HIGH PROPPANT CONCENTRATION/LOW VOLUME FRACTURE TREATMENT COMBINED WITH FORCED CLOSURE YIELDS SUCCESS IN CLEARFORK FORMATION

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INTRODUCTION

Fracture acidizing and hydraulic fracturing utilizing propping agents has been used successfully in the stimulation of oil and gas wells for over 40 years. A tremendous number of these acidizing and proppant fracturing treatments have been conducted in carbonate reservoirs in west Texas. It is the purpose of this paper to report a fairly extensive program to optimize stimulation results, primarily in the Clearfork, but also in other west Texas reservoirs. The operator was noting declining production and wanted to institute a program to stimulate oil production but also at the same time attempt to control many of the operational problems typically encountered with proppant fracturing. The operator, when attempting restimulation, had seen little or no success over the years with many types of acidizing techniques.

After several different approaches were taken in an attempt to solve the problem, we felt that utilization of high concentrations of high conductivity propping agents uniformly distributed across the producing interval was the answer to obtaining sustained productivity increases.[1-7] Although several proppant fracture treatments had been conducted in the area, we felt quite strongly that job design, job execution, and shut-in and flowback procedures were inadequate to properly stimulate the reservoir.

Our initial premise was to utilize as simple a fluid as possible, thereby eliminating job execution and fluid problems. We also wanted an efficient fracturing fluid with excellent proppant transport properties to be able to achieve a very high conductivity propped fracture. Additionally, we utilized the forced closure technique[1,8] to minimize proppant settling in the producing interval. The authors felt that a major problem in the area was settling of the proppant into water-producing intervals in the lower part of the Clearfork.

In the paper, we will give very specific examples of the use of intense quality control and also go into our evolution into the use of 35 lb/1000 gal borate crosslink gels, as well as the very simple, straightforward polyemulsion system. We feel in both cases that the use of an aggressive proppant schedule, proper job design, and an aggressive flowback schedule has allowed a very successful stimulation program to be accomplished. We will give extensive results on pre- and post-fracture productivity, as well as economics.

HISTORY

Texland Petroleum, Inc. operates many waterflood units and individual wells in west Texas. In the summer of 1988, Texland employed S.A. Holditch and Associates to evaluate the performance of a Terry county waterflood unit. Part of that evaluation consisted of a review of past stimulation practices. Well histories were studied, and the predominate method of completion was an acid treatment or acid fracture treatment. Sometimes these were followed by a gelled water hydraulic fracture treatment with sand as a propping agent.

The hydraulic fracture treatments pumped were either low volume and rate treatments or high volume along with high pumping rate. The low volume treatments usually consisted of 15,000 gallons of cross-linked water gel and 50,000 pounds pumped at 8 barrels per minute. The high volume and rate treatments contained 75,000 gallons of cross-linked gel and 170,000 pounds of sand pumped at 40 barrels per minute. Both treatments limited the maximum sand concentration to about 5 or 6 pounds per gallon of gel. These treatments were followed by an overnight shut-in period and then opened for production the next day.

A "FracHite" log run on a nearby well indicated that the in-situ stress contrast between the pay interval and the surrounding barren formation was only 400 psi. The high viscosity of the cross linked gel can create very large excess pressures irrespective of pump rate.[9] These two facts led to the conclusion that the fracture will most likely grow vertically out of the pay interval. This is not disastrous by itself, assuming the surrounding formation is not water productive. However, when long shut-in periods follow the treatment, proppant settling occurs until the fracture is closed. In low permeability wells, fracture closure time can be excessive allowing virtually all of the proppant to be placed in the lower portion of the created fracture. Therefore, the past hydraulic fracture treatments were most likely ineffective in stimulating the Clearfork formation due to excessive vertical height growth accompanied by the proppant settling out of zone.

Figures 1a to 1c demonstrate the various stages of a fracture treatment pumped as described above. The slurry is pumped into the well in Figure 1a. The sand settles to the bottom of the created fracture in Figure 1b. Then the fracture closes on the proppant out of zone in Figure 1c. When forced fracture closure techniques are followed the proppant is placed in the pay interval as shown in Figure 1d.

A fracture treatment was then designed to take advantage of what little stress contrasts were present and the technique of forced fracture closure was recommended. A polyemulsion fluid was utilized as the fracturing fluid and an aggressive proppant schedule was recommended with the maximum sand concentration being 10 pounds per gallon. The polyemulsion fluid has a moderate viscosity with good sand transport properties and extremely low fluid leakoff. The moderate viscosity aids in limiting height growth where stress contrast existed. The treatment design is presented in Table 1. This design contains 16,000 gallons of polyemulsion and 80,000 pounds of sand. The fracture treatment was pumped down casing at a rate of 20 to 25 barrels per minute.

Following several successful fracture treatments with good production response, the design was used in a Lubbock county Clearfork field where it met with mixed results. Oil production was increased, but water production greatly increased. The producing interval in this case was close to a water bearing interval with no apparent stress contrast between them. Without significant stress contrast, a fracture will grow radially or "penny shaped". To successfully fracture this interval, a design was needed that would not grow down into the water productive interval. The water zone lay about 100 feet below the pay interval which was scattered over a 100 foot gross section. The treatment designed utilized a Borate cross linked gel and was considerably smaller than the earlier treatments. The design is presented in Table 2 and consists of 10,000 gallons of gel and 50,000 pounds of sand. The treatment is designed to create a "penny shaped" fracture that will not reach the water interval. The fracture was also to be initiated in the top of the pay interval by covering the lower perforations with sand. Often additional perforations were needed in order to achieve the desired fracturing rates. These treatments have had moderate success in minimizing water cuts and volume; however, they have been very successful in improving oil production.

Borate treatments have also been pumped when treatment down casing was not possible. This was sometimes due to squeeze perforations which existed uphole from the pay interval. Polyemulsion treatments have been pumped down tubing on two occasions. Due to the high friction pressures associated with polyemulsion, they must be pumped at low rate when treating down tubing and costs can dramatically increase due to increased hydraulic horsepower.

QUALITY CONTROL

For all of the fracture treatments discussed in this paper, conventional and intense quality control[10] was practiced. Conventional quality control of a fracture treatment is very straightforward and should be performed on all treatments. Intense quality control involves pilot testing the fracturing fluids in the field, which is as critical to the success of the treatment as conventional procedures.

Conventional quality control would include measuring and recording information on water analysis, base gel viscosity, the presence of bacterial, reducing agents, oxidizing agents, and other additives. It is important to evaluate the quality of the base gel fluids, the propping agents, and the additives. We also recommend sieving the proppant delivered to location and testing the crosslink time of each tank of gel when high viscosity fracturing fluids are to be used.

It is essential that pre- and post-treatment inventories of all items on location to be used in the fracturing treatment be performed. Without such a complete inventory, it is impossible to know exactly what was pumped downhole. We also recommend that the pumping equipment and treating iron be inspected to insure that it meets the required pressure limitations of the job. Also, the method used to rig-up the surface equipment should be checked for safety reasons, i.e. lines properly staked, treating iron flexible, check valve near the wellhead, etc. The above mentioned practice of conventional quality control is very straight forward and should be practiced on every fracture treatment. However, we also believe that by using on-site measurement of in-situ viscosity and viscosity degradation with time, we can improve the success ratio of stimulation treatments. Intense quality control involves pilot testing the fracturing fluids in the field. The fracture treatments discussed in this paper utilized either borate crosslinked or polyemulsion fracturing fluids. All of the wells had reservoir temperatures less than 120°F, which is a very critical temperature range in terms of obtaining the desired gel degradation. For these low temperature wells, the intense quality control testing techniques are relatively inexpensive and straight forward. One simply needs to have a heated testing cup and a Fann 35 viscometer with both B-1 and B-2 bobs. The smaller B-2 bob allows the conventional viscometer to be used for crosslinked gels.

For the borate crosslinked jobs, we took samples of the base gel, in the field, added the crosslinker, oxidizer breaker, breaker activator (typically required for temperatures <130°F), and all other additives and then transferred the sample to the heated cup. The fluid was then warmed to reservoir temperature and placed on the Fann 35 at 100 rpm or 37.5 sec^{-1}, to record apparent viscosity vs. time. This was to assure that the breaker loadings used would efficiently break the gel over the desired time and conversely that a premature break did not occur. Unfortunately, we have found that it is much more the rule than the exception that the recommended breaker loading is often drastically altered, requiring several iterations of the testing process.

For the polyemulsion systems, we also followed the same procedure with the exception of bob size. The polyemulsion viscosities typically are 100-130 cp which can be measured with the standard B-1 bob on a Fann 35 at 300 rpm. The polyemulsion is placed in the heat cup with the breaker and degradation is monitored over time. Because an enzyme breaker is used for this system (applicable for a pH range of 3.5-8.5), we have not observed the severity of break problems found with the borate crosslink. Nevertheless, intense quality control should be practiced.

The testing of fracturing fluids should be done in the field like all companies test cement blends before a cement job. No operator would pump a cement slurry in a well without testing the cement for thickening time, compressive strength, and setting time. We feel that the intense quality control technique is just as important to the success of a fracture treatment as is the testing of cement to the success of a completion. If the gels are not tested and a problem occurs, it could result in a premature screenout or in gels that do not break and clean up properly. If either situation occurs, the well will not recover as much oil and gas and revenue will be reduced.

CASE HISTORIES

Well No. 1

This well is a Terry County Clearfork producer currently being waterflooded. It was also the first well treated with the polyemulsion design. The fracture treatment consisted of 16,000 gallons of fluid and 66,000 pounds of 20/40 mesh Ottawa sand and was pumped at a rate of 16 BPM. The frac was performed in early 1989. Figure 2 shows the production history for the well and indicates an excellent production response to the stimulation treatment.

Well No. 2

This well is a Lubbock County Clearfork producer. It is also under waterflood. The treatment consisted of 10,000 gallons of Borate cross linked gel and 50,000 pounds of 20/40 mesh Ottawa sand pumped at a rate of 26 BPM. As can be seen in Figure 3, the oil production was dramatically increased by this stimulation treatment. When pumping a treatment this size down casing, the slurry entering the wellbore can be already at 10 ppg before sand has reached the perforations. This practice can be nerve racking, since total pump time is about 12 minutes at 26 BPM.

Well No. 3

This well is an Abo producer in Hockley County and is also under waterflood. The fracture treatment was pumped in January 1990 and consisted of 21,000 gallons of polyemulsion fluid and 116,250 pounds of 20/40 mesh Ottawa sand. It was pumped down casing at a rate of 24 BPM. Excellent initial production response can be noted in Figure 4. It seems that production may have quickly dropped off after the initial response.

Well No. 4

This well is another Lubbock County Clearfork producer also under waterflood. The fracture treatment was pumped in October 1990. This was also another Borate gel treatment which contained 15,000 gallons of gel and 50,000 pounds of 20/40 mesh Ottawa sand. Figure 5 is a plot of the wells producing history. The well is showing good initial response to the stimulation as it had its two most productive months after the treatment.

Summary

In summary, Texland has pumped 36 fracture treatments since the initial fracture treatment in February of 1989. Twenty-four of these treatments have been with polyemulsion fluid and twelve with Borate cross linked gel. The average polyemulsion job has consisted of 17,400 gallons of fluid and 81,800 pounds of sand. The average Borate job has been 12,600 gallons of gel and 51,800 pounds of sand. The maximum sand concentration for these jobs has been up to 12 ppg with a total sand pumped in these 36 jobs of over 2.5 million pounds. Figure 6 is a plot of the before and after average oil production rates for the wells fracture treated (new completions have not been included in this graph). The plot indicates that the wells have responded very well to the treatments pumped, with the first three months incremental production recovery totalling about 2000 barrels per well. The average workover cost of these treatments have been about $30,000 per well.

CONCLUSIONS

Significant sustained increases in production of hydrocarbons have been achieved through the application of the following techniques.

1. The utilization of aggressive proppant schedules including high proppant concentrations with 20/40 Ottawa sand.

2. The application of the forced closure technique negating proppant settling thereby assuring the majority of the proppant is placed across the entire productive interval.

3. The utilization of intense quality control. This technique by pilot testing all fluids prior to pumping has allowed the operator to be assured of quality fluids but also to be certain that they will break back to base fluid allowing cleanup of the proppant pack.

4. Application of state-of-the-art frac design technology allowing optimization of fracture size based upon realistic stress profile.

5. In most cases very simple, moderate viscosity, highly efficient fracturing fluids that are almost fail safe in application.

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Table 1
Polyemulsion Fracture Treatment Design

5000 gallons Poly-Emulsion as pad

2000 gallons Poly-Emulsion w/ 2.5 ppg 20/40 mesh sand

2000 gallons Poly-Emulsion w/ 5.0 ppg 20/40 mesh sand

2000 gallons Poly-Emulsion w/ 7.5 ppg 20/40 mesh sand

5000 gallons Poly-Emulsion w/ 10.0 ppg 20/40 mesh sand

Flush to top perforation with lease crude

Table 2
Borate Gel Fracture Treatment Design

3,500 gallons 35# Borate cross linked gel as pad

1,000 gallons 35# Borate gel w/ 2.5 ppg 20/40 mesh sand

1,000 gallons 35# Borate gel w/ 5.0 ppg 20/40 mesh sand

1,000 gallons 35# Borate gel w/ 7.5 ppg 20/40 mesh sand

3,500 gallons 35# Borate gel w/ 10.0 ppg 20/40 mesh sand

Flush to top perforation with slickwater

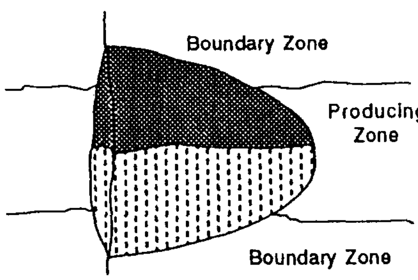

Figure 1A - Settled pack - no closure

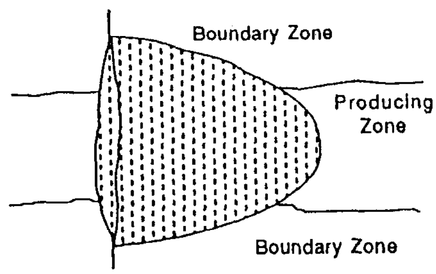

Figure 1B - Proppant pack at end of pumping

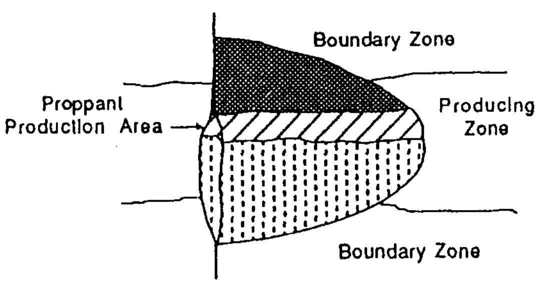

Figure 1C - Settled pack after closure

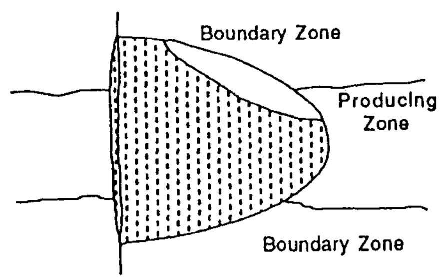

Figure 1D - Ideal proppant pack with forced closure

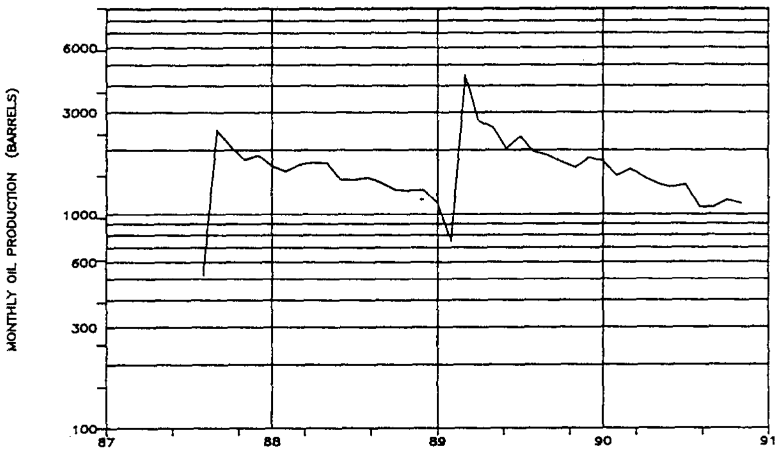

Figure 2 - Texland Well No. 1

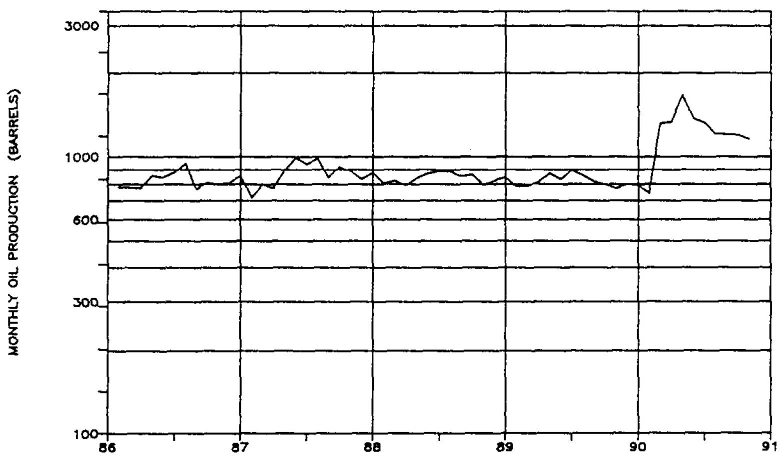

Figure 3 - Texland Well No. 2

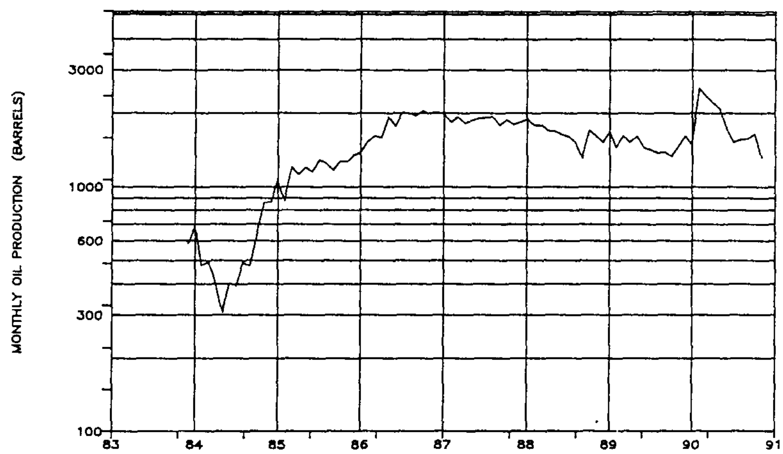

Figure 4 - Texland Well No. 3

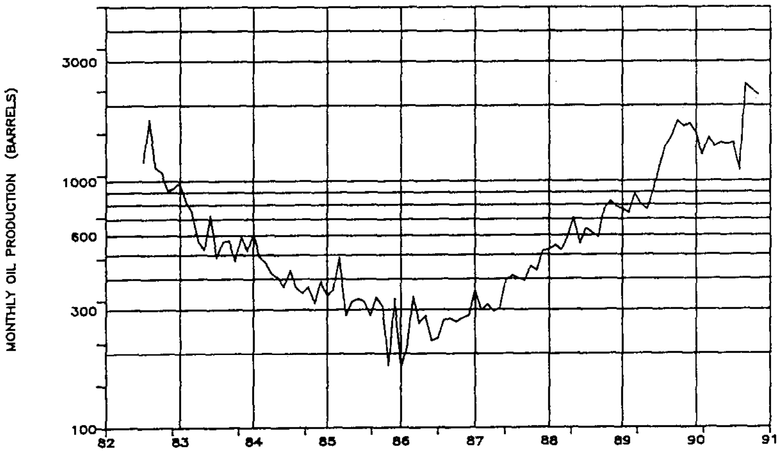

Figure 5 - Texland Well No. 4

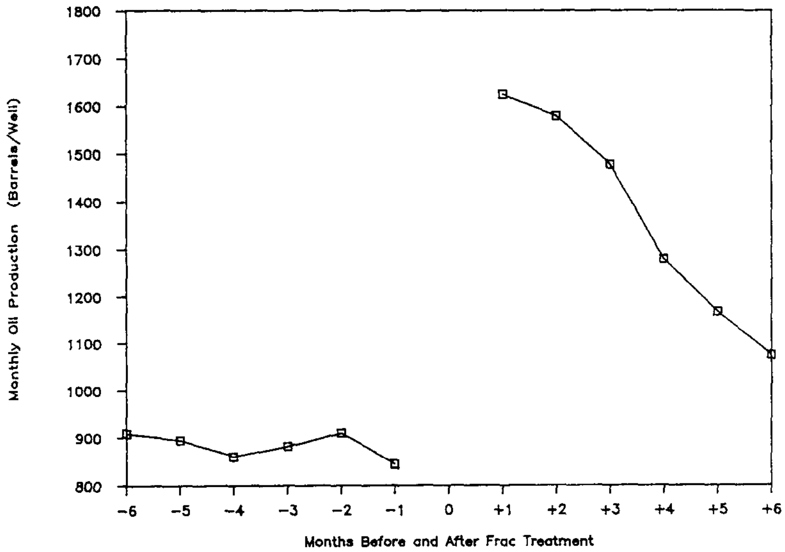

Figure 6 - Frac treatment oil production response