PROPPANT SELECTION - THE KEY TO SUCCESSFUL FRACTURE STIMULATION

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ABSTRACT

There are many types of proppants and mesh sizes to consider in the design of a fracture stimulation treatment. When considering proppants, sand (Ottawa, Texas Mining, Unisil), bauxite, intermediate strength proppants (ISP), resin-coated sand (RCS), precured resin-coated sand (PRCS) and Z-prop, the principal questions seem to be, "Which one do I select and how should I use it?"

Maximizing adequate long-term productivity in low-permeability reservoirs is dependent on both fracture penetration and fracture, conductivity. How to obtain deeply penetrating fractures, contained and adjacent to the porous interval, is one of the problems that challenges the industry. The other is how to obtain sufficient fracture conductivity to effectively utilize the deep penetration. This paper discusses how to determine and obtain sufficient fracture conductivity. Fracture conductivity is a function of the proppant properties (i.e., strength, roundness, fines content, etc.), closure stress, drawdown rate, formation properties (i.e., proppant embedment conditions) and resultant propped fracture width. The engineering principles involved in the selection of the proper type and amount of proppant are supported with a case history.

This is a "state-of-the-art" paper, attempting to bring the current technology on proppants together in one place.

INTRODUCTION

As we explore for reserves at depths exceeding 10,000 ft, the tendency is to find reservoirs that have low permeability and contain natural gas. Because of the low permeability of the formation, both the natural rate of production and the drainage area are often too low to provide a commercial well.

Propped hydraulic fracture stimulation treatments that create deeply penetrating, highly conductive, flow channels can be used to increase both the rate of production and the drainage area.[1]

The factors which control the improvements in productivity provided by hydraulic fracturing (i.e., productivity index) are the following.

- Propped Fracture Area (ft^2) - This is the area of the fracture, adjacent to the porous interval, that has been propped (length x height). All of the fracture area adjacent to the porous interval that is created may not be propped, and only that fracture area that is propped adjacent to the productive porosity is considered as effective area.

- Conductivity of the Propped Fracture (md-ft) - This is a measurement of how well the propped fracture is able to conduct the produced fluids. In addition to the effect of closure stress on the permeability of the proppant, such factors as embedment, proppant distribution and resultant fracture width must be considered to determine the conductivity of the fracture at reservoir producing conditions.

- Reservoir Permeability - This value is used to determine the fracture conductivity required to effectively utilize the proposed fracture penetration.

- Drainage Radius - As with reservoir permeability, the value is used to determine the length of fracture needed. A long fracture is needed if the well spacing is large and the reservoir permeability is low.

Typical Well

To show how the principles that are described in this paper work, we will use a typical gas well with the following properties:

Depth	=	12,000 ft
Permeability (k_g)	=	0.03 md
Height of Pay Zone	=	100 ft
Porosity (ϕ)	=	6%
Fracture Gradient	=	0.85 psi/ft
Gas Gravity	=	0.65
Gas Compressibility at 6,000 psi	=	1.02×10^{-4} psi^{-1}
Gas Viscosity	=	0.02 cp
Bottom-Hole Pressure (BHP)	=	6,000 psi
Bottom-Hole Producing Pressure(BHPP)	=	2,000 psi
Bottom-Hole Temperature (BHT)	=	250°F
Well Spacing	=	640 acres

Effect of Reservoir Permeability on Fracturing

In deep, hot, low-permeability sandstone reservoirs, it is important to develop deeply penetrating fractures with adequate conductivity. Once reservoir permeability is known, it is important to optimize the fracture length and conductivity by comparing treatment cost to expected production. The pressure drop down a propped fracture with insufficient capacity will limit the production from a well. A fracture with excessive fracture capacity is not cost effective.

Figure 1[2] can be used as a guide to help select the desired effective fracture length based on reservoir permeability. When the reservoir permeability is greater than about 0.1 md, the desired fracture lengths are generally 1,000 ft or less. In low-permeability reservoirs (k_g < 0.1 md), production can be almost directly proportional to fracture length prior to reaching boundary conditions. The longer the fracture, with adequate fracture flow conductivity, the higher the producing rate. For example, in very low-permeability (i.e., 0.001 to 0.0001 md) reservoirs, fracture half-length of 2,500 to 4,000 ft can be used to effectively increase production. In the example typical well with a permeability of 0.03 md, it can be seen from Figure 1 that creating and propping 1,400- to 2,000-ft fractures (1,800 ft used in example problems) should be attempted to achieve maximum production.

Effect of Fracture Conductivity and Fracture Length on Production

Figure 2 was generated using a reservoir simulator[3] and shows the effect of fracture conductivity (F_{CD}) and fracture length on production in dimensionless terms. Dimensionless time (t_{Dx_f}) is related to the producing time (t) and fracture length (x_f) as shown in Equation 1.

$$t_{Dx_f} = \frac{2.634 \times 10^{-4}\ kt}{\phi\ \mu\ C_t x_f^2} \qquad (1)$$

where

t_{Dx_f} = Dimensionless Time,

t = Time, hr,
k = Formation Permeability, md,

ϕ = Formation Porosity, fraction,

μ = Viscosity, cp,

c_t = Total System Compressibility, psi^{-1}, and

x_f = Fracture Half-Length, ft.

Production rate (q) is proportional to dimensionless rate (q_D) as shown in Equation 2.

$$1/q_D = \frac{k\ h\ \Delta\ p}{141.2\ q\ \mu\ \beta} \qquad (2)$$

where

$1/q_D$ = Dimensionless Flow Rate,

k = Permeability, md,

μ = Viscosity, cp,

B = Formation Volume Factor, RB/STB,

h = Formation Thickness, ft,

q = Rate, STB/day (STB = Stock Tank BBL) or Mcfd, and

Δp = Pressure Drop, psi.

The dimensionless fracture capacity (F_{CD}) is shown in Equation 3.

$$F_{CD} = \frac{k_p w}{k_{EH} x_f} \tag{3}$$

where

k_p = Proppant Permeability at Producing Closure Conditions,

w = Fracture Width, ft,

k_{EH} = Effective Horizontal Formation Permeability, md, and

x_f = Fracture Half-Length, ft.

Equation 3 is the key equation in optimizing fracture conductivity, fracture length and formation permeability. The permeability (k_{EH}) of the formation is fixed. The permeability of the proppant (k_p) varies with closure stress, proppant size, proppant composition and quality. The width of the producing fracture (w) varies with closure stress, the amount of proppant within the fracture, proppant strength, and formation hardness and strength. The length of the fracture (x_f) must be optimized by varying the fracture conductivity ($k_p w$) and the ability of keeping the fracture in zone.

As can be noted in Figure 2, an F_{CD} of 10 or greater provides essentially the same production performance when dimensionless times are greater than 0.1. This would be about 165 days in real time in the example well. The well would perform essentially the same with an F_{CD} of 10 to 500 after 165 days of production; therefore, the expense of an F_{CD} of 500 is not justified by incremental increase in production. Therefore, the fracture should be optimized for an F_{CD} of 10. As longer fractures are created to increase production, the fracture conductivity ($k_p w$) must be increased to maintain the F_{CD} value equal to, or larger than, 10.

Figure 3 shows the required fracture conductivity to give an F_{CD} of 10 for various formation permeabilities and fracture lengths.

In the typical well example with a formation permeability of 0.03 md and with a selected fracture length from Figure 1 of 1,800 ft, the fracture conductivity must be at least 500 md-ft.

How to Determine the Actual Bottom-Hole Producing Fracture Conductivity

The best method of determining fracture conductivity is by using core samples from the well in question, preparing core halves to simulate fracture faces and "**measuring**" the fracture conductivity under closure pressure in the laboratory using different amounts and types of proppants.

Tables 1, 2 and 3 present data that were generated in the laboratory using cores from the depths and formations indicated. The data show that even though the fracture width is wider in the fractures propped with sand due to the lower specific gravity of sand, the fracture conductivity of the fractures propped with bauxite is from 5 to 27 times higher due to the strength of the bauxite and limited proppant crushing.

Because of the expense and difficulties of getting actual cores, the fracture conductivity normally cannot be measured in the laboratory using this technique. Fracture conductivity is normally "**calculated**" by assuming a width based (this will be discussed) on the pounds of proppant per square foot of fracture area times the measured permeability of the proppant at the producing closure pressure conditions.

There have been numerous papers and brochures written on the measurement and values of proppant permeability in the laboratory.[4-12] The measurements are usually done using hard metal plates to simulate the fracture faces. The values reported vary widely, probably because of differences in the testing procedures. Figures 4 through 18 show average values and error bars from as many as 17 different tests and nine different sources for sintered bauxite, intermediate strength bauxite, fused ceramic (Z-prop), resin-coated sand and the best quality fracturing sand. It is hoped that the average values are more representative of the actual value that should be used rather than the extremes the literature shows.

Closure Pressure

The permeability of the proppant within the fracture varies with closure pressure. The fracture closure stress is essentially the stress required to open the fracture minus the bottom-hole producing stress within the fracture as shown in Equation 4. This closure stress is available to close the fracture and will tend to reduce the fracture conductivity.

$$CS = P_{fg}D - BHPP \tag{4}$$

where

CS = Closure Stress, psi,

P_{fg} = Current Fracture Gradient, psi/ft,

D = Depth, ft, and

BHPP = Bottom-Hole Producing Pressure, psi.

It is common practice to use the fracture gradient (P_{fg}) and the reservoir abandonment pressure to calculate the maximum closure stress on the proppant. As the reservoir pressure is being depleted, both the fracture gradient and bottom-hole pressure are being reduced but at different rates. Therefore, effective stress on the proppant is increasing.[14] This increase is generally not sufficient to change the decision on proppant selection and the above practice should be sufficient for most cases. On deep gas wells, the most severe closure stress condition happens early in the life of the well because the amount of stress required to open the fracture is at the highest value. If the well is allowed to produce at the maximum rate or is swabbed hard during the initial completion, an extremely low pressure within the fracture will be temporarily created causing an unduly high closure stress.

Fracture Width

Experience has shown that propped fractures greater than 0.25 in. are very difficult to achieve, particularly at the deeper depths. A good place to start a design is to assume a width of 0.1 in. (0.008 ft). This width can be varied somewhat to allow for larger conductivities if required. Fracture width can also be calculated from Equation 3 if k_p is known.

Case History

To show how the principles described above work, using the typical well parameters and an assumed propped width of 0.008 ft (0.1 in.), it can be calculated from Equation 3 that the proppant permeability (k_p) required to achieve an F_{CD} of 10 is as follows.

$$F_{CD} = \frac{k_p w}{k_{EH} x_f} = 10 \tag{5}$$

where

w (propped width) = 0.008 ft (0.1 in.)

$$k_p = \frac{(k_{EH})(x_f)(10)}{w}$$

$$k_p = \frac{(0.03 \text{ md})(1{,}800 \text{ ft})(10)}{0.008 \text{ ft}}$$

$$k_p = 67{,}500 \text{ md}$$

The closure stress this well will experience can be calculated from Equation 4.

$$CS = P_{fg}D - BHPP$$

$$CS = (0.85 \text{ psi/ft})(12{,}000 \text{ ft}) - 2{,}000 \text{ psi}$$

$$CS = 8{,}200 \text{ psi}$$

If the well was swabbed hard after the fracture treatment, the pressure within the fracture could be less than 2,000 psi and the closure stress even greater than 8,200 psi. For example, if the BHPP were brought down to 500 psi because of swabbing or high initial production rates, then:

$$CS = (0.85 \text{ psi/ft})(12{,}000 \text{ ft}) - 500 \text{ psi}$$

or

$$CS = 9{,}700 \text{ psi.}$$

Using Figures 4 through 18, the k_p of the various proppants at these two closures is the following.

Proppant	k_p in md @ 8,200-psi Closure	k_p in md @ 9,700-psi Closure
12/20 Sand	7,300	4,600
20/40 Sand	7,800	4,800
40/70 Sand	4,350	3,500
20/40 Resin-Coated Sand	118,000	6,400
12/20 ISP	880,000	720,000
16/20 ISP	430,000	350,000
20/40 ISP	212,000	177,000
40/70 ISP	94,000	79,000
16/20 Z-Prop	600,000	350,000
20/40 Z-Prop	235,000	217,000
40/70 Z-Prop	92,000	88,000
12/20 Bauxite	990,000	850,000
16/20 Bauxite	800,000	700,000
20/40 Bauxite	260,000	235,000
40/60 Bauxite	74,000	65,000

In this case, to obtain the required k_p of 67,500 md, any of the available proppants except sand could be used. This number is still very optimistic, however, because of several ill-defined factors. Cooke[4] has shown that hot brine causes as much as two- to threefold permeability reductions in sand and bauxite proppant packs.

Although the data presented in Figures 4 through 18 were run with 2% KCl and at various temperatures, it is still felt some k_p reduction will result due to hot formation brines. A second factor is that the published data (including flow data in this paper) on k_p were generated with short time intervals between each measurement. Figure 19 shows the effect of time at closure pressure using hardened metal plates to simulate fracture faces. As can be seen, the fracture conductivity continues to be reduced for several months before the sand pack comes into an equilibrium condition. This is due to sand particles breaking and geometric particle rearrangement to the minimum pack porosity.

A third factor is embedment. Several authors[11,13] have shown that embedment improves the retention of permeability at higher closure stresses. This is caused because the stress is spread over a larger portion of the particle. Rather than having a point-to-point contact as with the linear flow apparatus, the proppant embeds into the rock at increased closure spreading the stress over a larger area. This embedment is a function of the modulus of the rock and, therefore, final conductivity is a function of the modulus. On the opposite side, embedment does allow partial fracture closure which will reduce fracture width and conductivity. Other factors that influence final conductivity but are very difficult to define are the effect of gel residue in the fracture, movement of formation fines into the fracture and very long-term degradation of the proppant. Taken together it is believed that in deep well completions the final recommended conductivity needs to be two to three times higher than the theoretical designed conductivity. In this case, one-half of the mentioned proppants would not meet this criterion and, if used, a wider producing fracture would have to be created.

Using the example of the typical well, the 67,500-md k_p would become 135,000 to 202,500 md. Therefore, it should be recommended that 12/20-, 16/20- or 20/40-mesh ISP, Z-Prop or Bauxite be used. It then becomes a matter of economics to obtain adequate k_p at the lowest cost.

Proppant Volume

Figures 20 and 21 show the proppant concentration in pounds per square foot of fracture area vs the width of the fracture for various proppants. The figure assumes there is no embedment and the porosity remains constant for each proppant at its recommended closure stress range. For the example well using 20/40 bauxite and a fracture width of 0.1 in. (0.008 ft), 1.2 lb of proppant per square foot of fracture area is required. The predicted propped fracture area would be Fracture Length (1,800 ft) x Net Fracture Height (100 ft) x 2 Fracture Wings = 360,000 ft^2. Taking this number times the 1.2 lb of proppant per square foot shows that 432,000 lb of bauxite would be required for this treatment.

Economics of Typical Well Example

The well used in this paper, in an undamaged condition, should produce approximately 7.5% of the initial gas in place from the 640-acre drainage area in 20 yr. With a 1,800-ft fracture having a dimensionless flow capacity of 10, that same well would deplete almost 35%, of that initial gas in place, in the same amount of time. The initial rates, for the fractured well, would be higher than those of the unfractured well. Its ultimate recovery would also be greater. These two factors are key points when determining the economics of a single well or when trying to determine required well spacing.

CONCLUSIONS

1. Based on individual well conditions, the optimized proppant can be selected based on the conditions found in that well.

2. Both the effective fracture length and fracture conductivity can be selected and calculated by the design engineer.

3. Fracture conductivity is significantly affected by closure stress as shown on rock samples.

ACKNOWLEDGMENTS

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Table 1
Fracture Conductivity in the Morrow Formation at a Proppant Concentration of 2 lb/ft^2

Depth = 14,060 ft
Closure Stress = 10,000 psi

Proppant	Fracture Width (in.)	Fracture Conductivity (darcy-ft)	Permeability (darcy)
20/40 Sand	0.177	0.11	7.7
20/40 Bauxite	0.157	3.14	240

Table 2
Fracture Conductivity in the Granite Wash Formation at a Proppant Concentration of 2 lb/ft^2

Depth = 13,075 ft
Fracture Gradient = 0.69 psi/ft

Proppant	Fracture Width (in.)	Fracture Conductivity (darcy-ft)	Permeability (darcy)
20/40 Sand	0.200	0.47	28.2
20/40 Bauxite	0.162	2.46	182.5
12/20 Bauxite	0.162	5.62	416.5

Table 3
Embedment of Bauxite (20/40)-Vicksburg Formation

Depth = 10,712 ft

Closure Stress (psi)	Conductivity (darcy-ft)			
	0.5 lb/ft^2	1.0 lb/ft^2	2.4 lb/ft^2	4.5 lb/ft^2
1,000	3.5	2.81	2.71	3.18
3,000	1.2	1.76	1.92	2.71
5,000	0.08	1.48	1.76	2.53
7,000	0.05	1.06	1.40	2.28
9,000	0.02	0.91	1.28	2.17

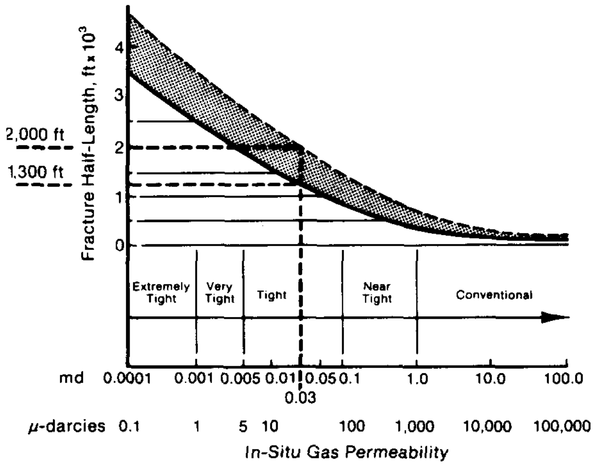

Figure 1 - Required fracture half-lengths vs. formation permeability

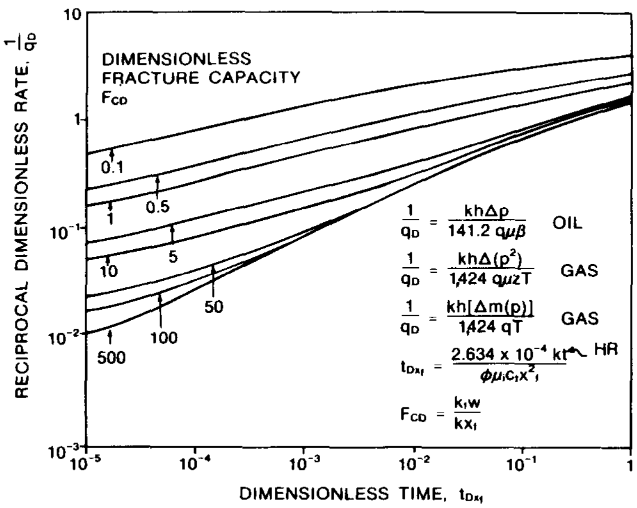

Figure 2 - Log-log type curves for finite capacity vertical fractures --constant wellbore pressure

$k_f w = k_{EH} \times x_f \times 10$

Fracture Capacity = Formation Permeability x Fracture Half Length x F_{CD}

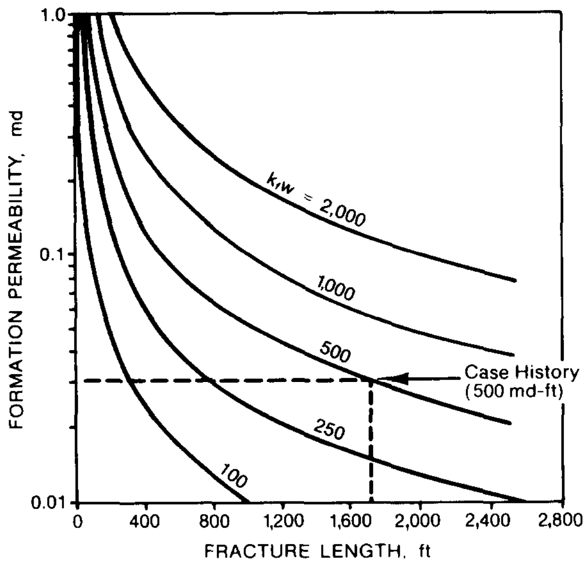

Figure 3 - Fracture conductivity for formation permeability vs. fracture length

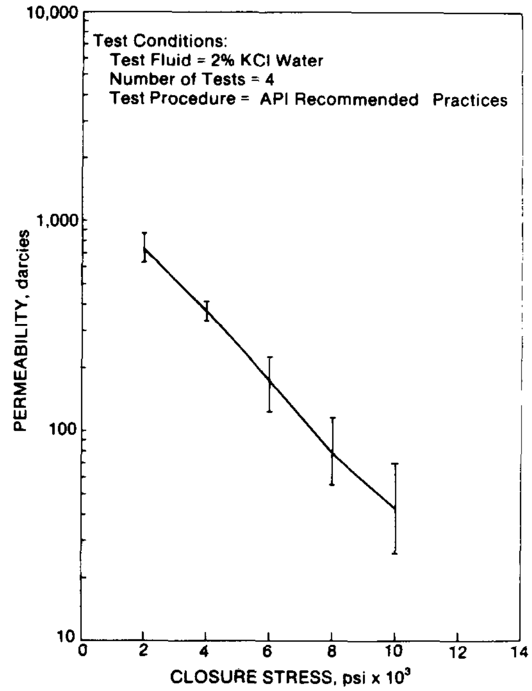

Figure 4 - Permeability vs. closure stress of 12/20 best quality fracturing sand

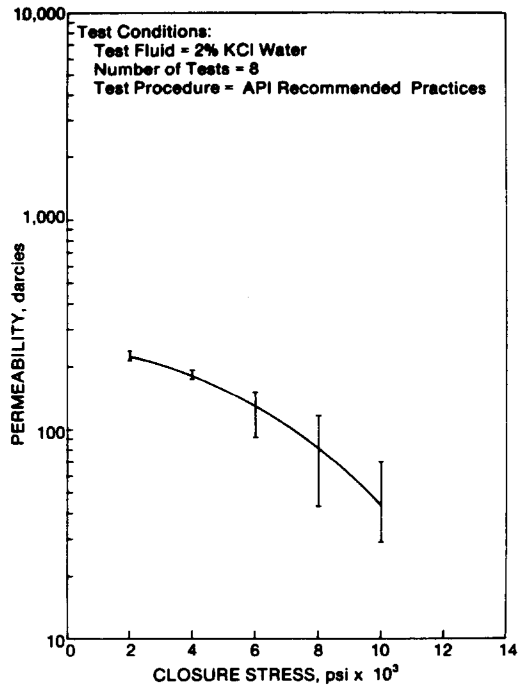

Figure 5 - Permeability vs. closure stress of 20/40 best quality fracturing sand

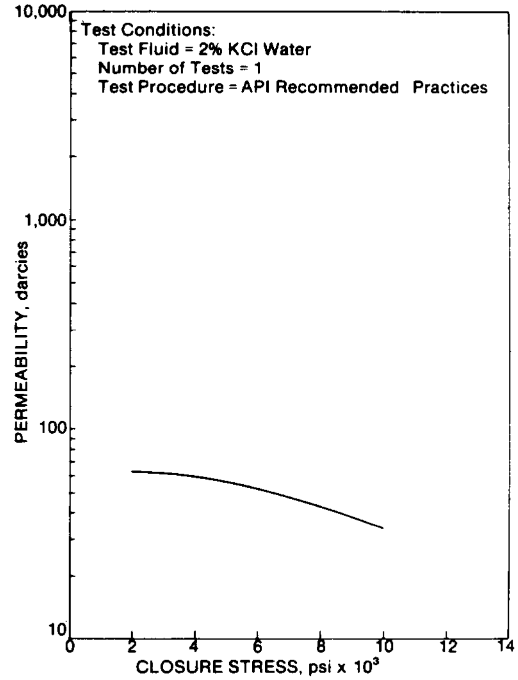

Figure 6 - Permeability vs. closure stress of 40/70 best quality fracturing sand

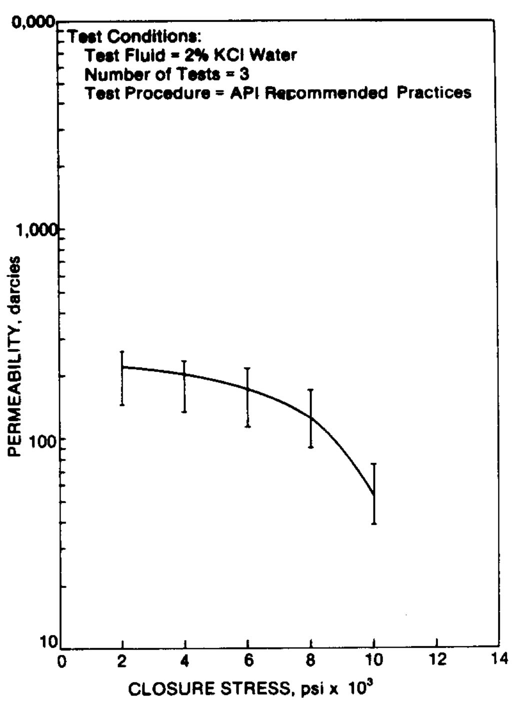

Figure 7 - Permeability vs. closure stress of 20/40 precured resin-coated sand (RCS)

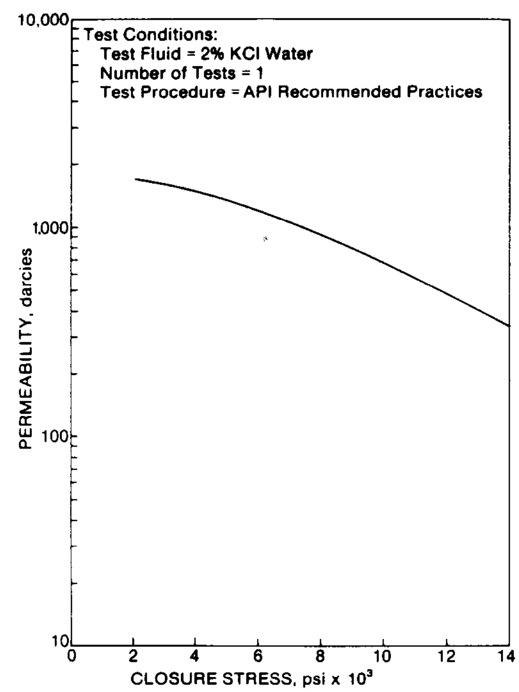

Figure 8 - Permeability vs. closure stress of 12/20 intermediate strength proppant (ISP)

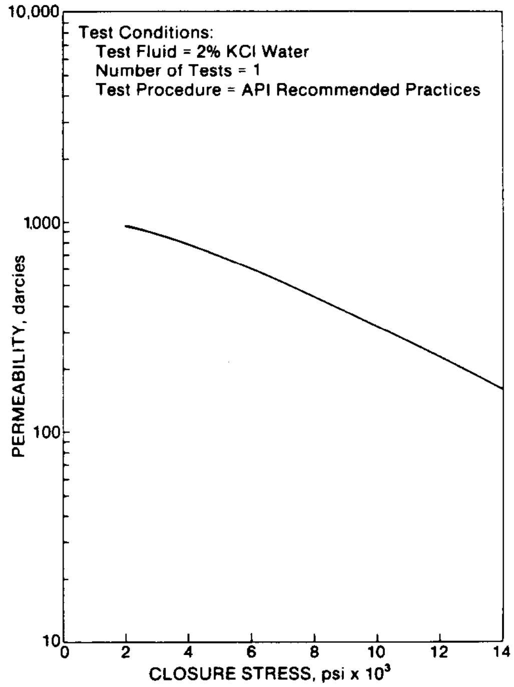

Figure 9 - Permeability vs. closure stress of 16/20 intermediate strength proppant (ISP)

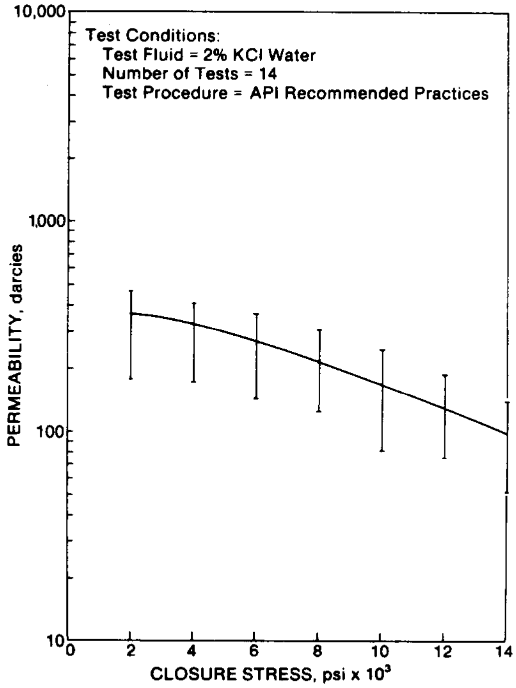

Figure 10 - Permeability vs. closure stress of 20/40 intermediate strength proppant (ISP)

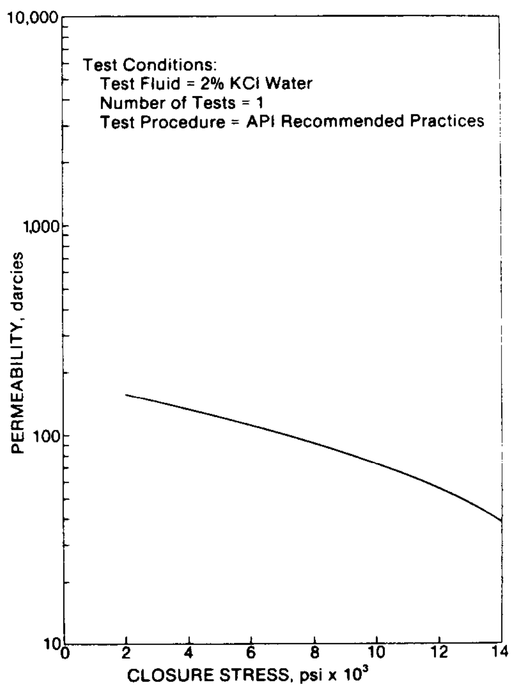

Figure 11 - Permeability vs. closure stress of 40/70 intermediate strength proppant (ISP)

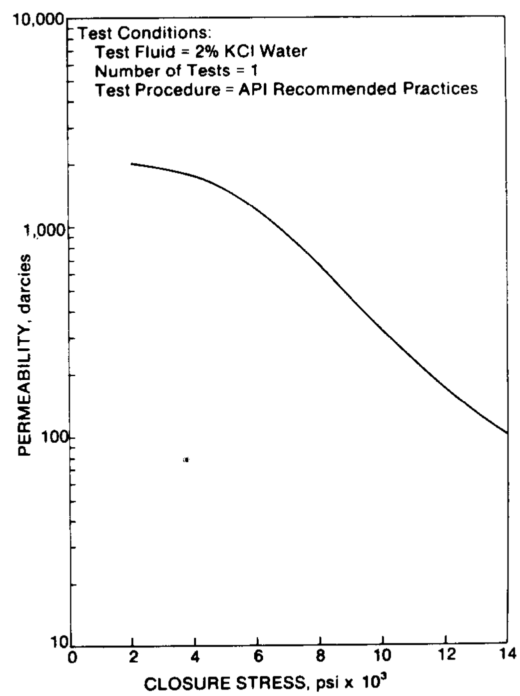

Figure 12 - Permeability vs. closure stress of 16/20 fused ceramic (Z-Prop)

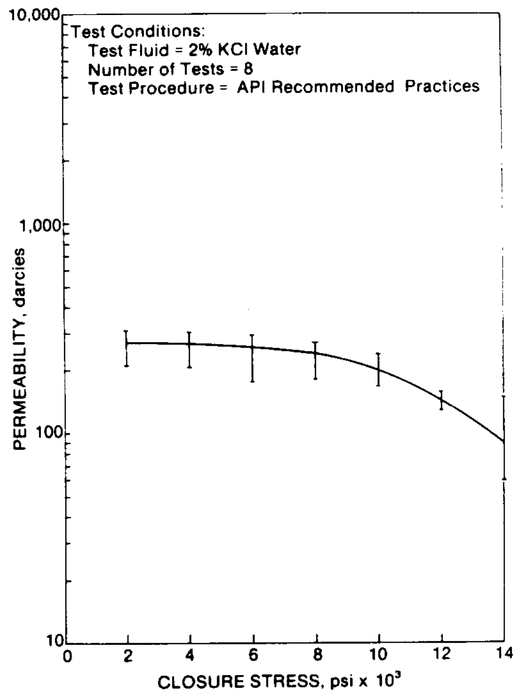

Figure 13 - Permeability vs. closure stress of 20/40 fused ceramic (Z-Prop)

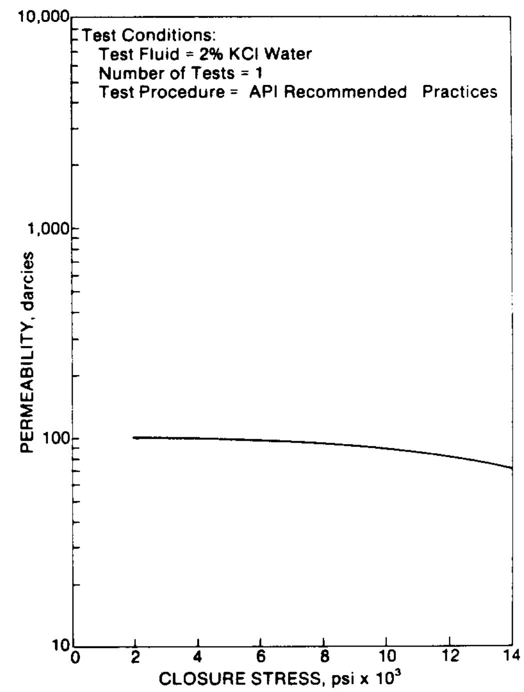

Figure 14 - Permeability vs. closure stress of 40/70 fused ceramic (Z-Prop)

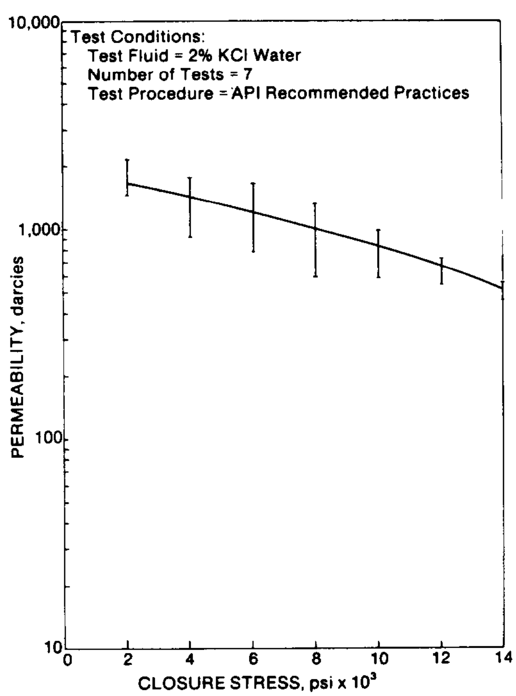

Figure 15 - Permeability vs. closure stress of 12/20 sintered bauxite

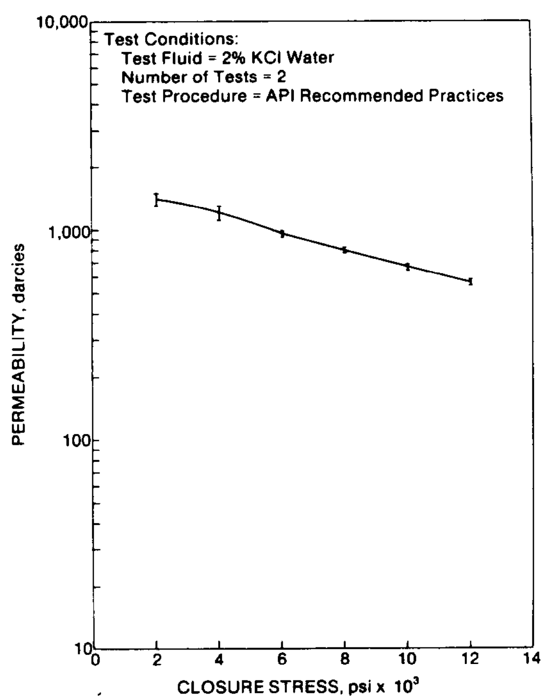

Figure 16 - Permeability vs. closure stress of 16/20 sintered bauxite

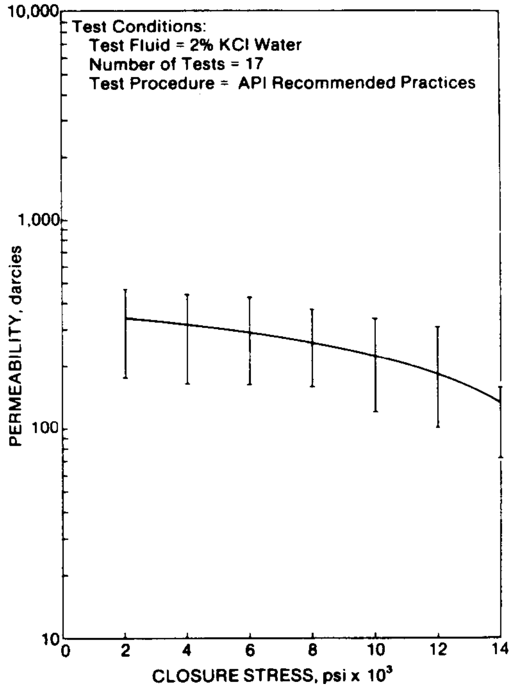

Figure 17 - Permeability vs. closure stress of 20/40 sintered bauxite

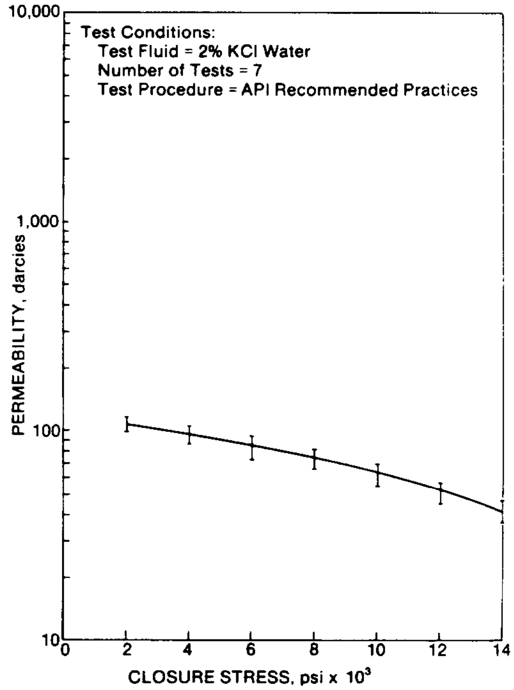

Figure 18 - Permeability vs. closure stress of 40/70 sintered bauxite

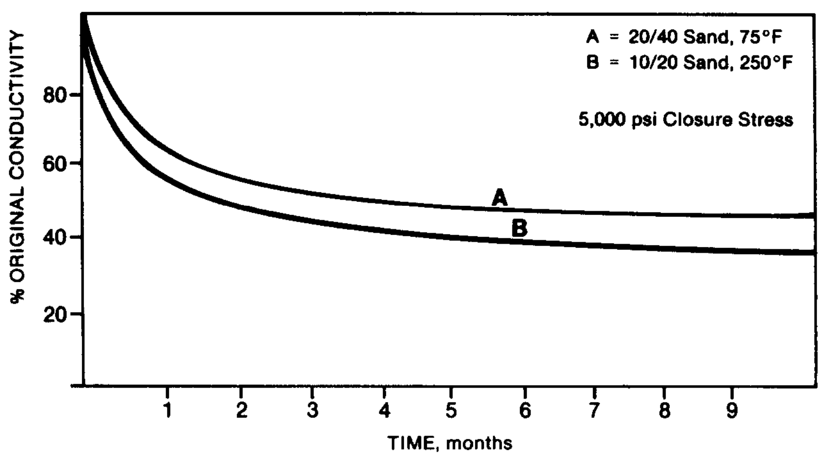

Figure 19 - Percent of original conductivity vs. time

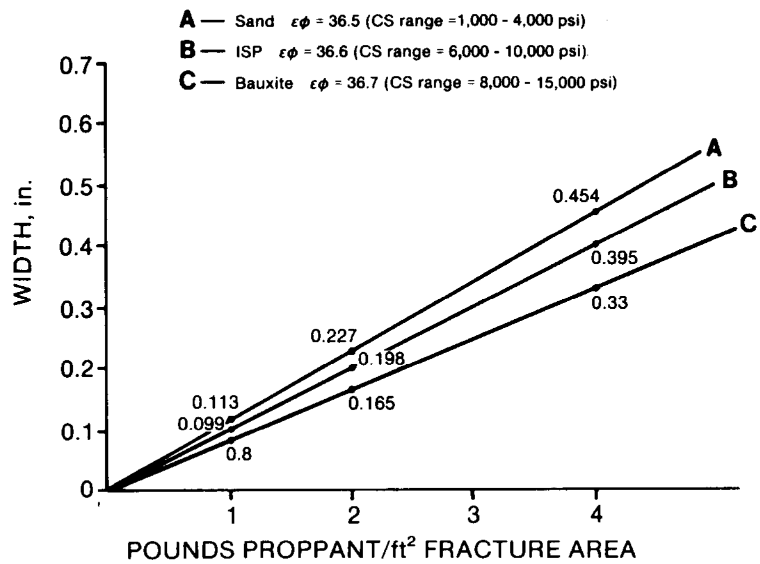

Figure 20 - Pounds of proppant per square foot of fracture vs. fracture width using 20/40 sand, intermediate strength proppant (ISP) and bauxite

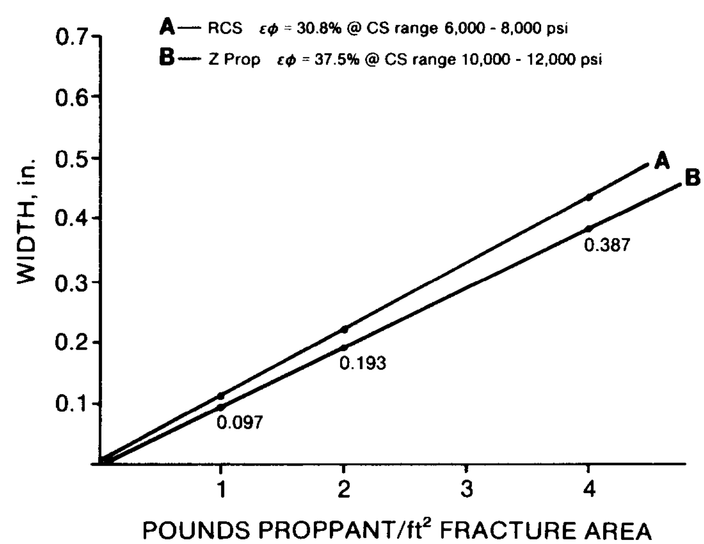

Figure 21 - Pounds of proppant per square foot of fracture vs fracture width using 20/40 precured resin-coated sand (RCS) and fused ceramic (Z-Prop)