retention increase dramatically. The molecular weight and size of the polymer must be small enough to allow the polymer to propagate effectively through all permeabilities and layers so that internal pore plugging does not occur.

Fractional Flow Calculations

Simulation studies of polymer flooding are valuable to examine complex reservoir configurations and combined effects of multiple physical, chemical and fluid phenomena. Of course, inappropriate assumptions can lead to unrealistic predictions and flaws in the output that may not be readily apparent. As an alternative to simulation, fractional flow analysis can be used to quantify polymer flood performance. This type of analysis has the advantage of being sufficiently transparent to readily determine whether the projections are realistic. After establishing credible behavior for simple systems, fractional flow analysis results can be used as benchmarks for future, more complex calculations using simulations.

For viscous crudes, the density difference between water and oil is relatively small. Consequently, gravity effects were considered negligible in the fractional flow calculations. The analyses also assumed incompressible flow and no density or capillary pressure differences between phases. For the North Slope parameters and a single reservoir layer with linear flow, the Y-axis in Figure 1 plots the percentage of the mobile oil recovered for a given pore volume (PV) of water injected. The total mobile oil is given by the difference between the original oil saturation at the connate water saturation and residual oil saturation.

The next step in the study was considering linear displacement through two layers of equal thickness, with all other parameters and conditions kept the same as in the single-layer case. Two subsets were analyzed, one with no cross-flow between the two layers and one with free cross-flow between the layers. The two-layer case with no cross-flow was straight forward, since the displacements in the individual layers could be treated separately and then combined to yield the overall displacement efficiency. The free cross-flow case required applying vertical equilibrium between the layers.

Table 1 lists the recovery values at 1.0 PV of water injection for the relative permeabilities associated with both the base case and the North Slope reservoirs based on the fractional flow calculations both with and without cross-flow conditions. Along with Figure 1, this table hints at the potential for polymer flooding. For any given oil viscosity (say, 1,000 cp), one can envision that a 10-fold decrease in the oil/water viscosity ratio (injecting a 10-cp polymer solution instead of water) could increase oil recovery by a substantial percentage.

Reservoir engineering analysis indicates two key expectations. First, as the mobility ratio becomes smaller (below unity), vertical sweep efficiency should increase both with and without cross-flow. However, the cross-flow case achieves much higher recovery efficiencies. Second, as the mobility ratio becomes increasingly large (above unity), sweep efficiency decreases for both the cross-flow and no cross-flow cases, but the cross-flow case suffers lower recovery efficiency. In other words, cross-flow causes efficiency to be lost much faster as the mobility ratio

TABLE 1

Percentage of Mobile Oil Recovered after 1.0 PV of 1.0-cp Water Injection

Oil Viscosity (cp)	One layer		Two layers, no cross-flow		Two layers, with cross-flow	
	Base case	North Slope case	Base case	North Slope case	Base case	North Slope case
1	99	96	98	76	99	96
10	92	87	70	57	62	58
100	70	72	62	50	43	41
1,000	43	54	38	41	27	30
10,000	22	38	20	33	14	22
100,000	11	25	10	23	7	15

TABLE 2

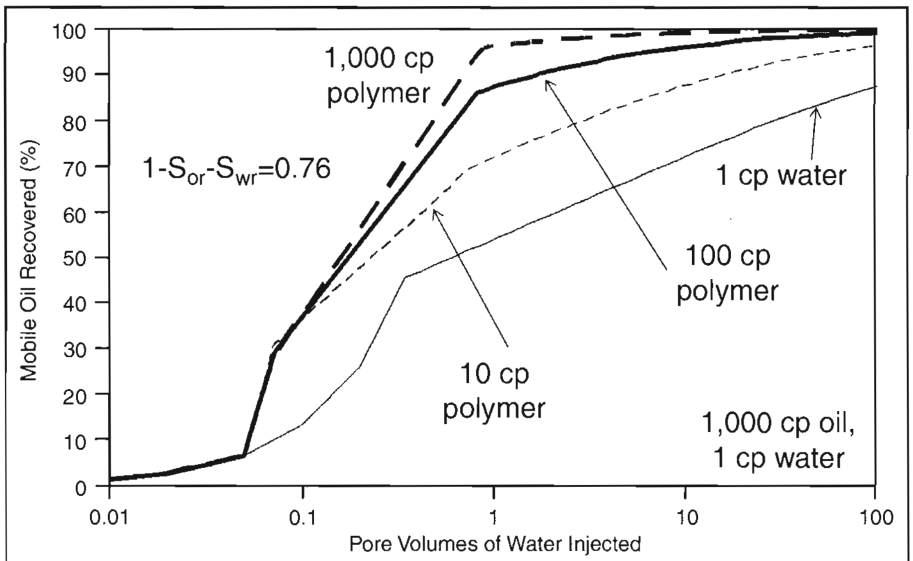
Percentage of Mobile Oil Recovered (1,000-cp Oil)

With 0.5 PV Polymer						
Polymer Viscosity (cp)	One layer		Two layers, no cross-flow		Two layers, with cross-flow	
	Base case	North Slope case	Base case	North Slope case	Base case	North Slope case
1	36	48	31	32	22	27
10	53	59	45	51	37	38
100	70	64	56	59	53	51
1,000	73	66	60	63	72	62

With 1.0 PV Polymer						
Polymer Viscosity (cp)	One layer		Two layers, no cross-flow		Two layers, with cross-flow	
	Base case	North Slope case	Base case	North Slope case	Base case	North Slope case
1	43	54	38	41	27	30
10	70	72	53	57	42	41
100	92	87	63	64	62	57
1,000	99	96	66	67	99	96

FIGURE 2

Polymer Flood Results for One Homogeneous North Slope Layer



increases.

These expectations are confirmed in Table 1. In addition, because the mobile oil saturation is considerably larger for the North Slope parameters than for the base case, it provides a much bigger oil "target." At 1.0 PV, when the oil viscosity is above 100 cp, the waterflood response using the North Slope parameters appears more favorable than for the base case.

Polymer Flood Designs

Fractional flow calculations were performed on a polymer flood implemented to displace 1,000-cp oil. At the start of the flood, connate water saturation was 0.3 (base cases) and 0.12 (North Slope cases), and water viscosity was 1.0 cp. Mobile oil saturation was 100 percent at the start of polymer injection. Figure 2 shows displacement for one homogeneous layer for the North Slope case, while displacement for two layers of equal thickness and porosity are shown both with no cross-flow and free cross-flow in Figures 3A and 3B, respectively. In each figure, results are shown for 1.0-cp waterflooding, 10-cp polymer injection, 100-cp polymer injection, and 1,000-cp polymer injection.

Table 2 summarizes the recovery values as a percentage of the original mobile oil saturation recovered after injecting both 0.5 PV and 1.0 PV of polymer solution. One important observation is that increases in injectant viscosity virtually always leads to a significant increase in oil recovery. As expected, for any given water throughput and polymer solution viscosity (except the 1,000-cp polymer cases), recovery efficiency was substantially better for the one-layer model in Figure 2 compared with the two-layer cases in Figures 3A and 3B.

Interestingly, the recovery curves when injecting 1,000-cp polymer solution were similar for both the one- and two-layer cases with free cross-flow (the thick dashed curves in Figures 2 and 3B). This finding is consistent with the concept of vertical equilibrium; if the mobility contrast between the displacing and displaced phases is greater than or equal to the permeability contrast, the displacement efficiency for two layers will appear the same as for one layer.

For both the single- and two-layer cases with free cross-flow, the waterfloods with 1.0-cp polymer were noticeably more efficient for the North Slope conditions than the base case. For the two-layer model with no cross-flow, the waterflood

FIGURE 3A

Polymer Flood Results for Two Layers with No Cross-Flow

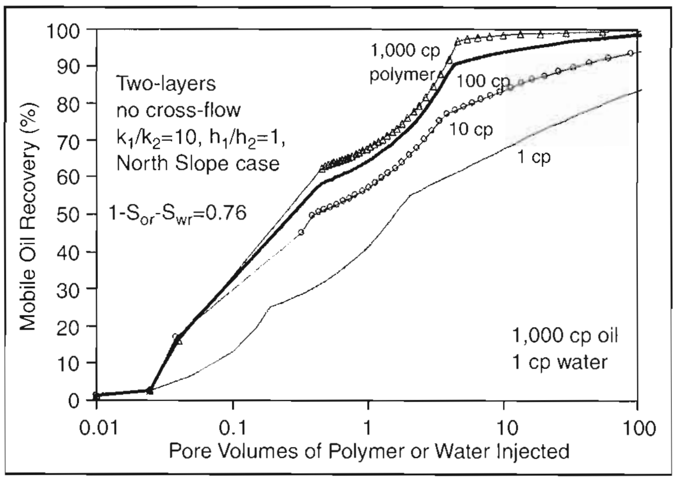
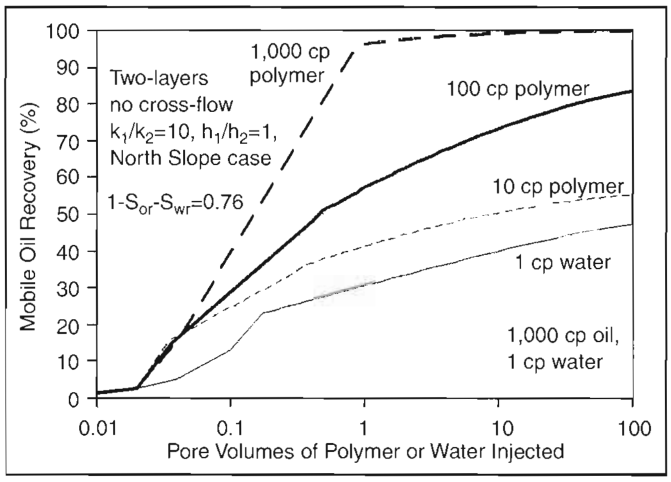


FIGURE 3B

Polymer Flood Results for Two Layers with Free Cross-Flow



recoveries were similar for the North Slope and base cases. At any given injection volume in the cases with no cross-flow, the largest increases in recovery generally occur when increasing the injectant viscosity from 1.0 cp to 10 cp. For the cases with free cross-flow, the largest recovery increase occurs when raising injectant viscosity from 100 to 1,000 cp. It should be noted that most polymer floods have been in reservoirs with oil/water viscosity ratios less than 10, although the most successful field projects have had ratios between 15 and 114.

Simple Benefit Analysis

Using these recovery results, a simple benefit analysis was performed to make a preliminary assessment of the potential for polymer flooding in reservoirs with viscous oils. For much of this analysis, a pessimistic oil price of $20/bbl was assumed with water treatment/injection costs of $0.25/bbl and polymer cost of $1.50/pound.

For viscosities above 10 cp, viscosity rises roughly with the square of polymer concentration. This behavior is an advantage when using polymer solutions to displace viscous oils. Most conventional polymer flood projects (directed at oil with viscosities less than 50 cp) have used relatively low polymer concentrations of 1,000 ppm or less. In this range, the relationship between viscosity and polymer concentration is nearly linear, which means viscosity and polymer solution cost are directly proportional to polymer concentration.

So if a doubling of viscosity is desired, polymer solution cost also would double. For viscous oils, higher polymer solution viscosities may be needed to efficiently displace oil. For these more viscous polymer solutions, a concentration exponent of two means that the solution viscosity can be doubled by increasing polymer concentration and cost by only 40 percent.

Other than water handling and polymer chemical costs, no other operating or capital costs were assumed in the economic analysis. Basically, for any given value of water or polymer solution injected, the relative profit is defined as the total value of the oil produced minus the total cost of the polymer injected and cost of water treatment. Figures 4A and 4B show the results from the economic analysis.

The relative profit for a given North Slope case typically was about twice that of a corresponding base case, largely because of the greater mobile oil saturation. For most cases, the peak in profitability was noticeably higher when injecting

FIGURE 4A

Two-Layers with Free Cross-Flow (Base Case)

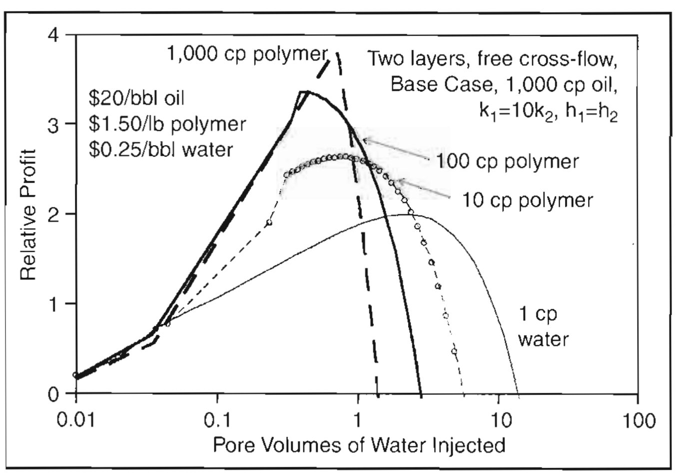


FIGURE 4B

Two-Layers with Free Cross-Flow (North Slope)

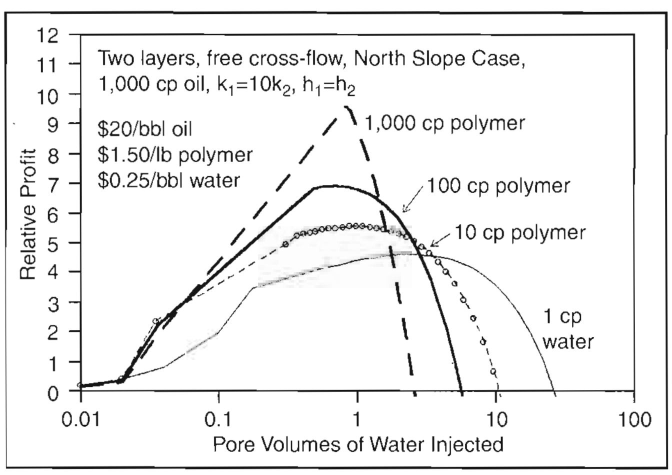
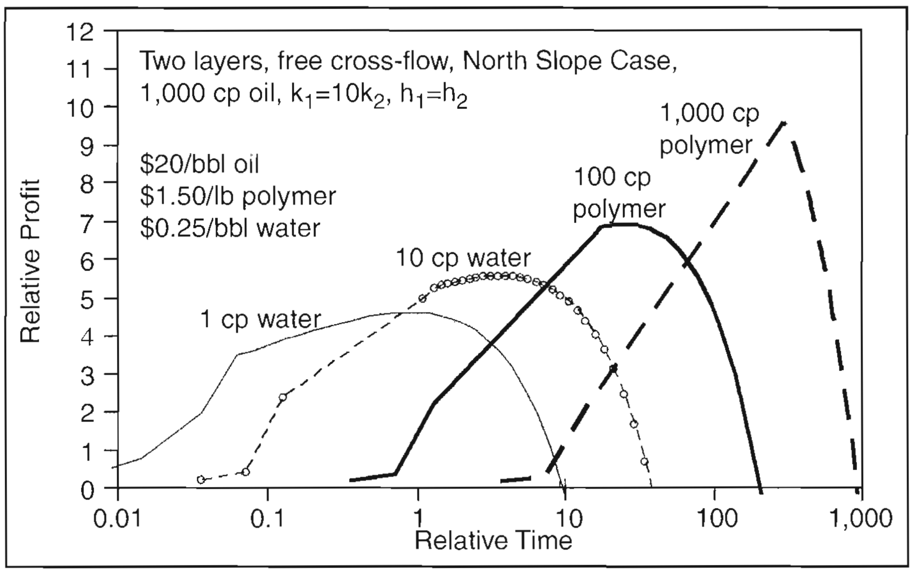


FIGURE 5

Two-Layers with Free Cross-Flow (with Injectivity and Injection Viscosity Varying Inversely)



polymer solution rather than waterflooding. Polymer flooding also provided a higher relative profit than waterflooding over a significant range of throughput values. The basic shapes of the curves remain the same at various oil prices; only the magnitude of the relative profit rises in proportion to oil price and the magnitude of the oil target.

If the only issue was the value of the produced oil relative to the cost of the injectants, the results indicate that 1,000-cp polymer solutions would be preferred. Increasing polymer viscosity decreases the PV at which peak profitability is observed, as well as increasing the relative profit. However, this observation does not necessarily mean that polymer flooding will accelerate profits.

If injectivity is assumed to be inversely proportional to polymer viscosity, Figure 4B can be replotted as Figure 5 to show profit versus time. It suggests that injecting a 10-cp polymer solution may be economically attractive compared with waterflooding, but the benefits from injecting 100-cp or 1,000-cp polymer solutions may be delayed for unacceptably long times.

The results indicate that injectivity limitations are significantly more important than polymer costs in recovering viscous oils. Maximizing the injectivity of polymer solutions is a critical need, making horizontal wells or fractures to maximize injectivity and accelerate oil production key to implementing polymer flooding in reservoirs with viscous oils.

Reduced Permeability

The analysis assumes that polymer reduces mobility simply by increasing solution viscosity, and that the effective polymer solution viscosity (resistance factor) was the same in all layers regardless of permeability. However, high-molecular weight HPAM sometimes reduces the mobility of aqueous solutions in porous media by a greater factor than can be rationalized based on solution viscosity. The incremental mobility reduction is attributed to lower permeability caused by the adsorption or mechanical entrapment of high-molecular weight polymers.

This effect has been touted to be of great benefit for polymer floods simply because the polymer appears to provide significantly more apparent viscosity in porous media. In practice, however, this benefit is difficult to achieve because normal field handling and flow through an injection sand face at high velocity mechanically degrades the large molecules responsible for reducing permeability. Also, the largest molecules tend to be preferentially retained in pores and stripped from the polymer solution before penetrating deep into the formation.

So even if high permeability reductions could be achieved, would it actually be of benefit? How does mobility reduction vary with permeability of porous media?

For adsorbed polymers, resistance factors and residual resistance factors increase with decreasing permeability. In other words, polymers can reduce the flow capacity of low-permeability rock by a greater factor than high-permeability rock. Depending on the magnitude of this effect, polymers and gels can harm vertical flow profiles in wells, even though the polymer penetrates significantly farther into higher-permeability rock.

Various cases were considered where resistance factors were greater in low-permeability layers than in high-permeability layers. For the base and North Slope cases, the resistance factors (effective viscosities) in all layers were assumed to be equal. The analysis shows that linear flow (with no potential for cross-flow between layers) can be reasonably forgiving if the permeability contrast and the polymer solution resistance factors are sufficiently large. Similar calculations performed for radial flow with no cross-flow reveal that radial flow is much less forgiving to high resistance values.

Logical Remedy

A logical remedy to unacceptable resistance factors in linear or radial flows is to choose a polymer with a lower molecular weight so that resistance factors do not increase dramatically with decreasing permeability. Whether a particular polymer will be acceptable in a given reservoir depends on numerous factors, including polymer molecular weight, rock permeability, water salinity, the presence of residual oil, reservoir temperature, clay content, pore structure, and the degree of mechanical degradation before entering the rock.

In most cases where cross-flow can occur, the ratio between the resistance factors of multiple layers has little effect on the relative distance that polymer can penetrate into the zones. Because the distance between wells is usually much greater than the height of any given strata, if a pressure difference exists between two adjacent communicating zones, cross-flow will quickly dampen any pressure difference because of the close proximity of the zones. Because of vertical equilibrium, the pressure gradients in two adjacent zones with no flow barriers will be the same for any given horizontal position. Put another way, for a given distance from the well bore, the pressure will be the same in both zones.

It has been suggested that shear thinning exhibited by polymer solutions can be detrimental to sweep efficiency. If two noncommunicating layers of different permeability were completely filled with a shear-thinning fluid, the vertical flow profile would be worse than for a Newtonian fluid. However, this is not relevant to polymer floods, where a viscous polymer solution displaces oil and water. For practical conditions during polymer floods, the vertical sweep efficiency using shear-thinning fluids is not expected to be dramatically different from that for Newtonian or shear-thickening fluids. The overall viscosity (resistance factor) of the polymer solution is of far greater relevance than the rheology.

Examining important aspects of polymer flooding reveals that higher oil prices, modest polymer prices, the increased use of horizontal wells, and controlled injection above the formation parting pressure help considerably to extend the applicability of polymer floods in reservoirs with high-viscosity oils.

Fractional flow calculations demonstrate that the high mobile oil saturation, degree of heterogeneity, and relatively free potential for cross-flow in the target reservoir also promote polymer flooding potential. For reservoir conditions with no cross-flow between layers, most of the benefit from polymer flooding a two-layer reservoir with 1,000-cp oil materializes using a 10-cp polymer solution. A smaller incremental benefit can occur when using more viscous polymer solutions. When free cross-flow does exists between layers in a two-layer reservoir with 1,000-cp oil, injecting more viscous polymer solutions is preferred, as long as injectivity limitations are not present.

Reduced injectivity may be a greater limitation in polymer flooding of viscous oil reservoirs than the cost of chemicals. Of course, many cost factors can influence the feasibility of polymer flooding, but for existing EOR polymers, viscosity increases with polymer concentration, a fact that aids polymer flood economics in viscous oils. ❐

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