Well Stimulation With CO_2

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INTRODUCTION

Liquid Carbon Dioxide (CO_2) is added to treating fluids to improve results and to eliminate some of the problems associated with the stimulation of oil and gas wells. It especially promotes fast clean up of wells without the need of swabbing (and the danger of lost swabs). When pressure is released at the well head after treatment, the CO_2 vaporizes and forces the treating fluids from the formation. The presence of this gaseous CO_2 in these fluids reduces the weight of the fluid column so that normal reservoir drive can then unload the fluids from the well. Immediate recovery of 75 - 90% of the stimulation fluids is normal.

CO_2 also improves well productivity by preventing formation damage from the stimulation fluids and by cleaning up the critical area near thewell bore. The use of CO_2 quite often results in the recovery of formation fines, silt, reaction products, and mud or mud filtrate lost during drilling.

Where water is the treating fluid the carbonated solution that is formed has an acidic pH. This prevents the swelling of clays, the precipitation of hydroxides and the precipitation of gyp. The use of expensive acid or calcium chloride solutions for this same purpose is thus eliminated. Because of the solubility of various carbonates in such a solution the permeability of carbonaceous formations is also improved.

In oil treatments the viscosity of the oil is reduced considerably by the addition of CO_2. This results in lower friction losses and higher injection rates with consequent savings in total hydraulic horsepower requirements.

Since CO_2 is injected in the liquid state, it has the ability to carry propping agents just as water does and there is no special danger of screenout if large volumes of CO_2 are used. Also, it is compatable with all treating fluids (acid, oil or water), and with all additives utilized in simultation treatments. Likewise, CO_2 is compatable with formation fluids.

CO_2 is pumped by conventional pumping equipment with the addition of a relatively inexpensive supercharging pump. Practically all of the well stimulation service companies are now equipped to handle and pump liquid carbon dioxide.

PHYSICAL PROPERTIES OF CARBON DIOXIDE

At atmospheric temperature and pressure carbon dioxide is a colorless, odorless gas about 1.5 times as heavy as air. For oil field work, CO_2 is liquified and transported in insulated transports at approximately 0° F and 300 psi. In this state it is handled in much the same manner as liquified petroleum gases. Being non-combustible, however, there is no danger of fire or explosion and, in fact, it could be used as an auxiliary fire fighting medium on well stimulation work if desired.

Some of the physical constants of carbon dioxide are as follows:

Molecular symbol . . . . CO_2
Molecular weight 44
Critical temperature . . . . 88.6° F
Critical pressure . . . . 1051.3 psig
Liquid density at 2° F. . . . . . . 63.3 lbs per cu ft
or 8.46 lb per gal
Vapor density at 60° F
and 14.7 psi . . . . 0.1163 lb per cu ft
Latent heat of liquid at 2° F
and 301.2 psig. . . . . . 119.0 BUT per pound

Some of the conversion factors useful in well stimulation work are as follows:

One ton of liquid CO_2 yields 17,198 s.c.f. of gaseous CO_2.

One barrel of liquid CO_2 (@-10° F) yields 3151 s.c.f. of gaseous CO_2.

One gallon of liquid CO_2 (@-10° F) yields 75.0 s.c.f. of gaseous CO_2.

One pound of liquid CO_2 yields 8.59 s.c.f. of gaseous CO_2.

The viscosity of low gravity oils is greatly reduced by the addition of CO_2. Viscosity of high gravity oils is also lowered but to a lesser extent. The viscosity of water however, is only slightly altered by the addition of CO_2. Average viscosity reduction in various gravity crudes at CO_2 saturation is as follows:[3,13]

Oil Gravity	Viscosity - CP. 70° F		100° F		CO_2
°API	WO/CO_2	W/CO_2	WO/CO_2	W/CO_2	Gas in Sol.
18	500	22	180	12	700
20	200	12.5	80	7	735
25	40	3.5	23	2.5	800
30	17.5	2.1	10	1.5	870
38	6	1.35	4	.9	1075
45	3	.6	2	.5	1175

The solubility of CO_2 (std. cu ft/bbl) at 100° F[2,4] in various treating fluids is as follows:

	100 psi	1000 psi	2000 psi	4000 psi
Fresh Water	20	152	174	191
Salt Water (100,000 ppm)	13	108	127	139
Salt Water (260,000 ppm)	6	53	63	69
Crude Oil 38° Gvty. (85° F)	45	1025	1075	1075
Crude Oil 20° Gvty. (120° F)	35	415	700	700

For further details on physical properties of CO_2 the reader is invited to consult the references listed.

CHEMICAL PROPERTIES OF CO_2

Carbonic acid is formed when water is saturated with CO_2. This acid, with a stable pH of 3.3 to 3.7, is relatively non-corrosive and requires no inhibition for well treating applications[2]. Some of the benefits in well stimulation work from this chemical effect are as follows:

1. The high hydrogen ion concentration of carbonic acid will tend to shrink or floculate clay particles by replacement of basic elements of appreciable atomic weigh with hydrogen, the lightest of all the elements. This control of swelling is especially important in formations containing appreciable amounts of bentonitic clays.
2. Most formations of a classic nature and many carbonate formations contain salts of iron and aluminum. These salts are dissolved during acidization. Should the pH rise to 5 or above during a treatment these iron and aluminum ions would percipitate as gelatinous hydroxides which can effectively block flow channels.[8,9]. The low pH of carbonated treating fluids prevents this from happening.
3. Gypsum and anhydrite are dissolved by aqueous treating fluids. If the treating fluid does not remain acidic, insoluble compounds such as calcium sulfate ("gyp") may precipitate thus restricting flow.[10] Here again the presence of CO_2 in the solution helps prevent such a precipitation.
4. Dolomites, limestone, and silicates are soluble in carbonated water to varying extents. Under well treatment conditions 2625 lb of magnesium carbonate will dossolve in 100 bbl of carbonated water. Calcite will dissolve to the extent of 80 pounds per 100 bbl and silicates such as $CaSiO_3$, $SrSiO_3$, and $BaSiO_3$ are soluble in ranges of from 100 to 200 lb per 100 bbl. The removal from the formation of such materials by solution will result in increased permeability of the formation.

ENGINEERING CARBONATED WELL TREATMENTS

By an engineered design in which the many well variables are taken into consideration a treating fluid can be provided with the proper level of carbonation. This quantity of CO_2 is injected simultaneously with the treating fluids and normally remains in the liquid state until after the fluid injection ceases. Heat transfer from the formation then results in vaporization of the CO_2 and on release of the surface pressure the CO_2 vapor expands and imparts a gas lift effect to the well.[12] Rapid, high rate flow back of carbonated treating fluids substantially increases well productivity by taking advantage of the CO_2 gas expansion to provide energy for the formation face clean up.

To simplify the engineering of carbonated well stimulation work the variables involved have been plotted in a series of curves. The use of these curves is discussed below.

A. Carbonated Fluid Flow Curves

Carbonic Chemicals' Carbonated Fluid Flow Curves are flowing pressure gradients (psi/foot) based on the density of the flowing mixture. Consideration has been given to pressure, temperature, flow rate, depth, fluid characteristics, CO_2 solubility, and flow string cross sectional area. The curves were calculated using data published by Baxendell and Thomas in the October 1961, issue of the Journal of Petroleum Technology entitled "The Calculation of Pressure Gradients in High-Rate Flowing Wells." These curves present the approximate flowing pressure traverses for given CO_2 - liquid ratios. From this data it can be determined how much CO_2 will be required to lift injected fluids from a well bore.

Data Required Before Using Curves

1. Flow string size (select the tubing, casing, or annulus size for the anticipated manner of return flow of the injected fluids): Because only slight differences are encountered, casing curves are valid for any normally encountered annular flow inside the casing. (Example, the 5 1/2 in. casing curves will be accurate enough for use in determining CO_2 - liquid ratio requirements for annular flow between 5 1/2 in. casing and 2 1/2 in., 2 in. or smaller tubing).
2. Formation Depth
3. Fluid type: Curves are available for fresh water, saltwater with 100,000 ppm total solids, saltwater with 260,000 ppm total solids and 38° gravity crude oil. Interpolation of curves for the various waters may be utilized to more accurately determine requirements for a salt water of any specific gravity. The fresh water curves can be utilized for the various acids injected. Viscous, low gravity oils vary greatly in CO_2 - liquid ratio requirements and must be handled on an individual basis.
4. Bottom Hole Pressure: Anticipated flowing bottom hole pressure is required. Field usage for gas wells indicates that 80% of static shut in bottom hole pressure can effectively be used for this requirement. It is necessary to preplan for oil well flowing bottom hole pressure. Consideration is given: anticipated formation pressure draw-down at varing flow rates and economic CO_2 requirements at various flowing bottom hole pressures. For desired flow back, a minimum necessity is a productive capacity (after frac) of 150 BFPD at no more than about 50% pressure draw down. Productive capacity is determined by using Darcy's Law and various articles available on prediction of productivity inceases due to fracturing.

Darcy's Law (Radical Flow);

$$Q = \frac{7.07\, k\, h\, (Pe - Pw)}{u\, \ln(re/rw)}$$

Q	=	bbl per day
k	=	darcies
h	=	pay thickness - ft
u	=	cp.
re	=	radius of drainage - ft
rw	=	radius of well bore - ft
Pe	=	pressure at radius of drainage - psia
Pw	=	pressure at well bore - psia

EXAMPLE

Data:

1. k	=	25 md
2. h	=	10 ft
3. u	=	1 cp. (35° Oil W/CO_2 @ 100° F)
4. re	=	660 ft
5. rw	=	.25 ft
6. Pe	=	2000 psi

Procedure: (For a 50% drawdown in pressure)

1. Q (before fracture,) (no formation damage) =

$$\left(\frac{7.07 \times .025 \times 10 \times (2000 - 1000)}{1 \times \ln (660/0.25)}\right.$$

$$Q = 225 \text{ BOPD}$$

2. Using data available for the effect of vertical fractures on well productivity [14] a 1.4 increase in production is predicted (over that assumed for no fracture with no formation damage). This is based on a fracture capacity of 600 md - ft (for 10-20 mesh sand with high over burden pressure [18]), and 10% fracture penetration of drainage radius.

$$1.4 \times 225 \text{ BOPD} = 315 \text{ BOPD}$$

This rate is greater than the minimum 150 BOPD requirement. Use of 50% drawdown is recommended for this case. This results in an anticipated flowing bottom hole pressure of 1000 psi and this figure is used in the carbonated treatment design.

The following examples are given to illustrate the use of the Carbonated Fluid Flow Curves.

EXAMPLE - Gas Well (Figure 1)

Data:

1. Flow String Size: 5 1/2 in. OD
2. Formation Depth: 7000 ft.
3. Fluid Type: Fresh Water (Gelled). 480 bbl frac. Fluid, 180 bbl Flush, or 660 bbl Total Fluid.
4. Static Shut in Bottom Hole Pressure: 2000 psig (Use 80% x 2000 psig - 1600 psig for Flowing Bottom Hole Pressure)

Procedure:

1. Use Chart titled "Casing Size 5 1/2 in. O.D., Fluid type - Fresh Water"
2. On left side of page find 7000 ft (formation depth) and move horizontally to intersection with 1600 psig bottom hole flowing pressure (which is read from top of the page.)
3. Determine CO_2 - liquid ratio as 450 cu ft bbl (If point falls to right of 300 cu ft bbl curve use 300 as a minimum requirement. If point falls to left of 1500 cu ft bbl curve the use of CO_2 for lifting may not be advisable.
4. Multiply total volume of well treating fluid by CO_2 - liquid ratio: 660 bbl (total fluid) x 450 cu ft/bbl - 297,000 std cu ft CO_2 required (or 297,000/17198 - 17.3 tons CO_2)

EXAMPLE - Oil Well (Figure 2)

Data:

1. Flow String Size: 2 1/2 in. ID
2. Formation Depth: 3000 ft
3. Fluid Type: Lease Crude - 35° A.P.I. 240 bbl Frac Fluid, 20 bbl Flush, or 260 bbl Total Fluid.
4. Static Shut In Bottom Hole Pressure: 1000 psig (Use of 50% Draw down of formation pressure desirable in this care to obtain a predicted productive capacity (after frac) in excess of 20 bbl per hr) 50% x 1000 = 500 psig Flowing Bottom Hole Pressure

Procedure:

1. Use Chart titled "Tubing Size 2 1/2 in. I.D., Fluid Type - Oil (38° A.P.I. Gravity).
2. On left side of page find 3000 ft (formation depth) and move horizontally to intersection with 500 psig bottom hole flowing pressure (which is read from top of the page).
3. Determine CO_2 - liquid ratio as 650 cu ft bbl
4. Multiply total volume of well treating fluid by CO_2 - liquid ratio: 260 bbl x 650 cu ft/bbl. = 169,000 std cu ft CO_2 required (9.8 tons)

During a well treatment the leading portion of the carbonated treating fluids may become greatly diluted due to its mixing with the formation fluids (particularly treatments using a relatively viscous frac oil in a high gravity oil reservoir). Carbonation in such a mixture may then become diluted to a level below that required to unload all of the resulting mixture. Addition of CO_2 in excess of the normal ratio during the early part of such a treatment must be used to overcome this problem.

In this particular case addition of 50% more CO_2 than necessary during the first half of the treatment should yield more desirable results. This would require the addition of 325 std cu ft x 130 bbl = 42,250 std cu ft CO_2 (2.5 tons).

B. Carbonated Fluid Maximum Efficient Return Rate Curves

These curves (Figure 3) give the treating fluid return flow rates necessary for maximum efficiency in recovery of the initial load. They have been calculated to assure turbulent flow in the well bore since under turbulent flow conditions little or no gas slippage occurs and it is possible to more accurately determine the gas requirements for lifting. These rates yield desired clean up near the well bore and provide a sufficient rate to remove formation fines or silt and loose or crushed grains of fracturing material. Lower return flow rates are recommended for oil well treatments, but care must be exercised to prevent the return flow being killed due to excessive gas slippage.

Because of its higher viscosity, oil in a reservoir exhibits much lower mobility than gas. Return flow rates for production from an oil must be controlled to prevent excessive pressure drawdown in the formation. To prevent excessive gas slippage a minimum flow back rate (for all flow string sizes) of 10 barrels fluid per hr is recommended. Oil well flow back rates should be regulated near the predicted productive capacity of the well (at the flowing bottom hole pressure utilized in the carbonated treatment design).

Maximum recommended oil well flow back rates (bbl/hr) are as follows:

Tubing Size ID	Casing Size OD
1 1/2 in. - 19-20	4 1/2 in. - 75-105
2 in. - 23-26	5 1/2 in. - 95-130
2 1/2 in. - 30-35	7 in. - 115-170
3 in. - 65-75	

Carbon dioxide vapor will diffuse through formation fluids over an extended period of time. To insure proper unloading open the treated well for flow back as soon as possible (a shut in period in excess of 8-12 hrs is undesirable).

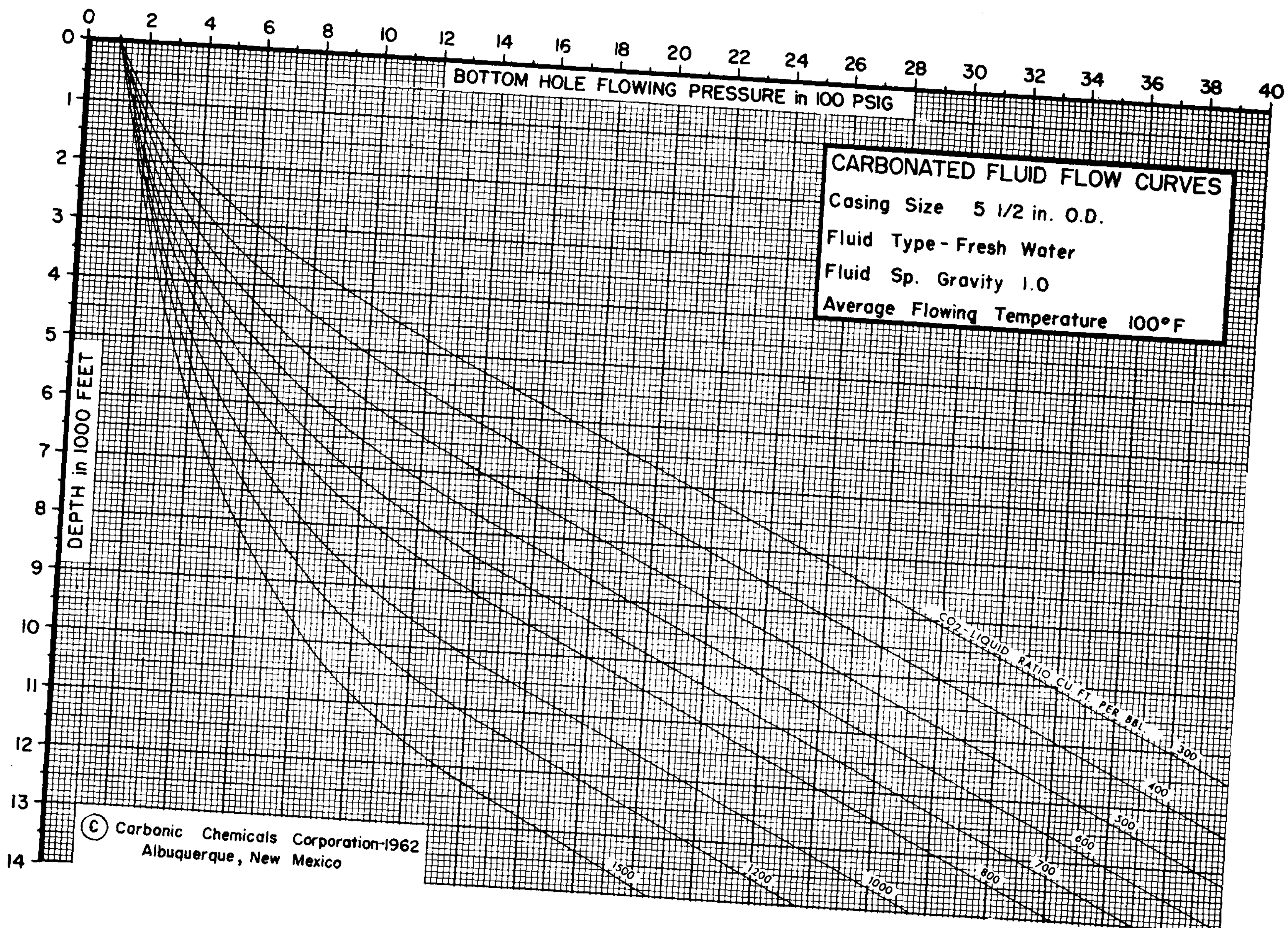
CARBONATED FLUID FLOW CURVES
Casing Size 5 1/2 in. O.D.
Fluid Type - Fresh Water
Fluid Sp. Gravity 1.0
Average Flowing Temperature 100°F
BOTTOM HOLE FLOWING PRESSURE in 100 PSIG
DEPTH in 1000 FEET
CO2-LIQUID RATIO CU FT. PER BBL.
300
400
500
600
700
800
1000
1200
1500
0 2 4 6 8 10 12 14 16 18 20 22 24 26 28 30 32 34 36 38 40
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14
© Carbonic Chemicals Corporation-1962
Albuquerque, New Mexico

Fig. 1

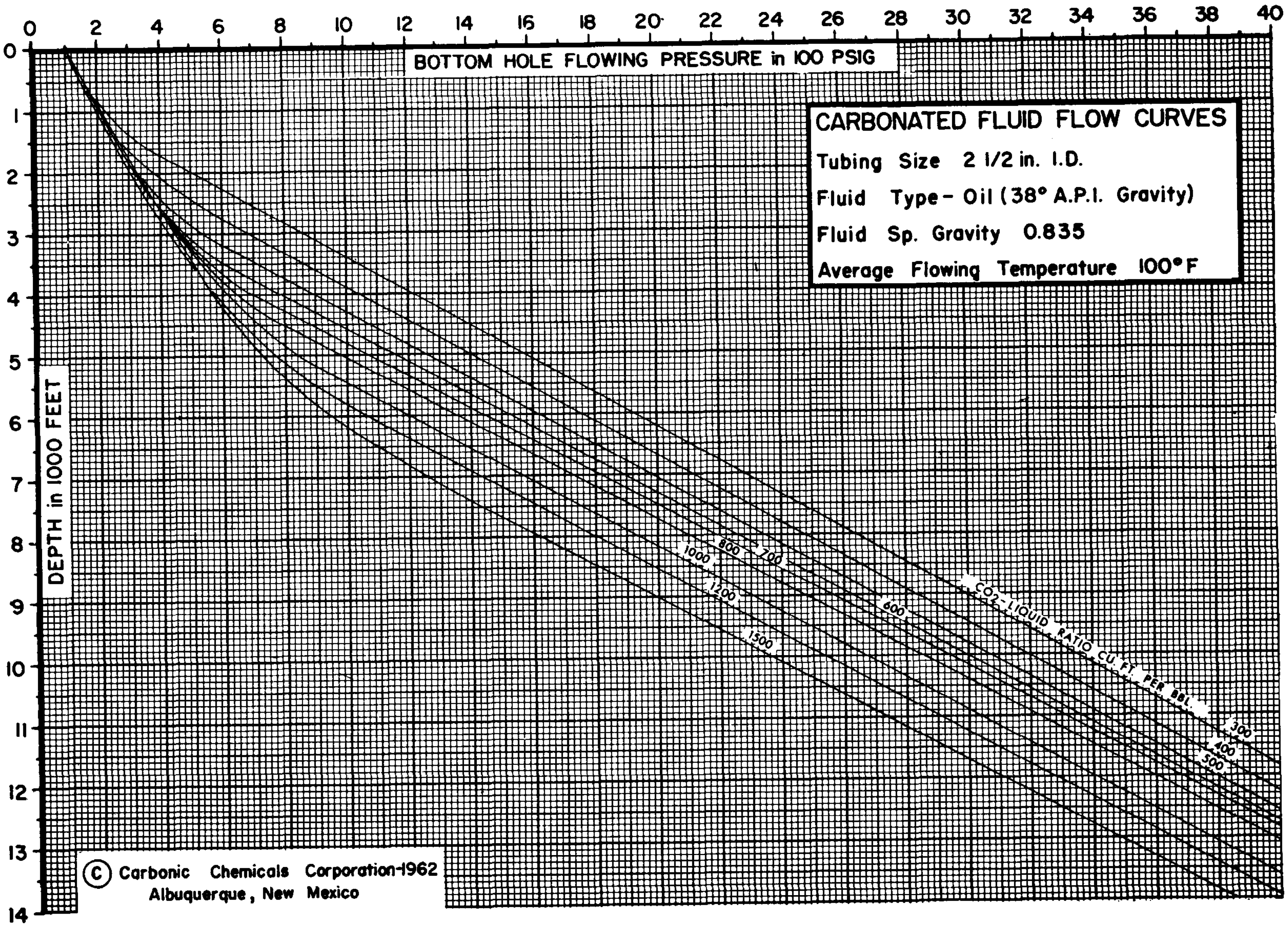
BOTTOM HOLE FLOWING PRESSURE in 100 PSIG
0 2 4 6 8 10 12 14 16 18 20 22 24 26 28 30 32 34 36 38 40
DEPTH in 1000 FEET
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14
CARBONATED FLUID FLOW CURVES
Tubing Size 2 1/2 in. I.D.
Fluid Type - Oil (38° A.P.I. Gravity)
Fluid Sp. Gravity 0.835
Average Flowing Temperature 100° F
CO2-LIQUID RATIO CU. FT. PER BBL.
300
400
500
600
700
800
1000
1200
1500
© Carbonic Chemicals Corporation-1962
Albuquerque, New Mexico

Fig. 2

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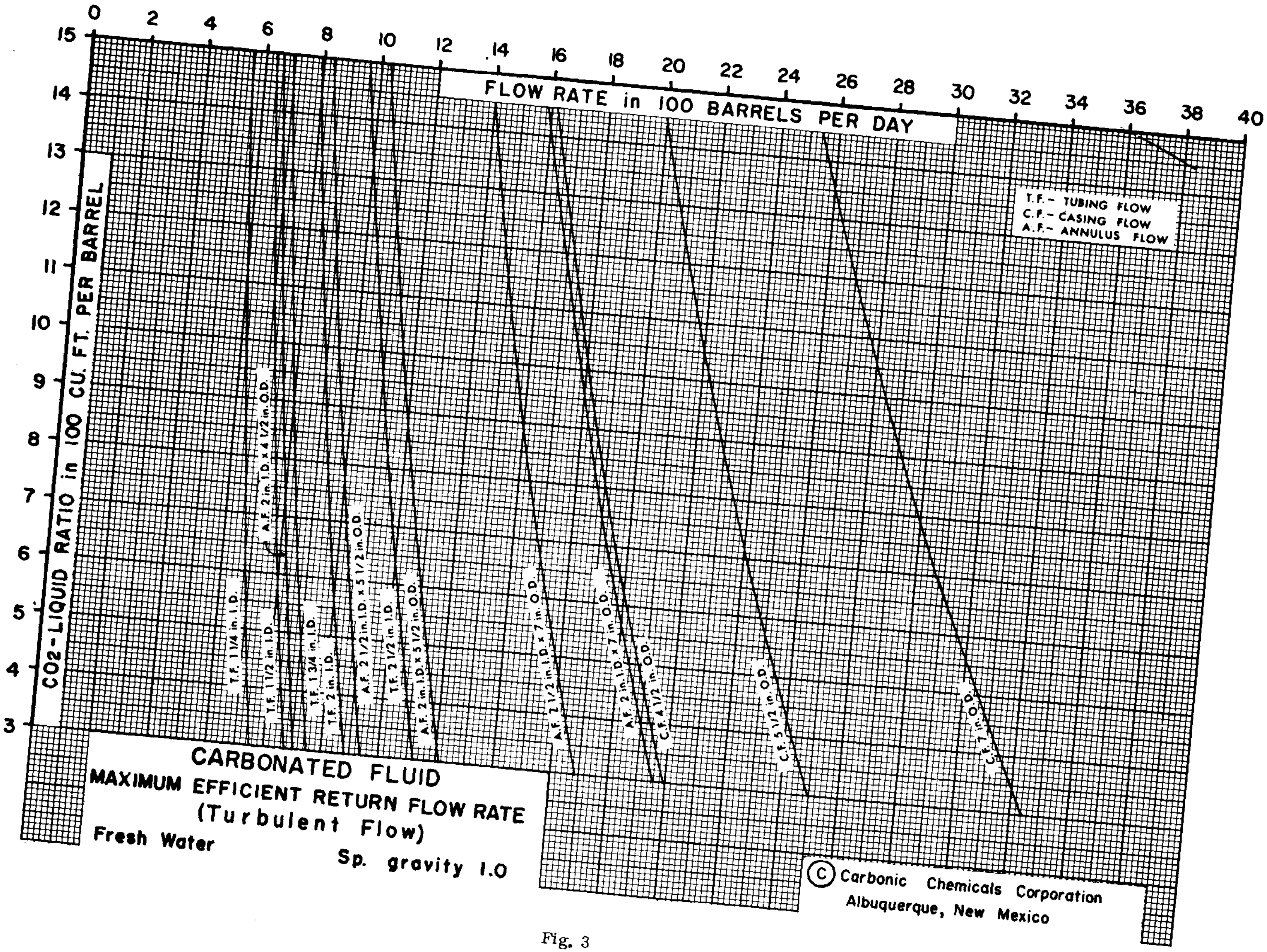

FLOW RATE in 100 BARRELS PER DAY
CO2-LIQUID RATIO in 100 CU. FT. PER BARREL
T.F. - TUBING FLOW
C.F. - CASING FLOW
A.F. - ANNULUS FLOW
T.F. 1 1/4 in. I.D.
T.F. 1 1/2 in. I.D.
A.F. 2 in. I.D. x 4 1/2 in. O.D.
T.F. 1 3/4 in. I.D.
T.F. 2 in. I.D.
A.F. 2 1/2 in. I.D. x 5 1/2 in. O.D.
T.F. 2 1/2 in. I.D.
A.F. 2 in. I.D. x 5 1/2 in. O.D.
A.F. 2 1/2 in. I.D. x 7 in. O.D.
A.F. 2 in. I.D. x 7 in. O.D.
C.F. 4 1/2 in. O.D.
C.F. 5 1/2 in. O.D.
C.F. 7 in. O.D.
CARBONATED FLUID
MAXIMUM EFFICIENT RETURN FLOW RATE
(Turbulent Flow)
Fresh Water
Sp. gravity 1.0
© Carbonic Chemicals Corporation
Albuquerque, New Mexico

Fig. 3

General Design Information

At high flow back rates (as recommended for gas wells), less friction will occur in large tubing or casing. Energy loss in small tubing at greater depths may become severe and limit or eliminate the economic use of CO_2 for lifting. Investigation of requirements for annular or casing flew may result in a more favorable treatment design.

As the amount of the gas is increased, total fluid density becomes lighter (thus decreasing pressure at depth). However, increasing the proportion of gas will reach a condition of diminishing returns. A large increase in gas-liquid ratio (above 1500) will only slightly lighten the pressure gradient.

Pressure at the surface is additive to any pressure due to fluid head and friction. A surface flowing pressure of 100 psi was used in constructing the carbonated fluid flow curves. High surface flowing pressures yields less advantageous use of gas expansion and will result in lower lift efficiency.

Special care should also be taken when a well is treated by injection down the tubing and annulus and simultaneously using a common injection manifold. When flushing these jobs care must be taken to see that the CO_2 is not being injected down the tubing only. If this situation occurs it may become impossible to kick off the well due to the relatively large quantities of uncarbonated fluid in the annulus falling back and killing the carbonated tubing flow. When CO_2 injection is down the annulus only during flush the tubing may be found dead when the well is opened. In this case, however, the annular flow back may be sufficient to unload the tubing fluid until its static head is overcome. These problems are best avoided by shutting in the tubing while flushing the annulus and then flushing the tubing separately at the end of the treatment.

RESULTS

Data on 115 productive wells fractured or acidized using CO_2 is included with this paper. Other data is available (but not presented) on treatments of non productive wells and on various specialized applications of CO_2 in well work. From this data a definite trend of increased well potential when using CO_2 is noted.

Increased potential occurs more often when well conditions permit high return flow rates and quick clean up after treatment. It is by this action that crushed sand and formation fines (released from the fracture surfaces) are removed from the well bore thereby allowing reater fracture flow capacity and higher well potentials.[15] In the case of gas wells, field experience using non-carbonated aqueous fluids for stimulation indicates that fluid recovery after fracture treating is usually in the range of 25 to 50% of that injected (with about 1/3 recovery being average). The unrecovered fluids are probably retained in the first 2 or 3 in. of the formation adjacent to the fracture and thus will accupy, at least half the porosity formerly occupied by gas. From published data [19, 22] this additional water saturation can easily reduce effective permeability to 2% or less of its former permeability. The work of Van Poolen [16] indicates that this damage will reduce well productivity to as little, as 1/3 of that expected if no damage had occurred. By the recovering of from 75% to 90% of these aqueous fluids (as is normal in CO_2 treatments) this damage is neld to a minimum. This undoubtedly is one of the principal reasons for the substantially greater potentials observed in CO_2 stimulated gas wells.

Application of CO_2 has varied from area to area. Discussion follows on experience obtained in the various areas where CO_2 has been utilized extensively.

A. Texas - Oklahoma Panhandle Area

In this area CO_2 has been mainly used in fracture treatments with water or weak HCl acid solutions as the treating fluid. Its application has provided a means of obtaining better effective permeability to oil or gas in the formation. Also salt leached by the treating water is effectively removed from these formations.[20,21]

Morrow Sand

Excellent clean up and increased well potential has resulted from use of CO_2 in treatments of this formation. Almost all wells treated were gas wells. In 63% of the cases where comparison with offset wells could be made, use of CO_2 resulted in substantially increased potential. Prevention of clay and silicate swelling due to the chemical effects of CO_2 in water, along with rapid fluid removal may have been important in obtaining these better results.

Red Cave Sand

Outstanding results have occurred in over 2/3 of the cases where CO_2 has been used in the treatment of this shallow gas sand. Typical of the general use of CO_2 in water for treating gas wells is the following comparison of 3 wells treated with CO_2 and 3 without CO_2. Treatments of the wells without CO_2 were increased in size so that costs for all treatments would be equal.

Well	Natural Formation Productive Capacity md.-ft.	AOF Potential After Frac Mcf		AOF Mcf per md - ft
		...Without CO_2...		
A	244.5	7500		30.75
B	190	4400		23
C	96	2900		30
			Ave.	27.9
		...With CO_2...		
D	173	7100		41
E	168	6300		37.5
F	40.3	1700		42.5
			Ave.	40.3

Wells treated using CO_2 showed an average of 44% increased productivity.

Tonkawa Sand

Results from treatments in this formation (principally oil wells) show better results are obtained on wells with good productive capacity or with high formation mobility (gas wells or high G.O.R. wells).

RESULTS OF WELL STIMULATION WITH CO_2—TEXAS-OKLAHOMA PANHANDLE AREA GAS WELLS

Well	Field	County	State	Depth	Fluid 1000 Gal	General Treatment Type	General Treatment Sand 1000#	CO_2 Tons	Well Pot. MCF	Offsets Av. Pot.-MCF	Remarks
	BROWN DOLO										
1.	Texas-Hugoton	Sherman,	Tex.	3009-3216	30	GW	45	32½	612P	454P	35% Incr.
									(Hugoton Delv. Test)		(Open F. Ga. 21200)
2.	W. Panhandle	Carson,	Tex.	2236-2834	12	5% GA	18	10	2269P	1904P	
									3400A		19% Incr. (Pot. before W.O. 870)
3.	W. Panhandle	Carson,	Tex.	2679-2779	10	5% GA	15	10	1833P		
									2800A		(Pot. Before Retreating 746)
4.	W. Panhandle	Gray,	Tex.	2507-2568	29	GW	31½	35	15500A	1132P	Better than Expected)
5.	W. Panhandle	Hutchinson,	Tex.	2275-2645	20	5% GA	30	25	8173P	7322A	
									9000A		11% Incr. (Pot. before Retreating 5589)
6.	W. Panhandle	Moore,	Tex.	2863-3060	30	GW	45	15	1923P	2072P	
									7500A		Equal to Offsets
7.	W. Panhandle	Carson,	Tex.	2519-2801	12	5% GA	18	10	3699P	1115P	230% (Current test 1 yr. after frac.)
8.	Texas-Hugoton	Sherman,	Tex.	3097-3120	30	2% GA	45	11½	Ga2196@60psi	None	Better than Expected
	CHESTER LIME										
1.	Mocane-Laverne	Beaver,	Okla.	7160-7238	20	15% GA	....	20	7800A	7250A	Equal (Mech. Difficulties)
	RED CAVE SAND										
1.	W. Panhandle	Potter,	Tex.	1502-1534	15	GW	15	10	6300A	Ave.	40%
2.	W. Panhandle	Potter,	Tex.	1480-1534	15	GW	15	10	7100A	4760A	
3.	W. Panhandle	Potter,	Tex.	1650-1670	35	GW	50	10	1100P (Est.)	1025P (Est.)	
									1700A		Equal to Offsets
4.	W. Panhandle	Hutchinson,	Tex.	1846-1902	40	GW	80	17½	7300A		
5.	W. Panhandle	Hutchinson,	Tex.	1830-81	40	GW	80	17½	12300A		
6.	W. Panhandle	Hutchinson,	Tex.	1844-86	40	GW	80	17½	8000A		
7.	W. Panhandle	Hutchinson,	Tex.	1880-1950	40	GW	80	17½	11900A	4310	119% Incr.
8.	W. Panhandle	Hutchinson,	Tex.	1921-81	40	GW	80	17½	8410A		
9.	W. Panhandle	Hutchinson,	Tex.	1794-1851	30	GW	60	17½	10600A		
10.	W. Panhandle	Hutchinson,	Tex.	1522-40	18	GW	27	10	1450A		
									1008P	882P	14% Incr.

RESULTS OF WELL STIMULATION WITH CO_2 TEXAS-OKLAHOMA PANHANDLE AREA GAS WELLS

Well	Field	County	State	Depth	Fluid 1000 Gal	General Treatment Type	Sand 1000#	CO_2 Tons	Well Pot. MCF	Offsets Ave. Pot.-MCF	REMARKS
RED CAVE SAND											
11.	W. Panhandle	Hutchinson,	Tex.	1634-1720	20	GW	30	10	2180		
									1233P	822P	39% Incr.
12.	W. Panhandle	Hutchinson,	Tex.	1437-1667	30	GW	45	10	5450A	1914P	Equal to Offsets
									2060P		
13.	W. Panhandle	Hutchinson,	Tex.	1695-1781	20	GW	40	10	6800A	3425A	98% Incr.
14.	W. Panhandle	Hutchinson,	Tex	1825-94	15	GW	30	10	2500A		
									1300P (Est.)	1300P (Est.)	Equal to Offsets
15.	W. Panhandle	Moore,	Tex.	1755-1948	20	5% GA	20	20	5200A		
									2000P (Est.)	1516P	32% Incr.
CLEVELAND SAND											
1.	N. Mammoth Ck.	Lipscomb,	Tex.	7393-7416	15	3% GA	22	20	12000A	9750A	23% Incr.
2.	N. Mammoth Ck.	Lipscomb,	Tex.	7427-64	15	3% GA	22½	21	9000A	5580A	61% Incr.
3.	N. Mammoth Ck.	Lipscomb,	Tex.	7488-7508	15	3% GA	22½	17	6000A	6000A (Approx.)	Equal to Offsets
MORROW SAND											
1.	Hansford, U.M.	Hansford,	Tex.	7244-89	21	GW	21	25	37000A	6925A	433% Incr.
2.	Hansford, U.M.	Hansford,	Tex.	7228	20	GW	20	30	6800A	2400A	183% Incr.
3.	Hansford, U.M.	Hansford,	Tex.	6924-77	20	3% GA	20	20	3316P	1950P	
									10250A		74% Incr.
4.	Parnell, L.M.	Ochiltree,	Tex.	9857-9963	10	2% GA	6	13½	4350A	1-960A	
										1-9200A	Equal to Expected
5.	Parnell, L.M.	Ochiltree,	Tex.	9826-58	10	5% GA	3.9	14	3600A	3906A	Equal to Offsets
6.	Mocane-Laverne	Beaver,	Okla.	6162-99	20	5% GA	20	13½	4250A	3800A	12% Incr.
7.	Mocane-Laverne	Harper,	Okla.	6275-84	20	GW	20	17	4500A	None	Better than Expected
8.	Richfield	Morton,	Kans.	5039-5127	22	3% GA	22	19½	8000A	4340A	84% Incr.
9.	Hansford, L.M.	Hansford,	Tex.	7475-81	20	3% GA	20	20	1118P	138P	
									2400A		708% Incr.
10.	Wamble, U.M.	Ochiltree,	Tex.	8260-86	22	GA	20	20	49500A	20700A	139% Incr.
11.	So. Turner, U.M.	Ochiltree,	Tex.	8980-88	40	IA		20	2100A	984A	113% Incr.

RESULTS OF WELL STIMULATION WITH CO_2 TEXAS-OKLAHOMA PANHANDLE AREA GAS WELLS

Well	Field	County State	Depth	Fluid, 1000 Gal	General Treatment Type	General Treatment Sand 1000#	CO_2 Tons	Well Pot. MCF	Offsets Ave. Pot.-MCF	Remarks
	MORROW SAND									
12.	So. Logan	Beaver, Okla.	8428-86	30	GC	30	24	4100A	None	Equal to Expected
13.	Notla L. M.	Ochiltree, Tex.	10138-385	15	GA	7½	32	3500A	1-944A 1-Diag. 15200A	Equal to Expected
14.	Wildcat	Lipscomb, Tex.	10564-74	15	GW	15	22	23500A	None	Before—F1000Mcf ¾" Ck
15.	Wildcat	Hansford, Tex.	7573-83	20	GW	30	20	4500A	None	Better than Expected
	TONKAWA SAND									
1.	Bechtold	Lipscomb, Tex.	6188	19	GW	7.75GB	16	22000A	9000A	144% Incr.
2.	E. Lipscomb	Lipscomb, Tex.	6698-708	10	GW	20	14Ga	3120 & 47BOPD +57BSWPD	None	(1"Ck—350#)

RESULTS OF WELL STIMULATION WITH CO_2 OKLAHOMA AREA GAS WELLS

Well	Field	County State	Depth	Fluid, 1000 Gal	General Treatment Type	General Treatment Sand 1000#	CO_2 Tons	Well Pot. MCF	Offsets Ave. Pot.-MCF	Remarks
	ATOKA SAND									
1.	N. W. Kinta	Haskell, Okla.	5824-61	20	SLW	1WH 11.25	20	5713A	5650A	Equal to Offsets
	MANNING LIME									
1.	Dover-Hennessey	Kingfisher, Okla.	6787-96	15	GW	.62WH 4.37	10½	Ga 1918 ⅜" Ck-650#	None	Better Than Expected

RESULTS OF WELL STIMULATION WITH CO_2 FOUR CORNERS AREA GAS WELLS

Well	Field	Co. State	Depth	General Treatment Fluid 1000 gal	Type	Sand 1000#	CO2 Tons	Well Potential-Mcf.	Offsets Ave. Potential-Mcf.	Remarks
DAKOTA SAND										
1.	San Juan Basin	Rio Arriba, N. M.	7540-7738	71.6	SLW	75	40	6144A	4593A	34% Incr.
2.	San Juan Basin	San Juan, N. M.	6744-6924	65	SLW	40	40	4247A	2544A	67% Incr.
3.	San Juan Basin	San Juan, N. M.	6444-6630	69.7	SLW	75	40¾	2625A	None	
4	San Juan Basin	San Juan, N. M.	6660-6740	86.1	SLW	60	33	2112A		Equal to Offsets
5.	San Juan Basin	San Juan, N. M.	6568-6692	115.5	SLW	75	40	4120A	3140A	31% Incr.
6.	San Juan Basin	San Juan, N. M.	6250-6368	96.6	SLW	100	42½	6636A		Flow Tests—3 CO_2 Wells
7.	San Juan Basin	San Juan, N. M.	6178-6358	110	SLW	100	36	5004A		4115 Mcf Ave. (3 Other
8.	San Juan Basin	San Juan, N. M.	6344-6502	74.5	SLW	76	30½	5925A		wells—3303 Mcf Ave., 25% Incr.)
CHACRA										
1.	San Juan Basin	Rio Arriba, N. M.	3890-3903	34.8	SLW	30	20	1100		Equal to Offsets
PICTURE CLIFFS										
1.	San Juan Basin	Rio Arriba, N. M.	3276-3300	30.4	SLW	30	9½	2671A	2254A	18½% Incr.
2.	San Juan Basin	Rio Arriba, N. M.	3302-26	31.3	SLW	30	9½	5352A	3020A	77% Incr.
MESA VERDE										
1.	San Juan Basin	San Juan, N. M.	4432-4588	62.6	SLW	50	29½	1738A	None	OWWO Redrilled
2.	San Juan Basin	Rio Arriba, N. M.	5600-6091	60.2	SLW	42	40	2214A	None	OWWO Redrilled

LO—Lease Oil
15% A—Acid
RO—Refined Oil
GA—Gelled Acid
GW—Gelled Water
GC—Gelled Cond.

SLW—Slick Water
OWWO—Old Well Workover
ck—Choke
A—Absolute Open Flow
P—Potential Test (Based on Field Rules)
F—Flow, P—Pump, SW—Salt Water

WH—Walnut Hulls
GB—Glass Beads
IA—Isop. Alcohol
Ga—Gage

RESULTS OF WELL STIMULATION WITH CO_2 TEXAS-OKLAHOMA PANHANDLE AREA OIL WELLS

Well	Field	Co.—State	Depth	Zone	Fluid 1000 gal	General Treatment Type	Sand 1000#	CO_2 Tons	Well Potential BOPD	Remarks
	TONKAWA SAND									
1.	Feldman	Hemphill, Tex.	7715-7799		10	GO	7.5	18	F122+9%SW	15/64"ck-250#
2.	Feldman	Hemphill, Tex.	7728-7806		30	GW	30	35	F205	¾"ck
3.	Feldman	Hemphill, Tex.	7782-7810		30	GW	30	35	F122+24%SW	1¾"ck
4.	Bechtold	Lipscomb, Tex.	6188-94		10	GW	20	20	F223	⅜"ck-800# Offset F24+56SW
5.	Frass	Lipscomb, Tex.	6188-98		10	GW	10	18½	F120+2740Mcf	¼"ck-1300# Offsets 2-F102§151 (High GOR's) 2-P26§41
6.	N. Fork	Beaver, Okla.	6060-69		7.5	GW	7.5	13	F905+17SW	½"ck-425# Offsets 1-F459 ¾"ck 1-F168 By Heads
7.	Bradford	Lipscomb, Tex.	6586-96		5	GW	10	13	F360+50%SW	1"ck-100# Offset P-72+42%SW
8.	Wildcat	Ellis, Okla.	7895-924		30	GO	30	37	F536	24/64"ck
	DES MOINES									
1.	Farnsworth-Conner	Ochiltree, Tex.	6669-79		15	7½%A		19½	P120	Equal to Offsets
2. (Old Well)	Twin-Des Moines	Hansford, Tex.	6240-58		10	15%A		12	F117	(Before F30)
3.	Farnsworth-Conner	Ochiltree, Tex.	6580-6824		10	7½A		20	P114	
4.	Farnsworth-Conner	Ochiltree, Tex.	6614-6834		9	7½A		18	P112	
1. (Old Well)	Panhandle	Hutchinson, Tex.	2672-2796	Brown Dolo.	10	GW	30	10	P25	Equal to Offset Retreatments
2. (Old Well)	Panhandle	Hutchinson, Tex.	2610-2758	Brown Dolo.	10	GW	20	10	P60	Better than Offset Retreatments
3.	Perry-Clev.	Lipscomb, Tex.	7318-57	Cleveland	16	GW	20	25	F184+14%SW	½"ck (No Offsets)
4.	Dutcher	Ochiltree, Tex.	7538-7691	Cleveland	20	3%GA	20	14½	P51	Poor Pay Dev. Offset P63
5.	Taloga	Morton, Kans.	4614-22	Morrow Sd.	20	GO	15	18	P360+120SW	Better Than Expected

RESULTS OF WELL STIMULATION WITH CO_2 OKLAHOMA AREA OIL WELLS

Well	Field	Co.—State	Depth	Zone	Fluid 1000 gal	General Treatment Type	Sand 1000#	CO_2 Tons	Well Potential BOPD	Remarks
1.	Dover-Hennessey	Kingfisher, Okla.	5636-42	Cleveland	15	GW	1.9+1.4WH	10¾	F100 (Low GOR)	¼"ck-500# Offsets 1-P50+20SW, 1-F211 (High GOR)
2.	Dover-Hennessey	Kingfisher, Okla.	6248-55	Oswego Lm.	10	15%A		15	F46	5/16"ck Equal to Better Field Wells
3.	Dover-Hennessey	Kingfisher, Okla.	6170-79	Red Fork Sd.	15	GO	15	2	F62	⅜"ck-375# (No Offsets)
4.	S. W. Lacey	Kingfisher, Okla.	7785-964	Meramec Lm.				33	F225	11/64"ck
5.	S. W. Wakita	Grant, Okla.	5029-34	Cherokee Sd.	7.5	GO	7.5	6¾	F192	7/32"ck-430# Offsets 1-F192, 1-P35
6.	N. Lovell	Logan, Okla.	4969-75	Cottage Grove, Sd.	10	GO	10	6	F346	12/64"ck-800# (Wildcat)

RESULTS OF WELL STIMULATION WITH CO_2 W. TEXAS OIL WELLS

Well	Field	Co. State	Depth	Zone	General Treatment Fluid 1000 gal	Type	Sand 1000#	CO_2 Tons	Well Potential BOPD	Remarks
1.	Parker-Canyon	Andrews, Tex.	9303-12	Canyon Reef	10	15%A		15	F201-275#	Later F306+87SW-200#
2.	Nena Lucia	Nolan, Tex.	7089-97	Strawn Reef	30	15%GA	20	55½	F126-400#	24/64"ck (Before-treated w/6500 gal acid P33BO+10BAWPD
3.	Magnolia Sealy	Ward, Texas	2740-846	Yates	20	GW	30	17½	F90+40SW	Before P2 to 5 BOPD, Offset-F25BOPD
4.	N. Ackerly-Dean	Dawson, Tex.	8483-642	Dean	30	RO	3.25 4.25WH	19	F231	Offset Pot Ave 150BOPD
5.	Wasson-W.-A.	Yoakum, Tex.	8250-403	Wichita-Albany	23	15%GA		19	F856-150#	21/64"ck Offset Pot Ave F280BOPD
6.	Tubbs	Crane, Tex.	6493-526	Devonian	10	LO	10	20	F119-720#	8/64"ck
7.	N. Andrews	Andrews, Tex.	10485-523	Devonian	2.5	15%A		16	F224-100#	½"ck
8.	N. Andrews	Andrews, Tex.	10392-402	Devonian	50	15%A	35	57	P158+29%SW	
9.	Emma-Strawn	Andrews, Tex.	9094-199	Strawn	10	15%A		16	F114-40#	1"ck
10.	Britt-Sprab.	Dawson, Tex.	7397-415	Spraberry	20	RO	40	21½	P165+30%SW	
11.	N. Robertson	Gaines, Tex.	7025-180	Clearfork				21	P155+19%SW	
12.	Smyer	Hockley, Tex.	5808-940	Clearfork	15	15%A		19	P113	
13.	Smyer	Hockley, Tex.	5830-958	Clearfork	10	15%A		15	P22+20%SW	
14.	Smyer	Hockley, Tex.	5810-960	Clearfork	10	LO	15 +.5WH	18½	P105+4%SW	
15.	Univ. Waddell	Crane, Tex.	7540-672	Penn.	15	15%A		37	P85+6%SW	
16.	S. Ward	Ward, Tex.	2382-503	Penn Grandfalls	10	GW	20	17	P21+12%SW	
SAN ANDRES										
1.	Parker-S. A.	Andrews, Tex.	4594-619		5	15%A		9	P100	
2.	Parker-S.A.	Andrews, Tex.	4613-65		20	LO	27	28	F142	
3.	Parker-S.A.	Andrews, Tex.	4665-93		20	LO	27	31	P32+41SW	
4.	Parker-S.A.	Andrews, Tex.			20	LO	27	28	P78+12SW	
5.	Parker-S.A.	Andrews, Tex.	4610-58		20	LO	27	28	P97+81SW	
6.	Martin S.A.	Andrews, Tex.	4267-99		3	RO	6	5	F96	
7.	Harper S.A.	Ector, Tex.	4100		21	GW	14	15	P198	
8.	Parker S.A.	Andrews, Tex.	4648-68		20	LO	27	28	F170	48/64"ck
9.	Martin S.A.	Andrews, Tex.	4276-93		3	RO	6	7	P41+17SW	Had Emulsion Block Before (Swabbed Dry)
FUSSELMAN										
1.	Midland Farms	Andrews, Tex.	11915-65		50	15%GA	37½	104	F297-600#	
2.	Midland Farms	Andrews, Tex.	11870-923		50	15%GA	37½	94	F348-500#	20/64"ck
3.	Midland Farms	Andrews, Tex.	11850-95		50	15%GA	37½	99½		Test F483 BOPD
4.	Midland Farms	Andrews, Tex.	11905-50		50	15%GA	37½	118	F328-250#	20/64"ck
5.	Wildcat	Ector, Tex.			5	15%		12		
					50	15%GA	37½	119½		Test F771+179BAW-24 hr 700#
GRAYBURG										
1.	Parker-Grayburg	Andrews, Tex.	4524-84		31	LO	46	38	F110-100#	
2.	Parker-Grayburg	Andrews, Tex.	4512-80		30	LO	45	38	F217-60#	
3.	Parker-Grayburg	Andrews, Tex.	4511-80		30	LO	45	38	P145+38SW	
4.	Midland Farms	Andrews, Tex.			30	LO	45	37	P44+8SW	Later Test P88 with no SW
5.	McElroy	Upton, Tex.	3092-146		25	RO	50	27	P55	
DELAWARE										
1.	El Mar	Loving, Tex.	4490-4500		2	RO		3½	F70-420#	Rework-Before F20-BOPD
2.	El Mar	Loving, Tex.	4500		2	RO		3½	F115-560#	Rework-Before F20-25 BOPD
3.	El Mar	Loving, Tex.	4500		2	RO		3½	F70-400#	Rework-Before F20-25 BOPD
4.	El Mar	Loving, Tex.	4500		2	RO		3½	F82-600#	Rework-Before F20-25 BOPD
5.	El Mar	Loving, Tex.	4490-501		2	RO		3½	F63-600#	Rework-Before Dead

RESULTS OF WELL STIMULATION WITH CO_2 S. E. NEW MEXICO OIL WELLS

Well	Field	Co. State	Depth	Zone	General Treatment Fluid 1000 gal	General Treatment Type	General Treatment Sand 1000#	CO_2 Tons	Well Potential BOPD	Remarks
1.	Pearl-Queen	Lea, N. M.	4950-62	Queens	30	RO	90	14	P220	
2.	Vaccum-Abo	Lea, N. M.	8692-902	Abo	20	15%A		30	F296	20/64"ck
3.	Vaccum-Abo	Lea, N. M.	8586-850	Abo	10	15%A		15	F288	22/64"ck
4.	Vacuum-Abo	Lea, N. M.	8600	Abo	20	15%A		20	150	Rework-Before 77BOPD
5.	Vaccum Yeso	Lea, N. M.	6419-705	Yeso-Paddock	20	LO	40	15½	F105	10/64"ck GOR 1850
6.	Vaccum Devonian	Lea, N. M.	12070-105	Devonian	2	15%A		10	F172-200#	26/64"ck GOR 4780
7.	Wildcat	Chaves, N. M.	2068-122	San Andres	30	GW	14	14½	F38	1"ck (Area undeveloped because all previous wells uncommercial.)
8.	Milnesand	Roosevelt, N. M.	4601-23	San Andres	15	LO	30	12½	F48	½"ck
9.	Undesignated	Chaves, N. M.	3156	San Andres	10	LO	10	12½	P22+10SW	Equal to Offset Wells
10.	Double X	Lea, N. M.	4904	Delaware	3	LO	7.5	4½	F86	Other wells in field pump
11.	Double X	Lea, N. M.	4900	Delaware	1	LO	1	3½	P44+30SW	
12.	Double X	Lea, N. M.	4920	Delaware	2	LO	2	10	P20	Offset P9BOPD

RESULTS OF WELL STIMULATION WITH CO_2 S. E. NEW MEXICO GAS WELLS

Well	Field	Co. State	Depth	Zone	Fluid 1000 gal	Type	Sand 1000#	CO_2 Tons	Well Potential	Remarks
1.	Wildcat	Eddy, N. M.	7375-7538	Cisco	30	15%A		20½	15,000Mcf	Offset 12,848 Mcf 1½"ck

Other Formations

In general almost all gas wells have been good applications for the use of CO_2 in stimulation treatments. Results of treating the Brown Dolomite in the old Panhandle Gas Field have varied. Increased formation permeability has resulted from the dissolving action of carbonated water on dolomite. However, low formation pressure (50 - 100 psi @ 2500 - 3000) in much of the field precludes the use of CO_2 for effective fracturing fluid removal.

West Texas

In this area CO_2 has been mainly used in oil well fracturing treatments with oils or 15% HCl acid as the treating fluid. Addition of CO_2 in viscous treating oils used in this area has resulted in higher injection rates, due to viscosity reduction, with little adverse effect in sand carrying ability. Best results have generally occurred in deeper wells (below 6500 ft with high bottom hole pressure). Shallower wells with above average GOR's and good natural productive capacity have also responded well to treatments using CO_2. In this area CO_2 is used principally for rapid cleanup along with elimination or reduction of swabbing expense.

Treatments in the deep, high pressure Fusselman Lime have been particularly successful. Potentials of these wells have been significantly greater than those of comparable wells treated without CO_2. The use of CO_2 has resulted in better removal of the spent acid and in more effective all - around clean up. Also, the shorter clean up time involved has allowed these wells to be placed on production many days sooner.

OTHER AREAS

Results obtained from numerous treatments in Central Oklahoma, Southeast New Mexico, and the Four Corners areas, are similar to those obtained in the areas already discussed. Thus it is apparent from wide regional usage that CO_2 has extensive application in well stimulation work.

ECONOMICS

Elimination of 2 days swabbing expense will usually pay for the total additional expense incurred in using CO_2 in an average stimulation treatment. If a drilling rig is being used for completion the CO_2 expense can be offset by the elimination of as little as one day's rig time.

In some cases the cost of the CO_2 for water fracture treatments can be saved by eliminating the weak HCl acid solutions used for the prevention of formation damage.

Additions of CO_2 to a viscous frac oil reduces friction losses and thus lowers the hydraulic horsepower requirements for injection. For an average treatment down 5 1/2 in. OD casing at a 30 bbl per minute rate these savings will be more than half of the direct cost of the CO_2 used.

The primary economic consideration, however, is the increased well productivity that can be obtained by using CO_2. As indicated above these increases can be obtained for little or no additional cash outlay. In the long run they amount to a substantial increase in income to the operator.

CONCLUSIONS

Results of work done to data indicate that the following benefits can usually be obtained when carbon dioxide is correctly used in well stimulation work:

1. Rapid and effective removal of treating fluids from the formation.
2. Better well potentials than with other stimulation techniques at little or no additional cost.

The best applications for CO_2 appear to be in the stimulation of gas wells and in the stimulation of those oil wells which have relatively high bottom hole pressure or good productive capacity.

There are 2 principal reasons for the increased potentials of carbon dioxide treated wells. The first is the practically complete removal of treating fluids and other flow restricting materials from the fracture surfaces. The second is the prevention of damage to the formation by the treating fluids during and after the stimulation treatment.

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