Sweep-Improvement Options for the Daqing Oil Field

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Summary

This paper investigates the potential of various approaches for improving sweep in parts of the Daqing oil field that have been enhanced-oil-recovery (EOR) targets. Our studies indicated that the polymer flood should have provided excellent sweep throughout the vast majority of the patterns under consideration. However, because alkaline/surfactant/polymer (ASP) flooding is being considered to increase recovery efficiency from the Daqing oil field, mobility control and sweep improvement will be especially important and challenging during implementation of any future ASP process.

Fractures were present in a number of Daqing wells (both injectors and producers). Because the fractures were narrow and far from the wellbore, severe channeling did not occur. On the contrary, fractures near the wellbore aided reservoir sweep. Near-wellbore fractures increased the injectivity index substantially during the injection of polymer solutions and increased oil-productivity index in the production wells. These observations may be valuable during implementation of future floods where very-low-mobility chemical (i.e., ASP) banks must be injected to maintain mobility control.

Several modes of polymer degradation were considered, with mechanical (shear) degradation being of greatest concern. Appropriate use of near-wellbore fractures may mitigate mechanical degradation effectively, as well as improving injectivity.

Several new polymers show potential for cost-effective improvements at Daqing. Increased polymer concentration was also considered. A number of other approaches are (or have been) under investigation, including colloidal dispersion gels, foams, ASP foams, steam, microbes, and polymer solutions prepared with reduced salinity.

Introduction

Laboratory research began in the 1960s, investigating the potential of EOR processes in the Daqing oil field. The use of polymer flooding was identified as a key method to improve areal and vertical sweep efficiency, as well as providing mobility control (Wang 1995). Consequently, the world's largest polymer flood was implemented at Daqing, beginning in 1996 (Wankui et al. 2000, Wang et al. 2002). By 2004, 22.7% of total production from the Daqing oil field was attributed to polymer flooding. Polymer flooding should boost the ultimate recovery for the field to more than 50% of original oil in place (OOIP), which is 10% OOIP more than from waterflooding.

ASP flooding also has experienced extensive laboratory testing in China. The ASP technique was gradually perfected for application at Daqing and has been pilot tested on a large scale (Wang et al. 1999; Jirui et al. 2001; Wang 2003). Results from two typical pilot tests in the south and north parts of the Daqing field revealed incremental-oil-recovery values as high as 20% OOIP. By the end of 2003, the Center Xinger pilot site showed a definitive increase in oil production and decrease in water cut. In the east area of this site (the largest portion included within the ASP pattern area), the predicted EOR was approximately 18% OOIP more than from waterflooding.

Although field tests of polymer and ASP flooding have been very successful at Daqing, concerns about sweep efficiency persist—particularly the possibility of channeling expensive chemical formulations through the reservoir. Therefore, the sweep efficiency at Daqing is receiving intense scrutiny, and possibilities for improvement are being considered. In this paper, we examine the nature of reservoir sweep in parts of the Daqing oil field that have been EOR targets. We investigate the potential of various approaches for improving sweep. Our objective is to establish better options in the future for improving sweep in the main producing zone.

Sweep Efficiency in the Daqing Oil Field

Stratification. What is the nature of the sweep-efficiency problem at Daqing? This study focused on the Eastern Berxi polymer-flooding area of the Daqing field—specifically on 17 production wells and eight injection wells. Layer PI, a principal target for EOR at Daqing, is composed of up to seven named "zones." The gross pay for Layer PI varied between 18 and 33 m. Net pay varied from 11 to 31 m, averaging 18 m. Within the net pay, some degree of vertical stratification existed. **Figs. 1 through 3** illustrate this stratification for three wells. For the 25 wells, the Dykstra-Parsons coefficient of permeability variation ranged from 0.14 to 0.89, averaging 0.70. Fig. 1 illustrates the distribution for production Well B2-4-P43. In this well, five strata were identified, with the top zone being the most-permeable zone (1.2 μm^2). Three intermediate zones had approximately the same permeability, ranging from 0.4 to 0.5 μm^2. A small zone at the bottom was the least permeable, with 0.232 μm^2. For this well, most flow capacity and net pay existed in a single interval where crossflow could freely occur. This feature was shared by 32% of the wells examined.

Fig. 2 illustrates the distribution for production Well B2-D6-P45. Four strata were identified, with the top and bottom zones having similar permeabilities (0.49 to 0.5 μm^2). A 0.316-μm^2 zone at 1017 m probably had direct flow contact (crossflow) with the bottom zone. A small 0.142-μm^2 zone at 1010 m appeared distinct from the other zones. For this well, most of the net pay existed in zones that had approximately the same permeability. This feature was exhibited by 36% of the wells examined.

Fig. 3 illustrates the distribution for production Well B2-D6-P47, where seven strata were identified. The interval from 988 to 1001 m should be considered as a single flow unit, with an average permeability of approximately 0.5 μm^2. A 1.2-μm^2 zone existed at 1017 m. Between 1005 and 1013 m, three small zones were present, with permeabilities ranging from 0.147 to 0.21 μm^2. Thus, for this well, the net pay existed in distinct zones with noticeably different permeabilities. This characterization was shared by 28% of the wells examined.

Mobility Ratios. At Daqing, the endpoint relative permeabilities were $k_{rw}\approx 0.5$ and $k_{ro}\approx 0.8$, oil viscosity of 9 mPa·s, and water viscosity of 0.6 mPa·s. Thus, during waterflooding, the endpoint mobility ratio was 9.4. With this unfavorable mobility ratio, viscous fingers can form that lead to severe channeling, especially when zones with different permeability are present.

By injecting a viscous polymer solution, the mobility ratio was increased to the point of making it favorable. The viscosity of the

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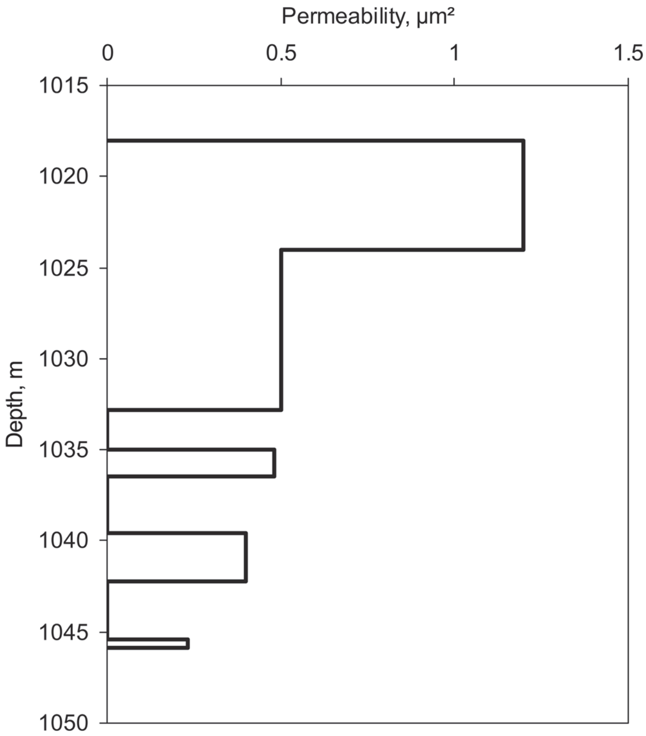

Fig. 1—Permeability distribution for Producer B2-4-P43.

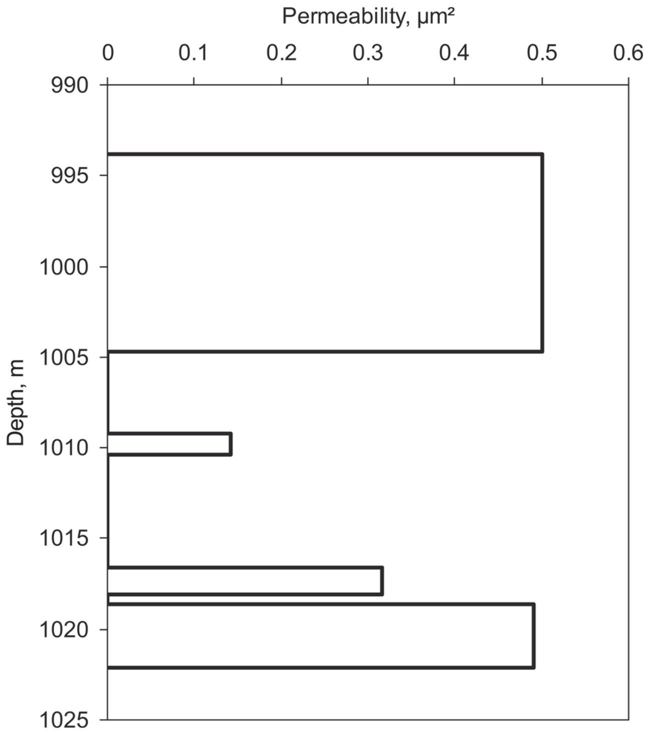

Fig. 2—Permeability distribution for Producer B2-D6-P45.

injected polymer solution was typically 35 to 40 mPa·s. If polymer degradation was not significant, this level of viscosity decreased the mobility ratio from 9.4 to approximately 0.25. When fluids can crossflow freely between strata, the rate of movement of a polymer front is independent of permeability, as long as the reciprocal of the mobility ratio is greater than the permeability contrast between the strata (Sorbie and Seright 1992). The two upper strata in Fig. 1 had, respectively, permeabilities of 0.5 and 1.2 μm^2 (i.e., a permeability contrast of 2.4 and combined average permeability of 0.783 μm^2) and were subject to unrestricted crossflow. Thus, during polymer flow in which the reciprocal mobility ratio was 4 (i.e., 1/0.25), the upper strata in Well B2-4-P43 should have been swept quite efficiently.

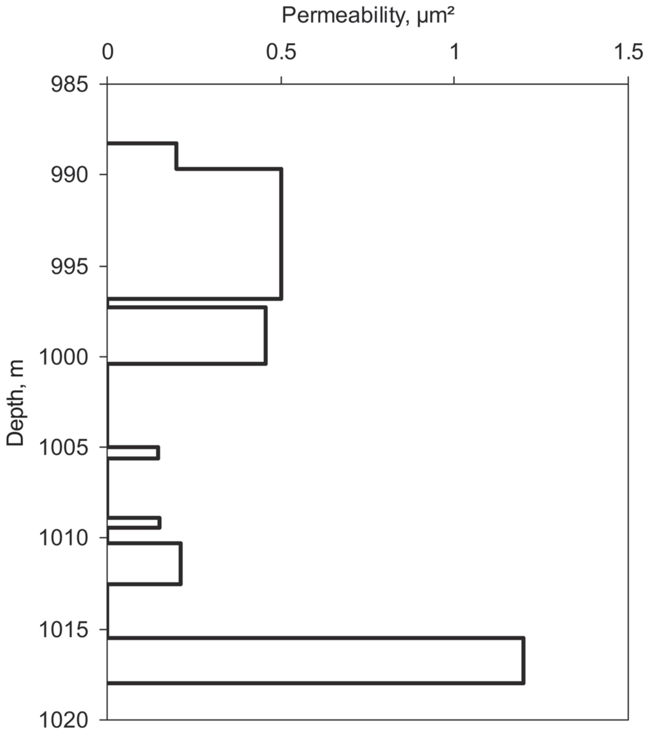

Fig. 3—Permeability distribution for Producer B2-D6-P47.

The bottom three strata in Fig. 1 had permeabilities of 0.482, 0.398, and 0.232 μm^2, respectively. The relative rates of propagation for the polymer fronts in each stratum can be estimated using the methods in Sorbie and Seright (1992), Seright (1988), and Seright (2007). Given the permeabilities and the above mobility ratio, the relative rates of propagation of the polymer fronts for radial flow in the five zones would be 1, 1, 0.79, 0.72, and 0.56, respectively. Some evidence exists that the polymer may experience viscosity losses of up to 50% during injection. If the reciprocal mobility ratio was 2 instead of 4, the relative rates of propagation of the polymer fronts in the five zones were 1, 1, 0.78, 0.71, and 0.54, respectively.

For the above circumstances, sweep efficiency during the polymer flood should be quite good, with the possible exception of the very small 0.232-μm^2 bottom zone. Similar calculations can be made for the wells illustrated in Figs. 2 and 3. These calculations reveal that the polymer flood should have provided excellent sweep in all but the small zone at 1010 m for Well B2-D6-P45 (Fig. 2) and the small zones from 1005 to 1013 m in Well B2-D6-P47 (Fig. 3). More generally, these calculations indicated that the polymer flood should have provided excellent sweep throughout the vast majority of the patterns associated with the 25 wells under consideration. Thus, if sweep was truly inadequate during the polymer flood, a reason for this inadequacy must be identified.

Mobility Control During ASP Flooding

ASP flooding is being considered to increase recovery efficiency from the Daqing oil field. Mobility control and sweep improvement will be especially important during implementation of the ASP process.

Mobility-Control Requirements for ASP Flooding After Polymer Flooding. During a chemical flood (e.g., an ASP flood), mobility control means each successive fluid bank injected must be less mobile than the bank ahead of it. Without mobility control, expensive chemical banks experience significant channeling (through viscous fingers) even in homogeneous reservoirs. In het-

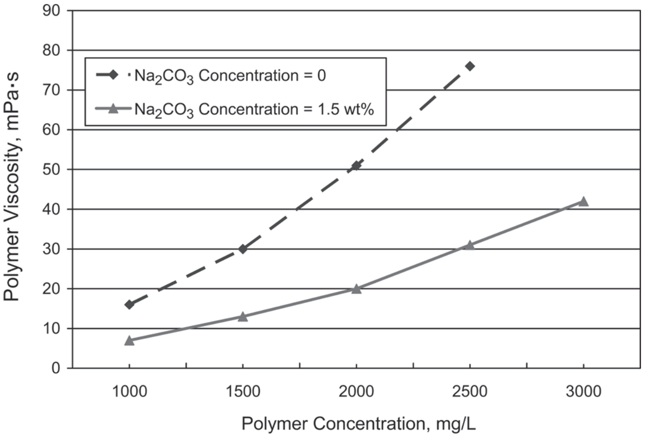

Fig. 4—Viscosity vs. concentration of medium-molecular-weight polymer [LIANHUA-1500™ (Petrochina Daqing Refining and Petrochemical Company; 2001; Daqing, China)].

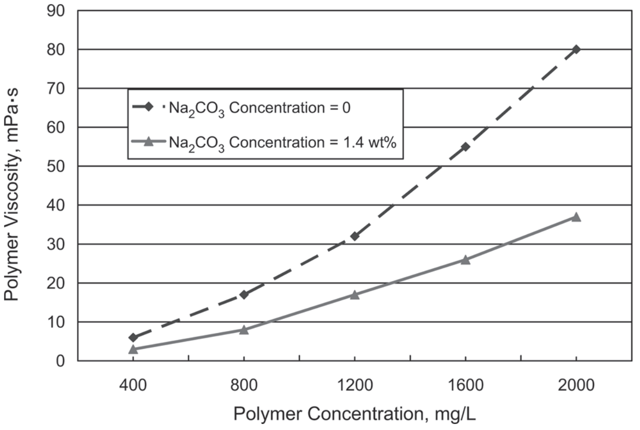

Fig. 5—Viscosity vs. concentration of ultrahigh-molecular-weight polymer [HENGJU™ (Beijing Hengju Chemical Agent Ltd.; 2004; Beijing)].

erogeneous reservoirs, channeling is accentuated with unfavorable mobility ratios.

If an ASP flood is the first EOR method applied in a reservoir, the ASP bank should be less mobile (more viscous) than the oil/water bank that is being displaced. Because an ASP formulation decreases the residual-oil saturation, effective permeability to the aqueous phase (i.e., the ASP formulation) can be much greater than that in a preceding waterflood. Consequently, the level of viscosity enhancement (mobility reduction) needed to provide mobility control is significantly greater than if no reduction in S_{or} occurred.

For some areas of the Daquing oil field, ASP floods may be applied in patterns that were previously polymer flooded. Because the preceding polymer bank was quite viscous (20 to 40 mPa·s), the ASP bank must be even more viscous to maintain mobility control.

Higher Salinity of ASP Reduces Viscosity. Compounding this mobility problem, alkaline agents significantly increase the ionic strength of ASP formulations. The viscosity of a given concentration of anionic polymer (e.g., partially-hydrolyzed polyacrylamide or HPAM) is much lower in saline solutions (e.g., an ASP formulation) than in fresh water (e.g., used during the Daqing polymer floods) (Wankui et al. 2000; Wang et al. 1999, 2002; Jirui et al. 2001; Wang 2003). Thus, the concentrations and expense for polymer may be unusually high when applying ASP flooding after a polymer flood.

Figs. 4 and 5 show viscosity vs. polymer concentration for polymers with medium and ultrahigh molecular weights, respectively. As expected, viscosity increased with the increased polymer concentration, and was significantly lower with 1.4 to 1.5% alkali than without alkali.

Fig. 6 shows how polymer solution viscosity (using 1000 mg/L HPAM) is affected by the presence of NaCl, Na_2CO_3, or NaOH. For a given ionic strength, viscosity was highest with NaOH and lowest with NaCl, reflecting the increase in pH with increased alkalinity. Presumably, this trend occurs because hydrolysis of amide groups adds charge to the polymer molecules and increases solution viscosity. Of course, increased solution viscosity is desirable, but increased polymer hydrolysis may lead to higher polymer retention in the reservoir.

Polymer Stability in the Presence of Alkali. When HPAM solutions are exposed either to high temperatures or to high pH values, the polymer's amide groups can hydrolyze (Moradi-Araghi and Doe 1984, Ryles 1988). However, the carbon/carbon backbone of the polymer is quite stable, as long as oxygen and free radials are absent. **Fig. 7** shows the stability of an ASP solution when the alkali concentration is 1.2%. The curve demonstrates that the ASP viscosity can be kept stable for at least 3 months when the polymer concentration is 1200 mg/L.

If exposure of HPAM to high pH values drives the degree of hydrolysis to high levels, the polymer can precipitate (and therefore cause viscosity loss) if significant concentrations of divalent cations are present (Moradi-Araghi and Doe 1984, Ryles 1988). Fortunately, high pH values also induce precipitation and suppress dissolution of divalent cations, so polymer precipitation is mitigated. Nevertheless, the issue should be kept in mind for those parts of the reservoir where neutralized ASP solutions may contact reservoir brine with higher cation levels.

Reduced Injectivity for Viscous Solutions. ASP flooding displaces residual oil and increases the effective permeability, espe-

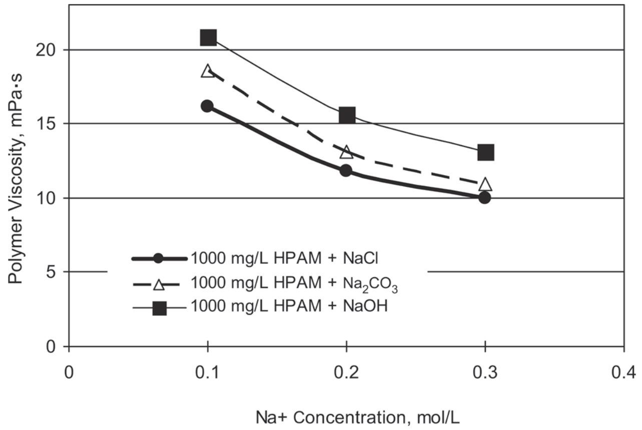

Fig. 6—Viscosity vs. Na+concentration for different anions.

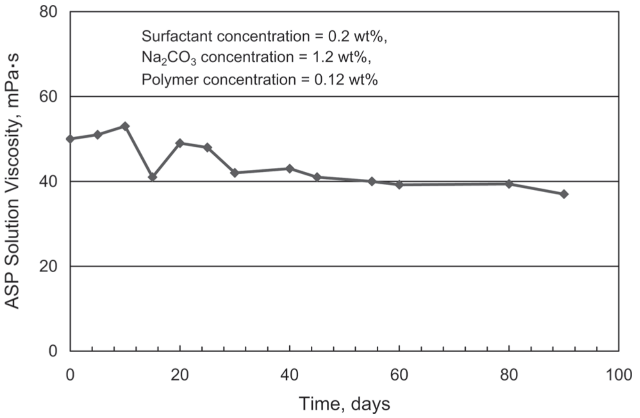

Fig. 7—Stability of ASP solution viscosity.

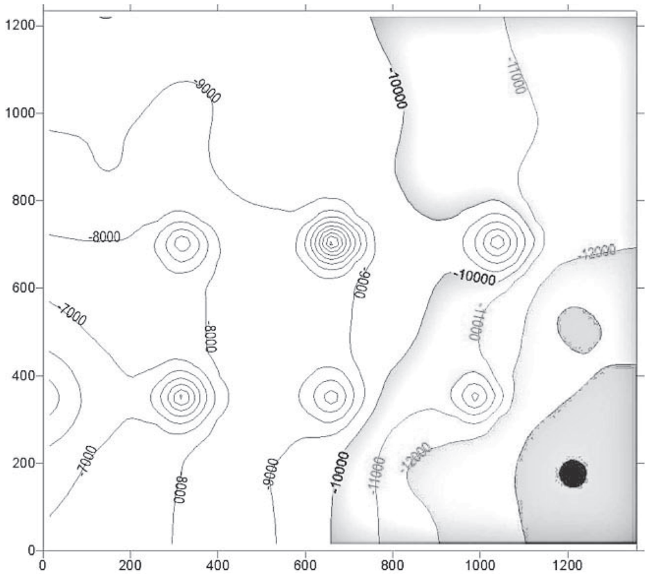

Fig. 8—Pattern pressures before ASP.

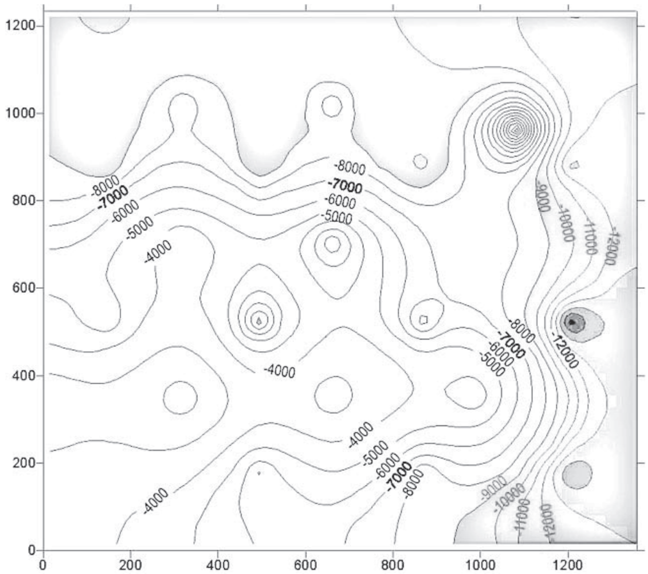

Fig. 9—Pattern pressures after ASP.

cially near injection wells. This effect enhances the injectivity index. However, this beneficial effect is countered by the increased viscosity, reduced mobility, and/or any permeability reduction associated with polymer in the ASP formulation (Wang 2003).

Figs. 8 and 9 show the predicted variation of injection pressures (on the basis of the numerical simulation and the real data from the pilot site) before vs. after ASP flooding, respectively, in the first north fault from the West pilot test. (Pressure contours are in units of kPa.) Injection pressures increased gradually during injection of ASP solution. After 0.23 pore volumes (PV) of ASP, the average injection pressure increased from 9.18 MPa (during water drive) to 12.47 MPa—an increase of 3.29 MPa. Here, the injection rate was 0.206 PV/yr, and the ASP injection viscosity was 37 mPa·s (approximately the same viscosity as during the polymer flood). Consequently, the injection ability and flow pressure decreased, but the injection pressure was still 1.03 MPa below the formation fracture pressure. Under the conditions of this pilot site, injectivity was acceptable if the reservoir pressure was below 10 MPa. At the peak predicted injection pressure, the water-injectivity index for ASP was 13.9% less than during water injection. Even so, this loss of injectivity was less than that observed during polymer flooding, see **Tables 1 and 2.** This finding is attributed to the ASP formulation driving the oil saturation to a lower value than that during the polymer flood—consequently, the effective permeability was higher during ASP flooding than during polymer flooding.

Because ASP floods drive residual oil to low values and the chemical formulations are expensive, mobility control is extremely important. Achieving and maintaining satisfactory mobility control will be challenging for future ASP floods at Daqing, especially for patterns that were previously polymer flooded. The viscosity of the ASP formulations must be balanced to provide (1) effective mobility control and efficient reservoir sweep, (2) acceptable injectivity and timely fluid displacement through the reservoir, and (3) cost-effective use of the injected chemicals.

TABLE 1—VARIATION OF INJECTION PRESSURE

Method	Well Distance (m)	Injection Intensity (m^3/d·m)	Injection Pressure (MPa) Water-Drive	Injection Pressure (MPa) Chemical Flood	Pressure Increase (MPa)
ASP	250	20.5	9.18	12.47	3.29
Polymer	250	17.3	5.5	12.3	6.8

Are Fractures Important? Are Gels Viable To Reduce Channeling?

We examined whether fractures might cause significant channeling of polymer between some injector/producer pairs at Daqing. Typically, approximately 2,000 wells were intentionally hydraulically fractured each year at Daqing. Unintentional fracturing of injection wells is a possibility during waterflood operations. Also, natural fractures may exist. If fractures are responsible for significant channeling between wells, gel treatments could be a viable solution. If fractures are not responsible for channeling, other sweep-improvement options may be more appropriate.

In assessing whether fractures cause channeling, we considered three sets of data: (1) pattern oil-recovery factors, (2) injectivity and productivity indices, and (3) interwell polymer-breakthrough times.

Pattern Oil-Recovery Factors. In examining our 25 wells, oil-recovery factors were generally quite high for individual pattern areas—at least 33% OOIP and more typically approximately 50% OOIP. Thus, if channeling through fractures was a problem, we must use means other than recovery factors to identify the offending fractures.

Injectivity/Productivity Indices. One method to assess the importance of fractures is to compare the actual injectivity or productivity index for a well $q/\Delta p$ with the value calculated using the Darcy equation for radial flow (Seright et al. 2003).

$$q/\Delta p = \Sigma kh/[\mu \ln(r_e/r_w)]. \quad \ldots\ldots (1)$$

If the left side of Eq. 1 is substantially greater than the right side, a fracture or fracture-like feature probably intersects the well. On the other hand, if the left side of Eq. 1 is less than or equal to the right side, fractures may not contribute significantly to the flow capacity of the well. We applied this method to our 25 Daqing wells. Most wells showed behavior that was consistent with radial flow (no significant fractures). However, the analysis revealed that fractures were present in three injection wells and three production wells. During polymer flooding, the injectivity or productivity indices for these wells were typically three to five times greater than values calculated using the right side of Eq. 1.

For those wells where fractures were present, injectivity or productivity indices can be used to estimate fracture widths, w_f :

$$k_f w_f = \{[q\mu/(\Delta p h_f)] - [k_m/\ln(r_e/r_w)]\}\, L_f/2, \quad \ldots\ldots (2)$$

$$w_f(\text{in mm}) = 1.49(k_f w_f)^{1/3}, \text{ where } k_f w_f \text{ is in } \mu\text{m}^2 \cdot \text{m}. \quad \ldots\ldots (3)$$

TABLE 2—VARIATION OF WATER-INJECTIVITY INDEX

Method	Well Distance (m)	Injection Intensity (m^3/d-m)	Water-Injectivity Index (m^3/d-m-MPa)		Pressure Increase (MPa)
			Waterdrive	Chemical Flood	
ASP	250	20.5	3.51	3.02	3.29
Polymer	250	17.3	2.75	2.08	6.8

In these equations, k_f is effective fracture permeability, q is the total fluid injection or production rate; μ is fluid viscosity; Δp is the well/formation pressure difference; h_f is fracture height; L_f is fracture half-length; k_m is effective permeability of the porous rock (average $k_w = 0.259$ μm^2 at S_{or}); r_e is external drainage radius (approximately 150 m); and r_w is wellbore radius (0.1 m). Using Eqs. 2 and 3 and data applicable during polymer injection, calculated fracture widths for the six target wells ranged from 1.4 to 5.0 mm. Interestingly, during water injection after polymer injection, these calculations suggested that the fracture widths ranged from 0 to 1.8 mm. Injection pressures were noticeably higher during polymer injection than during the subsequent water injection, so the fractures may have been more open during polymer flooding.

Interwell Polymer Breakthrough. The interwell transit time for a tracer can also be used to assess whether channeling through fractures is important. We estimated the expected transit time, t, for flow through the matrix along the fastest streamline connecting an injection well and a production well. Eq. 4 was used to make this estimate.

$$t \approx L^2\phi(1-S_{or})\mu/(k_m\Delta p). \qquad (4)$$

In this equation, L is the distance between wells (300 m or approximately 1,000 ft); ϕ is formation porosity (0.261); S_{or} is residual-oil saturation (0.28); and Δp is pressure difference between the wells (20 MPa or ≈2,900 psi). For most wells examined, the actual polymer-breakthrough times (6 to 8 months) were reasonably consistent with the times calculated with Eq. 4, assuming flow through matrix (porous rock). However, for the six wells where injectivity/productivity data suggested the presence of fractures, the actual polymer-breakthrough times were noticeably faster than those estimated with Eq. 4. So initially, we viewed this result as confirmation that fractures caused significant channeling between three injector/producer pairs.

If a fracture is dominantly responsible for channeling between two wells, Eq. 5 can be used to estimate the effective permeability of the fracture, and Eq. 6 can convert the effective fracture permeability to an effective average fracture width.

$$k_m \approx L^2\mu/(t\Delta p), \qquad (5)$$

$$w_f(\text{in mm}) = 3.46\times10^{-3}(k_f)^{0.5}, \text{ where } k_f \text{ is in } \mu\text{m}^2. \qquad (6)$$

Applying Eqs. 5 and 6 to our six candidate wells yielded estimates of effective fracture widths of approximately 0.01 mm—far smaller than the 1- to 5-mm values from Eqs. 2 and 3. How can this discrepancy be explained? A credible possibility is that the fractures are significantly wider near the wells than deep within the formation. Calculations based on injectivity/productivity data are dominated by fracture widths near the well, while calculations based on interwell tracer data are dominated by the most restricted part of the fracture (presumably far from the wells).

Are Gel Treatments Needed? We performed a simulation study to consider whether a gel treatment would improve sweep efficiency between an injector/producer pair with a connecting fracture. We assumed (1) the pattern area was 300×300 m, (2) the matrix permeability was uniformly 0.259 μm^2, and (3) a pressure drop, Δp, of 20 MPa was applied between the two wells. Additional details of the simulation can be found in Seright (2005). We focused on the importance of areal locations of gel plugs in reservoirs with fractures.

For a fracture width of 1 mm, the pressure distribution is shown in **Fig. 10.** Because the pressure distribution was symmetrical about the fracture, only half of the pattern is illustrated. (The fracture is located on the front face of Fig. 10 and subsequent similar figures.) **Fig. 11** shows the pressure distribution for the same half-pattern when no fracture connected the wells. For the open-fracture case, the flow rate through the half-pattern was 4.7 times greater than for the no-fracture case. On the positive side, the fracture allowed the pattern to experience much higher injectivity and productivity indices than the no-fracture case. However, on the negative side, most of the injected fluid simply channeled through the fracture. Also on the positive side, higher pressure gradients were distributed more deeply through the pattern for the open-fracture case than for the no-fracture case (compare Figs. 10 and 11). For the open-fracture case, 75% of the pattern experienced a pressure gradient over 34 kPa/m, while for the no-fracture case, only 26% of the pattern experienced a pressure gradient more than

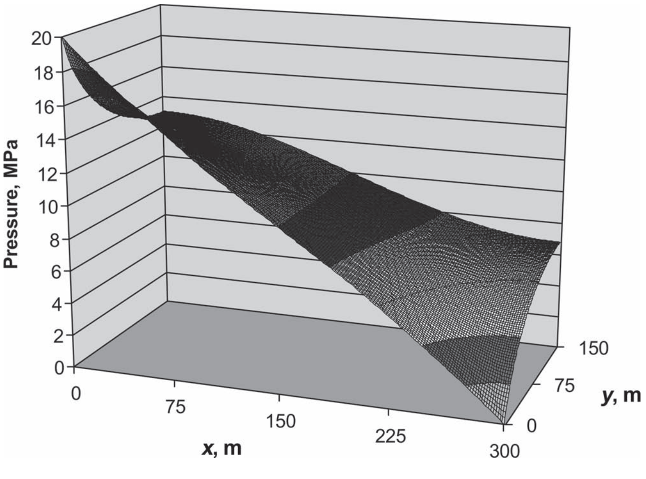

Fig. 10—Pressure distribution with a 1-mm-wide fracture in 0.259-μm^2 rock.

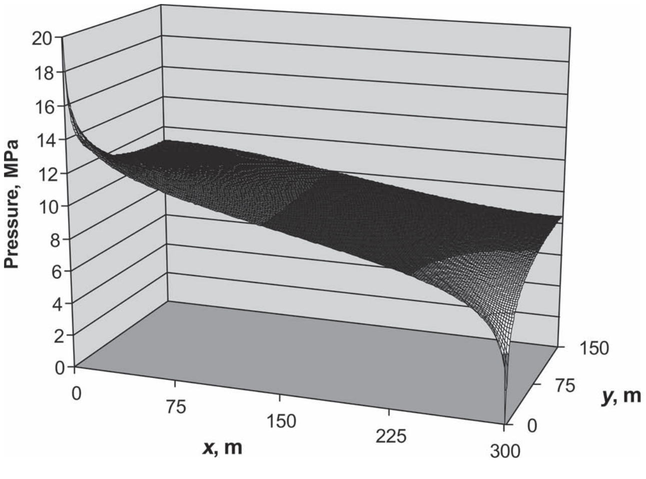

Fig. 11—Pressure distribution with no fracture present.

34 kPa/m. Higher pressure gradients aid in driving oil from deep within the pattern. However, from a practical view, a 20-MPa pressure difference may be difficult to maintain across the pattern when the fracture is fully open. If high flow rates overwhelm the pumps, a lower pressure drop may result—leading to lower pressure gradients throughout the pattern than those indicated in Fig. 10. Incidentally, it may help to view the pressure distributions in Figs. 10 through 12 as "waterfalls" or inclined surfaces that direct drainage of fluid from the pattern. Near-horizontal surfaces indicate poor drainage, while steep surfaces indicate rapid drainage.

The greatest improvement in sweep occurs if the middle portion of the fracture can be plugged while leaving the fracture open near the wells (Seright 2005). This situation allows a high fluid-injectivity index, a high oil-productivity index, and a fairly even sweep of most of the pattern.

For the three injector/producer pairs where we suspected channeling through fractures, the combined results from injectivity/productivity calculations and interwell polymer breakthroughs indicated that fractures were more than 1 mm wide near the wells, but less than 0.02 mm wide far from the wells. Simulations were performed to examine sweep in the pattern with this and similar scenarios. **Fig. 12** shows a representative result. In this case, the simulation assumed the fracture width was 1 mm from the injector to 100 m along the fracture, 0.15 mm for the middle 100 m of the fracture, and 1 mm for the final 100 m to the production well. Sweep efficiency was excellent, while injectivity and productivity indices were high. The pressure-gradient pattern shown in Fig. 12 was virtually identical to those from other simulations where the middle part of the fracture was narrower (or even when the middle fracture width was zero). The pattern in Fig. 12 was also very similar to cases where the near-wellbore parts of the fracture had widths greater than 1 mm.

The results in Fig. 12 and from similar simulations suggest that gel treatments are not needed for the three injector/producer pairs where fractures were present. Because the fractures are narrow far from the wellbore, severe channeling does not occur. On the contrary, the existence of the fractures near the wellbore aids reservoir sweep (compare the no-fracture case in Fig. 11 with Fig. 12). Furthermore, the near-wellbore fractures substantially increase the injectivity index during injection of polymer solutions and increase oil-productivity index in the production wells (i.e., by a factor of 1.8 for the cases illustrated in Figs. 11 and 12).

Mitigating Polymer Degradation

If channeling truly occurred during the applied polymer floods, it is possible that polymer degradation was responsible for sweep efficiency being lower than expected. This section considers the causes of polymer degradation and their mitigation.

Mechanical or Shear Degradation. During preparation and injection, the polymer solution passed through a number of mixers, pumps, valves, filters, and pipes. Flow through this equipment can break polymer chains and decrease solution viscosity to some extent (called shear or mechanical degradation). **Fig. 13** shows viscosity data for samples at different points along the flow stream during polymer injection at Daqing (Zhang 1995). Most viscosity loss occurred from the high-pressure injection pumps and mixing system to the near-wellbore region—amounting to approximately 64% of the total loss. Consistent with other work (Seright 1983), the greatest restriction to flow and the greatest mechanical degradation occurred from entering the porous rock at the high velocities at the injection sandface.

The presence of a fracture in a well can mitigate mechanical degradation (Seright 1983). Fractures provide a dramatic increase in flow area at the injection sandface, thus decreasing the velocity of the polymer solution at this important constriction, and thereby reducing mechanical degradation. As mentioned earlier, the presence of fractures in wells can increase well injectivity and productivity indices significantly. However, if fractures are used for these purposes, care must be taken so that the orientation and length of the fractures are not such that they accentuate channeling (Crawford and Collins 1954, Dyes et al. 1958) or extend out of zone. The analysis presented earlier indicates that fractures in the target Daqing wells satisfy this requirement. Consequently, there may be considerable value in intentionally fracturing (and perhaps propping) injection wells during future chemical-flooding projects at Daqing.

Oxidative Degradation. Fresh water was used to prepare polymer solutions in the Daqing-field projects. This water had a high concentration of dissolved oxygen, and no processing was used to remove it. The presence of dissolved oxygen, free radicals, and/or a redox couple can severely degrade HPAM polymers (Knight 1973, Shupe 1981). Thus, oxidative degradation could be a serious concern. Three observations help to mitigate this concern. First, the reservoir temperature is relatively low (45°C), which should inhibit free-radical generation. Second, oil in the reservoir should combine with oxygen and (it is hoped) eliminate it. Third (and most convincingly), polymer produced from the reservoir was not reduced in molecular weight by more than 50% compared to the injected polymer. If oxidative degradation was important, the polymer should have been degraded to a low molecular weight, and polymer-solution viscosity should have been reduced to that near water (Knight 1973, Shupe 1981). Thus, mechanical degradation (as discussed above) seems a more serious issue for Daqing than oxidative degradation. If future efforts are made to reduce dissolved oxygen in the water, gas stripping is probably a more technically and economically effective method than the use of chemical oxygen scavengers.

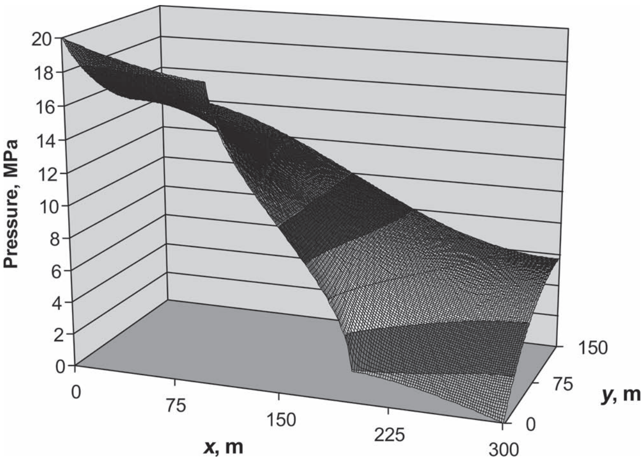

Fig. 12—w_f=1 mm for the first and third 100-m fracture sections; w_f=0.15 mm in second section.

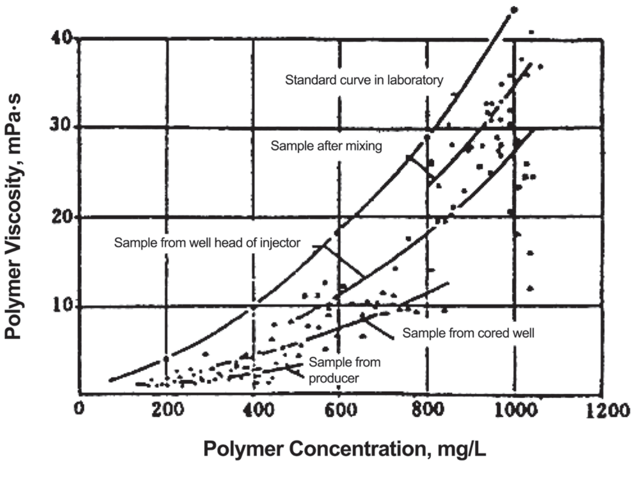

Fig. 13—Polymer-solution viscosities at various points during injection (Zhang et al. 1995).

Microbial Degradation. In concept, microbial attack could also lead to polymer degradation and viscosity loss. However, two factors indicated that microbial degradation was not responsible for the viscosity losses noted at Daqing to date. First, although microorganisms have been known to metabolize the side groups on HPAM and to flocculate with the polymer, degradation of the HPAM backbone has not been proved. Second, evidence of extensive microbial activity at Daqing has not been reported.

Of course, biocides can be used to mitigate concern about microbial degradation. A successful test was performed using a biocide in Shuanhe in the Henan oil field, where the reservoir temperature was 72°C.

More-Viscous Polymer Solutions

Using Higher Polymer Concentrations. Mobility ratios and reservoir sweep can be improved by injecting more-viscous polymer solutions—i.e., solutions with higher polymer concentrations. This basic concept from accepted reservoir-engineering concepts can be confirmed readily using numerical simulation. Given the same volume of injected polymer solution, higher polymer concentrations yield more oil production (OOIP). An added benefit is that the higher polymer concentrations are more tolerant to mechanical degradation (Morris and Jackson 1978). Furthermore, they impart greater solution viscoelasticity, which provides higher oil recoveries and lower residual-oil saturations under Daqing conditions (Wang et al. 2001a).

From the two pilot tests (Yang et al. 2004) at Daqing (specifically, at areas called “West of Center” and “4-4# Station of the Northwest in Lamadian”), the following observations were noted: (1) The water intake profile (i.e., the flow profile during injection) was improved after injecting higher polymer concentrations; (2) during polymer flooding, the period of relatively low water cuts can be prolonged by injecting higher polymer concentrations; and (3) interestingly, the injection of more concentrated polymer solutions (2000 to 2500 mg/L rather than 1000 mg/L) did not result in substantially increased injection pressures (Yang et al. 2004). This result suggests that fractures exist near the wells. If these fractures are extended during injection of the more-viscous polymer solutions, increases in injection pressure will be mitigated. Both pilot tests involving higher polymer concentrations were implemented in the later stages of the main polymer flood. In both cases, the tests were begun after the main response to the polymer flood had occurred and water cut had resumed its rise. (As mentioned above, injection of the more-concentrated polymer alleviated this rise in water cut.) These tests are still under way, so the economic viability of this process change must await further results and be evaluated in light of the chemical costs, oil price, and geographic factors associated with the test site. Another pilot test was initiated in May 2005 in a Daqing pattern that was not previously polymer flooded (Number 1 of the east area of the first area of south). This test may provide the most definitive evaluation of the high-polymer-concentration process. As of April of 2006, approximately 0.1 PV of polymer solution has been injected. Injection pressures are only 1 MPa greater than an adjacent area where the polymer solution with the original (lower) concentration was injected. Current injection pressures are thought to be below the fracture pressure (3 to 4 MPa). The project will continue to be monitored.

New Salinity-Tolerant Polymer. A new salinity-tolerant polymer (Li and Luo 2001, Luo et al. 2002) [called KYPAM™ (Bejing Hengju Chemical Agent Ltd.; 2004; Beijing)] was developed at Daqing that provides higher viscosities in saline waters than those provided by conventional HPAM polymers. This new copolymer incorporates a small fraction of new monomers with acrylamide to form comb-like copolymers. There are currently two varieties of this KYPAM polymer. One has a high molecular weight (20 to 25 million daltons) and uses as the functional group—aromatic hydrocarbon with ethylene (AHPE). At present, we are most interested in the second variety, which has medium (12 to 17 million daltons) or low (3 to 11 million daltons) molecular weight. The medium-molecular-weight copolymer incorporates the monomer, 2-mercaptobenzimidazole, while the low-molecular-weight copolymer contains sulfhydryl (RSO).

Table 3 compares viscosities for the new polymer with conventional HPAM polymers—one with ultrahigh molecular weight (35 million daltons) and one with medium molecular weight (7 to 15 million daltons). Viscosities were measured in waters with two salinities—1000 mg/L and 4000 mg/L. In the more-saline water, the salinity-tolerant polymer provided the highest viscosity, and it experienced a smaller percentage change in viscosity in the two waters.

The above polymers can all be produced at approximately the same cost, so polymer performance is the main criterion of importance. In more-saline waters, the salinity-tolerant polymer will be preferred. For very fresh waters and high-permeability rock, the ultrahigh molecular weight (M_w) polymer will be preferred. In very fresh water and less-permeable rock, the medium-M_w polymer may be most functional.

Using Other New Polymers. A new water-soluble hydrophobic associative polymer [called AP-P4™ (Sichuan Guangya Science and Technology Stock Ltd.; 2005; Nanchong City, China)] was tested in Zhongyuan oil field in central China. On the basis of preliminary results from the pilot, Well W94-4 produced 4.5 tons/day of incremental oil. Water cut declined 4%.

This polymer can be dissolved as rapidly as HPAM—for example, a solution with 5000 mg/L can be prepared in 2 hours if the temperature is greater than 35°C (Li and Luo 2001). Compared to the KYPAM polymer, AP-P4 can provide greater viscosity.

At present, the cost of this new hydrophobic associative polymer is 10% more than HPAM polymers, but it can provide a larger financial internal rate of return. Further laboratory testing is under way to determine if the new hydrophobic associative polymer will provide superior performance to HPAM in the important areas of polymer stability and retention.

Recently, displacement experiments were performed comparing xanthan and HPAM (Yang et al. 2004). For either a given polymer concentration or viscosity level, HPAM solutions provided significantly greater oil-recovery levels under Daqing conditions. This result was believed to occur because HPAM solutions exhibited significantly greater viscoelasticity than xanthan solutions.

Use of Less-Saline Water. HPAM and other anionic polymers are well known to provide much higher viscosities in fresh water than in saline waters. Maitin (1992) demonstrated that low-salinity HPAM solutions can sweep effectively through high salinity reservoirs (i.e., without destructive mixing and salinity increase in the polymer bank) if mobility control is maintained. At Daqing, the lowest water salinity used for polymer mixing contained approximately 300 mg/L total dissolved solids (TDS). However, significant variations in water salinity occur. Water quality varies with the amount of rain, surface temperature, and humidity during the four seasons. Also, the content of Ca^{2+} and Mg^{2+} in the Daqing water is lower in summer and higher in winter.

Can reverse osmosis be applied practically to prepare polymer solutions with less than 200 mg/L TDS at Daqing? This question remains to be investigated. At present, use of available fresh water (approximately 400 mg/L TDS) for polymer mixing costs USD 0.49/m^3 more than the use of produced water (approximately 3000 mg/L TDS). Current thinking at Daqing is directed more toward

TABLE 3—VISCOSITIES FOR SOLUTIONS WITH 1000 mg/L POLYMER, 45°C

Salinity (mg/L)	1000	4000	Ratio, %
Ultrahigh M_w HPAM	82.8 mPa-s	40.3 mPa-s	48.7
Salinity-tolerant polymer with medium M_w	62.2 mPa-s	52.3 mPa-s	84.1
Medium M_w HPAM	38.9 mPa-s	16.8 mPa-s	43.2

the development of polymers that provide the desired viscosities and resistance factors using Daqing produced water.

Other Options

A number of other approaches are (or have been) under investigation, including pattern adjustment (Cheng et al. 2006), colloidal dispersion gels (Chang et al. 2006, Seright et al. 2006), foams (Wang et al. 2006, Zhang and Seright 2007), ASP foams (Wang et al. 2001b), steamflooding (Wang et al. 2006, Shi et al. 2006), steam huff 'n' puff, and microbes (Wang et al. 2006, Wankui et al. 2006). Steam huff 'n' puff and microbe methods have shown promise in lower-permeability areas that are not targets for polymer flooding. With the exception of the colloidal dispersion gels, most of these approaches showed merit. Colloidal dispersion gels (HPAM crosslinked with aluminum citrate) were field tested at Daqing, and claims were made for their success (Chang et al. 2006). However, analyses of laboratory and field results raise doubts about the viability of colloidal dispersion gels (Seright et al. 2006, Seright 2007). Careful analysis of the Daqing-field data presented in Chang et al. (2006) and additional unpublished data associated with the project indicates no significant difference between the colloidal dispersion gel (CDG) flood and the normal polymer flood (Seright et al. 2006). Injectivity behavior was not significantly different for the two cases (Seright et al. 2006). Also, water/oil ratios and production trends cannot be credibly distinguished for the two processes. The analysis suggested that the aluminum was either removed (by adsorption or precipitation) or was present in concentrations too low to allow crosslinking.

Steam- or *in-situ*-combustion methods present interesting possibilities for application at Daqing after polymerflooding. Because these processes may destroy polymer in the reservoir, they might overcome the mobility problem that confronts ASP flooding after polymer flooding. Of course, efficient reservoir sweep is also an important issue for thermal-recovery processes. Implementation of a thermal recovery process may require reconfiguring the well pattern (e.g., from 5-spot to 9-spot).

Microbial EOR (MEOR) also raises interesting possibilities for application after polymerflooding. In concept, microbes might be engineered to either (1) degrade the polymer bank ahead of it or (2) grow and sweep the reservoir in a manner that is different from conventional chemical flooding. Of course, the traditional challenges associated with MEOR are (1) identifying microbial systems that will fulfill the difficult and unique requirements and (2) controlling the process adequately during field applications.

Conclusions

Sweep improvement in the Daquing oil field was considered using various approaches. Given that the reservoir-description and polymer input data were correct, the polymerflood should have provided excellent sweep throughout the majority of the Daqing patterns under consideration. If ASP flooding is applied to increase recovery efficiency, mobility control and sweep improvement will be especially important and challenging during implementation.

In a number of Daqing wells (both injectors and producers), fractures were present. These fractures were narrow far from the wellbore, so channeling was not significant. On the contrary, near-wellbore fractures aided reservoir sweep. They substantially increased the injectivity index during the injection of polymer solutions and increased oil-productivity index in the production wells. Near-wellbore fractures with the proper length, orientation, and width may play a crucial role during future floods if very viscous chemical (i.e., ASP) banks must be injected to maintain mobility control. Appropriate use of near-wellbore fractures may also mitigate mechanical degradation.

Cost-effective improvements at Daqing may be realized using one or more new polymers. ASP foams, steam, and microbes showed positive indications during field tests. Analyses of laboratory and field results raise doubts about the viability of colloidal dispersion gels. Additional work may be warranted concerning the potential of foams and polymer solutions prepared with reduced salinity.

Nomenclature

h = formation height, m
h_f = fracture height, m
k = permeability, μm^2
k_f = fracture permeability, μm^2
k_m = permeability of matrix or porous rock, μm^2
k_{ro} = relative permeability to oil, μm^2
k_{rw} = relative permeability to water, μm^2
L = distance between wells, m
L_f = fracture half-length, m
PV = pore volumes of fluid injected
q = flow rate, m^3/d
r_e = external drainage radius, m
r_w = wellbore radius, m
S_{or} = residual-oil saturation
t = breakthrough time, days
w_f = fracture width, mm
Δp = pressure drop, Pa
$\Delta p/\Delta l$ = pressure gradient, psi/ft [Pa/m]
μ = viscosity, mPa·s
ϕ = porosity

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SI Metric Conversion Factors

cp × 1.0* E-03 = Pa·s
°F (°F−32)/1.8 = °C
ft × 3.048* E-01 = m
ft^3 × 2.831 685 E–02 = m^3
in. × 2.54* E+00 = cm
md × 9.869 233 E-04 = μm^2
psi × 6.894 757 E+00 = kPa

*Conversion factor is exact.

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