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Key Aspects of Project Design for Polymer Flooding

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Abstract
After a pilot site meets the screening qualifications for polymer flooding, the injection measures and the injection formula are key points when designing a polymer flood. This paper places special emphasis on some new design factors that were found to be important during extensive experience during polymer flooding. These factors include (1) recognizing when profile modification is needed before polymer injection and when zone isolation is of value during polymer injection, (2) establishing the optimum polymer formulations, injection rates, and individual well production allocations, and (3) time-dependent variation of the molecular weight of the polymer used in the injected slugs.

At Daqing, polymers with molecular weights from 12 to 38 million Daltons were designed and supplied to meet the requirements for different reservoir geological conditions. The optimum polymer injection volume varied around 0.7 pore volume (PV),[1] depending on the water cut in the different flooding units. The average polymer concentration was designed about 1,000 mg/L, but for an individual injection station, it could be much more.[2,3] The injection rate should be less than 0.2 PV/yr, depending on well spacing. Additionally, the project design should follow certain rules when allocating the injection rate and production rate for individual wells.

Introduction
Many elements have long been recognized as important during the design of a polymer flood.[4-12] This paper spells out some of those elements using examples from the Daqing oilfield. Critical reservoir factors that traditionally receive consideration are the reservoir lithology, stratigraphy, important heterogeneities (such as fractures), distribution of remaining oil, well pattern, and well distance. Critical polymer properties include cost-effectiveness (e.g., cost per unit of viscosity), resistance to degradation (mechanical or shear, oxidative, thermal, microbial), tolerance of reservoir salinity and hardness, retention by rock, inaccessible pore volume, permeability dependence of performance, rheology, and compatibility with other chemicals that might be used. Issues long recognized as important for polymer bank design include bank size (volume), polymer concentration and salinity (affecting bank viscosity and mobility), and whether (and how) to grade polymer concentrations in the chase water.

At the end of 2006, oil production from polymer flooding at the Daqing Oilfield was more than 10 million tons (63 million barrels) per year (sustained for 5 years). This paper describes the design procedures that led to favorable incremental oil production and reduced water production during 12 years of successful polymer flooding in the Daqing Oil Field.

1 Zone Management before Polymer Flooding
1.1 Profile Modification before Polymer Injection
Under some circumstances, use of gel treatments or other types of "profile modification" methods may be of value before implementation of a polymer or chemical flood.[13] If fractures cause severe channeling, gel treatments can greatly enhance reservoir sweep if applied before injection of large volumes of expensive polymer or surfactant formulations.[14] Also, if one or more high permeability stratum are watered out, there may be considerable value in applying profile modification methods before starting the EOR project.

For some Daqing wells with layers with no crossflow, numerical simulation demonstrated that oil recovery can be enhanced 2-4 % original oil in place (OOIP) with profile modification before polymer injection.[15] (10-12% OOIP was the typical EOR due to polymer flooding alone.) As expected, the benefits from profile modification decrease if it is implemented toward the middle or end of polymer injection.

Based on field experience with profile modification at Daqing, the following basic principles were observed:

1.1.1 Wells that are candidates for profile modification
① The pressure at the start of polymer injection is lower than the average level for injectors in the site.[16]

② The pressure injection index, *PI*, is less than the average value in the pilot site.[17] *PI*, is defined by Eq. 1.

$$PI = \frac{1}{t}\int_0^t p(t)dt \quad \text{...}(1)$$

p(t) is the well pressure after the injector is shut in for time *t*.

③ Injection pressures are less than the average level and the water cut at the offset production wells are larger than the average level.

1.1.2 Layers that are candidates for profile modification

① Choose layers that show good lateral connectivity between wells, that have high permeability differential from adjacent layers, that have high permeability and thick net pay, and that exhibit effective permeability barriers between adjacent zones. (Here, permability differential is defined as permeability of the high permeability zone divided by the permeability of the low permeability zone.)

② Choose layers with a high water cut, high water saturation, or appear watered-out.

③Choose layers with a large difference in water intake from other layers. (Water intake index = injection rate divided by Δp times net pay of the injectors.[16])

1.2 Separate Layer Injection

If crossflow can occur between adjacent strata, sweep in the less permeable zones can be almost as great as that in the high permeability zones if the mobility ratio times the permeability differential is less than unity.[18] However, if no crossflow occurs between strata, sweep in the less permeable zone will be no better than approximately the square root of the reciprocal of the permeability differential.[18]

At Daqing, a means was devised to improve this sweep problem when crossflow does not occur. Based on theoretical studies and practical results from Daqing pilot tests,[19,20] separate layer injection was found to improve flow profiles, reservoir sweep efficiency, and injection rates, and can reduce the water cut in production wells. Numerical simulation studies reveal that the efficiency of polymer flooding depends importantly on the permeability differential between layers and when separate layer injection occurs.

An example based on numerical simulation is provided in Table 1, where the permeability differential was 2.5 and flooding occurred until 98% water cut was reached. In this case, the incremental recovery using layer separation was 2.04% more than the case with no layer separation.

Table 1—Effect of separate layer injection.

Injection method	Layer	D_{znet}, m	k_{eff}, 10^{-3} μm^2	Water cut, %	OOIP, %
Separated	Lower	5	400	98	53.36
	Higher	5	1000	98	53.34
	Combined	**10**	**700**	**98**	**53.35**
Not separated	Lower	5	400	94	45.33
	Higher	5	1000	99.6	57.29
	Combined	**10**	**700**	**98**	**51.31**

Fig. 1 shows ultimate recovery results for various conditions when the injection rate was held constant in different layers (i.e., the same injection rate per unit of net pay occurred in all layers). In this figure, the final polymer slug had a polymer concentration-volume product (i.e., a polymer mass) of 600 mg/L•PV.[19] The *x*-axis plots the delay (expressed in mg/L•PV) between the start of initial polymer injection (with no separation of injection) and when separate layer injection was initiated. The figure shows that separate layer injection did not affect ultimate oil recovery if the polymer mass at the time of layer separation was less than 200 mg/L•PV. However, above this value, the total effectiveness decreased with delay of the start of separate injection. Increased vertical heterogeneity accentuated this effect.

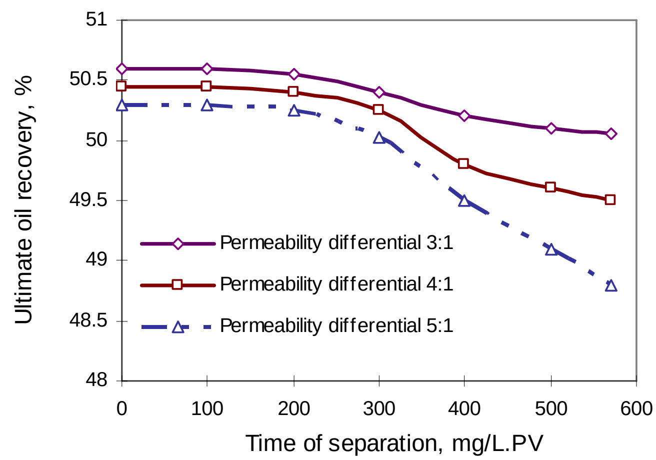

Fig. 1—Effect on ultimate recovery of time at which separate layer injection is initiated. Constant total rate.

Results from both theoretical studies and practical pilot tests indicate that separate layer injection should be implemented before the polymer concentration-volume-product (mass) is 200 mg/L•PV if this technology can be implemented in the sites.[21] For those wells where injection can not be separated because of technical or other reasons, flow profiles should be controlled as well as practical, and separate layer injection should be implemented when it becomes feasible.

Our theoretical studies and pilot tests revealed that the conditions which favor separate layer injection at Daqing include:[19]

①The permeability differential between oil zones ≥ 2.5;

②The net pay for the lower permeability oil zones should account for at least 30% of the total net pay;

③Layers should be separated by at least one meter and should show consistent lateral continuity between wells.

2 Optimization of the Polymer Injection Formula

Important factors to optimize when formulating the polymer bank include (1) polymer solution viscosity, (2) polymer molecular weight, (3) polymer concentration, (4) polymer volume, and (5) injection rate.

2.1 Polymer Solution Viscosity

The polymer solution viscosity is a key parameter to improve the mobility ratio between oil and water and adjust the water intake profile. As injection viscosity increases, the effectiveness of polymer flooding increases. The viscosity can be affected by a number of factors. First, for a given set of conditions, solution viscosity increases with increased polymer molecular weight. Second, increased polymer concentration leads to higher viscosity, and increased sweep efficiency. Third, as the degree of HPAM hydrolysis increases up to a certain value, viscosity increases. Fourth, as temperature increases, solution viscosity decreases. Polymer degradation can also decrease viscosity. Fifth, increased salinity and hardness in the reservoir water also decreases solution viscosity for anionic polymers.

The effectiveness of a polymer flood is directly determined by the magnitude of the polymer viscosity. The viscosity depends on the quality of the water used for dilution. A change in water quantity directly affects the polymer solution viscosity. At Daqing, the water quantity changes with the rainfall, ground temperature and humidity during the seasons. The concentrations of Ca^{2+} and Mg^{2+} in the water source are lower in summer and higher in winter. Consequently, the polymer viscosity is also relatively higher in summer and lower in winter.

Using a medium Mw HPAM polymer, the injection polymer concentration and solution viscosity can be adjusted according to Fig. 2. These curves were used during project design for the pilot site in the center of Saertu at Daqing. The curves were valuable in adjusting polymer concentrations to respond to changes in water quality (salinity). In this application, for a medium Mw polymer (12 to 16 million Daltons), 40 mPa•s was recommended. This viscosity level was sufficient to overcome (1) the unfavorable mobility ratio (i.e., 9.4) and (2) permeability differential up to 4:1.

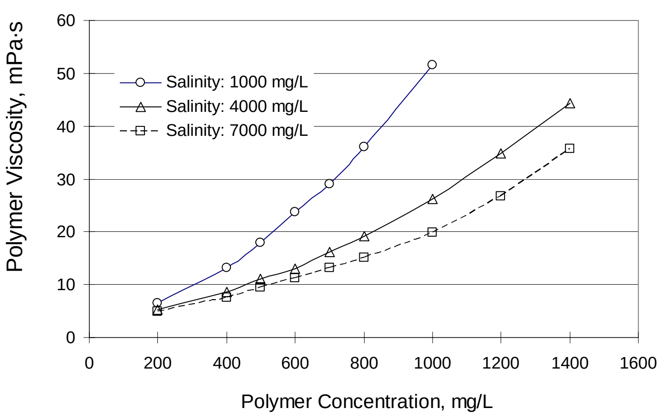

Fig. 2—Viscosity versus concentration for different salinities with medium Mw (15 million Daltons) polymer.[20]

For a high Mw polymer (17-25 million Daltons) or extra high Mw polymer (25 to 38 million Daltons), 50 mPa•s viscosity could be provided cost-effectively. For new polymers that provide special fluid properties, additional laboratory investigations are needed before implementation in a polymer flood.

2.2 Polymer Molecular Weight

The effectiveness of a polymer flood is affected significantly by the polymer Mw. As illustrated in Fig. 3, polymers with higher Mw provide greater viscosity. For many circumstances, larger polymer Mw also leads to improved oil recovery. Coreflood simulation (Table 2) verifies this expectation for cases of constant polymer slug volume and concentration.

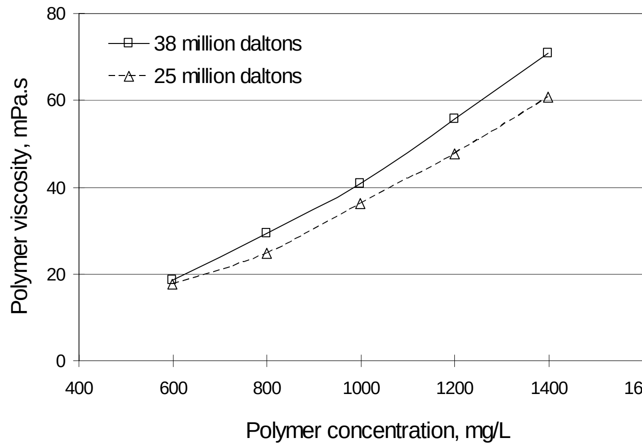

Fig. 3—Viscosity versus concentration and Mw for polymers used in the central part of Xing4-5[22]

Table 2—Effect of polymer molecular weight (Mw) on EOR.

Mw, 10^6 daltons	Waterflood recovery, %	Polymer flood EOR, %	Ultimate recovery, %
5.5	32.7	10.6	43.3
11	32.9	17.9	51.8
18.6	32.2	22.6	54.8

Total injected polymer mass: 570 mg/L•PV. Polymer concentration: 1,000 mg/L. 3 zones. Heterogeneity: V_k=0.72.

Our laboratory tests with a fixed volume of polymer solution injected confirmed that oil recovery increases with increased polymer Mw.[2] The reason is simply that for a given polymer concentration, solution viscosity and sweep efficiency increase with increased polymer Mw. Stated another way, to recover a given volume of oil, less polymer is needed using a high Mw polymer than a low Mw polymer.

The above argument must be tempered because the levels of mobility and permeability reduction (i.e., the resistance factor and residual resistance factor) for polymer with a given Mw can increase with decreasing permeability.[6] This effect is accentuated as Mw increases. Mechanical entrapment can significantly retard polymer propagation if the pore throat size and permeability are too small. Thus, depending on Mw and permeability differential, this effect can reduce sweep efficiency.[18] A trade-off must be made in choosing the highest Mw polymer that will not exhibit pore plugging or significant mechanical entrapment in the less permeable zones.

Two factors should be considered when choosing the polymer molecular weight. First, choose the polymer with the highest Mw practical to minimize the polymer volume. Second, the Mw must be small enough so that the polymer can enter and propagate effectively through the reservoir rock. For a given rock permeability and pore throat size, a threshold Mw exists, above which polymers exhibit difficulty in propagation.

Based on lab results and practical experience at Daqing, the medium polymer molecular weight (12-16 million Daltons) is applicable for oil zones with average permeability greater than 0.1 μm^2 and net pay greater than 1 m. The high polymer molecular weight (17-25 million Daltons) is appropriate for oil zones with average permeability greater than 0.4 μm^2. Table 3 shows recovery results for various combinations of polymer Mw and core permeability. Table 4 lists resistance factors (F_r) and residual resistance factors (F_{rr}) for different combinations of polymer Mw and core permeability.

Table 3—Effectiveness for different Mw and k_{water}.

k_{water}, 10^{-3} μm^2	Waterflood recovery, % OOIP	Ultimate Recovery % OOIP	Polymer EOR, % OOIP	Mw, 10^6 Daltons
330.3	50.46	72.48	22.02*	38
333.3	50.00	68.86	18.86	25
364.3	59.26	67.38	8.12	
456.8	58.89	67.54	8.65	15
327.0	61.29	68.85	7.56	
96.9	56.73	63.63	6.90	8
85.85	57.87	64.61	6.74	
46.9	44.25	48.62	4.37	5.5
51.96	48.44	52.96	4.52	
9.11	43.21	46.91	3.70	2.4
16.63	41.39	45.26	3.87	

* Polymer mass = 500 mg/L•PV for this case.
Polymer mass = 570 mg/L•PV for the other cases.

Table 4—F_r and F_{rr} for different k_{air} and Mw.

Mw, 10^6 daltons	k_{air}, μm^2	F_r	F_{rr}	Note
	0.498	8.5	3.2	
15	0.235	10.1	4.1	
	0.239	7.75	5.0	block polymer
25−30	1.000	27	4.7	
38	1.500	53	3.6	

Economics and injectivity behavior can favor changing the polymer molecular weight during the course of injecting the polymer slug. This point can be appreciated from Table 5, which considers six cases where a bank of high Mw (17.9 million Daltons) HPAM polymer was injected before switching to a bank of medium Mw (12 million Daltons) HPAM polymer. In this simulation example, the total polymer concentration (1,000 mg/L) and bank size (570 mg/L•PV) were maintained constant. The first column of Table 1 lists the percentage of the total bank that involved injection of the high Mw polymer, while the second column lists the total enhanced oil recovery (EOR) from the polymer flood. The last column lists the incremental EOR, compared with using only the medium Mw polymer.

Table 5—Injecting 17.9 million Dalton polymer before 12 million Dalton polymer[3]

High Mw proportion, %	EOR, % OOIP	Incremental EOR, % OOIP
0	20.7	0
10	21.6	0.9
20	22.7	2.0
33	23.6	2.9
50	23.6	2.0
100	23.7	3.0

Total injection polymer mass: 570 mg/L•PV. Polymer concentration: 1,000 mg/L. 3 zones. Heterogeneity: V_k=0.72.

In Table 5, the enhanced oil recovery from injection of only the higher Mw polymer was 3.0% OOIP greater than that from injection of only the medium Mw polymer (12 million Daltons). Most of the benefit (i.e., 2%) was achieved if only 20% of the bank had the high Mw polymer. Increasing the high Mw polymer fraction in the bank provided little additional increase in oil recovery. If injectivity is lower and cost is higher for the high Mw polymer than for the lower Mw polymer, a significant benefit can be achieved by changing (i.e., decreasing) the polymer Mw during injection of the polymer slug. For the particular example here, the high Mw polymer costs 1.1 to 1.3 times more than the medium Mw polymer. For the same polymer concentration, injectivity for the high Mw polymer was 70% of that for the medium Mw polymer.

2.3 Polymer Solution Concentration

Polymer concentration determines the polymer solution viscosity and the size of the required polymer solution slug. The polymer solution concentration dominates every index that changes during the course of polymer flooding.

①Higher injection concentrations cause greater reductions in water cut and can shorten the time required for polymer flooding. For a certain range, they can also lead to an earlier response time in the production wells, a faster decrease in water cut, a greater decrease in water cut, less required pore volumes of polymer, and less required volume of water injected during the overall period of polymer flooding. Table 6 shows the effectiveness of polymer flooding as a function of polymer concentration when the injected polymer mass is 640 mg/L•PV. As polymer concentration increases, enhanced oil recovery increases and the minimum in water cut during polymer flooding decreases.

② Above a certain value, the injected polymer concentration has little effect on the efficiency of polymer flooding. For a pilot project, the economics of injecting higher polymer concentrations should be considered. The polymer solution concentration has a large effect on the change in water cut. However, consideration should also be given to the fact that higher concentrations will cause higher injection pressures and lower injectivity. Considering the technical feasibility and conditions at Daqing, the average injection polymer concentration ranges from 1,000 mg/L to 1,400 mg/L for our projects. For individual wells, the concentration can be adjusted to meet particular conditions.

Table 6—Ultimate recovery and EOR versus polymer concentration. Values noted at polymer mass = 640 mg/L•PV.

Polymer, mg/L	Minimum water cut, %	Ultimate recovery, %	EOR, %
600	87.1	50.58	7.69
800	85.0	52.52	9.64
1,000	83.1	52.83	9.95
1,200	82.4	52.89	10.01
1,500	81.0	53.03	10.15

③Additional steps can increase effectiveness when using slugs with higher polymer concentrations. First, effectiveness can be improved by injecting polymer solutions with higher concentrations during the initial period of polymer flooding. The increase in effectiveness comes from the wells or the units that experienced in-depth vertical sweep improvement during the early stages of polymer flooding. Second, the increase in water cut during the third stage of polymer flooding (i.e., after the minimum in water cut) can be controlled effectively using injection of higher polymer concentrations. Based on the pilot test at the Western of Central Area and the 1-4# station in the Beixi of Lamadian in the Daqing field, the water intake profile became much more uniform after injecting 2,200 to 2,500 mg/L polymer solution in 2004.[23]

Polymer retention also plays an important role in determining the appropriate polymer concentration. Sufficient polymer must be injected to allow the polymer to propagate most of the way through the reservoir. Laboratory measurements using Daqing core material revealed retention values of 126 μg/g for a 15 million Dalton HPAM and 155 μg/g for a 25 million Dalton HPAM. Calculations suggest that injection of 1 PV of 1,000 mg/L polymer solution would experience 65% depletion by retention for the 15 million Dalton polymer and 80% depletion for the 25 million Dalton polymer.

2.4 Polymer Volume

An important mechanism of polymer flooding is to improve the mobility between oil and water and to increase the swept volume. Based on theory,[24,25] oil recovery efficiency decreases with increased mobility of the injectant. Consequently to avoid fingering, a continuous polymer flood could be used instead of a water flood. However, because polymer solutions are more expensive than water, economics limit the volume of polymer that should be injected.

For the first polymer pilot tests at Daqing, the polymer volume-concentration product (mass) was designed from 240 to 380 mg/L•PV. Later, the polymer mass was increased to 570 mg/L•PV. At present, the polymer mass is 640 mg/L•PV to 700 mg/L•PV in the large scale industrial sites.

Based on our theoretical research and practical experiences, the polymer volume should be determined by the gross water cut of the flooding unit. Generally, when the gross water cut achieves 92%-94%, the polymer injection should be stopped.

Based on statistics from the 1-4# station of the Eastern Lamadian part of the Daqing field, the rate of increase in the water cut is about the same during the last part of the polymer flood as it is during the follow-up water drive. Generally at Daqing, polymer injection is switched to water drive when the water cut reaches 92% to 94%.

Based on our observations of the response to polymer flooding, we characterize the entire polymer flooding process in four stages:[26,27]

(1) The initial stage (the response stage) where a decrease in water cut can be seen.

(2) The period where the water cut change is relatively stable. The minimum water cut was observed during this period.

(3) The stage where water cut again rises rapidly.

(4) The stage of the follow-up water drive.

Based on numerical simulation, ultimate oil recovery becomes less sensitive to bank size as the polymer mass increases to high values. Of course, increased polymer mass enhances the oil recovery (middle column of Table 7). However, the extent of the incremental oil recovery (defined in the right column of Table 7) decreases with increased polymer mass. Consequentally, there is an economic optimum in the polymer bank size.

Table 7—Incremental recovery versus polymer mass[20]

Polymer mass, mg/L•PV	Ultimate recovery, %	Incremental extent of recovery, % / mg/L·PV
570	50.74	
665	51.24	0.0147
760	53.26	0.0118
855	54.28	0.0107
950	55.10	0.0086

For large polymer banks, polymer was produced from wells after the water cut increased back up to 92%. So, more extended injection of polymer hurts income and economics because the produced polymer is effectively wasted.

Fig. 4 plots the incremental oil (expressed per ton of polymer injected). Based on our economic evaluation, optimum effectiveness can be obtained if a suitable time to end polymer injection is chosen, followed by a water-injection stage. For Daqing, the optimum polymer mass ranged from 640 mg/L•PV to 700 mg/L•PV. Projects at Daqing were profitable within this range, for the oil prices experienced over the past 12 years.

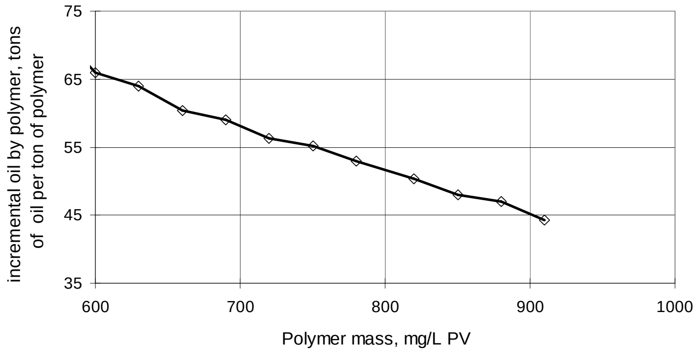

Fig. 4—Incremental oil versus polymer mass.[28]

To better understand the origin of this optimum, consider the following two points (trade-offs). First, field data (Table 8) revealed that the rate of increase in water cut (defined in the right column of Table 8) was notably less for polymer masses of 640 mg/L•PV or greater than for those less than 640 mg/L•PV.

Table 8—Rate of water cut increase for the center wells in the south of Lamadian.[28]

Well pattern	Polymer mass, mg/L·PV	Rate of water cut increase, %/（mg/L·PV）
6-P3435	460	0.0651
6-P3555	524	0.1004
5-P3515	640	0.0438
5-P3425	681	0.0523

Second, numerical simulation and our economic evaluation revealed that when income from the polymer project matched the investment (i.e., the "break-even point"), the incremental oil was 55 tons of oil per ton of polymer [when the oil price was 1280 Chinese Yuan per metric ton or about 25.5 US$/bbl, and the polymer mass was 750 mg/L•PV (See Fig. 4)]. Of course, the optimum polymer mass depends on oil price. With the current high oil prices, greater polymer masses could be attractive.

2.5 Injection Rate

The polymer solution injection rate is another key factor in the project design. It determines the oil production rates. Table 9 shows the effect of injection rate on the effectiveness of polymer flooding. It shows that the magnitude of the injection rate has little effect on the final recovery. It also has a minor effect on the fraction of the injected polymer mass that is ultimately produced (fourth column of Table 9). However, the injection rate has a significant effect on the cumulative production time. Lower injection rates lead to longer production times. So when we program the design, the injection rate shouldn't be too small.

Fig. 5 shows how reservoir pressure changes with the injection rate after the completion of polymer injection. As expected, the average reservoir pressure near the injectors increases as the injection rate increases while decreasing near production wells. Also, higher injection rates cause a larger disparity between injection and production. Injection rates must be controlled (i.e., not too high) to minimize polymer flow out of the pattern or out of the target zones.

Table 9—Effect of injection rate on polymer flooding

Inj. rate PV/yr	Ultimate recovery %	EOR %	Polymer prod./inj. %	Prod. time, years	Inj. PV
0.08	51.51	12.32	48.36	9.54	0.763
0.10	51.36	12.17	48.46	7.62	0.762
0.12	51.22	12.03	48.57	6.34	0.761
0.14	51.07	11.88	48.68	5.43	0.760
0.16	50.94	11.78	48.81	4.75	0.760
0.18	50.81	11.62	48.93	4.22	0.760
0.20	50.68	11.49	49.06	3.79	0.758

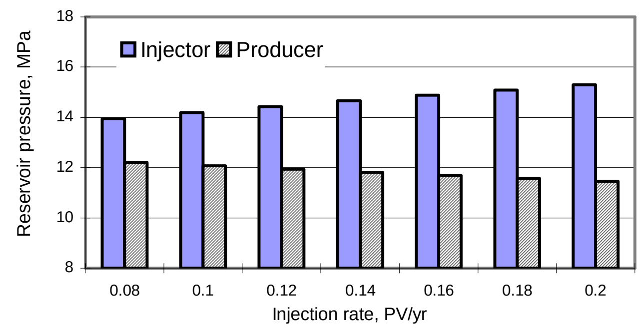

Fig. 5—Injection rate vs reservoir pressure.

Changes in the behavior of gross water cut with time depend on the injection rate too (Fig. 6). Lower injection rates lead to slower increases in water cut and delays the time when lowest water cut begins to increase. As a result, the stable period with lower water cut is extended.

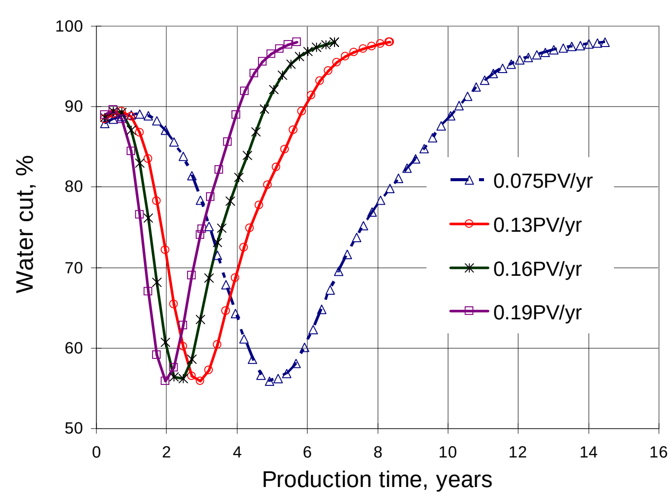

Fig. 6—Water Cut Changes for Different Injection Rates

The injection rate determines the time period when oil can be recovered economically. Fig. 7 shows how injection rates affect the oil production rate. It also demonstrates how the term of economic production varies injection rate. To maximize the term of oil production and maximize ultimate production, the injection rate at Daqing should be maintained under 0.16 PV/yr with 250 m well spacing.

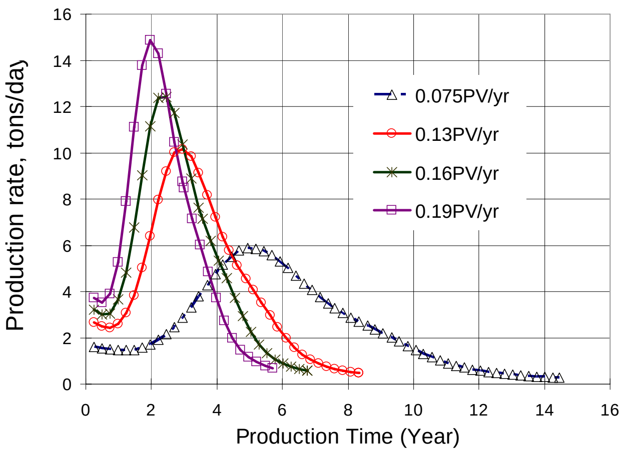

Fig. 7—Changes in oil production rate vs injection rate.

In summary, the injection rate affects the whole development and effectiveness of polymer flooding. Equation 2 can be used to relate the highest pressure at the injection well head and the average individual injection rate with the polymer injection rate and the average apparent water intake index for different reservoir conditions. In general, the injection rate shouldn't exceed the reservoir fracture pressure.

$p_{max} = l^2 \phi q \ (180 \ N_{min})$..(2)

p_{max}—highest wellhead pressure, MPa.
l—distance between injector and producer, m
ϕ—porosity, %
N_{min} —lowest apparent water intake index, m^3/d•m•MPa
q —injection rate, PV/yr

For the best results at Daqing, the polymer injection rate should be designed from 0.14 PV/yr to 0.16 PV/yr for 250 m well spacing, and 0.16 PV/yr to 0.20 PV/yr for 150 m to 175 m well spacing.

3 Individual Production and Injection Rate Allocation

Injection and production rates in every flooded unit should be properly balanced to achieve optimum sweep. For a polymer flood, this process requires special attention to injection rates and polymer concentrations for individual wells. The following principles be applied for allocations of production rate and injection rate for individual wells.[20]

①For those central wells with high mobile oil saturations, proper balancing of injection and production is needed, often involving an increase in injection rates, to ensure that the timing of oil production coincides with that of other patterns.

②For wells near a fault, the injection rate and polymer concentration should often be lower than average designed, especially if the injection pressure is higher than average.

③For some wells, the reservoir properties may not be favorable. For example, water saturations are too high near line drive wells associated with the first waterflood pattern at Daqing. Also, oil zones are thin and permeabilities are low in areas where sediments were deposited by an ancient river. Low permeabilities are also associated with other depositional features.

④For wells with lower injection pressure, higher water throughput, a heterogeneous water intake profile, or areas known for channeling, profile modification should be applied before polymer injection.

⑤ Injection and production rates should be balanced throughout the project area.

4 Conclusions

Based on over 12 years of experience at the Daqing Oil Field, we identified key aspects of project design for polymer flooding.

1. For some Daqing wells, oil recovery can be enhanced 2-4 % original oil in place (OOIP) with profile modification before polymer injection.
2. For some Daqing wells with significant permeability differential between layers and no crossflow, injecting polymer solutions separately into different layers improved flow profiles, reservoir sweep efficiency, and injection rates, and reduced the water cut in production wells.
3. Experience over time revealed that larger polymer bank sizes are preferred. Bank sizes grew from 240-380 mg/L•PV during the initial pilots to 640-700 mg/L•PV in the most recent large scale industrial sites.
4. Economics and injectivity behavior can favor changing the polymer molecular weight and polymer concentration during the course of injecting the polymer slug. Polymers with molecular weights from 12 to 38 million Daltons were designed and supplied to meet the requirements for different reservoir geological conditions. The optimum polymer injection volume varied around 0.7 PV, depending on the water cut in the different flooding units. The average polymer concentration was designed about 1,000 mg/L, but for an individual injection station, it could be 2,000 mg/L or more.
5. At Daqing, the injection rates should be less than 0.14-0.20 PV/yr, depending on well spacing. Additionally, the project design should follow certain rules when allocating the injection rate and production rate for individual wells.

Nomenclature

D_{znet} = net zone height, m
F_r = resistance factor
F_{rr} = residual resistance factor (permeability before/after polymer placement)
k_{air} = permeability to air, μm^2
k_{eff} = effective permeability, μm^2
k_{water} = permeability to water, μm^2

l = distance between injector and producer, m
M_w = molecular weight, Daltons
N_{min} = lowest apparent water intake index, m3/d•m•MPa
p = pressure, MPa
PI = Pressure index for an injector, MPa
p_{max} = highest wellhead pressure, MPa
PV = pore volumes
Δp = pressure difference from wellbore to formation, MPa
q = injection rate, PV/yr
t =time, min
V_k = Dystra-Parsons coefficient of permeability variation
ϕ = porosity

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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

*Conversion is exact.