BULLHEAD TREATMENTS FOR WATER REDUCTION IN GAS WELLS

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ABSTRACT

Water production in gas wells can be an immense problem, causing premature well abandonment in many cases. Numerous techniques are used in attempts to allow continued production, including the use of foams and plunger systems; however, these techniques require continuous injection of chemicals and/or maintenance of equipment. Stopping or slowing down the water is another approach to the problem.

This paper discusses a bullhead polymer system that reduces the permeability to water much more than it does to gas. The system does not require zonal isolation of the water-producing zone, allowing a much simpler job design and execution than standard crosslinked-gel treatments. The paper also discusses the polymer chemistry, laboratory test data, job-design and execution details, and case histories.

INTRODUCTION

Controlling water production has been an objective of the oil/gas industry since its inception. Produced water can have a major economic impact on the profitability of a field. Producing one barrel of water requires as much or more energy than producing the same volume of oil. Oftentimes, each barrel of produced water represents an equal amount of unproduced oil. Water production also causes related problems, such as sand production, the need for separators, disposal and handling concerns, and corrosion of tubulars and surface equipment.

Gas wells introduce additional challenges when coupled with excessive water production. The impact on a gas well's production rate can be more serious than an oil well. In gas wells, liquid accumulation in the wellbore is often referred to as liquid loading or liquid impairment. In a well with high gas-production rates, liquid is carried to the surface as a fine mist of droplets. However, at some point, the gas-production velocity will fall below a critical level at which the gas can no longer lift the liquid out of the well. At this point, liquid starts to accumulate in the well, leading to hydrostatic pressures high enough to cease gas flow.

To combat this liquid loading and eventual death of the well, artificial lift interventions are often used. These can take the form of either chemical or mechanical solutions. The main chemical solution is the use of foamers. Mechanical solutions include rod pumps, hydraulic-piston pumps, gas-lift systems, hydraulic-jet pumps, progressive-cavity pumps and plunger-lift systems. All of these systems have inherent advantages and disadvantages. This paper focuses on a chemical system and the use of foamers. Foamers are often used because they are seen as a low-cost system. They can be introduced into a well through the use of soap sticks that can simply be dropped into a well. Liquid foamers can also be used. Foamers can be used in conjunction with other systems, such as velocity strings, plungers, and gas-lift systems. Some of the disadvantages of foamers are the need to continuously inject the chemical (or periodically drop sticks) and that concentrations might need adjustment so the foam will break when it reaches the surface.

While these artificial-lift techniques have been used successfully for many years, another approach to the problem is to attempt to stop (or slow down) the water from being produced. There are many techniques that have been used throughout the years in attempts to slow down water production, including both mechanical and chemical methods; this work only focuses on the chemical methods. Two categories of chemical systems are available for reducing water production: (1) sealing systems that completely block the flow of fluids, and (2) nonsealing systems that allow the flow of fluids.

Sealing Systems

Sealing systems are porosity fill materials, which can be valuable when a water-producing zone can be mechanically or chemically isolated. However, in many situations, a target zone cannot be isolated and the sealing system sometimes penetrates zones that should not be treated. Although claims have been made that sealing systems can reduce water permeability much more than they reduce oil/gas permeability, pumping such a system without zonal isolation is extremely risky.

Nonsealing Systems

Nonsealing (or bullhead) systems are typically diluted solutions of water-soluble polymers that adsorb onto the formation. These polymers most likely reduce the effective water permeability through a wall effect (Zaitoun et al. 1998) where the polymer adsorbs onto the formation and creates a layer of hydrated polymer along the pore throat; this inhibits water flow, yet does not affect the permeability to oil and/or gas.

The technology described in this paper uses a hydrophobically modified, water-soluble polymer (HMP). The development of this polymer has been described in detail in a previous work (Eoff et al. 2003). **Figure 1** illustrates the adsorption of a generic water-soluble polymer onto a rock surface pore throat wall, as well as the adsorption of a HMP. The presence of the hydrophobic groups on the polymer increases the level of polymer adsorption by allowing polymer to adsorb to polymer. This leads to higher levels of water-permeability reduction than a non-modified polymer, without damage to hydrocarbon permeability.

Laboratory results have shown the ability of HMP to reduce water permeability with minimal effect on hydrocarbon permeability, although most of the reported data has been with oil (Zaitoun et al. 1998). **Figure 2** shows results from a test using gas. In this test, sandstone cores were placed in a Hassler sleeve so brine and gas could be cycled through to measure permeabilities. In the case of the core labeled gas, the last fluid pumped through the core before the treatment was gas. In the case of the core labeled water, the last fluid pumped through the core before the treatment was water. Following the treatment, either gas or water flow was resumed for measurement of the final permeability. As shown, there was a much greater effect on water permeability than on gas permeability. This effect has been seen on a large number of cores of various permeabilities and lithologies and at a wide range of temperatures.

CANDIDATE SELECTION

Proper well selection is perhaps the most important factor to consider in determining the potential for economic success of a treatment using HMP. Wells with the following conditions are possible candidates for HMP treatments:

- Bottomhole temperatures up to 325°F
- Permeability greater than 0.10 md and less than 6000 md
- Layered formations without crossflow within the reservoir
- Capability of sustained production if the water-oil ratio (WOR) or water-gas ratio (WGR) can be reduced

The most important criterion is that the well must have potential for the production of hydrocarbons. A depleted reservoir, or one with no energy remaining to move hydrocarbons to the wellbore, might not be a good candidate. It might be possible to restrict water entry in such wells, but oil or gas production will not necessarily be improved.

If poor cement sheaths, channels, near-wellbore fractures, or similar anomalies provide access to aquifers above or below the hydrocarbon-producing interval, the HMP application might not be the preferred treatment. Other permanent plugging or positive shutoff materials should be considered first.

When selecting a well for HMP treatment, the production rates and the drawdown pressure should be considered. If reduced water-production rate is the desired result, it is important to maintain the same drawdown pressure after the treatment as before the treatment. However, if the increased oil-production rate is desired with a similar water-production rate, then the drawdown differential should be increased.

FIELD APPLICATIONS

More than 230 HMP jobs have been pumped around the world. While the majority of these treatments have been in oil wells, a number of them have been in gas wells. **Table 1** illustrates just a few examples from gas wells, showing gas and water rates before and after the treatment. One point to be made when looking at job results is that success of the treatment should be defined before job execution. As shown in Table 1, in some cases, the gas rate increases when the water rate is decreased, but this is not always the case. A decision on whether a drop in water rate with no increase in gas rate is acceptable should be made before pumping the treatment.

In one location in the United States, seven wells have been treated with HMP. In all cases, the water rate was decreased and, in one case, the gas rate increased. In the other six cases the gas rate did not increase, but the gas-decline rate the well had been experiencing was slowed, which was viewed as a positive impact on the well. The evaluation period following the treatments varied from approximately two months to one year, and for all seven wells, the increased gas production was ~237,000 Mcf (for six of the wells, this was based on comparing the original decline curve to the new decline curve).

Two cases of water reduction in gas wells in South America are described in more detail below.

Case 1—Low Reservoir Pressure

Gas production on this well started in 1979. In 2003, water production began and gradually reached 40 BWPD (**Figure 3**). Gas production declined rapidly and sand production was also initiated. The first attempt to control water production consisted of placing a cement plug through coiled tubing (CT) to isolate the lower section of producing interval. The reduction in water production lasted less than two months (**Figure 4**). Rapid decline in gas production and sand fills indicated the need for a different approach.

A gel treatment was not chosen because there was no room for isolation of the high water-saturation zone and, therefore, there was high risk of totally shutting off well production. However, an HMP treatment was a viable option.

The steps that were taken in the HMP treatment are listed below:

- Clean out sand fill with CT and nitrogen foam
- Pickling of CT with citric acid solution
- 10 bbl of 7% KCl preflush
- 50 bbl of HMP treatment
- 29 bbl of 7% KCl post flush and displacement
- POOH with CT and lift well by injecting 62 Mcf of gas.

The sand cleanout was necessary before the job because the sand fill was covering the target zone. At some stage of the sand cleanout, the sand accumulation was harder and it was not possible to lift it with nitrogen foam. Therefore, a downhole motor was necessary to finalize the job and plain brine had to be used to circulate out. Because of low formation pressure, about 50 bbl of brine was lost to the formation.

After the initial 62 Mcf of gas, the well accumulated in 8 hours; 52 bbl of KCl returns and further gas injection in the following two days allowed for an additional 82 bbl of KCl returns. On the fourth day after treatment, the well produced 120 Mcf of gas and no water. Unfortunately, the well sanded out again. An additional CT and nitrogen-foam operation was required. It was also decided to reperforate the upper zone of the target zone, considering the critical situation of sand production.

After the last sand cleanout, the well was shut-in for one month based on operational requirements and workover program. One month later, the well was opened, but it declined rapidly. Gas lift was then injected for around 11 hours, accumulating higher wellhead pressure. Then, the well was placed on production through a separator. The production stabilized at 514 Mcf/D of gas and no water. More than a year and a half after the treatment, the gas production was still stable with a lower production-decline rate compared to pretreatment conditions and no water (see **Figure 5**).

Case 2—Reservoir Pressure Slightly Below Normal Pressure

This well was shut in for one year before treatment because of high water production. The placement technique used in this case was bullheading through the production string. The treatment was performed according to the following basic operational program:

- Hold a meeting for safety and environmental awareness and to review operational guidelines.
- Test high-pressure lines and pump units with 5,000 $lb/in.^2$ of pressure.
- Perform a short injection test with compatible brine (2% KCl + surfactant + clay stabilizer).
- Start the injection of 80 bbl of HMP treatment based on target-zone porosity and thickness to allow for approximately 8 ft of radial penetration.

- Overflush with 20 bbl of compatible brine (2% KCl + surfactant + clay stabilizer).
- Displacement to top perforations with compatible brine
- Open the well and produce immediately after the treatment. (No shut-in time is required.)

The maximum injection pressure observed during the treatment was 2,300 lb/in.^{2}, and the average injection rate was 0.6 bbl/min.

Results of this treatment a few hours after the end of the job initially showed water at 396 BWPD, then falling to 332 BWPD. The gas production started at 230 Mscf/D, with peaks near 800 Mscf/D and then stabilized near 400 Mscf/D. Surface pressure was 1,800 lb/in.^{2} with a 16/64-in. choke (**Figure 6**).

Because this well was part of a group of potential candidate wells, a decision was made to perform a second HMP treatment to try to decrease the water production even further. The second treatment was performed much the same as the first job, again using 80 bbl of treatment. Results with a 16/64-in. choke after two days of production were 290 BWPD, 1,080 lb/in.^{2}, and gas increase from 262 to 397 Mscf/D.

CONCLUSIONS

- When properly designed and executed, and when they function downhole as intended, HMP treatments can be successfully applied to excessive-water-production problems occurring in either oil- or gas-production wells.
- When a treatable excessive-water-production problem occurs, HMP treatments can be applied using bullhead injection (not requiring the use of mechanical zonal isolation) or CT, depending on specifics of well intervention, economics, and equipment availability.
- The HMP treatment showed potential to help improve gas recovery by reducing water production and water loading.
- In the sensitive sand-production scenario of Case 1, the HMP treatment had the additional benefit of reducing or eliminating sand production that is inherent to water production, especially in formations with low consolidation.
- The HMP treatment does not completely stop water production.
- The HMP treatments were economically attractive because gas production was recovered in conditions where it was previously totally lost.
- Based on the results in this paper, it is believed that single-well treatments are beneficial and an integrated process to provide a conformance solution should be extended to field-wide, multiwell treatments.

REFERENCES

Zaitoun, A., Bertin, H., and Lasseux, D. 1998. Two Phase Flow Property Modifications by Polymer Adsorption. Paper SPE/DOE 396631 presented at the SPE/DOE Improved Oil Recovery Symposium, Tulsa, Oklahoma, 19–22 April.

Eoff, L., Dalrymple, D, Reddy, B.R., Morgan, J., and Frampton, H. 2003. Development of a Hydrophobically Modified Water Soluble Polymer as a Selective Bullhead System for Water Production Problems. Paper SPE 80206 presented at the International Symposium on Oilfield Chemistry, Houston, Texas, 5–8 February.

Table 1
Field Results from HMP Treatments

Gas Rate Before Treatment, Mscf/D	Gas Rate After Treatment, Mscf/D	Water Rate Before Treatment, BWPD	Water Rate After Treatment, BWPD
426	2343	*	*
720	600	30	0
8000	8000	399	232
386	484	457	114
1100	965	700	300
301	350	290	7.5

* Rates not available, but fluid level in the well dropped by ~70 ft

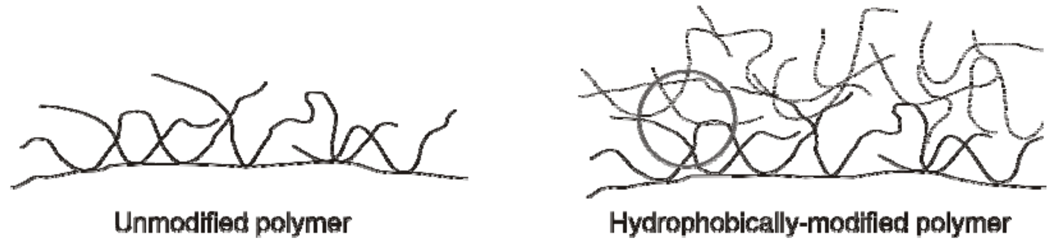

Figure 1—Adsorption of nonmodified (left) and hydrophobically-modified (right) polymers.

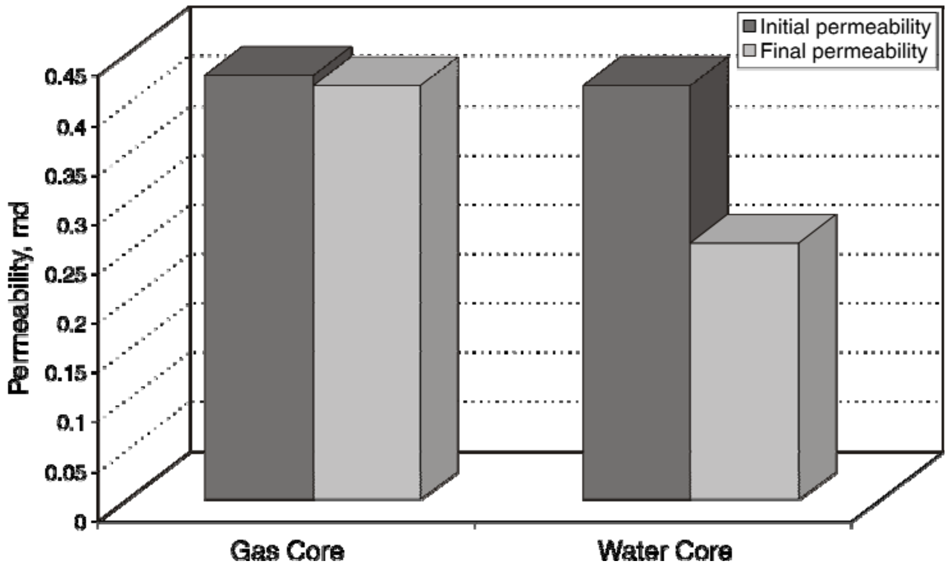

Figure 2—Core flow-test results.

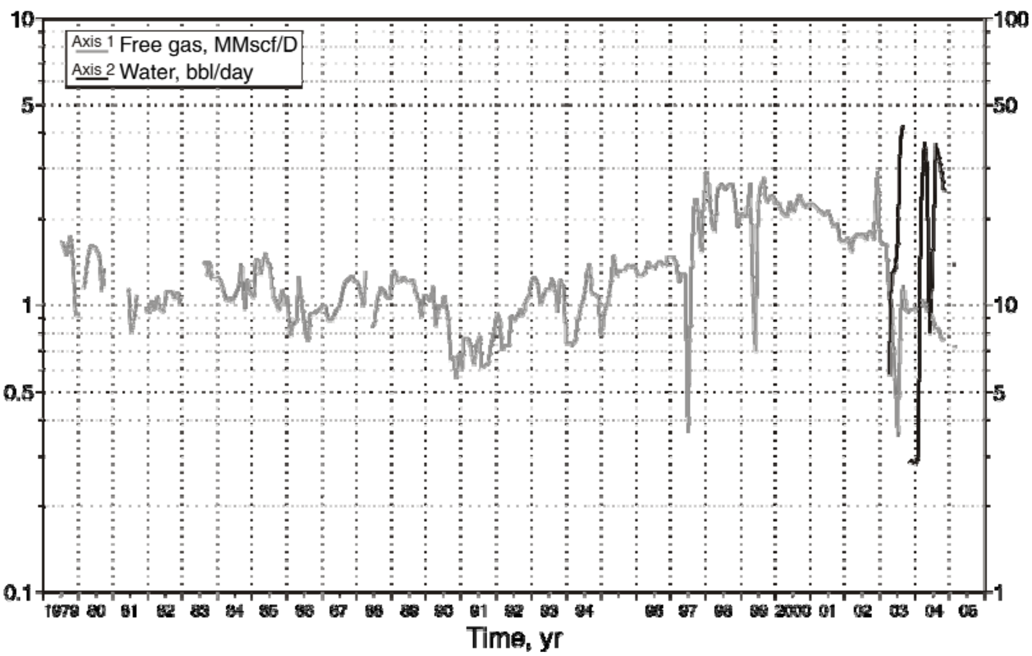

Figure 3—Case 1 production history before squeeze job and HMP treatment.

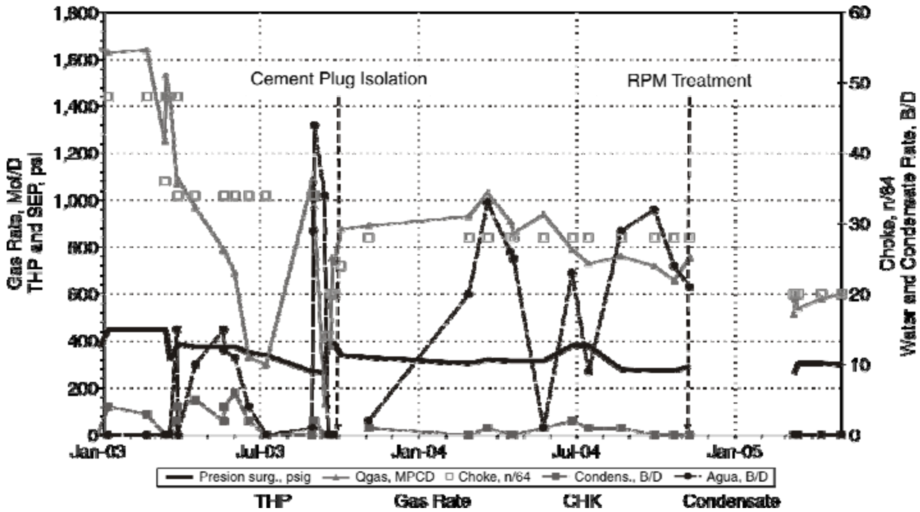

Figure 4—Case 1 production history showing squeeze job and effect of HMP treatment.

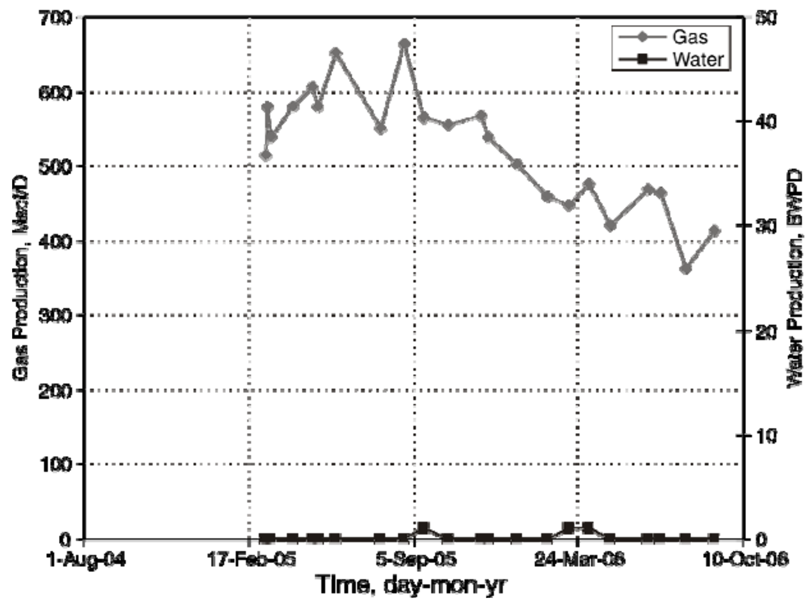

Figure 5—Case 1 production history after HMP treatment.

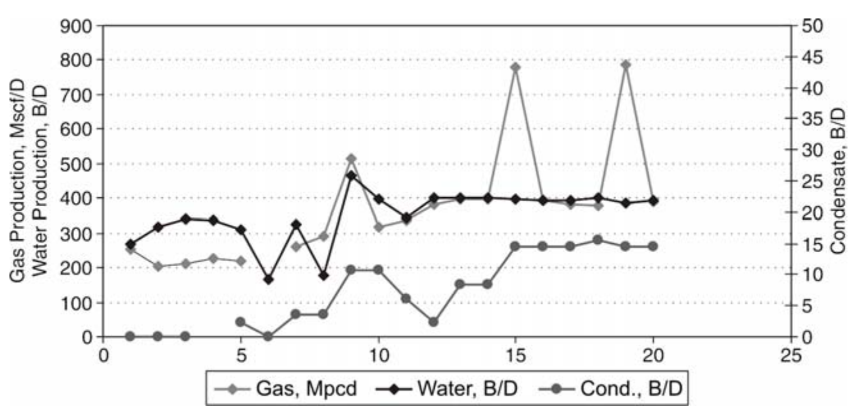

Figure 6—Case 2 initial production after HMP treatment.