SUCCESSFUL FRACTURING RESULTS THROUGH BETTER PLANNING AND POST-TREATMENT ANALYSIS OF REAL DATA

Billy Ray Smith

Abstract

Fracturing designs are generally based on information from 2D simulators, 3D simulators, field experience, or previous designs. Once a fracturing job is designed and a fracturing schedule is established, the job is usually pumped according to design without any changes. Because of such inefficient planning and procedures, millions of dollars are wasted each year on fracturing jobs that fail to provide the expected results. Preplanning and real-time analysis are key factors for successful hydraulic fracturing and increased hydrocarbon production. The following seven-step process can be followed to incorporate real-time analysis and improve fracturing procedures:

1. Gather information about the initial wells to be stimulated.
2. Design a fracturing procedure based on information and well parameters.
3. Perform a step-rate test and pump-in test to evaluate both the formation and near-wellbore regions.
4. Fracture the first well as it was predesigned.
5. Analyze pressure response during the fracturing procedure and perform pressure matching to obtain fracture parameters such as propped length, propped height, and conductivity.
6. Use the information collected in Step 5 to modify the original design.
7. Continue real-time analysis on each well.

Implementing this seven-step process should enable producers to achieve the best possible fracture design.

Step 1—Gathering Information

Gathering well information for a fracturing procedure is generally not difficult; to achieve the best design results, the engineer must collect as much information as possible. At minimum, the following well parameters must be obtained:

- porosity
- permeability
- formation type
- production history
- estimated fracture gradient
- formation stresses
- Young's modulus
- Poisson's ratio
- well spacing

A common misconception is that data for the producing zone is the only information needed for a successful fracturing design. In reality, information about the formations 100 to 200 ft above and below the zone of interest also affect stimulation design, and should be examined thoroughly. For best results, engineers should also always use the most current information about the well during job design; for example, although the virgin reservoir pressure of the well is of interest, it is not as critical to the fracturing design as the current reservoir pressure.

Step 2—Designing a Fracture Procedure

Field experience, 2D and 3D simulators, and even the use of previously successful designs have been used for fracture-treatment design. With the advancement of computer technology, pseudo-3D fracturing simulators, such as FRACPRO™ (by RES/GRI), are being used to design many fracturing treatments. Fracturing treatments are designed to maximize production by creating the ideal fracture length with the ideal fracture conductivity for each individual well. Ideal fracture conductivity is directly related to formation permeability and formation pressure. Once the ideal fracture length and conductivity are known, the fracture design can be completed.

Production-Increase Curves

Walters and Byrd production increase curves can be used for determining ideal fracture length. **Table 1** shows the data that was used for finding the ideal fracture length and conductivity for a particular well. **Fig. 1** shows the well's production-increase curves along with the corresponding lengths and conductivity. The maximum length needed is 469 ft on 20-acre spacing. With a conductivity of 2,600 md-ft, the highest production increase would be approximately eight-fold. Once this information is established, engineers can determine optimal length and conductivity on the basis of economics.

Step 3—Perform Diagnostic Tests

Formation characteristics such as closure pressure, tortuosity, and leakoff parameters can be analyzed through diagnostic testing to prevent some potential fracturing problems. At minimum, pump-in/shut-in and step-down tests should be performed on each well to be fractured.

Perform the Pump-in/Shut-in Test

The pump-in/shut-in test consists of pumping the fracturing fluid at the designed fracturing rate until a relatively stable rate and BHTP are observed. Then, the well is shut down and pressure decline is monitored. Several pieces of information can be obtained from performing a pump-in/shut-in test:

- fracture gradient
- friction pressure
- closure pressure
- fluid efficiency

Fracture Gradient

The value obtained for the instantaneous shut-in pressure (ISIP) can be used to gain an accurate value for the static fracture gradient. The ISIP is equal to the pressure inside the open fracture immediately after pumping has stopped. The following formula is used for determining the fracture gradient:

$$Fracture\ gradient\ (psi/ft) = \frac{ISIP + Hydrostatic\ of\ fluid\ column}{Depth} \quad (1)$$

Friction Pressure

Friction pressure is the treating pressure subtracted from the ISIP. The friction pressure is the pressure from both the pipe and the fracture-entry friction. If the fluid pumped during the pump-in test is linear and the fracturing fluid will be crosslinked, the actual treating pressures for the job will be different. A step-down test can be performed for analyzing and determining the entry friction.

Closure Pressure and Fluid Efficiency

To determine closure pressure, engineers must monitor pressure decline after shutdown. The closure pressure is obtained from a log-log plot of the pressure vs. time. Different portions and the corresponding different slopes of the straight line have different interpretations. Wellbore storage should have a theoretical slope of 1.00, but it can range from 0.90 to 1.1 (**Fig. 2**). Fracture linear flow has a theoretical value of 0.5, but it can range from 0.4 to 0.7 (**Fig. 3**). Bilinear flow should have a value of 0.25, but it can range from 0.2 to 0.4 (**Fig. 4**).

The point at which the slope starts changing from fracture linear flow to bilinear flow is the theoretical point at which the fracture closed (**Fig. 3**). This point can be checked with a pressure vs. square-root-of-time plot (**Fig. 5**). The fracture linear flow should be a straight line, and the point at which the pressure deviates from the straight-line portion should indicate closure. This time and pressure should be very close to the log-log time and pressure. Once the closure pressure has been determined, fluid efficiency can also be estimated.

Perform the Step-Down Test

A step-down test will allow engineers to determine near-wellbore tortuosity and perforation friction. The procedure for performing a step-down test is to first accelerate the rate to the designed fracturing rate and then incrementally decrease the rate at least four times. Each time the rate is dropped, the pressure is allowed to stabilize (usually 10 to 20 seconds), and the rate and pressure of each increment is recorded. Once the increments have been obtained, a plot of pressure vs. injection rate is obtained.

The pressure that should be plotted is the bottomhole pressure (BHP), which can be obtained either from a bottomhole pressure gauge or the following calculation:

$$BHP = Surface\ pressure - (Wellbore\ friction + Hydrostatic\ pressure) \quad (2)$$

Once the bottomhole pressure is obtained for all step increments, a plot of pressure vs. rate is made. The plot represents total entry friction of both the tortuosity and near-wellbore friction. The line that is plotted will be either concave or convex. A concave curve represents near-wellbore friction, and a convex curve represents tortuosity. The curvature of the line represents the most dominant friction effect.

After the near-wellbore friction and perforation friction are determined, the possibilities of premature screenout can be assessed. Because of the complexity of different formations, one certain pressure does not determine if actions are necessary to remedy the entry problem. For example, in some areas, a 600-psi tortuosity value will cause no premature screenout problems; however, in other areas, a 400-psi tortuosity value would require corrective action. A greater knowledge of the pressures that can pose potential problems will become apparent as more step-down tests are performed in each field. **Table 2** and **Fig. 6** show an actual field example of a step-down test. The designed fracturing rate was predicted to be 8 bbl/min with approximately eight holes. **Fig. 7** shows the graph of the total friction. The curve is slightly concave, representing more near-wellbore friction present.

If tortuosity is too high, a proppant slug can be pumped and/or a high-viscosity treating fluid can be used to reduce the extent of the problem. Proppant slugs can range from 1 to 10 lb/gal. Once again, the size of the slug will depend on the formation and previous attempts that have been made in that field. High-viscosity gel slugs have also been used to reduce these effects. For best results, the gel viscosity should be approximately three to four times greater than the treatment fluid. The use of proppant slugs and high-viscosity slugs are the best options available to combat extreme cases of entry friction, but these will not cure all cases. If the perforation friction is too high, a perforation cleanup will be necessary. This cleanup can be performed with an acid ballout treatment, through the use of a selective injection packer, or by reperforating the well. The effects of multiple fractures on perforation friction and near-wellbore friction must be carefully considered. Multiple fractures are discussed in detail by Hyden and Stegent.

Perform a Minifrac

If little information is known about a certain formation, a minifrac may need to be performed, which is a larger version of the pump-in/shut-in test. The fluid volume for this expanded minifrac is typically equal to the planned pad volume. The rate used for the test is the same as the designed fracturing rate. Like the pump-in/shut-in test, the minifrac analysis allows engineers to determine closure and fluid efficiency. Since the same volume and rate are being pumped, the minifrac should encounter most of the same formation responses as the main fracturing treatment. Because of its smaller size, a pump-in/shut-in test may not. Once again, field experience will help engineers determine which test should be run. Minifrac data can also be used for pressure matching with 3D fracture simulators.

Step 4—Fracture the First Well

Once the diagnostic testing has been performed, the fracturing treatment can be pumped. During the treatment, 3D simulators can be used to perform real-time analysis performed on the basis of predetermined reservoir parameters. The simulator uses the actual pumping rates, treating pressures, and proppant concentrations to estimate such parameters as fracture length and conductivity.

Step 5—Analyze Pressure Response (3D Pressure Matching)

Process Description

After the fracturing procedure, a pressure match can be performed. Pressure matches allow engineers to determine fracture and reservoir parameters more accurately. A pressure match is obtained when the observed net pressure (ONP) from the actual job and the predicted net pressure (PNP) from the simulator overlay each other. The ONP is the pressure in the main body of the fracture subtracted from the closure pressure. The net pressure is directly connected to the fracture length, width, and height. Therefore, ONP is found by

$$ONP = (Surface\ treating\ pressure + Hydrostatic - Total\ friction) - Closure\ pressure \qquad (3)$$

As shown in the equation above, pressure in the main body of the fracture is equal to the surface treating pressure plus the hydrostatic pressure minus total friction. Total friction includes wellbore, perforation, and near-wellbore friction. These parameters can be found through diagnostic tests.

To match the predicted net pressure to the observed net pressure, engineers must change various input parameters in the model. Rock properties such as permeability, Poisson's ratio, and Young's modulus can be changed to affect the pressure response. Two points are critical to the pressure-matching procedure: instantaneous shut-in pressure (ISIP) and pressure decline after shut-in. The shut-in pressure point must be closely matched because at the shut-in point, the pressure response is not affected by the friction pressures and should be representative of the pressure in the fracture. The pressure decline, which is directly related to formation permeability, is then matched. When surface treating pressure is used, the observed net pressure during the treatment will be more difficult to match because of the variations in fracture-fluid properties and friction pressures; however, careful monitoring of fluid viscosity and fluid additives can improve the matching procedure.

Field Examples

The following field examples show how the pressure match yields fracture geometry. **Fig. 8** shows the predicted net pressure from the original design. The original design resulted in the following parameters:

Propped Length = 237 ft
Propped Height = 267 ft
Average Fracture Conductivity = 1,788 md-ft

A pressure match was then performed (**Fig. 9**). The shut-in portion of the graph does not match because the well was flowed back immediately, thus making pressure matching of the shut-in portion virtually impossible. The results of the pressure match were

Propped Length = 137 ft
Propped Height = 271 ft
Average Fracture Conductivity = 2,587 md-ft

Step 6—Redesign the Fracture Procedure

On the basis of **Fig. 1** and economic considerations, the ideal fracture half-length would be 220 ft with a conductivity of 1,800 md-ft. The original design achieved these results; however, the actual pumped procedure did not. The new fracture procedure was changed, resulting in the following parameters (**Fig. 10**):

Propped Length = 205 ft
Propped Height = 328 ft
Average Fracture Conductivity = 1,850 md-ft

Step 7—Continue Real-Time Analysis

Once a new design is made and implemented, real-time analysis and diagnostic testing should continue on each well. The 3D design should be altered as needed to accomplish the production company's goals.

Conclusion

Planning and real-time analysis are becoming a necessity for successful fracturing procedures. Companies can no longer afford to model new designs on the basis of previous models. Planning (collecting reservoir and field information), diagnostic testing (performing pump-in and step-down tests), and real-time analysis (pressure matching and designing) are ways to help make a fracturing procedure successful. Using this seven-step process will not solve all fracturing problems or make every fracturing attempt a success, but it will provide the best possible chance for success on every job.

Bibliography

Aud, W.W. Harkrider, Hansen, J.D.: " Better Frac Jobs With Careful Fluid Design," *Hart's Petroleum Engineer International*, January, 1997, pages 41- 49.

GRI.: " In-Situ Stress Profile," Gas Research Institute, GRI-95/0256.

GRI.: "Advanced Real-Time Analysis," Gas Research Institute, GRI-95/0253.

GRI.: "Multiple Hydraulic Fractures," Gas Research Institute GRI-95/0258.

GRI.: "Near-Wellbore Fracture Tortuosity," Gas Research Institute, GRI-95/0257.

GRI.: "Quality Control," Gas Research Institute, GRI-95/0259.

GRI.: "Real Data (Net Pressure) Fracture Analysis," Gas Research Institute, GRI-95/0254.

Hyden, R.E. and Stegent, N.A.: "Pump-in/Shut-down Tests Key to Finding Near-Wellbore Restrictions," paper SPE 35194 presented at the 1996 Permian Basin Oil and Gas Recovery Conference at Midland, Mar. 27-29.

Tan, H.C. , McGowen, J.M., Lee, W.S., Soliman, M.Y.: "Field Application of Minifrac Analysis to Improve Fracturing Treatment Design," paper SPE 17463 presented at the 1988 California Regional Meeting at Long Beach, Mar. 23-25.

Wright, C.: " On-Site, Step-Down Test Analysis Diagnosis Problems and Improves Fracture Treatment Success," *Hart's Petroleum Engineer International*, January, 1997, pages 51-63.

Wright, C.A., Weijers, L., Minner W.A., Snow, D.M.: " Robust Technique for Real-Time Closure Stress Determination," paper SPE 30503 presented at the 1995 SPE Annual Technical Conference & Exhibition, Dallas, Texas, Oct. 22-25.

Figure Captions

Table 1
Well Data Used for Computing Fracture Length

Permeability (md)	1
Hole Size (in.)	5.5
Well Spacing (acre)	20
Minimum Production Increase	2
Maximum Production Increase	8

Table 2
Near Wellbore Friction Calculation

# Perfs	8					
Perf Dia.	0.4					
Disc. Coef.	0.65					
Fluid Density	8.35					
ISIP	329					
	Rate	**Pressure**	**Pipe Friction**	**Perf Friction**	**Total Friction**	**Near Wellbore**
Step 1	8.08	1,344	630	186.64	1,015	198
Step 2	6.15	1,006	415	108.13	677	154
Step 3	4.14	754	229	49	425	147
Step 4	2.11	480	83	12.73	151	55
Step 5	0	0	0	0	0	0
Step 6	0	0	0	0	0	0

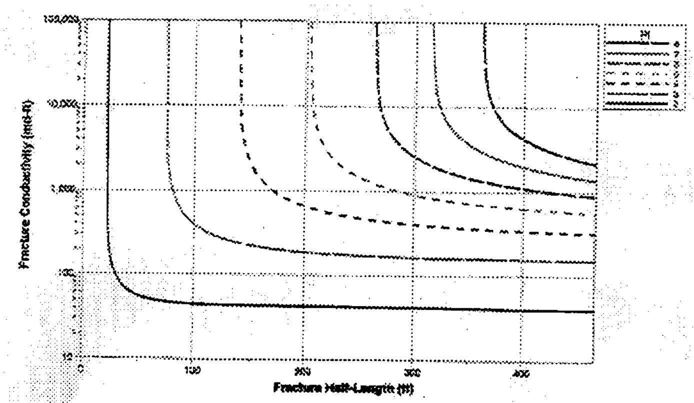

Figure 1

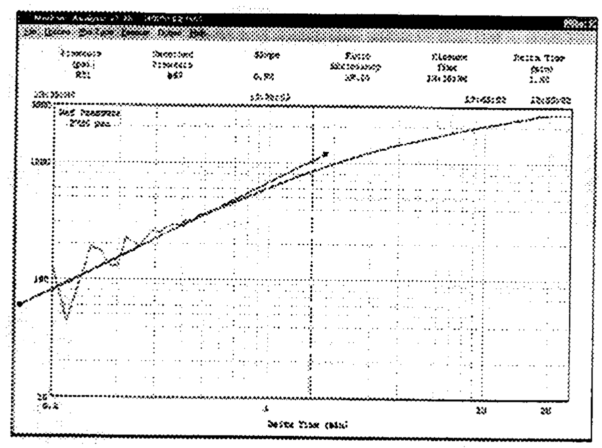

Figure 2

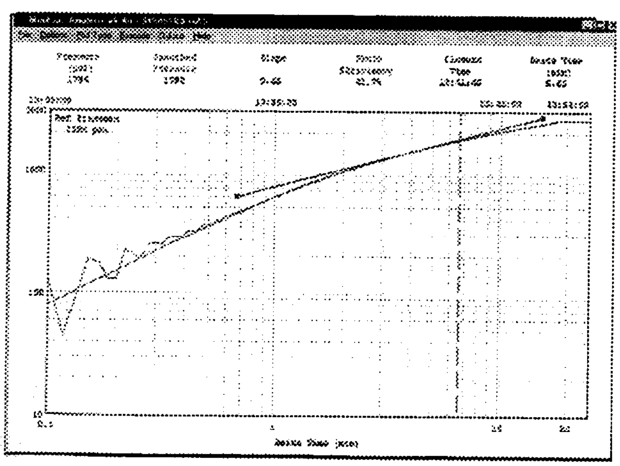

Figure 3

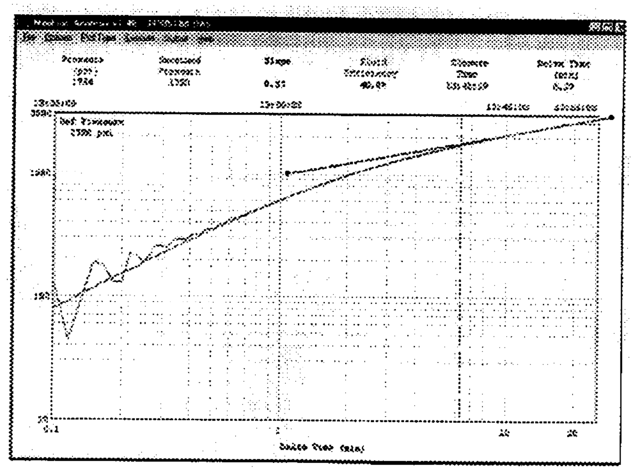

Figure 4

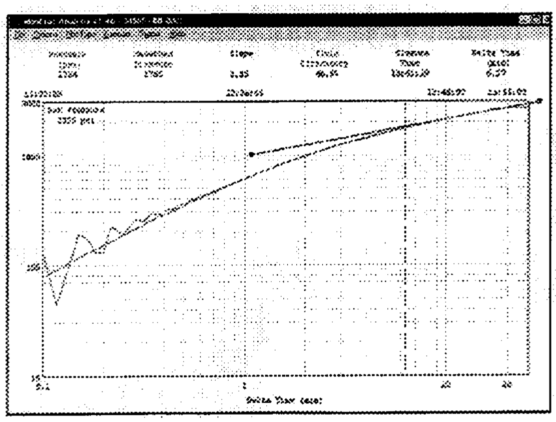

Figure 5

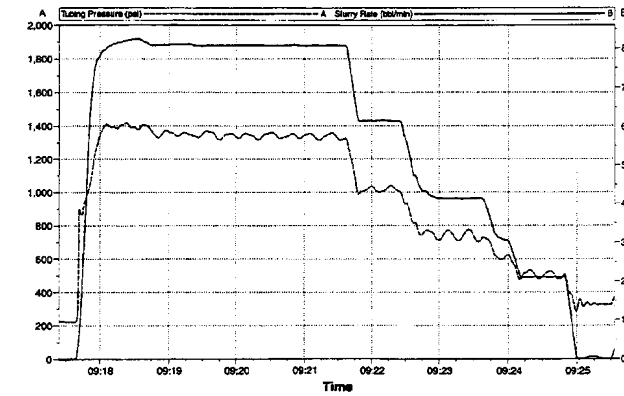

Figure 6

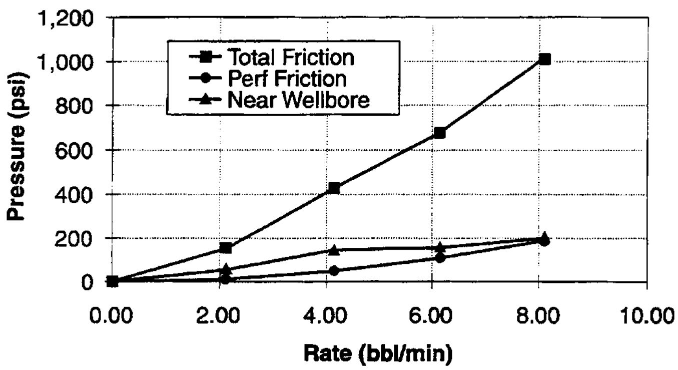

Figure 7

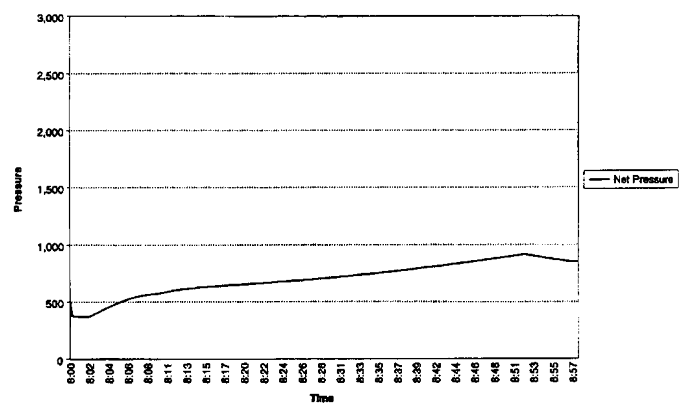

Figure 8

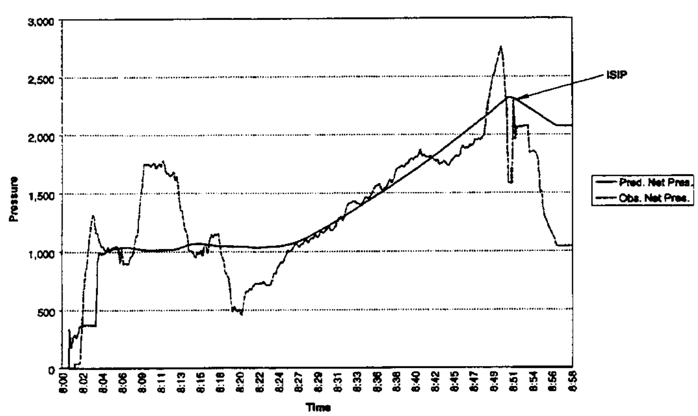

Figure 9

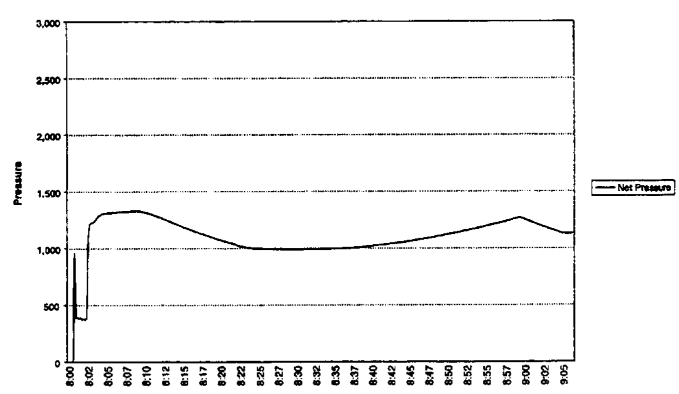

Figure 10