

# Gel polymer treatments provide lasting production, economic benefits

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**Bottom line.** Castle Resources Inc. performed gel polymer treatments on four Arbuckle Sand producers in its Vine A lease in the Solomon field in Ellis County, Kansas, during 1995. The treatments, which cost \$14,000 to \$18,000 per well, including polymer and well servicing costs, increased total oil production by about 30 bopd while lowering water production about 1,000 bwpd (based on well tests 100 days after treatments).

Lifting costs with lower production were reduced about \$300/month/well. With less stress on lifting equipment, well-servicing costs were also reduced about \$2,400/year/well. Through mid-2000, about 37,500 bbl of incremental oil has been economically recovered, representing about \$1.60 per incremental bbl to date—and several years remaining production is still anticipated. The gel polymer treatments extended the lease economic life at least seven years.

**The problem.** In mid-1995 seven wells, six Arbuckle and one Topeka, produced on Castle Resources, Inc.'s (Castle) Vine A lease in Solomon field in Ellis County, Kansas. As is typical with production from the fractured Arbuckle dolomite (depth of about 3,800 ft), water production in the Arbuckle producers was very high (99% plus). The high water production was inhibiting oil production and, with the high operating costs associated with high water production, the lease was near its economic limit.

**Gel polymer as one solution.** High water production from Kansas's Arbuckle formation results from the combination of extensive fracturing and a strong water drive. Wells that produce significant oil before transitioning to high water cut production are considered good candidates for gel polymer treatments. Some indication of significant mobile oil saturation that has been bypassed by water producing through the natural fracture system or high-permeability streaks is desired. Although considered, structural position relative to the oil/water contact is not a determining factor. Wells that produce a large volume of fluid, but cannot be pumped off with existing equipment, are excellent candidates. Bottom water drives in fractured carbonates, such as dolomites and limestones, have had the highest success rates.

There are three key factors in designing gel polymer treatments—the type of gel polymer/crosslinker and concentration; treatment volume; and treating procedure. For this application, high-molecular-weight, partially hydrolyzed polyacrylamide polymers crosslinked with a metal ion are a common solution.

For the Vine A treatments, Polymer Systems Inc. (PSI) recommended polymer concentrations ranging from 3,000 to 6,000 ppm. Lower polymer concentrations were used in the beginning stages of the treatments to achieve maximum pen-

etration, and then gradually increased to increase gel strength as the treatments progressed. The highest polymer concentrations at the end of the treatments served to “lock in” the earlier stages and prevent polymer flow back or water encroachment in the area of highest differential pressure near the wellbore.

All treatments were made up in fresh water. PSI often recommends fresh water or 2% KCl water for gel polymer treatments on production wells to assure control over gel times and prevent gel degradation problems that can be experienced when using lease water with undesirable elements. Once the polymer gel has matured, it is mostly immune from degradation by lease water, as long as those elements are not incorporated into the structure of the gel during the mixing process.

Treatments were recommended for four wells (Wells 1, 3, 4 and 8). Each well produced about 400 bfpd at a 99%+ water cut. Wells 1 and 8 were not drawing the working fluid level down from the static fluid level at that production rate. Completed intervals ranged from 4–14 ft in these Arbuckle completions. Most of the wells were completed open hole.

Recommended treatment volumes ranged from 685 bbl (Well 8) to 1,000 bbl (Well 1). Treatments were sized considering length of completed interval, production rate and draw-down factors. Final treatment volumes were determined during the job by monitoring injection rate and pressure response. The goal was to achieve the greatest radial penetration possible. Pressure response was used as an indicator that fill-up was being achieved on the larger fractures near the wellbore. However, careful attention was paid to the rate of pressure buildup to assure plugging of the matrix or pore space did not occur, in order to avoid blocking off the remaining oil saturation.

In performing polymer gel treatments, it is important to assure that the wellbore, open hole interval or perforations are clean. Many older wells are found to have a significant buildup of iron sulfide or various types of scale/solids. Wells often have significant fillup, even though they are capable of producing at high producing rates. If this fill is not cleaned out prior to polymer injection, problems can occur through several mechanisms. Polymer is a viscous, sticky fluid that tends to pick up solids and carry them into the reservoir, resulting in decreased or lost injectivity and plugging of flow channels near the wellbore. Iron within iron sulfide can react with the polymer and cause premature gelation and over-crosslinking, resulting in rapid deterioration of the gel structure.

To prevent such problems, wells should be sand pumped or otherwise mechanically cleaned-out to TD, followed by a small acid clean-up treatment. To assure injectivity prior to

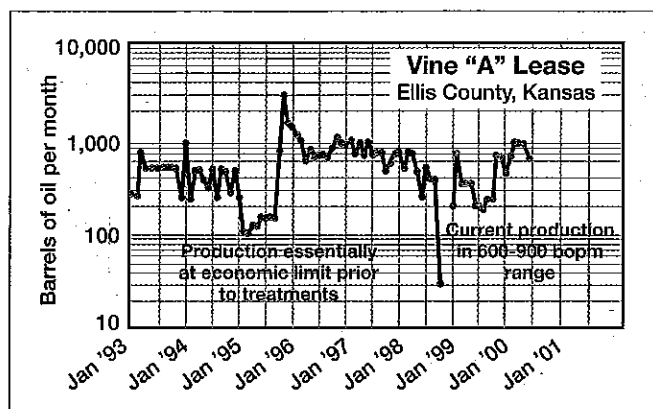


Fig. 1. This lease was near its economic limit in late 1995. One year after treatment, production was still 800 to 900 bbl per month, over five times pre-treatment production. Through June 2000, an additional 37,500 bbl of oil have been produced.

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polymer injection, a preflush is pumped using the treatment makeup water. After the polymer stage is pumped, it is important to overflush and clear the wellbore using a crude oil overflush. This step flushes any polymer from the oil-bearing part of the reservoir and assures open flow channels for oil mobilized by the treatment. PSI uses a specially designed mobile blender/pump truck combination unit to blend, pump and monitor polymer gel treatments.

**Treatment results.** The four gel polymer treatments were performed within a one-month period in the fall of 1995. Polymer costs ranged from \$8,000 to \$10,000 per well, with total cost, including fresh water and well servicing costs, being in the \$14,000 to \$18,000 range per well. Stabilized production (based on well tests 100 days after treatment) showed increased oil production and decreased water production, Table 1. Remember, all wells produced about 4 bopd at a 99%+ watercut prior to treatment. In Wells 3 and 4, smaller gel polymer casing leak treatments were also performed.

Pre- and post-treatment oil production through June 2000 are illustrated in Fig. 1. Without the gel polymer treatments, the lease was near its economic limit in late 1995. One year after the treatments, lease production was still 800–900 bbl per month, over five times pre-treatment production. At a later date, Well 9 was also treated with gel polymer—by perforating the oil/water contact and treating with 400 bbl of gel polymer, then completing in the oil zone.

Lease production in mid-2000 is still in the 600–900 bopm range. Through June 2000, an additional 37,500 bbl of oil have been produced—essentially all considered incremental due to the gel polymer treatments. With a combined treatment cost of about \$60,000 (for the four initial wells), this equates to about \$1.60 per incremental barrel. With several years of economic production remaining, ulti-

**Table 1. Results of gel polymer treatments on Vine "A" Arbuckle wells**

Well	Date	Gel polymer volume (Polymer cost)	Well test (100 days after)		
			bopd	bfpd	% water
1	9/28/95	1,000 bbl (\$8,000)	7	128	95
3	10/23/95	975 bbl (\$8,335)	12	112	89
4	10/19/95	700 bbl (\$6,087)	8	119	93
8	10/18/95	685 bbl (\$6,006)	17	292	94

mate incremental cost could approach \$1.00 per incremental barrel.

**Economic conclusions.** Four gel polymer treatments on fractured Arbuckle producers increased oil production by a total of about 30 bopd, while lowering water production about 1,000 bwpd (based on well tests 100 days after treatments). Lifting costs with lower production were reduced about \$300/month/well. With less stress on lifting equipment, well-servicing costs were reduced about \$2,400/year/well. Through mid-2000, about 37,500 bbl of incremental oil has been economically recovered, representing about \$1.60 per incremental bbl to date—and several years' remaining production is still anticipated. The gel polymer treatments extended the lease economic life at least seven years. **PTD**

#### THE AUTHORS

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