OTC 22040

Effect of Residual Oil Saturation on Recovery Efficiency during Polymer Flooding of Viscous Oils

Karthik Kamaraj, SPE, Guoyin Zhang, SPE, Yi Liu, SPE, and R.S.Seright, SPE, New Mexico Petroleum Recovery Research Center

Abstract
This paper examines the potential of polymer flooding for recovering viscous oils when the polymer is able to reduce the residual oil saturation to a value less than that of a waterflood. If polymers can reduce the residual oil saturation, that is an important factor for polymer flooding of light and medium gravity crude oils. However, is it important when displacing viscous oils? Since the displacement efficiency is often poor when water or even polymer solutions are injected to displace viscous oils, some have questioned whether the S_{or} is relevant. This paper uses fractional flow calculations to examine this question for conditions in North Slope reservoirs with viscous oils. Variables considered include oil viscosity, water/polymer viscosity, relative permeability characteristics, connate water and residual oil saturations, formation layering, presence/absence of crossflow, and pore volume throughput. We found that induced changes in S_{or} can make a significant difference to recovery efficiency. As expected, the impact of S_{or} reduction by a polymer flood on oil recovery is more pronounced in reservoirs where residual oil saturations are high at the start of polymer flooding. The impact of S_{or} reduction diminishes with increasing degree of heterogeneity. A polymer flood can be effective for recovery of viscous oils even if the reservoir is extensively waterflooded before application of the polymer flood. A reduction in S_{or} was beneficial for all waterflood delays that we examined.

Introduction
The objective of this work is to examine the effect of reduction of residual oil saturation (S_{or}) by polymer flooding on viscous oil recovery. Polymers generally do not significantly alter the oil-water interfacial tension. Consequentally, the S_{or} value after extensive polymer flooding is expected to be the same as that of a waterflooding. But recent reports indicate that polymer flooding is able to reduce the residual oil saturation at a constant capillary number. Wu et al. (2007) observed that HPAM polymers reduced the waterflood S_{or} by up to 15 saturation percentage points (i.e., a S_{or} of 36.8% with waterflooding versus 21.75% for polymer flooding) using a constant capillary number of $5x10^{-5}$. Huh and Pope (2008) observed S_{or} reductions ranging from 2 to 22 saturation percentage points using Antolini cores and a constant capillary number of $4x10^{-6}$.

Alaska's North Slope contains a very large unconventional oil resource—over 20 billion barrels of heavy/viscous oil (Stryker et al. 1995, Thomas et al. 2007). Seright (2010a) examined the potential of polymer flooding in such heavy oil reservoirs. However, his analysis assumed that polymer would not reduce S_{or}. If polymers can reduce the residual oil saturation, that is an important factor for polymer flooding of light and medium gravity crude oils. However, is it important when displacing viscous oils? Since the displacement efficiency is often poor when water or even polymer solutions are injected to displace viscous oils, some have questioned whether the S_{or} is relevant. This paper uses fractional flow calculations to examine this question for conditions in North Slope reservoirs with viscous oils. A simple case of one homogeneous layer is analyzed, followed by consideration of free-crossflow and no-crossflow cases in a two-layer system. For these cases, polymer is injected after primary recovery of oil. Then the analysis is extended for a polymer flood when a waterflood was in operation prior to polymer injection.

Fractional Flow Calculations
Simulation results for a polymer flood can be misleading if the user is not familiar with complex assumptions inherent in a simulator. Seright (2010a) presented cases where the assumptions projected inappropriate results. So in this work, fractional flow calculations were used which provided more transparent recovery projections. Fractional flow analysis was used by

several authors to predict the recovery from a polymer flood (Lake 1989, Sorbie 1991, Green and Willhite 1998, Seright 2010a).

For our fractional flow analyses, flow was assumed to be incompressible and the capillary pressure differences between phases were neglected. Polymer was assumed to exhibit Newtonian behavior and the properties observed were independent of permeability. Also, polymer retention was assumed to balance the inaccessible pore volume.

The relative permeability characteristics were given by Eqs. 1 and 2. Seright (2010a) presented the conditions for the Base case and North Slope case given by Eqs. 3 and 4, respectively. The North Slope case was representative of the viscous oils in certain North Slope reservoirs.

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

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

BASE CASE: k_{rwo}=0.1, k_{roo}=1, S_{or}=0.3, S_{wr}=0.3, nw=2, no=2 .... (3)

NORTH SLOPE CASE: k_{rwo}=0.1, k_{roo}=1, S_{or}=0.12, S_{wr}=0.12, nw=4, no=2.5 .... (4)

Each of the following figures plots original oil in place (OOIP) recovered on the *y*-axis for a given pore volume (PV) of polymer or water that was injected. OOIP is given by (1-S_{wr}). S_{wr} is connate or irreducible water saturation. All cases used 1-cp connate water and 1,000-cp oil. The residual oil saturation for waterflood and polymer flood was different, so waterflood residual oil saturation was denoted by S_{orw} and polymer flood by S_{orp}. For the analyses where a polymer flood reduces the residual oil saturation, we considered four cases: (1) no S_{orp} reduction (0%), (2) 20% S_{orp} reduction, (3) 60% S_{orp} reduction, and (4) 100% S_{orp} reduction. Note that in Case (1), S_{orw}=S_{orp}, and in Case (4), S_{orp}=0.

Effect of S_{orp} Reduction on Oil Recovery

One Homogeneous Layer. Reduction of residual oil saturation by a polymer flood has a significant effect on the amount of viscous oils recovered. A simple system of one homogeneous layer was considered first. Figs. 1 and 2 pertain to the Base case, whereas Figs. 3 and 4 to the North Slope case. Figs. 1 and 3 apply to an unfavorable displacement where 1,000-cp oil is displaced by 10-cp polymer. Favorable displacements are shown in Figs. 2 and 4, where 1,000-cp polymer displaces 1,000-cp oil. Polymer flooding provided a substantially increased recovery in all cases.

When a polymer flood caused a reduction in S_{orp}, the Base case had high potential for additional oil recovery, as is evident from Figs. 1 and 2. Even for an unfavorable displacement in Fig. 1, the increase in oil recovery with S_{orp} reduction was significant. For example, at 1 PV of 10-cp polymer injection, the oil recovery increased from 41% for S_{orp}=0.3 to 45% for S_{orp}=0.24 (a 20% S_{orp} reduction). For the North Slope case (Figs. 3 and 4), a reduction of S_{orp} made less difference to oil recovered, compared to the Base case. For example for the North Slope case at 1 PV of 10-cp polymer injection, the oil recovery increased only from 61% for S_{orp}=0.12 to 63% for S_{orp}=0.096 (again, a 20% S_{orp} reduction). The Base-case waterflood had a much higher residual oil saturation (S_{orw}=0.3), compared to North Slope case (S_{orw}=0.12). Naturally, reservoirs with high residual oil saturations were more sensitive (in terms of oil recovery) to S_{orp} reduction. Reductions of S_{orp} had a greater effect on oil recovery for favorable displacements in both the Base case and the North Slope case (at 1 PV, compare Fig. 2 with Fig. 1 and compare Fig. 4 with Fig. 3).

Table 1 presents the OOIP recovered at the end of 1 PV injection of 1-cp water, 10-cp, 100-cp and 1,000-cp polymer for displacing 1,000-cp oil. For the Base case with 10-cp polymer displacing 1,000-cp oil in one homogeneous layer, oil recovery was 23% OOIP higher for S_{orp}=0 than for S_{orp}=0.3 (see Eq. 3). For the Base case with 1,000-cp polymer displacing 1,000-cp oil in one homogeneous layer, oil recovery was 41% OOIP higher for S_{orp}=0 than for S_{orp}=0.3. For the North Slope case with 10-cp polymer displacing 1,000-cp oil in one homogeneous layer, oil recovery was 9% OOIP higher for S_{orp}=0 than for S_{orp}=0.12 (see Eq. 4). For the North Slope case with 1,000-cp polymer displacing 1,000-cp oil in one homogeneous layer, oil recovery was 13% OOIP higher for S_{orp}=0 than for S_{orp}=0.12. So, a reduction of S_{orp} had a significant effect on the %OOIP recovered for viscous oils. Close examination of Table 1 reveals that S_{orp} reductions of only 20% had a significant effect on oil recovery for both the Base and North Slope cases. As expected, a given % reduction in S_{orp} had a much greater effect for the Base case than for the North Slope case—simply because the S_{orw} was 2.5 times greater for the Base case than for the North Slope case.

Comparing Fig. 2 versus Fig. 1 and Fig. 4 versus Fig. 3 reveals that reductions of S_{orp} had a greater effect on oil recovery for favorable displacements than for unfavorable displacements. As expected, the effect was less important for the North Slope case than for the Base case (again, simply because the Base case had a greater oil target).

For additional comparison, we calculated the incremental increase of oil recovery—i.e., the difference in oil recovery for the two extremes (0% reduction and 100% reduction) divided by the recovery for 0% S_{orp} reduction. In Table 1, the Base-case one-layer incremental increase rose from 54% for 1-cp polymer to 72% for 1,000-cp polymer. In contrast, the incremental increase remained about the same (~15%) for the North Slope case. As mentioned earlier, reductions in S_{or} were less important if the waterflood residual oil saturation was low (as in North Slope case).

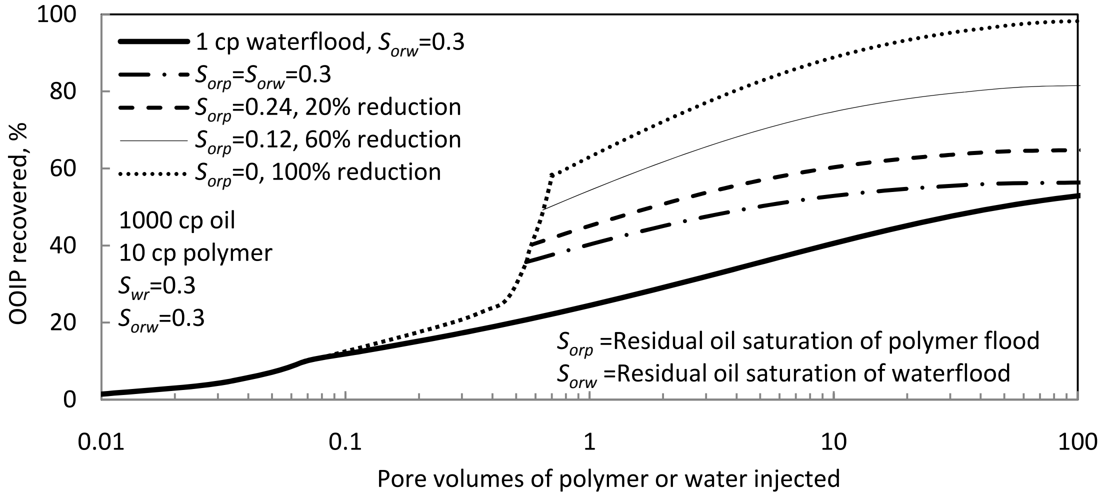

Fig. 1—10-cp polymer flood results for S_{orp} reduction, one layer. Base case.

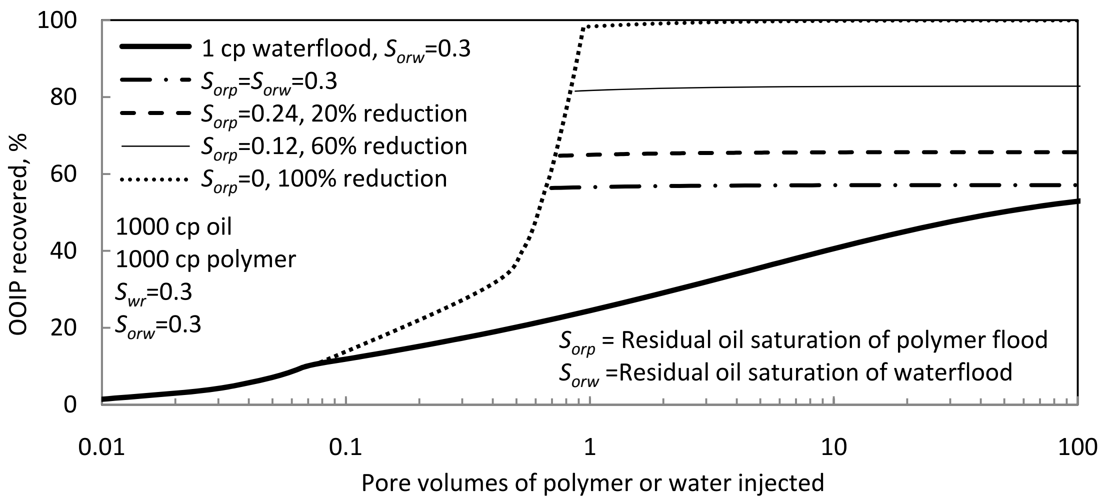

Fig. 2—1,000-cp polymer flood results for S_{orp} reduction, one layer. Base case.

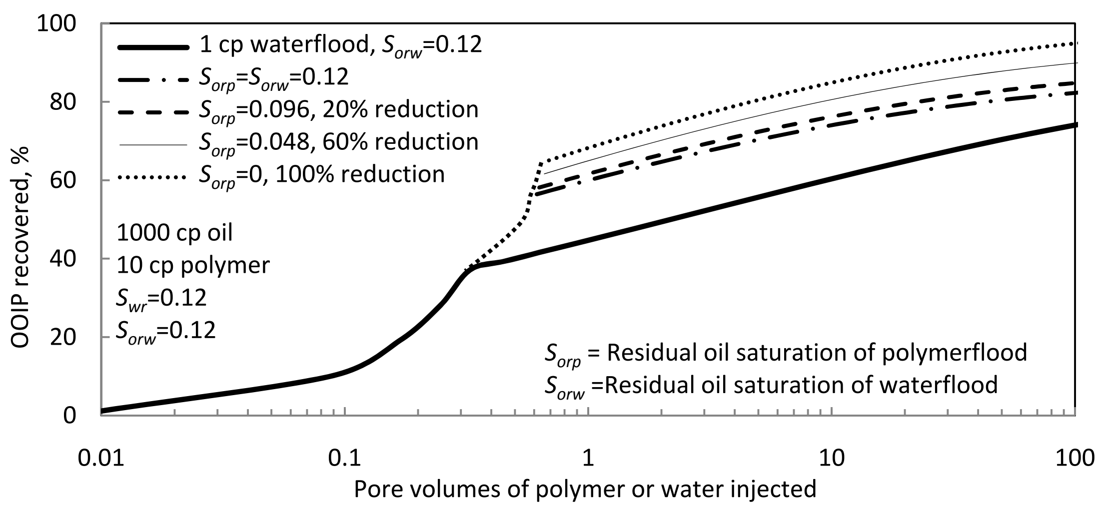

Fig. 3—10-cp polymer flood results for S_{orp} reduction, one layer. North Slope case.

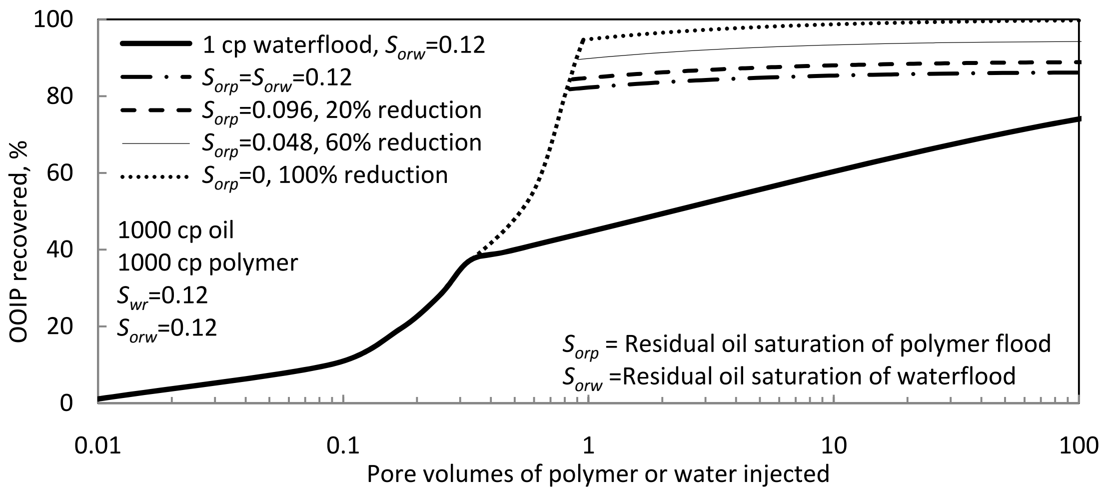

Fig. 4—1,000-cp polymer flood results for S_{orp} reduction, one layer. North Slope case.

Table 1—% OOIP recovered after 1 PV injection for displacing 1,000-cp oil

Polymer viscosity, cp	S_{orp} reduction, %	OOIP recovered, %	
		One layer (Base case)	One layer (North Slope case)
1	0 (S_{orp}=S_{orw})	24	45
	20	27	46
	60	32	48
	100 (S_{orp}=0)	37	51
	Incremental increase	(37-24)100/24=54%	(51-45)100/45=13%
10	0 (S_{orp}=S_{orw})	41	61
	20	45	63
	60	54	66
	100 (S_{orp}=0)	64	70
	Incremental increase	(64-41)100/41=56%	(70-61)100/61=15%
100	0 (S_{orp}=S_{orw})	53	74
	20	60	77
	60	75	81
	100 (S_{orp}=0)	88	85
	Incremental increase	(88-53)100/53=66%	(85-74)100/74=15%
1000	0 (S_{orp}=S_{orw})	57	82
	20	65	85
	60	82	90
	100 (S_{orp}=0)	98	95
	Incremental increase	(98-57)100/57=72%	(95-82)100/82=16%

Effect of Heterogeneity

The effect of heterogeneity was analyzed by considering two layers with and without crossflow between the layers. Both layers had equal thickness with k_1=1 darcy, ϕ_1=0.3, k_2=0.1 darcy, ϕ_2=0.3. All other parameters and conditions were the same as those used in the one-layer case. For the no-crossflow case, displacements in the individual layers were treated separately and then combined to yield the overall displacement efficiency (Green and Willhite 1998). The free-crossflow case required application of vertical equilibrium between the layers (Zapata and Lake 1981, Lake 1989). For both the free-crossflow and no-crossflow cases, spreadsheets were used to solve the fractional flow equations. Examples of these spreadsheets can be found in Seright 2010c.

Fig. 5 shows the one-layer North Slope case for 100-cp polymer displacing 1,000-cp oil. Figs. 6 and 7 illustrate the free-crossflow and no-crossflow North Slope cases for 100-cp polymer displacing 1,000-cp oil. The difference in incremental oil recovery between no S_{orp} reduction and 100% S_{orp} reduction was moderate for the one-layer case (11% OOIP) and was smaller for both the free-crossflow (8% OOIP) and no-crossflow (6% OOIP) cases. With the increase in heterogeneity (i.e., the two-layer cases), a reduction of S_{orp} has a smaller effect, compared to that seen for one layer.

At low mobility ratios, the two-layer, free-crossflow recovery curves can approach those for one homogeneous layer. A comparison of Figs. 4 and 8 demonstrates this finding for 1,000-cp polymer displacing 1,000-cp oil.

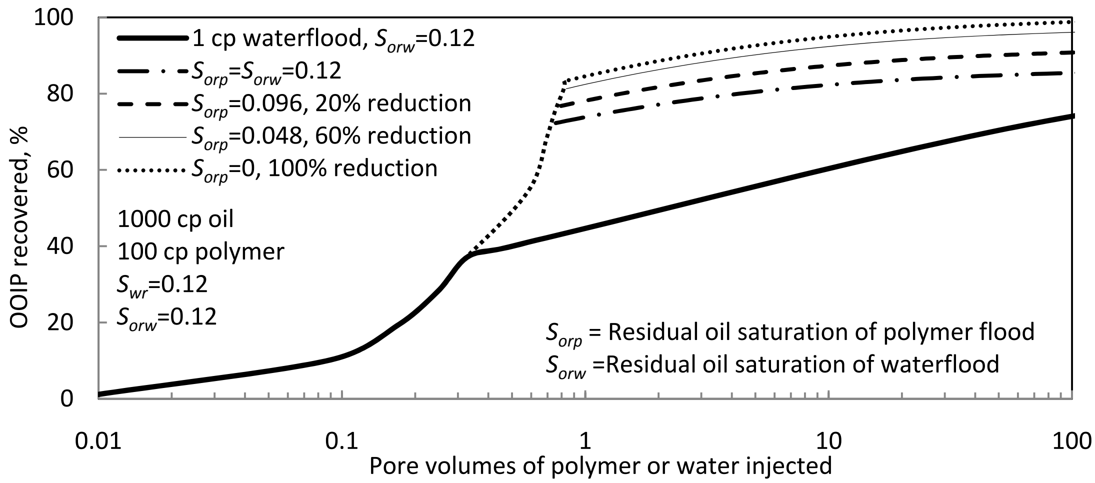

Fig. 5—100-cp polymer flood results for one homogeneous layer. North Slope case.

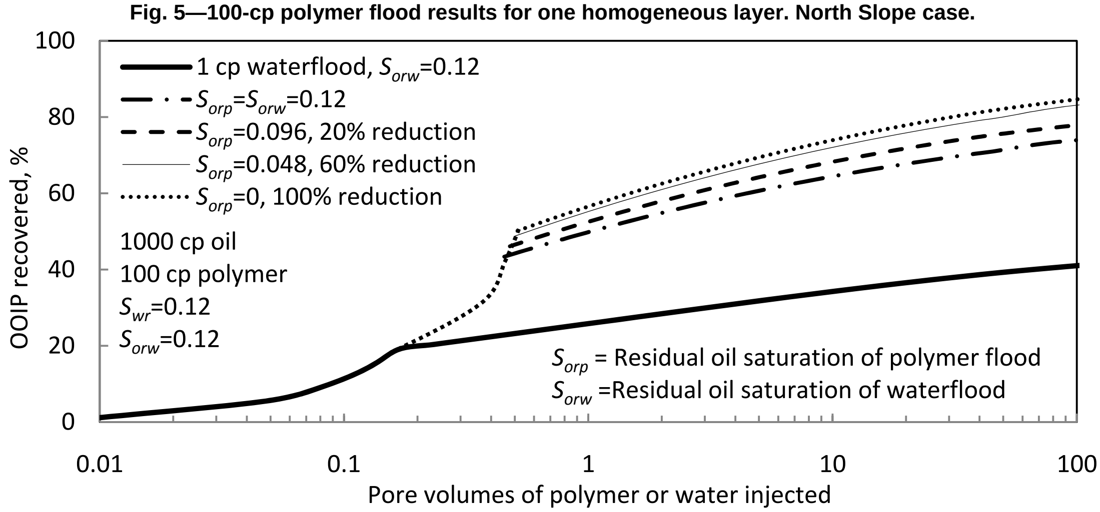

Fig. 6—100-cp polymer flood results for two layers. Free crossflow. North Slope case.

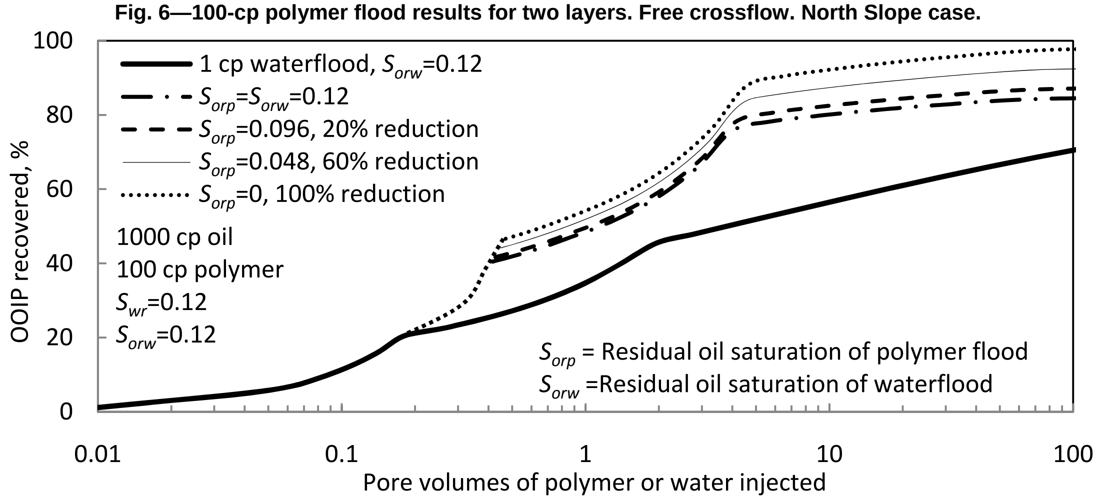

Fig. 7—100-cp polymer flood results for two layers. No crossflow. North Slope case.

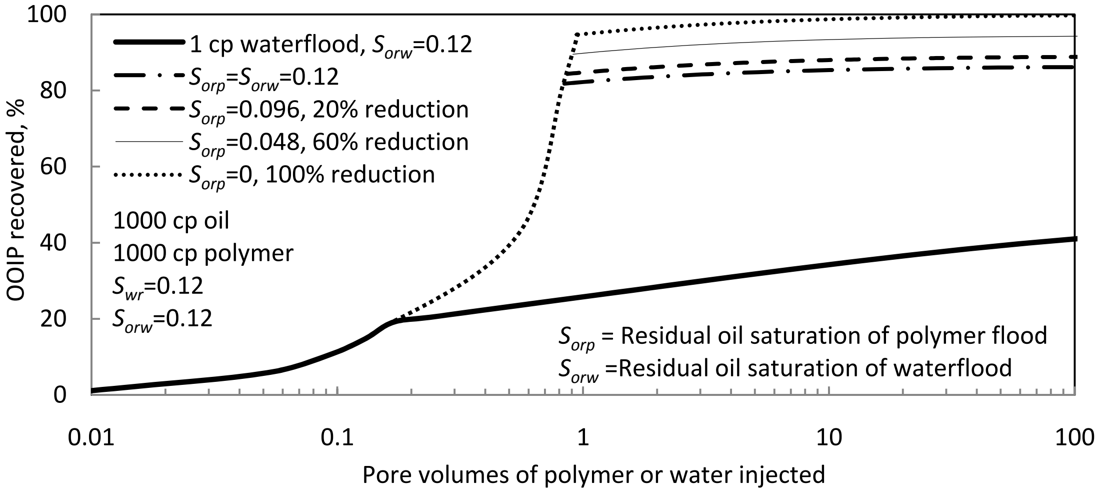

Fig. 8—1,000-cp polymer flood results for two layers. Free crossflow. North Slope case.

Table 2 lists the recovery values for 1,000-cp oil at 1 PV injection of 1-cp water, 10-cp, 100-cp and 1,000-cp polymer. Along with Figs. 6 and 7, Table 2 explains the effects of heterogeneity and S_{orp} reduction on oil recovery. For no-crossflow and free-cross flow cases during an unfavorable displacement, the effect of S_{orp} reduction on oil recovery was noticably less than that in one layer. For an unfavorable displacement and a given set of conditions, the free-crossflow case provided the lowest recoveries. As the displacement became more favorable, recovery efficiency improved more for the free-crossflow case than the no-crossflow case. During injection of the most viscous polymer solution, the free-crossflow case closely followed the behavior seen when only one layer was present.

Our findings are consistent with the behavior that was observed by others (Coats et al. 1971, Craig 1971, Zapata and Lake 1981, Sorbie and Seright 1992). As the displacement becomes more favorable, crossflow cases achieve higher recovery compared to no-crossflow cases. For unfavorable displacements, no-crossflow cases achieve higher recovery than free-crossflow cases.

Table 2—% OOIP recovered after 1 PV injection for displacing 1,000-cp oil (North Slope case)

Polymer viscosity, cp	S_{orp} reduction, %	OOIP recovered, %		
		One layer	Two layers, no crossflow	Two layers, free crossflow
1	0 (S_{orp}=S_{orw})	45	34	26
	20	46	35	27
	60	48	36	28
	100 (S_{orp}=0)	51	38	30
	Max. difference	(51-45)=6	(38-34)=4	(30-26)=4
10	0 (S_{orp}=S_{orw})	61	43	35
	20	63	45	36
	60	66	47	38
	100 (S_{orp}=0)	70	50	40
	Max. difference	(70-61)=9	(50-43)=7	(40-35)=5
100	0 (S_{orp}=S_{orw})	74	49	52
	20	77	51	54
	60	81	54	55
	100 (S_{orp}=0)	85	57	58
	Max. difference	(85-74)=11	(57-49)=8	(58-52)=6
1000	0 (S_{orp}=S_{orw})	82	53	82
	20	85	54	85
	60	90	57	90
	100 (S_{orp}=0)	95	59	95
	Max. difference	(95-82)=13	(59-53)=6	(95-82)=13

For the analyses of two-layered systems above, the permeability ratio, k_1/k_2, was fixed at a value of 10. We considered other permeability ratios, including 2 and 5. Figs. 9 and 10 explain the effects of heterogeneity and S_{orp} reduction on oil recovery by considering different permeability ratios for 1,000-cp oil displaced by 100-cp polymer (North Slope parameters).

Fig. 9 describes the free-crossflow case, comparing the extreme cases of no S_{orp} reduction and 100% reduction (to S_{orp} =0). At 1 PV injection of polymer with free crossflow, the effect of S_{orp} reduction on oil recovery diminished with increased permeability ratio: i.e., by 10.5% OOIP at k_1/k_2=1, by 10.5% OOIP at k_1/k_2=2, by 7.5% OOIP at k_1/k_2=5, and by 6.5% OOIP at k_1/k_2=10. No-crossflow cases (described by Fig. 10) exhibit a similar trend for increasing heterogeneity. At 1 PV injection of polymer with no crossflow, the effect of S_{orp} reduction on oil recovery diminished with increased permeability ratio: i.e., by 10.5% OOIP at k_1/k_2=1, by 9.3% OOIP at k_1/k_2=2, by 6.9% OOIP at k_1/k_2=5, and by 5.6% OOIP at k_1/k_2=10. Thus, the effect of S_{orp} reduction on oil recovery becomes less significant for both free-crossflow and no-crossflow cases with increasing reservoir heterogeneity.

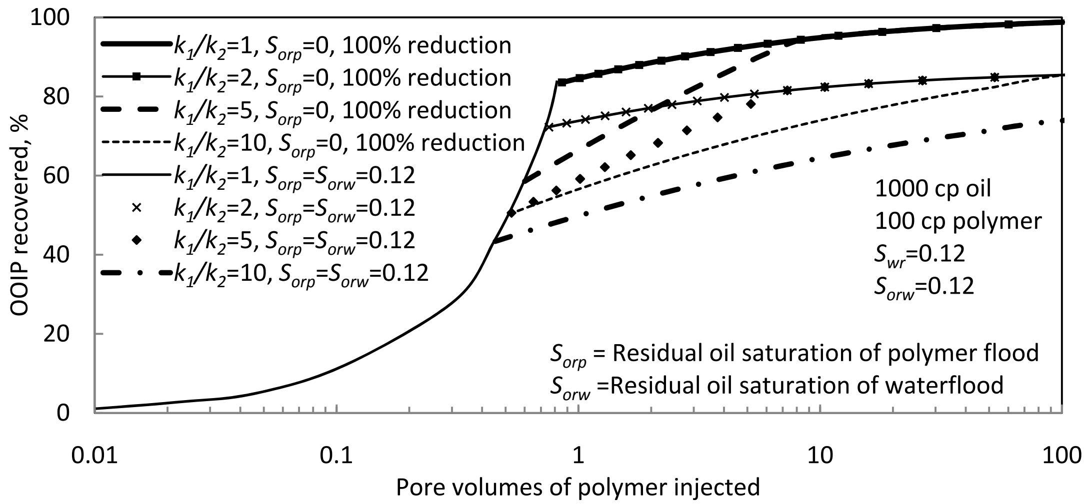

Fig. 9—Effect of heterogeneity. Free crossflow. North Slope case.

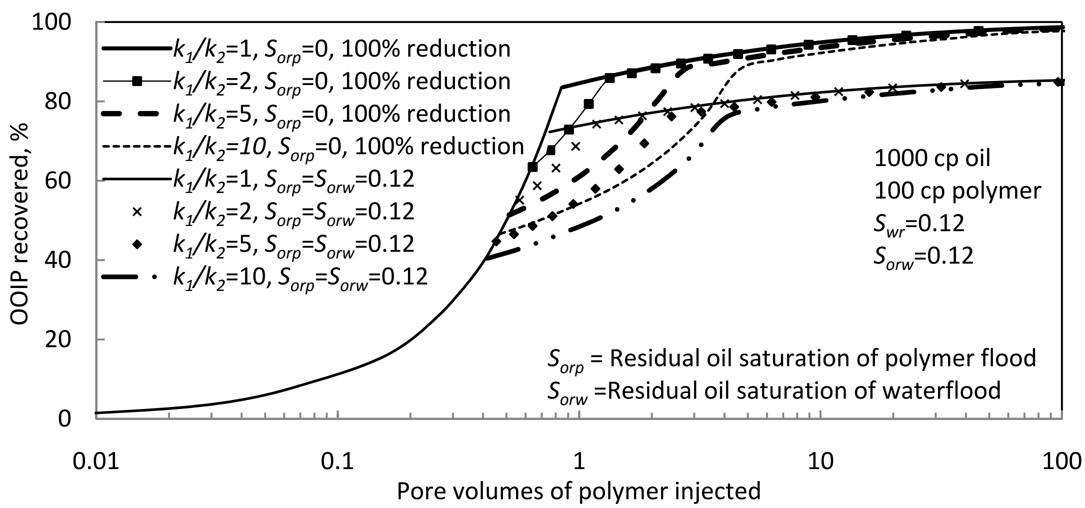

Fig. 10—Effect of heterogeneity. No crossflow. North Slope case.

Polymer Flooding After a Waterflood

Seright (2010b) explained how a polymer flood can be effective for recovery of viscous oils even if the reservoir is extensively waterflooded before application of the polymer flood. We extended this analysis for a polymer flood that reduces the residual oil saturation to a value lower than that possible by a waterflood. The bottom thick solid line in Fig. 11 shows oil recovery projections for continuous water injection (with 1-cp water), while all other curves show projections for continuous polymer solution injection (with 100-cp polymer). Depending on the extent of S_{orp} reduction (0%, 20%, 60%, 100%), different recovery projections were obtained for a polymer flood. In this figure, flow was linear, one homogeneous layer was present, porosity was 0.3, the reservoir contained 1,000-cp oil at connate water saturation (S_{wr}=0.12) and our "North Slope" parameters were used. The near-vertical line segments that connect the continuous-water-injection to the continuous-polymer-injection curves show cases where polymer flooding was initiated after injecting the specified volumes of water (from 1 to 10 PV). To explain this curve, consider the case of 1 PV delay. When 100-cp polymer is injected into the one-layer reservoir, oil recovery follows the bottom waterflooding curve for 1.75 PV (i.e., 1 PV associated with water injection plus 0.75 PV delay associated with polymer propagating through the reservoir). After that point, a 0.355-PV oil bank (for no S_{orp} reduction, S_{orp}=0.12) arrives at the production well, the oil recovery rate increases significantly, and the recovery curve jumps to join the continuous-polymer-injection curves. All other PV delays (2, 5, and 10 PV) followed a similar behavior. When a polymer flood reduced the residual oil saturation, the size of the oil bank increased. For 1 PV delay, the size of the oil bank increased from 0.355 to 0.526 PV when the polymer flood was able to achieve 100% S_{orp} reduction. With increased size of the pre-polymer waterflood (Fig. 11), the oil bank diminished, but the effect of S_{orp} reduction on oil bank formation remained constant and was equal to the PV of oil bank between 0% reduction (where the oil recovery projection joined the continuous polymer flood) and 100% reduction (extreme cases). Note that Fig. 11 is similar to Fig. 5 (North Slope case, one layer, 100-cp polymer displacing 1,000-cp oil). The oil bank size mentioned above (between 0% reduction and 100% reduction) is the same as the difference in oil recovery (in terms of PV) between the extreme cases in Fig. 5. The key point is that even though the oil bank decreases with increasing size of the pre-polymer waterflood, the effect of S_{orp} reduction on oil bank is independent of the waterflood bank size. In other words, the oil bank formed due to reduction of S_{orp} by a polymer flood is the same for polymer as a secondary flood or a tertiary flood (after a waterflood).

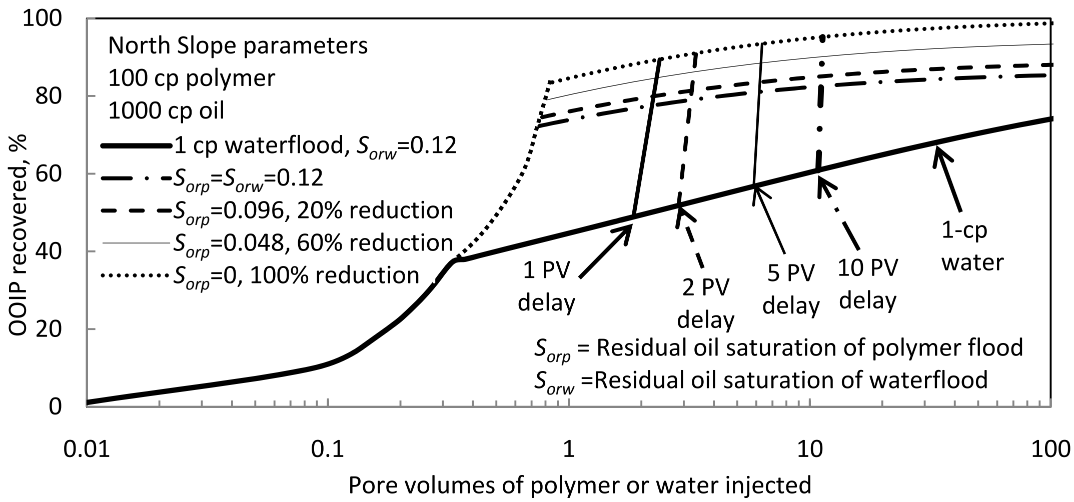

Fig. 11—Injection of 100-cp polymer, initiated after waterflooding of specified PV, 1 layer.

Conclusions

1. If a polymer flood of viscous oil is able to decrease the residual oil saturation (below that expected for a waterflood), a significant amount of additional oil can be recovered, compared to the case where polymer does not reduce S_{or}.
2. As expected, the impact of S_{or} reduction by a polymer flood on oil recovery is more pronounced in reservoirs where residual oil saturations are high at the start of polymer flooding.
3. The impact of S_{or} reduction diminishes with increasing degree of heterogeneity.
4. A polymer flood can be effective for recovery of viscous oils even if the reservoir is extensively waterflooded before application of the polymer flood. A reduction in S_{or} was beneficial for all waterflood delays that we examined.

Acknowledgements

We gratefully acknowledge financial support of this work from the U.S. Department of Energy (Award No. DE-NT000655), CP Kelco, SNF Floerger, and Statoil. We also thank ConocoPhillips for information about key North Slope oil fields.

Nomenclature

h_1 = height of zone 1, ft
h_2 = height of zone 2, ft
k_1 = permeability of zone 1, mD
k_2 = permeability of zone 2, mD
k_{ro} = relative permeability to oil
k_{rw} = relative permeability to water
k_{roo} = endpoint relative permeability to oil
k_{rwo} = endpoint relative permeability to water
no = oil-saturation exponent
nw = water-saturation exponent
OOIP = original oil in place
PV = pore volumes of fluid injected
S_{or} = residual oil saturation
S_{orp} = residual oil saturation of polymer flood
S_{orw} = residual oil saturation of waterflood

S_w = water saturation
S_{wr} = residual-water saturation
ϕ_1 = porosity in layer 1
ϕ_2 = porosity in layer 2
μ = viscosity, cp [mPa-s]

References

Coats, K.H., Dempsey, J.R., and Henderson, J.H. 1971. The Use of Vertical Equilibrium in Two-Dimensional Simulation of Three-Dimensional Reservoir Performance. *SPEJ*, **11**(1): 63–71.

Craig, F.F. 1971. *The Reservoir Engineering Aspects of Waterflooding*. Monograph Series, SPE, Richardson, Texas **3:** 45–75.

Green, D.W., and Willite, G.P. 1998. *Enhanced Oil Recovery*. Textbook Series, SPE, Richardson, Texas **6**: 100–185.

Huh, C., and Pope, G.A. 2008. Residual Oil Saturation from Polymer Floods: Laboratory Measurements and Theoretical Interpretation. Paper SPE 113417 presented at the SPE/DOE Improved Oil Recovery Symposium, Tulsa, Oklahoma, 19–23 April.

Lake, L.W. 1989. *Enhanced Oil Recovery*. 314–353, Englewood Cliffs, New Jersey: Prentice Hall, Inc.

Seright, R.S. 2010a. Potential for Polymer Flooding Reservoirs with Viscous Oils. *SPE Reservoir Evaluation and Engineering*, August, 730-740.

Seright, R.S.2010b.Use of Polymers to Recover Viscous Oil from Unconventional Reservoirs. Second Annual Report, U.S. Department of Energy, DOE Contract No.: DE-NT0006555, US DOE, Washington, DC, September 2010.

Seright, R.S. 2010c. http://baervan.nmt.edu/randy/.

Sorbie, K.S. 1991. *Polymer-Improved Oil Recovery*. 115. Glasgow, Scotland: Blackie and Son, Ltd.

Sorbie, K.S. and Seright, R.S. 1992. Gel Placement in Heterogeneous Systems with Crossflow. Paper SPE 24192 presented at the SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, Oklahoma, 22–24 April.

Stryker, A.R., Watkins, R., Olsen, D.K., et al. 1995. Feasibility Study of Heavy Oil Recovery in the United States. Final Report, Contract No. DE-AC2294PC91008, US DOE, Washington, DC (September 1995).

Thomas, C.P., Faulder, D.D., Doughty, T.C., Hite, D.M., and White, G.J. 2007. Alaska North Slope Oil and Gas, a Promising Future or an Area in Decline? Summary Report DOE/NETL-2007/1279, US DOE, Washington, DC (August 2007)

Wu, W., Wang, D., and Jiang, H. 2007. Effect of the Visco-Elasiticity of Displacing Fluids on the Relationship of Capillary Number and Displacement Efficiency in Weak Oil-Wet Cores. Paper SPE 109228 presented at the SPE Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, Indonesia, 30 October–1 November.

Zapata, V.J. and Lake, L.W. 1981. A Theoretical Analysis of Viscous Crossflow. Paper SPE 10111 presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, 5–7 October.

SI Metric Conversion Factors

cp x 1.0*	E-03	=Pa.s
ft x 3.048*	E-01	= m
in. x 2.54*	E+00	= cm
md x 9.869 233	E-04	= μm^2
psi x 6.894 757	E+00	= kPa