An Investigation of Hydraulics In Well Stimulation Treatments

By PAUL L. CRENSHAW, JACK F. FLETCHER and HARRY L. HORTON
Dowell Division of The Dow Chemical Co.

INTRODUCTION

The art of stimulating oil and gas wells to improve their production characteristics and extend their economic life has undergone tremendous development since the early "trial-and-error" days of its inception. Nowadays, both acidizing and fracturing treatments can be pre-planned on the basis of sound engineering calculations, specific laboratory and well data, and the experience gained in thousands of previous treatments. An investigation of the hydraulics of well stimulation treatments involves a detailed study of fluid mechanics. Fluid characteristics, such as density, viscosity, friction loss, compressibility, gel strength, and fluid loss, all play an important part in designing and performing stimulation treatments.

(1) Fluid density is important in predicting the performance of fluid pumps, in calculating bottom-hole fracturing pressures, and in determining the sand-carrying ability of the fluid.
(2) The viscosity of a fracturing fluid influences its friction loss, sand-carrying ability, fluid loss, and the width of the fracture created in the formation.
(3) Friction loss results in wasted horsepower, spent in moving the fluid down the casing; however, high friction losses may prove beneficial by increasing the width of the fracture, when the fluid enters the formation.
(4) Fluid compressibility must be considered in planning hydraulic fracturing treatments, for it is related to the volume measurement and proper placement of the fracturing materials.
(5) The sand-carrying ability of a fracturing fluid is primarily a function of the viscosity or the gel strength of the fracturing fluid.
(6) The fluid loss of a fracturing fluid is defined as the rate of fluid leak-off through the fracture faces into natural flow channels in the matrix rock.

Preliminary consideration of these treatment factors makes possible designing the most effective, yet economical, stimulation treatment for a particular well, and examines its natural characteristics and those of available fracturing materials. Many of these properties can be modified by the inclusion of suitable chemical additives in the stimulation fluid.

THE MECHANICS OF FLUID INJECTION

It has been shown that only limited amounts of stimulation fluid can be injected into the natural pore structures of a formation rock. This limitation is due to the high resistance to flow presented by the tiny natural flow channels in the rock. Calculations using basic flow equations have shown that, in a formation with an effective permeability of 100 md, an effective porosity of 20 per cent will accept 0.77 BPM of a 1 cp fluid, at a differential pressure of 2710 psi (1). At lower permeabilities or porosities, even higher differential pressures are required to attain any appreciable injection rate into the formation rock.

Actually, in most cases, the pressure differential required to produce any appreciable flow magnitude will exceed the yield pressure of the formation rock. Thus, a fracture is formed which is of comparatively higher permeability than is the native rock, so the stimulation fluids will enter this high-capacity flow channel in preference to the lower permeability native rock. This effect is especially true of the predominantly low permeability carbonate reservoirs of the Permian Basin in West Texas and Southeast New Mexico. Thus, it is now believed that many acidizing treatments, conducted at high down-hole pressures to attain a desired injection rate, actually were fracturing treatments in which the derived benefits could be attributed to the creation of a high-capacity fracture and to the acid-conditioning of the faces thereof, to remove all possible flow restrictions. In effect, it is now believed that fractures can be created in any exposed portion of a formation, if sufficient hydraulic force is applied to it.

Considerable study has been devoted to the mechanics of creating fractures in different types of rock formations, and a number of theories have been advanced to explain observed phenomena. Some of these theories are widely accepted; others remain highly controversial. Still existing are many unknowns which make it impossible to provide a definitive answer explaining all observations made during actual fracturing treatments in the oil fields. Because the Permian Basin area is of immediate interest, the following discussion is intended to be restricted to these low-permeability carbonate reservoirs, unless otherwise stated.

Probably, in many cases, new fractures are not actually created; but rather pre-existing natural fractures, fissures, or joint planes -- previously created by dynamic forces in the earth's crust over long periods of time -- are opened and extended (2). There could be cited many examples in which coring and exploration work have revealed, in formation rock, the existence of natural fractures which correspond closely, in inclination and orientation, to predictions based on pressure gradients and rock properties defined by (or derived from) fracturing treatments. Although it is impossible to predict with finite accuracy the exact orientation of all hydraulically induced fractures, their probable inclination can usually be established with sufficient accuracy to aid in the planning of such well stimulation treatments.

The characteristic behavior of rocks subjected to hydraulic pressure also plays an important part in planning a fracturing treatment. In comparison with the partially or wholly unconsolidated sand formations encountered in other parts of the country, the carbonate reservoirs in the Permian Basin area are hard and competent.

When subjected to hydraulic force, these sand formations are considered to behave as plastic or dilatant-type materials, and they require a high rate of hydraulic loading to accomplish parting of the rock. In contrast, the hard and competent carbonate formations in the Permian Basin respond as brittle, elastic materials, in which fractures can be initiated by low rates of loading

(3, 4). Thus, it may be seen that high injection rates may not be required to initiate a fracture; however, they are often desirable to attain greater fracture width and extension.

FRACTURING PRESSURES

The bottom-hole pressure required to initiate a fracture may be calculated in several ways. First, ignoring the effect of overburden and tensile strength of the rock, one may calculate, from modified equations derived from Darcy's flow formulas (1), the pressures required to inject fluids into natural formation flow channels and fissures. For field applications, treatment data from previous fracturing treatments or injection tests may be used to calculate the probable fracturing pressure (5). Based on these two calculated values, one can predict whether, for a given bottom-hole pressure, stimulation fluids will enter the formation through pre-existing permeability, or whether fracturing will take place and a new, high permeability flow channel will be created in the rock.

The estimated bottom-hole pressure required to produce a fracture in the formation, is usually estimated from the following formula:

$$P_R = P_H + P_S - P_F$$

Where:

P_R = Formation fracturing pressure, at the face of the pay

P_H = Hydrostatic head of fluid in the hole

P_S = Surface gauge pressure, while injecting fluid at a constant rate

P_f = Predetermined friction loss of the fluid, based on pipe size

(Note: All pressures expressed as total psi, for entire depth of well.)

From the above equation, the fracture gradient, P_r, is usually derived and is equivalent to the total bottom-hole fracturing pressure P_r divided by the depth in feet to the zone to be fractured, and expressed as psi per ft. Encountered have been fracture gradients ranging from 0.40 to 2.0; however, for most wells in the Permian Basin area, the fracture gradient will range between 0.5 and 1.3 psi per ft. Field experience has shown that individual fields usually possess a characteristic fracture gradient, so, once several fracturing treatments have been conducted in a particular area, it is possible to predict the fracturing pressures that will be encountered during subsequent fracturing treatments in the same field.

FRACTURE INCLINATION

In general, it is believed that a fairly reliable indication of the fracture inclination may be derived from the observed fracture gradient. In other words, vertical fractures are distinguished by fracture gradients of 0.7 or lower, whereas fracture gradients of 0.9 or higher usually indicate that a horizontal fracture has been achieved. The inclination of fractures in wells exhibiting intermediate fracture gradients between 0.7 and 0.9, are indeterminate and are assumed to represent inclined fractures ranging from 30 to 60° from the horizontal (2).

Aside from visual evidence from cores, packer markings, down-hole photographs, etc., this concept is based on the fact that in most cases the average weight of overburden is 1.0 lbs per ft. To create a horizontal fracture, it would be necessary to lift this overburden; therefore fracture gradients greater than 1.0 psi per foot would be expected. In contrast, a vertical fracture could result in shifting the formation laterally to each side of the fracture, without specifically lifting the overburden above it. Therefore, fracture gradients ranging from 0.4 to 0.7 are entirely feasible, because it is not necessary to lift the overburden to separate the two fracture faces.

It is important that, wherever possible, it be determined whether the probable fracture inclination will be horizontal or vertical, because of the difference in flow patterns during the two types of fracture treatments. Thus, in the case of a horizontal fracture, pretreatment calculations are based on a circular-shaped fracture, formed by radial flow from the well bore; whereas, in the case of a vertical fracture, the calculations are based on a radial flow or a restricted rectangular-shaped fracture, formed by linear flow from the well bore.

The greatest difficulty in predicting the configuration of a vertical fracture is in estimating the height of the fracture. This prediction will vary from one formation to another, depending upon the heterogeneity of the formation rock, and the presence or absence of nearby shale beds. Usually, however, this value can be approximated from field experience, with sufficient accuracy to proceed with preliminary job calculations.

FRACTURING TREATMENT PREPLANNING

Regardless of the geometry of the fracture, the fracture area (expressed in square feet) is entirely dependent upon the measurable properties of the fracturing fluids used, and upon the characteristics of the reservoir being fractured. Also, one of the factors in determining the probable productivity increase resulting from a stimulation treatment is the maximum fracture area achieved. Thus, starting with the desired productivity level following fracturing, one first estimates the fracture area necessary to attain this increase. Then, the other job requirements necessary to attain this fracture area (such as injection rate, volume and type of fracturing fluid, and amounts of additives and propping agents included) must be selected (5). All these factors must be considered together, because they are interdependent. Predictions of treatment results must be tempered by knowledge of results attained on similar fracturing treatments in the same area, because any calculated predictions must involve assumptions regarding the reservoir which cannot be accurately defined.

Injection rates and size of treatment are certainly important factors in determining the fracture area created during a particular fracturing operation; however, evaluation of fracturing fluid characteristics is an equally important consideration in preplanning a fracturing treatment. Often, the incorporation of suitable additives in the fracturing fluid will greatly improve the efficiency of the fracturing treatment and result in additional valuable fracture extension. For this reason, a careful study of the fracturing fluid characteristics is essential to the development of an optimum treating technique under any specific well conditions.

FLUID DENSITY

The specific gravity of a fracturing fluid usually plays a minor part in the planning of a fracturing treatment; however, it does have several significant effects on treatment conditions. First, the density is directly related to the head of the fluid column in the well, so denser fluids provide higher hydrostatic pressure and in turn, reduce the amount of surface pressure which must be applied to obtain fracturing breakdown pressure at the face of the formation. The density of a fracturing fluid will also have an effect on the prop-carrying ability of the fluid: all other conditions being equal, the closer the density of the fracturing fluid to the density of the propping agent, the better will be the prop-supporting characteristics of the fluid.

VISCOSITY

The viscosity of a fracturing fluid plays several roles in fracturing operations. When fracturing with oils, the higher the viscosity, the greater the friction loss experienced when pumping down the well; thus, much higher surface pressures must be attained to reach fracturing breakdown pressure at the face of the formation. On the other hand, the combined factors of fracture fluid viscosity and injection rate control the width of the fracture formed in the rock. Formulas have been proposed for estimating fracture width, based on these factors (6).

Fracture width is an important factor in determining fracture conductivity, sometimes referred to as fracture permeability. The productivity increase obtained as a result of a fracturing treatment depends on (2) the area of the created fracture, and (b) the conductivity of the fracture. It has been established that the permeability of the fracture, in terms of Darcy feet, should be a minimum of ten times greater than the natural permeability of the formation (7). West Texas carbonate reservoirs present no problem in obtaining this minimum conductivity; however, some of the highly permeable sand formations in West Texas present a problem.

One way of increasing fracture conductivity is to open wider the fracture and use larger size propping agents to support it. In such cases, increased fracturing fluid viscosity, in combination with higher injection rates, may be used to solve this problem; however, the viscosity must not be increased to a point where the friction losses will become prohibitive. It becomes necessary, then, to strike a balance between viscosity and friction loss, to obtain maximum fracture width.

Viscosity also plays an important part in determining the prop-carrying characteristics of the fracturing fluid. This determination is particularly important at low velocities. In a fracture extending in a radial pattern from the well bore, the fracturing fluid moves slower and slower as it penetrates farther away from the well bore; and when the velocity of the fluid is no longer sufficient to support the propping agent, a screen-out occurs and no further fracture extension is possible. Improvement in the sand-supporting characteristics of the fracturing fluid will naturally increase the radial penetration of the fracturing media before such screen-out occurs.

The viscosity of the fracturing fluid is also a factor in determining its leak-off rate, which in turn controls fracture extension and fracture area. Higher viscosity fluids have a slower rate of leak-off, so more of the fracturing fluid remains in the fracture to widen and extend it. Such high viscosity fluids are particularly advantageous for fracturing operations in Permian Basin low-permeability carbonate reservoirs. Comparative viscosities of typical fracturing fluids are shown in Table I.

FRICTION LOSS

The problem of increased friction loss accompanying increased viscosities in fracturing fluids has been overcome by the recent development of chemical additives which provide the fluids with pseudo-plastic properties; thus the injection rates can be increased, with very little corresponding friction loss increase Furthermore, less surface horsepower is needed to overcome downhole friction losses, and a greater proportion of the expended horsepower is available to provide hydraulic force for fracturing the formation.

Small concentrations of friction loss additives have little effect on a fracturing fluid, other than to make it "slick." In higher concentrations, however, many of these materials impart an "apparent viscosity" to the fracturing fluid and, at the same time, provide even greater reductions in friction loss. This viscosity is highly advantageous, for the "thicker" fracturing fluid exhibits improved prop-carrying characteristics and provides greater fracture widths, without the accompanying disadvantage of excessive friction losses.

For example, the friction loss of fresh water in 2 in. tubing, at an injection rate of 8 BPM is about 740 psi per 1000 ft. The addition of as little as 2-1/2 to 5 lb of friction reduction additives per 1000 gal of water will reduce the friction loss to 205 - 350 psi per 1000 ft (depending upon the additive used), with little or no change in the fluid viscosity. If 40 or 50 lb of friction reduction additive per 1000 gal of water is used, the friction loss drops to 170-270 psi per 1000 ft, while the apparent viscosity increases to some 6 to 50 times that of fresh water.

COMPRESSIBILITY

In most cases, fracturing fluids are considered to be incompressible. Actual practice shows, however, that a 2-in. column of weathered oil, 10,000 ft high, will compress as much as 2 bbl. Under these same conditions, water or hydrochloric acid may compress as much as 1 bbl. An extreme example of compressibility is the use of a fresh, gaseous crude as a fracturing fluid; then extra hydraulic horsepower is required to compress the fluid until it approaches 100 per cent efficiency in transmitting the hydraulic force. Also, frac-pump efficiency is greatly reduced when a gaseous fluid is pumped.

In actual practice, this problem is eliminated by pumping fluid into the formation and establishing a maximum injection pressure, before injecting the fracturing fluid. The best fracturing fluid, from a compressibility standpoint, is one which is completely free from gas. Caution should be exercised in selecting crude oils as fracturing fluids.

SAND-CARRYING ABILITY

The importance of the sand-carrying ability of a fracturing fluid has already been discussed. The fall-out rate of sand in fresh water, and other low viscosity fluids, is approximately 17 ft per min. If one assumes

TABLE I

VISCOSITIES OF TYPICAL FRACTURING FLUIDS AT 100 F

Fracturing Fluid	Viscosity (centipoises)
Refined oil	80-100
Lease crude	5
Brine water	0.9
Thickened water	50
Gelled crude oil	18
Acid-kerosene emulsion	175

that a fracturing treatment is being performed down 7-in. casing, a pump rate of 1 BPM results in a flow velocity of 45 ft per min, so sand-carrying ability is not a serious factor in the well bore. As the fracturing fluid enters the fracture, however, its velocity is appreciably reduced, whether it is in linear or radial flow; and its sand-carrying ability becomes of prime importance.

Laboratory models have shown the effect of the viscosity of the fracturing fluid on sand fall-out in a fracture. Low viscosity fluids allow sand to fall out immediately upon entering the fracture, and to build up until the fracture is almost closed. As the flow channel becomes more and more restricted, the sand-laden fracturing fluid passes through it at a higher velocity until the fluid begins picking up sand grains from the top of the sand pack. Finally, the rate of fall-out is balanced by the rate of sand pick-up of the rapidly moving fluid. This sand moves on back into a less restricted portion of the fracture, where fluid velocity is reduced; and the sand again begins to fall out.

It may be seen that the packed sand in the fracture grows from the well bore toward the far end of the fracture. In contrast, when a viscous fracturing fluid, such as gelled water or thickened oil, is used, the sand or other propping agent is carried to the far end of the fracture before it is deposited. By controlling the concentration of propping material in a viscous fracturing fluid, it is possible to deposit a monolayer or partial monolayer which will support the fracture, but retain higher residual conductivity.

An advantage of using gelled water as a fracturing fluid is the increase in gel strength as its velocity decreases. Therefore, as the sand-laden fluid enters the fracture, the gel strength increases and holds the sand in suspension. The fall-out rate of sand in gelled water is about 1/4 ft per min, in contrast to the 17 ft per min fall-out rate in unthickened brine or fresh water.

FLUID LOSS

The fluid loss of a fracturing fluid may be defined as the rate of fluid leak-off into the pores and flow channels of the matrix rock, exposed in the fracture faces. This property is, in effect, a measure of the efficiency of a particular fracturing fluid in extending fractures. Fluid loss is now considered to be the most important characteristic of a fracturing fluid; as fluid loss decreases, fracturing fluid efficiency increases.

In practice, fluid loss is controlled by dispersing a fluid-loss additive throughout the fracturing fluid. During the fracturing treatment, this fine-grain solid material is deposited in a thin layer over the face of the fracture. The filter cake starts to build up as the first fluid enters the fracture and continues until the pores of the matrix are sealed off. The loss of fracturing fluid into the formation is thereby halted. At the completion of the fracturing job, the fine solids in this filter cake are slowly dissolved in formation fluids; and the formation permeability of the fracture faces is thereby partially restored.

Evaluation of different fluid-loss additives is accomplished by the use of standard fluid-loss test procedures described in API Bulletin RP-39. Fluid loss is usually reported in terms of cc's per 30 min, and this value should be determined for all contemplated fracturing fluids. Frac Guide calculations, used in the pre-planning of fracturing treatments, take into account the factor of fluid loss by considering two numbers, called the "C_W number" and the "spurt loss". The C_W number (or wall-building coefficient) is a measure of the filter cake efficiency; whereas the spurt loss represents the amount of fracturing fluid lost to the formation before the filter cake is formed. Fluid loss data for some typical fracturing fluids are shown in Table II.

TABLE II

FLUID LOSS PROPERTIES OF TYPICAL FRACTURING FLUID

Fracturing Fluid	Coefficient Cw	Spurt Loss (cc)
Crude oil+FLA RA liquid loss additive	1.0	3
Crude oil + FLA B	1.2	8
Fresh water + FLA C	1.8	10
Acid-kerosene emulsion + FLAD	1.6	12
Brine + FLA E	2.0	2

TREATMENT DESIGN

In planning a stimulation treatment for a given well in a particular reservoir, two basic factors must be taken into consideration: (a) formation characteristics, and (b) physical characteristics of available fracturing fluids, as previously described. Analysis of these factors is usually performed in the following sequence (5):

1. Determine the extent of productivity increase desired (folds of increase).
2. Determine fracture conductivity and fracture width required.
3. Determine total fracture area needed to provide the required productivity increase.
4. Determine size, depth, and pressure limitations of tubular goods through which the fracturing fluid will be pumped.
5. Calculate the volume and injection rate necessary to create the required fracture area and width; fracturing fluids of various efficiencies, or C numbers are compared.
6. Select the most economical fluid that will meet the above requirements and limitations; and by using the desired injection rate, calculate the surface pressure required to achieve fracturing breakdown pressure at the face of the formation.
   a. If the tubular goods have a diameter of 5-1/2in. or more, friction loss will usually not be a problem. If the calculated surface pressure is in excess of the well limitation, the use of a friction reducing additive should be considered.
   b. If the size of the tubular goods is less than 5-1/2 in. in diameter, then friction becomes a major problem. If the calculated surface pressure is in excess of well limitations, the use of friction reducing additives is definitely advisable. This procedure will usually suffice with aqueous fracturing fluids; however, in some situations, in which viscous oil-base fracturing fluids are employed, it may not be possible to lower the friction sufficiently to bring the calculated surface pressure within limits. Under these circumstances, it is usually desirable to use a less viscous fluid and, by increasing the injection rate, to attempt to compensate for the loss of viscosity. A higher density fluid, with lower viscosity and friction loss can be used; however, such high density fluids usually require a fluid-loss additive; and

in extreme cases, it may be necessary to reduce the size of the propping materials. It should be remembered, however, that fracture conductivity and fracture area must be maintained at the desired amounts. Therefore, the fracture width cannot be less than that calculated.

7. On the basis of the injection rate and surface pressure required, using the selected fracturing fluid, calculate the necessary hydraulic horsepower required to inject the fracturing fluid during the treatment. Appropriate pumping equipment may then be selected.

SUMMARY AND CONCLUSIONS

1. Combination of laboratory research and extensive field experience has made it possible to design fracturing treatments on the basis of sound engineering principles.
2. The density, viscosity, friction loss, compressibility, gel strength, and fluid loss of various fracturing fluids are important in determining how well the fluids will function during a fracturing treatment.
3. Consideration of specific well data, in conjunction with the established properties of various available fracturing fluids enables the engineer to design an optimum fracturing treatment that will most effectively and economically fulfill well requirements.
4. Continued analyses of well problems and evaluation of treatment results should provide increased understanding of hydraulic factors involved in formation fracturing, and make possible continued improvement in fracturing materials and techniques.

REFERENCES

(1) A. R. Hendrickson, R. E. Hurst, and D. R. Wieland. "Engineered Guide for Planning Acidizing Treatments Based on Specific Reservoir Characteristics," Annual Fall Meeting, SPE of AIME, Dallas (1959).

(2) B. C. Critendon. "The Mechanics of Design and Interpretation of Hydraulic Fracture Treatments," Annual Fall Meeting, SPE of AIME, Houston (1958).

(3) T. K. Perkins and L. R. Kern. "Widths of Hydraulic Fractures," Annual Fall Meeting, SPE of AIME, Dallas (1961).

(4) H. K. Van Poolen and W. T. Malone. "A Stimulation and Sand Control Method," AIME Paper No. 1321-G (1959).

(5) Dowell Frac Guide, Dowell Division of The Dow Chemical Co., Tulsa (1959).

(6) R. E. Hurst. "An Engineer Method for the Evaluation and Control of Fracturing Treatments," Mid-Continent District API Meeting, Amarillo, Texas (1959).

(7) L. R. Kern, R. E. Wyant and T. K. Perkins. "Propping Fractures with Aluminum Particles," Annual Fall Meeting, SPE of AIME, Denver (1960).

(8) G. C. Howard and C. R. Fast. Optimum Fluid Characteristics for Fracture Extension," API Drilling and Production Practice (1957) p. 261.

ACKNOWLEDGMENTS

The authors wish to express their appreciation to Dowell Division of The Dow Chemical Company for permission to present this paper, and to S. J. Martinez of the Unviersity of Tulsa for assistance in its prearation.