FIELD EVALUATION OF VISCOUS PADS IN ACIDIZING CARBONATE ROCK

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INTRODUCTION

An acidizing technique has been developed for treating carbonate reservoirs that will give deep penetrating fractures with high flow capacity. Production results from these treatments have been excellent. The technique uses the principle of hydraulic fracturing with a thickened fluid. Instead of using a proppant in the fluid, acid is used to produce flow capacity by controlled etching of the fracture system.

Overall treatment success has been good. New and old producers with varying productive capacity have been treated. New wells have performed at least equal to and in most cases better than conventionally treated offset wells. Some old wells have performed exceptionally well; others indicated no favorable increase in production.

The advent of complex fracturing fluids led to the idea of using a viscous pad to control leak-off of acid for more fracture height and width. These factors, it was theorized, would give greater acid penetration. The method was first tried in a well where conventional treatments had been unsuccessful. Results, which were good, led to laboratory work to determine possible reasons of success. This work indicated that the fingering of thin acid through a viscous fluid was the key to the treatment. Figures 1, 2 and 3 show laboratory models illustrating what occurs in this treatment. An analytical procedure for treatment design followed this investigation. Figure 4 is a typical computer-designed treatment.

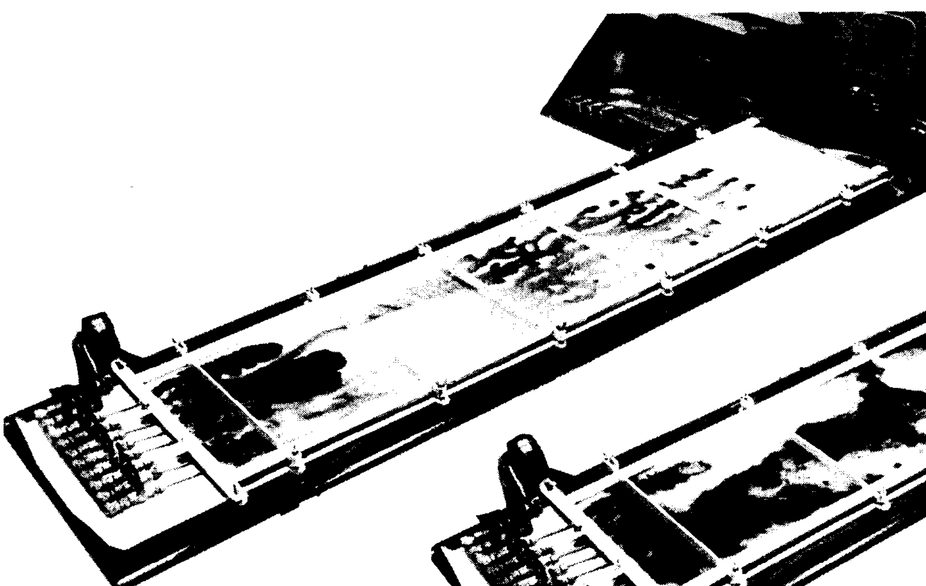

FIG. 1—LABORATORY MODEL

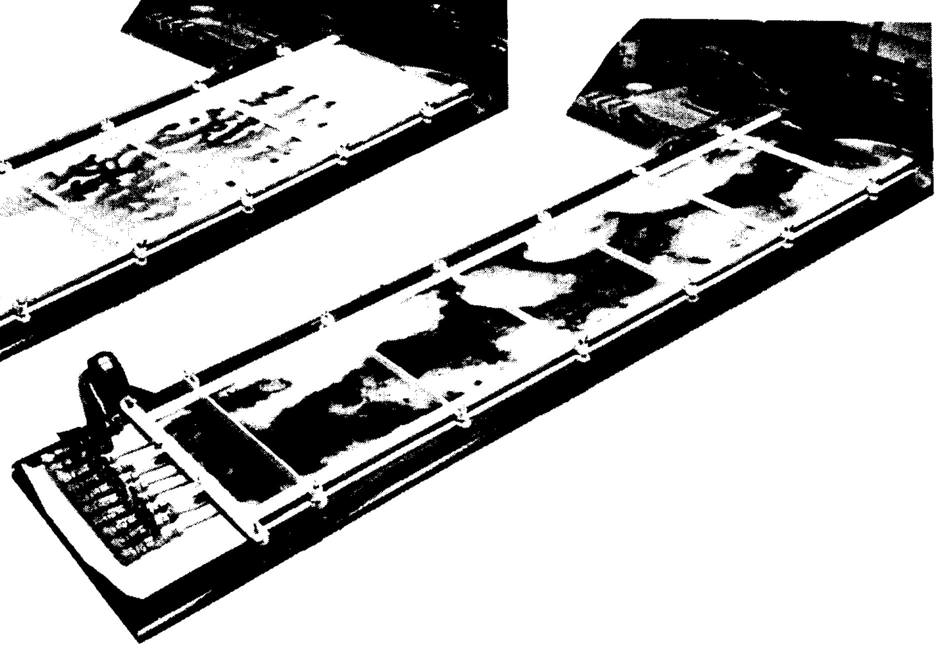

FIG. 2—LABORATORY MODEL

FIG. 3a—POOR ETCHING PATTERN,
FIG. 3b—IMPROVED ETCHING USING VISCOUS PAD

ADVANTAGES

The pad-acid technique offers several advantages over established acid treatments. The first advantage is deep penetration of live acid. Treatment radius is comparable to propped fracture treatment radius and is much greater than conventional acid treatment radius.

The second advantage is higher flow capacity of the fracture. The flow capacity is obtained by the fingering of the acid through the viscous pad. Since the acid etches only in its flow channel, a pillar and post effect occurs as illustrated in Fig. 3b.

A third advantage is the convenient cleanup of the formation after the acid treatment. Fines released during acidizing are removed through the large flow channels by the returning pad fluid which has a residual viscosity of 3 to 5 cps. A properly designed pre-pad will flush out many released or undissolved fines.

Elimination of proppants such as sand is a fourth advantage. The expense of removing sand from wells and replacing sand-cut equipment is therefore eliminated.

CRITERIA

This treatment has been applied to both limestones and dolomites. Selection of the proper acid for this technique requires knowledge of the type of reservoir rock. To date this type of treatment has been applied only to carbonate reservoirs.

The second criterion in selecting this technique is consideration of previous treatments. Two most commonly encountered treatments are acidizing and hydraulic fracturing with proppants. If the previous treatment was an acid stimulation,

WELL OWNER AND LOCATION

WELL INFORMATION
Tubing: ID 1.99 OD 2.37 inches
Casing: ID 4.00 OD 4.50 inches
Depth (ft) = 4900.
Formation Temperature (F) = 106.0
Net Formation Thickness (ft) = 35.
Assumed Fracture Height (ft) = 70.
Modulus of Elasticity = 6.190E+06
Well Spacing (acres) = 40.
Drainage Radius (ft) = 660.
Reservoir Pressure (psi) = 1100.
Reservoir Fluid Viscosity (cp) = 1.500
Reservoir Fluid Compressibility (psi -1) = 2.500E-05
Damage Ratio = 1.0
Porosity (percent) = 10.0
Initial Permeability (md) = 2.0

TREATING INFORMATION
Acid Type: 20% N. E. Acid
Reaction Time (min) = 100.
Pump Rate (bbl/min) = 8.
Bottom Treating Pressure (psi) = 2900.
Preflush Temperature (F) = 70.
Viscous Fingering (percent) = 30.
Viscous Fluid: Nprime = 0.465 Kprime = 0.89000E-01

	Preflush	Vis-Fluid	Acid	Overflush
Specific Gravity:	0.850	0.900	1.100	1.000
Viscosity (cp):	5.0	-----	1.4	1.0
C Value:	.00600	.00200	.01000	.01000
Ceff:	.00109	.00063	.00127	.00127

J/Jo	Frac Length*		Volume of Treating Fluid (Gallons)			
(Fold)	%RE	FEET	Preflush	Vis-Preflush	Acid	Overflush
1.74	7.1	47.	357.	509.	182.	182.
2.30	14.3	94.	713.	1030.	534.	534.
2.77	21.4	141.	1125.	1842.	876.	876.
3.19	28.6	189.	1758.	2816.	1318.	1318.
3.58	35.7	236.	2522.	3828.	1824.	1824.
3.97	42.9	283.	3365.	5055.	2400.	2400.
4.38	50.0	330.	4280.	6326.	3028.	3028.
4.82	57.1	377.	5416.	7597.	3678.	3678.
5.35	64.3	424.	6552.	9097.	4398.	4398.

Frac Length* - Effective fracture length....this is defined as the distance to which live acid travels down the fracture.

Reaction Time - Reaction time is defined as the time required for an acid to spend to a concentration of 3.2% in a reaction time test cell which simulates a 0.24 inch fracture.

FRACTURE WIDTHS

J/Jo	Preflush	Vis-Preflush	Acid	Overflush
1.74	0.021	0.072	0.072	0.072
2.30	0.042	0.143	0.143	0.143
2.77	0.060	0.164	0.164	0.164
3.19	0.065	0.180	0.180	0.180
3.58	0.068	0.195	0.195	0.195
3.97	0.072	0.207	0.207	0.207
4.38	0.075	0.218	0.218	0.218
4.82	0.077	0.229	0.229	0.229
5.35	0.079	0.238	0.238	0.238

FIG. 4—COMPUTER PROGRAM OF VISCOUS PAD

consideration should be given to the effective penetration of the treatment. Formations that have not been effectively penetrated are candidates for this technique. Conventional acidizing may provide poor etching patterns (Fig. 3a); use of a viscous pad can improve etching (Fig. 3b). Fluids previously used in acidizing could have caused a secondary precipitation or release extremely fine undissolved formation particles. This makes some previously treated wells candidates for viscous pad treatments.

Several common problems in hydraulic fracturing with proppants are solved by the fracture-acidizing technique. Many formations will accept little or no sand. Expensive posttreatment cleanup and production equipment changes (such as sand-cut pumps) due to sand production may also follow a "frac" job. Closure pressure may cause crushing or embedment of the proppant with consequent reduction in productivity. These problems indicate a need for a different treatment.

In designing this treatment there are several facts that need to be known about the formation. Porosity is the first of the factors. It is necessary to know the degree and the type of porosity. Types of porosity best adapted to this treatment are connected vugular, fractured, and true intergranular porosity with high permeability. Certain types of permeability are best adapted to this treatment. Two types are high matrix permeability and/or high fracture permeability. These permeabilities, in either case, are those that allow excessive leak-off of normal fracturing fluids or acid.

Bottomhole temperature is an important consideration. The temperature is needed for selection of acid and viscous fluid compositions. Bottomhole temperature is one of the parameters that most affects the reaction time of any acidic solution on carbonate rock. Most fluids thin with temperature. For deep, hot wells, only select fluids may be used. Therefore, with higher bottomhole temperature wells, this treatment is preferable to conventional acidizing because of the increased reaction time of any acid used in this technique. Reservoir pressure should be sufficient to recover the treating fluid. Produced fluid should be considered for compatability with treating fluids, which can be matched to produced fluids, whether gas or oil.

Mechanical limitation, such as allowable pressure on tubular goods should be considered. This technique is applicable to wells that cannot be sand-fractured with present mechanical equipment or where horsepower requirements are excessive.

TECHNIQUE

The general procedure for treating a formation with this technique is to use a thin pre-pad fluid followed by a very viscous pad fluid. With the formation thus prepared, acid is injected and overflushed for maximum penetration into the formation. The purpose of the thin fluid is to initiate the fracture, pressure the formation, and control fluid loss to the matrix or high permeability portions of the zone. Cooling the formation for increased acid reactive life is another pad fluid function.

After the pre-pad is pumped, a viscous pad is injected. The purpose of viscous pad is to propagate the fracture, provide fracture width and provide "fingering". When a viscous fluid is displaced by a thin fluid, displacement is not uniform. Instead, part of the viscous fluid is by-passed and fingering will occur, (Fig. 1). This fingering is a key function of the viscous pad. Rock surface area that is contacted by acid is reduced. Flow channels are deeper, support is greater and acid penetrates further. This viscous pad can be either water or oil base. Water-base fluids can be of two types: (1) complex guar gum or (2) synthetic polymer. All fluids contain fluid loss additives.

Examples of oil-base fluids are: (1) emulsions, (2) water-oil dispersion such as Superfrac® Fluid, and (3) thickened crude or refined oils. The viscous fluid used depends on economics and compatability with formation fluids (oil or gas), bottomhole temperature, and bottomhole pressure.

The third fluid to be pumped in the treatment is the acid, which will dissolve the rock in a controlled pattern to provide the necessary flow channels in the fracture. Correct selection of acid is extremely important. The most commonly used is regular 15% hydrochloric acid with the proper surfactants. High strength (20-28%) hydrochloric acid is the next most commonly used. Least commonly used are retarded and sequestered acid.

Finally, overflush is pumped to provide for displacement of the acid in the formation while still reactive. The overflush is water or oil and contains only friction reducer and the proper surfactant.

Fluid entry into the formation is important on all jobs. In some wells the mechanics of the well will be control enough; in others, portions of the zone must be isolated or the fluid must be diverted. Control of the fluid entry is important to provide treatment of the entire zone. This control cannot be overstressed. Every well and every job must be considered individually. Mechanical isolation can be accomplished with a packer and bridge plug. Diversion is accomplished with granular bridging agents or Perfpac ball sealers. Temperature surveys or radioactive tracers may be used to determine that diversion is accomplished.

RESULTS

Treatments analyzed in this study have shown good success, defined as a 1.50-fold or better increase in hydrocarbon production (Table 1). Treatments have been performed in more than 20 fields and 14 different formations. The best results were obtained from carefully designed and applied treatments. Better results were realized when treatments were properly controlled.

Table 1 also shows failure of this treatment. Stimulation was accomplished but with no hydrocarbon increase. The increased production of water could have been caused by lack of job control or inadequate reservoir information. Loss of control while treating generally resulted in no increase in hydrocarbon production. Lack of information has resulted in some poorly designed jobs. Treating fluids such as pads, surfactants, breakers, and acids may have been poorly selected. There is always a possibility that the candidate for this treatment was not productive.

Three groups of San Andres waterflood wells were analyzed. The first of these groups was in the Levelland Field. Both cased and open-hole completions have been treated in the Levelland Field. The treatment has been standardized as 7500 gal.lease oil with adomite Mark II® pre-pad, 10,500 gal. Super Emulsifrac fluid, and 5250 gal. 20% N.E. acid. Wells were stimulated in three stages, separated with rock salt or benzoic acid, or a combination. A tracer stage, 50 bbl water, and temperature surveys were used to trace the zones of injection.

The six old wells treated averaged 1.56-fold oil production increase and 2.37-fold increase in total fluid. Four new wells were completed in the field with this technique. Potentials were greater than expected, and production has been more sustained.

Sand-water fracs had been extensively used previously. Large water production increases occurred even though rates were limited to 6 BPM to reduce vertical fracture height. Super Emulsifrac-acid treatments have not shown this problem.

The second group of San Andres wells to be analyzed was in the North Cowden Field. They were treated in the following manner:

1. Aromatic solvent and lease crude with paraffin inhibitor
2. Pump well for a day
3. 2000 gal. pre-pad-gelled water with fluid loss additive and scale inhibitor
4. Viscous pad—7000 gal. MY-T-GEL® fluid
5. 5000 gal. 20% CRA-35 acid
6. Overflush 5000 gal. gelled water.

The average increase in oil production of five wells treated was 2.5-fold while total fluid increase was 3-fold. The above mentioned treatment is a good example of how old producers should be prepared before treatment. In areas where paraffin and scale problems occur, inhibitors can be placed in the treatment.

The third group of wells considered was in the Maljamar Field. Results from the treatments in the New Mexico field have been good. Treatment of five wells in the field resulted in an overall production increase of 3.7-fold and a 2.5-fold increase in oil. Treatment fluid volumes varied from well to well. The average total treatment consisted of 1000 gal. of gelled water pre-pad, 3300 gal. of MY-T-GEL® fluid and 3500 gal. of MOD 202 acid which was pumped in two stages. The wells were completed open hole. Zone isolation was accomplished with an open-hole packer arrangement. On one occasion the treatment was diverted with benzoic acid.

SUMMARY

High production fold increases have resulted in many different reservoirs where the viscous pad-acid technique has been applied. When viscous pad-acid treatments are properly designed and applied, field results have shown the process to be excellent. It has been successful in fields where conventional acid treatment has failed. The treatment has shown results as good as hydraulic fracturing with proppant, or better, in several fields. Viscous fingering does occur, resulting in increased penetration and improved flow capacity when compared to conventional acid treatments. Deep, hot wells, which could not be successfully stimulated by conventional means, have responded to this treatment. The process can, in many cases, be directly substituted for hydraulic fracturing.

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TABLE 1

Formation	County	Field	Acid Type	Viscous Pad Type	Before Production BOPD	Before Production BWPD	After Production BOPD	After Production BWPD	Remarks
San Andres	Hockley	Levelland	20% NEA	Emulsion	75	31	126	50	
San Andres	Hockley	Levelland	20% NEA	Emulsion	38	24	71	53	
San Andres	Hockley	Levelland	20% NEA	Emulsion	22	3	31	5	
San Andres	Hockley	Levelland	20% NEA	Emulsion	92	16	125	31	
San Andres	Hockley	Levelland	20% NEA	Emulsion	New		120	31	
San Andres	Hockley	Levelland	20% NEA	Emulsion	New		67	22	
San Andres	Hockley	Levelland	20% NEA	Emulsion	New		72	25	
San Andres	Hockley	Levelland	20% NEA	Emulsion	New		157	120	
San Andres	Hockley	Levelland	20% NEA	Emulsion	10	4	30	9	
San Andres	Hockley	Levelland	20% NEA	Emulsion	40	18	48	69	
Grayburg-San Andres	Ector	N. Cowden	20% CRA-Fe	MY-T-GEL	17	2	46	15	
Grayburg-San Andres	Ector	N. Cowden	20% CRA-Fe	MY-T-GEL	8	2	52	43	
Grayburg-San Andres	Ector	N. Cowden	20% CRA-Fe	MY-T-GEL	29	12	24	73	
Grayburg-San Andres	Ector	N. Cowden	20% CRA-Fe	MY-T-GEL	0	0	42	61	
Grayburg-San Andres	Ector	N. Cowden	20% CRA-Fe	MY-T-GEL	7	0	37	7	
San Andres	Terry	Cedar Lake	15% N. E.	MY-T-GEL	65	56	82	57	
San Andres	Terry	Cedar Lake	15% N. E.	MY-T-GEL	66	42	89	59	
San Andres	Terry	Cedar Lake	15% N. E.	Lo-Gel	14	18	13	14	
San Andres	Lea	N. Vacuum	20% NEA	Emulsion	27	--	62	--	
San Andres	Lea	N. Vacuum	20% NEA	Emulsion	41	--	120	--	
San Andres	Lea	N. Vacuum	20% NEA	Emulsion	34	--	100	--	
San Andres	Eddy	Maljamar	MOD 202	MY-T-GEL	16	135	22	390	
San Andres	Eddy	Maljamar	MOD 202	MY-T-GEL	16	40	47	110	
San Andres	Eddy	Maljamar	MOD 202	MY-T-GEL	9	31	32	60	
San Andres	Eddy	Maljamar	MOD 202	MY-T-GEL	14	21	20	60	
San Andres	Eddy	Maljamar	MOD 202	MY-T-GEL	13	31	18	91	
San Andres	Eddy	Maljamar	MOD 202	MY-T-GEL	11	25	12	55	
San Andres	Yoakum	Wasson	20% NEA	Emulsion	New		76	--	
San Andres	Yoakum	Wasson	20% NEA	Emulsion	New		40	--	
Glorieta	Lea	N. Vacuum	20% NEA	MY-T-GEL	1	--	88	--	
Clearfork	Yoakum	Wasson NE	20% CRA	Guar	20	35	15	200	(TA)
Abo	Eddy	Empire	28% NEA	MY-T-GEL	New		125	--	Increase from 30 BOPD swab
Abo	Lea	Vacuum	28% NEA	MY-T-GEL	TA	--	50	--	
Wolfcamp	Pecos	Coyanosa	28% NEA	MY-T-GEL	133	576 MCF	418	2500 MCF	
Wolfcamp	Pecos	Coyanosa	28% NEA	MY-T-GEL	21	--	26	--	(300 MCF gas)
Wolfcamp	Howard	Vealmoor	28% NEA	MY-T-GEL	New		60	--	
Penn	Lea	N. Bagley	20% CRA	MY-T-GEL	TA		103	189	
Penn	Lea	N. Bagley	20% CRA	MY-T-GEL	48	58	91	85	
Penn	Lea	N. Bagley	MOD 202	MY-T-GEL	New		85	93	(non-commercial on log)
Penn	Lea	N. Bagley	MOD 202	Emulsion	181	60	272	112	
Penn	Lea	Vada	MOD 202	MY-T-GEL	TA		66	28	
Penn	Lea	Cerca	20% Fe	MY-T-GEL	TA		P&A		(no reserve)
Penn	Lea	S. Vacuum	20% CRA	MY-T-GEL	0	--	0	--	(no reserve)
Penn	Kent		20% CRA	MY-T-GEL	2	--	30	--	
Mississippian	Scurry		20% CRA	MY-T-GEL	New		P&A		(no reserve)
Devonian	Andrews	Magutex	20% CRA	Emulsion	93	2	164	80	
Devonian	Lea	Bagley	20% CRA	Emulsion	60	300	91	315	(test is questionable)
Devonian	Ward	ROC	15% CRA	HY-GEL	New		11406 MCF		
Devonian	Howard		20% CRA	MY-T-GEL	9		TA		
Fusselman	Lea	McCormick	MOD 202	MY-T-GEL	3	21	54	20	
Fusselman	Upton	Amacker	28% N. E.	MY-T-GEL	0	0	97	43	GOR 10258:1
Fusselman	Howard	Big Spring	28% CRA	MY-T-GEL	15	10	22	10	(P&A)
Fusselman	Howard	SE Luther	20% CRA	MY-T-GEL	20	--	50	--	
Ellenburger	Crockett	Todd	MOD 202	MY-T-GEL	0		0		
Ellenburger	Pecos	Gomez	92-8	Gelled Water	New		8200 MCF		
Ellenburger	Pecos	Gomez	92-8	Gelled Water	New		17800 MCF		
Ellenburger	Ward	ROC	20% CRA	HY-GEL	New		5881 MCF		
Buda	Houston		28%	MY-T-GEL	0		Much Water		
Buda	Houston		28%	MY-T-GEL	10	--	28	120	
Buda	Houston		28%	MY-T-GEL	30	--	500		
Smackover	Hopkins		MOD 202	MY-T-GEL	200	--	500	--	
Glenrose	Houston		28%	MY-T-GEL	Trace	--	Trace	--	
Glenrose	Van Zandt		28%	MY-T-GEL	140	--	250	--	
Edwards	Houston		28%	MY-T-GEL	Trace		40	--	