FRACTURING FLUIDS FOR DEEP-HOT FORMATIONS

Christie Hsu, Michael W. Conway
Halliburton Services

ABSTRACT

Crosslinked gels are adequately stable at high fluid temperatures and have thus established their usefulness for fracturing high-temperature formations. However, in certain treatment situations, they may develop high friction pressure in tubular goods which can limit their injection rate. Furthermore, the rheological properties exhibit a time-shear history dependency that is quite difficult to predict.

Two-stage gel systems have been very successful in providing a means to develop desired viscosity at downhole conditions without causing high tubular friction pressures. However, several currently available systems do not have the stability required for large volume treatments at temperatures above 250°F (120°C).

A fracturing fluid has been developed that solves many disadvantages and limitations of both crosslinked and two-stage gel systems. This is made possible by the use of a new delayed hydrating gelling agent. The fluid has the desired two-stage viscosity qualities and can be formulated to provide the desired viscosity throughout a treatment. In addition, the rheological properties of the new fluid system are highly predictable.

This fracturing fluid system has been successfully tested in the field. Fluid design and treatment results will be presented.

INTRODUCTION

The commercial success of Massive Hydraulic Fracturing (MHF) in tight gas reservoirs has been well documented.[1-5] Successful stimulation programs have been used to produce wells in the Cotton Valley Lime, Cotton Valley Sand, Edwards Lime, J Sand, and Mesa Verde Sand formations, for example.[6-11]

Recent renewed efforts to develop deep formations with temperatures which exceed 250°F (121°C) such as the Silcos Sand, Grey Sand, Shannon Sand, and deep Cotton Valley Lime, have required that more stable fracturing gels be developed to successfully place large quantities of proppant. This is especially true for placing the higher density bauxite proppant required for most of these deep formations where closure pressures could well exceed 12,000 psi (6.9

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x 10^7 pascal). Typical job volumes in these formations range from 80,000 gal. (300 m^3) to 800,000 gal. (3030 m^3) of gelled fluids with pumping time ranging from 3 to 14 hours.

Most fracturing fluid systems available for stimulation under these temperature and pumping time conditions are based on the use of various derivatized guar polymers as the basic viscosifying agent. The temperature stabilities of these polymers are functions of fluid pH, ionic strength and the presence of added stabilizers. Many of the available fluid systems are also crosslinked with one of a variety of metal crosslinking agents. In general, the ability to stabilize the base polymer will dictate the time-temperature stability of the system. Furthermore, the upper temperature limit for crosslinked systems may be less than that of the base polymer with the appropriate stabilizers and delayed hydrating polymer.[12]

During recent efforts to improve the design of MHF treatments, the critical role of viscosity control has been defined.[13] Fluids with too little viscosity may suffer from excessive fluid loss, short prop length, narrow width and premature proppant deposition. Fluids with too high viscosity may create excessive fracture widths which can reduce the propped fracture length and cause high fracture friction pressure which may result in premature job termination.[14] Since each fluid increment experiences different fluid temperature profiles, careful control of fracture viscosity requires the use of multiple fluid formulations.

Derivatized guar fluids can be used for treatments up to 250°F (121°C) without added stabilizers. The use of methanol and other stabilizers[15,16] has extended the fluid stabibility to 350°F (177°C). Recent developments which utilize a synergistic mixture of temperature stabilizers has provided a fluid which is usable at greater than 400°F (204°C) fluid temperature.

In this work, a report on the characteristics of a new two-stage fracturing gel system for treating wells with greater than 250°F (121°C) bottom-hole temperature is given; testing procedures, criteria of the fluid system and the properties of the delayed hydrating polymer will be covered.

Apparatus and Test Procedure

Viscosity measurements were made on a Model 50 Fann Viscometer using standard bob and sleeve ($R_s/R_b = 1.0678$) for uncrosslinked fluids and a modified bob ($R_s/R_b = 1.4826$) for crosslinked fluids. The fluids for the two-stage systems were prepared by first prehydrating the base polymer in a Waring Blendor jar for 15 minutes in the presence of adequate buffer concentrations to control pH. Then gel stabilizers, surfactants, fluid loss additives and the delayed hydrating polymer were added to the base gel and mixed for one minute. For crosslinked fluid, the crosslinking agent was added to the fluid volumes while they were recirculating through a Model 4730-0001 Jabsco pump. The fluid was transferred to the viscometer and heated to the test temperature at a rate of 8°F (4.4°C)/min unless otherwise stated.

The viscosity versus time at 120°F (49°C) fluid temperatures were conducted on a Model 35 Fann Viscometer with a modified stirring heat cup (Fig. 1). The stirring heat cup kept the fluid at test temperature and under dynamic conditions. A hole was drilled through the cup's double wall construction and a tube used to seal off the two compartments. Water from a circulating heating bath was circulated through the outer compartment to maintain the gel at constant temperature during the test. A 0.48% prehydrated base polymer was adjusted to the pH values as stated in the presence of an adequate buffer concentration to maintain pH. Various pH control agents common to the industry were used to obtain stable desired fluid pH. After stabilizing the base gel at the desired temperature, the delayed hydrating polymer was added. All the viscosity readings were taken under dynamic conditions.

DISCUSSION

Criteria for Deep-Hot Well Stimulation

Most deep, high temperature reservoirs have low natural formation flow capacity. Gas permeabilities generally range from 0.001 to 1.0 md. To be able to produce at a commercial rate, these reservoirs often require massive hydraulic fracturing stimulation treatments to create highly conductive flow channels that penetrate deep into the reservoir. Design propped fracture lengths generally range from 500 to 1500 feet for one wing of fracture (wellbore to fracture tip).

To create such fracture extension, a fracturing fluid should have the following characteristics:

1. Low fluid loss properties for adequate fluid efficiency.

2. Low friction pressure that allows adequate treatment rates with a minimum of hydraulic horsepower.

3. Lowest possible viscosity consistent with desired fracture geometry, fluid efficiency and proppant placement ability.

4. Viscosity stability to carry the proppant in the fracture.

5. Predictable rheological properties.

6. Adequate fluid breaking properties for fluid flowback.

A fluid system has been developed which meets all of the above requirements. Generally, this system consists of the use of two guar gums. One is chemically treated to provide the necessary time of delay before hydration. The downhole viscosity is independent of pumping viscosity in this system.

Secondary Gelling Agent Characteristics

A number of delayed polymers have been developed and are commercially available. Products initially developed were most effectively inhibited at low pH (3-4) and yielded viscosity as a function of time and temperature. Figure 2 shows the behavior of a typical delayed hydrating polymer at 120°F (49°C).

The major disadvantage of these products for high temperature applications is that they require low pH for maximum inhibition of hydration, and hydration occurs at relatively low temperatures. The relatively low hydration temperature prevents the use of the high polymer loads needed for formations with reservoir temperature above 300°F (149°C). Furthermore, the fluid pH required for maximum inhibition is much lower than the pH required for maximum polymer stability.

The behavior at the new delayed hydrating polymer at 120°F (49°C) is shown in Figure 3. It is a chemically inhibited hydroxypropyl guar (HPG) and provides only a moderate viscosity increase when the fluid pH is greater than 6.0. In field applications, the new delayed hydrating polymer will gradually hydrate as the base gel viscosity decreases due to the increase in temperature. Full hydration of the polymer does not occur until the fluid reaches 250°F (121°C). Furthermore, the viscosity profile is practically independent of heating rate. Figure 4 shows the viscosity profile observed for a fast heating rate at 8°F (4.4°C)/minute and a slow heating rate at 2.5°F (1.4°C)/minute.

Gel Stability

Above 250°F (121°C), the stability of guar based polymer fluids is determined by the presence of gel stabilizers. Methanol was the first temperature stabilizer used commercially and other stabilizers have since been introduced.[15-17] With addition of the stabilizers, the stability of the fluid increases; with decrease or withdrawal of the stabilizers, the breaking properties of the fluid can be controlled. According to the field experience, breakers are not required for the high temperature fluid due to its high temperature applications (greater than 250°F (121°C). The effect of various stabilizer combinations on viscosity stability at 350°F (177°C) is shown in Figure 5.

The particular stabilizers shown in Figure 5 are not intended to represent optimum commercial systems but rather show the magnitude of various gel stabilizers effect on viscosity. In most cases, maximum stability is achieved with a mixture of gel stabilizers.

The superior viscosity stability of the high temperature fluid over a traditional two-stage fluid and a stabilized crosslinked fluid at 300°F (149°C) and 350°F (177°C) are shown in Figures 6 and 7, respectively. The crosslinked system used for this comparison is a titanium crosslinked HPG with a secondary gelling agent incorporated. This crosslinked system is a representative of the high temperature crosslinked fracturing fluid used by the industry today. The time-temperature stability studies on the crosslinked system were made using previously defined methods and procedures.[12] As was reported in those studies, there is a maximum temperature limit for all crosslinked fluid systems. Above that temperature limit, no viscosity enhancement over that of the base gel can be observed.

Figure 7 shows the advantage of the high temperature fluid over the crosslinked fluid system at 350°F (117°C). At temperatures below the maximum temperature for the crosslinked fluid system, comparable viscosities at the longer times for the two stage gel system may be obtained by using approximately twice the polymer loading used in the crosslinked fluid system. Note, however, that the viscosity obtained for the crosslinked fluid system is shear dependent. In case where long, small diameter tubing is used in the treatment, the predicted viscosities of crosslinked fluid system may be optimistic. The stability achieved with the stabilized high temperature fluid has not not been matched by any other fluid system investigated.

Since the temperature stable fluid is a two-stage system, the downhole fluid viscosity in the fracture is independent of the pumping viscosity, and the total polymer concentration is not limited by friction pressures limitations. The viscosity of the base gel can be altered depending on treatment conditions, and is adequate for both transporting the proppant in the surface equipment and the downhole tubular goods. The viscosity stability of the system is a function of the concentration of secondary gelling agent and gel stabilizers. The break characteristics of the fluid are controlled by decreasing the polymer concentration and gel stabilizers in different fluid increments during the treatment.

Treatment Design

Computerized fracturing design programs are a definite aid in designing massive hydraulic fracturing treatments. Fluid rheology plays a major role in these programs in determining the resultant predicted fracture geometry and proppant placement profiles. However, most present fracture design programs use one set of input rheology parameters. This input rheology parameters do not completely reflect temperature profiles that the fluid will experience in the fracture as well as the loss of viscosity due to polymer degradation.

For field applications, the design approach involves first determining the optimum viscosity for a particular treatment, which provides the best fracture geometry and production increase by using a fluid design program.[18] The second step is to incrementally determine the mean temperature of the fluid in the fracture using a fracture temperature prediction program.[19,20] Utilizing the expected time-temperature profile, the polymer loads and viscosity stabilizers are incrementally varied to provide the desired viscosity in the fracture. Figure 8 shows the viscosity profile in the fracture for the proppant-laden fluid of a proposed treatment for an example well with a bottom-hole static temperature of 350°F (177°C).

Field Test Results

At the present time, the high temperature fluid has been successfully tested in field treatments on reservoirs with BHT of 265°F (129°C) to 402°F (206°C). Representative treatment summaries are shown in Table 1. Both and sand bauxite proppants were used in the treatments, depending upon expected fracture closure pressures. The potential of the system is for high temperature treatments is exemplified by treatments where 3+ lb/gal. of 20/40 bauxite proppant was successfully placed at low rates.

One of the major factors which affects the success of high temperature treatments is the treatment rates. Since the viscosity stability is a function of time at temperature, the maximum amount of the proppant-laden fluid that can be placed with the desired viscosity will also depend on the treating rate. Furthermore, fluid efficiency and effective fracture cool-down of a given volume of treating fluid is much better at higher rates. The fluid loss coefficient of the high temperature fluid is controlled by viscous flow.[21] The fluid efficiency can be improved by the addition of fluid loss additives and the system is compatible with all fluid loss agents used by the industry today.

In deep, hot wells the completion practive may result in a treating string with a small internal diameter annulus (2.3 inches). Therefore, the friction pressure of the fluid will play a major role in determining whether the fluid is used. Treatment results to data have indicated that the high temperature fluid described has excellent low friction properties. For example, on a pumping rate test in the Wilcox formation using 15,440 ft (4706 m) of 2.259 inch (0.057 m) inside diameter tubing at 12 BPM (1.9 m^3/ min), the friction pressure of the high temperature fluid containing 0.72% HPG and 0.72% delayed hydrating HPG was 22 psi (152 M Pa) per 100 ft (30.5 m). Actual friction pressures encountered have been significantly less than other alternate systems which have been used.

SUMMARY

1. A two component high temperature fluid has been developed which provides nearconstant viscosity in the fracture.

2. The temperature stability of the system is determined by pH, synergistic stabilizer combinations and the total polymer concentration.

3. A comprehensive MHF treatment design procedure has been developed for the high temperature fluid.

4. Treatment test summaries have been provided for treatments in wells having BHST from 265°F (130°C) to 402°F (205°C).

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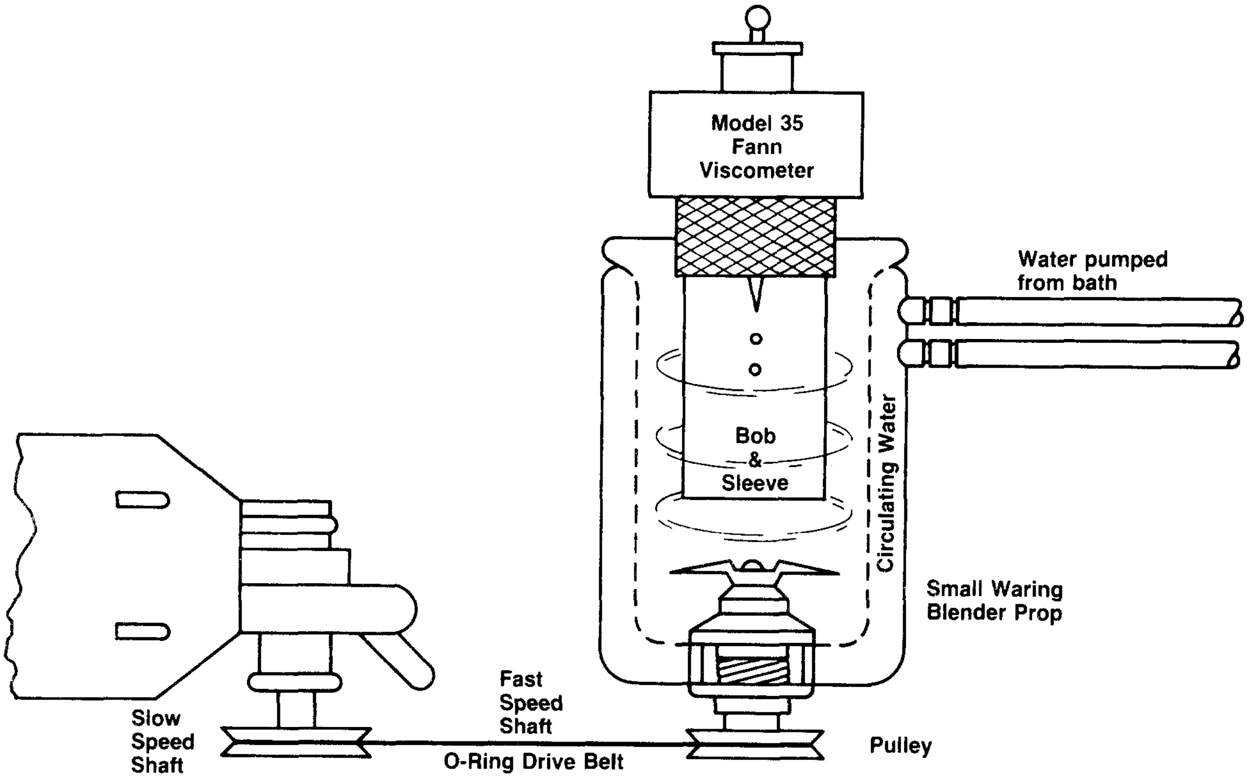

Fig. 1 Stirring Heating Cup for Hydration Tests

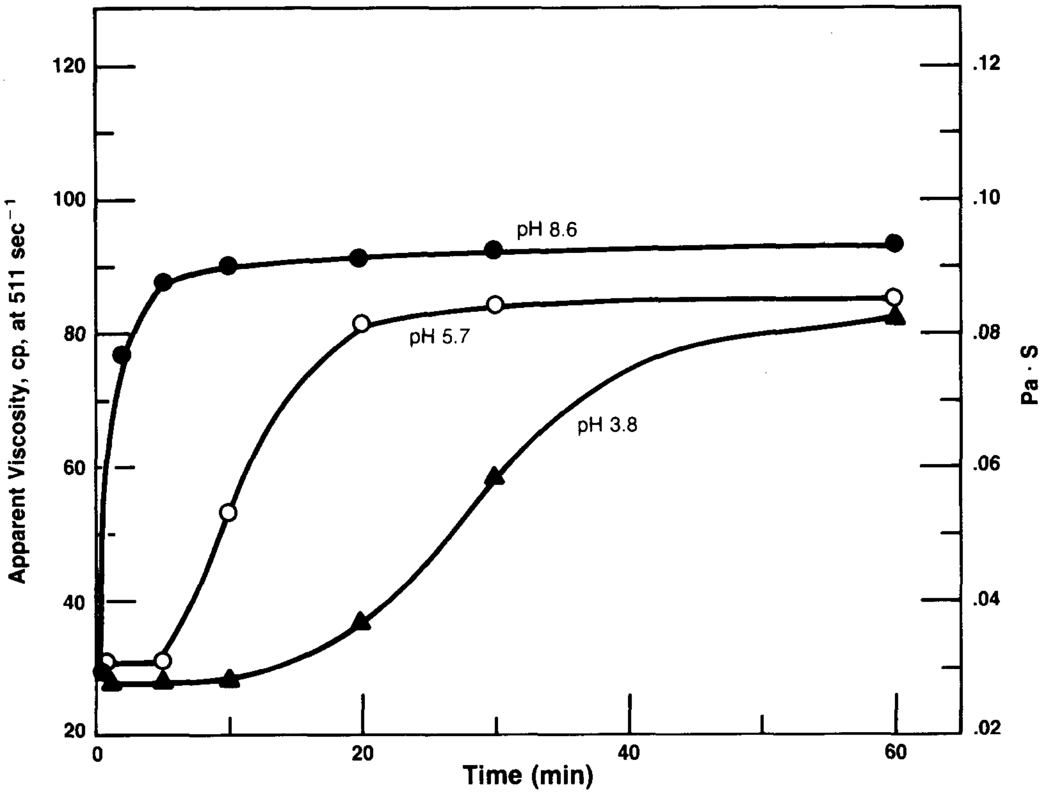

Fig. 2 Behavior of Traditional Delayed Hydrating HPG as a Function of pH
[Temp. = 49°C (120°F)]
(0.48% HPG + 0.48% Delayed Hydrating HPG)

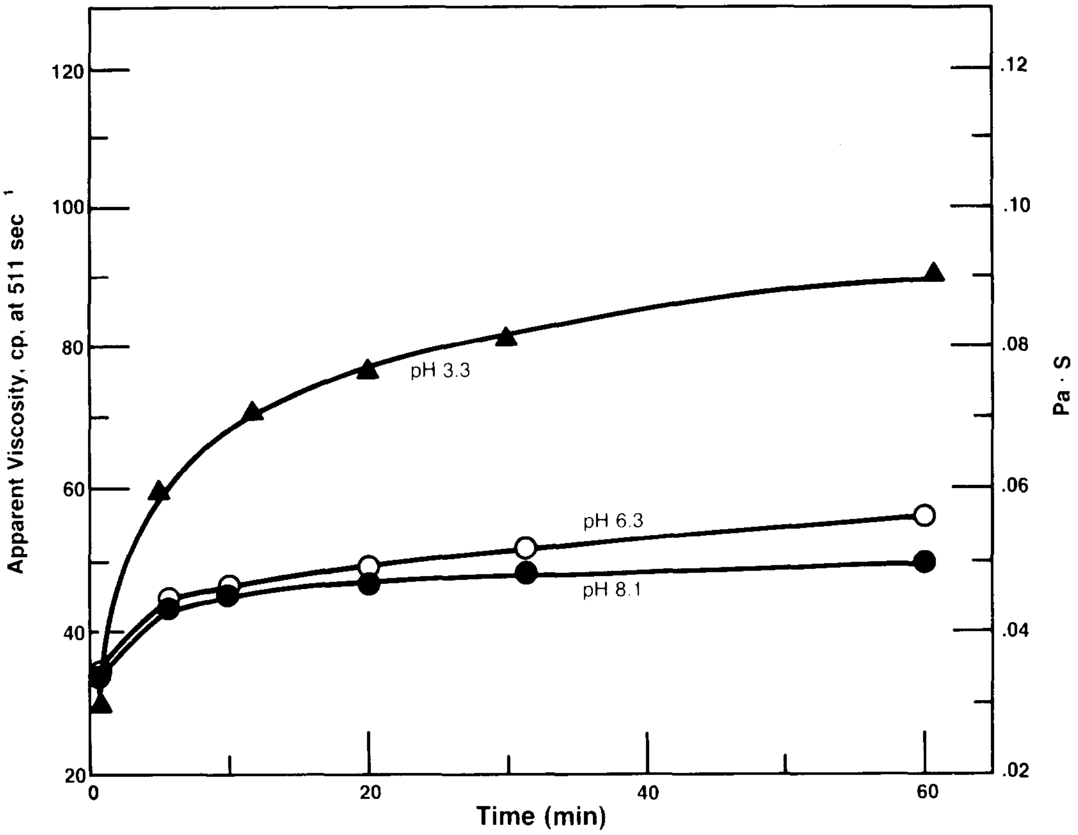

Fig. 3 Behavior of the new Delayed HPG as a Function of pH
[Temp. = 49°C (120°F)]
(0.48% HPG + 0.48% Delayed Hydrating HPG)

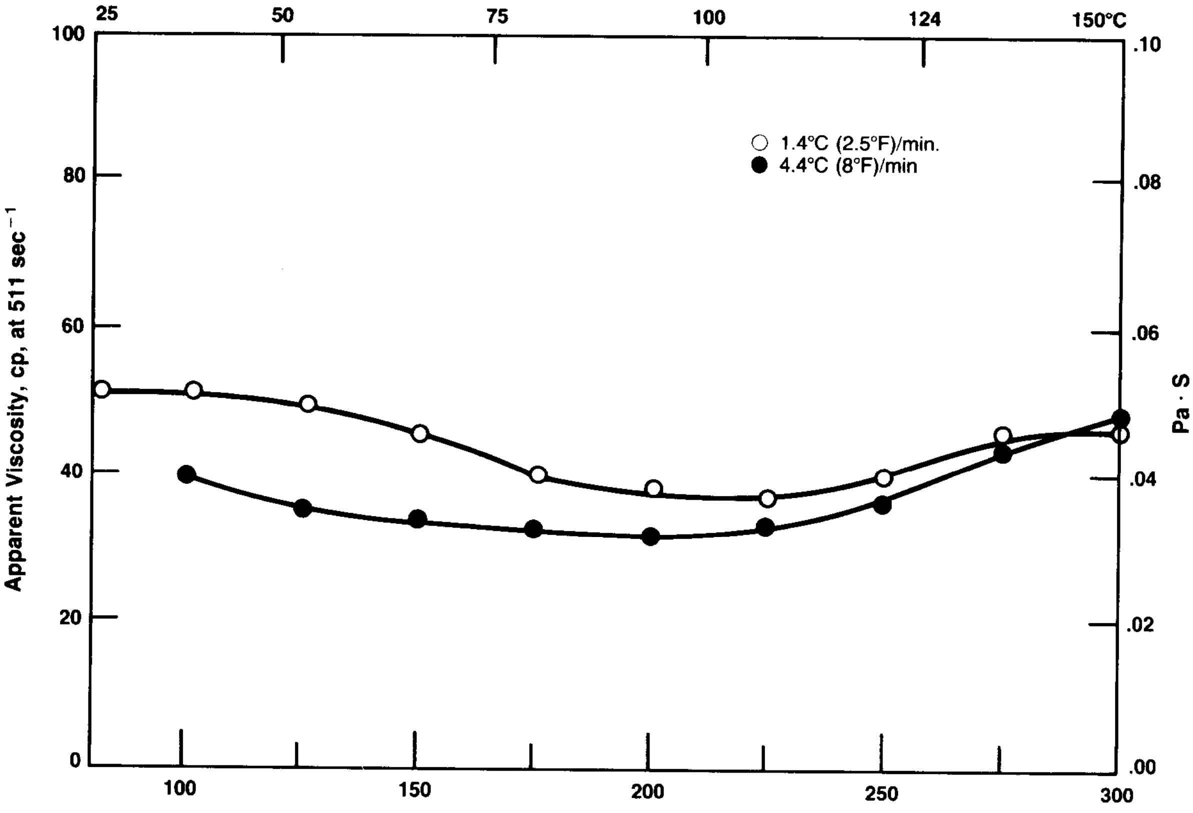

Fig. 4 Effect of Heating Rate on the High Temperature Fluid (0.6% HPG + 0.48% Delayed HPG)

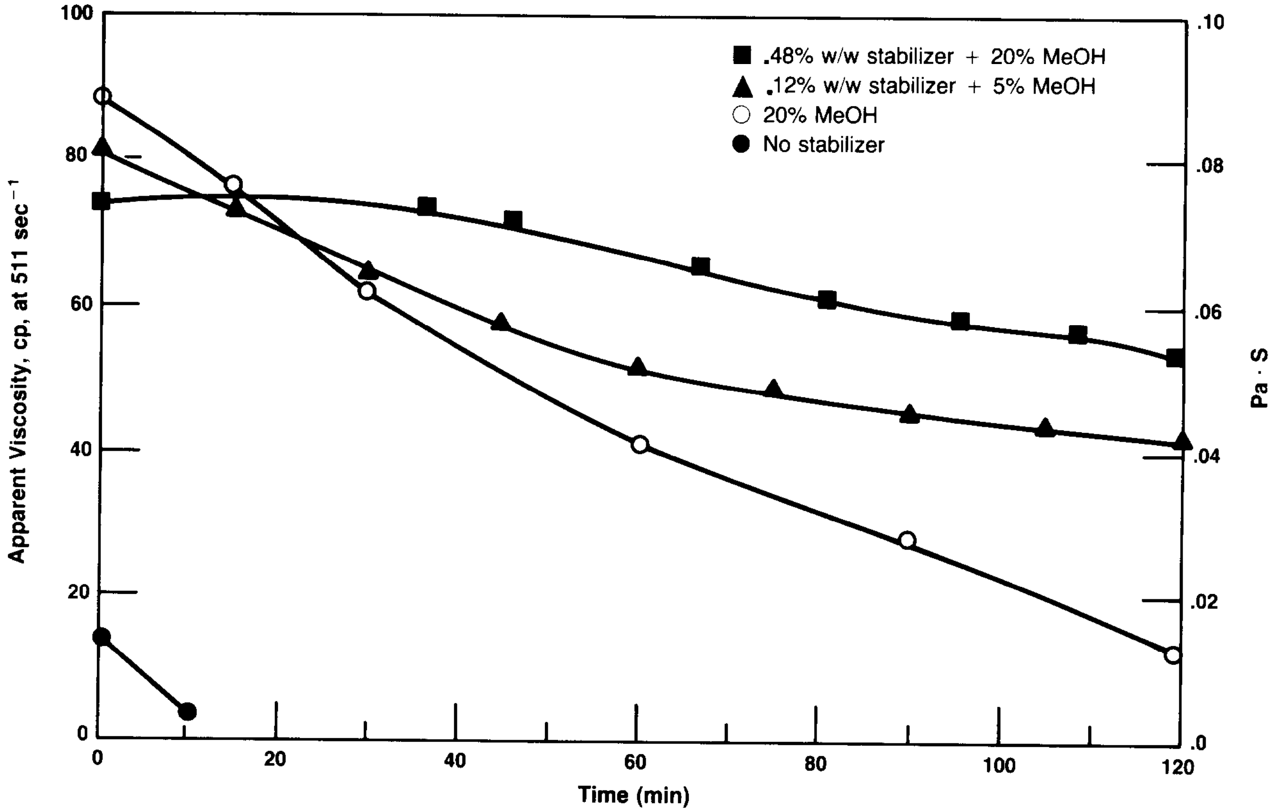

Fig.5 Stability of the High Temperature Fluid (0.6% HPG + 0.84% Delayed HPG) at 177°C (350°F) with Different Gel Stabilizers

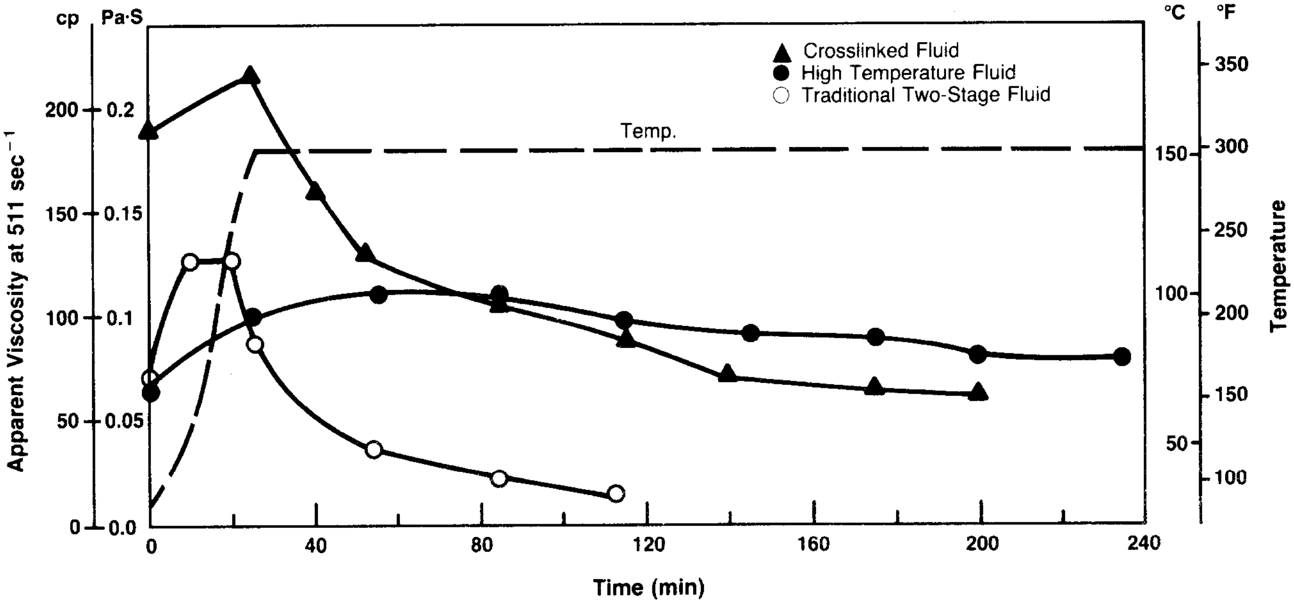

Fig. 6 Comparison of High Temperature Fluid, Traditional Two-Stage Fluid and a Typical Crosslinked Fluid (0.72% HPG + 0.72% Delayed HPG)

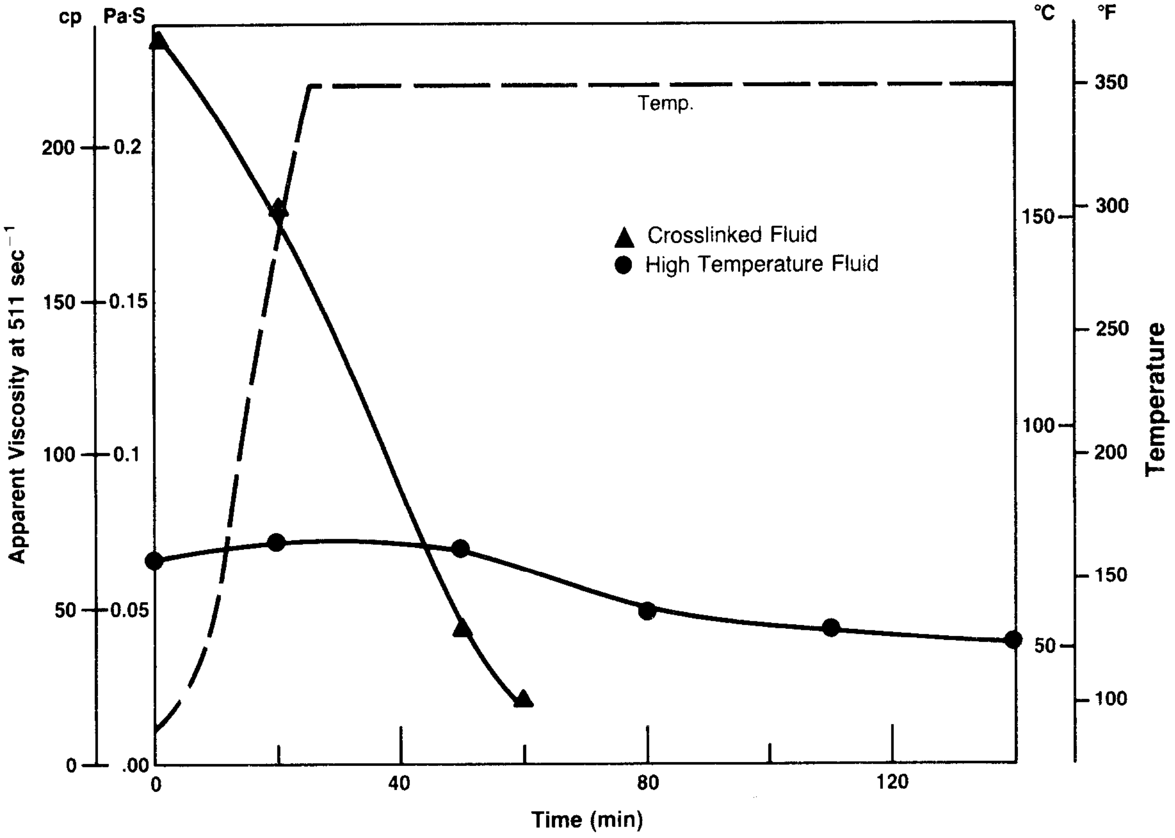

Fig. 7 Comparison of High Temperature Fluid and a Typical Crosslinked Fluid (0.72% HPG + 0.72% Delayed HPG)

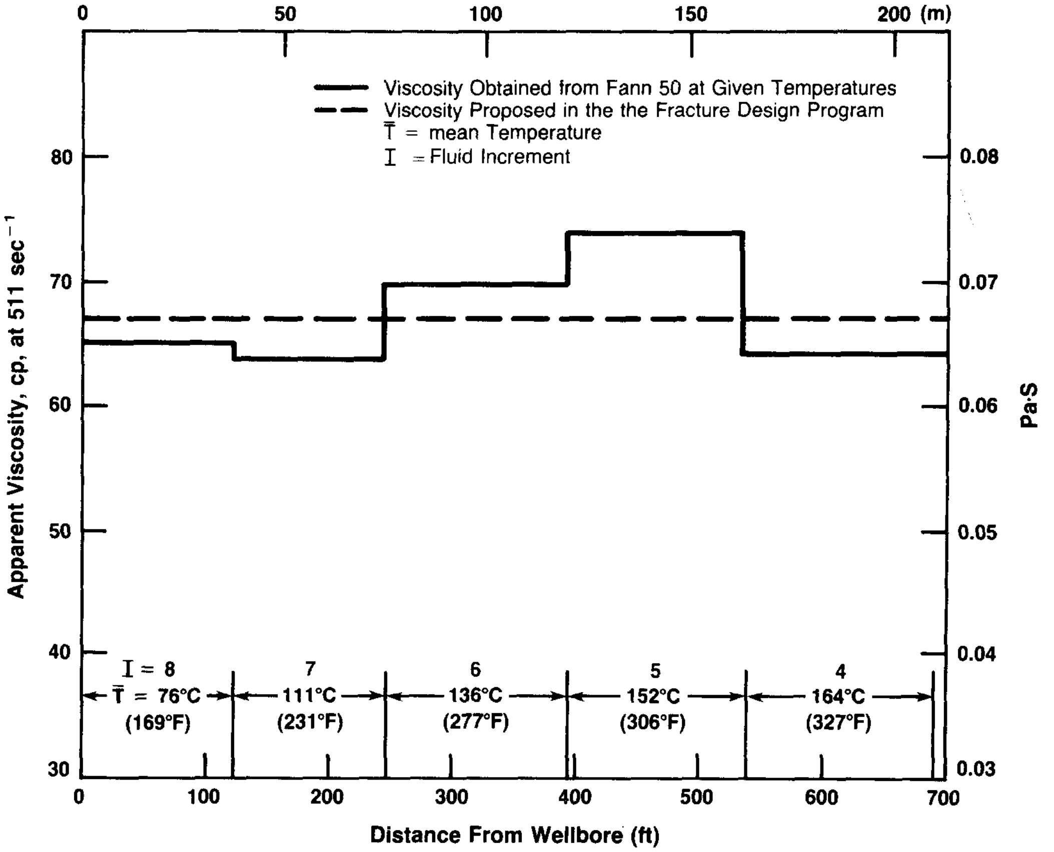

Fig. 8 Viscosity Profile of the Proppant Laden Fluid in the Fracture