CONFORMANCE-IMPROVEMENT-TREATMENT DESIGN AND IMPLEMENTATION STRATEGIES TO MAXIMIZE PERFORMANCE – BASED ON 20 YEARS OF EXPERIENCE WITH A SINGLE POLYMER-GEL TECHNOLOGY

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ABSTRACT

Based on 20 years of experience with a single oilfield polymer-gel technology, design and implementation strategies are enumerated for maximizing the performance and the economic rate of return for polymer-gel conformance-improvement treatments that are applied to fractured and other high-permeability-anomaly-containing oil and gas reservoirs. The design and implementation strategies are based on two decades of experience with successful large field projects involving the application of the CC/AP (chromium(III)-carboxylate/acrylamide-polymer) gel conformance-improvement technology, where most of the results of these field projects have been reported in the open scientific and/or petroleum-engineering literature. When all other factors are equal and held constant, increasing the volume of such gel treatments often correlates with improved treatment performance and economics. As a separate topic, it is noted that the application of polymer-gel conformance-improvement treatments in conjunction with CO_2 flooding in naturally fractured reservoirs is an often overlooked and under utilized strategy that holds substantial economic promise.

INTRODUCTION

This paper is based on the author's 20-years of experience in successfully applying the CC/AP (chromium(III)-carboxylate/acrylamide-polymer) gel conformance-improvement technology,[1,2] where this experience has involved the application of these gels where chromic triacetate is normally used as the chemical crosslinking agent within the aqueous polymer gels. The chromic-triacetate CC/AP gel technology has emerged to become, on a worldwide basis, one of the most widely and most successfully applied petroleum-industry conformance-improvement gel technologies.

This paper is limited to discussing gel treatments of petroleum reservoirs that are suffering from conformance problems involving the counter-productive channeling of fluids through fractures or other high-permeability-anomaly flow conduits having permeabilities greater than roughly 2 darcies. Such other high-permeability anomalies can include: solution channels, interconnected vugs, rubblized zones, karsted features, ultra-high matrix rock permeability (greater than 2 darcies), faults, and joints. This paper will not consider polymer-gel conformance-improvement treatments that are applied to matrix-rock-only petroleum reservoirs where conformance problems result from variations in permeability in the matrix reservoir rock and where the high-permeability reservoir flow channels have permeabilities less than roughly 2 darcies. This paper will also not consider gel treatments that are applied to high-temperature (>180° F) reservoirs.

The primary objective of this paper is to provide the reader with design and implementation strategies on how to maximize the performance and the economic rate of return for polymer-gel conformance-improvement treatments that are applied to oil or gas reservoirs suffering from fracture or other high-permeability-anomaly reservoir flow-channel conformance problems. For the sake of simplicity during the remainder of this paper, only fractured reservoirs will, for the most part, be discussed in terms of being treated with conformance-improvement polymer gels. However, it is imperative to note that *all the material that is subsequently discussed in this paper relating to fractured reservoirs being treated with polymer gels also applies to reservoirs containing other high-permeability-anomaly flow channels, such as solution channels or interconnected vugular porosity*.

All of the following discussion in this paper will assume that an effective, appropriate, and state-of-the-art conformance-improvement polymer-gel technology is being applied to the reservoir, well, and/or well pattern being discussed.

This paper will also briefly touch on the often overlooked and economically promising use of polymer-gel conformance-improvement treatments to improve conformance and to substantially improve the performance and the economics of many CO_2 flooding operations that are being conducted in naturally fractured oil reservoirs.

STRATEGIES TO MAXIMIZE PERFORMANCE

To follow is a discussion of design and implementation strategies for improving the performance, and for maximizing the economic rate of return, of conformance-improvement polymer-gel treatments that are applied to oil or gas reservoirs suffering from detrimental, counterproductive, and often costly fracture or other high-permeability-anomaly flow-channel problems within the reservoir.

Strive for Truly Attractive Production Responses

This paper is striving to provide for operators strategies that can be applied when implementing conformance-improvement polymer-gel treatments so as to generate undeniably attractive economic rates of return from the gel treatments and to generate undisputable large volumes of economically attractive incremental oil or gas production. This author likes to strive, whenever possible, for undisputable and unequivocal favorable treatment responses from conformance gel treatments, where the measurement of the treatment response does *not* rely on for example: 1) minor and hard to verify changes in oil-production decline curves, or 2) the use of projections for future incremental oil production derived from the extrapolation of WOR (water/oil ratio) vs. cumulative oil production curves to the economic limit for WOR.

The type of unequivocal favorable production response, which this author strives for when applying conformance-improvement polymer-gel treatments to naturally fractured reservoirs, is shown in the following three figures. Figures 1 and 2 show the production response to two CC/AP gel sweep-improvement treatments that were applied to injection wells of a naturally fractured carbonate reservoir in the SOB field of the Big Horn Basin of Wyoming. These two treatments were part of the seven first-ever CC/AP gel treatments applied to fractured injection wells in Wyoming. The production responses shown in the two figures are the combined production responses for all four of the directly offsetting production wells to the gel-treated injection well. Incremental oil production resulting from these two sweep-improvement gel treatments is unequivocally and undeniably demonstrated. For more information regarding these two gel sweep-improvement treatments, see Reference 6. Figure 3 shows the production response to the first ever CC/AP ("flowing") gel water-shutoff (WSO) treatment that was applied to a naturally fractured production well. This well was located in the Big Horn Basin of Wyoming. As strived for, this figure shows, undeniably and unequivocally, that the gel treatment did favorably reduce water production from the treated well. For more information regarding this gel WSO treatment, also see Reference 6.

Permeability of Offending Flow Channels

Historically, there has been a very pervasive trend whereby operators, when first considering the application of conformance-improvement gel treatments to a new field, tend to badly underestimate the fluid-flow capacity (permeability) of the high-permeability channels and flow paths within the reservoir to be treated.[2] This trend is so pervasive that it could almost be referred to as a "law" for gel conformance-improvement treatments.

At this point, it is not being suggested that an operator, who is applying a conformance-improvement gel treatment for the first time in a new field, should abandon or fudge the best estimate that the operator has for the permeability of the high-permeability channels within the reservoir in question.

The strategy that is suggested is one that can have a profound positive effect on the performance and the outcome of such a first-time gel treatment. The strategy is for the operator to realize that there is a *probability* that the permeability of the high-permeability channels within the reservoir to be treated is actually greater than what has been estimated. Thus in the design of the gel treatment, the gel that is emplaced should be designed to not only successfully treat the estimated permeability of the offending high-permeability flow channels, but also be able to effectively treat the offending flow channels should they actually have permeabilities that are much greater that what were initially estimated.

Injection Vs. Production Well Treatments[2,13]

In general, gel sweep-improvement treatments in naturally fractured reservoirs for promoting incremental oil production are most advantageously applied from the injection-well side. During oil-recovery flooding operations, there is no place within a well pattern, when applying a sweep-improvement treatment, from which you can potentially generated more incremental oil than when successfully conducting a sweep-improvement treatment at the injection well. When a sweep-improvement treatment is conducted at the injection well, it holds the potential of being able to redirect the oil-recovery fluid flow so as to be able better sweep the *entire* well pattern.

On the other hand and in general, when applying polymer-gel treatments for water or gas shutoff purposes and for the associated purpose of reducing OPEX, such gel conformance-improvement treatments are most advantageously applied from the production-well side. Such conformance-improvement treatments are most often smaller in size and less expensive than injection-well conformance-improvement treatments for application within a given well pattern. In addition, favorable production responses to production-well treatments most often occur faster than for injection-well conformance-improvement treatments. In fact, normally when a production well is put back on production following a water or gas shutoff gel treatment, the operator will immediately be able to get a sense of how successful the gel treatment will be.

An important exception to the above guidelines is when treating conformance problems in a naturally fractured reservoir undergoing gas flooding (especially CO_2 flooding). In this situation, no matter whether the objective is to promote sweep improvement or fluid shutoff, gel treatments are, in general, more advantageously applied from the injection-well side.

Moveable Oil Must Be Present

In view that conformance-improvement treatments do not reduce residual oil saturation or increase microscopic displacement efficiency during oil-recovery flooding operations, there must be an economically attractive volume of moveable oil saturation within the well pattern to be treated with a gel conformance treatment, or such a gel treatment should not be undertaken. Stated conversely, a conformance-improvement gel treatment will be of no value when placed within a well pattern that has been previously thoroughly swept during an oil-recovery flooding operation (e.g., waterflooding).

The Worse the Conformance Problem, the Better Is the Candidate Well Pattern

As a corollary to the previous section, the worse the conformance problem and the more problematic is the reservoir high-permeability flow-channel anomaly, the poorer will be the sweep efficiency of any given oil-recovery flooding operation and the more unswept moveable oil saturation will likely be remaining within any given well pattern after a given amount of oil-recovery flood fluid has been injected.

Thus, when holding all other factors equal and constant, in general well-patterns having the most problematic high-permeability-anomaly flow channels can be (if an appropriate and strong enough gel is available) a favored candidate for a conformance-improvement polymer-gel treatment.

High WOR Favored[2]

When conducting production-well polymer-gel water-shutoff (WSO) treatments in naturally fractured reservoirs, wells producing at high WOR (water/oil ratio) are normally favored over wells producing at low WOR. This is because of two factors. First, at low WOR, there is more of a propensity of inadvertently shutting off oil production, and as a consequence, suffering an adverse economic outcome. Second, at high WOR, there is much larger water-production rate for the polymer-gel WSO treatment to be able to shutoff without harming the oil production rate. This results in a larger target for reducing OPEX resulting from excessive water production at high WOR. Furthermore, at high WOR, when the water production rate is reduced substantially, there is a larger potential target for the amount of incremental oil production that can be obtained as a result of having applied the gel WSO treatment.

Reservoir Plumbing

A key element that an oilfield operator must implement in order to be able to successfully apply conformance-improvement polymer-gel treatments to fractured reservoirs is to determine, or deduce, the nature of the reservoir flow channels causing the conformance problem that is to be treated. For production-well WSO treatments, this boils down to identifying the source of the excessive and undesirable water production and identifying the nature of the flow paths of such water from its source to the wellbore.

A cost-effective strategy that really seems to help with this task is for the operator to get himself/herself and his/her professional staff to attempt to visualize the reservoir's offending conformance problems in terms of the *"reservoir plumbing"* of the offending reservoir high-permeability-anomaly flow conduits.[2] This cost-effective strategy seems to work well because most oilfield personnel appear to quite readily be able to visualize high-permeability-anomaly flow conduits in terms of reservoir-plumbing concepts, where they may not be able to do so well at this task using more conventional reservoir-engineering concepts. The reservoir-plumbing strategy also often permits non-professional field personnel to make significant contributions to this critical process and determination.

For example when dealing with a reservoir natural-fracture network and an associated conformance problem, it is relatively quite intuitive for nearly all field and reservoir personnel to be able to appreciate the importance of the following *reservoir plumbing aspects* of the natural fracture network: 1) the aperture widths and width distribution of the fractures, 2) the height and height distribution of vertical fractures, 3) the volume of the fracture network, 4) the orientation in three-dimensional space of the various fractures, 5) the spacing density of the fracture network, and 6) the nature of the interconnectivity of the fractures.

Treat Simplest Problems First

When treating large and complex naturally fractured oil reservoirs, a good strategy is to apply gel conformance treatments first to wells and well patterns suffering from the most easily treated conformance problems. This concept is discussed in more detail in Reference 3 as it applies to WSO treatments.

When conducting production-well WSO treatments in naturally fractured reservoirs, polymer-gel WSO treatments are most effectively and most easily applied when the excessive water production is being produced up to the well via vertical fractures from an aquifer underlying the oil reservoir. In fact, this is a highly favored type of excessive water-production problem to be able to successfully treated with polymer-gel WSO treatments.[4]

Treatment Volume Considerations

The volume of present-generation and state-of-the-art successful polymer-gel treatments tend to be much larger (often by nearly an order of magnitude) than previous generation conformance-improvement polymer-gel treatments.[2,4-13]

During the previous generation of polymer-gel treatments that were applied to injection wells of naturally fractured reservoirs for sweep-improvement purposes, the gel treatment volume was often on the order of 1,000 bbl. Modern and state-of-the-art polymer-gel treatments for such sweep-improvement treatments often have gel treatment volumes on the order of 10,000 bbl and up.[5-9]

During the previous generation of polymer-gel treatments that were applied to production wells of naturally fractured reservoirs for WSO purposes, the gel treatment volume was often on the order of several 100 bbl. Modern and state-of-the-art gel treatments for such WSO treatments often have gel treatment volumes on the order of several 1,000 bbl.[4,10-12]

In general and when holding all other factors constant and equal, *there is a trend*, for conformance-improvement polymer-gel treatments that are applied to naturally fractured reservoirs, *for the amount of incremental oil production to increase with the volume of the gel treatment injected* (over the range of gel treatment volumes preformed and studied to date).

For example, this is shown in Figure 4 which is derived from data reported in Reference 6. This figure shows how the volume of incremental oil production increased with the volume of gel injected per foot of net formation interval for the first seven CC/AP gel sweep-improvement treatments that were ever applied to injection wells of naturally fractured oil reservoirs in the Big Horn Basin of Wyoming. The reservoir formations treated were a combination of the Tensleep sandstone formation and the Embar carbonate formation. The amount of polymer-gel injected for these seven gel treatments ranged up to 670 bbl of gel injected per perforated foot of net producing interval and up to 37,000 bbl of gel injected per treatment.

Figure 5 shows how the volume of incremental oil increased as the volume of the CC/AP gel WSO treatments increased for five production wells of the fractured Arbuckle carbonate formation in Kansas. This data is taken from Reference 10. The five wells of Figure 5 are all the open-hole completions wells of a seven-well set where a careful study of the seven CC/AP-gel-treated wells was conducted by University of Kansas personnel and where downhole pressure data were attained before, during, and following the gel treatments.

Regarding both Figures 4 and 5, it should be noted that the linear trend of these figures cannot extrapolate to infinity. That is, if one were to inject an infinite volume of gel, one would not recover an infinite volume of incremental oil from a finite reservoir. At some point, the curves of Figures 4 and 5 must eventually bend over. However, there is no indication for the volumes of the gel treatments depicted in these two figures that the largest-volume gel treatment injected is anywhere near this inflection point on the curve.

It also has been the experience of the author that spanning the volumes of conformance polymer-gel treatments that he has been involved with to date, increasing the volume size of the gel treatment not only tends to correlate with increasing incremental oil production, but also in general with increasing treatment profitability. Of course, this only holds when maintaining all other treatment factors constant and when there is good match between the applied polymer-gel technology and the conformance problems of the reservoir being treated.

Thus, the suggested strategy, when conducting conformance-improvement polymer-gel treatments in naturally fractured reservoirs, is to inject as large a volume of polymer gel as is reasonable in terms of economic and operational considerations.

Polymer Molecular Weight

The acrylamide polymer that has historically been employed most extensively in conformance-improvement CC/AP gels for routine use in naturally fractured reservoirs at reasonably low reservoir temperatures (<170°F) is hydrolyzed polyacrylamide (HPAM) that possesses an intermediate-high molecular weight (MW) of about 4 to 7 million amu (atomic mass units) and a hydrolysis level of 5 to 10 mole%. Such HPAM polymer is much less sensitive to mechanical shear degradation than the higher MW HPAM polymer that is used in sweep-improvement polymer flooding. Mechanical shear degradation of the polymer during gelant injection of a conformance treatment in a naturally fractured reservoir is not, for several reasons, nearly as much of a concern as mechanical shear degradation of the polymer is during polymer-augmented waterflooding.

However, it should be realized that when all other factors are held constant, the strength of a polymer gel does increase with the MW of the polymer used in the gel formulation.

Figure 6 shows, when all other factors are held constant, how gel strength increases with the MW of the polymer that is incorporated into a chromic-triacetate CC/AP gel formulation. This CC/AP gel was formulated with 2.0 wt% HPAM possessing a hydrolysis level of about 2 mole%. The gel was crosslinked with a chromic-triacetate crosslinker loading of 88:1 weight ratio of active HPAM polymer to Cr(III) of the crosslinking agent. The dynamic-oscillatory-viscosity gel strength was measured at 140°F, where the viscosity measurements were made at an oscillatory rate of 0.1 radian/sec and a strain of 100%. As an aside note, steady-shear viscometry cannot be used to measure polymer-gel combined elastic and storage modulus strengths. The just-listed dynamic-oscillatory-viscometry conditions will also hold for all the following plots involving dynamic oscillatory viscosity.

In view that there is often not a substantial price differential between HPAM polymers of intermediate-high MW and higher MW, then using gel formulations with relatively higher MW polymer can be an attractive and cost-effective means to increase the strength of a gel used in conformance treatments of fractured reservoirs.

However, there are several factors that must be considered when employing exceptionally high-MW polymer in a conformance gel formulation. First, the viscosity of the injected gelant solution will be relatively higher when holding all other gel-formulation factors constant. Second, when employing relatively high MW polymer, the gelant solution becomes relatively more sensitive and prone to mechanical shear degradation of the polymer during gelant-solution injection.

In general and strategy-wise for routine application of conformance-improvement polymer-gel treatments in fractured reservoirs, the use of intermediate-high MW (4 to 7 million amu) HPAM polymer is normally recommended by this author.

Polymer Hydrolysis

As noted in the previous section, the acrylamide polymer that has been historically employed most often in conformance-improvement polymer gels for routine use in naturally fractured reservoirs at relatively low reservoir temperatures (<170°F) is hydrolyzed polyacrylamide (HPAM) possessing an intermediate-high MW of about 4 to 7 million amu and a hydrolysis (carboxylate) level of 5 to 10 mole%. At such temperatures, the range of 5 to 10 mole% hydrolysis in conformance-gel HPAM polymer for treating fractures appears to be the optimum hydrolysis level for promoting maximum *inter*-polymer chemical crosslinking (desirable) and minimum *intra*-polymer chemical crosslinking (can be undesirable).

As the temperature of the reservoir to be treated rises (above about 150°F), HPAM polymer with lower hydrolysis (carboxylate) content is often used in the CC/AP gel formulation to be applied. The use of polymer with lower hydrolysis levels reduces the rate of gelation. When holding all other factors constant, the rate of gelation increases with increasing temperature.

Figure 7 shows how, when holding all other factors constant and over the studied temperature range, the rate of gelation for a chromic-triacetate CC/AP gel increases with increasing temperature.

When applying HPAM polymer gels to high-temperature (greater than ~180°F) reservoirs, spontaneous auto-hydrolysis of the polymer will occur with time within the reservoir. That is, the hydrolysis level of the polymer will spontaneously increase with time. Such spontaneous auto-hydrolysis of HPAM polymer invokes a whole host of additional considerations that are beyond the scope of the present paper. The discussion of strategies for the application of conformance-improvement polymer-gel treatments to high-temperature reservoirs is beyond the scope of this paper.

Crosslinking Agent Concentration

As shown in Figure 8, increasing the concentration of the chemical crosslinking agent of a polymer gel normally increases the gel strength when holding all other factors constant. In this figure, the chromic-triacetate CC/AP gel was formulated with 2.0 wt% HPAM polymer possessing a MW of 11 million amu and a hydrolysis level of about 2 mole%. The dynamic-oscillatory viscosity testing was conducted at 140°F. In this figure, the crosslinking-agent loading ranged from 40:1 to 10:1 weight ratio of active HPAM polymer to active chromic-triacetate crosslinking agent. Thus, the lower this ratio is, the higher is the crosslinking-agent concentration in the gel formulation. In this plot, the concentration of active chromic triacetate in the gel ranged from 500 to 2,000 ppm.

It is important for oilfield operators to note that varying the chemical crosslinking-agent concentration is not a good, nor the recommended, means and strategy to control gelation rates in the field setting for conformance-improvement polymer-gel treatments. Other means, such as using chemical gelation-rate retarding or accelerating agents or by varying the hydrolysis level of the HPAM polymer employed in a CC/AP gel formulation, should be used to control gelation rates. This is because the crosslinking-agent loading normally recommended by a conformance-improvement polymer-gel service company is usually set so that the recommended concentration will be somewhat below the crosslinker concentration where undesirable gel syneresis will set in. Gel syneresis occurs when too much crosslinking agent is added to the gel formulation. Decreasing the crosslinking-agent concentration below the service-company-recommended concentration will decrease the gelation rate. However, it will also decrease gel strength. This is normally a poor trade off. The service-company-recommended crosslinking-agent concentration normally renders nearly maximum gel strength without adding too much crosslinking agent so that undesirable gel syneresis will ultimately occur. When holding all other factors constant, increasing the crosslinking-agent concentration up to near the maximum crosslinking-agent concentration, just below where gel syneresis will occur, is one of the most cost-effective means to increase gel strength and performance. Thus, oilfield operators should normally avoid varying crosslinking-agent concentration as means of varying and controlling gelation rates.[13] The strategy, of varying the gelation rate of conformance-improvement polymer gels by varying the concentration of the crosslinking agent within the gel, is normally a poor and ill advised strategy.

Polymer Concentration

As shown in Figure 9, increasing the concentration of the polymer of a polymer gel increases the gel strength when holding all other factors constant. In this figure, the CC/AP gel was formulated with HPAM polymer possessing a MW of 11 million amu and a hydrolysis level of about 2 mole%. The gel contained a chromic-triacetate crosslinking-agent loading of 88:1 weight ratio of active polymer to Cr(III) of the crosslinking agent. The dynamic-oscillatory viscosity testing was conducted at 140°F.

Varying the polymer concentration within the gel formulation is the most commonly employed means and strategy to vary the gel strength of conformance-improvement polymer gels that are used to treat naturally fractured reservoirs (although varying polymer MW is used for this purpose in certain circumstances).

Polymer-Concentration Staging

During the application of conformance-improvement polymer-gel treatments in naturally fractured reservoirs, the strategy that is most often employed is to increase in stages the polymer concentration within the gelant (pre-gel fluid) as the injection of the gel treatment proceeds, especially when conducting production-well WSO treatments.

This strategy is employed for several reasons. First, one is often not certain of the fluid-flow capacity and the aperture widths of the fractures or other high-permeability anomalies that will be treated by the injected gel. So if the fractures or other high-permeability reservoir anomalies being treated happen to have narrower apertures than originally anticipated, an exceptionally low-polymer-concentration gel, as is normally initially injected, will be well suited to treat and plug such narrow-aperture flow channels.

Second, Seright has shown that polymer gels tend to dehydrate as they are extruded and propagated through fractures.[14,15] As a result, such polymer gels become more concentrated in terms of crosslinked polymer and become stronger as water leaks off from the gel and the gel dehydration proceeds. Seright has shown that the gel dehydration rate and the associated leakoff rate (into the matrix rock adjacent to the fracture) of the expelled water from the polymer gel is a function of the square root of time during gel extrusion through a fracture.[15] The low-polymer-concentration gel that is initially injected during a conformance gel treatment will tend to concentrate and become stronger with time as the gel-treatment injection proceeds. Therefore, the initially injected polymer gel, during a fracture-problem conformance-improvement treatment, does not need to contain the relatively higher polymer concentration as might be desired of the gel in its final form at the end of the gel-treatment injection.

Third, and especially for production-well gel treatments applied to naturally fractured reservoirs where there are high drawdown pressures, the final gel volume injected should be the strongest gel injected. This is because, in the near-wellbore environment where the gel that was injected last will reside, this will be at this location the largest pressure gradients that the gel treatment will experience. In this near-wellbore environment, relatively strong gel will, as a consequence, be required so that the gel will remain immobile and plug the near-wellbore fracture volume being treated – as desired. If the gel is to be placed in the fracture in the near-wellbore region and the gel is not overdisplaced on purpose away from the near-wellbore region by an overdisplacement fluid during gel-treatment injection, then for a number of reasons, it is imperative that the near-wellbore gel be strong enough so that it will not be dislodged and be back produced when the well is put back on production. As discussed in the previous section of this paper, increasing the polymer concentration of a given gel is normally the best means and strategy to increase the gel strength.

Gel Makeup Water

Often times and for a variety of reasons, the use of oilfield produced water is the desired makeup water for conformance-improvement polymer gels for treating naturally fractured reservoirs. Produced water can be, and often is, used as the makeup water for CC/AP gels when treating naturally fractured reservoirs.

However, a note of caution is needed. If the produced water contains H_2S, then the gel-production operation needs to be kept as an absolutely closed system and kept oxygen free. First, in this situation for safety and environmental reasons, the gel-producing operation needs to be conducted in a closed system that is totally isolated from the atmosphere and workers. Second, although H_2S is not detrimental in itself and as found in an oil reservoir to CC/AP gels and their performance, H_2S, in combination with oxygen, can degrade polymer gels. That is because H_2S, in contact with oxygen, can generate peroxy and free-radical sulfur-based chemical species that are very effective at degrading polymer gels by chemically cleaving the carbon-carbon-chain backbone of the polymers making up the polymer gel.

Thus, as a related aside here, when taking samples in the field of polymer gels that contain H_2S in their makeup water, these samples should immediately be nitrogen blanketed in order to prevent gel degradation with time resulting from the sample-contamination (oxygen-contamination) phenomenon described in the previous paragraph.

Polymer gels, which are used to successfully treat conformance problems in fractured reservoirs, can be, and quite often are, formulated with fresh water – especially if the field's produced water contains H_2S. Although the performance of CC/AP gels are really quite insensitive to the salinity and ionic makeup of most natural brines, there is a small, but noteworthy, decrease in the strength for a given CA/AP gel (when holding all other factors constant) when the salinity of the gel's makeup water is less than about 1,000 ppm – this is especially the case during the gelation process itself.[16] As a result, the use of "ultra fresh" water, as the makeup water for CC/AP gels that are employed to treat fracture conformance problems, may not be favored.

In summary, it is, in general, a good strategy to use, where feasible and appropriate, produced water as the gel makeup water for CC/AP polymer gels that are applied to treat conformance problems in naturally fractured reservoirs (having temperatures less than ~170°F).

Injection Rates

Obviously for economic and operational reasons, an operator would normally like to inject a polymer-gel treatment as rapidly as reasonably possible. The major constraint here is to not inject the gel-treatment fluids at such a high rate so as to cause formation parting or fracturing.

Sometimes operators are concerned that injecting the gelant fluid at too high of an injection rate will cause deleterious mechanical shear degradation of the polymer in the gel-treatment fluid being injected. Because relatively shear-resistant intermediate-high MW (4-7 million amu) HPAM polymer is normally used when treating fracture conformance problems and because the performance of polymers used in conformance-improvement gels is not highly affected if the high-MW-tail portion of the polymer MW distribution is mechanically shear degraded (as is problematic for HPAM of polymer-augmented waterflooding), shear degradation of gelant polymer is not normally a significant problem – even when injecting polymer-gel-treatment fluids into fractured reservoirs at exceptionally high rates.

However of note here and as briefly mentioned, in part, earlier in this paper, work at New Mexico Tech has shown that as polymer gels are extruded and propagated through fractures, the gels tend to dehydrate, become more concentrated and stronger, and expel water into the matrix rock adjacent to the fracture.[14,15] The gel dehydration rate of the expelled water from the polymer gel in this situation is a function of the square root of time during gel extrusion through the fracture.[15] There are two major consequences of the gel dehydration as it relates to choosing desirable injection rates for polymer-gel treatments that are applied to naturally fractured reservoirs. First, if the goal and/or strategy (for a given gel formulation) is to maximize the depth of gel placement in the fracture network, then the gel treatment should be injected as rapidly as feasible and prudent. Second, if the goal and/or strategy (for a given gel formulation) is to maximize the strength of the emplaced polymer gel, then the gel-treatment fluid should be injected at the lowest rate feasible.

Injection Pressure

As touched on in the previous section, injecting gel-treatment fluids at pressures exceeding formation parting and fracturing pressure should generally be avoided. The creation of new fracture flow conduits in the reservoir, where these new fracture flow conduits could promote additional conformance problems and could result in new undesirable high-permeability flow conduits, is something that should be avoided.

As an aside, if gel-treatment fluid (especially a relatively small volume) should be injected inadvertently at pressures exceeding the formation parting pressure, this is normally not a significant problem. This is because after gel-fluid injection ceases, the parted fracture will normally close and after the residual gel in the closed fracture fully matures, the fracture should normally be fully healed by the sealing polymer gel remaining in the fracture.

An injection-pressure strategy that is often used and recommended is to engineer the gel-treatment polymer-concentration staging on the fly as the gel treatment is being injected so as when ending the injection of the planned gel-treatment volume, the maximum allowable gel-treatment injection pressure (usually just below the reservoir parting and/or fracture pressure) is achieved at that point. This assures (for gel-placement considerations) that at least some gel was injected at the maximum permissible injection pressure.

Keeping Gel Out of Matrix Rock

When conducting conformance-improvement polymer-gel treatments that are to function by reducing the fluid-flow capacity within the treated fractures, such gel treatment fluids should be designed so that they are placed solely within the treated fractures -- and do not invade into, and plug, the matrix reservoir rock that resides adjacent to the gel-treated fractures.

The good news here, at least for the CC/AP gel technology, is that this is something that the oilfield operator does not normally need to worry much about. Service companies providing the chromic-triacetate CC/AP gel technology are very good at nearly always providing gel treatment designs where no significant amount of the treatment gelant fluid leaks off from the treated fractures into the adjacent matrix reservoir rock. In addition, as demonstrated in the literature,[17] properly formulated fracture-conformance-problem CC/AP gel fluids show very little propensity for being able to leak off a significant distance from the fractures being treated into the adjacent matrix reservoir rock.

Operator Involvement

Historically, it has been noted that the degree of technical and economic success of conformance-improvement polymer-gel treatments, which are applied to fractured reservoirs, is often correlatable to operator involvement in the treatment.[2]

In view of the critical importance of correctly indentifying or deducing the reservoir nature of the conformance problem to be treated during a polymer-gel treatment that is to be applied to a fractured oil or gas reservoir, the degree of operator involvement in the gel treatment is often correlatable to treatment success. There is normally no one better qualified to know or deduce the nature of the conformance problem in the reservoir to be treated than the field operator. It is the operator who normally is best qualified and situated to understand and identify the nature of the reservoir "plumbing" that is causing the conformance problems in his or her reservoir to be treated.

Operator involvement in conformance gel treatments does not mean that the operator needs to have to get involved in the "nuts and bolts" and the details of the actual treatment design and application. The recommended strategy that the operator should undertake is to take an active roll in the supervision and oversight of the design and application conformance polymer-gel treatments – including quality-control aspects of the treatment that will be discussed in more detail in the following section.

Quality Control and Bottle Testing

The degree of quality control and quality assurance that is implemented during a conformance polymer-gel treatment is another factor that is correlatable with the degree of success that an operator will normally derive from a conformance gel treatment.[2,13] This concern primarily involves quality control and assurance as it relates to the actual polymer gel that is injected.

The actual quality control program is normally conducted by the service company performing the gel treatment. The role of the operator in this instance is two fold. First, the operator must insist that a good and thorough quality-control program is undertaken during the gel treatment and gel injection. Second, the operator should actively oversee the quality-control program.

If an operator does not insist that a good quality control and assurance program be undertaken in association with a conformance polymer-gel treatment, at times, such a quality-control program is not implemented. In this instance, on-site personnel making and injecting the polymer gel know that they may not be fully accountable for their responsibilities and as, a result, less than optimum gel can be much more likely injected and placed in the reservoir that is to be treated.

A good strategy to assure good quality control and assurance of the polymer gel that is being injected is to periodically take, in an appropriate manner, gel samples at the wellhead as the gel is being injected and as the gel treatment proceeds.[2,13] By periodically visually observing polymer-gel samples that are stored/aged in an appropriate manner in bottles, the operator can obtain semi-quantitative information on: 1) gelation rate of the gel, 2) ultimate gel strength, and 3) gel long-term stability. A widely and quite successfully employed visual technique that is employed to evaluate and monitor polymer-gel performance as a function of time in conjunction with polymer-gel bottle testing is the use of the Bottle-Testing Gel Strength Code as documented on page V-1201 of Reference 13.

On the Fly Modifications During Gel Treatment Injection

A strategy that can profoundly affect favorably the outcome of a conformance-improvement polymer-gel treatment that is being applied to a naturally fractured reservoir is to permit, and to encourage, the field engineer (of the operating company and/or the service company) to modify on the fly (using good engineering judgment during gel-fluid injection and based on the gel-fluid injectivity being encountered) the polymer concentration, the polymer-concentration staging, and the treatment injection rate. What the on-site engineer (or possibly the engineer in an office while monitoring remotely in real time the gel treatment) is doing is using good engineering judgment, relating to the gel-treatment injectivity being observed, in order to optimize the gel treatment on the fly. What the engineer is learning on the fly is some real-time indication of the fluid-flow capacity of the reservoir flow channels being treated, and the engineer is custom tailoring on the fly the gel treatment fluids being injected in order to best treat the problematic reservoir flow channels that are actually being encountered. Such reservoir-flow-channel information is not normally known with certainty prior to the initiation of the injection of the gel-treatment fluids. The implementation of this strategy can be expected to greatly improve the performance of many polymer-gel treatments that are applied to naturally fractured reservoirs.

Well Stimulation Treatments Combined with Conformance WSO Treatments

There is an emerging and promising strategy of combining production stimulation treatments with successful conformance polymer-gel WSO treatments. That is, the conducting a production stimulation treatment following the application of a successful polymer-gel WSO treatment to a production well – especially productions wells that are fully drawn down after the polymer-gel WSO treatment. The idea here is to, after conducting a successful polymer-gel WSO treatment, apply a well stimulation treatment (e.g., acidize, mini fracture, or deeply perforate) in order to stimulate additional oil production from the successfully gel-treated production well. The objective is to add further economic value, by adding additional oil-production rate, following a successful WSO polymer-gel treatment of production well that is fully (or nearly fully) drawn down following the gel WSO treatment (normally wells that were not highly drawn down prior to the gel treatment).

CO_2 FLOODING

In the opinion of this author, the strategy of using polymer-gel conformance-improvement treatments to substantially improve the economic performance of a number of CO_2 flooding operations that are being conducted in numerous naturally fractured reservoirs is a strategy that, at the present time, has been badly overlooked and badly under utilized by the oil industry. Conformance-improvement polymer-gel treatments can, and have been field-demonstrated to be able to, substantially improve conformance and improve flooding performance of CO_2 flooding operations that are being conducted in naturally fractured reservoirs. The following two large field projects, which have been documented in the open scientific and petroleum engineering literature, nicely demonstrate this contention.

First, Borling [7] (of then Amoco) reported on successful conformance-improvement CC/AP gel treatments that were applied in 1991 through 1993 at the Wertz field CO_2 tertiary WAG flooding project in the Wind River Basin of Wyoming. In the paper, he reviewed 10 injection-well gel treatments applied to a 165°F naturally fractured Tensleep sandstone reservoir. The following benefits were reported to have been derived from having applied these gel treatments during the Wertz CO_2 flooding project in this naturally fractured reservoir:

- Resulted in incremental oil recoveries of up to 140,000 barrels per well pattern
- Increased oil production rates by 100 to 300 BOPD per well pattern
- Extended the economic lives of marginal well patterns by nearly two years
- Reduced GORs and WORs
- Reduced gas and water cycling
- Reduced gas and water breakthrough times
- Improved water and gas injection profiles

- Reduced operating expenses
- Contributed substantially to the field-wide decline-rate reduction in 1992 from 24% to 9%
- Were effective where conventional oilfield foams had failed
- Had rapid payout times of often less than three months
- Recovered substantial reserves that would not have been otherwise recovered

Hild and Wackowski [9] reported on 44 injection-well CC/AP gel treatments that were applied during 1994 through 1997 at the large CO_2 miscible WAG flooding project of the Rangely Weber Sand Unit that is located in northwestern Colorado. The Rangely field was reported in the paper to be the largest oilfield in the Rocky Mountain region in terms of daily and cumulative oil production. The economic rate of return for these large-volume (~10,000 bbl) injector gel treatments was reported to be 365%. The economic success rate for these polymer-gel treatments was reported to be 80%.

A reasonable question to ask is why more similar conformance-improvement polymer-gel treatments were not performed subsequently in the two above oil fields or in other naturally fractured reservoirs where CO_2 flooding operations are being conducted. The most applicable answer is that shortly after performing the above Wertz and Rangely conformance polymer-gel treatments, the oil industry entered into its most recent economic downturn and very little improved-oil-recovery activity was undertaken by the industry during the most recent and prolonged economic downturn in the oil industry. More specifically regarding the Wertz CO_2 flooding project and after Reference 7 was published, the engineer championing the conformance-improvement gel treatments at Wertz was transferred to an overseas company asset, and shortly thereafter Amoco was acquired by BP. Relating to the Rangely CO_2 flooding project and after Reference 9 was published, the Rangely operating company apparently decided to not make additional substantial investments, involving improve oil recovery, in the Rangely field during the business downturn (and thereafter). It also appeared that the best well candidates for exceptional production responses from conformance-improvement polymer-gel treatments were treated early on during the Rangely gel-treatment campaign.

As way of note, the previously mentioned trend relating to gel treatment success is something that can occur during a conformance-improvement polymer-gel treatment campaign in any naturally fractured reservoir. Often wells and well patterns with the most problematic conformance problems are treated first within any given field. As previously discussed in this paper, wells and well patterns with the worse conformance problems often tend to provide the best economic outcomes when polymer-gel treatments are applied. As a result, as a campaign of conformance-improvement polymer-gel treatments is conducted in any given oil field, the economic performance of the gel treatments, in this particular instance, can at times decrease (at least somewhat) as the gel-treatment campaign progresses within the field.

CONCLUDING SUMMARY

This paper enumerated design and implementation strategies for maximizing the performance and the economic rate of return for polymer-gel conformance-improvement treatments that are applied to fractured and other high-permeability-anomaly-containing oil and gas reservoirs. The discussed design and implementation strategies are based on two decades of experience with successful large field projects involving the application of the CC/AP gel conformance-improvement technology, where most of the results of these field projects have been reported in the open scientific and/or petroleum-engineering literature. When all other factors are held equal and constant, increasing the volume of such gel treatments often correlates with improved treatment performance and economics. As a separate note, application of polymer-gel conformance-improvement treatments in conjunction with CO_2 flooding in naturally fractured reservoirs is an often overlooked and under utilized strategy that holds substantial economic promise.

NOMENCLATURE AND ABBREVIATIONS

amu	=	atomic mass units
BOPD	=	barrels oil per day
CC/AP	=	chromium(III)-carboxylate/acrylamide-polymer
HPAM	=	hydrolyzes polyacrylamide
MW	=	molecular weight
OPEX	=	operating expense

WOR = water/oil ratio
WSO = water shutoff

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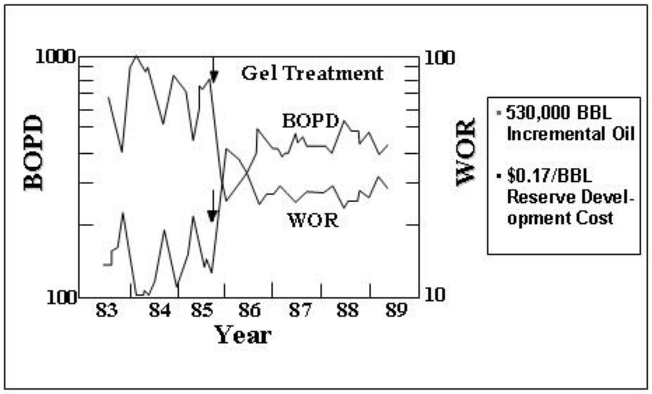

Figure 1 - Production response to a CC/AP gel treatment of injection-well 0-7 in the SOB field.

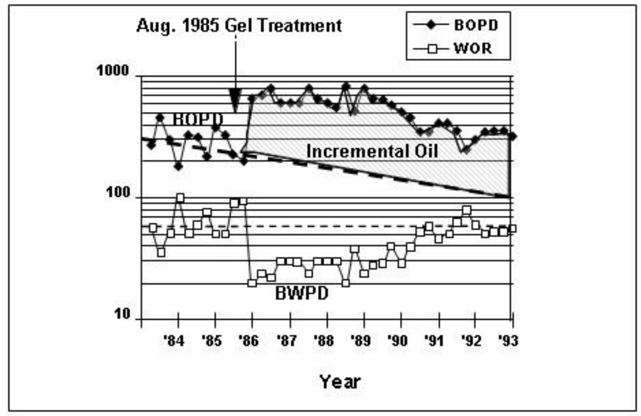

Figure 2 – Production response to a CC/AP gel treatment of injection-well 0-17 of the SOB field.

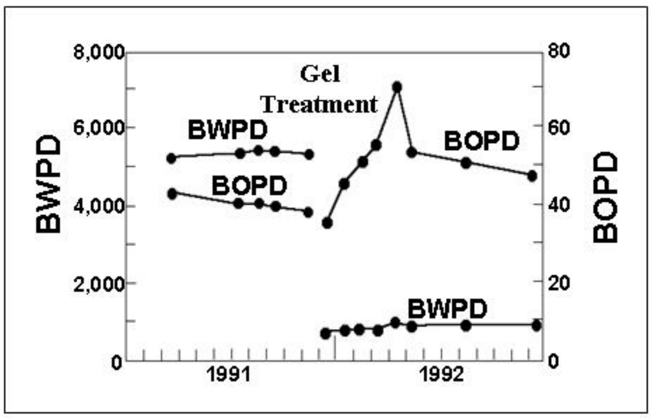

Figure 3 – Production response to the Wyoming LSD N-17P production-well CC/AP gel WSO treatment.

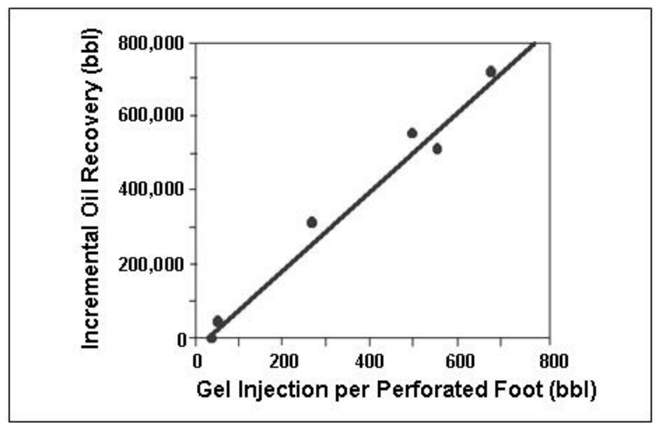

Figure 4 – Volume incremental oil vs. volume gel for first 7 CC/AP gel injection-well treatments in Wyoming.

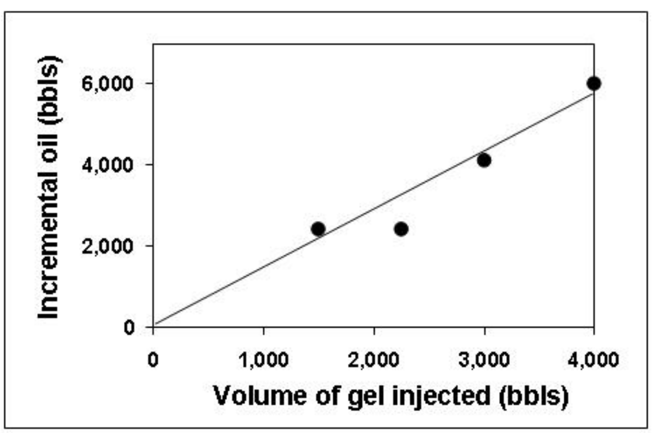

Figure 5 - Volume of incremental oil vs. volume of gel injected during Arbuckle WSO CC/AP gel treatments.

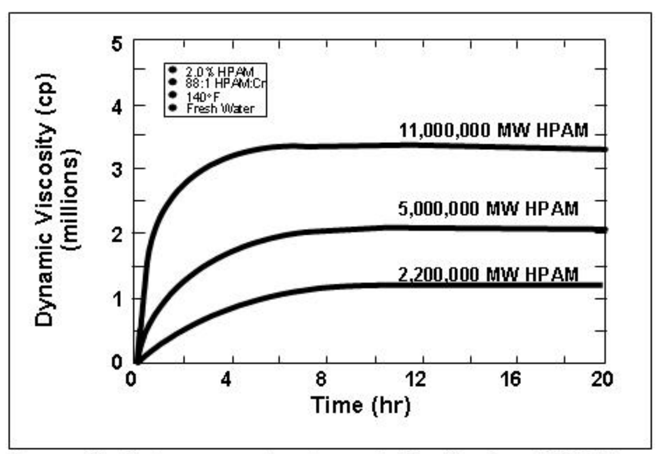

Figure 6 - Polymer molecular-weight effect on CC/AP gel strength.

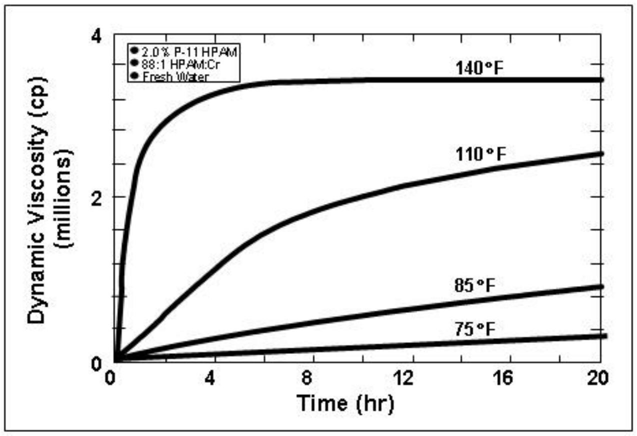

Figure 7 - Temperature effect on CC/AP gelation rate.

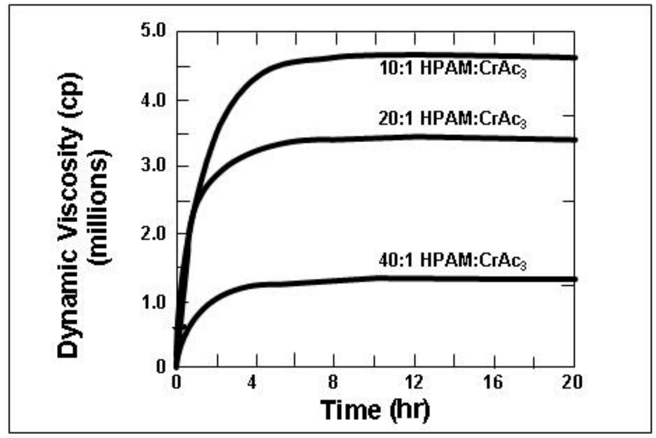

Figure 8 – Crosslinker concentration effect on CC/AP gel strength.

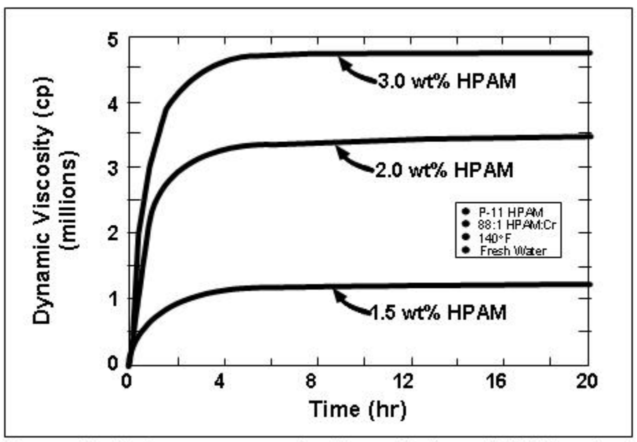

Figure 9 - Polymer concentration effect on CC/AP gel strength.