SOCIETY OF PETROLEUM ENGINEERS OF AIME
6200 North Central Expressway
Dallas, Texas 75206

PAPER NUMBER SPE 3160

THIS IS A PREPRINT --- SUBJECT TO CORRECTION

How to Stimulate Deep Hunton and Morrow Horizons in the Anadarko Basin

By

E. A. Ernst and R. E. Hurst, Members AIME, Dowell Division of The Dow Chemical Co.

© Copyright 1970
American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc.

This paper was prepared for the Central Plains Regional Meeting of the Society of Petroleum Engineers of AIME, to be held in Amarillo, Tex., Nov. 16-17, 1970. Permission to copy is restricted to an abstract of not more than 300 words. Illustrations may not be copied. The abstract should contain conspicuous acknowledgment of where and by whom the paper is presented. Publication elsewhere after publication in the JOURNAL OF PETROLEUM TECHNOLOGY or the SOCIETY OF PETROLEUM ENGINEERS JOURNAL is usually granted upon request to the Editor of the appropriate journal provided agreement to give proper credit is made.

Discussion of this paper is invited. Three copies of any discussion should be sent to the Society of Petroleum Engineers office. Such discussion may be presented at the above meeting and, with the paper, may be considered for publication in one of the two SPE magazines.

Downloaded from http://admin.onepetro.org/speprof/proceedings-pdf/70CPR/All-70CPR/SPE-3160-MS/2692307/spe-3160-ms.pdf by guest on 30 November 2023

ABSTRACT

The deep horizons of the Anadarko Basin pose many problems in the drilling, completion and production of wells. This paper deals with the problems and solutions for stimulation and production maintenance.

The weaker, less efficient organic acids were commonly used to stimulate the Hunton zone because of corrosion problems at the bottom-hole temperatures. This problem has recently been overcome by using calculated cool down fluid volumes prior to injection of acid solutions into the well. New friction reducers have been developed to reduce friction pressures during treatment and this in turn allows higher injection rates and minimizes tubing exposure to acid solutions.

The fracturing treatments, in the Morrow zone, have also been limited because of elevated temperatures adversely affecting the treating fluids. The cool down approach has been used here also in order to realize greater fluid viscosities and to provide more efficient prop transport. A new fluid system has recently been used in the lower Morrow where rates were limited and adequate viscosity was essential.

The production of these wells has created problems because of corrosion and scale build-up that severely restricts well capabilities. Many attempts have been made to adequately control corrosion. A recently completed well was squeezed with a corrosion and scale inhibitor. This paper also deals with the latest procedures that have been used to clean up scale that has created wellbore restriction and loss of production.

The Hunton and Morrow intervals are productive throughout the Texas Panhandle and in Western Oklahoma, but the most recent and extensive activity has been in Hemphill County, Texas. The main areas of concern for this paper are the Buffalo Wallow and Washita Creek gas fields.

INTRODUCTION

The discovery well in the Buffalo Wallow field was completed in the Hunton by Union Oil Company of California in October, 1967. The

* References and illustrations at end of paper.

primary concern at this time was to adequately stimulate the well with acid solutions and provide corrosion protection to bottom-hole well equipment. Several acid formulations were considered but the decision was made to clean up the perforations and wellbore using a formulation of formic and acetic acids with an arsenic base inhibitor. The well was further stimulated using a mixture of hydrochloric and acetic acids with an arsenic base inhibitor for corrosion protection. The results of this treatment are shown in Table I.

This clean-up and stimulation procedure was used on other completions in the area but as a result of development work in the Delaware Basin of West Texas[1], two changes were made on later treatments.

An area of concern was the use of arsenic inhibitors in presence of H_2S in the produced gas. A change was made using an organic inhibitor for corrosion protection in an acid formulation of hydrochloric and formic acids. This procedure was continued on subsequent wells drilled in the area and provided adequate stimulation as shown in Table I.

The early wells completed in the Washita Creek area were all stimulated using organic acids and organic inhibitors. These wells, just as the ones in Buffalo Wallow, were realizing good production increases but the operators were becoming concerned with completion costs. All of the operators in the area were attempting to cut drilling time[2] to reduce costs and this carried over to completion. A great deal of work had been done in other areas using high concentration hydrochloric acid[3] for stimulating wells, but these treatments were performed at much lower bottom-hole temperature and corrosion was not a problem. The high concentration acid provides the most economical method of rock removal of any acids that have been used. This is shown in Table II. The work done by Ramey[4] provided a method of calculating volumes of fluid to be pumped for cool down prior to acid injection in order to have acceptable corrosion protection.

Laboratory tests have been run to determine safe exposure time for well equipment using various acid formulations at elevated temperatures. The results of these tests are shown in Table III. Based on these results, it was decided if bottom hole equipment could be cooled to 200 - 250°F range, then high concentration acid and an organic inhibitor could be used with minimum danger from corrosion.

FIELD APPLICATION USING CONCENTRATED HYDROCHLORIC ACID

The first stimulation treatment using concentrated hydrochloric acid on a Hunton lime well was performed in September, 1969. The computer cool down program was used to calculate pad volumes for cooling well equipment to less than 240°F. The treatment was performed in the following manner:

Perforations:	19,512 - 19,522 19,546 - 19,556 19,576 - 19,596 19,756 - 19,766 19,830 - 19,840 19,870 - 19,910
BHT	360°F
Injection Rate	20 BPM
Maximum Pressure	9000 psi
Minimum Pressure	2900 psi
Fluid Pumped	750 bbls fresh water - cool down pad 720 bbls 28% inhibited HCl 480 bbls fresh water overflush

The treatment was done in four equal stages with ball sealers for diverting.

The well was cleaned up and tested for COF of 2750 MMCF/day.

Since the completion of this first well, with the high strength acid, eight more wells have been completed in a similar manner in the Washita Creek and Buffalo Wallow fields. This same technique has been applied to other Hunton zones in shallower portions of the basin with excellent results.

MORROW COMPLETIONS

The Morrow sandstone has proved to be another prolific gas producer in both the Buffalo Wallow and Washita Creek Fields. Several twin wells have been completed in the Upper Morrow zone in Buffalo Wallow.

The Morrow is a high pressure zone but normally must be stimulated in order to provide adequate production. The stimulation is a two stage process consisting of:

1. Hydrochloric-hydrofluoric acid for clean-up.

2. Gelled water fracture treatment with a mixture of 20-40 sand and 12-20 glass beads as propping material.

The fracturing treatment volumes are quite large, ranging from 60,000 gallons to 140,000 gallons. In most cases, the propping material is mixed at a ratio of 70 per cent sand to 30 per cent beads. The normal treatment pressures range from 6500 psi to 10,000 psi and injection

Downloaded from http://admin.onepetro.org/specpr/proceedings-pdf/70CPR/All-70CPR/SPE-3160-MS/2692307/spe-3160-ms.pdf by guest on 30 November 2023

rates of 20-25 BPM. The results of some Morrow treatments are found in Table IV.

An attempt was made recently to complete in the lower Morrow A and B sands. A matter of concern was being able to maintain viscosity for prop transport at BHT (280°F) in this well. The decision was made against using a large volume of water as a cool down pad, in order to use conventional natural polymer gels. The recently developed crosslinked natural polymer gels were tested at this elevated temperature and found to have a viscosity of 100 centipoises and were able to maintain this viscosity for three hours. This zone was successfully treated at a pressure in excess of 10,000 psi with no screenout. The treatment is listed as Well B in Table IV.

WORKOVERS FOR SCALE CLEAN-UP

Many of the operators in the area have been concerned about corrosion and scale during the production of their wells. It is not the intent of this paper to discuss this in detail but only to point up the concern and methods being used to monitor for problems.

The earlier completed wells have had some decrease in deliverability and loss of tubing pressure. Laboratory tests have been run on scale samples taken from separators and also from tubing that has been pulled from wells. These samples have been identified as iron oxide, siderite ($FeCO_2$) and magnetite (Fe_3O_4). A few traces of calcium carbonate and calcium sulfate have also been identified. Periodic water analyses are run on all produced waters taken from Buffalo Wallow wells. The following analysis was run August 9, 1970.

Formation - Hunton
Field - Buffalo Wallow

Dissolved Solids:

Cations	mg/l
Sodium, Na (calc)	625
Calcium, Ca	100
Magnesium, Mg	33
Barium	N.F.
Strontium	N.F.
Anions	
Chloride, Cl	550
Sulfate, SO_4	2
Bicarbonate, HCO_3	780
Total dissolved solids (calc)	2090
Iron, Fe (total)	9
Sulfide, as H_2S	None

Other Properties:

pH	6.63
Specific Gravity	1.001 at 78°F

One of the operators in the area was experiencing a sizeable loss in deliverability. A pressure build-up was run on one well to determine if a skin did exist. The calculations made from this build-up showed a skin of +2.49 and a differential across the skin of 2232 psi. Based on this interpretation of the build-up, a clean-up was designed by the operator to eliminate this damage. It was decided that first the tubular equipment must be cleaned before any attempt to remove damage from the formation could be undertaken. The procedure was as follows:

1. Pump 1260 gallons 10% formic acid with organic inhibitor.
2. Pump 80 barrels produced water containing organic inhibitor and 300 SCF N_2/bbl.
3. Pump 34 barrels produced water containing 500 SCF N_2/bbl.

The well was opened immediately and samples taken of returned fluid were analyzed for iron on location. The fluid reached a maximum of 23,000 ppm iron in solution and then declined. It was decided from this that all the scale was removed from the tubing. The clean-up then proceeded.

1. Pump 160 barrels produced water to cool down, the last 30 barrels to contain organic inhibitor.
2. Pump 9000 gallons 28 per cent hydrochloric acid containing organic inhibitor, use 6 ball sealers.
3. Pump 30 barrels produced water containing organic inhibitor.
4. Flush with 118 barrels produced water containing 500 SCF N_2/bbl.

The well was opened immediately and allowed to clean up. The well produced at a rate of 17.5 MMCFD with F.T.P. of 2500 psi prior to clean-up. The well was tested after clean-up to produce 16.2 MMCFD with F.T.P. of 4125 psi. This increase in flowing pressure compares favorably with the calculated differential across skin, so operator feels damage has been removed.

HIGH TEMPERATURE CORROSION TESTING

The corrosion problem that exists in the Hunton producing zone has caused a great deal of concern to operators in the area. This in

Downloaded from http://admin.onepetro.org/specpr/proceedings-pdf/70CPR/All-70CPR/SPE-3160-MS/2692307/spe-3160-ms.pdf by guest on 30 November 2023

turn has led to a great deal of testing both in the laboratory and in the field in an effort to learn more of this problem.

Some tests have been made at temperatures above 300°F in an attempt to determine protection levels that could be obtained with available inhibitors. The average protection level at 100 ppm inhibitor on 1010 mixed steel was 86 per cent. Metal blistering is essentially eliminated with the inhibitor that was tested. Further testing is currently in progress to determine methods of overcoming this problem completely.

The testing procedure and complete results are listed in the appendix in Tables V and VI.

CONCLUSIONS

1. The use of high concentrations of hydrochloric acid will provide the best and most economical results in the Hunton Section.

2. The organic inhibitor used in acidizing will provide excellent corrosion protection by using adequate cool down fluid volumes prior to acid injections.

3. The build-up of scale can be controlled by periodic clean-up with proper acid formulations.

4. The Morrow zone requires large volume fracture stimulation.

5. Research must be continued by all parties concerned to further define and find solutions for corrosion and scale problems.

ACKNOWLEDGEMENTS

The authors wish to express appreciation to Dowell Division of The Dow Chemical Company for permission to publish this paper. We also wish to thank Gulf Oil Corporation and Union Oil Company of California for their aid in gathering information.

REFERENCES

1. Crenshaw, P. L. and Flippen, F. F., "Stimulation of the Deep Ellenburger in the Delaware Basin," SPE 2075, presented at SPE Deep Drilling Symposium in Monahans, Texas, March, 1968.

2. Berry, S. C., "Deep Drilling Practices in the Texas Panhandle," API Paper No. 851-44-F, presented at Spring meeting of Mid-Continent District, Wichita, Kansas, April, 1970.

3. Harris, O. E., Hendrickson, A. R., and Coulter, A. W., "High-Concentration Hydrochloric Acid Aids Stimulation Results in Carbonate Reservoirs," Jr. Pet. Tech., October, 1966, 18, No. 10, 1291.

4. Ramey, H. J., "Wellbore Heat Transmission," Trans. AIME, 225, 427 (1962).

APPENDIX

Procedure

Metals Coupons

5 mil shimstock, stock no. S-50 (1010 mild steel) 6 inches long and 1/2 inch wide

Fluids Used

Brine saturated with hydrogen sulfide and containing:

10% NaCl
0.5% $CaCl_2$
.08% glacial acetic acid

Oil phase used was kerosene saturated with hydrogen sulfide.

Test Cells

Test cells were of 304 stainless steel. These cells were one inch in diameter, 10 inches in length and capped on both ends.

Test cells were filled with a 1 per cent solution of corrosion inhibitor in fresh water and allowed to stand for 30 minutes. The solution was removed and cells were flushed with water (5 cell volumes) and then allowed to drip dry. Each cell was filled with 100 ml of brine (see above) and 10 ml of kerosene (see above). This volume of fluid in the cell allows for a 40 cc gas space for expansion. Varying amounts of corrosion inhibitor were added to the fluid-containing cells. The preweighed coupons, which were cradled on each end with Teflon to prevent metal-metal contact and galvanic corrosion, were placed in the cells. Each cell was then flushed with H_2S and capped.

The cells were placed in a 300-325°F oil bath for 16 hours. At the completion of the 16 hours, the cells were removed from the bath, cooled to room temperature and opened. The coupons were removed and cleaned. Cleaning the coupons consisted of placing all coupons in inhibited 15 per cent HCl for approximately 10 minutes. Each coupon was then washed with a brush and water, placed in acetone and then removed for drying and re-weighing.

Downloaded from http://admin.onepetro.org/specpr/proceedings-pdf/70CPR/All-70CPR/SPE-3160-MS/2692307/spe-3160-ms.pdf by guest on 30 November 2023

TABLE I

Hunton Zone

Well	Field	Treatment on Completion	Results	Remarks
A	Buffalo Wallow	23,000 gallons formic-acetic acid mixture - arsenic inhibitor - clean-up	6 MMCFD - Natural 14 MMCFD - Clean-up	
		100,000 gallons hydrochloric-acetic acid mixture - arsenic inhibitor - stimulation	70 MMCFD - Stimulation	
B	Buffalo Wallow	100,000 gallons hydrochloric-acetic acid mixture - arsenic inhibitor	1.8 MMCFD - Natural 82 MMCFD - Stimulation	This well has been acidized three times to clean up scale
C	Buffalo Wallow	100,000 gallons hydrochloric-acetic acid mixture - arsenic inhibitor	9.5 MMCFD - Natural 80 MMCFD - Stimulation	This well treated 5/70 with formic acid and 28 per cent HCl to clean up scale
D	Buffalo Wallow	22,000 gallons hydrochloric-formic acid mixture - organic inhibitor	40 MMCFD - Natural 120 MMCFD - Clean-up	
		100,000 gallons hydrochloric-formic acid mixture - organic inhibitor	350 MMCFD - Stimulation	
E	Buffalo Wallow	30,000 gallons hydrochloric-formic acid mixture - organic inhibitor	31 MMCFD - Natural ? - Stimulation	This well retreated 1970 with 30,000 gallons 28 per cent HCl acid
F	Buffalo Wallow	30,000 gallons 28 per cent hydrochloric acid - cool down pad - overflush - organic inhibitor	? - Natural 2750 MMCFD - Stimulation	
G	Buffalo Wallow	40,000 gallons 28 per cent hydrochloric acid - cool down pad - overflush - organic inhibitor	? - Natural 800 MMCFD - Stimulation	
H	Buffalo Wallow	Cool down pad - 80,000 gallons gelled pre-pad - 40,000 gallons 28 per cent hydrochloric acid - 40,000 gallons fresh water overflush - organic inhibitor - 4 stages	? - Natural 88.6 MMCFD - Stimulation	
I	Washita Creek	Cool down pad - gelled pre-pad - 40,000 gallons 28 per cent hydrochloric acid - fresh water overflush - organic inhibitor	? - Natural 275 MMCFD - Stimulation	
J	Unnamed	Cool down pad - 22,500 gallons 28 per cent hydrochloric acid - fresh water overflush - organic inhibitor	? - Natural 140 MMCFD - Stimulation	Perforations 16,815 - 16,896

Downloaded from http://admin.onepetro.org/specpr/proceedings-pdf/70CPR/All-70CPR/SPE-3160-MS/2692307/spe-3160-ms.pdf by guest on 30 November 2023

TABLE II

Comparison of Acids

Acid System	Limestone Dissolved (lb/1000 gallons)	Cost/1000 gallons of Acid Inhibited to 250°F*	Removal Cost (¢/lb)
15% Hydrochloric Acid	1840	300.00	16.3
20% Hydrochloric Acid	2500	391.00	15.5
28% Hydrochloric Acid	3670	515.00	14.05
HCl-Acetic	2384	600.00	25.1
HCl-Formic	2455	590.00	23.1

* All acid formulations inhibited with an organic inhibitor

TABLE III

Protection Time* (Hrs.) of N80 Oil Field Tubing Exposed to Acid Containing Optimum Amount of Inhibitor @ 250°F

Acid System and Per Cent	Type Inhibitor System			
	Arsenic[1]	Organic[2]	Organic[3]	Organic[4]
15% Hydrochloric Acid	16	10	--	10
20% Hydrochloric Acid	16	N	2c	2
28% Hydrochloric Acid	X	N	2c	2
15.5% HCl-7.9% Acetic	--	8	—	—
13.8% HCl-8.8% Formic	--	8	—	—

* Time for removal of 0.05 lbs/ft^2 with no pitting
X Severe pitting
N Excessive metal loss with minor pitting
c Excessive cost

1 Arsenic compound
2 Organic nitrogen compounds
3 (2) with inhibitor aid
4 Organic nitrogen compounds

Downloaded from http://admin.onepetro.org/specpr/proceedings-pdf/70CPR/All-70CPR/SPE-3160-MS/2692307/spe-3160-ms.pdf by guest on 30 November 2023

TABLE IV

Morrow Zone

Well	Field	Interval	Clean-up	Stimulation	Results
A	Washita Creek	13,550-13,590	6,000 gals. hydro-chloric-hydrofluoric Ball sealers	60,000 gals. gelled salt water 28,000 lbs. 20-40 sand 12,000 lbs. 12-20 beads Ball sealers	7 MMCFD - after acid 20 MMCFD - after frac
B	Buffalo Wallow	15,876-15,912	8,000 gals. formic - hydrofluoric acids + surfactant Ball sealers	80,000 gals. gelled water 35,700 lbs. 20-40 sand 16,300 lbs. 12-20 beads Ball sealers IR - 18 BPM P_s - 10,000 psi	Water - after frac
C	Buffalo Wallow	14,009-14,035		30,000 gals. gelled water 12,600 lbs. 20-40 sand 5,900 lbs. 20-40 beads IR - 18 BPM P_s - 10,000 psi	19 MMCFD - after frac
D	Buffalo Wallow	13,658-13,880	10,000 gals. formic - hydrofluoric acid Ball sealers	130,000 gals. gelled water 51,000 lbs. 20-40 sand 19,000 lbs. 12-20 beads Ball sealers IR - 20 BPM P_s - 8,700 psi	50 MMCFD - after frac
E	Buffalo Wallow	13,918-13,964	5,000 gals. hydro-chloric-hydrofluoric + surfactant 1,000 gals. 7.5% hy-drochloric 4,000 gals. 7.5% hy-drochloric + clay stabilizer Ball sealers	84,000 gals. gelled water 31,000 lbs. 20-40 sand 29,000 lbs. 12-20 beads Ball sealers IR - 20 BPM P_s - 4,000 psi	82.5 MMCFD after frac
F	Buffalo Wallow	13,890-13,965 15,500-15,505	8,000 gals. hydro-chloric-hydrofluoric + surfactant 2,000 gals. 7.5% hy-chloric 6,400 gals. 7.5% hy-drochloric + clay stabilizer Ball sealers	135,000 gals. gelled water 49,600 lbs. 20-40 sand 46,400 lbs. 12-20 beads Ball sealers IR - 25 BPM P_s - 8,000 psi	61 MMCFD - after acid 265 MMCFD after frac
G	Buffalo Wallow	14,142-14,479	4,500 gals. hydro-chloric-hydrofluoric + surfactant 1,500 gals. 7.5% hy-hydrochloric 3,000 gals. 7.5% hy-chloric + clay stabilizer Ball sealers	84,000 gals. gelled water 31,000 lbs. 20-40 sand 29,000 lbs. 12-20 beads Ball sealers IR - 20 BPM P_s - 9,000 psi	6 MMCFD - after acid 28 MMCFD - after frac

Downloaded from http://admin.onepetro.org/specpr/proceedings-pdf/70CPR/All-70CPR/SPE-3160-MS/2692307/spe-3160-ms.pdf by guest on 30 November 2023

TABLE V

Corrosion Protection Levels at Varying Concentrations of Corrosion Inhibitor at 325°F on 1010 Mild Steel

Test Run	Conc (ppm)	Weight Loss (mg)	Per cent Protection
1	0	132.9	0
1	0	182.4	0
1	0	145.3	0
2	0	121.6	0
2	0	120.0	0
3	0	96.2	0
3	0	73.5	0
3	0	122.2	0
4	0	89.9	0
4	0	119.3	0
3	50	24.8	75
1	100	14.0	91
1	100	29.8	81
2	100	25.9	77
2	100	28.4	75
2	100	32.3	72
3	100	19.2	81
3	100	16.4	84
4	175	24.1	77
4	175	17.2	88
3	250	11.5	89
3	250	15.0	85
4	250	10.0	91
4	250	13.5	88
3	500	11.4	89
4	500	11.9	89
1	1000	11.9	89
1	1000	26.6	85
1	1000	18.4	88
2	1000	20.6	82
2	1000	11.7	90
2	1000	10.6	91

Note: Per cent of protection is based on weight loss of blanks of each run.

TABLE VI

Average Corrosion Protection Levels at Each Concentration Tested (325°F/1010 Mild Steel)

Total Number of Tests	Conc (ppm)	Per cent Protection
2	50	75
7	100	86.14
2	175	80.5
4	250	88.2
2	500	89.0
6	1000	87.5

Downloaded from http://admin.onepetro.org/specpr/proceedings-pdf/70CPR/All-70CPR/SPE-3160-MS/2692307/spe-3160-ms.pdf by guest on 30 November 2023