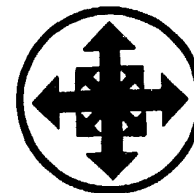


SPE 4118
August 1973
JPT



Successful Stimulation of Deep Wells Using High Proppant Concentrations

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Introduction

Large portions of the easily recovered hydrocarbons of the world are rapidly being depleted. This is particularly the case in the confines of the western hemisphere where many of the most productive fields are in the latter stages of primary and secondary recovery.

If complete dependence on foreign oil or a large energy gap is to be averted, new supplies of energy must be found soon. One promising source is the oil and gas tightly held in formations that have very low permeability and porosity. If these formations, a large number of which are deep, high-temperature reservoirs, are to be economically produced, an effective means of stimulation must be developed.

Types of Stimulation

There are basically three different types of stimulation methods available to the industry today. The first, chemical stimulation, has not been useful in tight sandstone reservoirs except in the removal of formation damage.¹ In deep, high-temperature and highly soluble formations, it is difficult to use this technique because the acid is rapidly spent near the wellbore. Without deep penetration of live acid into the fracture, effective stimulation cannot be achieved. In some cases the use of large volumes of fluid to cool the formation helps to overcome this deficiency.

The second type of stimulation, which is undergoing limited study today, is the use of both conventional and nuclear explosives.²⁻⁴ At this time, two nuclear explosive projects have been conducted. The

tests were apparently successful in safely setting off a nuclear device and achieving some stimulation. However, the economic feasibility of nuclear stimulation is still questioned by a large segment of the industry. The use of conventional explosives presents a considerable hazard during injection; detonation in thin layers at large distances from the wellbore is difficult and not always successful.

The third type of stimulation is hydraulic fracturing. Since the inception of fracturing in 1949, many different fluids and proppants have been investigated.⁵⁻⁸ In the early 1950's, viscous petroleum base fluids were being used industrywide. From the mid-1950's through the mid-1960's, the trend was to use less viscous fluids pumped at higher rates. Also, the trend has been toward using water-based fluids rather than oil-based fluids for fracturing.

The theory of fracturing developed quite rapidly between the mid-50's and mid-60's. In 1957, Howard and Fast⁹ introduced some of the first literature for the calculation of fracture geometry from treatment data. Since that time a continuous stream of literature, which is much too abundant to reference completely, has been published on fracture dimensions and design criteria. The work that has been published indicates that the ratio of (1) fracture length to the radius drained, and (2) fracture flow capacity to formation permeability are the most critical relationships in the design.¹⁰ The methods most often used for predicting productivity increase are those by McGuire and Sikora,¹¹ by Prats,¹² and by

A unique viscous fluid has been used in fracturing deep, high-temperature reservoirs. By using large treatments and high concentrations of proppants, reservoirs with low permeability and porosity can be successfully stimulated. Data from widely varying formations are compared, with special emphasis on the Vicksburg.

Tinsley *et al.*¹³ All of these predict production increase ratios as functions of fracture conductivity and fracture penetration.

It is apparent, upon review of the information relating the variables¹⁰⁻¹³ to be considered, that for tighter rocks it is desirable to have a longer fracture with moderate flow capacity. However, obtaining even moderate flow capacity in the deeper formations has always presented problems.

Problems in Fracturing Deep Formations

In stimulating deep formations, the greatest difficulties lie in creating and maintaining large, highly conductive fractures. Adequate flow capacity is difficult to maintain because the high closure stresses tend to embed or crush the proppant.^{14,15} The movement of fines, which tend to plug the fracture, causes additional problems.¹⁶

This paper presents the results obtained with a viscous water-based fluid developed for fracturing deep wells.⁵ Before the development of this fluid, gas wells were fractured with fluids having surface viscosities of about 25 cp, which degraded to about 2 cp at formation temperature. These fluids were pumped at rates of 20 bbl/min or greater and carried proppant at a maximum concentration of 1 to 1½ lb/gal. The propped fracture lengths and heights were possibly adequate, but in most cases the propped fracture widths were narrow. In deep reservoirs, a narrow fracture is particularly susceptible to embedment and crushing.¹⁴⁻¹⁷

Mechanical Aspects

Extremely large, high-pressure fracturing treatments have been conducted using conventional surface pumping equipment. Often this equipment, even with special high-pressure fluid ends, was not adequate for extended pumping of fluid carrying high concentrations of proppant. Manifolds and ball injectors were not always suitable. However, most of the problems of high-pressure pumping have been solved through the use of pump intensifiers and special surface lines.

In stimulating deep, high-pressure wells, the mode of completion greatly influences the results. Small tubing, low-pressure wellhead equipment, improperly selected packers, and too many perforations can drastically limit the size and effectiveness of the treatment. It is of utmost importance to complete a well so it can be fractured at adequate rates and pressures.

The Gel

For a fluid to be applicable for stimulating deep, high-temperature wells, it should meet the following criteria.

1. It must have low friction pressure properties.
2. It should be temperature stable up to 450°F.
3. It should be nondamaging; that is, it should leave little or no residue in the formation after breaking.
4. It should be compatible with the various salts used for clay stabilization.
5. Its viscosity in the fracture should be independent of its surface viscosity.
6. It must have good proppant support characteristics

for transport into the fracture and for dispersion of the proppant throughout the area of the fracture.

7. It must degrade to the viscosity of the base fluid for ease in cleanup operations.

A fluid was developed that met all the above requirements.⁵ The most rigorous of the requirements — that which calls for down-hole viscosity — was met by using a retarded gelling agent that is triggered by bottom-hole temperature. By using this retarded gelling agent in conjunction with a batch-mixed gel for surface proppant transport, down-hole viscosity can be optimized to meet varying bottom-hole temperatures.

Generally, the fluid contains two chemically substituted polymers. One of these is formulated chemically so that it provides the necessary time delay to develop viscosity down hole.

Screenouts have not been a problem with this fluid. Experience has shown that with strict quality control on pH and viscosity and with adequate rates and careful down-hole preparation, the chance of bridging at the perforations or of screening out in the fracture is nil. It has been found that inadequate rate — less than 6 bbl/min — or large numbers of perforations have caused most of the screenout problems to date. The actual incidence of screenout is less than 5 percent.

The Vicksburg Formation

Results from 17 geopressured Vicksburg wells that have been fractured within the past 2½ years provide much of the information presented here. The major cause of difficulties in stimulating the Vicksburg is the softness of the formation. Calculations using the method of Rixe *et al.*⁷ and laboratory data on Vicksburg cores show that fractures that are propped only one to two grains wide will heal long before the reservoir depletes. The embedment occurs at 50 percent reservoir depletion. In fracturing such a formation, obtaining wide, well propped fractures is a necessity. When fracturing was introduced as a stimulation technique in the Vicksburg formation, low-viscosity, low-sand-concentration treatments were the trend in the industry. These treatments produced the narrow fractures that were highly susceptible to embedment as the pore pressure was reduced. If sufficient fracture flow capacity is to be obtained, the propped fracture width for the Vicksburg should be several proppant grains wide. With a fracture of this width, the outer layers of proppant still embed, but several layers will remain open until depletion. Using the high-viscosity, high-proppant-concentration treatments, fractures with calculated widths of about 0.4 in. are being created. Sand at concentrations of 5 to 6 lb/gal is being pumped for as much as half the treatment. These wide, well propped fractures should remain open even at maximum closure pressures. Of the 17 wells discussed, nine were fractured upon initial completion and the remaining eight wells were produced several years before they were stimulated.

Comparison With Low-Viscosity Treatments

Tables 1 and 2 detail most of the fracture treatments that have been performed in one particular South

Texas field. Table 1 presents the data on the viscous gel treatments that have been performed. Table 2 compares the details of the high- and low-viscosity treatments.

Note that in Table 2 the permeabilities and the volumes of fluid pumped for both types of treatment are similar. The main difference is that the high-viscosity treatments carried more than twice the amount of sand per gallon as the low-viscosity treatments. The next four columns of Table 2 are the C-values for each well, calculated using the following equation.¹⁸

$$C\text{-value} = \frac{Q\mu(\bar{p})Z(\bar{p})}{(p_s^2 - p_{wf}^2)}$$

where

Q = flow rate, MMcf/D

μ = viscosity, cp

Z = gas deviation factor

p_s = static reservoir pressure, psi

p_{wf} = flowing bottom-hole pressure, psi

$$\bar{p} = (p_s + p_{wf})/2$$

The majority of the C-values on Table 2 were calculated using pressures measured on a pressure bomb during annual 90-hour buildups. A few of the C-values were calculated using pressures estimated from flowing tubing pressures and plots of p/Z vs cumulative gas produced.

It can be seen that the average C-values before

TABLE 1—STABILIZED PRODUCTION INCREASE, VICKSBURG FORMATION, FIELD A

Well	Reservoir Pressure (psi)	Depth (ft)	Permeability (md)	Net Pay (ft)	Volume (gal)	Proppant (lb)	Before Fracturing		After Fracturing	
							Mcf/D	psi	Mcf/D	psi
1(1)	5,700	11,700	0.12	127	150,000	225,000	2,690	1,275	6,890	2,200
2(1)	4,290	12,100	0.30	81	52,000	116,400	3,100	1,600	5,000	1,600
*3(1)	5,700	10,700	0.20	100	160,000	376,400	5,178	1,400	11,000	4,000
*4(1)	4,540	10,800	0.10	120	134,000	306,400	2,065	1,250	9,050	2,350
5(1)	6,000	10,500	0.09	86	160,000	375,000	1,418	1,200	4,854	1,700
6(2)	4,200	10,800	0.22	98	159,000	400,000	4,400	1,400	8,015	1,750
7(2)	5,400	11,800	0.21	108	223,000	488,000	5,000	1,375	11,405	3,400
8(2)	5,200	11,800	0.15	124	222,000	500,000	4,500	1,350	10,925	2,700
9(3)	9,800	11,800	0.18	40	146,800	404,000	3,000	4,500	7,000	6,900
*10(3)	10,500	12,250	0.46	42	153,000	397,000	6,000	5,700	7,500	7,600
11(3)	11,500	12,800	0.15	59	138,500	370,000	3,800	4,000	5,700	7,900
*12(3)	10,500	12,250	0.10	44	125,000	322,000	65	1,950	3,500	1,800

*Positive skin.

(1) Fractured in 1970-71.

(2) Fractured in 1972.

(3) Drilled and fractured in 1972.

TABLE 2—COMPARISON OF LOW-VISCOSITY TREATMENTS WITH HIGH-VISCOSITY TREATMENTS, FIELD A

Well	Viscosity	Permeability (md)	Volume (gal)	Proppant (lb)	C-Value $\times 10^{-9}$				Remarks
					Before Fracturing	After Fracturing	6 Months After Fracturing	2 Years After Fracturing	
1	High	0.12	150,000	225,000	2.22	8.47	7.37	7.30	These are the first five wells from Table 1, fractured in 1970-71.
2	High	0.30	52,000	116,400	5.11	7.67	9.52	11.60	
3*	High	0.20	160,000	376,400	4.38	35.0	24.0	27.0	
4*	High	0.10	134,000	306,400	2.15	22.0	17.63	18.01	
5	High	0.09	160,000	375,000	0.93	3.53	1.86	1.40	
Average		0.162	131,200	279,920	2.96	15.5	12.08	13.07	
6	High	0.22	159,000	400,000	6.53	19.11	14.0		These are Wells 6, 7, and 8 from Table 1, fractured in 1972.
7	High	0.21	223,000	488,000	4.17	9.62	9.45		
8	High	0.15	222,000	500,000	4.11	15.0	16.0		
Average		0.193	201,333	462,666	4.94	14.58	13.15		
9	Low	0.03	315,000	288,000	1.14	9.91	3.64	1.93	These are the 12 wells from Field A that were fractured in 1962-65.
10*	Low	0.05	119,000	88,000	1.50	16.80	5.29	6.05	
11	Low	0.20	118,000	100,000	0.76	0.91	0.78	0.24	
12	Low**	0.10	117,000	100,000	1.13	3.08	2.74	1.62	
13	Low	0.03	94,000	52,000	0.50	2.71	0.85	0.33	
14	Low	0.30	508,000	400,000	2.00	16.01	13.94	9.32	
15	Low	0.20	180,000	150,000	0.78	10.46	5.12	3.94	
16*	Low	0.20	204,000	200,000	0.33	2.63	1.71	0.48	
17*	Low	0.30	210,000	210,000	0.44	11.08	15.81	7.05	
18*	Low	0.25	219,000	300,000	4.96	65.81	19.56	10.99	
19	Low**	0.10	80,000	76,000	1.82	5.31	1.12	1.02	
20*	Low	0.30	200,000	200,000	1.43	24.07	17.67	6.78	
Average		0.171	197,000	180,000	1.40	14.07	7.35	4.13	

*Positive skin.

**Screened out.

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TABLE 3—STABILIZED PRODUCTION INCREASE, VICKSBURG FORMATION, FIELD B

Well	Reservoir Pressure (psi)	Depth (ft)	Permeability (md)	Net Pay (ft)	Volume (gal)	Proppant (lb)	Before Fracturing		After Fracturing	
							Mcf/D	psi	Mcf/D	psi
1	10,000	12,000	0.82	39	135,000	305,600	3,866	3,600	5,624	6,450
2	10,865	12,200	0.14	54	152,000	365,400	1,000	5,500	3,000	8,800
3*	9,569	11,300	0.15	47	160,000	340,000	1,225	680	9,000	6,800
4*	11,000	12,150	0.23	52	205,000	515,000	2,350	2,200	5,220	8,500
5	10,500	12,300	0.20	95	153,000	267,000	5,000	5,400	10,000	8,400

*Positive skin.

fracturing for the three categories of wells are quite different. This difference is explained by the number of damaged wells in each category. After the fracture treatments, the average C-values are quite close. Since the permeabilities, closure pressures, net pays, and drainage radii of wells in all three categories are similar, it must be concluded that the initial stimulation from either the high-viscosity or the low-viscosity treatments was about equal. But as can be seen, the C-values for the high-viscosity treatments have held up, whereas the C-values of the low-viscosity treatments show marked decreases with time. As previously explained, the reason for the decrease is embedment of the proppant. The wider fractures are clearly remaining open.

It should be mentioned that the C-value equation is applicable only in semisteady-state flow. For the Vicksburg data, semisteady-state flow for an unfractured well is reached in about 15 days. Work published by Morse and Von Gonten¹⁰ indicates that for reservoirs with very low permeability the productivity of a fractured well may take months to stabilize. Therefore the C-values reported on Table 2 in the "After Fracturing" column were calculated several months after the jobs had been completed. Using the rates and pressures from Table 1 for calculating C-values after the job will lead to erroneously high productivity increases. The flow rates are stabilized, but they are not necessarily in semisteady-state flow.

Effect on Rate and Recovery in the Vicksburg Formation

Tables 1 and 3 list the stabilized flow rates and tubing pressures for the Vicksburg wells stimulated with the high proppant concentration treatments. Fig. 1 shows the flow rate history of Well 1 in Table 1.

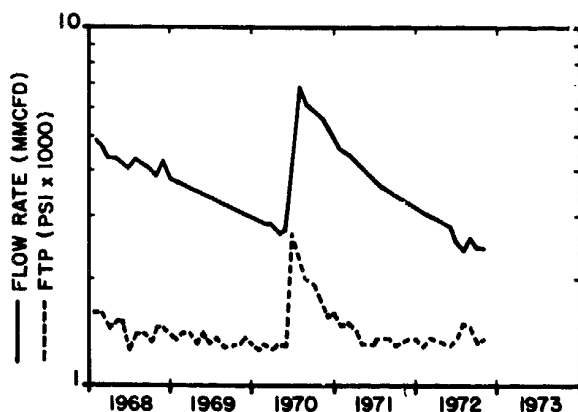


Fig. 1—Flow rate performance, Well 1, Table 1.

All the rates quoted in this paper are stabilized values taken from plots such as Fig. 1.

The after-fracturing rates indicate the gas actually produced to sales. Comparing these rates with the rates before fracturing gives the production increase ratio that must be used to calculate numbers such as payout. The average production increase ratio for Table 1 is 3.8 and for Table 3 is 3.2.

To determine the actual effect of the fracture treatment on the production of a well it is necessary to consider recovery. Table 4 presents the results of calculations made for Wells 1 through 5 of Table 1. Of the wells that were treated using the viscous gel, these five are the only ones with enough production history to validate such calculations.

Two methods were used to calculate reserves. First the production curves, such as Fig. 1, were extrapolated to an economic limit. Second, the C-values were used to calculate the abandonment pressures before and after fracturing. Then using the plots of p/Z vs cumulative gas produced, the increase in recovery was determined. The recovery of the five wells considered has been increased by about 8.3 Bcf.

Results From Other Formations

Listed in Table 4 are results of viscous gel treatments in the Devonian, Wilcox, and Hosston formations. The four results shown in the Devonian are for wells located near Ft. Stockton, Tex. In this area, the formation is hard, dolomitic limestone with acid solubility of 30 percent and higher. In Wells 1 and 2, 15,000 lb of 12-20 glass beads were pumped at 5 lb/gal at the end of the treatment. On the other two wells and for the remainder of Treatments 1 and 2, 20-40 sand alone was used. It should be noted that the large fluid volume pumped on these treatments includes some 60,000 gal of thin prepad fluid plus substantial pad volume.

The Wilcox treatments shown are two examples of treatments on deep, tight sandstone reservoirs in the Central and South Texas area. Again, only 20-40 sand is used. (A comprehensive review of Wilcox stimulation has been given by Seidel and Stahl.⁵) The results from the Hosston formation came from

TABLE 4—RESERVE ESTIMATES, WELLS 1 THROUGH 5 OF TABLE 1

Well	Before Fracturing (Bcf)	After Fracturing (Bcf)	Increased Recovery (Bcf)
1	3.5	5.7	2.2
2	2.7	3.4	0.7
3	10.0	12.4	2.4
4	2.0	4.5	2.5
5	1.4	1.9	0.5

TABLE 5—STABILIZED PRODUCTION INCREASE

Well	Formation	Pressure (psi)	Depth (ft)	Permeability (md)	Net Pay (ft)	Volume (gal)	Proppant (lb)	Before Fracturing		After Fracturing	
								Mcf/D	psi	Mcf/D	psi
1	Devonian	4,000	14,600	2.0	120	113,000	113,000	4,600	1,200	10,593	1,200
2	Devonian	4,000	13,520	1.8	112	113,000	60,000	3,913	1,200	7,720	1,200
3	Devonian	4,000	14,670	1.9	120	70,000	48,000	2,199	1,200	6,065	1,200
4	Devonian	4,000	14,040	2.1	95	113,000	42,000	3,800	1,150	7,200	1,150
5*	Wilcox	13,700	14,850	1.0	20	53,000	90,000	200	400	1,500	3,200
6	Wilcox	10,300	12,000	1.0	74	38,000	110,000	2,800	7,300	2,800	8,300
7*	Hosston	3,800	8,000	2.0	9	37,000	50,000	200	50	3,000	1,500
9	Hosston	3,500	8,300	2.0	7	20,000	39,000	200	100	1,600	1,000
8*	Hosston	2,525	5,500	2.0	29	127,000	230,000	4,500	480	10,000	480
10	Hosston	2,525	5,800	2.0	10	127,000	200,000	5,000	500	11,600	500
11	Hosston	3,800	6,200	5.0	75	162,000	376,000	6,900	500	15,000	750

*Positive skin.

the Northern and Central Louisiana area. Results from Wells 3, 4, and 5 illustrate the use of the process in lower-temperature applications — 180°F.

In addition to the aforementioned producing horizons, the Atoka, Morrow, San Andres, Frio, Cotton Valley, Haynesville, Carter and Sanders, Smackover, and Olmos have been successfully stimulated. In some areas, the high proppant concentration treatments have become the standard stimulation method. Results from these treatments have not been included because we do not wish to burden the reader with a large number of results that cannot be objectively compared with those from other forms of stimulation. However, it should suffice to say that of more than 200 treatments performed to date, the success ratio has exceeded 75 percent.

Economics

There must always be economic justification for stimulating a well. An example of a well that obviously justifies such treatment is one that has adequate gas in place but an unacceptably low flow rate. Several of the wells reported here met those conditions. Consider Well 3 in Table 3. A combination of low permeability and high skin caused Well 3 to flow at a rate considered to be uneconomic before stimulation. After the fracture treatment, Well 3 was greatly improved. For this particular case, stimulation made the difference between a dry hole and a producer. The other four wells listed on Table 3, although better than Well 3, would probably not have paid out the drilling and completion costs without stimulation. Therefore, for the five wells listed on Table 3, the economics was sound, since the fracture treatment converted marginal and unprofitable wells into highly profitable ones.

For a well that produces initially at adequate rates, stimulation in the latter stages of depletion is more difficult to justify. Here, the profitability can be based on acceleration economics. Fracturing can be used to shorten the life of the well, thus recovering the reserves sooner and reducing operating costs. Also, by shortening the life of the well, many mechanical difficulties can be avoided. When the life of a well is prolonged, there is no assurance that the casing, packer, or tubing will not give way, corrode, or collapse before the reserves are produced.

The stimulation of tight gas reservoirs should be

optimized on the basis of the combined effects of accelerating and increasing gas recovery. In this case, it is critical to calculate the potential increase in productivity and recovery for fractures of various lengths. Then with an adequate knowledge of formation flow capacity, drainage radius, economic limit, and the cost of creating fractures of various lengths, one can optimize the size of a stimulation treatment for a given well.

Conclusions

On the basis of the data presented in this paper, the following conclusions have been reached:

1. An effective means of stimulating deep, low-permeability gas wells has been developed.
2. The success of the high-viscosity, high-proppant-concentration method is attributed to its ability to create and pack a wide fracture.
3. In low-permeability formations, it is possible to increase recovery by decreasing the abandonment pressure.

Acknowledgment

We wish to express our appreciation to Shell Oil Co. and Halliburton Services for permission to publish this paper. Also, we thank those who have obtained data and assisted in preparing the paper.

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Paper (SPE 4118) was presented at SPE-AIME Southwest Texas Section Regional Meeting, held in Corpus Christi, Tex., April 27, 1973. © Copyright 1973 American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc.