THE DESIGN OF STABLE FOAM FRACTURING TREATMENTS

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INTRODUCTION

Hydraulically induced fractures have been used to stimulate oil and gas wells for the past 25 years. Hassebroek and Waters[1] summarized the advancements in fracturing technology through the first 15 years. During this period, great strides were made in the understanding, engineering and mechanical aspects of hydraulic fracturing. In the last few years, interest in hydraulic fracturing has gained a renewed momentum. The combination of declining domestic reserves and increased prices for oil and gas has turned the petroleum industry's attention toward the recovery of hydrocarbons from tight reservoirs. In these low-permeability formations, hydraulic fracturing treatments are routinely performed upon initial completion.

Successful stimulation depends upon creating a fracture, which can be propped for the desired length, using a fluid that does not substantially reduce the formation permeability next to the fracture. The selection of the fluid, therefore, is usually the key to designing a successful fracture treatment. One of the more recent innovations in fracturing technology is the use of foam as a fracturing fluid.[2,3]

Foam, which is a mixture of gaseous nitrogen, water and a surfactant, has been used for many years as a drilling and workover fluid.[4,5,6] The properties of foam, such as low hydrostatic head, low water content and excellent suspension of solids, make it an ideal fluid for drilling into or working over low-pressure, water-sensitive reservoirs. These same properties led to the development of foam as a fracturing fluid.

The viscosity of foam was investigated by Mitchell.[7] His experimental findings confirmed the existing theories that foam flow could be predicted using single-phase flow theory. Blauer, et al.[8] extended Mitchell's work by investigating foam flow in oilfield-size tubulars. The results of their work have been successfully applied to the design of hundreds of stable foam fracturing treatments during the past two years.

The properties of foam as a fracturing fluid have been well documented.[2,3] In both Refs. 2 and 3, sections were included which discussed the design procedure for fracturing with foam.

The purpose of this paper is to present a computerized approach to the engineering design of stable foam fracturing treatments. A computer program, which is available for industry use, has been written which calculates the behavior of the foam in the tubulars and the resulting fracture dimensions. The effects of specific changes in fracture treatment design can be easily analyzed, which allows the engineer to optimize the treatment design.

EFFECTS OF TEMPERATURE AND PRESSURE

Stable foam is composed of about 70-85% gaseous nitrogen. The foam quality, which refers to the percent volume of gas in the foam, must be defined at a given temperature and pressure. To calculate a change in foam quality, the water compressibility is considered to be zero and the nitrogen volume behaves as predicted by the real gas law. (All symbols are defined in the Nomenclature.)

$$V = \frac{ZnRT}{P} \tag{1}$$

Correlations for estimating the compressibility factor of nitrogen, Z, have been published[9] and are reproduced in Appendix A.

Using Eq. (1), the volume factor of nitrogen can be expressed as follows:

$$B = 199.3 \left[\frac{P}{TZ}\right] \frac{SCF}{BBL} \qquad (2)$$

Where:

$P_{SC} = 14.65$ psia
$T_{SC} = 520°R$
$Z_{SC} = 1.0$

Foam quality will, therefore, be dependent on the temperature and pressure of the foam. An example of how foam quality can change is presented in Appendix B.

FOAM IN THE TUBULARS

The behavior of foam in tubular goods can be described using Eqs. (3)-(6).

$$\mu_e = \mu_p + 38.7559 \times T_y \times D^3/Q_t \qquad (3)$$

$$\rho = 8.331 \times (1 - FQ) \qquad (4)$$

$$N_{RE} = 15916.2 \times Q_t \times \rho/(D \times \mu_e) \qquad (5)$$

$$\Delta P/L = 11.408 \times f \times \rho \times Q_t^2/D^5 \qquad (6)$$

Equation 3 is used to calculate the effective viscosity of foam, μ_e, at a given total foam injection rate, Q_t, and foam quality. The values of plastic viscosity, μ_p, and yield stress, T_y, are presented in Table 1 as a function of foam quality. The density of the foam, ρ, is calculated by assuming that the weight of the gas is negligible compared to the weight of water.

TABLE 1 – TABLE OF FOAM PROPERTIES

Foam Quality (%)	Plastic Viscosity (cp)	Yield Stress (lb/ft^2)
65	4.0	.15
70	4.6	.25
75	5.4	.40
80	6.45	.60
85	8.1	.82

After the effective viscosity and density of the foam are determined, Eq. (5) is used to calculate the Reynolds number. Then, using a Moody diagram to obtain the friction factor, f, Eq. (6) can be used to calculate the frictional pressure gradient, $\Delta P/L$.

To determine the friction pressure gradient for annular flow, Eqs. (3), (5) and (6) must be modified. The following equations apply for concentric annular flow:

$$\mu_e = \mu_p + \frac{29.0648T_y(Di - Do)^2 (Di + Do)}{Q_t} \qquad (7)$$

$$N_{RE} = \frac{15916.2Q_t\rho}{(Di\text{-}Do)\,\mu_e} \qquad (8)$$

$$\frac{\Delta P}{L} = \frac{11.408f\rho Q_t^2}{(Di - Do)^3 (Di + Do)^2} \qquad (9)$$

The friction factors for laminar flow in a concentric annulus can be obtained from Table 2. For turbulent flow, the friction factor can be obtained from a Moody diagram, using the hydraulic diameter. (Di-Do).

TABLE 2 – FRICTION FACTORS FOR LAMINAR FLOW IN A CONCENTRIC ANNULUS

Do/Di	f x N_{RE}
.0001	17.9450
.001	18.6700
.01	20.0275
.05	21.5675
.1	22.3425
.2	23.0875
.4	23.6775
.6	23.8975
.8	23.9800
1.0	24.0000

Equations (3)-(9) have been solved for a variety of foam qualities, tubular sizes and injection rates. The results of these calculations have been published and are available for industry use.[10] It should be emphasized that the values calculated for friction pressure gradient are point values, which are only valid for the specified injection rate and foam quality.

The pressure at any point in the tubulars depends on the bottomhole treating pressure, the hydrostatic head, the perforation friction and the friction pressure loss in the tubulars. Depending on the situation, the total pressure drop can either increase or decrease with depth. Therefore, to accurately determine the surface injection pressure, the pressure change in the tubulars must be determined incrementally. Starting from the known pressure (the bottomhole treating pressure), and assuming a foam injection rate and foam quality at the bottom of the hole, the data in Ref. 10 can be used to solve for surface injection pressure to any desired degree of accuracy.

However, in field practice, there is only one situation which dictates the use of small increments. That situation occurs when the total friction pressure drop is much greater than the hydrostatic head of the foam. When this occurs, the pressure at the surface can be several thousand pounds greater than the pressure at the bottom of the hole. If there is a large pressure drop down the tubulars, the nitrogen will expand and both the injection rate and foam quality will increase substantially.

The computer program, which is described in this paper, solves the pressure profile up the tubulars incrementally. The desired increment can be specified in the input data; however, for nearly every situation, a 100-ft increment will provide sufficient accuracy.

FOAM IN THE FRACTURE

The behavior of foam in the tubular goods must be solved to determine the surface injection pressure. The maximum allowable surface pressure determines the maximum allowable injection rate. However, the optimum injection rate is the value which the engineer is trying to determine. The optimum injection rate, injection volume and foam quality can be considered to be the combination of those values which maximizes the profit for a particular well. For low- permeability gas reservoirs, this usually means that one is trying to obtain a maximum fracture length for the minimum cost. Therefore, the created fracture dimensions and propped fracture length which result from a stable foam fracturing treatment are of primary concern to the engineer.

In the computer program, the equations of Geertsma and de Klerk[11] were used to calculate the created fracture dimensions. The exact formulas used in the program were Eqs. 7a and 21a in Ref. 11. The following two equations, which approximate the more complicated formulas, are presented for the purpose of discussion.

$$W \rightarrow 2.1 \left[\frac{\mu_e Q_t L^2}{Gh}\right]^{1/4} \qquad (10)$$

$$L \rightarrow \frac{1}{2\pi} \frac{Q_t\sqrt{t}}{h\ C_T} \qquad (11)$$

By observing these two equations, it should be possible to estimate the effect of changes in data on the calculated fracture width and length. However, foam is a shear-sensitive fluid, which means the viscosity varies with shear rate. Therefore, a third equation must be incorporated which calculates the effective viscosity of the foam in the fracture.

$$\mu_e = \mu_p + \frac{888.16 T_y W^2 h}{Q_t} \qquad (12)$$

These three equations contain four unknowns, namely, W, L, h and μ_e. To solve the equations, the value for fracture height is specified in the input data; then only three unknowns remain. Notice that because of Eq. (10), two solutions are possible. In the computer model, consideration was given to this problem, and Newtonian iteration was used to obtain the correct solution.

To explain the relationship of Eqs. (10)-(12), consider what would happen if the injection rate were increased. From Eq. (12), the effective viscosity should decrease. From Eq. (11), the fracture length should increase. However, in Eq. (10), the effective viscosity has decreased and the injection rate and fracture length have increased, so it is impossible to say for sure what will happen to the width, without actually calculating the new value. This example illustrates the best use of a computer program for an engineer. Using the computer, it is relatively simple to vary the input data and to determine the effect of these changes on the calculated fracture dimensions.

Of primary concern to the engineer are the values of propped fracture length, propped fracture height and production increase ratio. These values are also the most difficult to estimate. In the computer model, the propped fracture length is determined by first calculating the volume of pad that is still in the fracture at the end of the treatment. This volume represents the initial pad volume minus the volume lost to the formation due to spurt and fluid loss. By assuming the remaining pad volume occupies the far end of the fracture, the propped fracture length is the distance from the wellbore to the remaining pad.

The propped fracture height is calculated in the model, by assuming that all of the sand settles to the bottom of the fracture. This approach is commonly used in many fracture design programs and is usually correct for low-viscosity, water-base frac fluids. In stable foam fracturing, however, the sand-carrying capability of foam is excellent and the propped fracture height is undoubtedly much greater than the value calculated in the computer program. Therefore, the values for propped fracture height calculated in the program should be considered as minimum values and, in most cases, overly pessimistic. Likewise, the created fracture widths can be considered to be optimistic values for propped fracture width.

The production increase ratio is calculated using Prats'[12] formula:

$$\frac{J}{J_o} = \frac{\ln (r_e/r_w)}{\ln (r_e/0.5L)} \tag{13}$$

INPUT DATA

An example of the input data required to design a stable foam fracturing treatment is illustrated in Table 3. The data are entered under five different categories. Most of the values in Table 3 are self explanatory; however, several items do require some discussion.

In one run, a computer design can be made for 10 volumes at 10 different rates. The number of volumes and number of injection rates are specified as integer control values. Notice that the sample in Table 3 is calling for 10 volumes at two rates, or for a total of 20 different fracture treatment designs.

In the program, the total fracture fluid coefficient is calculated using the following equation:[13]

$$\frac{1}{C_T} = \frac{1}{C_I} + \frac{1}{C_{II}} + \frac{1}{C_{III}} \tag{14}$$

where:

$$C_I = 0.001483 \left[\frac{k \Delta P \phi}{\mu_e}\right]^{1/2} \tag{15}$$

$$C_{II} = 0.001183 \, \Delta P \left[\frac{k \phi C_r}{\mu_r}\right]^{1/2} \tag{16}$$

C_{III} is normally measured in the laboratory and is a function of filter cake permeability for wall-building fluids. In stable foam fracturing, fluid-loss additives are not present; therefore, the value of C_{III} is undefined.

TABLE 3—EXAMPLE NO. 1

TREATMENT DOWN TUBING

INTEGER CONTROL VALUES	
NUMBER OF PERFORATIONS	13
NUMBER OF VOLUMES	10
NUMBER OF INJECTION RATES	2
NUMBER OF SAND CONCENTRATIONS	3
TUBING INTERVAL LENGTH	100
WELL COMPLETION DATA	
DEPTH OF FORMATION - FT	2600
DEPTH OF PACKER - FT	2500
TUBING I.D. - IN	2.441
TUBING O.D. - IN	2.875
CASING I.D. - IN	4.670
PERFORATION DIAMETER - IN	0.250
RESERVOIR DATA	
FRAC GRADIENT - PSI/FT	0.720
FORMATION POROSITY - FRACTION	0.200
FORMATION PERMEABILITY - MD	0.1000
WELL SPACING - ACRES	160.
WELL BORE RADIUS - FT	0.250
RESERVOIR PRESSURE - PSI	1200.
RESERVOIR FLUID VISCOSITY - CP	0.010
RESERVOIR FLUID COMPRESSIBILITY - PSI-1	0.00000
ESTIMATED FRACTURE HEIGHT - FT	200.
ESTIMATED FORMATION HEIGHT - FT	150.
MODULUS OF ELASTICITY - PSI	0.25000E 07
SURFACE TEMPERATURE - F	70.
FRAC FLUID DATA	
FOAM QUALITY	0.8000
SPURT LOSS COEFFICIENT - GAL/SQFT	0.001000
FLUID LOSS COEFFICIENT - FT/SQRTMIN	0.000700
WATER VISCOSITY - CP	1.000
PAD VOLUME - FRACTION OF TOTAL	0.15
FRACTION OF N2 DOWN ANNULUS - MODE 4	1.0000

Under frac fluid data in Table 3, if zero is input for fluid-loss coefficient, the following equation is used to calculate the total fluid-loss coefficient.

$$C_T = \frac{C_I C_{II}}{C_I + C_{II}} \tag{17}$$

In some cases, dynamic fluid-loss tests using stable foam and cores have been run. If data are available from such tests, they should be entered in the program.

The reservoir fluid compressibility is used in Eq. (16) to calculate C_{II}. If the well to be fractured is in a gas reservoir, zero should be entered in the program and Eq. (18) will be used to estimate the compressibility.

$$C_r = 1/\overline{P} \tag{18}$$

The fifth category of input data provides for the volumes, injection rates and the proppant pumping schedule. These values are output along with the injection pressures and calculated fracture dimensions.

TREATMENT DESIGN

To design the optimum stable foam fracture treatment, the computer program should be run for a variety of conditions. The input data which are required to run the program can be grouped into two main categories. One group consists of those data which must be estimated and cannot be controlled, such as the in situ formation properties. In most cases, these parameters can be estimated with an acceptable degree of accuracy. However, in new fields some of these in situ properties may not be known. Values for rock hardness and created fracture height are especially difficult to estimate. When sufficient doubt exists, the program should be run for a maximum, median and minimum estimation of the parameter in question. A treatment design can then be chosen which minimizes the risk of mechanical failure.

The second category of data consists of those parameters which can be controlled, such as foam quality, injection rate, injection volume, and in some cases, the mode of completion. The computer

TABLE 4

FOAM INJECTION RATE - BPM	13.0
WATER INJECTION RATE - BPM	2.60
NITROGEN INJECTION RATE - SCF/MIN	7540.
SURFACE INJECTION PRESSURE - PSI	2532.
HYDRAULIC HORSEPOWER - HHP	161.
REQUIRED N2 RATIO - SCF/BBL	2900.
WATER VOLUME IN FOAM FLUSH - BBLS	3.34
NITROGEN VOLUME IN N2 FLUSH - SCF	11304.
SURFACE CLOSURE PRESSURE WITH FOAM - PSI	1490.
SURFACE CLOSURE PRESSURE WITH NITROGEN - PSI	1653.

ERROR	VOLUME GALS	TIME MINS	FOAM VIS CPS	WIDTH IN	CREATED LENGTH FT	PROPPED LENGTH FT	PROPPED HEIGHT FT	PROPPANT WEIGHT LBS	FOLDS INCREASE
0.	25000.	49.	202.679	0.155	474.	431.	28.	36500.	4.50
0.	30000.	59.	241.872	0.169	520.	473.	29.	45000.	4.72
0.	35000.	69.	281.158	0.183	563.	512.	30.	53500.	4.93
0.	40000.	78.	320.358	0.196	603.	547.	30.	62000.	5.13
0.	45000.	88.	359.571	0.208	640.	581.	30.	70500.	5.32
0.	50000.	98.	398.804	0.219	675.	612.	31.	79000.	5.50
0.	55000.	108.	438.041	0.229	709.	643.	31.	87500.	5.67
0.	60000.	118.	477.293	0.240	741.	671.	31.	96000.	5.83
0.	65000.	128.	516.547	0.249	771.	699.	31.	104500.	6.00
0.	70000.	138.	555.813	0.259	801.	725.	31.	113000.	6.15

PROPPANT PUMPING SCHEDULE

SAND CONCENTRATION PPG	VOLUME	
0.0	15.	PERCENT
1.0	4000.	GALLONS
1.5	4000.	GALLONS
2.0		REMAINDER

program should be run for a wide range of these data. For example, the output in Tables 4 and 5 were calculated from the input data in Table 3. These results allow the engineer to determine the effect of volume and injection rate on the fracture design. In this particular example, only minor changes in the fracture dimensions resulted from the increase in injection rate from 13 to 20 BPM. The only major change was a 1000-psi increase in the surface injection pressure, which of course, increases the cost of the job.

Another aspect of treatment design which requires discussion, concerns the concept of fracture area. It has been well-established that foam is an efficient fracturing fluid. However, the property of foam which is responsible for the low fluid loss, namely, the high effective viscosity, also detracts from the ability of foam to create longer fractures. When a fracturing fluid is efficient, this simply means that a large percentage of the fluid remains in the fracture and does not leak off into the formation. Therefore, the created fracture volume using foam should always be greater than the volume created by most water-base fluids. However, if a water-base fluid which has a low fluid-loss coefficient and a low viscosity is compared to foam, the created fracture areas may not be appreciably different.

The most probable explanation for the success of

TABLE 5

FOAM INJECTION RATE - BPM	20.0
WATER INJECTION RATE - BPM	4.00
NITROGEN INJECTION RATE - SCF/MIN	12800.
SURFACE INJECTION PRESSURE - PSI	3580.
HYDRAULIC HORSEPOWER - HHP	351.
REQUIRED N2 RATIO - SCF/BBL	3200.
WATER VOLUME IN FOAM FLUSH - BBLS	3.68
NITROGEN VOLUME IN N2 FLUSH - SCF	13757.
SURFACE CLOSURE PRESSURE WITH FOAM - PSI	1502.
SURFACE CLOSURE PRESSURE WITH NITROGEN - PSI	1653.

ERROR	VOLUME GALS	TIME MINS	FOAM VIS CPS	WIDTH IN	CREATED LENGTH FT	PROPPED LENGTH FT	PROPPED HEIGHT FT	PROPPANT WEIGHT LBS	FOLDS INCREASE
0.	25000.	32.	140.866	0.159	483.	439.	27.	36500.	4.54
0.	30000.	38.	167.523	0.174	530.	482.	28.	45000.	4.77
0.	35000.	45.	194.187	0.188	574.	521.	28.	53500.	4.99
0.	40000.	51.	220.916	0.201	615.	558.	29.	62000.	5.19
0.	45000.	57.	247.575	0.213	653.	592.	29.	70500.	5.38
0.	50000.	64.	274.246	0.224	689.	625.	29.	79000.	5.56
0.	55000.	70.	300.924	0.235	724.	655.	29.	87500.	5.74
0.	60000.	77.	327.609	0.245	756.	685.	30.	96000.	5.91
0.	65000.	83.	354.299	0.255	788.	713.	30.	104500.	6.08
0.	70000.	89.	380.994	0.265	818.	740.	30.	113000.	6.24

PROPPANT PUMPING SCHEDULE

SAND CONCENTRATION PPG	VOLUME	
0.0	15.	PERCENT
1.0	4000.	GALLONS
1.5	4000.	GALLONS
2.0		REMAINDER

foam fracturing is the fact that less water is introduced into the formation during the fracture treatment. In low-permeability reservoirs, capillary pressures can be quite large. Any free water left in the fracture will be quickly imbibed into the formation. If the pressure drop during clean-up is not sufficient to overcome the capillary end effect between the fracture and the formation, several months may be required to establish a maximum well productivity. If the formation adjacent to the fracture is damaged by the frac fluid, the capillary pressure in this zone can increase and the possibility of a complete water block then exists. Stable foam fracture treatments help to minimize these problems by minimizing the amount of water injected and maximizing the pressure drop during clean-up.

Of course, there still remain certain limitations on the use of foam as a frac fluid. The main limitation is the mechanical problem of introducing sand into the foam. Currently, about two pounds of sand per gallon of foam is the limit. To take full advantage of the wide fractures created by foam, concentrations on the order of 4-5 ppg would be desirable.

There is also a depth limitation for foam fracturing at the present time. In most formations below about 7000-8000 ft, high sand concentrations must be used to insure that the fracture will remain open. Propping agent concentrations on the order of 4-5 ppg are usually desirable. Also, the high bottomhole treating pressures require that large volumes of nitrogen be pumped at high rates. These requirements present significant mechanical problems, and the costs of such treatments could far exceed the costs of conventional fracture treatments.

FIELD RESULTS

During 1975, over 200 stable foam fracturing treatments were designed using the workbook[10] or the computer program. Jobs were performed down many different sizes of tubing, casing and annuli. For some jobs, the annulus and tubing were manifolded and foam was pumped down both sides of the tubing. Experience from the jobs performed during 1975 has confirmed the validity of the calculation procedures described in this paper. The calculated surface injection pressures have rarely differed more than a few hundred psi from the actual pressures.

Tables 6 and 7 list some of the states, counties and formations in which stable foam fracturing treatments have been performed. Results from some of the wells fractured during 1975 are presented in Table 8. These wells were selected to demonstrate the typical depths, foam rates, surface treating pressures and sand volumes of the jobs performed during 1975.

SUMMARY

The application of foam as a fracturing fluid has gained wide acceptance during the past two years. The rheological properties of foam have been well-documented, and several papers are available which describe the process of fracturing with foam. This paper has presented a computerized procedure for

TABLE 6 — GEOGRAPHIC LOCATIONS WHERE SOME STABLE FOAM FRACTURING JOBS WERE PERFORMED IN 1975

State	Counties
Texas	Val Verde, Sterling, Ward, Sutton, Edwards, Webb, Crockett, Reeves, Hale, Hemphill, Coke, Irion, Upton
Colorado	Welol, Cheyenne, Weld, Elbert, Rio Blanco, Larmier
Oklahoma	Texas, Okmulgee, Carter, Kay, Pittsburg
Kansas	Morton, Sherman, Grant
Wyoming	Converse, Niobrara, Sweetwater
New Mexico	San Juan, Lea
California	Fresno
Pennsylvania	Forrest

TABLE 7 — FORMATIONS IN WHICH SOME STABLE FOAM FRACTURING JOBS WERE PERFORMED IN 1975

Arbuckle	Lewis
Canyon	Mancus B
Chester	Morrow
Clearfork	Muddy J
Council Grove	Olmos
Douglas	Picture Cliff
Hawtshorne	Sprayberry
	Strawn

TABLE 8— SAMPLE OF FIELD RESULTS

Formation	Depth (ft)	Mode*	Fluid Rate (BPM)	Foam Rate (BPM)	Wellhead Treating Pressure (psi)	Proppant Amount (lbs)	Proppant Type (Mesh)	Production Before	Production After
Olmos	7,403	1	4.2	16	4,600	38,000	10-20	500 MCFD	1400 MCFD
Council Grove	2,900	3	16	58	1,600	100,000	20-40	100 MCFD	2400 MCFD
Mancus-B	2,300	2	8	38	2,640	82,000	20-40	100 MCFD	800 MCFD
Picture Cliff	3,150	2	4	15	1,800	15,000 5,000	10-20 8-12	**	215 MCFD
Picture Cliff	1,860	2	3.5	10	1,500	3,000 1,500	10-20 8-12	**	1096 MCFD
Strawn	6,500	3	4	12	4,200	37,500	20-40	**	44 BOPD
Canyon	7,000	2	4.5	18	5,200	61,000	20-40	16 MCFD	300 MCFD
Canyon	6,895	2	4.5	18	4,695	25,000	20-40	75 MCFD	260 MCFD
Douglas	7,040	2	7	24	3,000	53,000	10-20	**	10,000 MCFD
Clearfork	6,000	3	7.5	30	2,200	75,670	20-40	9 BOPD	23 BOPD

* Mode
1. Tubing
2. Casing
3. Manifolded Tubing & Casing

** New Completion - Test Data Prior to Frac Not Available

designing stable foam fracturing treatments. The computer program calculates the behavior of the foam in the tubulars and the dimensions of the resulting fracture. By varying the input data, the program can be used to optimize the design of stable foam fracturing treatments. Experience from the fracture treatments performed during 1975 has confirmed that the programmed calculation procedures are valid.

NOMENCLATURE

B = Volume factor for nitrogen (SCF/BBL)

C_r = Reservoir fluid compressibility (psi^{-1})

C_T = Total fluid loss coefficient (ft/ $\sqrt{\text{min}}$)

C_I = Fluid loss coefficient for fracture fluid (ft/ $\sqrt{\text{min}}$)

C_{II} - Fluid loss coefficient for reservoir fluid (ft/ $\sqrt{\text{min}}$)

C_{III} = Fluid loss coefficient for wall building fluids (ft/ $\sqrt{\text{min}}$)

D = Internal diameter of tubing or casing (in)

D_i = Internal diameter of casing (in)

D_o = Outside diameter of tubing (in)

f = Friction factor

FQ = Foam quality (fraction)

G = Modulus of Elasticity (psi)

h = Created fracture height (ft)

J = Productivity index of fractured well (bbls/day/psi)

J_o = Productivity index of unfractured well (bbls/day/psi)

k = Permeability (md)

L = Fracture length (ft)

n = Number of moles

N_{RE} = Reynold's number

P = Pressure (psia)

P_{sc} = Standard pressure (psia)

$\bar{P}$ = Average pressure (psia)

ΔP = Pressure drop (psia)

$\Delta P/L$ = Pressure gradient (psi/ft)

Q_t = Total foam flow rate (bbls/min)

R = Gas constant (10.72 ft^3-lb/mole in^2 ^oR)

r_e = Radius of drainage (ft)

r_w = Radius of well bore (ft)

T = Temperature (^oR)

T_{sc} = Standard temperature (^oR)

T_y = Yield stress (lbs/ft^2)

t = time (min)

V	= Volume (ft^3)
W	= Fracture width (in)
Z	= Gas deviation factor
Z_{sc}	= Standard gas deviation factor
ρ	= Foam density (lb/gal)
ϕ	= Porosity (fraction)
μ_e	= Effective viscosity (cp)
μ_p	= Plastic viscosity (cp)
μ_r	= Reservoir fluid viscosity (cp)

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APPENDIX A

<u>Calculation of N_2 Z Factors</u>

$$Z = AP^2 + BP + C$$

$500 < P < 4000$

$A = 1.679393 \times 10^{-7} - 6.2243 \times 10^{-10}T + 8.0385 \times 10^{-13}T^2 - 3.5472 \times 10^{-16}T^3$

$B = -3.122 \times 10^{-4} + 8.488 \times 10^{-7}T - 5.37 \times 10^{-10}T^2$

$C = 1.0$

$4000 < P < 8000$

$A = 0$

$B = 2.2817 \times 10^{-4} - 4.0066 \times 10^{-7}T + 2.3 \times 10^{-10}T^2$

$C = -0.0956 + 2.5 \times 10^{-3}T - 1.5 \times 10^{-6}T^2$

$P > 8000$

$A = 0$

$B = 2.2042 \times 10^{-4} - 3.515 \times 10^{-7}T + 1.815 \times 10^{-10}T^2$

$C = -0.1573 + 2.438 \times 10^{-3}T - 1.4 \times 10^{-6}T^2$

Where: P = pressure (psi)
T = temperature (°R)

APPENDIX B

<u>Calculation of change in foam quality</u>

Given: T = 100°F = 560°R
P = 5000 psi
FQ = 70 %

Calculate: Foam quality at P = 4000 psi and T = 140°F

1. From Table IX in Ref. 9

$B = 1487 \frac{SCF}{BBL}$ at 5000 psi and 100°F

$B = 1173 \frac{SCF}{BBL}$ at 4000 psi and 140°F

2. At 5000 psi and 100°F for 1 BBL of foam

Volume of H_2O = .30 BBLS

Volume of N_2 = .70 BBLS

3. At 4000 psi and 140°F

Volume of H_2O = .30 BBLS

Volume of $N_2 = .70 \text{ BBLS} \times \frac{1487}{1173} = .887$ BBLS

4. Total volume at 4000 psi and 140°F

Total foam volume $= .30\ BBLS_{H_2O} + .887\ BBLS_{N_2} = 1.187$ BBLS

5. New foam quality at 4000 psi and 140°F

$$FQ = \frac{Volume_{N_2}}{Volume_{Foam}} \times 100 = \frac{.887 \text{ BBLS}}{1.187 \text{ BBLS}} \times 100 = 74.7\%$$