A CLOSER LOOK AT STIMULATION DESIGN OPTIMIZATION

D. K. BARRINGER AND V. J. PAI

THE WESTERN COMPANY OF NORTH AMERICA

ABSTRACT

The rapid expansion of the petroleum industry has caused a shortage of experienced field personnel. Even though there are volumes upon volumes written regarding specific stimulation techniques and processes, one finds that many of the routine aspects of performing these treatments are overlooked. We will look specifically at a study of optimized perforation costs in relation to hydraulic horsepower requirements, optimization of stimulation fluids - first in terms of unit cost, and then take a particular fluid and look at treatment cost compared to productivity increase.

INTRODUCTION

With the present availability of the computer and numerous computer models one can calculate (theoretically) the exact volume of fluid and weight of sand necessary to achieve any given penetration into a reservoir. The preciseness that is so easily arrived at on paper is not so easily transferred to field conditions. We will go through a theoretical job design and point out a few of the ways in which we can take theories, combine them with some real world practicalities and end up with sound stimulation treatment designs. The example well on which our calculations are based are shown in Table I.

PERFORATING COST VERSUS HORSEPOWER REQUIREMENTS

A study was made by B. J. Bucy in 1959 regarding this subject.[1] In his paper, Bucy states that statistical data indicated no appreciable differences between cased hole completions with a reduced number of perforations and open hole completions. In those instances where the so-called "Limited Entry Technique" is to be employed, it is necessary to optimize the number of perforations in regard to hydraulic horsepower requirements.

By taking the various equations for perforation friction pressure, hydraulic horsepower costs and perforating costs, we can combine them to obtain the following expression:

$$Y = A+B+C(X-Z) + \frac{0.00911\ Q^3\ D\ H}{d^4 \cdot X^2} \qquad (1)$$

One can then take this expression and, using a hand calculator, rather easily develop a graph to predict the optimum number of perforations for any given injection rate. Realizing the vast number of potential situations, we will consider only two cases - one in which the zone will be perforated with one (1) 0.4" diameter hole per foot, and the other where a zone is perforated with one (1) 0.375" diameter hole per foot.

For the 0.4" diameter perforations (Figure 1), we can see that for the three (3) injection rates, the optimum number of perforations is approximately equal to the injection rate. For the 0.375" diameter perforations (Figure 2), the optimum lies at 15 holes for 20 BPM, 24 holes for 30 BPM and 32 holes for 40 BPM, which is about 1.25 BPM per hole. These types of curves can be developed for virtually any perforating method, and could be used to design a modified limited entry situation.

FRACTURING FLUID COSTS

The number and types of fracturing fluids available today are numerous. With the use of such additives as special surfactants, fluid loss agents, clay stabilizers, temperature stabilizers, etc., the variations become almost limitless. Table II is a small comparison of the more popular systems in use today in terms of cost per 1,000 gal. For simplicity we have also indicated a cost for 20-40 mesh sand at 2 ppg average concentration. The Fixed Costs shown represent an average cost for equipment required to treat our example well. We can thus select a particular fluid system, a total volume and calculate a total job cost. There are incidentals which do not appear in this cost (tank rental, flush chemicals, transport charges, etc.), but probably the only significant cost that does not appear is the cost for the hydrocarbons in those two systems. The cost for the lease oil, condensate, or kerosene for these systems normally represents a fairly high initial investment, but the total use cost is not that great as they command a good resale value.

METHODS FOR OPTIMIZING TREATMENT COSTS

Using the parameters previously described in Table I for our example well conditions, we will now select two of the fluid systems from Table II and attempt to select the one which is more cost effective. We will show which fluid gives the higher productivity increase for less total cost.[2] The two fluids chosen are the HPG (Hydroxy Propyl Guar) system, which we shall call System I, and the HPG plus 5% hydrocarbon, which shall be termed System II.

By using computer models, we can rapidly develop sufficient data to plot several different sets of curves for both System I and System II.[3,4] The data generated is shown in Figure 3, 4 and 5. Figure 3 shows the volume-penetration relationship for the indicated conditions. As shown, System II is the more efficient system. For example, at 800 feet penetration, the required volume of System II is 32,000 gal. as opposed to 55,000 gal. of System I. Figures 4 and 5 indicate the relationship between penetration and injection rate at a constant volume for each of the two systems. These figures are a dramatic indication that, under the specified conditions, the amount of additonal penetration achieved with injection rates greater than 10 BPM is hardly worth the additional HHP costs.

The final evaluation to be made involves use of virtually all the previous tables and graphs, in addition to the McGuire & Sikora Productivity Increase Curve (Figure 6), to summarize our data and predict the optimum fluid system, injection rate and volume to stimulate our hypothetical well. This figure indicates that System II, even though being more expensive on a unit cost basis, is actually sufficiently more efficient a fluid to justify its use. We can also use this type of curve to determine the point at which any additional penetration into the well bore does not achieve sufficient incremental increase in J/Jo to justify the additional expense. In our example, the J/Jo cut-off is not clearly evident, but lies somewhere in the 7.6 to 8.0 range, which corresponds to approximately $15,000 for the System II treatment.

SUMMARY

By using some of the methods described herein, it is possible to use optimization in the design of perforating and/or stimulation programs. Certainly not every situation is adaptible to these methods, but by being aware of our goals we can design more efficiently and possibly offset to some extent the steadily rising completion costs.

ACKNOWLEDGEMENT

The authors wish to express their appreciation to CRC Wireline and Permian Perforators, Inc. for their assistance in developing the perforating cost curves used in this paper.

NOMENCLATURE

A	-	Service charge for perforating service, dollars
B	-	Minimum perforating charge, dollars
C	-	Cost for each perforation over the minimum, dollars
D	-	Fracturing fluid density, lb/gal
d	-	Perforation diameter, inches
H	-	Cost of HHP furnished, dollars/HHP
Q	-	Injection Rate of fracture treatment, BPM
X	-	Number of perforations
Y	-	Total costs attributed to perforations, dollars
Z	-	Total number of perforations included in minimum perforating charge (B)
J	-	Production after stimulation
Jo	-	Production before stimulation

REFERENCES

1. Bucy, B. J.; "Reduce Completion Costs by Using Optimum Number of Perforations", SPE Paper No. 1294-G, Fall Meeting of SPE-AIME, Dallas (October 4-7, 1959).

2. McGuire, W. J. and Sikora, V. J.; "The Effect of Vertical Fractures on Well Productivities", Trans., AIME, Vol. 219, 1960 pp 401-403.

3. Western Company Stimulation Program Library.

4. Craft, B. C. and Holden, W. R. and Graves, E. D., Jr.: Well Design Drilling and Production, Prentice-Hall, Inc., Englewood Cliffs (1962) pp 483-533.

PERFORATION OPTIMIZATION - 0.4" DIAMETER PERFORATIONS

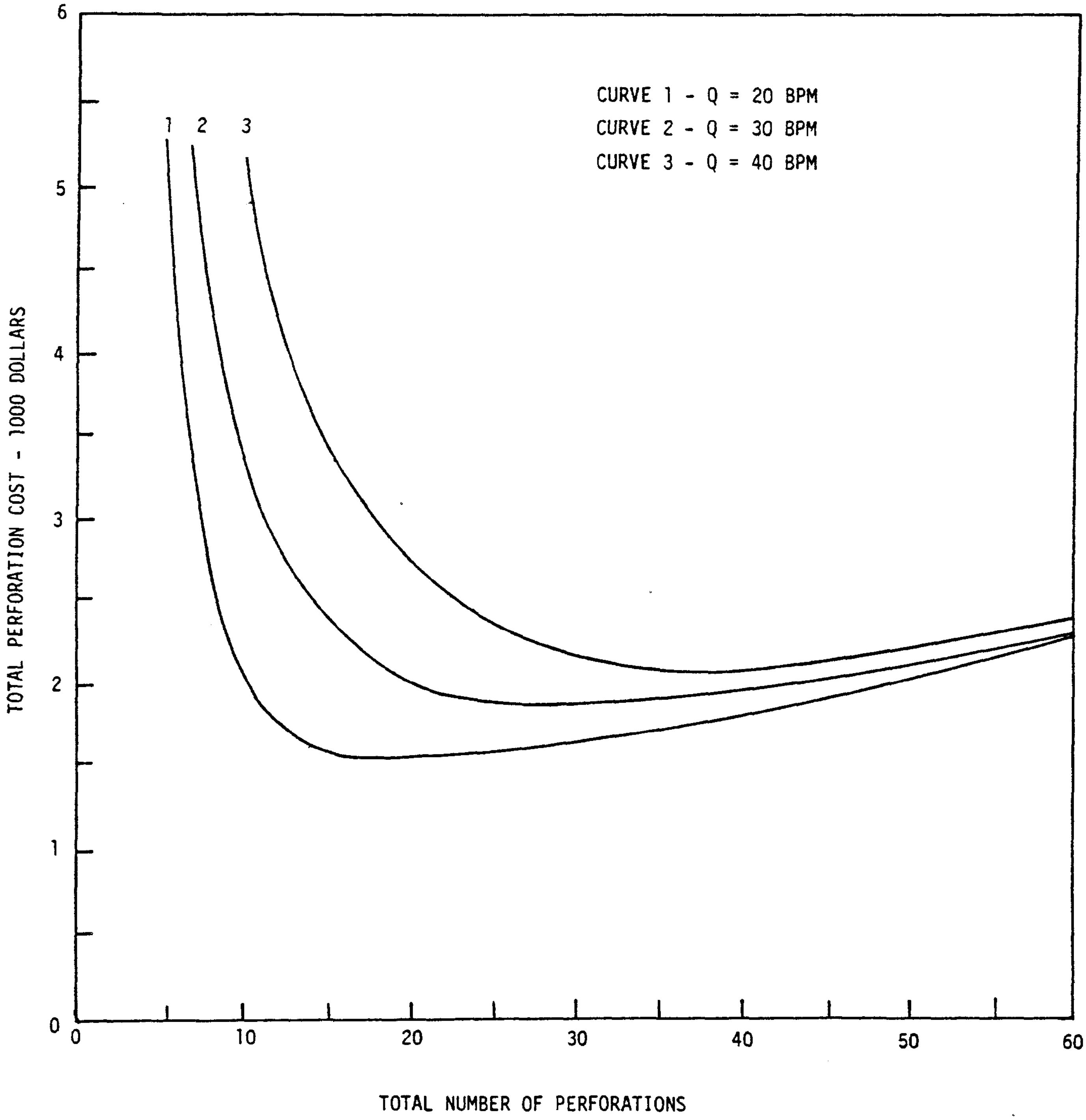


FIGURE 1

PERFORATION OPTIMIZATION - 0.375" DIAMETER PERFORATIONS

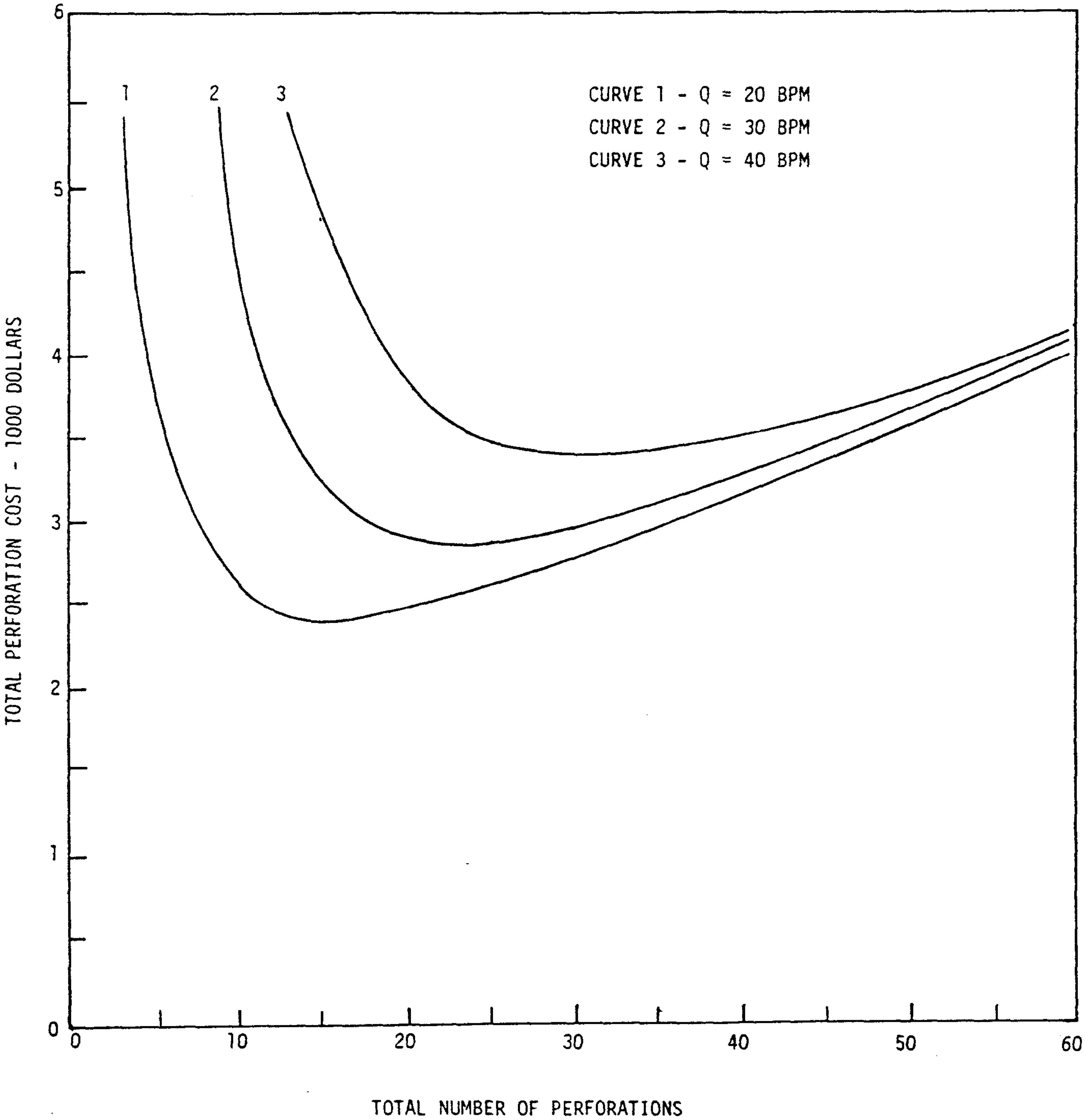


FIGURE 2

VOLUME - PENETRATION RELATIONSHIP

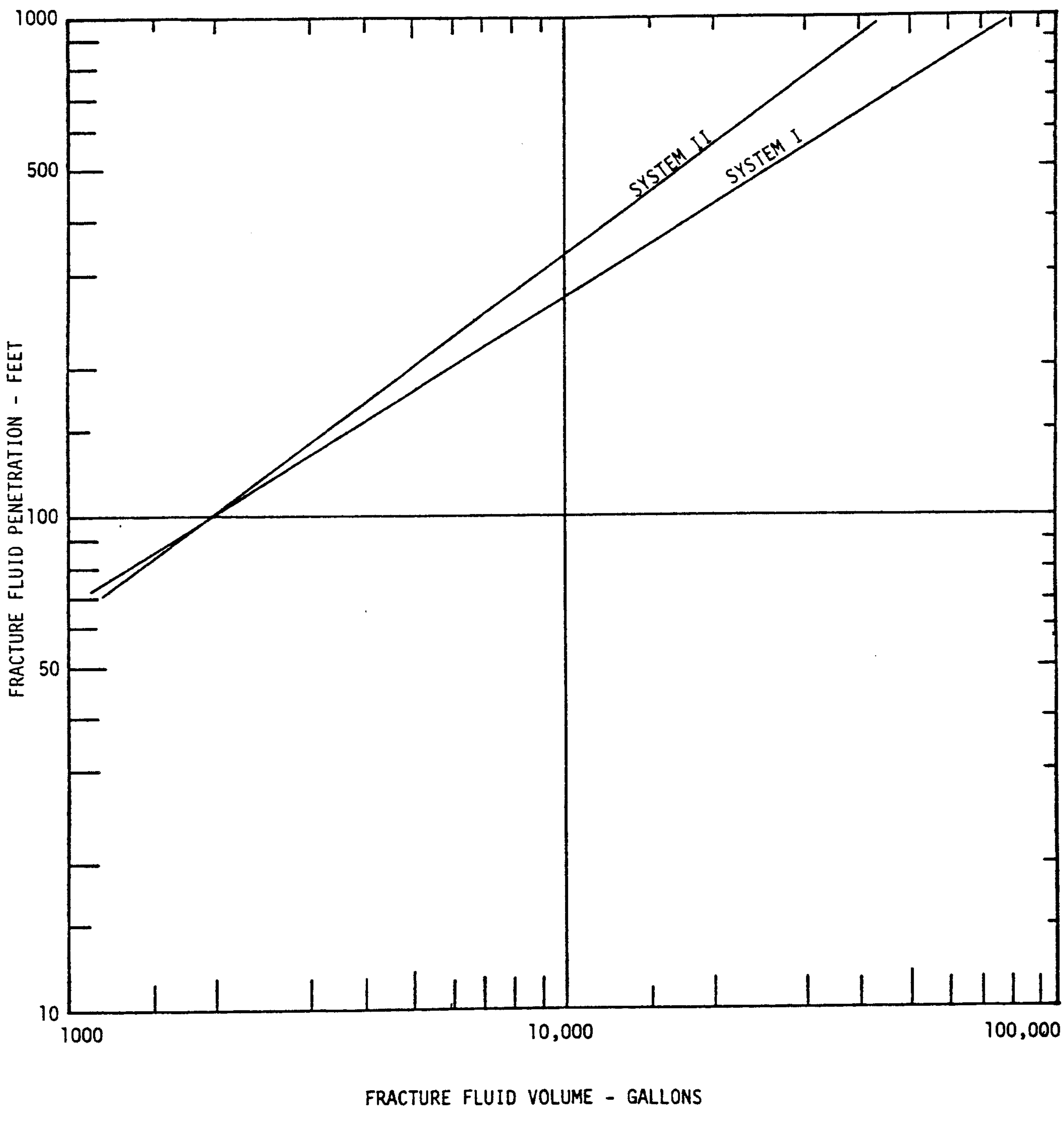
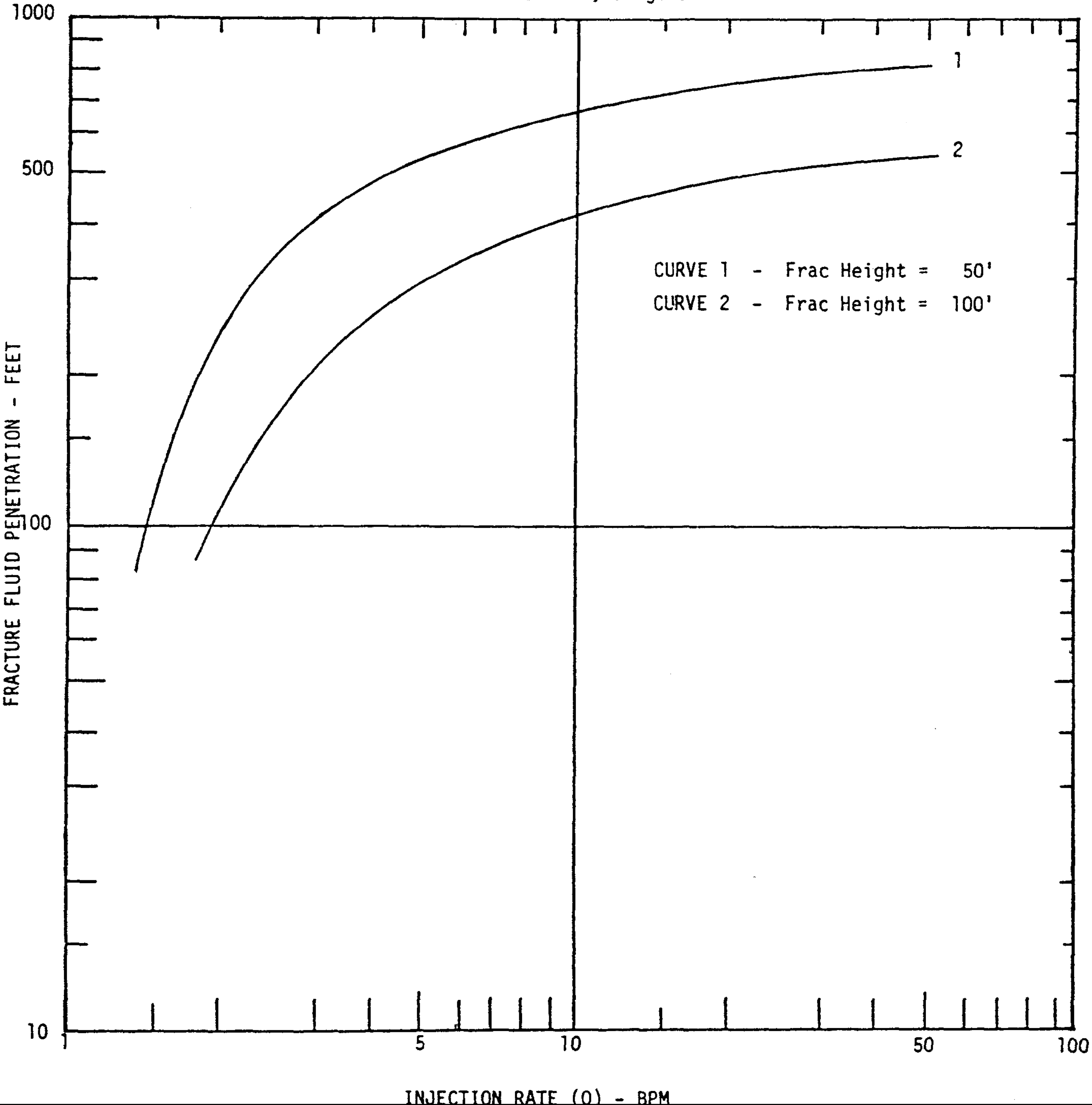


FIGURE 3

INJECTION RATE - PENETRATION RELATIONSHIP

SYSTEM I

Total Volume = 40,000 gal.



INJECTION RATE - PENETRATION RELATIONSHIP
SYSTEM II
Total Volume = 40,000 gal.

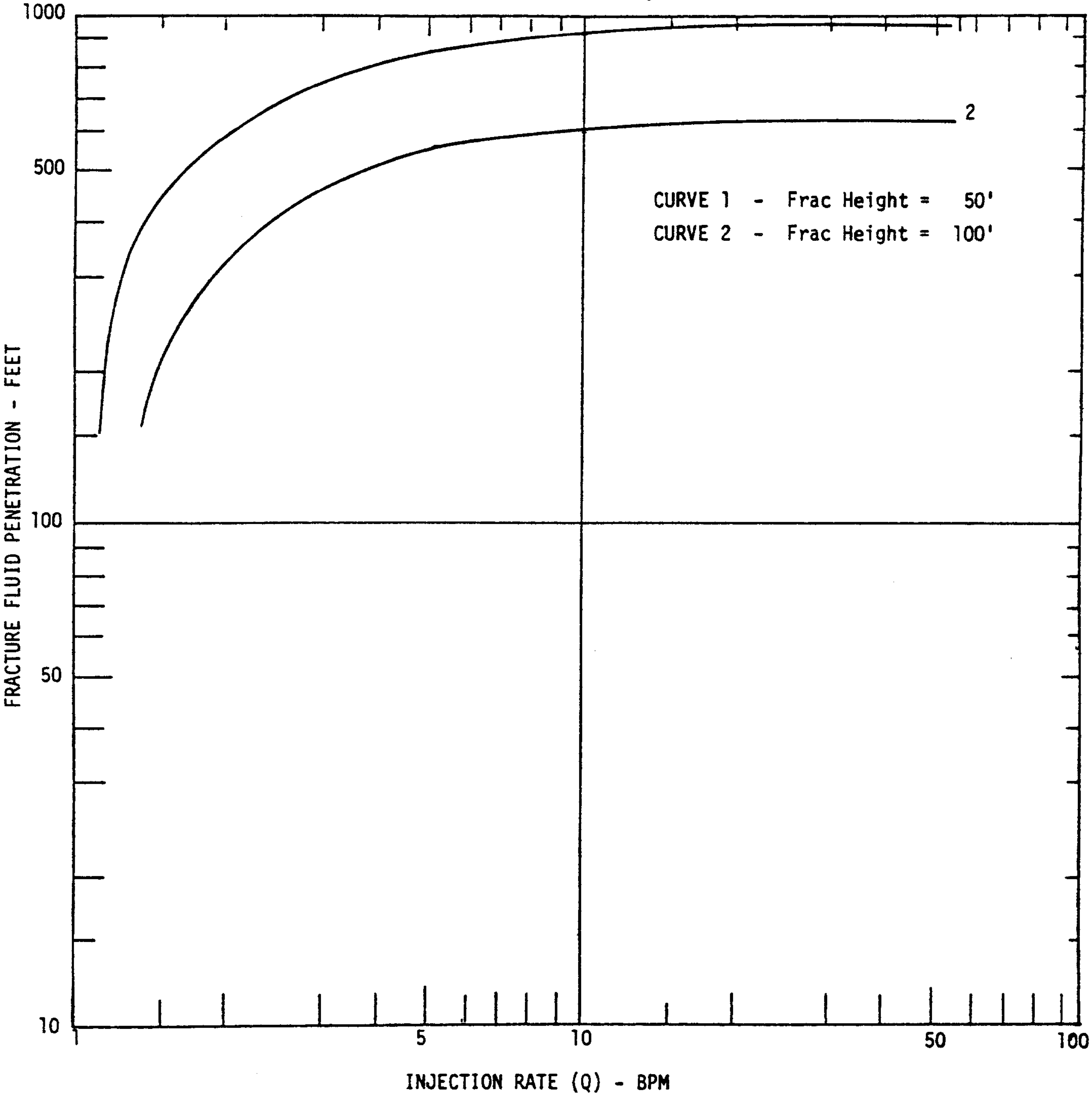


FIGURE 5

COST - J/Jo RELATIONSHIP

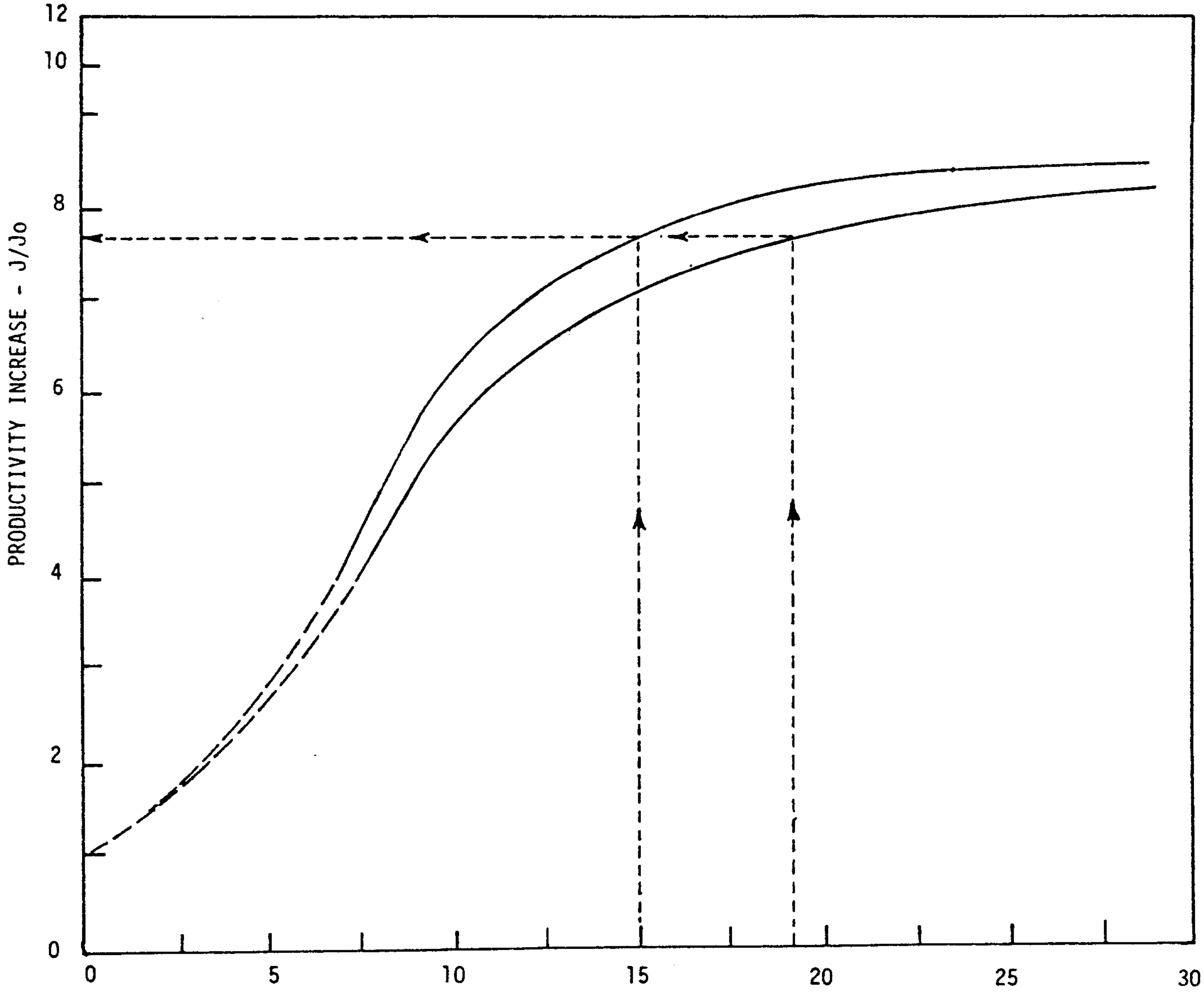


FIGURE 6

TABLE I

ASSUMED WELL CONDITIONS

DEPTH:	8200'
PAY ZONE:	8125' to 8175'
CASING:	5-1/2"
TUBING:	2-7/8"
FRACTURE GRADIENT (G_f):	0.76 psi/ft
RESERVOIR PRESSURE GRADIENT (G_p):	0.40 psi/ft
OVERBURDEN PRESSURE:	2935 psi
PERMEABILITY:	2 md
POROSITY:	12%
RESERVOIR FLUID VISCOSITY:	0.8 cp
RESERVOIR FLUID COMPRESSIBILITY:	2.5 E-4
BHT:	140° F
WELL SPACING:	80 acre (933' drainage radius)

TABLE II

FRAC FLUID COSTS IN $ PER 1000 GALLONS

	AQUEOUS				HYDROCARBON	
SYSTEM	Guar Gum	HPG	CMHEC	HPG + 5% Hydro-Carbon	Emul-sion*	Gelled LO*
Base	110.00	130.00	160.00	190.00	55.00	170.00
Surfactant	19.00	19.00	19.00		6.33	
Breaker (100°F)	31.00	31.00	31.00	31.00		54.00
Fluid Loss Additive	31.00	31.00	31.00	62.50	3.60	12.50
Clay Stabilizer	21.00	21.00	21.00	21.00		
KCl (2%)	29.00	29.00	29.00	29.00	9.67	
License Fee					7.60	
TOTAL	241.00	261.00	291.00	333.50	82.20	236.50

*Does not include the cost of hydrocarbon.

PROPPANT COSTS - PER 1000 GALLONS

Proppant @ 2 ppg	90.00
Proppant Delivery (50 miles)	27.50
Proppant Pumping	4.60
	122.10

FIXED COSTS

1450 HHP	3,625.00
Blending	570.00
Mileage	240.00
	4,435.00