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Advances in Polymer Flooding and Alkaline/Surfactant/Polymer Processes as Developed and Applied in the People's Republic of China

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Abstract

Polymer flooding (PF) and alkaline/surfactant/polymer (ASP) flooding have been applied throughout the world for more than 20 years. However, few large-scale successes with these processes have been reported, except in China. To date, the PF process has been applied successfully in several major Chinese oil fields such as Daqing and Shengli. PF alone contributed approximately 250,000 BOPD of production in 2004 from these two fields. Incremental oil recoveries of up to 14% of the original oil in place (OOIP) have been obtained in good-quality reservoirs.

Profile modifications by use of polymers and a crosslinker to form colloidal-dispersion gels (CDGs) also have been implemented successfully in large-scale production operations in China. Results show that the CDG process is more cost-effective than the PF process.

Several ASP floods also have been pilot tested in various Chinese oil fields. Incremental recoveries of up to 25% OOIP have been reported, although commercial-scale applications have not been implemented. Plans to implement three large-scale projects have been made for 2006 in the Daqing oil field. This paper discusses the progress made in these processes in China over the last 20 years, including field results, new concepts, and economics.

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Facts 2004	
Total Development	31 blocks
Total Area	67,759 acres
OOIP	3.62 billion bbl
Total Wells	5,343
Injection Wells	2,427
Producing Wells	2,916
Cum. Polymer Injected	1.1 billion lbm
Cum. Production	525 million bbl
Cum. Incremental	322 million bbl
Annual Polymer Injection	190.3 million lbm
Annual Production	73.5 million bbl

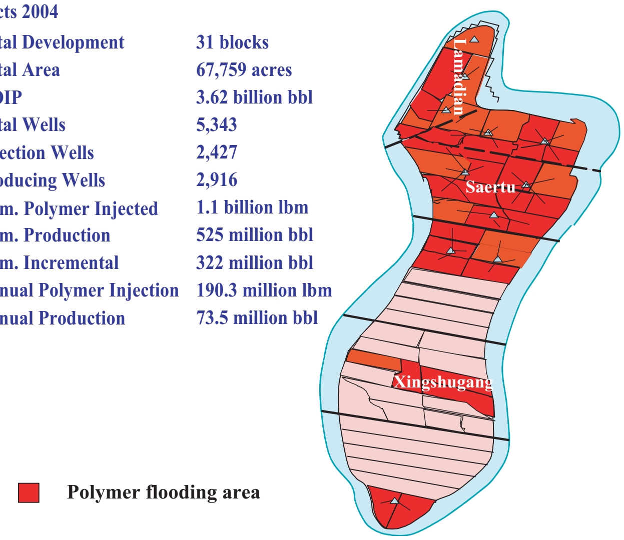

Fig. 1—Areas with polymer flooding in Daqing oil field.

Introduction

The PF concept in the U.S. has been to use a small slug at low polymer concentrations. The amount of polymer used is measured with a combination unit calculated by multiplying the concentration in parts per million (ppm) by the slug size in pore volume (V_p). The 1976 U.S. Natl. Petroleum Council (NPC) study used 125 ppm·V_p. The amount of polymer used in the 1984 NPC study was increased to 240 ppm·V_p, but it was still much less than that used in China. NPC projected incremental recoveries were in the range of 6 to 8% OOIP in successful projects,[1] approximately 50% of that obtained in good-quality reservoirs in the Daqing oil field.

Seven PF pilot tests were conducted in the Daqing oil field from 1972 through 1998. Continued research and field testing led to fieldwide expansion in 1996. There were 31 commercial-scale PF projects in Daqing in 2004, with 2,427 injection wells and 2,916 production wells. Currently, PF is implemented in a total area of 67,759 acres, as shown in **Fig. 1.** Oil production from PF has been maintained since 1999. The production reached 73.5 million bbl in 2004, approximately 23% of the total field production.

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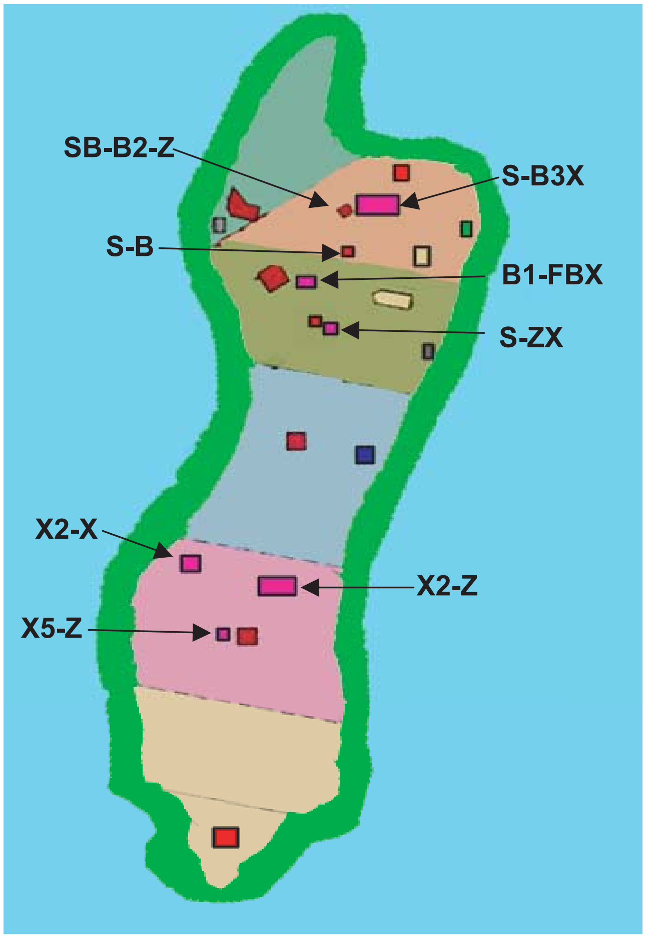

Fig. 2—ASP pilot test locations in Daqing oil field.

PF also has been implemented in other oil fields in China, including its second largest oil field, Shengli. Nine pilot tests were conducted in three major reservoirs—Gudao, Gudong, and Shengtuo—from 1997 through 2002. Incremental recoveries varied from 4 to 8% OOIP in most cases. The annual oil production resulting from PF in Shengli increased from 2.7 million bbl in 1997 to 16.7 million bbl in 2004, approximately 13% of the total field production.

Besides PF, Daqing also has tested the ASP and CDG processes. Eight ASP tests were conducted from 1994 through 2005, and three CDG tests were conducted from 1999 through 2005. Locations of the ASP tests are shown in **Fig. 2.**

Other Chinese oil fields, such as Shengli and Karamay, also successfully tested the ASP process. Recovery efficiencies of the ASP process ranged from 15 to 25% OOIP, although the economics are not as favorable as for the PF process **(Table 1).** Results from the CDG pilot test showed better economics and better performances than PF.

Most of the field tests are summarized briefly here with emphasis on key completed projects. Fundamental mechanisms of chemical-flooding processes have been published in the literature during the last 30 years, and, therefore, these will not be addressed here.

PF

The incremental oil recovery, beyond waterflood (WF) projects for medium- and high-viscosity oils, may be obtained by adding low concentrations, 500 to 2,500 ppm, of water-soluble polymers to the injection water to improve the mobility ratio, defined as $(k_{rw}/\mu_w)/(k_{ro}/\mu_o)$. Although the key mechanism for PF is increasing the water-phase viscosity, polymers also can reduce the water-phase relative permeability in porous media.

Daqing Oil Field. This giant field was discovered in 1959. The reservoir is a lacustrine sedimentary deposit with multiple sand intervals. Reservoirs in various parts of the field are highly heterogeneous, with Dykstra-Parson indices greater than 0.5. The structure is a 90-mile-long, 6-mile-wide, and 2,300- to 3,900-ft-deep anticline trending north-northeast/south-southwest, with approximately 36 billion bbl OOIP. Chemical flooding has been implemented in 31 blocks in the Lamadian (L), Saertu (S), and Xinshugang reservoirs. Most of these reservoirs contain medium-viscosity oils (approximately 9 cp at reservoir conditions) and low-salinity brines [5,000 to 7,000 ppm total dissolved solids (TDS)] with mild temperature (113°C), making them especially favorable for PF.

Table 1—Comparison of Chemical Costs for PF, CDG, and ASP Processes

			ASP			
Chemicals	CDG	PF	Preflood	ASP Slug 1	ASP Slug 2	Poly. Drive
Slug Size, V_p	0.50	0.50	0.04	0.35	0.10	0.20
HPAM to Crosslinker Ratio	30.00	—	—			
HPAM Concentration, ppm	600	1,000	1,400	1,800	1,600	1,400
X-Linker Concentration, ppm	20.00	—	—			
HPAM Costs*, U.S. $/lbm	1.03	1.03	1.03	1.03	1.03	1.03
X-Linker Cost*, U.S. $/lbm	22.92	—	—			
Surfactants, ppm	—	—	—	3,000	1,000	—
Surfactants*, U.S. $/lbm	—	—	—	2.20	2.20	—
Alkaline Agents, ppm	—	—	—	15,000	12,000	—
Alkaline Agents*, U.S. $/lbm	—	—	—	0.12	0.12	—
Recovery Efficiency, %OOIP	12	10	20			
Chemical Slug Costs, U.S. $/bbl	0.38	0.36	0.51	3.58	1.84	0.51
Chemical Costs/bbl Incremental Recovery, U.S. $	2.25	2.58	11.12			

* All chemical costs are based on 100% active and current prices.

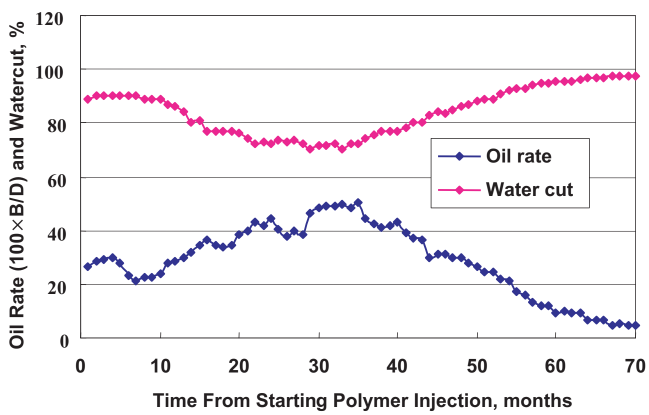

Fig. 3—Oil rate and water cut in 16 central production wells (B1-FBX polymer pilot test).

Small-Scale Pilot Tests. Three pilot tests were conducted from 1972 through 1986. These tests showed poor recovery efficiencies, less than 5% OOIP. Laboratory studies were continued, and a fourth small-well-spacing test was initiated in the west-central area of the S reservoir in 1990.[2] The test was conducted in two adjacent blocks, PO and PT. The Block PO test was conducted in an area with a single 38-ft-net-pay reservoir layer, and the Block PT area had two zones with a total net pay of 69 ft. An approximately 500-ppm·V_p polymer was used in the test, and incremental recoveries were 11.6 and 14.0% OOIP in Blocks PO and PT, respectively.

First Large-Scale PF Field Test. A large-scale field test with multiple patterns and large well spacing* was conducted in 1993 in a 766-acre area (approximately 37 million bbl OOIP) in the B1-FBX block of the S reservoir. The target formation was the PI_{1-4} zones. The average net pay was 49 ft, and the effective permeability was 72 0 md. The test was conducted in a five-spot pattern containing 36 producing wells and 25 injection wells.[3]

Oil production from the WF in this area began in 1963 by use of a line-drive pattern with well spacings of 1,640 ft. Infill drilling was undertaken and converted the line-drive to a five-spot pattern and reduced the well spacing to 820–984 ft. Before PF, the average single-well oil production was 290 B/D at a water cut of 88%. The cumulative water injection was 0.66 V_p, with a recovery efficiency of 29.5%.

Seven water-supply wells were drilled in the test area to secure adequate freshwater volumes. Good-quality water with TDS of less than 1,275 ppm and Mg^{++}/Ca^{++} ion concentrations less than 50 ppm was obtained. Four polymers with molecular weight (MW) from 11.5 to 18.0 million daltons were used in the field. The high-MW polymer was selected to test the effect of MW on recovery performance, injectivity, and polymer degradation.

A tracer program was conducted to detect any directional flow and the distribution of high-permeability thief zones. Native-state cores were also acquired. These core and log data were used to improve the reservoir description.

Water injection was continued before PF to establish a production baseline and resulted in the additional recovery of 4.4% OOIP. A polymer slug was injected from January 1993 to April 1997 totaling 592 ppm·V_p. Approximately 40% of the polymer used in the first slug was the high-MW polymer. The polymer concentration was reduced from 1,000 to 800 ppm, and the injection rate was reduced by 9% when high-MW polymer was used.

The total oil production at the end of polymer injection was 10.3 million bbl, representing a gross recovery of 18% OOIP and net PF incremental recovery of 13% OOIP. The oil production and water cuts are shown in **Fig. 3.** Post-PF waterdrive was completed in October 1998. The water cut was 98% at the end of water injection, with 1.9% OOIP additional recovery.

Initial production responses were observed after approximately 0.1 V_p of polymer slug was injected, with an increase in injection pressure and oil production and a decrease in water cut. Oil production peaked after 0.64 V_p of polymer slug was injected, with the oil production increasing from 4,800 to 10,000 B/D and the water cut decreasing from 91 to 74%. The overall recovery efficiency at 98% water cut was 53.8% OOIP.

The gross cash flow was U.S. $71 million, with capital investments of U.S. $35 million and an oil price of U.S. $10/bbl at that time.

Additional Large-Scale Field Tests. Two more large-scale PF tests were conducted in 1994 to investigate the effect of reservoir quality on recovery efficiency. The incremental recovery was 10% OOIP in the northern part of the S reservoir, with permeabilities and pay thicknesses ranging from 40 to 500 md and 1.3 to 13.0 ft, respectively. Another test conducted in the northern part of the L reservoir with better reservoir properties showed an incremental recovery of 14% OOIP.

Large-Scale Fieldwide PF Applications. Fieldwide expansion of the PF was initiated in 1996. The OOIP in the PF area (67,759 acres) was 3.53 billion bbl. Incremental recoveries from PF since 1999 have been maintained between 40 and 50 million bbl/yr with an average annual rate of approximately 45 million bbl. Cumulative incremental recoveries from PF were approximately 380 million bbl through 2005. Approximately 38% of the polymer injection was in the Type II reservoirs,** in which average permeabilities are less than 500 md. Incremental recoveries are on the order of 12% OOIP in Type I reservoirs and less than 10% OOIP in Type II reservoirs. In 1995, Daqing built an on-site polymer-production facility with an initial annual production capacity of 110 million lbm.

Daqing plans to maintain the current level of PF production by applying the process in 30 more blocks from 2005 through 2010. Brine-resistant and high-MW (>25 million daltons) polymers were tested successfully in the field. New polymers are being evaluated that are more cost-effective and suitable for higher-salinity and low-permeability formations.

Other Fields. Along with the PF field tests conducted in the Daqing oil field, several other fields including Shengli, Dagang, Karamay, and Henan also tested the PF process. The reservoir quality and fluid properties in the other fields are not nearly as favorable as in Daqing. Recovery efficiencies in most cases were less than 10% OOIP. Only the Shengli oil field's PF will be discussed here.

PF in the Shengli Oil Field. The second largest fieldwide PF application in China is in the Shengli oil field in the Bohai Bay area. The first small-scale PF pilot test was conducted in the Gudao oil reservoir in 1992. Then, a series of tests was conducted in various parts of the field with different reservoir qualities.

*Note that in China, well spacing is defined as the distance between an injection well and adjacent production wells. Normal or large well spacing for enhanced-oil-recovery projects in Daqing is approximately 820 ft or greater.

**The Type II reservoir also has poorer continuity and thinner sand layers, less than 3 ft in many areas.

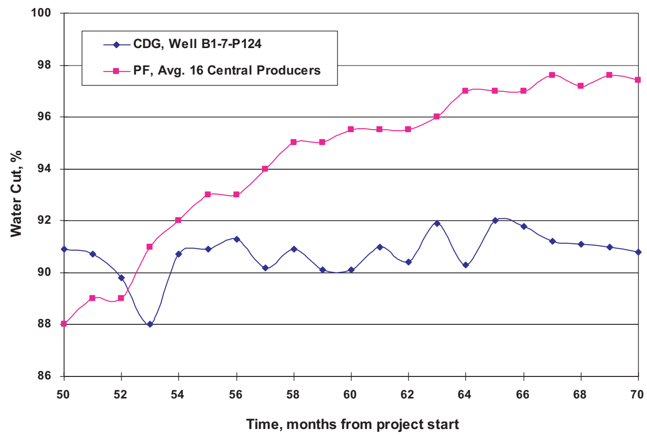

Fig. 4—Comparison of water cut in post-flooding (polymer flooding vs. CDG process).

One of the main differences in reservoir and fluid properties between Shengli and Daqing is that Daqing has almost the same fluid properties and temperature throughout the field, but Shengli has unique fluid and reservoir properties and temperatures in each reservoir, with oil viscosities of up to 130 cp, temperatures up to 180°F, and salinities as great as 160,000 ppm TDS. The formations are mostly unconsolidated sands with high permeabilities (>1,000 md) and porosities greater than 30%. Strategies in the design of polymer slugs were to use higher concentrations (>1,500 ppm) with smaller slug sizes (<50% V_p).

Gudao Z1-Ng3 Commercial-Scale PF Field Tests. The test area is at the top part of the reservoir, covering 1,100 acres with an average net pay of 40 ft and containing 79 million bbl OOIP. The Guantao sand deposit has an average porosity of 33%, permeabilities from 1,500 to 2,500 md, and an initial oil saturation of 68%. The reservoir temperature is 158°F. The oil is a low-wax-content, low-freezing-point asphaltic crude with a viscosity of 46 cp at initial reservoir conditions. The reservoir brine has TDS of 7,000 ppm. These are favorable conditions for PF.

The primary production in the test area began in 1971, and a WF was implemented in 1974. The pilot area had 40 injection wells and 85 producing wells. The average single-well oil production was 66 B/D at 94% water cut. The WF recovery efficiency at that time was 38.1%, with predicted final WF recovery of 43.8% at 98% water cut.

A two-slug process was designed, with 2,000 ppm of polymer in the first slug of 0.0225 V_p and 1,500 ppm in the second slug of 0.2565 V_p. The polymer slug was injected from December 1994 through late 1996. The initial response was observed after about 0.12 V_p of polymer injection. Oil production continued to increase from a pre-PF rate of 4,168 B/D to a peak rate of 6,622 B/D, and water cut decreased from 94 to 89%. The final incremental recovery was 7.6 million bbl or 9.6% OOIP. The cost of the project was approximately U.S. \$26 million, and incremental oil sales were approximately U.S. \$131 million at an oil price of U.S. \$18/bbl at that time.

Currently, there are 11 polymer projects in the Gudao reservoir, with 1.2 billion bbl OOIP and cumulative PF recoveries to date of approximately 45 million bbl. Shengli oil field also plans to expand the PF into the Shengtuo reservoir, one of largest reservoirs in Shengli with poorer reservoir and fluid quality than Gudao.

Conclusions and Improvements in PF.

1. Significant progress has been made in China in PF in the last 20 years, including the use of larger amounts of polymer to increase the incremental recovery above 10% OOIP in good-quality reservoirs. PF can be applied effectively to reservoirs with water cuts ≥95%.
2. Production of large amounts of polymers in producing wells is expected, and in-depth profile modification can be used with PF to lower the polymer production and improve recovery efficiency.
3. Moderate loss of injectivity is expected when the polymer slug is injected, but most of the pre-PF injectivity may be restored after the polymer slug has been injected.
4. Polymers with MW between 10 and 18 million daltons are suitable for most reservoirs; polymers with higher MW are more effective in high-permeability reservoirs, and brine-resistant polymers with lower MW are needed for low-permeability reservoirs.
5. Rapid decline in oil rate and increase in water cut are expected after termination of polymer injection.

Improvements in PF include developing better polymers for reservoirs with hostile conditions, optimizing the slug design to fit the reservoir characteristics, and reducing polymer production and increasing recovery by combining with in-depth profile modification to maximize the economic returns.

CDG

The CDG system is a weak gel that can be transported through the porous media to create resistance factor (RF) and residual resistance factor (RRF) in the reservoir higher than polymer at the same concentration.[4] These effects would prevent the channeling of water or polymer in high-permeability and thief zones and improve the injection profiles.

Daqing Oil Field was the first company in China to learn about the process and initiated a pilot test in 1999 in Zones SII_{1-2} of the S reservoir, with a Dykstra-Parson index of 0.716. The average permeability and thickness are 570 md and 21 ft, respectively. Wells were arranged in a five-spot pattern with a well spacing of 820 ft. There were six injection wells, two central producing wells, and 10 outside producing wells in the pattern.

Three chemical slugs (0.18 V_p CDG, 0.15 V_p polymer, and 0.20 V_p CDG) were injected from May 1999 through May 2003. The polymer concentration and polymer/aluminum ratio in CDG slugs were 600 ppm and 30:1, respectively. The polymer concentration in the polymer slug was also 600 ppm. Detailed project designs, implementation, and results were reported in 2004.[5] Incremental recovery was 12% OOIP at the end of the CDG injection. The post-CDG waterdrive has continued since that time. The oil rate and water cut have remained almost constant during the last 2 years because of the high RRF created in the reservoir. Estimated ultimate incremental recovery is more than 14% OOIP. **Fig. 4** shows a comparison of changes in water cut between PF and CDG process in post-flood periods.

Conclusions From the CDG Pilot Tests.

1. CDG performed better than PF, with an incremental recovery efficiency of approximately 14% OOIP.
2. The CDG process uses a lower concentration of polymer in the slug, 600 vs. 1,000 ppm, in the same type of reservoir, and with a small amount of crosslinking chemical, approximately 20 ppm.
3. A combination of PF with CDG would maximize the benefits of both mobility and profile improvements because a large amount of CDG would preferentially enter the high-permeability or thief

zones and divert polymer or water into medium- and low-permeability zones.

4. High, long-term RF and RRF created in the reservoir significantly improved vertical injection profiles[5] and sustained the project life much longer than PF (Fig. 4).

5. Higher polymer retention, approximately 90% in CDG vs. 70% in PF,[5] minimizes the polymer production from producing wells.

6. Lower chemical costs and higher recovery in the CDG process, as shown in Table 1, result in better economics.

Daqing has implemented two additional CDG projects in 2002. Results to date are favorable. Other fields in China also plan to test the feasibility of the process in 2006.

ASP Flooding

It was recognized in the U.S. that certain alkaline agents would react with acidic crude oils to generate surfactants in situ to improve oil recovery. Normally, the requirement of minimum acids in the crude oil for the process to be effective is approximately 0.3 mg KOH/g of oil, although additional small amounts of surfactants (<0.5 wt%) and polymers could be added to the alkaline slug to improve the displacement efficiency and mobility control.

Because there are several complex mechanisms[6] in the ASP process, including the interfacial-tension (IFT) reduction, emulsification, and wettability alteration, each chemical/crude-oil system may have different controlling mechanisms that require different combinations of the ASP chemicals. In some cases, only alkaline and polymer (i.e., AP) chemicals were used, and in other cases, all ASP chemicals were necessary. The design of the ASP system in Daqing was based mainly on IFT reduction, although the role of emulsification in ASP flooding also was being studied.[7] Because the acid contents are low (less than 0.1 mg KOH/g of oil) in the Daqing crude oil, more surfactants (>3%) were used in ASP pilot tests in Daqing.

ASP Flooding in Daqing Oil Field. Daqing had conducted 8 ASP pilot tests since 1994. A summary of these tests is given in **Table 2.**[8] In this table, Slug 1 refers to a preflush with polymer, Slugs 2 and 3 usually are ASP slugs with different chemical compositions, and Slug 4 is the polymer drive. However, Slug 3 may not be used in some cases. The size of these tests varied from well spacing of 246 to 820 ft. Three of the tests are still ongoing. Sodium hydroxide was used in most of these tests, but sodium carbonate also was tried. Several types of surfactants, including alkyl benzene sulfonates, petroleum sulfonates, lignosulfonates, petroleum carboxylates, and biologically produced surfactants, were tested. Hydrolyzed polyacrylamide (HPAM) polymers with different MWs were used in the preflush, ASP slug, and driving slug. Incremental recovery efficiencies from the five completed projects varied from 19 to 25% OOIP.

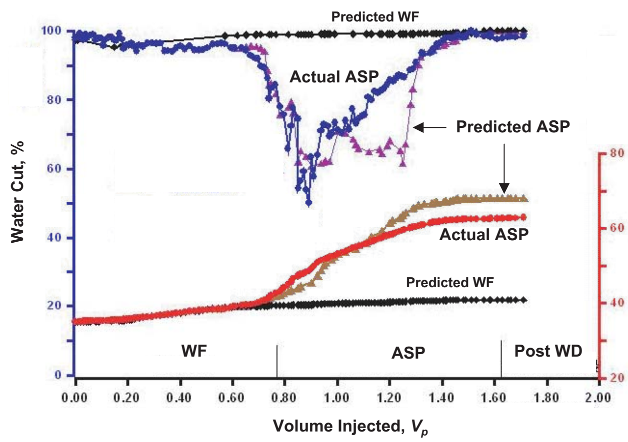

Fig. 5—B1-FBX ASP pilot test results (central producing wells).

B1-FBX Large Spacing ASP Pilot Test. This field test was conducted in 1997 to evaluate the performance of the ASP process in larger-well-spacing operations. There were six injection wells and 12 producing wells. The recovery efficiency of this test was 22% OOIP, with a maximum water cut reduction from 90 to 50%, as shown in **Fig. 5.**

XII-Z Commercial-Scale ASP Test. A larger multipattern large-well-spacing ASP-flooding test with 17 injection wells and 27 producing wells was conducted in 2001 in the S reservoir. Results through 2004 showed that the recovery efficiencies were 13.4% OOIP in the eastern part of the test area with better reservoir connectivity and 8.4% OOIP in the western part of the test area with poorer connectivity. Estimated final recovery efficiency in the eastern area could reach 18%. Results from two other tests are not yet available.

Although the current oil production from ASP flooding is small, Daqing expects to replace the oil production from PF with ASP flooding beyond 2010. Estimated long-term ASP-flooding potential would double that of PF. Three more commercial-scale tests with multiple patterns are being planned for 2006.

Table 2—Summary of ASP Pilot Tests Conducted in Daqing Oil Field

Number	Location	Spacing (ft)	Wells (Injector/Producer)	Starting Date	Slug 1 (V_p)	Slug 2 (V_p)	Slug 3 (V_p)	Slug 4 (V_p)	Incremental Recovery (%OOIP)
ASP 1	S-ZX	348	4/9	September 1994	0.30	0.29			21.40
ASP 2	X5-Z	462	1/4	January 1995	0.30	0.30	0.18		25.00
ASP 3	X2-X	656	4/12	September 1996	0.04	0.35	0.10	0.25	19.40
ASP 4	S-B	246	3/4	December 1997	0.33	0.15	0.25		23.24
ASP 5	B1-FBX	820	6/12	March 1997	0.30	0.15	0.20		20.63
ASP 6	X2-Z	820	17/27	April 2000	0.04	0.35	0.10	0.20	Ongoing
ASP 7	SB-B2-Z	246	3/4	October 2004	0.04	0.35	0.15	0.20	Ongoing
ASP 8	S-B3X	820	–/13	August 2002	0.04	0.35	0.10	0.20	Ongoing

Testing the ASP Process in Other Oil Fields. In addition to the tests conducted in Daqing, the ASP process was tested in other fields including Shengli, Karamay, and Liaohe. This paper will discuss only ASP tests conducted in Shengli and Karamay.

Shengli. Shengli started experimental research in ASP flooding in the early 1980s, and the first small-well-spacing field test began in 1992 in the Gudong reservoir. Incremental recovery was reported to be 26% OOIP.[9] The second ASP pilot test was conducted in 1997 in the western part of the Gudao reservoir in an area of 150 acres. The well spacing and net pay were 695 ft and 53 ft, respectively. The reservoir is a channel-sand deposit with average porosity and permeability of 32% and 1,520 md, respectively. The pilot area has six injection wells and 10 producing wells with an average daily oil rate of 46 B/D. The WF recovery efficiency was 22.4% OOIP before ASP flooding.

The ASP process was conducted in a three-slug sequence.

1. Preflush: A 0.1-V_p 2,000-ppm polymer solution was injected for 306 days.
2. ASP Slug: A total of 0.3-V_p ASP slug containing 1.2% Na_2CO_3, 0.2% Surfactant A, 0.1% Surfactant B, and 1,700 ppm polymer was injected for 948 days.
3. Polymer Drive: A 0.05-V_p 1,500-ppm polymer solution was injected for 158 days.

The injection of chemical slugs was completed in 2002.

The oil rate increased from 630 to 1,490 B/D at peak production, and corresponding water cuts decreased from 96 to 83%. The total incremental recovery was 15.5% OOIP.

Karamay. An ASP pilot test was conducted in Karamay in 1995 in a heterogeneous conglomerate reservoir with a well spacing of 164 ft and four five-spot patterns.[10] A three-slug process was designed as follows.

1. A 0.40-V_p slug of 1.5% NaCl brine preflush.
2. A 0.34-V_p slug of ASP containing 1.4% Na_2CO_3, 0.3% crude-oil sulfonates, and 0.13% polymer.
3. A 0.15-V_p slug of 0.1% polymer and a 0.4% NaCl drive fluid.

The WF recovery efficiency in the pilot area before ASP-slug injection was approximately 50% OOIP at 99% water cut. The ASP slug was injected from July 1996 to June 1997 with continued waterdrive to early 1999. The increased recovery started after approximately 0.04 V_p of the ASP slug had been injected and peaked when approximately 0.2 V_p of the ASP slug had been injected, with a six-fold increase in oil rate and water-cut reduction from 99 to 79%. Incremental recovery in the central well was 25% OOIP. Severe emulsions in produced fluids were observed, and difficulties were encountered in breaking the emulsions.

Conclusions From the ASP Pilot Tests.

1. It was proved that >20% OOIP incremental recoveries can be obtained with the ASP process, but higher polymer concentrations are needed for effective mobility control.
2. ASP slugs with alkaline concentrations >1.0%, surfactant concentrations of approximately 0.3%, and polymer concentrations >1,500 ppm are effective in most tests conducted in China.
3. Small-scale tests appear to be more effective than large-scale tests because of reservoir heterogeneity and chromatographic separation of chemicals in the displacement process.
4. Better ASP systems need to be developed with more cost-effective surfactants in weak alkaline systems and with pH-tolerant polymers.
5. Optimization of the ASP slug; better understanding of the in-situ chemical transport and displacement mechanisms; cost-effective solutions to scale, emulsion, and other produced-fluid treatment; and a better descriptive model are needed.
6. The large-scale, fieldwide expansion has not been implemented in China because of the high cost of the chemical system, the potential injection and production problems, and lack of fully optimized chemical systems.

Nomenclature

k_{ro} = relative permeability to oil
k_{rw} = relative permeability to water
V_p = pore volume
μ_o = viscosity of oil
μ_w = viscosity of water

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