# Acidize Or Fracture?-An Engineered Approach for Permian Basin Reservoirs

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## INTRODUCTION

To evaluate the results of Permian Basin well stimulation treatments and thus improve treating techniques and materials, data have been compiled from thousands of such treatments over the last ten years. One of the conclusions reached from this study is that the matrix permeability of most of the reservoir rocks is so low that it is impossible to inject liquids at normal treating injection rates unless natural fractures are present in the formation or unless artificial fractures are created. Reservoirs having sufficient matrix permeability to accept fluids at the rate of 2 BPM without fracturing are the exception in the Permian Basin area and will therefore be excluded from this discussion. Essentially, acidizing may be considered a specialized form of fracture treatment in which no propping agent is used.

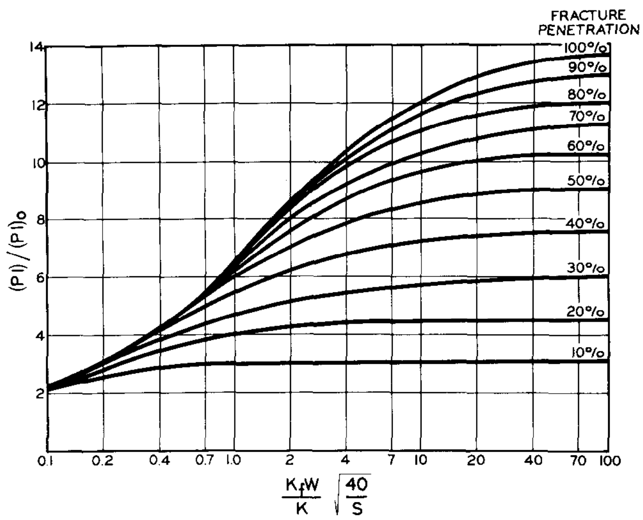


Fig. 1. Estimated productivity increase after stimulation, assuming vertical fracture in well with 6" diameter well bore, on 40 acre spacing. Based on fracture penetration (per cent of well drainage radius) in which

Kf = Fracture permeability, Darcys
W = Fracture width, ft
KfW = Fracture conductivity, Darcy-ft
K = Effective horizontal matrix permeability, millidarcys
(PI) = Productivity Index after treatment
(PI) = Productivity Index before treatment
S = Well spacing, acres

The following correction factor ($\frac{7.13}{\ln 0.472\ re/rw}$) should be applied to the Productivity increase ratio (PI)/(PI) to correct for different well diameters and well spacing, in which:

re = Drainage radius, ft
rw = Well bore radius, ft

## FRACTURE PURPOSE

So that fluid withdrawal from reservoir rocks of low permeability can be economical, required are fractures which possess conductivity several hundred times greater than the matrix rock and which penetrate a considerable distance from the well bore. The effect of formation penetration and fracture conductivity on well production was graphically expressed in a study by the Atlantic Oil and Refining Company, shown in Fig. 1.

From this graph, the expected increase in fluid flow can be predicted by knowing the ratio of fracture conductivity to that of the reservoir matrix, in vertically fractured reservoirs. For example, if the relative conductivity is 0.3 Darcy ft per millidarcy, the maximum productivity increase would be 3.8 times as great as is the original; the treatments providing an excess of 40 per cent penetration would be of little value. In contrast, if the relative conductivity could be increased to 6.0 Darcy ft per millidarcy, the same 40 per cent penetrating treatment would provide a seven-fold increase. And larger treatments would provide even greater increases in productivity.

## FRACTURE CONDUCTIVITY TESTING

The importance of the relationship between fracture conductivity and the productivity increase resulting from a stimulation treatment has been stressed in many publications.[1, 2, 3, 4] Considerable time and money have been spent on research to develop practical methods of increasing fracture conductivity. As a result, there have been recently introduced for this purpose a number of new propping agents: ground and graded walnut shells, steel balls, aluminum pellets, nylon cylinders, and other malleable materials which resist crushing under high overburden pressure, or resist embedment in soft reservoir rocks.

Where proper laboratory testing has indicated that, under well conditions, such materials should result in improved fracture conductivity, results of subsequent field applications have been very encouraging. Graded silica sands still remain the most commonly used propping agent used in conjunction with fracture treatments; and, where laboratory tests show that adequate conductivity results from its use, this approach is undoubtedly the most economical.

Laboratory conductivity data that will reliably simulate fracture conductivities obtained in actual field treatments are essential for the proper planning of such well stimulation treatments. A number of testing techniques have been developed by different laboratories and are explained in the technical literature. The procedure explained herein was developed by Dowell Division of The Dow Chemical Company at Midland, Texas.

This testing procedure attempts to evaluate comparatively inert fracture fluids containing props and chemically active fluids, such as acids, which will react with fracture faces. The conditions under which the tests are performed are designed to approach actual conditions existing in any individual well or reservoir.

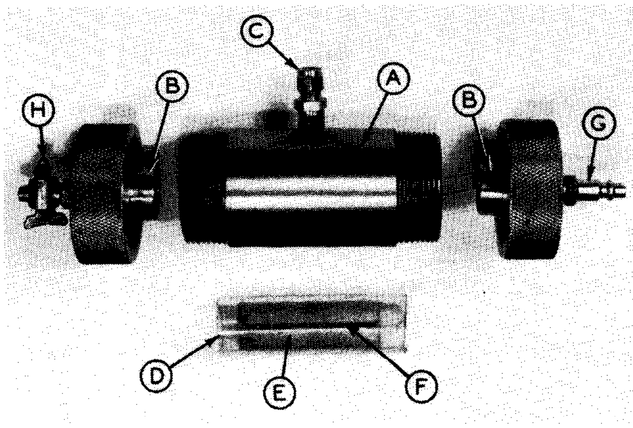


Fig. 2. Photo of disassembled fracture conductivity test apparatus. Component parts shown are: (A) Confinement cylinder capable of withstanding pressures in excess of 20,000 psi. (B) End caps which insert into flexible sleeve (d) and connect to cylinder (a). (C) Inlet through which pressure can be hydraulically applied to the exterior of the test plug, simulating overburden pressure. (D) Flexible sleeve which allows application of overburden pressures to the test plug, yet separating hydraulic fluid from stimulation materials in the test core plug and fracture. (E) Test plug taken from rotary core. Individual plugs, to be tested with different stimulation materials and fluids, are cut from rotary cores at the closest possible spacing. (F) Propping agent, in this case aluminum pellets, shown in place. The agent, concentration and particle size are varied on different tests for comparative purposes. (G) Inlet for stimulation materials injected into the fracture test plug; also used as an inlet for conductivity test fluids following. (H) Outlet for checking fluid flow during subsequent conductivity test. (I) (Not shown) Electrical heating jacket to duplicate bottomhole temperature.

Fig. 2 shows the basic apparatus used to determine the comparative fracture conductivity of a given formation, following different types of stimulation treatments.

## TEST PROCEDURE

The following is a brief summary of the test procedures used in determining comparative fracture conductivities resulting from different types of stimulation treatments:

1. Duplicate test plugs are cut from a standard rotary core; these cuts spaced as closely as possible.
2. A test plug is split to simulate a fracture and assembled in the test apparatus.
3. A propping agent is introduced into the fracture in the desired concentration (this process can be done by hand or introduced into the plug by means of a fluid carrier).
4. Overburden pressure is hydraulically applied to the exterior of the test plug.
5. For simulated fracture treatment tests, the suspended propping agent and fracture fluid are injected into the core and fracture and are left under pressure for 12 hours or more.
6. In testing acidizing solutions without propping agents, a minimum of one fracture volume of acid is spent on the test plug fracture faces under laminar flow, bottom-hole fracturing pressure and temperature. The spent acid is then allowed to stand, for 12 additional hours and under pressure, in the fracture.
7. From the fracture the stimulation fluid is then flushed with reservoir fluid or special test fluid, such as kerosene, from a regulated pressurized reservoir tank.
8. The flow rate through the fracture is measured at constant inlet pressure, while overburden pressure and simulated bottomhole temperature are held constant.

## SUMMARY OF TEST DATA

From the several hundred conductivity tests performed to date, no universal correlation has been found with the different reservoir rock properties that will serve as a guide in the selection of optimum treating fluid, without individual testing. However, certain observations have been made often enough to justify their statement as general patterns:

1. Dense hard rocks, with high confining pressure (above 6,000 psi) and with little or no acid solubility, usually show higher fracture conductivity when propped with a partial monolayer of malleable propping agent that will resist crushing than will the conventional sand-packed fracture.
2. Dense or permeable soft rocks, with high confining pressure, show best conductivity when malleable propping agents are used; however closer spacing of the individual particles is desirable than is necessary for the harder rocks.
3. Dense or permeable hard rocks, with high confining pressure and heterogeneous structure having an acid solubility in excess of 10 per cent (30 per cent soluble more desirable), usually show exceptionally good conductivity following treatment with acid solutions containing no propping agents.
4. Dense hard rocks, with low confining pressure (less than 6,000 psi) and little or no acid solubility, show adequate conductivity from packed fractures filled with uniform, graded silica sand.
5. Dense hard rocks, with low confining pressure and heterogeneous structure having fair to good acid solubility, respond well to properly selected acid solutions, without propping agents. If the rock is uniform in structure, regardless of its acid solubility, best results will be obtained by using the sand-packed fracture.

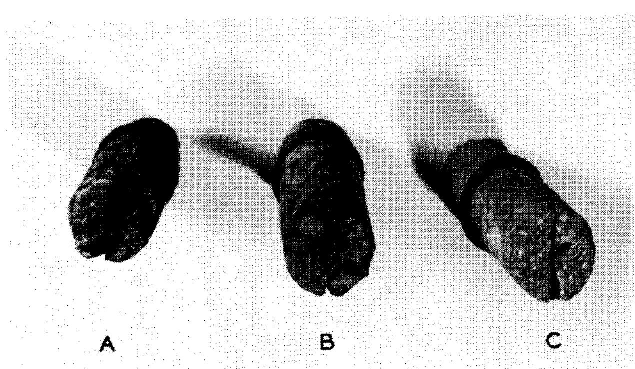


Fig. 3. Photo of split test plugs used in fracture conductivity tests. Sample A: Coral Reef formation, Canada. Sample B: Coral Reef formation, Canada. Sample C: Strawn limestone formation, West Texas.

TABLE I

COMPARATIVE FRACTURE CONDUCTIVITY TESTS

Fluid flow (cc/sec) through test plugs from different formations and locations.
Overburden pressure shown for specific wells from which core samples were taken.

| TEST CONDITONS | WELL A Devonian (7500 psi) | WELL B Devonian (7000 psi) | WELL C Devonian (5500 psi) | WELL D San Andres (3000 psi) | WELL E San Andres (2000 psi) | WELL F San Andres (3000 psi) | WELL G Dakota Sand (6000 psi) | WELL H Gallup Sand (4000 psi) |
|---|---|---|---|---|---|---|---|---|
| Oil with 20-40 mesh sand pack (0.85 lb/sq ft fracture area) | 4.00 | 3.86 | 7.70 | 12.47 | 16.80 | 10.90 | 6.60 | 8.80 |
| Water with 20-40 mesh sand pack (0.85 lb/sq ft fracture area) | 4.05 | 3.90 | 7.00 | 8.30 | 16.60 | 11.20 | 6.50 | 9.90 |
| Oil with 10-20 mesh sand pack (0.85 lb/sq ft fracture area) | - | - | 16.80 | - | 25.00 | 23.70 | 5.50 | - |
| Oil with aluminum pellets (0.06 lb/sq ft fracture area) | - | - | 30.00 | - | 25.00 | 31.80 | - | 49.80 |
| Oil with walnut shells (0.03 lb/sq ft fracture area) | - | - | - | - | 49.20 | 11.10 | 0.01 | 20.40 |
| Retarded acid solution (No propping agents) | 25.40 | 62.00 | 2.10 | 0.06 | 5.55 | 31.30 | - | - |

6. Soft or sugary-type rocks, with low confining pressures, respond erratically to stimulation. The best conductivity may be achieved from sand-packing the fracture or from the use of low concentrations of large size malleable propping agents.

Fracture conductivity data, obtained from typical Permian Basin formation samples, are shown in Table I. It may be seen that different cores from the same formation but different pools do not respond alike. This lack of similar response points up the importance of, wherever possible, pre-testing core samples from the specific well to be stimulated.

Fig. 3 shows three split test plugs as used in the fracture conductivity tests. Fig. 4 shows these same test plugs separated, to reveal the texture of the fracture face following treatment with slow-reacting acid.

Test plugs "A" and "B" were taken from the Coral Reef formation of Canada, at different depths. This formation has a high confining pressure (near 7,000 psi) and is classified as a hard, dense limestone with good acid solubility and non-uniform structure. Accordingly, would yield a fracture having the greatest conductivity. The split test plugs shown in the picture have been treated with a gelled acid under bottom-hole conditions of temperature and pressure. The surface irregularities caused by the non-uniform acid reaction provide natural propping so that the fracture remains open following treatment, even when subjected to 10,000 psi overburden pressure.

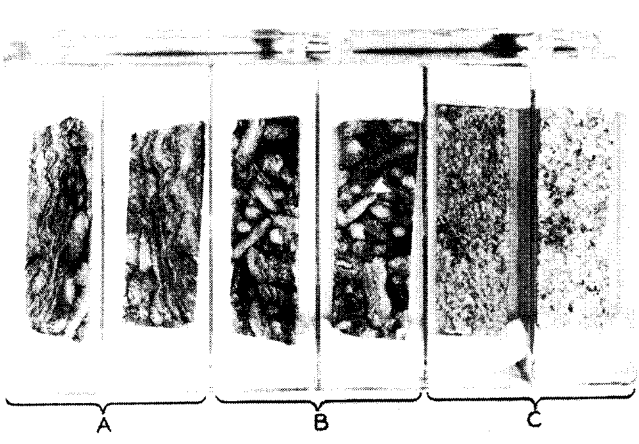


Fig. 4. Fracture faces of test plugs shown in Fig. 3, following acidizing treatment without propping agents.

Test plug "C" was taken from a Strawn limestone reservoir in West Texas. Here again, the heterogeneity of the rock resulted in an irregular surface following treatment with acid. In this case, the physical structure of the rock is more uniform so the differential attack of the acid is less pronounced. For this reason, the fracture conductivity was less than that of the preceding examples. However, because of high overburden pressure and the hardness of this rock, this type of acid treatment provided greater fracture conductivity than would conventional fracturing using a sand-packed fracture. At the time of this test, malleable props were not available, but it would be expected that the use of such props would give good results in this reservoir.

## TREATMENT PLANNING

Once the proper fracturing fluid (with or without propping agents) has been selected on the basis of fracture conductivity tests, other treatment considerations such as fluid volume, injection rate, etc., must be determined for the proper application of the treatment. Proper selection of these factors is an essential engineering problem, for this selection determines whether or not is obtained the desired fracture penetration, which is in turn related to the productivity of the well following stimulation.

The controlling principles for fracture extension have been widely discussed,[5, 6, 7] and will only be summarized here. The extent of fracture penetration is essentially dependent upon the amount of fracturing fluid remaining in the fracture at the end of the treatment. This, in effect, is the volume of fluid injected into the formation, less that which leaks off into the matrix through the fracture faces. The greater the ability of a fracturing fluid to resist leak-off, the greater the fracture penetration that will be achieved by a given initial volume of the fluid. The extent of leak-off is influenced by the following factors:

1. Exposure time (dependent upon injection rate).
2. Viscosity of the fracturing fluid.
3. Fluid-loss additives in solution or suspension.
4. Physical properties of reservoir fluid contained in the matrix.
5. Differential pressure required to maintain fracture extension.
6. Porosity and permeability of the matrix adjoining the fracture faces.

Taking all these factors into consideration, a numerical value can be assigned to each particular fracturing fluid under specific well conditions and will indicate the comparative ability of the fluid to resist leak-off during injection. This numerical value is called the "Fracturing Fluid Coefficient" and is usually expressed as a given number times $10^{-3}$. This coefficient, when plotted against injection rate, shows the resultant fracture area in sq ft for a given initial volume of fracturing fluid. Assuming a general flow pattern, the fracture penetration from the well bore can thus be approximated. The basic patterns normally assumed are horizontal radial or vertical rectangular, but there is no known method by which the actual flow pattern for a particular well or reservoir can be determined.

Observation of field data has indicated that reservoir rocks displaying fracture pressure gradients of less than 0.7 psi per ft of depth generally exhibit a vertical fracture pattern, whereas those displaying fracture pressure gradients approaching or exceeding 1.0 psi per ft exhibit horizontal fracture patterns. If the factors of fracture conducitivity and fracture penetration are given due consideration in planning a stimulation treatment, optimum productivity increases per dollar spent should result.

TABLE II

CASE HISTORY SHOWING FIELD APPLICATION OF FRACTURE CONDUCTIVITY DATA

Field: Azalea, Midland County, State of Texas.

Formation: Devonian Limestone - 11,400 feet.

Reservoir Thickness: Approx. 100 feet.

Fracture Gradient: 0.65 psi per foot.

Overburden Pressure: Approx. 7400 psi.

Results of Conductivity Test: (Avg test values for field)

| | |
|---|---|
| Oil & 20-40 mesh sand pack | 3.7 cc/sec |
| Acid gel & 20-40 mesh sand pack | 7.4 cc/sec |
| Acid gel & no sand | 24.0 cc/sec |

Fracture Fluid Coefficients: (Avg for field)

| | |
|---|---|
| Frac oil | $3.0 \times 10^{-3}$ |
| Acid gel | $3.0 \times 10^{-3}$ |

Figure I Abcissa Values: (Avg for field)

| | |
|---|---|
| Oil & 20-40 mesh sand | .13 Darcy ft/md |
| Acid gel & 20-40 mesh sand | .25 Darcy ft/md |
| Acid gel & no sand | 1.0 Darcy ft/md |

Expected penetration from different volumes:

| | |
|---|---|
| 50,000 | 40% |
| 75,000 | 70% |
| 150,000 | 100% |

INITIAL WELL PRODUCTION: (After drilling-damage removal)

Highly variable from 500 MCF to 3,000 MCF.

Avg value 1,000 MCF.

Expected folds of increase:

| | |
|---|---|
| 50,000 gal oil & 20-40 mesh sand | 2.6 |
| 75,000 gal oil & 20-40 mesh sand | 2.6 |
| 150,000 gal oil & 20-40 mesh sand | 2.6 |
| 50,000 gal acid gel & 20-40 mesh sand | 3.4 |
| 75,000 gal acid gel & 20-40 mesh sand | 3.4 |
| 150,000 gal acid gel & 20-40 mesh sand | 3.4 |
| 50,000 gal acid gel & no sand | 5.4 |
| 75,000 gal acid gel & no sand | 6.4 |
| 150,000 gal acid gel & no sand | 6.6 |

FIELD TREATMENTS:

| WELL | FLUID & VOLUME | ESTIMATE INITIAL PROD. | AFTER TEST | EXPECTED FOLDS | ACTUAL FOLDS |
|---|---|---|---|---|---|
| F-1 | 50,000 gal oil & 20-40 mesh sand | 1,600 MCF | 5,100 MCF | 2.6 | 3.2 |
| M-1 | 70,000 gal oil & 20-40 mesh sand | 900 MCF | 2,600 MCF | 2.6 | 2.9 |
| MB-1 | 50,000 gal acid & 20-40 mesh sand | 1,000 MCF | 3,600 MCF | 3.4 | 3.6 |
| R-1 | 75,000 gal acid & 20-40 mesh sand | 1,100 MCF | 3,300 MCF | 3.4 | 3.0 |
| SE-1 | 150,000 gal acid & 20-40 mesh sand | 800 MCF | 6,500 MCF | 3.4 | 8.0 |
| KU-1 | 75,000 gal acid - no sand | 900 MCF | 6,800 MCF | 6.4 | 7.5 |
| MT-1 | 120,000 gal acid - no sand | 750 MCF | 6,500 MCF | 6.5 | 8.6 |

## FIELD CASE HISTORY

These treatment planning techniques have proven highly beneficial during actual field use. In the Azalea field, Midland County, Texas, production results from over 50 treated wells substantiate the results obtained on preliminary fracture conductivity tests. Preliminary test data and typical treatment results in this field are shown in Table II.

Predicting productivity increases on the basis of a single, extensive fracture is extremely difficult. Results shown in this table indicate that high fracture penetration (over 50 per cent) yielded greater productivity increases than might be expected. This increase might be due to obtaining multiple vertical fractures, rather than to a single extensive fracture as assumed. As may be observed from the data shown here, the use of a treating fluid which would result in high fracture conductivity achieved equal or better results than larger volumes of treating fluids producing poor fracture conductivity.

## SUMMARY

1. Benefits from most stimulation treatments are directly related to the final conductivity of the treated fractures, under normal bottom-hole temperature and pressure conditions.

2. Crushing or embedment of fracture propping agents can be seriously detrimental to fracture conductivity. The degree of crushing or embedment that takes place is related to the physical properties of the formation rock in the presence of the stimulation fluids, under bottom-hole conditions.
3. Fracture conductivity tests have shown that high reservoir fluid-flow capacities are obtainable from fracture treatments using special acid solutions without propping agents, if the physical and chemical structure of the rock is suitable.
4. Although general patterns have developed from study of hundreds of laboratory tests, specific well responses to stimulation cannot be accurately predicted without preliminary laboratory examination of core samples, and proper testing under bottom-hole conditions.

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