SUCCESSFUL TECHNOLOGIES AND OPERATING PRACTICES FOR DEALING WITH PRODUCED WATER

Robert D. (Bob) Kiker, Petroleum Technology Transfer Council-Texas-Permian Basin
Rodney R. Reynolds, Petroleum Technology Transfer Council and Tertiary Oil Recovery Project at the University of Kansas

ABSTRACT

The largest volume waste stream associated with oil and gas production is produced water. Independent operators have identified produced water as a major constraint in the production of hydrocarbons. The costs of lifting, separating, handling, treating and disposing of this water are substantial. In addition to the economic burden it imposes, water can also directly reduce hydrocarbon production.

With these thoughts in mind and as partial fulfillment of a U. S. Department of Energy contract, the Petroleum Technology Transfer Council (PTTC) developed a manual as a reference source to assist independent operators in dealing with produced water. The manual addresses different technologies used for different water production issues operators face throughout the life cycle of a well. Many workshops conducted by PTTC have dealt with topics related to this subject. Much of the information in this manual was compiled from these workshop materials. The manual can be downloaded from the National PTTC website at http://www.pttc.org/pwn/produced_water.htm. Also attendees at the presentation will receive a CD of the manual and the updated slides of the presentation.

This paper will address some specific items in the manual but not all. There will also be more slides of case studies and results in the presentation. The idea of the manual was to present methods of water shut-off and then if that is not possible then present some "best practices" "or tips" for operators to minimize lifting costs with handling produced water.

One of the most important parts of the manual deals with water shut-off treatments using gelled polymers.

MANUAL OVERVIEW

The manual is divided into eight sections to better address the different technologies and issues operators deal with related to produced water. Not all technologies discussed in the manual are applicable to all situations, but they have lead in certain situations to improved return on investment and increased recoverable reserves.

The following outline summarizes the manual content:

I. Basic Properties and Data Management
    a. Rock properties
    b. Fluid saturation
    c. Reservoir drive mechanisms
    d. Collecting and organizing well and/or production data
    e. Knowing your related costs
II. Well Completion And Its Impact On Water Production
    a. Completion options
    b. Stimulation options
III. Dealing With High Water Production During Primary Production
    a. Water shut-off treatments using gelled polymers
IV. Dealing With Water Production During Waterfloods
    a. Water injection and production trends
    b. Reinjecting produced water versus make-up water
    c. Water quality needed to maintain injectivity
    d. Chemical tracers to identify channeling or premature water breakthrough
    e. Gelled polymers to modify permeability to increase sweep efficiency
V. Unexpected Increases In Water Production
    a. Sources

b. Methods to identify sources
c. Remedial actions

VI. Reducing Lifting Costs
a. Experienced based tips
b. Power cost reduction
c. On-site power generation
d. Surface versus downhole separation

VII. Corrosion and Mechanical Wear On Equipment Used In Handling Produced Water
a. Reducing downhole failures in producing wells
b. Surface facilities design
c. Injection/disposal systems

VIII. Regulatory and Environmental Issues Related To Produced Water
a. Injection and disposal wells
b. Oil and produced water spills
c. Spill prevention, control and countermeasure (SPCC) regulation
d. Cleanup guidelines

One of the most important parts of the manual deals with water shut-off treatments using gelled polymers.

WATER SHUT-OFF TREATMENT USING GELLED POLYMERS

For some producing wells, gelled polymer treatments are an option. In the U.S., most gelled polymer treatments in producing wells are in wells producing from fractured carbonate/dolomite formations that are associated with a natural water drive. Different polymer systems are available from different service providers. Recent successful treatments in the Midcontinent area have used the MARCIT^{sm} technology developed by Marathon Oil Company There have been over 300 gelled polymer jobs recently in Kansas, and some in the Permian Basin. An economic summary of the results will be shown at the presentation.
Service company experience seems to be a dominant factor in estimating how a particular formation in a given area will respond. Even then, service providers must be prepared to alter the original design based on the ability of a well/formation to accept a viscous fluid.

Pressure response during treatment provides key information. A slow, steady pressure increase over a period of time during pumping means one of two things - the problem zone is reaching polymer fill-up, or the reservoir temperature is causing the polymer to cross-link and build viscosity. Pressure response is a product of polymer volume, injection rate and gel strength. Altering any or all of these factors can improve the success of the treatment if reservoir resistance is not seen as the gelant is being pumped.

If the Hall plot indicates only a slight increase of pressure near the end of the treatment, service companies will typically recommend increasing polymer volume as a first step. Larger volume treatments lead to greater in-depth reservoir penetration, but they are more costly. Usually injection rates are increased at the beginning of the treatment to determine how easily the formation accepts a viscous fluid. Recent research and field experience has shown that higher pump rates can improve the effectiveness of treatments in carbonates that exhibit secondary permeability and porosity features. Increasing the injection rate also reduces the service company's field time, which lowers cost.

Increasing gel strength (viscosity) is another approach for achieving a pressure response. This is typically used at the midpoint of a treatment when the Hall plot shows no increase in slope. Gel strength can be increased by accelerating the cross-linking, increasing the polymer loading (concentration) of the gelant, or using a higher molecular weight polyacrylamide.

The best candidates for gelled polymer treatments are shut-in wells or wells producing at or near their economic limit. These types of wells benefit most from a successful treatment and little is at risk if the treatment fails, other than the treatment cost. Other selection criteria include significant remaining mobile oil in place, high water-oil ratio, high producing fluid level, high initial productivity, wells associated with active natural water drive, and high permeability contrast between oil- and water-saturated rock (i.e., vuggy and/or fractured reservoir). Successful treatments have been conducted in both cased and open hole completions.

Only empirical methods exist at this time for sizing treatments. Experience in a particular formation is important. In many instances, larger volume treatments appear to decrease water production for longer periods of time and recover more oil. Some rules of thumb include two times the well's daily production rate as the minimum polymer volume, or using the daily production capacity of the well at maximum drawdown (i.e., what the well would be capable of producing if it were pumped off) as the treatment volume. In lower fluid level wells, the daily production rate is sometimes used as the minimum polymer volume.

Before pumping treatments, ensure the wellbore is clean, acidize if necessary. Establish a maximum treating pressure, run a step rate test to determine parting pressure. Select an acceptable source of water. Having the service provider test water compatibility is important. Select a polymer-compatible biocide (typically 5-10 gallons per 500 barrels of mix water). Set tubing and packer above the zone to be treated. While pumping the treatment, use stages of increasing polymer concentration. Inject the treatment at a rate similar to the normal producing rate. Keep treatment pressure below the reservoir parting/fracture pressure. Changing conditions during the treatment may warrant design changes during the pumping. Over displace the treatment with water or oil.

In the Arbuckle formation in Kansas, water production can be excessive due to channeling in this water-drive reservoir. High water production restricts oil production and increases operating costs, often leading to leases and/or wells becoming prematurely uneconomic to produce. Gel polymer treatments have a long history in the mid-continent for blocking these channels. Recent treatments in Kansas Arbuckle producing wells are proving to be more effective in controlling water production and increasing oil production than past treatments.

Example of the oil and water production response on a Kansas Arbuckle well treated with gelled polymer. The Johnson B #3A is located in the SE SW SW of Section 29-T11S-R18W in Ellis County, Kansas. This well is in the Bemis-Shutts Field. Casing is set at 3718 ft. and perforated from 3526-3533 and 3576-3580. It was treated in August of 2001 by TIORCO using the MARCIT^{sm} system. The pre-polymer acid job was 250 gal followed by 1621 barrels of polymer. The treatment consisted of 118 bbls at 3500 ppm, 1001 bbls at 4000 ppm and 502 bbls at 5000 ppm. The treatment was overflushed with 80 bbls of oil. The maximum surface treating pressure was 51 psi and 97% (1578 bbls) of the treatment was at a vacuum at the surface. The average injection rate was 1025 bbls per day.

Prior to the treatment this well was producing 2 BOPD and 677 BWPD with a producing fluid level of 834 ft. above the perforations. The well was shut-in for 10 days following the treatment and returned to production. The initial production following the treatment was 116 BOPD and 62 BWPD. One month later the well was producing 43 BOPD and 130 BWPD. Six months following the treatment it was producing 14.5 BOPD and 147 BWPD. The producing fluid level following the treatment was approximately 200 ft. above the perforations. This well has produced approximately 8532 bbls of incremental oil to date as a result of the treatment. There were no artificial lift equipment changes on this well. Figure 1 is a plot illustrating production from this well.

USING GELLED POLYMERS TO MODIFY PERMEABILITY TO INCREASE SWEEP EFFICIENCY IN WATERFLOODS

Many waterfloods are plagued with low volumetric sweep efficiency. In many instances, poor performance is thought to be a result of water moving rapidly through high permeability channels or through natural or induced fractures. Induced fractures are often the result of over-pressuring the formation at some point. In other instances, water breakthrough may be related to permeability contrasts between different layers, which may or may not be in vertical communication in the reservoir.

Permeability modification treatments can help improve volumetric sweep efficiency. In waterfloods, injection-side treatments are most common. These treatments are conducted with either crosslinking or in-situ polymerization processes.

Crosslinked polymer treatments involve the addition of low concentrations of metal ions to the polymer solution causing the polymer molecules to bond to one another, greatly increasing the resultant gel’s ability to develop resistance to the flow of fluids in the reservoir rock. Depending on the concentration of polymer, crosslinking agent and rate of combining the two, a wide range of permeability adjustment is possible. In the in-situ polymerization process, monomers are polymerized in the reservoir. When treatments are properly placed in the targeted area, resulting fluid flow changes in most cases improve oil recovery and reduce operating costs due to reduced water cycling. Long-term performance of these treatments relies on the in-situ solutions having sufficient strength to stay in place during drawdown.

Permeability modification treatments must address correct identification of geological and reservoir characteristics, correct design and effective placement in the reservoir, and effectiveness lasting throughout the project period. Since different conformance improvement technologies are not applicable to all reservoir problems, the critical task is to successfully identify the channeling problem and then to match an appropriate technology to that problem.

Candidate well selection. Selection criteria for injection well candidates are: 1) significant remaining mobile oil-in-place that can be recovered if sweep efficiency is improved, 2) low secondary oil recovery due to poor sweep efficiency (i.e., high degree of reservoir heterogeneity), 3) premature water breakthrough at producing wells, 4) evidence of direct injector to producer channeling through fractures, vugs or high matrix permeability rock, and 5) high injection rate associated with low wellhead pressure.

Treatment design. The initial step in treatment design is selecting a process appropriate for the reservoir/producing problem and the treating/reservoir fluids. Choices to be made include near-wellbore versus deep gel treatments, type of polymer, crosslinking agent, and crosslinking process. On-site and laboratory testing by service companies with actual treating/reservoir fluids assists in chemical selection and treatment design.

A critical step is calculation of treatment volume and prediction of variation in polymer composition. Diverse tools, such as production/injection histories, well logs, surveys, workover history, and personal knowledge of the formation and geographical area are critical for prediction of treatment volume. It is impossible to calculate treatment volume exactly, but estimation within reasonable limits is possible. That is why it is essential that injection rate and pressure be continuously monitored during treatment and appropriate changes made to optimize treatment. Polymer solution should be injected until parting pressure is approached while injecting, the injected slug is produced at a peripheral producer, or the maximum design size is achieved. In most cases, parting pressure is the limiting factor for treatment size.

Performing the treatment. The candidate well should be cleaned prior to pumping the polymer solution. The goal of wellbore cleaning, whether mechanical or chemical, is to provide a clean formation face free of sludges, solids, or other materials that might interfere with the polymer solution or affect injectivity. Chemical performance and compatibility should be checked in the actual fluids on-site, since trucks and frac tanks can be sources of contaminants. Mixing/injection procedures must ensure that uniform polymer mixes are prepared.

Design treatment volumes and chemical concentrations should be used only as guidelines. Since each well will have a unique response, the well's ability to accept fluid (injectivity) should be continuously evaluated during treatment, and treatment compositions adjusted accordingly or the treatment terminated before the design volume is injected if the injection rate decreases too much. Rate restriction to avoid formation parting is essential. Hall plot slope analysis is very useful for real-time monitoring of treatments.

Other recommendations for placing a gel treatment are: 1) increase polymer concentration in stages, 2) inject treatment at a rate similar to normal injection rate, 3) stay below reservoir parting pressure, 4) keep offset producers active during treatment, and 5) over-displace the treatment with water (use more water in short perforated intervals).

Two other important parts of the manual (Sections 6 & 7) deal with Wellbore Management and Tips of Reducing Lifting Costs when you cannot shut off or reduce the produced water. Again these two sections represent a compilation of successful practices that have worked for some operators. They do not represent all of the successful practices, only those that the data was captured on through the research for the manual.

Section 7 deals with "Wellbore Management (Reducing Failures)". This has become a very important management action item in the past few years. Operators have become to recognize that the "Wellbore" is the primary asset and most of the major operating costs are directly associated with the well.
If produced water volumes are high and one has to live with them, operating and maintenance practices that control and reduce costs are critical. Tubing failures are usually internal from either corrosion or rod wear, or external from

buckling. Rod failures are usually due to corrosion, excessive loading, improper handling, or improper installation (make-up).

Internal corrosion has to be controlled with the corrosion inhibitor program or an internal coating mechanism. Section 7 presents some established successful practices for chemical programs to reduce corrosion. There are guidelines on batch treating and continuous treating, and includes recommended procedures for both types of treatments including the flush. Also included are some guidelines on pretreating sucker rods.

In addition to chemical treatment for corrosion there are some recommendations on the metallurgy being used for tubing, sucker rods, and pumps. Also popular coatings are discussed. Some of the specific corrosion practices that are in the manual will be shown in the presentation

In addition to practices for corrosion control there are successful practices in the manual to reduce mechanical wear in the wellbore. This consists of using tubing anchors, tubing rotators, rod guides, rod rotators, pump off controllers, timers, and the use of polyethylene liners. .

Polyethylene liners have been increasingly popular, both from reducing internal corrosion and reducing mechanical wear from the rods on the tubing. The polyethylene liners are inexpensive and can be installed on used tubing which also allows an operator to upgrade his tubulars without purchasing new expensive ones. These liners are chemically inert and are a seamless tube tolerant to minor surface imperfections. Some operators are installing the liners one or two joints above the pump, while others are installing the liner in half of the tubing string. Polyethylene tubing liners can be installed in used "green and or blue band" tubing for a cost of about $1.50 per foot. There is some ID loss, but favorable friction characteristics partially offset ID losses.

New technology on inside tubing scanners and computerized rod tongs for sucker rod and tubing makeup is also available.

Preferred Operating Practices and Philosophies to reduce well failures (Wellbore Management) is a significant part of section 7 in the manual and slides demonstrating successful programs will be shown in the presentation. An example of a successful program is shown in Figure 2.

Well failure frequency averages for successful programs are generally under one failure per well per year, and some are as low as 0.15 failures per well per year. One might argue—that's great, but I'm a small company. The good news is that smaller companies can apply the same concepts by employing the services of their vendors and maintaining good communication.

Common elements of successful programs are:

- Visual inspection of rod and tubing failures.
- Discussion of the problem and a review of the well history with team members-company, chemical, service company, equipment vendors, rod and tubing inspection personnel.
- Establishment and maintenance of a database of each well's failures. A tracking program can set up the database. The tracking program should also facilitate economic evaluation.

Over time, best operating practices in a given area should be developed. Successful programs usually employ the "pay me now, or pay me later" philosophy. Example; if a rod fails, successful programs call for either replacing the entire rod string with an inspected used rod string, or replacing the tapered section where the failure occurred. If one rod failed for mechanical or corrosive reasons, chances are that another failure will occur shortly. The pulled rod string is sent in for inspection.

LIFT EFFICIENCY

With any lifting system, "system efficiency" is very important. Overall system efficiency is defined as the amount of theoretical work required to lift the liquid from the net liquid level depth to the surface divided by the amount of power supplied to the motor. There are programs that evaluate system efficiencies. One system offered by Echometer is discussed in the manual. It is computerized and takes about 45 minutes per well. System efficiency quickly translates into power cost savings.

Section 7 concludes with some information on preferred practices on; surface facilities (vessels, tanks and water handling pumps), injection tubing, injection surface lines, and injection packers,

Section 6 deals with "tips on reducing lifting costs". A lot of this section deals with power reduction ideas and some case studies of actual power reduction will be shown in the presentation. Also included in this section is information on Downhole Oil Water Separators, and the new Cylindrical Cyclone Separators

SUMMARY

Dealing with produced water is an ongoing battle for oil and gas operators. It is an issue that has not been given the attention it deserves related to the costs associated with it. Operators are looking for help in dealing with produced water issues as evidenced by the authors of this paper being invited to conduct nineteen workshops nationally to date on this subject.

The information in this paper is a sampling of what is contained in the manual. A complete copy of the manual can be downloaded from the National PTTC website at http://www.pttc.org/pwm/produced_water.htm.

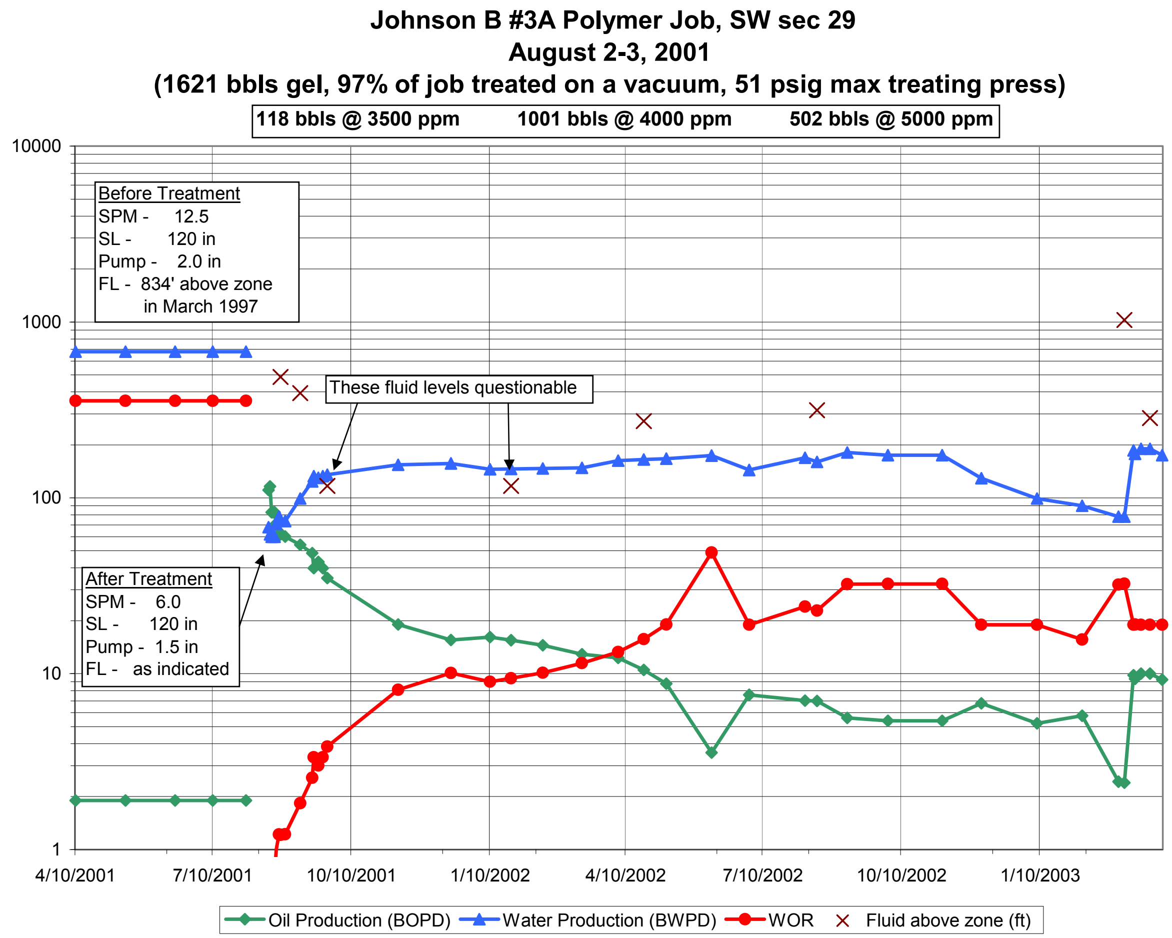

Figure 1 - Polymer Treatment Results on an Arbuckle Producing Well in Kansas

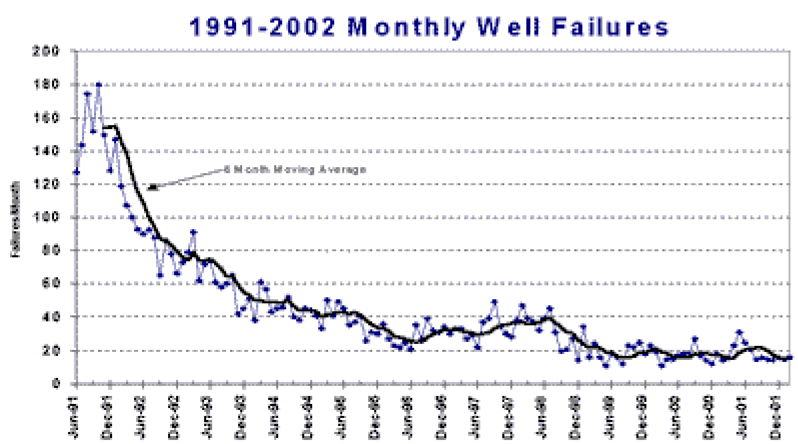

Figure 2 - Kent Gantz, "Holistic Producing-Well Improvement Reduces Failures/Servicing Costs," Fig. 1, Petroleum Technology Digest section of World Oil, June 2002, p. 59-60.