AN IMPROVED SYSTEM FOR MAKING PREDICTABLE, HIGH QUALITY FRACTURING FLUIDS UNDER FIELD CONDITIONS

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ABSTRACT

Over the last thirty years various polymers have been added to water to create the base fluid used in fracture stimulation treatments. Advances in improving these base fluids have been concentrated on developing polymers which are relatively free from damaging residue, while retaining the properties required to achieve the designed viscosities. Little attention has been focused on the effects of mixing these polymers under field conditions, where the majority of the hydration process is taking place in the low shear environment of large frac tanks.

Recently, a method has been developed to improve the actual hydration process of standard fracturing polymers. Through this process, a higher quality and more predictable base fluid can now be delivered to the well site. The mixing of the base fracturing fluid is now much less susceptible to the harsh mixing conditions found in the field. As a result of better control of the base fluid quality, better overall fracturing designs can be successfully pumped.

HISTORY OF HYDRAULIC FRACTURING

The concept of hydraulically fracturing a well with the intention of increasing the well's potential deliverability was first attempted in 1947 on a well located in the Hugoton gas field of western Kansas. The treatment was performed in four stages, on four isolated intervals, and consisted of 1,000 gallons of gasoline gelled with napalm followed by 2,000 gallons of gasoline containing an amine breaker for each zone. In contrast, hydraulic fracturing treatments of today most often utilize water as the base fracturing fluid, and in much larger quantities. Treatments have been pumped utilizing over 2,000,000 gallons of fluid and over 7,000,000 pounds of proppant. The transition from hydrocarbon based fluids to water based began in 1953, when starches were first added to water to viscosify the fluid, and by 1962 over fifty percent of all treatments were water based. The concept of complexing the gelled fluid to create a crosslink with greatly increased viscosity was first applied in oil well stimulation in the late 60's.

Proppants were first introduced several years after the Hugoton experiment as a means of holding the newly created fracture system open and therefore sustaining an increased production rate. The vast majority of all fracturing treatments now incorporate some type of proppant into treatment. Over the years, several materials have been used for propping agents, including: glass beads, nutshells, malleable metal pellets, sand, resin coated sand, and ceramic proppants. The last three are the basic proppants used today, with sand being the predominant material used.

ROLE OF FRACTURING FLUIDS

Fracturing fluids perform two basic functions. The first is to crack open the reservoir rock and propagate or extend this fracture. The second is to transport the selected proppant throughout the overall length of the fracture. Many fluids have the properties to accomplish these functions. To select the proper fluid, from the many available which could be used on a specific well, the following characteristics can be examined:

1. The fluid must be viscous enough to create the necessary fracture width and to carry the proppant along the length of the fracture. Ideally the fluid should initially show only enough viscosity to move the propping agent through the surface pumping equipment. The viscosity should remain fairly low until the fluid enters the wellbore perforations. At this point the fluid should exhibit enough viscosity to transport the proppant evenly throughout the fracture system.

2. The fluid should exhibit low friction pressures over a wide spectrum of shear rates. Low friction pressure at higher shear rates will ensure that surface treating pressures remain low while the fluid remains in the wellbore tubulars. This not only allows for a safety margin to remain within the pressure ratings of the tubulars, but also requires less hydraulic horsepower to pump a given treatment. Low friction pressures at the lower shear rates minimizes friction in the fracture and therefore helps prevent excessive height growth.

3. To ensure that the desired viscosity of the fluid reaches the actual fracture in the formation, the fluid must not be sensitive to high shear rates. This has been shown to be a severe problem when pumping certain crosslinked fluids down small tubulars. The viscosity of the complexed fluid can be greatly degraded due to the high shear. Once the crosslink has been damaged, it will never regain proper bonding even when returned to the low shear environment of the fracture.

4. Providing control over fluid loss is one of the most important features a fracturing fluid should have. For a

given fracture geometry it is the amount of fluid loss control that determines how much fracturing fluid will be needed. It is easiest to compare the effect of fluid loss for various fluids by comparing their fluid efficiencies. This is the ratio of the amount of fracturing fluid in a fracture to the total amount of fracturing fluid pumped.

The total fluid loss can be calculated at any given time during a fracturing treatment and represented as a fluid loss coefficient. The three components which comprise this coefficient are: C_I--fracturing fluid viscosity and relative permeability effects; C_{II}--reservoir fluid viscosity/compressibility effects, and; C_{III}--wall building effects of the fracturing fluid. (Figure 2)

In designing a fracturing fluid it is common to attempt to control fluid loss through the C_{III} fluid loss coefficient. This number is greatly impacted by the gel loading in the fluid, the temperature of the reservoir, and by the addition of fluid loss additives. The greater the concentration of the gel the lower the fluid loss number becomes. Two types of fluid loss additive (FLA) materials are routinely used in fracturing fluids. The first is a solid particulate material which is most effective in reservoirs with moderate to high permeability. These materials range from fine meshed sands, to blends of starches, to fine meshed resins. The second is the use of a 5% hydrocarbon phase dispersed in a gelled water. This system can significantly reduce leakoff in tight formations.

5. The fluid must be non-damaging to the overall producing system, including the reservoir fluids, the formation permeability, and the conductivity of the proppant pack. Water based fluids most often will contain additional additives to help minimize any potential damaging effects of the fluid. Specific surfactants are used to prevent such problems as emulsions, waterblocks, changes in wetability, and clay migration and swelling. The degree to which different fluids damage the conductivity of the proppant pack is still debatable. Data from Penny, Roodhart and McDaniel all indicate justification for using a damage factor in fracturing design which would result in using only 10% of the proppants undamaged permeability. The amount of damage from different fracturing fluids is still being researched at this time.

6. The fluid must break or degrade in viscosity once the treatment is completed. Ideally the fluid would go from its designed fracturing viscosity, back to its original viscosity, the moment pumping stopped. Currently, breakers are added which begin to degrade the backbone of the gelling structure from the moment of addition. The

ultimate breaker would not begin to reduce the viscosity of the fracturing fluid until the placement of the proppant was complete and pumping was stopped.

7. Once the fluid has placed the desired proppant and has broken, it should produce back or clean up very quickly. The fracturing fluid has, at this point, served its main functions and is now only a hindrance to the production of hydrocarbons. In an effort to remove this fluid as quickly as possible, surfactants are added to reduce the interfacial tension. In cases where the bottom hole pressure is not high enough, energy may be added in the form of nitrogen or carbon dioxide to aid in fluid recovery.

8. The fluid must be economical to use. To be economical, the fluid must not only be cost efficient on a per gallon basis on the surface, but must also have good fluid loss properties in order to yield a high fracturing efficiency. The overall economy of the fluid may be shown as:

$$\text{economy} \sim \frac{\text{surface fluid cost}}{\text{fracturing fluid efficiency}}$$

9. Finally, the fluid must be safe to handle on the surface during pumping operations, and environmentally safe to dispose of once the treatment is complete and fluids are returned to surface.

In considering all of these ideal characteristics, water based polymers are found to best fit the need in most fracture applications. Being able to vary the polymer loading and type of crosslink mechanism used, the desired viscosity of a fracturing fluid can easily be met with the water based systems. In general, they exhibit much lower friction pressure than hydrocarbon or emulsion based fluids. Their crosslinking rate can be adjusted so that high shear in the tubulars during the pumping operations does not adversely effect the viscosity in the fracture. The fluid loss of these fluids can be reasonably controlled by either crosslinking the fluid or by adding FLA material. The amount of formation damage a water based fluid exhibits can generally be controlled by the addition of additives. The controversy of proppant pack damage may best be dealt with by adding higher concentrations of proppant, until such time as other answers are presented. Water based fluids gelled with natural gum polymers are relatively safe for both personnel and the environment. Still, the biggest advantage of these fluids at this point in time is their overall economy.

DEVELOPMENT OF VISCOSITY WITH NATURAL GUM

The most widely used polymer for use in fracturing fluids is that of guar and its derivatives. The guar bean, used for the development of this polymer, is grown almost exclusively in the semi-arid regions of northern India and southern Pakistan. Minor production of this crop has come from the states of Texas and Oklahoma, but has not really developed into a predictable cash crop domestically.

It is the endosperm portion of this bean which is used to make the desired polymer. The endosperm is first separated from the embryo and seed coat portions through a mechanical splitting operation, which takes advantage of the varying hardness of the different portions of the bean. After the endosperm splits have been separated from the embryo and hull, the splits are ground into a powder which is marketed as guar gum. The inefficiencies in being able to remove all of the embryo and hull result in most of the reported residue from a natural guar fluid.

To manufacture the cleaner and more popular derivatives, such as hydroxypropyl guar (HPG), the guar powder is first put through a series of alternating water and acid soaks to remove as much of the leftover hull and embryo portions as possible. The guar is then reacted with propylene oxide at elevated pressures and temperatures, and then finally dried and reground to meet granulation and moisture specifications. This derivatized guar not only results in lower residue damage, but the physical behavior has been modified. The reacted side chains allow the substituted polymer to have a higher degree of solubility in both water and alcohols. The improved solubility of the polymer in water allows for a cleaner fluid with less residue upon breaking. An HPG polymer will hydrate in water to alcohol ratios of up to 1:1, whereas the natural guar can only tolerate approximately 20 percent alcohol before the polymer begins to precipitate.

In the process of adding the dry powdered polymer to an aqueous solution, there are several steps in the hydration which ultimately yield a viscous solution. The individual particles are crystalline in nature before they contact water. As these crystals contact water the polymer begins to unfold into a coil type structure. The polymer then begins to absorb water and starts to swell. Ultimately the polymer elongates to form a molecule that has stretched in length several thousand times. The actual viscosity of the solution begins to increase when the concentration of the elongated polymer chains becomes high enough that they become intertwined and entangled. The higher the molecular weight of the polymer (therefore the greater the length), the lower the concentration of polymer needed to develop a viscous structure.

There are several controlling factors which determine how efficiently this process takes place in actual operations. First, the individual crystals of polymer must be well separated, or dispersed, as they come in contact with aqueous solution. If they are not well separated, the polymer on the outside will begin to hydrate first and the interior polymer will become entangled in the gel structure before it can hydrate. When there are large clusters of crystals vying for the available water, the outside crystals hydrate and leave the interior crystals completely dry, making what is normally known as a "fish eye". When the clusters of crystals are much smaller, a "fish eye" may not be apparent to the naked eye. Yet, these "micro fish eyes" may be present in sufficient quantities to diminish the total viscosity yield of the fluid.

The hydration rate of the guar polymers is similar to a first order reaction rate in thermodynamics, assuming the gel particles are dispersed properly as they contact the water. This rate is altered by changing any of the following: pH, temperature, electrolyte (salt) concentration, and shear, during mixing. These parameters are so critical to the hydration process that any one of them can completely halt the reaction rate under certain conditions.

The natural and derivatized polymers hydrate best within a window of pH. In general, the mix water needs to be below a pH of around 10 and above a pH of 4. The polymers will have a much faster reaction rate as the pH scale is lowered. The polymer will actually hydrate in fluids with a pH of 0, but the viscosified fluid does not remain stable for any period of time, and becomes extremely unstable at temperatures above 100° F. The recommended pH window is between 5 and 7 for optimal hydration. (Figure 3)

The family of natural polymers have the ability to hydrate in water temperatures ranging from less than 40°F, to over 100°F, depending upon the grind size of the polymer and the pH of the water. Most commercial fracturing polymers are designed to be mixed in either cold waters (40° - 70°F), or warm waters (60° - 100°F). The impact of temperature on the rate of hydration can be seen in figure 4.

It is common to have problems mixing fracturing fluids in the field during the winter months. Hot oilers are often brought in to heat the water to aid the hydration process of the fracturing polymers, and to prevent unwanted stress to the tubulars, due to shrinkage from the cold fluids. Unknown chemicals or hydrocarbons present in the hot oiler can create hydration and crosslinking problems, as well as possible emulsions.

For non-ionic polymers, such as guar and HPG, the concentration of monovalent salts only marginally effects the ultimate viscosity of a gelled fluid. The anionic derivatives, such as CMHPG, are effected to a much higher degree. This is due to the electrostatic repulsion of the anionic groups, which ultimately reduces the degree of polymer chain entanglements. The viscosity of all natural polymers can be greatly diminished due to the presence of multivalent cations. In some instances, guar or its derivatives will even precipitate in brines of high electrolytic concentrations. (Figure 5 and 6)

The rate of hydration for all polymers is greatly improved when the fluid is sheared during the mixing procedure. Both the amount of shear and the length of duration the fluid sees shear are critical in the hydration process. High initial energy aids in breaking the crystal-like structure and quickens the uncoiling of the polymer. The shear also helps stretch the polymer to its full molecular length, allowing it to take on water much faster. The longer the shearing process, the higher the likelihood that the hydration of all of the gel particles will be enhanced through the mechanical energy.

CROSSLINKING

When viscosities of fracturing fluids need to be dramatically increased for proppant transport capabilities, or for leak off considerations, the base fluids can be crosslinked. This is a process where inorganic species, such as borate salts or organometallic complexes, react with two adjacent polymer molecules and bond them together. This bonding takes place between the multiple sidechain substituents coming off of the main backbone of the polymer. As the strands of polymer, which are already overlapped and intertwined, bond to one another, the effective molecular weight is increased and a rigid fluid is formed. This type of fluid is the most common fracturing fluid used, and has applications from the cool shallow wells, to the deep wells with bottom hole temperatures approaching 325 degrees F.

ADVANTAGES OF DISPERSED POLYMERS

Conventional fracturing polymers are presently being handled as a liquified slurry to improve their overall performance. The dry polymer is dispersed and suspended in a solvent of diesel. This initial dispersion ultimately helps ensure that superior dispersion occurs when the system is added to water. The gel particles are already separated from one another, and therefore need no further separation as they contact water.

Having these particles completely dispersed allows for the maximum possible viscosity yield to develop, due to the lack of the presence of "micro fish eyes". This predispersion also allows for additional polymer to be added to previously viscosified fluid, so precise design viscosities can be obtained, even in field applications. The importance of precise base fluid viscosity becomes very apparent in figure 7, where base fluid viscosities are compared under fracturing shear rates and after the fluid has been crosslinked.

The hydration rate of the slurried polymer is increased substantially through the dispersion of the gel particles and the energy imparted in the mixing system. Since the gel particles are already dispersed from one another, no reaction time is lost and hydration can immediately begin. The mixing system used for metering and adding the slurried polymer applies sufficient shear to help uncoil and stretch the polymer into its long molecular structure. The system also contains an internal buffering package, which creates a mixing environment with the proper pH for optimal hydration. (Figures 8 and 9)

In field applications where fracturing fluids are mixed into the low shear environment of a frac tank, anything which can be done to aid the hydration process before the fluid enters the tank will greatly enhance the ultimate hydration efficiency of the polymer. The hydration inefficiencies of a frac tank are compounded due to the preferential flow path which a fluid experiences as the fluid is rolled through the tank. Even when the frac tank has properly mounted gel lines, it has a fluid turnover efficiency rate of less than 20 per cent. This implies that when mixing a 500 barrel frac tank, polymer will be added to previously gelled fluid after 100 barrels of mixing. When a conventional dry polymer is added to already gelled fluid, the partially hydrated gel particles are surrounded and entangled by fully hydrtated polymers, and "micro fish eyes" can form. Without further shear, the gel will never completely hydrate, ultimately resulting in lower base fluid viscosities.

Dispersed polymers and their mixing systems help eliminate the detrimental consequences of inefficient mixing in a low shear environment. These polymers are not only hydrated to a further extent when they enter the frac tank, but the individual gel particles are also better dispersed within the fracturing fluid. This dispersion allows the hydration process to continue to completion in a low shear environment, without interference from other gel particles, or from previously hydrated gel.

The excellent dispersion qualities of the slurried polymers actually allow the addition of polymer to a fully hydrated gelled liquid. This ability of polymer boosting provides even further quality assurance capabilities when attempting to mix fluids to a precise viscosity. Either extra polymer or water could be added to a tank until the designed viscosity is reached.This ensures that viscosities will be adequte for proppant transport, and also increases fluid efficiency. The increased fluid efficiency comes from the improved C_I fluid loss coefficient, as the overall system has higher viscosities. The viscosity improvement, and resulting increased fluid efficiency, is even more apparent for crosslinked fluids. Additional fluid loss control is gained due to the two phase flow of the solvent and the fracturing fluid through the filter cake. Figure 10.

Precise metering of the quantities of polymer used is much simpler to accomplish with the advent of the slurried polymer. The quantities can be measured in liquid volume to a much greater degree of accuracy than that of a dry powder. Being able to measure the rate of addition of the polymer opens up the possibility of mixing fluids during the operation of a treatment. On large treatments, continuous mix applications can substantially reduce fluid costs by eliminating the loss of gelled fluid to tank bottoms.

The ability to readily change polymer loadings at any point in the fracturing treatment has many advantages. The polymer loading can be tailored throughout the job by design, or on the fly as needed, when fracturing pressures indicate a change would be beneficial. If bottom hole net pressure plots indicate that a treatment has the potential to have height growth, the viscosity can be brought down to lower the net fracturing pressure. Treatments have been pumped where the overall slurry viscosity of sand and fracturing fluid is kept constant by reducing the polymer loading of the fracturing fluid, while the sand concentration is increasing. Another application of tailoring the polymer loading would be to lower the viscosity throughout the treatment, knowing that the viscosities at the end of the treatment will not severely thermally degrade, and therefore will tolerate a lower polymer loading. An added benefit to lowering the polymer loading is the reduced proppant pack damage that would be associated with the decreased gel amounts.

The slurried polymers allow for extremely efficient internal buffering packages to be incorporated into the system. Most waters and brines, which are commonly used in the field, can therefore easily be gelled without the addition of extra chemical buffers. This also allows for using mix waters over a wide temperature range. The dispersed polymers will gel waters from less than 40 degrees F to over 100 degrees F, and still deliver the proper viscosity. (Figures 11 and 12)

Virtually any polymer used for fracture stimulation purposes can be put into a slurried form for use in the field. In addition to polymers, many standard FLA materials can be blended into the same slurry to insure proper dispersion of both materials. These dispersed systems have been used to prepare the base fluid for most treatments which are currently being pumped,including linear gels, crosslinked gels, gels foamed or energized with CO2 or N2, polyemulsions, and acid treatments.

CONCLUSIONS

Slurried polymers have the following advantages:

1. Increased viscosity yield due to superior dispersion.
2. More consistent base slurry viscosities.
3. Improved fluid efficiency.
4. Fewer buffering packages required for mixing purposes.
5. Potential for quality continuous mixed fluids.
6. Tailored polymer loading made possible.

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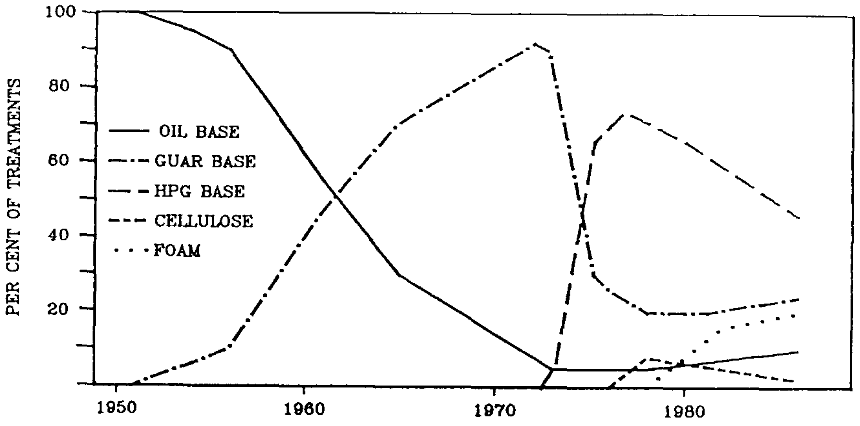

Figure 1 - Trends of base fracturing fluids

$$C_I = 0.0469 \sqrt{\frac{k \, \Delta p \, \phi}{\mu}} \; , \; \frac{ft}{(min)^{0.5}}$$

Viscosity and Relative Permeability Effects

$$C_{II} = 0.0374 \, \Delta p \sqrt{\frac{k \, \phi \, c}{\mu}} \; , \; \frac{ft}{(min)^{0.5}}$$

Reservoir Fluid Viscosity–Compressibility Effects

$$C_{III} = 0.0328 \left(\frac{m}{2A_e}\right) \; , \; \frac{ft}{(min)^{0.5}}$$

Wall–Building Effects

Figure 2 - Fracturing fluid coefficient

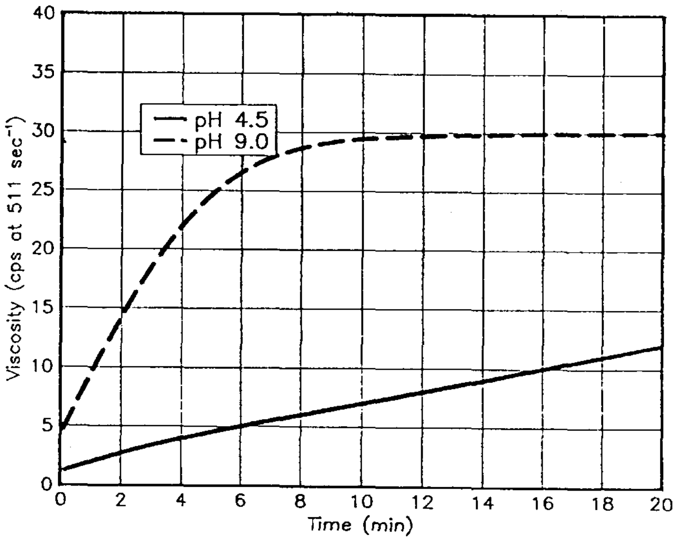

Figure 3 - HPG viscosity development pH effects

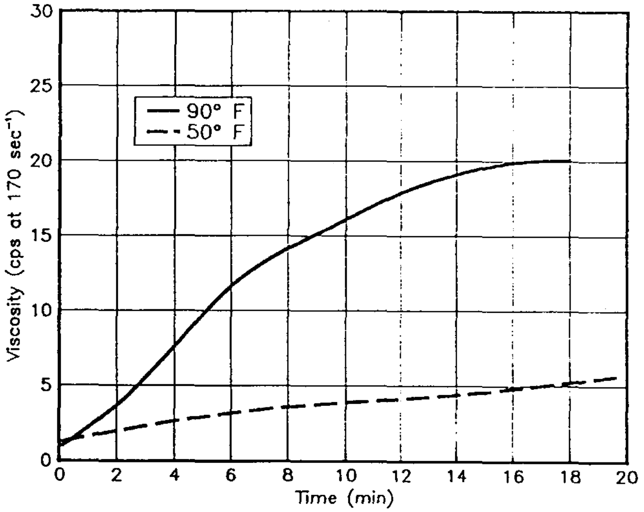

Figure 4 - HPG viscosity development temperature effect

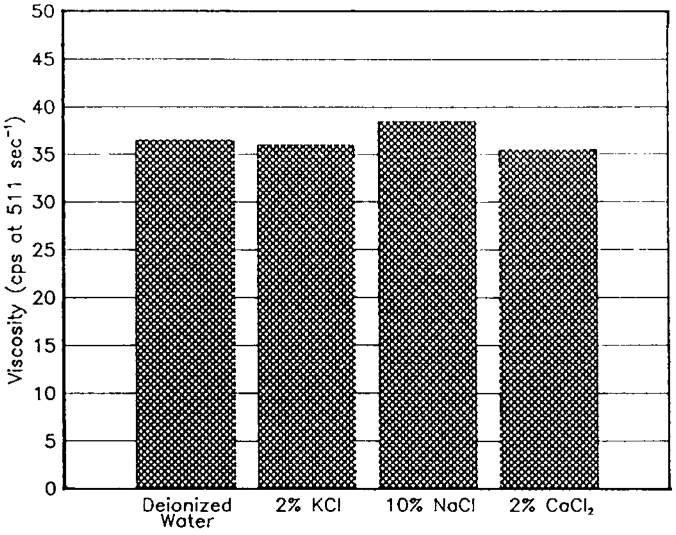

Figure 5 - Effect of salt on the viscosity of guar

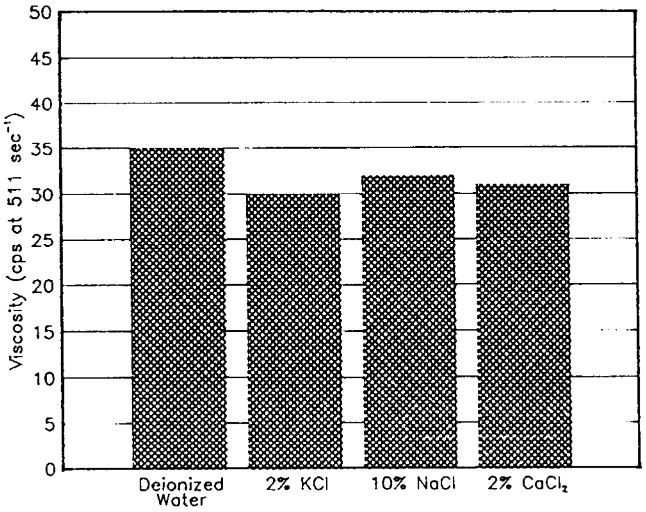

Figure 6 - Effect of salt on the viscosity of CMHPG

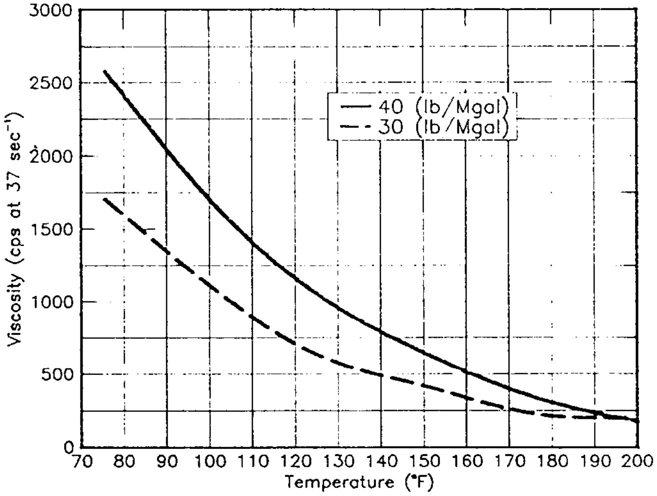

Figure 7 - Viscosity — polymer loading effect

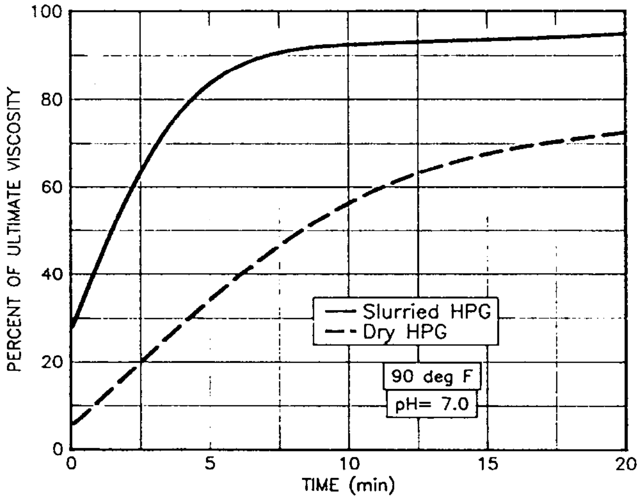

Figure 8 - Hydration rate — slurried HPG vs dry HPG

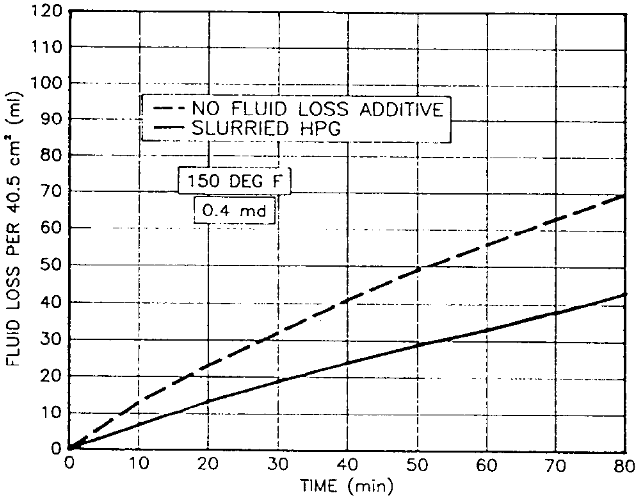

Figure 9 - Dynamic fluid loss - borate crosslinked HPG

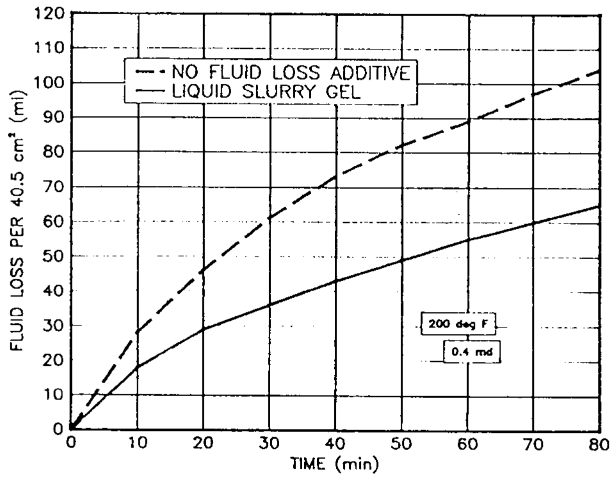

Figure 10 - Dynamic fluid loss - transition-metal crosslinked HPG

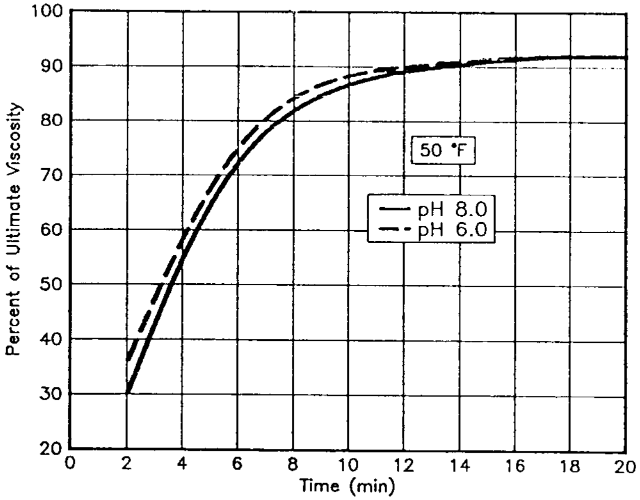

Figure 11 - Slurried HPG viscosity - pH effect

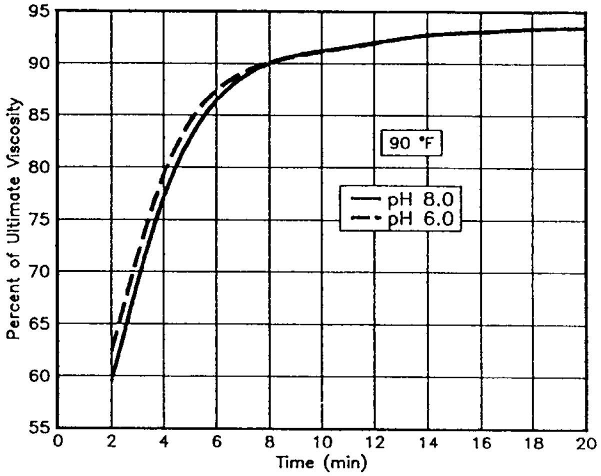

Figure 12 - Slurried HPG viscosity - pH effect