FIELD TEST RESULTS OF A NEW ACID GELLING AGENT

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ABSTRACT

A novel gelling agent for hydrochloric acid is evaluated through field tests. Increased formation conductivity and live acid penetration depth is reflected by sustained improvements in production after the treatments. The advantages of this new gelling agent are its stability in high concentrations of hydrochloric acid (28 percent) over a range of temperatures up to 300 F. Comparisons with ungelled acid and acid treatments using other gelling agents are presented. These case histories are in West Texas, New Mexico, North Dakota, Montana and other parts of the country.

INTRODUCTION

Maximizing live hydrochloric acid penetration distance is the most important concern in fracture acidizing treatments. The literature describes several ways to optimize this parameter through treatment design. Alternating stages of nonreactive pad and acid fluids[1,2] are proven methods used to attain deeper penetration in the fracture with live acid. This increases the conductivity of the complete fracture rather than just in the vicinity of the well bore. Another method widely utilized incorporates viscous fingering of a thin fluid (acid) through a thick fluid (viscous pad).[3] These techniques aid in retarding the acid reaction rate with the formation and reduce fluid loss. Live acid remains in the fracture longer. Another method is to use more concentrated acid. The use of strong acid (28 percent) provides more spending power. Strong acid tends to be very corrosive and release more fines as its principle disadvantages.

The use of linear gelled acid technology is gaining acceptance in the industry.[5,6] Linear gelled acid treatments are used in the same type treatment design as non-gelled acid and demonstrate improvements. Increasing the viscosity of the acid reduces fluid loss to the secondary porosity of the natural fractures and vugs in the formation. It further reduces the reaction rate of the acid compared to ungelled acid. Gelled acid applications range from small matrix-type cleanups for immediate well bore damage removal to large volume fracture-acidizing treatments.

A new acid gelling agent (Polymer A) for acidizing treatments was recently introduced. This material is designed for use in reservoirs with high temperatures (200-300 F), yet it is also effective in moderate to lower temperature environments (100-200 F). Polymer A is stable in all usable acid concentrations, especially 28 percent hydrochloric acid. The spent gelled acid fluid returned from field tests has some residual viscosity which aids in the cleanup of unreacted fines. This allows the use of 28 percent gelled acid in many instances where it is not normally used. Fines can reduce flow capacity if left behind in the formation.

Polymer A is also very stable in high concentrations of divalent ions, such as calcium, at elevated temperatures. Calcium can cause polymer precipitation resulting damage and reduce fracture flow capacity. This is the environment gelling agents are exposed to after the fracture-acidizing treatment for several days. Many gelling agents have limitations associated with one or more of these conditions. When this occurs the benefits of using acid gelling agents diminish and the production response resembles more like what is expected when ungelled acid is used.

Polymer A is a simple one component system. Crosslinking and breaking additives are not needed. Viscosity reduction occurs through the mechanism of dilution with broken pad fluids or conate water.

DISCUSSION

The results from the field tests using Polymer A to gel acid for fracture acidizing treatments are reflecting an interesting concept which is not discussed in the literature. Previous reports demonstrate advantages in using acid gelling agents to increase the production of wells stimulated. However, few comparisons are available to determine how a given well will respond when treated with ungelled acid or examples with offsetting wells treated with different gelling agents. This is especially true in evaluating the long term benefits of a given stimulation.

Gelled acid treatments using Polymer A not only provide a maximum increase in production initially, but tend to sustain this production increase longer. The production decline rate is not as dramatic after the gelled acid treatment using Polymer A as it was after the original stimulation with nongelled acid. Likewise, wells treated with gelled acid containing Polymer A tend to produce at a more sustained rate than wells treated with gelled acid containing Polymer B or Polymer C. All three polymers are synthetic polymers and commercial products.

A good stimulation be it matrix or fracture-acidizing serves to remove skin damage around the well bore. Acid fracturing also creates a conductive passageway for fluid flow. Heterogenous parts of the reservoir with regions of higher permeability are connected to the well bore. The benefits from improved fluid loss and reaction rate control are supported in some of the field case histories using Polymer A as a gelling agent. The sustained production increase observed is attributed to these factors possibly resulting in a larger effective drainage radius for a given well on a given spacing. When stability limitations of a gelling agent are exceeded, the benefits of using certain acid gelling agents are diminished. This may explain why wells treated with Polymer B and Polymer C are less effective in sustaining long production performance. The production decline rate more closely resembles an ungelled acid treatment or it is intermediate between that expected from ungelled acid treatments and those with Polymer A.

Methods of decline curve analysis using type curves are being conducted on these and other wells.[7] The results of these analysis should help explain some of the findings from the gelled acid treatments using Polymer A. This work will be reported later.

Case Histories

Fusselman Case History - Roosevelt County, New Mexico

Case Number 1 demonstrates the benefits of using Polymer A gelling agent in a well initially fractured with ungelled acid. The production history for Case Number 1 is plotted in Figure 1. Point A represents the initial completion date and Point B the recompletion date with gelled acid.

A 7,830-foot Fusselman well, bottom hole temperature 155 F, was initially treated with 18,000 gallons of 28 percent HCl in an acidizing treatment. The initial production from this 19 feet of net interval was 113 barrels of oil per day (BOPD), 55 barrels of water per day (BWPD), and 57 thousand standard cubic feet (MSCF) per day which declined at an annual rate of 70 percent to three BOPD.

The well was stimulated again with a sand fracture treatment. However, it was unsuccessful and oil production was unchanged at three BOPD.

Four months later, the well was treated for the third time with 500 gallons of 15 percent breakdown acid and fractured with 15,000 gallons of 20 percent HCl containing Polymer A as a gelling agent in combination with 12,000 gallons of pad and

6,000 gallons of flush. Three alternating pad-gelled acid stages were pumped at 13 BPM with 400 scf/bbl (standard cubic feet/barrel) of nitrogen.

Daily production averaged 35 BO, 5 BW, and 57 MSCF in the first month after treatment. Six months later production averaged 28 BOPD, 8 BWPD, and 14 MSCF. Using a least squares analysis of the production data, this well is declining at a 38 percent rate one year later.

Interlake Formation Case Histories - McKenzie County, North Dakota

A comparison is made in Figures 2 and 3 with the initial completions (represented by Point A) using ungelled acid and a recompletion (represented by Point B) using 28 percent acid gelled with Polymer A in Case Number 2 and with Polymer B in Case Number 3. The well described in Case Number 2 is offset by the well in Case Number 3. Case Number 3 is 1/4 mile south of Case Number 2 and it is 10 feet structurally higher. Figures 4 and 5 represent two other wells, Case Number 4 and Case Number 5 which are on the edge of the structure. Point A represents initial completion date and Point B is the recompletion date with gelled acid. Case Number 4 was recompleted using Polymer C as the acid gelling agent and Case Number 5 used Polymer A. The treatments for these wells are similar in size and design to Case Numbers 2 and 3. The monthly production numbers after the gelled acid treatments appear in Table I for comparison.

The Interlake formation in Case Number 2 at 12,570 feet is perforated over a 110 foot interval. Formation temperature is 282 F. The initial stimulation consisted of 5,000 gallons of 15 percent hydrochloric acid initiating daily production at 590 BOPD, 30 BWPD, and 927 MSCF per day in the first month. The production declined in the first eight months to 115 BOPD, resulting in a decline rate of 92 percent over this time period (Figure 2). Production was 77 BOPD, 21 BWPD and 30 MSCF per day before restimulation. The well in Case Number 2 was restimulated using 17,000 gallons of 28 percent HCl with Polymer A as the acid gelling agent. Ten thousand gallons of crosslinked pad and gelled flush fluids were used in four alternating pad and gelled acid stages. Ball sealers were used for diversion. Production was stimulated resulting in 516 BOPD, 71 BWPD and 860 MCFGPD in the first 30 days. Table I and Figure 2 show the production decline covering an 8-month period after gelled acid stimulation of 24 percent. This is a significant decrease in decline rate from 92 percent initially. Points A and B in the production history plot of Figure 2 depict the difference.

An offset well, Case Number 3 resembles as close as possible the reservoir and production characteristics of Case Number 2. It was initially completed (Figure 3, Point A) with 5,000 gallons of 28 percent acid and later recompleted (Figure 3, Point B) with the same type gelled acid treatment using Polymer B as the acid gelling agent. The initial production decline rate was 58 percent covering an 8-month period. Table I shows the production decline after the gelled acid treatment using Polymer B at 48 percent covering an 8-month period. The wells in Case Numbers 2 and 3 are flowing wells.

Two flank wells, Case Numbers 4 and 5, in this reservoir were initially completed (Figures 4 and 5, Point A) using regular 15 percent acid. Case Number 4 was later retreated (Figure 4, Point B) with gelled acid using Polymer C and Case Number 5 (Figure 5, Point B) was retreated using Polymer A. Both wells initially produced 100 BOPD, but only for the first month or less. Case Number 4 averaged 58 BOPD in two years production cumulating 29,000 barrels of oil total. Case Number 5 averaged 35 BOPD in one year producing 7,400 barrels of oil total. Both wells are pumping wells.

Case Number 4 was producing 40 BOPD, 10 BWPD and 50 MCFPD (Table I) before being treated in a similar fashion to Case Numbers 2 and 3 using Polymer C as the gelling agent. Oil production increased to 87 barrels per day in the first 30 days, but it declined rapidly to 45 BOPD average in four months.

Case Number 5 produced 31 BOPD, 88 BWPD and 37 MCFPD (Table I) prior to being recompleted with a gelled acid fracture treatment using Polymer A. After the treatment, oil production increased to 120 BOPD. The well in Case Number 5 was not being "pumped off" and the rate increased into the 160-145 BOPD range for the next three months.

The well in Case Number 5 increased above its initial production range of 100 BOPD. Case Number 4 did not return to 100 BOPD and quickly declined to where it was before stimulation.

Table II lists other wells treated in different parts of the world. Some of these gelled acid-fracture treatments demonstrate a more sustained production increase. In other cases it is too early to evaluate or there is not a good comparison. All treatments were successful stimulations.

CONCLUSIONS

1. Gelling the acid stage of a fracture acidizing treatment reduces acid leakoff and retards the reaction rate of the acid with the formation.

2. Gelled acid provides carrying capacity to help remove insoluble silts and fines from the fracture during cleanup. This allows the use of stronger acid (28 percent) for higher overall fracture conductivity.

3. Deeper penetration with live acid is obtained in fracture acidizing treatments using Polymer A.

4. Gelled acid treatments using Polymer A provide a maximum increase in initial production. Field test results demonstrate this production increase is more sustained using Polymer A as the gelling agent than in cases where Polymer B, C or no gelling agent is used. The production decline rate is less after a gelled acid fracture treatment using Polymer A in these comparisons. This lends credibility through actual field tests to the concept of deeper penetration using a high temperature, high acid concentration gelling agent such as Polymer A.

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TABLE 1
Production (BOPD/BWPD/MCFD)

Case Number	Gelled Acid Polymer	Before	30 Day	60 Day	90 Day	120 Day	150 Day	180 Day	210 Day	240 Day
2	Polymer A	77/21/30	516/71/860	481/54/741	477/63/801	436/50/702	410/84/644	459/62/733	379/56/616	390/48/648
3	Polymer B	95/20/-	508/48/838	465/25/-	448/25/650	430/23/660	390/18/640	360/25/500	280/20/420	265/17/420
4	Polymer C	40/10/50	87/70/130	65/27/-	55/20/-	45/18/-	45/10/-	45/10/-		
5	Polymer A	31/88/37	120/380/114	125/417/131	159/675/172	146/655/142	147/685/146			

Table 2

Location County/State	Formation	Formation Temperature, F	Acid Volume/Type Gallons/%	Galling Agent (wt/vol%)	Production (BOPD/BWPD/MCFPD) Before	1 Month	6 Month	1 Year
Roosevelt/NM	Wolfcamp	160	10,000/20	1.2	2/0/36	27/1/61	20/2/68	18/2/77
Val Verde/TX	Strawn	208	19,500/20	1.3	0/0/500	0/-/2,480	0/0/1,335	0/1/1,857
Renville/ND	Sherwood	117	5,000/28	0.8	14/2/0	65/25/0	25/24/0	25/6/-
Norwegian/North Sea	Cretaceous	260	60,000/28	1.5	0/0/0	5,352/100/32,000	3,928/-/29,070	3,354/-/23,430
Lea/NM	Wolfcamp	131	20,000/28	1.2	4/17/11	12/27/16	7/16/16	6/15/10
Roosevelt/MT	Charles "C"	160	7,000/28	1.2	72/10/-	208/29/-	167/36/28	
Roosevelt/MT	Charles "C"	160	7,000/28	1.2	New	273/49/-	279/60/195	
Norwegian/North Sea	Cretaceous	260	32,000/28	1.5	84/26/1,663	136/-/3,100	151/-/3,087	
Norwegian/North Sea	Cretaceous	275	60,000/28	1.5	0/0/0	2,913/-/25,030	2,113/-/23,700	
Lea/NM	San Andres	101	12,000/28	1.0	89/2/122	111/5/81	177/1/73	
Crane/TX	San Andres	100	8,000/20	0.9	New	21/10/22	13/6/16	
Washington/AL	Smackover	293	25,200/28	1.5	381/214/1,708 (offset)	1,564/38/7,632	1,466/85/8,557	
Eddy/NM	Grayburg-San Andres	100	27,000/20	0.9	New	32/66/41	34/45/17	
Ector/TX	Lower Clearfork	112	21,000/20	1.2	New	8/12/111	9/13/114	
Howard/TX	Fusselman	160	5,000/20	1.2	1/24/1	14/30/31	20/18/24	
Andrewa/TX	Wolfcamp	132	10,500/28	1.0	0/0/0	38/490	28/1/67	

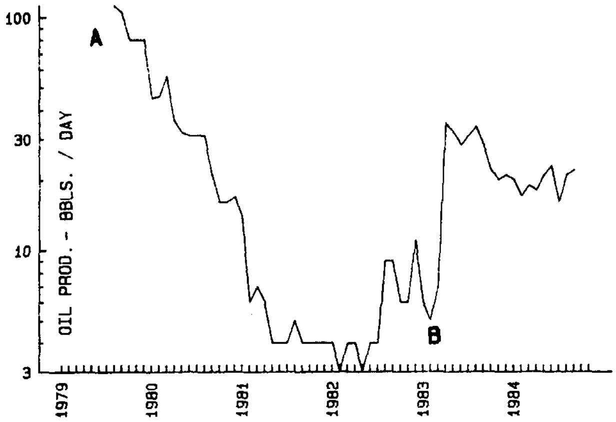

Figure 1 - Case Number 1 - daily oil production

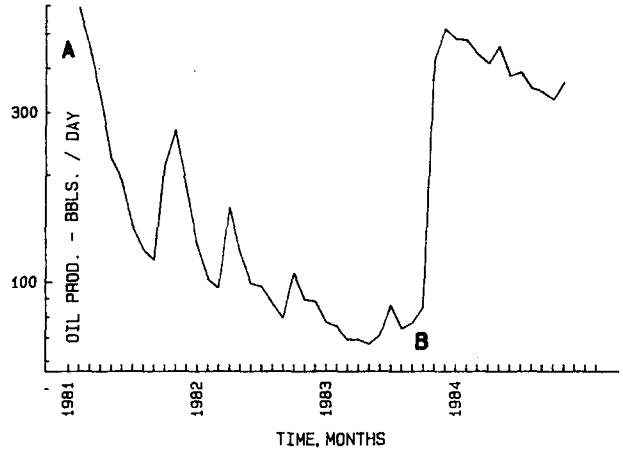

Figure 2 - Case Number 2 - daily oil production

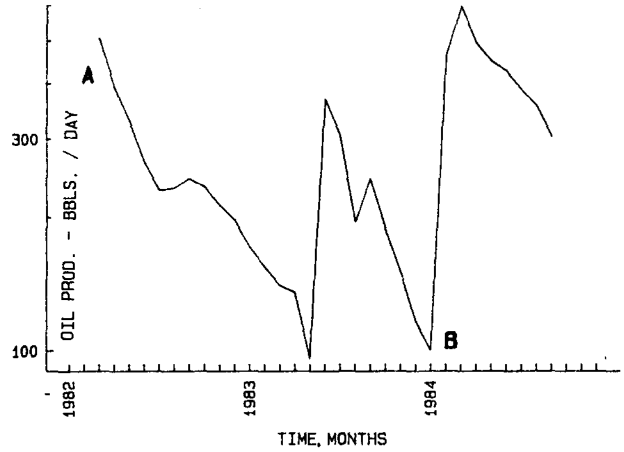

Figure 3 - Case Number 3 - daily oil production

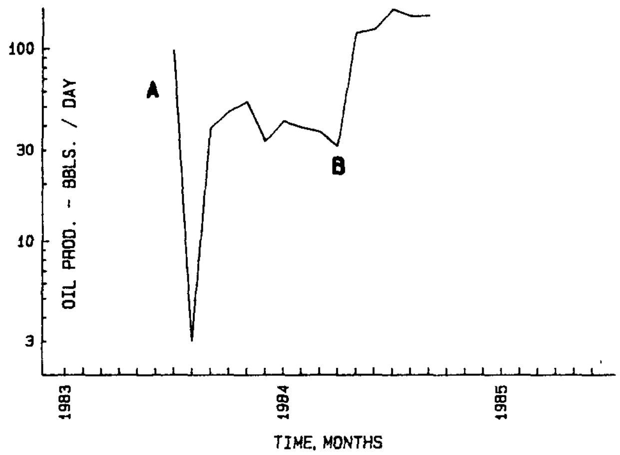

Figure 4 - Case Number 4 - daily oil production

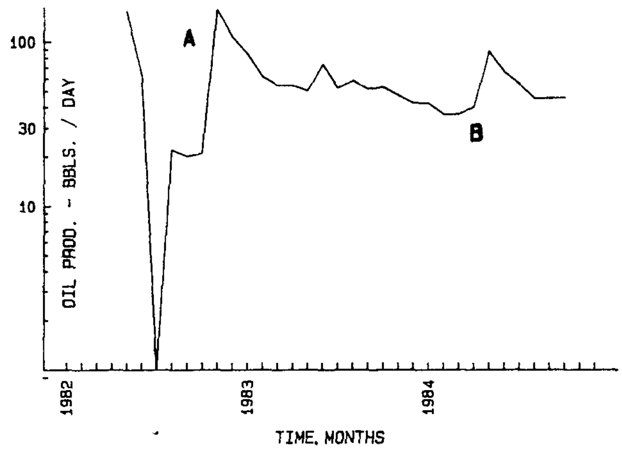

Figure 5 - Case Number 5 - daily oil production