A NEW FRACTURING FLUID FOR THE CANYON SAND

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ABSTRACT

One of the primary concerns in completion practices for the Canyon Sand in Sterling, Schleicher, Sutton, and Crockett counties has been to balance possible formation damage with completion costs. The low productivity, and until very recently, the low gas prices for this area has made the use of "exotic" fracturing treatments very difficult to justify. The fluids were normally a gelled water or gelled weak acid system, often used with CO_2. In those instances where the treatments are performed via tubing, low injection rates often contributed to screenouts. The recent advent of cross linked water based fluids and more effective clay stabilizers has reduced both the screenout problems and formation damage. Within the last 8-12 months, a complexed weak acid system has been developed which has demonstrated a combination of most of the advantages of the other systems with very few disadvantages.

The ability to transport sand out to the drainage boundary is the ideal stimulation practice for almost any "tight" sand.[1] This idealized treatment, though, is often not economically justifiable due to the inefficient nature of the fracture fluid, especially the earlier fluids used in this area. In this paper, we will investigate the theoretical and practical aspects of pumping a complexed weak acid system. This system possesses a large number of the desired characteristics for use in the Canyon Sand -- high viscosity, low friction loss, low pH compatibility with CO_2, compatibility with clay stabilizers and fluorocarbon surfactants, low fluid loss, and excellent sand transport properties.

INTRODUCTION

One of the more active areas in West Texas is the gas play in Sterling, Schleicher, Crockett, and Sutton counties. The major target is the Canyon Sand of Pennsylvanian age. The sand is found over a large area, however it can vary widely from well to well even in the heart of the development.

The existence of gas in the Canyon Sand has been known for some time; however, until the last few years it was considered non commercial due to low gas prices and remote gas collecting lines.

The recent demand for natural gas has resulted in improved gas prices and the construction of major gas collecting lines in and throughout the area. Recently, the Federal Energy Regulatory Commission has declared that the Canyon Sand in six West Texas counties has been designated a tight gas sand from which production qualifies for high cost incentive pricing under the Federal Natural Gas Policy Act of 1978. The counties include Terrell, Crockett, Schleicher, Sutton, Val Verde, and Edwards counties (see Figure 1). Under the federal act, gas from FERC-designated tight gas sands can be sold at a price that is 200 percent of the going rate for production from new onshore wells.

Even with these favorable prices it is very important to use proper techniques in drilling and completing wells in order to secure a favorable return on investment. The fracturing job represents a sizeable portion of the cost of the well and the outcome of the well is very dependent on the results of this treatment. This paper is mainly concerned with the stimulation treatments in the Canyon Sand. It presents a new fluid which is felt to be the ideal fluid for the Canyon Sand.

FORMATION CHARACTERISTICS

The Canyon Sand is comprised of interbedded sand and shale. The sand itself is a well consolidated, fine grained sandstone. The sand is slightly argillaceous (clay bearing). The particle size of this silt is very small and can disperse in moving fluids. The sand is cemented predominately with siliceous material. There is a small amount of carbonate material present. The acid solubility of the formation will range about 2 to 5%. The porosity of the formation will range from 2 to 12%. The reservoir permeability ranges from 0.01 md to 0.10 md. This low permeability makes the productivity of the well almost totally dependent upon the imposed fracture system obtained by hydraulic fracturing. The bottom hole temperature will be in the range of 165° F to 195° F. The formation pressures vary from 1500 to 3000 psi with frac gradients ranging from 0.70 to 1.0 psi per foot.

STIMULATION PRACTICES

The proper selection of the stimulation fluid, volume, rate, and perforating pattern is very important in the completion and resultant productivity of Canyon Sand wells. Being a sandstone with low porosity and low permeability, the productivity obtained is almost totally dependent upon the imposed fracture system obtained by hydraulic fracturing. Deeply penetrating fractures are necessary to provide maximum drainage of the formation.

The sandstone is generally very fine grained, which means large surface areas and small pore spaces, which makes the zone inherently fluid sensitive in that any fluid into the matrix tends to be retained. The formation also contains enough clay bearing minerals to warrant that the fluid system exhibit properties to control damage due to clay swelling or fines migration.

In the past, various fluid systems have been concocted to serve as fracture fluid systems. As with almost any hydraulic frac in the Permian Basin, the concern for the Canyon is to place as much proppant as far away from the wellbore as practical, and then to recover the fluid with minimum damage to the formation. The various fluid systems attempted in the earlier history included gas frac (a combination of LPG, alcohol, and gelled water), foam frac, oil-water emulsion, gelled weak acid, and gelled 2% KCl water. Carbon dioxide or nitrogen was often incorporated with the two latter systems.[2] These systems provided a means for efficient load recovery, but low viscosity development of the gel systems dictated that overall sand concentrations were limited to 1 to 1-1/2 pounds per gallon. In the early 1970's, the first complexed gel fluids were introduced. These fluids exhibited the viscosity development necessary to carry larger quantities of sand, but were not compatible with CO_2 and also were high pH fluids, and so were much more damaging than the previous systems. More recent development of crosslinking agents have provided fluids that are low pH systems and compatible with CO_2. In spite of this, a large number of operators continue to use the gelled acid-CO_2 system due to previous success.

With the recent development of a cross-linked weak acid system, we can now realize all of the benefits of sand transport capability, acidic pH, compatibility with CO_2 and nitrogen, and compatibility with clay stabilizing additives.[2]

COMPARISON OF FLUID PROPERTIES

Since our studies indicate that gelled weak acid systems are currently the more widely used fracture fluid in the Canyon, we will compare the properties of the gelled acid to the new cross-linked acid. Referring to Table I, we can see that the viscosity of the cross-linked acid is almost ten-fold greater than the gelled acid (220 cp vs. 24 cp), which is expected. The other property which is not readily apparent, but which is very important is that the cross-linked acid exhibits (near) perfect sand transport.[3] The combination of excellent viscosity for greater width development along with excellent sand transport provides the ability to create the highly conductive fracture system required for maximum production from the Canyon.[4]

COMPUTER AIDED DESIGN COMPARISONS

In order to determine the effects of pumping the cross-linked acid as compared to the gelled acid, we have taken some typical formation properties for the Canyon, as shown in Table II.

The effect of fluid volume on penetration was first considered. Figures 2 and 3 indicate the results of this study, indicating not only volume and penetration, but also volume vs. created width.[5] For 160 acre well spacing in order to achieve maximum penetration of the drainage radius (±1300') requires a slurry volume of 140,000 gallons of cross-linked acid and sand. The same slurry volume of gelled acid penetrates only 750 feet. The primary reason for this variation in penetration is due to the leak-off control of the cross-linked system. Figures 4 and 5 are graphic representations of the temperature profile of the fluid within the frac system at the end of the treatment.[5,6] The smooth temperature distribution shown for the cross-linked acid (Figure 5) is indicative of a fluid with low leak-off properties. The sharp upswing of the curve in Figure 4 is normal for fluids with poor fluid loss control.

We must also analyze the economics involved in recommending the cross-linked acid system. As would be expected, the cross-linked system is more expensive on a per-gallon basis than the gelled acid. Figure 6 indicates total job cost for varying fluid volumes. As shown, the cost for a 140,000 gallons job with cross-linked acid is about $103,000. The same volume of gelled acid would cost $84,000.

Since we are creating a longer and more highly conductive fracture with the cross-linked fluid, we can anticipate a higher productivity increase for the same volume.[7] Table III is from a computer study which shows the anticipated sand concentration profile of our theoretical treatment. The treatment consists of 120,000 gallons of cross-linked acid and 432,000 lbs. (19,440 gallons) of sand at concentrations varying from 1 ppg. to 8 ppg.[5] As shown, the sand concentration within the fracture averages approximately two (2) pounds per square foot of created area. In order to achieve a similar concentration with a banking fluid, such as gelled aicd, it would be necessary to achieve an equilibrium sand bank, which would require a volume of approximately 340,000 gallons, which would almost certainly not be economically feasible.[5] We have chosen, then to compare the above cross-linked acid treatment with a gelled acid treatment consisting of 131,000 gallons of fluid and 200,000 lbs. (9,000 gallons) of sand. A productivity increase analysis (Figure 7) indicates the difference in J/Jo for the two treatments (see also Tables IV and V.[7,8] As shown, the cross-linked acid treatment should give a productivity increase of 12.2, while an equal volume of gelled acid should have an 8.1 index.

Finally, we have established a "true cost curve", which indicates J/Jo versus cost for the two systems. This curve indicates that even if one spends the same amount of money ($103,000) for the gelled acid system, the anticipated J/Jo is increased to only 8.8, while the J/Jo for cross-linked acid is still greater than 12.

At the date of this writing eight (8) treatments have been performed with the cross-linked acid system in the area of concern. No adequate production data has been gathered to indicate whether or not the theoretical predictions are valid. We can make the following observations:

(1) In four (4) treatments in Sterling County, we have placed sand at concentrations of up to 6 ppg. in an area where screen-outs were common at 3 ppg.

(2) In Crockett County, in the Ozona Canyon field, a zone that had previously been screened-out with gelled acid at 10 BPM, the zone was refractured with cross-linked acid at 4 to 6 BPM and up to 2 ppg. with no screen-out.
(3) The only sand-out with the cross-linked acid experienced thus far was on a well that had had screen-out problems twice previously with gelled weak acid.

CONCLUSIONS

(1) Cross-linked weak acid offers many benefits that are desirable for stimulation of a tight gas sand, such as the Canyon.
(2) Cross-linked weak acid can be shown to be more cost effective than similar volumes of a less expensive gelled weak acid system.
(3) Initial treatments indicate that the fluid can be successfully utilized in the Canyon sand.

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AREA OF STUDY

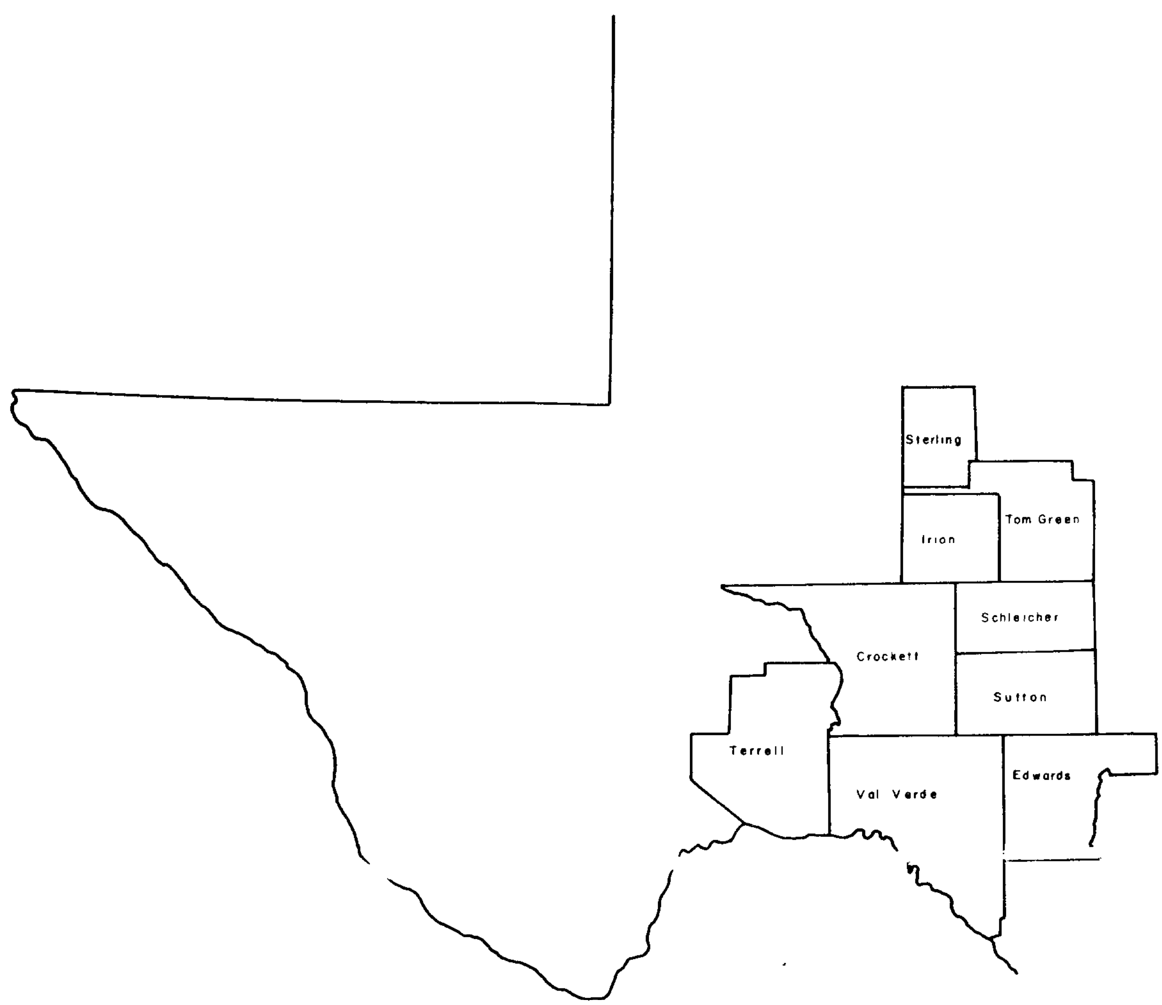

FIGURE 1

STIMULATION DESIGN CURVE

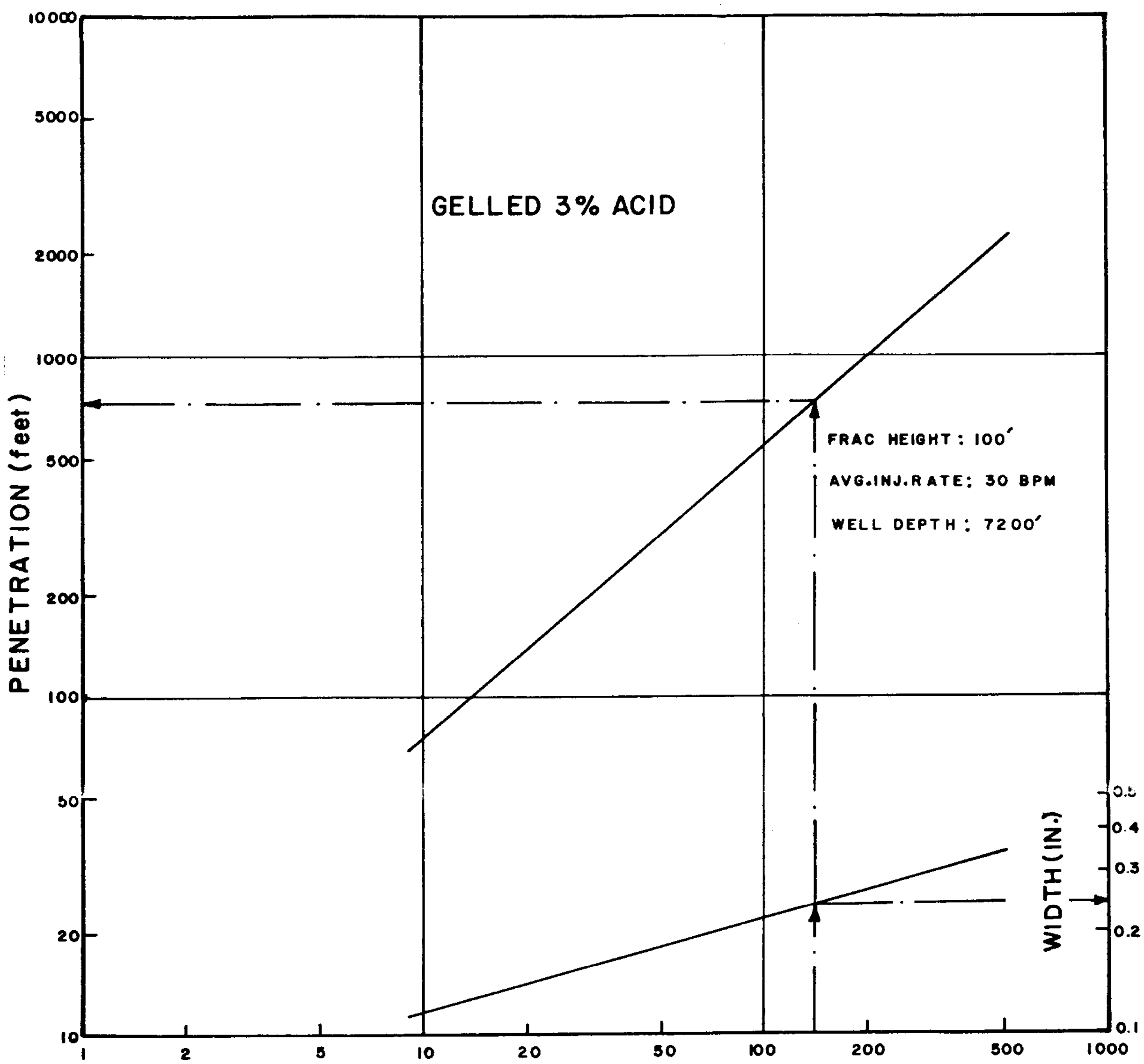

FIGURE 2—SLURRY VOLUME X 1,000 GALLONS

STIMULATION DESIGN CURVE

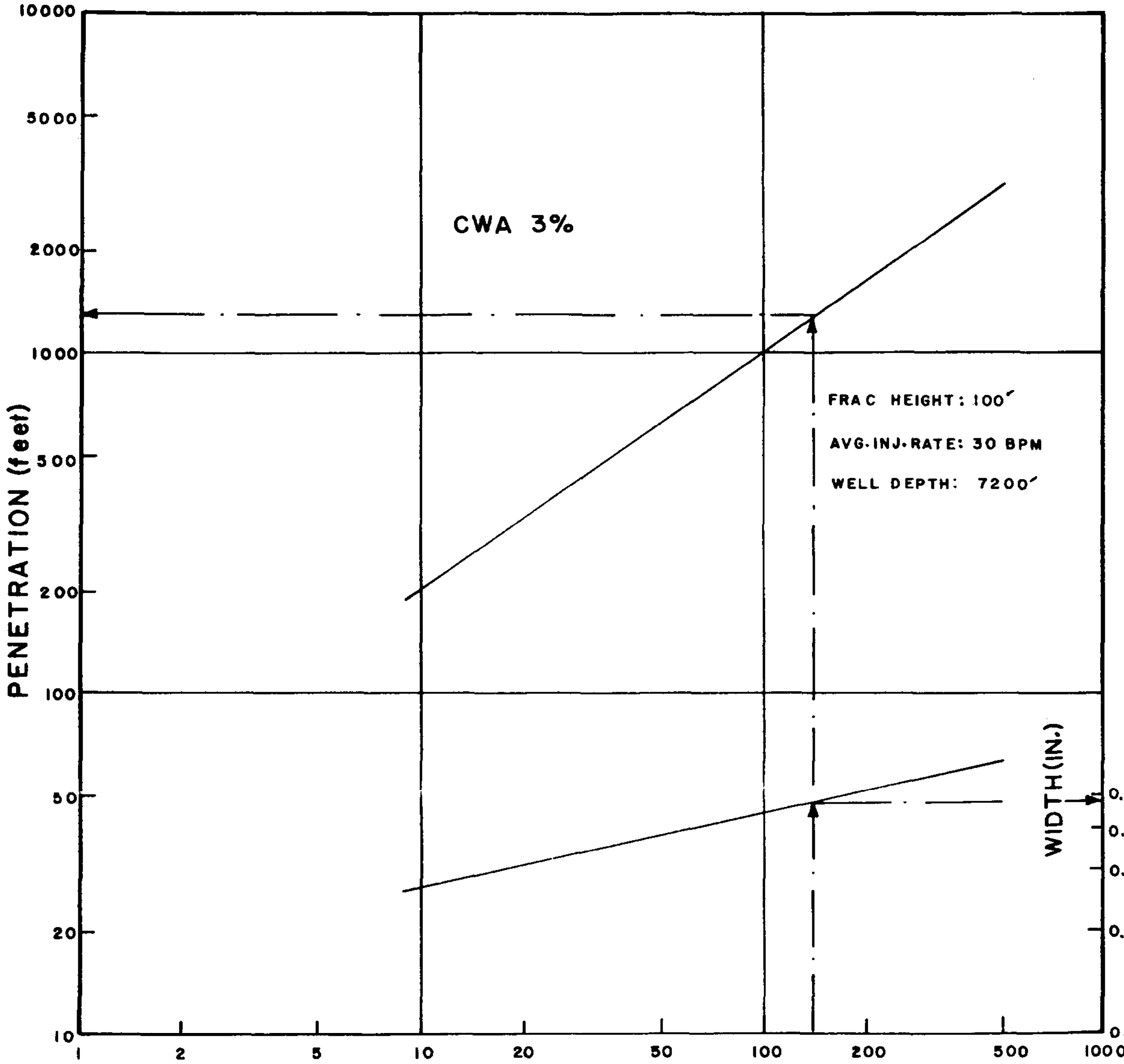

FIGURE 3—FRAC FLUID VOLUME X 1,000 GALLONS

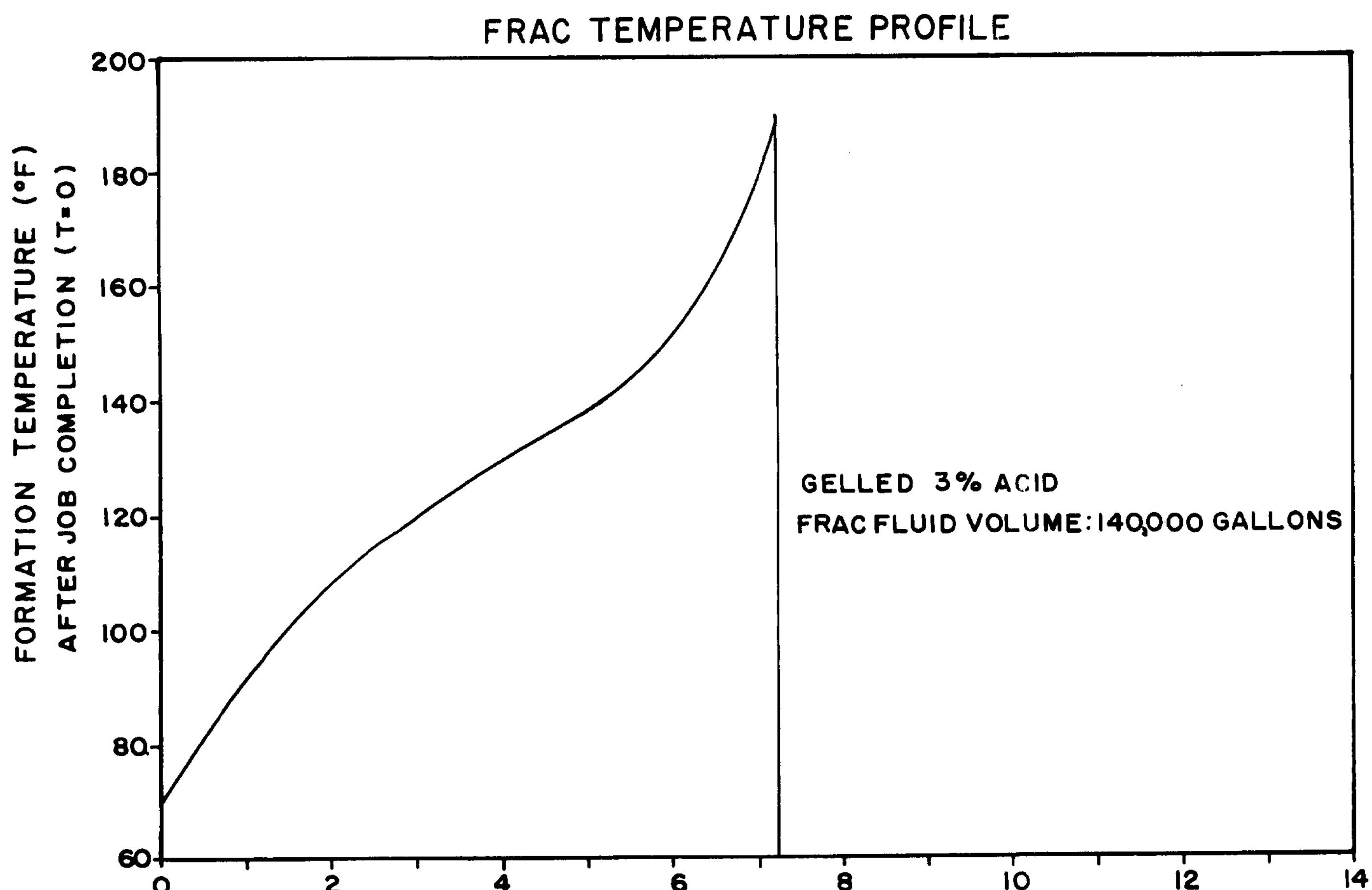

FIGURE 4—FRAC PENETRATION X 100 FEET

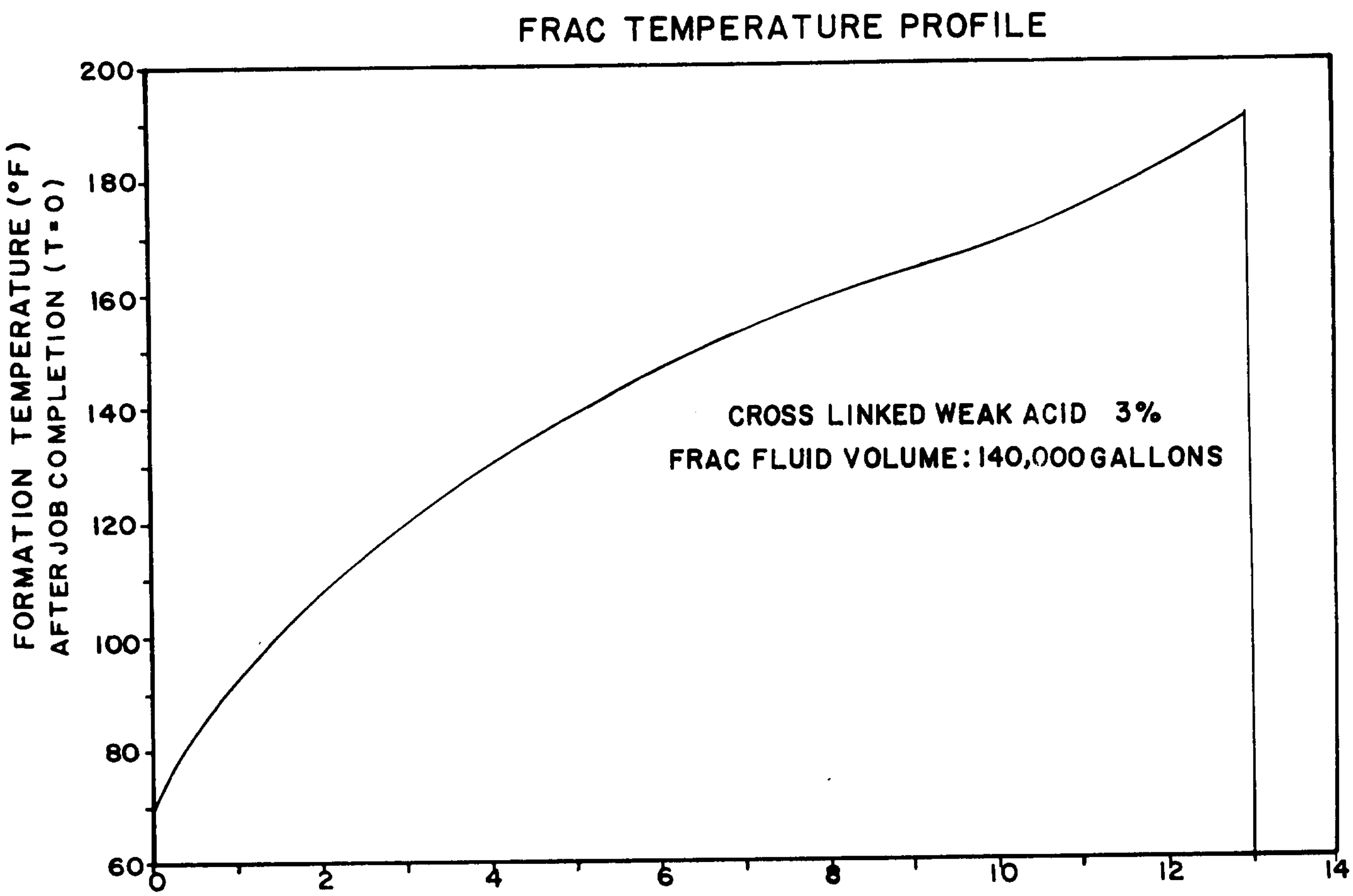

FIGURE 5—FRAC PENETRATION X 100 FEET

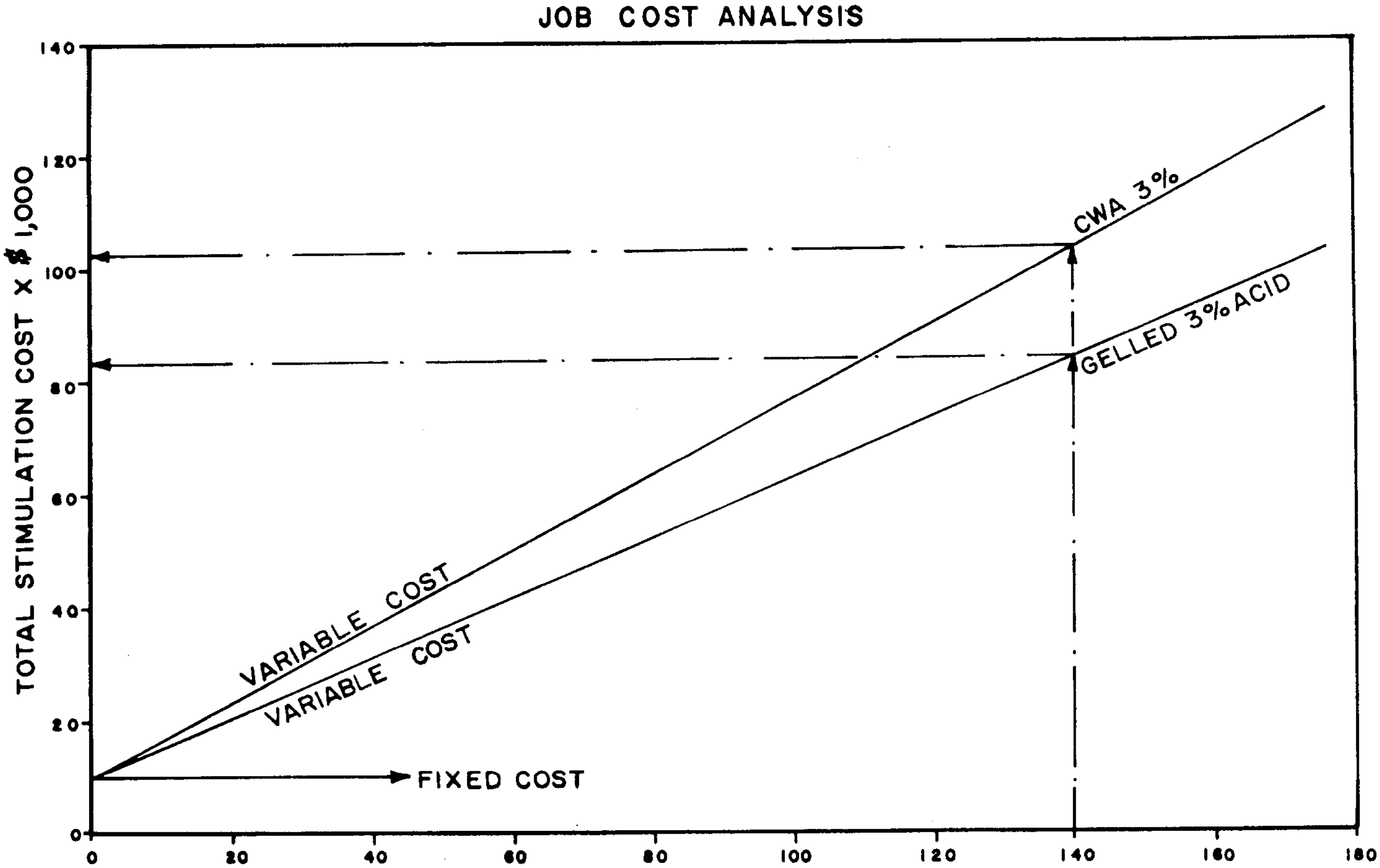

FIGURE 6—FRAC FLUID VOLUME X 1,000 GALLONS

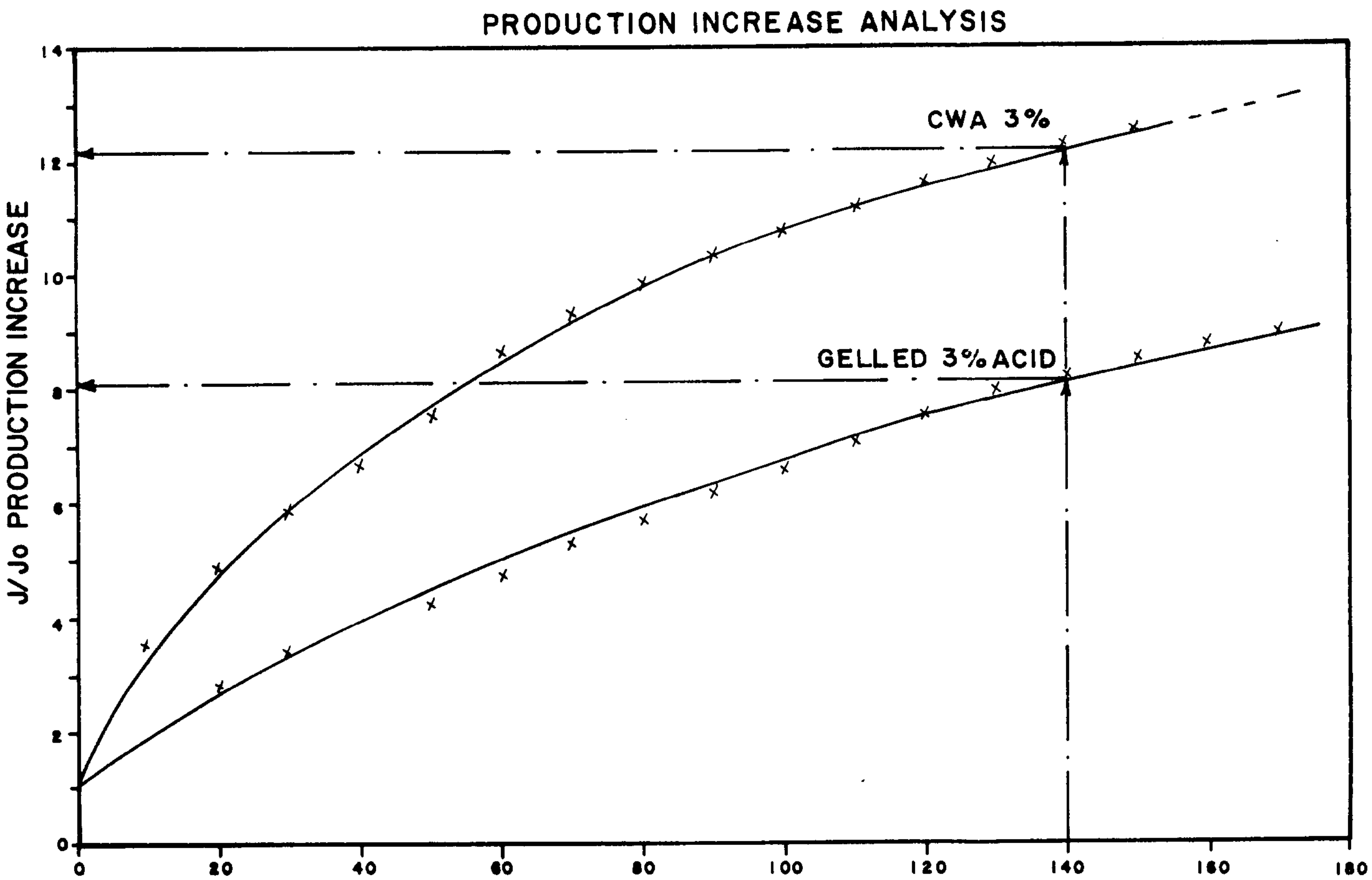

FIGURE 7—FRAC FLUID VOLUME X 1,000 GALLONS

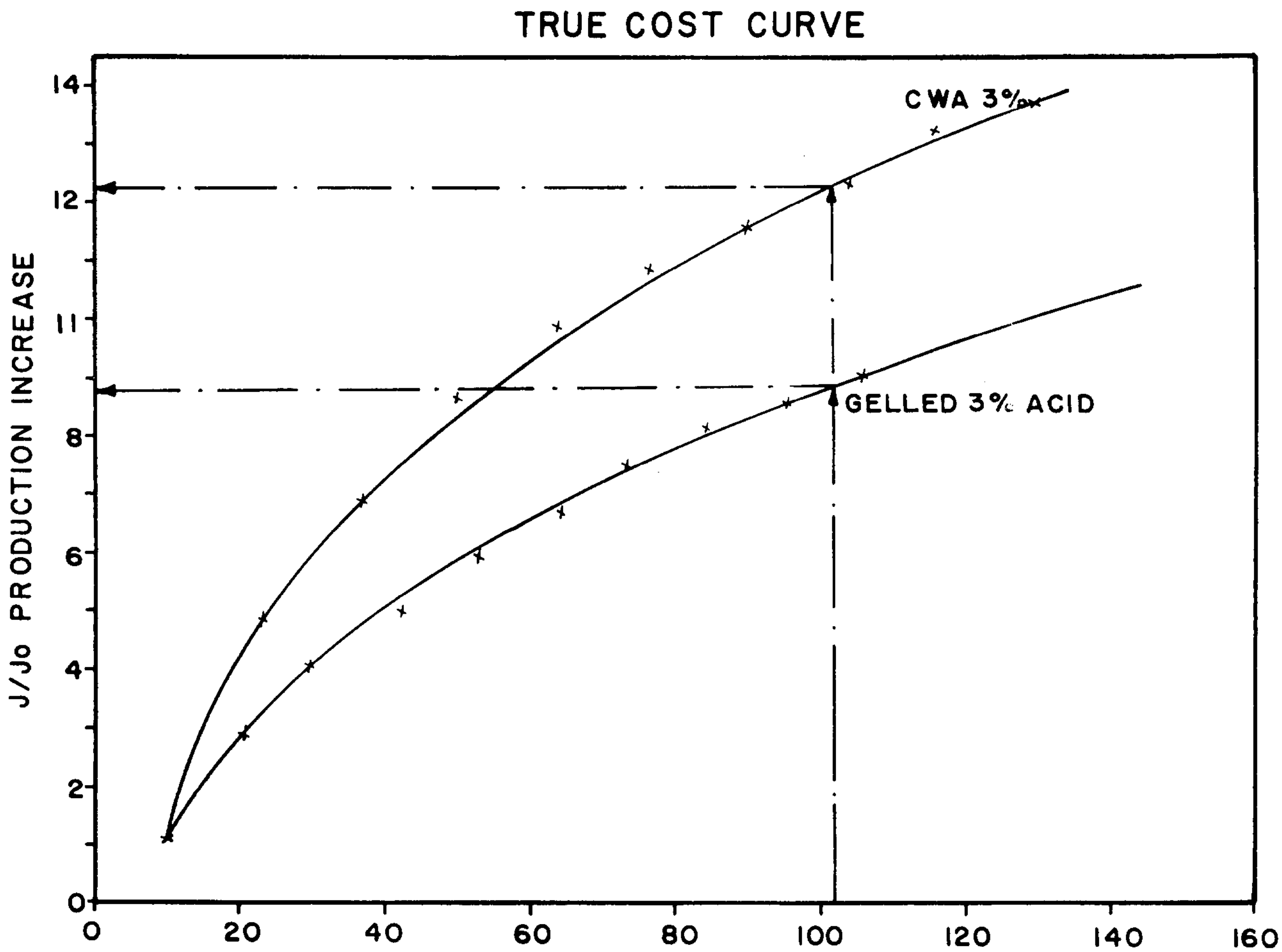

FIGURE 8—TOTAL STIMULATION COST X $1,000

TABLE 1—FRACTURING FLUID PROPERTIES

	GELLED ACID	COMPLEXED ACID
n'	.574	0.57
k' (lb_f - $sec^{n'}/ft^2$)	.00705	0.045
Viscosity (cpl @ 170 sec^{-1})	24	220
C_{III} @ 1000 psi ($ft/min^{\frac{1}{2}}$)	.0014	0.0015
Spurt Loss (c.c.)	21	3.2
Average Fluid Temperature (^{O}F)	160	160

TABLE 2—ASSUMED RESERVOIR PROPERTIES

Depth	7200 feet
Bottom Hole Frac Pressure	6000 psi
Reservoir Pressure	2200 psi
Young's Modulus	6×10^6 psi
Reservoir Fluid Viscosity	0.02 cp
Reservoir Fluid Compressiblity	2.6×10^{-4} psi^{-1}
Formation Height	100 feet
Permeability	0.01 md
Porosity	8%
Bottom Hole Temperature	190° F

TABLE 3—PROPPANT PROFILE STUDY CWA 3%

FLUID VOLUME (GAL.)	SURFACE PROPPANT (LB./GAL.)	LOCATION IN FRACTURE (FT.)	FRACTURE PROPPANT (LB./FT^2)	CUMULATIVE PROPPANT (LB.)	CUMULATIVE SLURRY VOLUME (GAL.)
24,000	0	1149 - 1278	0.000	0	24,000
12,000	1.0	1073 - 1149	0.789	12,000	36,544
12,000	2.0	986 - 1073	1.372	36,000	49,632
12,000	3.0	884 - 986	1.775	72,000	63,265
12,000	4.0	766 - 884	2.024	120,000	77,442
12,000	5.0	625 - 766	2.140	180,000	92,162
12,000	6.0	458 - 625	2.144	252,000	107,427
12,000	7.0	253 - 458	2.055	336,000	123,237
12,000	8.0	0 - 253	1.892	432,000	139,591

TABLE 4—PRODUCTION INCREASE ANALYSIS GELLED 3% ACID

VOLUME (gal.)	PENETRATION (feet)	L/Re*	J/JO
10,000	75	0.06	
20,000	137	0.10	2.91
30,000	194	0.15	3.46
40,000	249	0.19	3.91
50,000	301	0.22	4.19
60,000	354	0.27	4.73
70,000	405	0.31	5.23
80,000	452	0.34	5.64
90,000	502	0.38	6.19
100,000	555	0.42	6.50
110,000	600	0.45	7.05
120,000	644	0.49	7.55
130,000	698	0.53	7.92
140,000	740	0.56	8.19
150,000	790	0.60	8.65
160,000	835	0.63	8.78
170,000	875	0.66	8.97
180,000	920	0.69	9.10
190,000	965	0.73	9.46
200,000	1000	0.76	9.6

*Well Spacing = 160 acres.

TABLE 5—PRODUCTION INCREASE ANALYSIS CWA 3%

VOLUME (gal.)	PENETRATION (feet)	L/Re*	J/JO
10,000	202	0.15	3.56
20,000	330	0.25	4.82
30,000	440	0.33	5.82
40,000	535	0.41	6.73
50,000	630	0.48	7.64
60,000	710	0.54	8.74
70,000	795	0.60	9.37
80,000	870	0.66	9.83
90,000	945	0.72	10.36
100,000	1010	0.77	10.74
110,000	1090	0.83	11.27
120,000	1170	0.89	11.65
130,000	1225	0.93	11.97
140,000	1295	0.98	12.33
150,000	1360	1.03	12.65

*Well Spacing = 160 acres.