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Gel Water Shutoff in Fractured or Faulted Horizontal Wells

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Abstract

Advancement in design and implementation of polymer gel water shutoff treatments in horizontal wells that penetrate fractures or faults have come from empirical improvements in the field and synergism between monitored field treatments and independent laboratory research. One case history will be detailed, followed by a summary of several other treatments.

Simple calculations can give at least a rudimentary indication of the width of the fracture or fault that causes excess water production. Using laboratory data coupled with field data collected before, during, and after gel injection, the calculations can also give an indication of how far the gel has actually penetrated into the fracture. Our analyses reveal critical measurements that should be made during field applications and where additional laboratory work is needed to aid in the design of field applications.

Introduction

Fluid flow through natural fractures or faults (fissures) in petroleum reservoirs can adversely impact economics of petroleum recovery once hydrocarbons in the fissures are replaced by natural or injected drive water. This is almost universally true because such water flow does not aid hydrocarbon production from matrix or other fissures. Water flow through fissures impacts economics in several ways.

In production wells, water flow through fissures that connect to the well lead to a higher water cut for a given cumulative hydrocarbon production than would be experienced if all water production were *via* matrix. Such unnecessarily high water cut increases well and facility operating costs, inhibits hydrocarbon production rates, and results in early well or field abandonment and lost reserves. There is thus considerable economic incentive to shut off flow of unproductive water through fissures to production wells.

In waterflood (or tertiary recovery) injection wells, fissures contribute to high water (or other recovery fluid) cut at offset producers or loss of the fluid from the reservoir. In addition, loss or cycling of drive fluid through fissures can result in poor areal sweep efficiency and an unnecessarily high rate of reservoir pressure decline, both of which lead to lost reserves. Thus considerable economic incentive exists to divert injected recovery fluid from fissures to reservoir matrix flow.

Unproductive flow of water through fissures is of special concern for horizontal wells. In cases where the horizontal bore runs at any angle except parallel to the preferred fissure direction, there is a higher probability of intersection of the wellbore with vertical fissures than is the case with vertical wellbores. Additionally, isolation of the offending region of the wellbore for a water shutoff treatment is often not feasible in horizontal wells, due to issues with well completions. Many horizontal wells are completed open-hole, with no liner at all or with a slotted liner or pre-perforated uncemented liner. This is done for economic reasons. In cased cemented horizontal wells, the primary cement bond quality is often poor, especially uphole of the fissure, due to loss of whole cement into the fissure region. These problems can be exacerbated if large volumes of water injection or production have caused significant reservoir rock dissolution or solids movement. Thus mechanical zone isolation is foiled by flow through near-well matrix, through uncemented liner-by-formation annulus, or behind poorly cemented liner.

In spite of major incentives for controlling unproductive fluid flow through fissures, there have been generally insurmountable difficulties in doing so by mechanical intervention in the horizontal wellbore. For these reasons, there has been significant effort to selectively place plugging agents into fissures by pumping polymer gel without zone isolation (fullbore or bullhead). This paper explores the connection between laboratory gel extrusion observations and results from a successful polymer gel treatment that was bullheaded into a horizontal production well to shut off water entry from a fault. A summary of treatment performance for additional wells in several reservoirs is also described.

Laboratory and Theoretical Observations

Gel treatments currently provide the most effective means to reduce channeling through fractures.[1-5] Except in narrow fractures, extruded gels have a placement advantage over conventional gelant treatments. To explain, during conventional gel treatments, a fluid gelant solution typically flows into a reservoir through porous rock and fractures. After placement, chemical reactions (i.e., gelation) cause an immobile gel to form. During gelant injection, fluid velocities in the fracture are usually large enough that viscous forces dominate over gravity forces.[6] Consequently, for small-volume treatments, the gelant front is not greatly distorted by gravity during gelant injection. However, after gelant injection stops, a small density difference (e.g., 1%) between the gelant and the displaced reservoir fluids allows gravity to rapidly drain gelant from at least part of the fracture.[6] Generally, gelation times cannot be controlled well enough to prevent gravity segregation between gelant injection and gelation.

Alternative to conventional gelant treatments, formed gels can be extruded into fractures. Since these gels are 10^3 to 10^6 times mores viscous than gelants, gravity segregation is much less important than for gelants. In fact, for the most successful treatments in fractured reservoirs, formed gels were extruded through fractures during most of the placement process.[2-5]

Gels do not flow through porous rock after gelation.[6] This behavior is advantageous since the gel is confined to the fractures—it does not enter or damage the porous rock. Thus, after gel placement, water, oil, or gas can flow unimpeded through the rock, but flow through the fracture is reduced substantially.

Pressure Gradients during Extrusion. Extrusion of gels through fractures introduces new issues that are not of concern during placement of fluid gelant solutions. First, the pressure gradients required to extrude gels through fractures are greater than those for flow of gelants. For a Cr(III)-acetate-HPAM gel, the pressure gradient required for extrusion varied inversely with the square of fracture width (**Fig. 1**). A minimum pressure gradient is required to extrude a given gel through a fracture.[6-13] Once this minimum pressure gradient is exceeded, the pressure gradient during gel extrusion is insensitive to the flow rate.[6,8,12] In field applications, a practical consequence of this finding is that well pressures may not change much (over short time periods) as gel injection rate is varied. In contrast, with Newtonian fluids, one expects well pressure to vary in direct proportion to the injection rate.

The behavior in Fig. 1 is described fairly well by Eq. 1:

$$dp/dl = 0.02/\, w_f^{\,2} \,, \quad\text{..(1)}$$

where pressure gradient, dp/dl, has units of psi/ft and fracture width, w_f, has units of inches.

Fig. 1 applies to a one-day-old Cr(III)-acetate-HPAM gel at 41°C. Specifically, the experiments used an aqueous gel that contained 0.5% Ciba Alcoflood 935 HPAM (molecular weight ≈$5x10^6$ daltons; degree of hydrolysis 5% to 10%), 0.0417% Cr(III) acetate, 1% NaCl, and 0.1% $CaCl_2$ at pH=6. All experiments were performed at 41°C (105°F). The gelant formulations were aged at 41°C for 24 hours (5 times the gelation time) before injection into a fractured core.

Gel Dehydration. A second concern is that gels can concentrate (dehydrate) during extrusion through fractures.[9-12] Depending on fracture width and injection rate, this dehydration effect can significantly retard gel propagation (e.g., by factors up to 50). When large volumes of gel (described above) were extruded through fractures, progressive plugging (i.e., continuously increasing pressure gradients) was not observed.[9] Effluent from the fractures had the same appearance and a similar composition as those for the injected gel, even though a concentrated, immobile gel formed in the fracture. The concentrated gel formed when water leaked off from the gel along the length of the fracture. The driving force for gel dehydration (and water leakoff) was the pressure difference between the fracture and the adjacent porous rock. During gel extrusion through a fracture of a given width, the pressure gradients along the fracture and the dehydration factors were the same for fractures in 650-mD sandstone as in 50-mD sandstone and 1.5-mD limestone.[9-12]

During gel extrusion through fractures, the rate of water leakoff (i.e., the rate of gel dehydration) can be measured during laboratory experiments. (Details of how this was done can be found in Refs. 9-13.) Specifically, **Fig. 2** plots the average leakoff rate (u_l, in $ft^3/ft^2/d$ or ft/d) versus time (t, in days) for 15 separate experiments. The solid circles in Fig. 2 show results from 8 experiments in cores with 0.04-in.-wide fractures. In these experiments, fracture lengths ranged from 0.5 to 16 ft, fracture heights ranged from 1.5 to 12 in., and average gel injection fluxes ranged from 129 to 33,100 ft/d. Eq. 2 provided an excellent fit of the data from the 0.04-in.-wide fractures. The solid line in Fig. 2 illustrates this equation:

$$u_l = 0.05\, t^{-0.55} \quad\text{...(2)}$$

Five experiments were performed in fractures with widths of 0.08 in. and heights of 1.5 in. Four of these experiments were performed in 4-ft-long fractures using injection fluxes ranging from 207 to 16,500 ft/d. One experiment was performed in a 32-ft-long fracture using a flux of 5,170 ft/d. The open diamonds in Fig. 2 show the leakoff results.

One experiment was performed at a flux of 8,300 ft/d in a 0.16-in.-wide fracture. A final experiment was performed at a flux of 66,200 ft/d in a 0.02-in.-wide fracture. For these latter two experiments, fracture lengths were 4 ft and fracture heights were 1.5 in. The leakoff data from these experiments and the 0.08-in.-wide fractures do not fit Eq. 2 as well as the results from the 0.04-in.-wide fractures. Nevertheless, Eq. 2 provides a reasonable estimate of the leakoff data.

Eq. 2 provides leakoff rates that are averaged over the length of the fracture (more specifically, over the gel-contacted length of the fracture). Eq. 3 relates the average leakoff rate to the local leakoff rate, u_i, at a given distance, L, along the fracture.

$$u_l = \int u_i \, dL / L \quad (3)$$

The rate of gel front propagation, dL/dt, in a two-wing fracture can be found using a mass balance (Eq. 4).

$$h_f \, w_f \, dL/dt = q_t - 4 \, h_f \, L \, u_l \quad (4)$$

In Eq. 4, h_f is fracture height, w_f is fracture width, and q_t is total volumetric injection rate. Combined with Eq. 2, Eq. 4 can easily be applied to predict rates of gel front propagation and gel dehydration.

$$h_f \, w_f \, dL/dt = q_t - 0.2 \, h_f \, L \;\; t^{-0.55} \quad (5)$$

Eq. 5 must be solved numerically, but the solution is straightforward. (Of course, the appropriate units must be used for the various parameters.) Comparisons of predictions from Eq. 5 with experimental values can be found in Refs. 10 and 12.

Linear versus Radial Flow. Most of the previous discussion is relevant to gel extrusion in linear flow—for example, in vertical fractures that cut through vertical wells. In contrast, in vertical fractures that cut through horizontal wells, the flow geometry is radial (at least, near the well). How does gel extrusion in radial flow compare with that in linear flow? This question was addressed explicitly in Ref. 8. Because the pressure gradient during gel extrusion is almost independent of injection flux, the pressure gradient is nearly independent of radial position from the wellbore.[8] This prediction was confirmed by experiments.[8] Therefore, Eq. 5 applies to gel extrusion in fractures with any orientation relative to the wellbore.

Model Predictions in Long Fractures. Eq. 5 was applied to predict gel propagation in long fractures. **Fig. 3** presents these predictions for three injection rates (0.1 to 10 barrels per minute, BPM) in 0.04-in.-wide, two-wing fractures using our standard Cr(III)-acetate-HPAM gel. At a given rate, Fig. 3 shows the gel volume that must be injected to achieve a given distance of penetration along the fracture. This volume increased with distance of penetration raised approximately to the 1.5 power. For a given distance of penetration, the required gel volume decreased substantially with increased injection rate. For example, to penetrate 200 ft, the required gel volume was 5 times less at 10 BPM than at 1 BPM. Therefore, to maximize gel penetration, the highest practical injection rate should be used.

Eq. 5 was also applied assuming that it was valid for fracture widths ranging from 0.01 to 1 in. **Fig. 4** plots the predicted distances of gel penetration versus the volume of gel injected for three fracture widths during gel injection at 1 barrel per minute. Interestingly, the curves came together at high distances of penetration and low fracture widths. This result occurred because the rate of gel propagation was governed increasingly by the rate of gel dehydration (i.e., water leakoff given by Eq. 2) as fracture width decreased or as the desired distance of gel penetration increased. In contrast, for a fixed injection rate, gel propagation was governed simply by the fracture width (or volume) for large fracture widths or small distances of gel penetration.

A useful rule of thumb can be realized from the 1.5-power dependence of volume on distance of penetration in Figs. 3 and 4 (i.e., at moderate to large distances of penetration). Specifically, if the volume of gel needed to reach a certain distance of penetration is known, then reaching twice that distance requires injecting roughly three times the gel volume. In contrast, for "normal" behavior (i.e., if dehydration did not occur), doubling the distance of penetration only requires a doubling of gel volume. This "normal" behavior is approached for small distances of penetration and wide fractures. For example, in Fig. 4, the 1-in.-wide fracture approaches normal behavior for small distances of penetration (i.e., the slope approaches 1).

Rapid versus Slow Injection. The experimental results and calculations indicate that to maximize gel penetration along a fracture, the gel should be injected as rapidly as practical. However, in wide fractures, gel dehydration may be desirable to form rigid gels that are less likely to wash out after placement. In these applications, reduced injection rates may be appropriate. Our model may be used to estimate final gel concentrations as a function of injection rate.[10-12]

Field Treatments

Case History. Detailed discussion of this treatment, including candidate selection procedure, gel treatment design, and results are contained in an earlier paper; well and treatment description presented here draw from that earlier work.[5]

The candidate is a waterflood producer drilled on the periphery of the field, where total pay thickness of the ~50 – 100-mD sandstone is <50 ft and formation temperature is ~90°C (195°F). Reservoir pressure at time of treatment was ~3,200 psi. The completion is a cased and cemented liner that is nearly horizontal (85°) through the pay zone. The well was terminated at 11,853 ft measured depth (9,009 ft true vertical depth). Lost circulation problems were encountered during drilling beginning at 11,327 ft; returns averaged 70% from there to total depth. Gamma ray/neutron logs showed washed out shale at 11,335 ft, with repeats that suggested faulting. A cement bond log indicated poor bond quality uphole from 11,338 ft.

The gas-lifted well was completed with 4.5-in. tubing from surface to 10,640 ft. The 7-in. liner was perforated over the intervals 10,690 – 10,800 ft and 11,235 – 11,580 ft. It produced initially at 1,500 barrels of oil per day at 24% water cut. However, within three months, the oil rate had dropped to

~400 BOPD at ~90% water cut. A production log (2/90) indicated that all measurable production occurred between 11,327 and 11,345 ft. There was a +1°C (1.8°F) temperature anomaly at 11,338 ft, with no other anomalies noted. Thus all significant inflow was from, or very near, the faulted interval. As of mid-1993, the well had produced over 3.7 million barrels of water, which was shown by analysis to be nearly 100% aquifer water. All data supported a mechanism whereby the near-horizontal portion of the wellbore intersected a fault in the vicinity of 11,338 ft that connected the wellbore to the underlying aquifer. The aquifer was estimated to lie ~50 ft below the wellbore.

A cement squeeze to shut off water influx from the offending region was considered and rejected. The probablility of a successful cement squeeze was considered low, due to probable loss of whole cement to the fault. Evidence that this had happened during primary cementing was seen by the poor quality of the cement bond uphole of this region. In addition, there was concern that even if a cement squeeze were successful at sealing the fault at the wellbore, water influx *via* the fault could still occur unless the fault were sealed for several feet from the wellbore—a requirement not likely to be met by a cement squeeze under any circumstance. The only type of treatment considered capable of plugging the faulted interval for several feet from the wellbore was a polymer gel.

Given the poor cement bond up-hole from the faulted region, there was concern that mechanical zone isolation in the wellbore would not be successful at protecting the perforated intervals above the target interval. Thus the decision was made to treat with a gel that had documented success in selectively plugging natural fractures while preserving most of the matrix permeability after bullhead placement.[2] Such gel systems are often referred to as “flowing”, “tonguing”, “weak” or “fracture-plugging” gels. Chemically, they are characterized by a relatively high molecular weight polymer (>10^6 Daltons) employed at low concentration (0.30 – 1.20 % w/w). Physically, they are usually pumpable even after complete gelation, hence their descriptive nicknames. Even with some documentation of success, treatment with such a gel was considered a high-risk option because the mechanism of selective fissure-plugging was not well understood in the industry at the time.

The treatment design called for an upper limit of gel volume of 12,000 bbls. This was based on estimates of an average porosity of up to ~40% for the 20-foot fault zone and a 50-foot radius of treatment. Assuming no losses to matrix or gel dehydration, an assumption now believed incorrect based on subsequent research, this volume was believed to be capable of treating the fault zone over the distance from the wellbore to the aquifer. It was understood that a smaller volume would be pumped if maximum wellhead treating pressure was reached (~1,200 psi) before the design maximum volume was pumped. Makeup water for the gel was deoxygenated seawater at ~26°C (80°F). The simple rigup for the treatment is shown in **Fig. 5**. (Gel compositions are indicated in **Table 1**.)

The job was conducted in November 1993. Pump rate was held constant at 2 BPM. Initial wellhead pressure (WHP) was 400 psi, due to the presence of gas in the wellbore. As gas was displaced to the formation with a preflush of uncrosslinked polymer, the well went on vacuum. Pressure then rose gradually throughout the treatment, with modest positive and negative excursions, the causes of which are not clear, but which have been observed in most subsequent treatments. Volumes and average pressure behavior during treatment are summarized in the pump schedule shown in Table 1. One positive pressure excursion of several hours was observed after an equipment malfunction resulted in a 1.5-hour shutdown of the job.[5] The entire job took approximately 100 hours. Much of the gelation process occurred during the treatment. Even so, the well was shut in for five days as a precaution to insure that gelation was complete.

Fig. 6 is a production history of the well from startup in 1/89, through the 11/93 gel treatment and continuing until early 1996, while **Fig. 7** is a semi-log plot of water-oil-ratio (WOR) *vs*. cumulative oil production. These figures illustrate the success of the treatment. By shutting off unproductive water influxing through the fault system, well hydraulics were improved, thus significantly increasing the oil production rate. Thus oil production revenues were increased at the same time that water-handling costs were decreased. Fluid production behavior of the well since the treatment has been that expected for a maturing waterflood producer—total fluid rate has been nearly constant, with oil declining and water increasing.

As can be seen in Fig. 7, the WOR *vs*. cumulative oil trend has been permanently offset. Extrapolation of the before- and after-treatment slopes to some arbitrary economic limit of WOR, say 95%, demonstrates that the treatment has resulted in a considerable increase in economic reserves for this well.

Table 2 summarizes production behavior before and after treatment. Water productivity index (PI) was decreased by 75% while oil PI was initially decreased by 25%. Even with some damage to oil PI, the oil production rate increased due to improved hydraulics. After a month, and installation of a deeper gas lift design made possible by the improved hydraulics, the original oil PI had been nearly restored, while damage to water PI was nearly as great as immediately after the treatment. In light of recent research, we interpret the temporary loss of oil PI to plugging of perforations by dehydrated gel during the 100-hour treatment. With time and high drawdown pressure (estimated to be ~2,400 psi post-gas lift redesign), gel damage to perforations was mechanically removed by inflowing fluid.

Evolution of Field Treatment Design. Treatment design for the above case was developed in order to provide the highest reasonable probability of technical and economic success, with less emphasis on optimized cost. In subsequent treatments on similar horizontal wells in a number of fields, treatment volume has been decreased to 3,000 – 6,000 bbls of gel. In an effort to minimize the length of time that productive matrix is exposed to gel being pumped under pressure, and thus minimize damage to oil PI, placement rates have increased to 4 BPM or greater. The result has been that even short-lived damage to oil PI is not usually observed. Although developed empirically in the field, this is consistent with minimizing damage from the time-dependent gel dehydration discussed earlier. High-rate gel injection with no damage to oil PI has been routinely observed for uncemented completions and a dual lateral completion in addition to cemented liner completions. In individual instances, placement rates of 6, 8, and even 12 BPM were used in wells with very prolific faults.[14] However, in the case of a very massive fault or fracture, back-production of gel from a treated production well was often observed.[15] Based on the research results described earlier, it is likely that in such cases a lower placement rate will be desirable for all or some portion of the treatment. This could be done to encourage a *greater* degree of gel dehydration in the gel stage(s) nearest the wellbore to strengthen the gel there and thus minimize back production.

Estimation of Treatment Performance. From post-treatment performance of the field case and a number of similar faulted or fractured horizontal wells, it is possible to estimate post-treatment well performance of candidate wells in order to determine expected treatment economics. Observed reduction in water PI has consistently been 50 – 75%. Reduction in oil PI, where observed, has been temporary and no greater than ~25%. From this information, an analysis can be performed to estimate post-treatment water and oil rates. Improvement in oil rates will be due to the greater drawdown pressure allowed by the lower hydrostatic head and lower friction pressure in tubulars due to decreased water PI. Gel treatments do not increase oil PI—they are not stimulation treatments. Thus if there is no possibility of increased drawdown post-treatment, then there can be no reasonable expectation of increased oil rate.

Connecting Laboratory and Field Results

In this section, we examine the relation between field and laboratory results. Three important points will become evident from this discussion. First, fairly simple calculations can give at least a rudimentary indication of the width of the fracture that causes the excess water production. For the case of vertical fractures or faults that cross horizontal production wells, these calculations can also give an idea of how far the gel should penetrate to provide a beneficial effect. Using laboratory data coupled with field data collected before, during, and after gel injection, the calculations can also give an indication of how far the gel has actually penetrated into the fracture.

Second, this analysis points out areas where additional laboratory work is needed to aid in the design of field applications. In particular, a need exists for determination of gel extrusion properties at higher temperatures—at least up to 100°C. Also, a need exists to determine gel extrusion properties for gels over a range of concentrations, e.g., for polymer concentrations from 0.3% to 1.5%.

Third, our analysis reveals critical measurements that should be made during field applications. In particular, accurate flowing and static downhole pressures should be made at least before and after the gel treatment is applied. Some very useful insights can be gained if downhole pressures are measured during gel injection.

Fracture Characterization before the Treatment. Using the Darcy equation for radial flow, one can often confirm that a fracture (or fault) is or is not the cause of excess water production.[1] Eq. 6 provides the simplest form of this equation.

$$q/Dp = \Sigma\, k\, h \,/\, [\mu \ln (r_e / r_w)] \quad \text{.......................................(6)}$$

If the actual productivity index (i.e., the left side of Eq. 6) is less than or equal to the right side of Eq. 6, then a fracture or fault may not be the cause of the water problem. However, if the left side of Eq. 6 is significantly greater than the right side, then a linear-flow feature (e.g., a fracture) probably does cause the problem.[1] When using this equation, several points should be noted. First, the production rate, q, should include all significant fluid contributions (i.e., water, oil, and gas). Second, the downhole pressure drop, Dp, (the average reservoir pressure in the vicinity of the well minus the pressure in the wellbore) must be accurate and current. Third, the permeability(s) used in Eq. 6 must be from logs, core analysis, or pressure-transient data—not from production data.

In our field example (described earlier), before the gel treatment was applied, the total production rate was 4,756 BPD (466 BOPD + 4,290 BWPD), the pressure drawdown, Dp, was 1,600 psi (derived from Table 2), and water viscosity, μ, at reservoir temperature was about 0.3 cp. (Since water dominates fluid production, we can neglect the viscosity contribution from oil). Most of the measured production came from within an 18-ft interval, so initially, h in Eq. 6 will be given this value. The formation permeability, k, was on the order of 100-mD (from core analyses). The natural log term in Eq. 6 commonly has a value of 6 or 7. Inputting these values into Eq. 6 (using the appropriate conversion factors) reveals that the actual productivity index, q/Dp, was at least 4.5 times greater than that calculated from the right side of Eq. 6. This result confirms that a fracture (or more correctly, a fault in this case) caused the problem.

Eq. 6 can also be used to estimate the width and conductivity of the fault. In this case, we assume that all water production flows through the fault, and fracture conductivity, $k_f w_f$, is substituted for $\Sigma\, k\, h$ in Eq. 6. Using the parameters from the previous paragraph, fracture conductivity was estimated to be 681 darcy-ft. This conductivity can then be converted to an effective average fracture width using Eq. 7 (taken from Ref. 13).

$$w_f = 5.03 \times 10^{-4} \, (k_f w_f)^{1/3} \quad \text{,...(7)}$$

where $k_f w_f$ has units of darcy-ft and w_f has units of ft. Eq. 7 estimates that the fault has a width of 0.053 inches.

How Far into the Fault Should the Gel Penetrate? If the water production problem is caused by a single fracture or fault that intersects the horizontal wellbore, the distance of gel penetration into the fracture does not need to be particularly large.[14] In this case, the benefit gained varies approximately logarithmically with the distance of gel penetration. This point is illustrated in **Fig. 8**. The *y*-axis in this figure plots the productivity of the well relative to the productivity for the case where no fracture or fault is present. In other words, the *y*-value indicates the excess water contribution from the fault as a function of the radial distance of gel penetration into the fault (*x*-axis). In this example, if the fault is present and no gel treatment is applied, the well productivity is seven times greater than the case where no fault exists. Unfortunately, the extra well productivity comes only in the form of a large amount of water that channels through the fault from the aquifer. If the gel penetrates 400 ft into the fault, the well productivity is about the same as the case where no fault exists.

Fig. 8 reveals that most of the benefit from the gel treatment is achieved with relatively short distances of penetration. The well's water productivity is cut in half by only 3 ft of gel penetration and is reduced by about 75% with 20 ft of gel penetration. Thus, large-volume treatments may not be needed in this case. However, we must emphasize that this conclusion is specific to the particular scenario that we describe—i.e., a single fault or fracture intersecting a horizontal well. The conclusion may not be valid for vertical wells or if multiple fractures or faults intersect a horizontal well, or if a natural fracture system is present. Furthermore, even for the case of a single fault or fracture that intersects a horizontal well, some value may be realized by injecting a significant amount of gel to mitigate the possibility of gel washout after the well is returned to production. In the particular field example under discussion, no gel washout was observed.

Was the Injected Material a Gel or a Gelant? After the gel formulation was mixed and injected at 2 BPM, approximately 2 hours were required for the gelant to travel from the wellhead to the treated zone (225 bbl). Considering the high downhole temperature (~90°C at the start of gel injection) and the gelation times for these gels (a few hours at low temperatures; around 10 minutes at 90°C), we believe that the formulation existed as a gel (rather than as a fluid gelant solution) at the time it entered the fault.

How Far Did the Gel Penetrate? Two methods exist that allow us to estimate how far gel actually penetrated into the fault in the field application. Both methods rely on laboratory and field measurements. As will be seen, our application of these methods reveal a need for accurate measurements of pressure drawdowns in field applications and for laboratory measurement of gel-extrusion properties over a wider range of temperatures and gel compositions.

The first method is based on Fig. 1. This method requires knowledge of the downhole pressure drops during gel injection, the width of the fracture or fault, and the pressure gradient required to extrude the gel through a fracture of the given width. In our field example, we estimated the fault width to be 0.053 inches (discussed above). From Eq. 1, the pressure gradient during gel extrusion should be around 7 psi/ft if the gel contained 0.5% Alcoflood 935 HPAM and 0.0417% Cr(III)-acetate and the fracture temperature was 41°C. In reality, the reservoir temperature was around 90°C and a range of gel compositions were injected—with gels containing from 0.3% to 0.9% HPAM. (See Table 1. The polymer used and the relative Cr(III)-acetate concentrations were similar to those used in the laboratory experiments.) In the absence of gel extrusion data at 90°C and at other compositions, we must use existing data and appreciate the errors that may be introduced.

Assuming that the pressure gradient for gel extrusion is 7 psi/ft, the distance of gel penetration into the fault can be estimated from the downhole pressure drops. At the start of injection of the 0.45%-HPAM gel, the downhole pressure drop was estimated to be 946 psi. This value derives from the measured wellhead pressure of 225 psi (Table 1), a calculated pressure difference from the wellhead to the downhole well location (3,921 psi), and an estimated reservoir pressure of 3,200 psi. By dividing 946 psi by 7 psi/ft, the position of the gel front is estimated at 135 ft from the wellbore. At this time, injection of 2,045 bbl of 0.3%-HPAM gel was just completed, and injection of 5,500 bbl of 0.45%-HPAM gel had just started. One could argue that the extrusion properties of 0.3%-HPAM gel would be more appropriate as input for this calculation. Also, the calculation would be more reliable if a current, accurate downhole pressure drop was available in place of the estimated numbers. Again, these observations emphasize the importance of accurate downhole pressure measurements and of additional laboratory measurement of gel extrusion properties.

At the end of injection of the 0.45%-HPAM gel, the downhole pressure drop was estimated to be 1,246 psi. This value derives from the measured wellhead pressure of 525 psi (Table 1) in the same manner described above. By dividing 1,246 psi by 7 psi/ft, the position of the gel front is estimated at 178 ft from the wellbore. Thus, the method suggests that injecting 5,500 bbl of gel advanced the gel front by 32% (i.e., from 135 to 178 ft from the wellbore).

A second method can be used to estimate gel propagation. This method is based on Figs. 3 and 4. It assumes that gel dehydration dominates the rate of gel propagation so that the volume (V) of gel required to advance the gel front by a given distance is proportional to the 1.5 power of the new fracture area that is contacted by gel. For linear flow (e.g., a vertical well that is cut by a vertical fracture), this relation is given by Eq. 8:

$$V_2 / V_1 = (L_2 / L_1)^{1.5} \text{ , } \qquad (8)$$

Where V_2 represents the total volume of gel injected to reach a distance, L_2, of gel penetration into the fracture. For radial flow (e.g., a horizontal well that is cut by a vertical fracture or fault), this relation is given by Eq. 9:

$$V_2 / V_1 = [(r_2 / r_1)^2]^{1.5} , \qquad (9)$$

where V_2 represents the total volume of gel injected to reach a radius, r_2, of gel penetration into the fracture. Given values of 2,045 bbl, 7,545 bbl, and 135 ft for the parameters, V_1, V_2, and r_1, respectively, Eq. 9 estimates the radius of gel penetration to be 209 ft after injecting the 0.45%-HPAM gel bank. Thus, this method suggests that injecting 5,500 bbl of gel advanced the gel front by 55%, compared with 32% for the first method. Perhaps, the two methods would have been in closer agreement if more accurate gel extrusion properties and downhole pressures were available.

How Effectively Did Gel Seal the Fault? Earlier, we used Eq. 6 to estimate the conductivity of the fault before gel injection (681 darcy-ft). The same equation can be used to estimate fault conductivity after the gel treatment. One month after the treatment, the well produced 1,895 BWPD and 727 BOPD with a pressure drawdown of 2,430 psi. Assuming that all 1,895 BWPD were produced from the fault after the treatment, fault conductivity is calculated to be 198 darcy-ft. This result suggests that the fault conductivity was reduced 71% by the gel treatment—thus the treatment did not completely seal the fault. However, the calculation may be somewhat conservative. Consider the case where before the treatment, none of the oil was produced from the fault; however, some water was produced from portions of the well other than those associated with the fault. To justify this possibility, the spinner tool used to measure flow profiles before the treatment probably could not accurately detect differences less than 10%-15% of the total flow. Thus, the 466 BOPD and an equal volume of water could have entered the well somewhere other than at the fault. In that case, the conductivity of the fault may have been reduced by 80% by the gel treatment. Of course, more accurate profile logs could help resolve this issue.

Table 2 reveals that immediately after the gel treatment, the oil productivity index was reduced from 0.32 to 0.24 BPD/psi. However, one month after the treatment, the oil productivity index rose to 0.3 BPD/psi. Thus, the treatment reduced water productivity index much more than that for oil. This fact provides further evidence that the oil was not produced through the fault.

Conclusions

1. Polymer gel water shutoff treatments can be successfully bullheaded in faulted horizontal wells.

2. Simple calculations can give at least a rudimentary indication of the width of the fracture or fault that causes excess water production. For the case of vertical fractures or faults that cross horizontal production wells, these calculations can also give an idea of how far gel should penetrate to provide a beneficial effect. Using laboratory data coupled with field data collected before, during, and after gel injection, the calculations can also give an indication of how far the gel has actually penetrated into the fracture.

3. Our analyses point out areas where additional laboratory work is needed to aid in the design of field applications. In particular, a need exists for determination of gel extrusion properties at higher temperatures—at least up to 100°C. Also, a need exists to determine gel extrusion properties for gels over a range of concentrations, e.g., for polymer concentrations from 0.3% to 1.5%.

4. Our analyses reveal critical measurements that should be made during field applications. In particular, accurate flowing and static downhole pressures should be made at least before and after the gel treatment is applied. Some very useful insights can also be gained if downhole pressures are measured during gel injection.

Nomenclature

h_f = fracture height, ft [m]
k_f = fracture permeability, darcys [μm^2]
k_{gel} = gel permeability to water, darcys [μm^2]
L = distance along a fracture, ft [m]
L_f = fracture length, ft [m]
Dp = pressure drop, psi [Pa]
dp/dl = pressure gradient, psi/ft [Pa/m]
q = total injection or production rate, BPD [m^3/d]
r = radius of penetration along a fracture, ft [m]
u_i = local water leakoff rate, ft/d [cm/s]
u_l = water leakoff rate, ft/d [cm/s]
t = time, s
V = volume of gel injected, bbl [m^3]
w_f = fracture width, in. [m]

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Polymer (wt %)*	WHIP (psi)	Volume (bbls)	Comment
0.30	400 – 0	22	preflush
0.30	0 - 250	2045	
0.45	225 - 525	5500	
0.60	500 - 675	3225	
0.90	725 - 800	740	
0.30	800	100	overflush

Pump rate 2 BPM throughout
*Gels contained 1 part Cr(III)-acetate per 12 parts polymer (HPAM).

Table 1. Case History: Well Gel Job Data

Time	Oil (BPD)	Water (BPD)	WC (%)	Oil (PI)	Water (PI)
11/93	466	4290	90	0.32	2.95
Post-job	543	1700	76	0.24	0.74
1 mo	727	1895	72	0.30	0.78
1 yr	665	2175	77	-	-
1.5 yr	567	2410	81	-	-

Table 2. Case History: Well Production Data

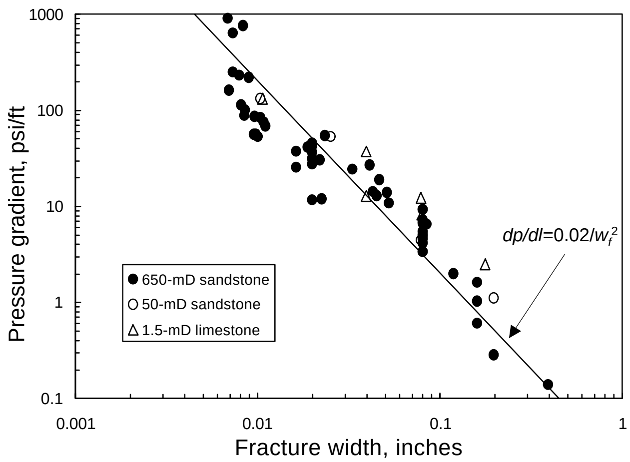

Fig. 1—Pressure gradients required for gel extrusion through open fractures.

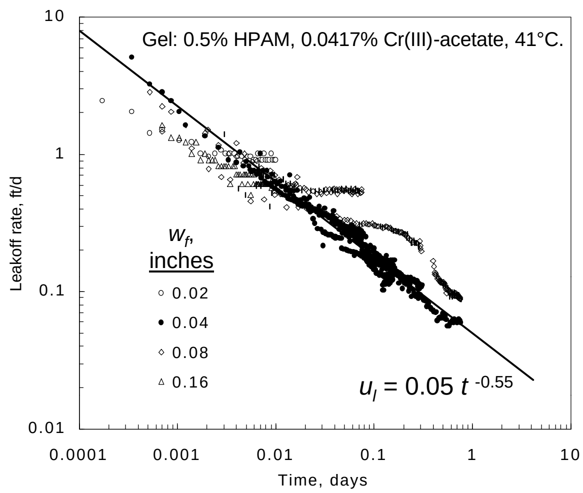

Fig. 2—Leakoff rates from 15 gel extrusion experiments.

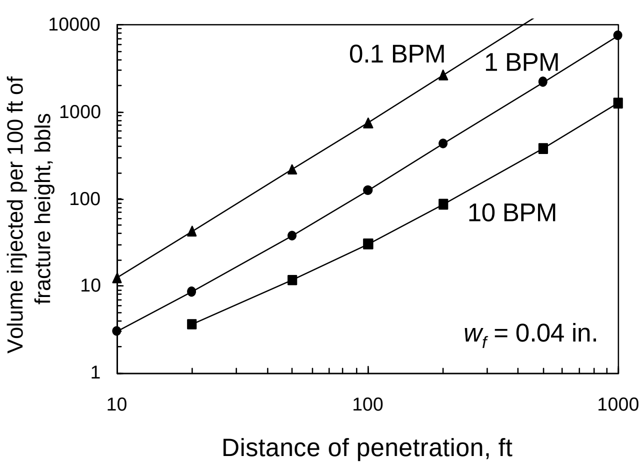

Fig. 3—Predictions in long two-wing fractures at different rates.

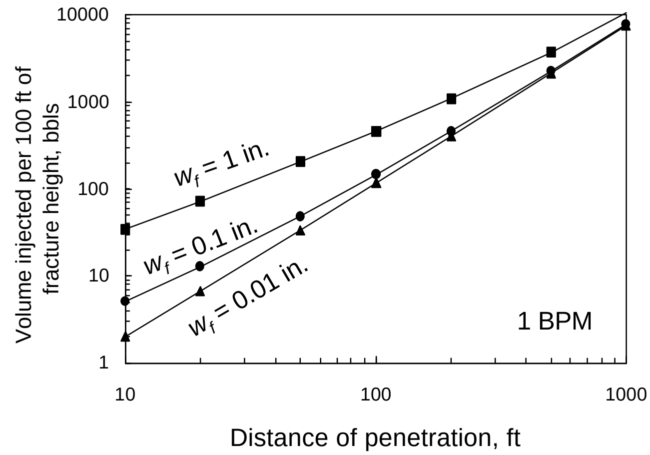

Fig. 4—Predictions in long two-wing fractures with different widths.

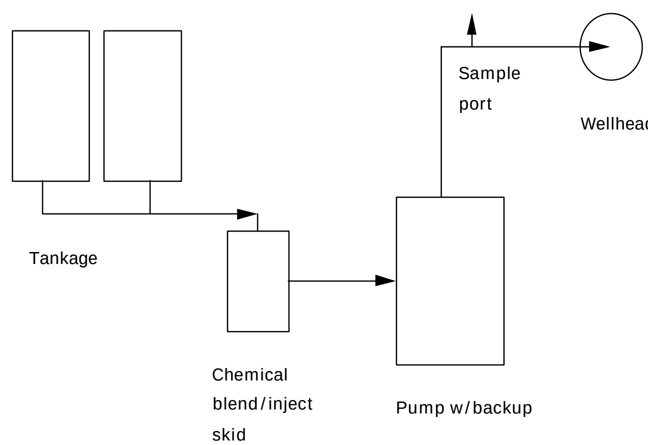

Fig. 5—Simple rigup for bullhead gel treatment.

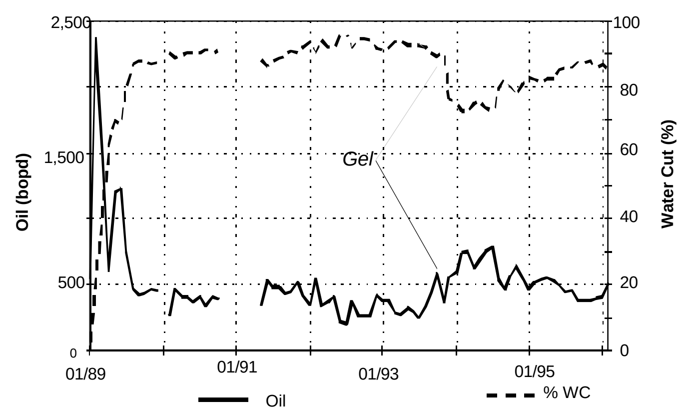

Fig. 6—Production history of field example.

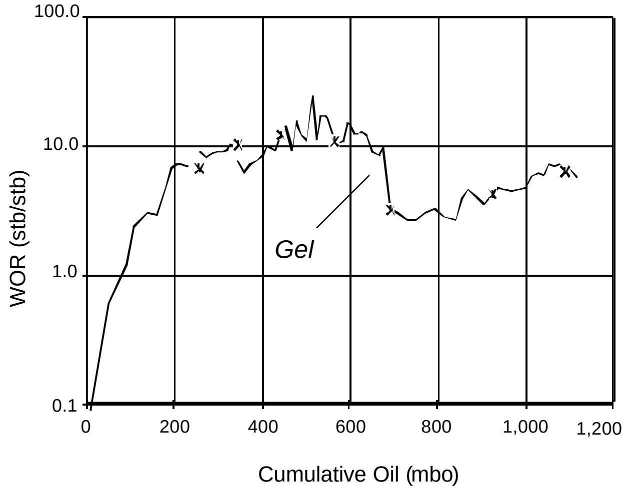

Fig. 7—Water-oil-ratio vs. cumultive oil production for the field example.

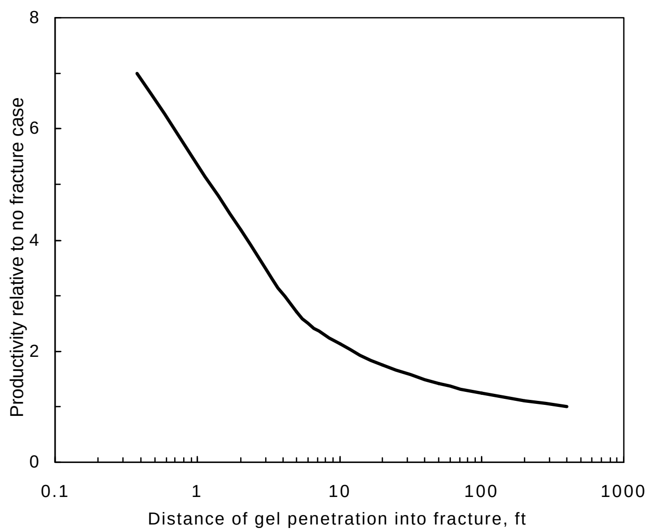

Fig. 8—Effect of gel penetration on fault plugging.