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The Rocket Science Behind Water Frac Design

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Abstract

The popularity of water fracs has increased in recent years. The reduction in fluid cost and overall fracture stimulation cost has in some cases revived exploration in low-permeability reservoirs like the Barnett shale in north central Texas. Water fracs have also been used effectively in reservoirs with low permeability and large net pays, which require large volumes of fluid to attain adequate fracture half-lengths to achieve commercial production.

In the past, the design of water fracs has been more of an art than a science. While the term “water frac” implies that the fluid is proppant-free, in most cases some proppant is usually pumped. The amount and concentration is usually low when compared to conventional fracture treatments. Water-frac designs are further complicated by the fact that fracture geometry, conductivity, and proppant transport are not easily modeled.

Despite these difficulties, the attractiveness of water fracs requires the implementation of a design methodology. This paper discusses a design procedure for water fracs from a field operation/design standpoint. Volume and rate requirements are discussed for a specific zone height, desired fracture length, and aerial width. A fracture width vs. proppant size requirement is applied, and a simple material balance calculation is performed to generate a fracture volume taking fluid leakoff into account. Fracture conductivity of a low proppant-concentration, high fluid-volume fracture is estimated to optimize proppant length and fracture conductivity ratio (C_{fd}). A pump schedule is generated based on the results of the previous calculations. All design calculations are simple and require only a handheld calculator or simple spreadsheet.

The design model was calibrated to a microseism-mapped Cotton Valley Lime test well. A leakoff coefficient multiplier was used to calibrate the model. The model-predicted volume was then compared to actual volume on a second Cotton

Valley Sand test well and on a 10-well average Barnett shale microseism fracture-mapping data set. The overall model-predicted volume for the mapped microseism geometry is compared to actual volume pumped.

Introduction

Water fracs have had various names through the years. From the mid 1970s to early 1980s, “river fracs” were performed on many Hugoton wells in Kansas. Water and sand from the Cimarron River was pumped at high rates (200 to 300 bbl/min) with little more than a few gallons of friction reducer, 20 to 30 dump trucks of river sand, and an occasional frog or turtle.

During the same time, “pit fracs” were pumped into the Hunton and Mississippi formation in Canadian County, Oklahoma. The term “pit” comes from the water-storage container, which was an earthen pit, sometimes lined. Frac volumes ranged from 4,000 to 38,000 bbl. Averages of 1,200 gal/ft and 0.425 lb/gal were most common.

From 1986 to 1988, UPRC performed water fracs in the Austin Chalk in both vertical and horizontal wells. Typical volumes were 400 bbl of acid pumped in stages with 30,000 bbl of water and wax beads diverter.

In 1997, Mitchell Energy (now DEVON) experimented with light sand fracs (LSF) in the Barnett shale. The company continued reducing polymer gel loadings to the point where little more than friction reducer and biocide were used. Average job size is 2,000 to 2,500 gal/ft or 24,000 bbl for a 400-ft section. Average proppant concentration is 0.3 lb/gal.

Other terms or descriptive mnemonics used to describe water fracs, including:

- LSF—light sand fracs
- SWF—slick water fracs
- LPF—low proppant fracs
- TWF—treated water fracs
- MHF—massive hydraulic fracs

Many rules of thumb are offered for water-frac design methods. The following “rules” are among the most common:

- Frac tanks per 100 ft of pay (tanks/100 ft)
- Barrels per ft (bbl/ft)
- lbm of proppant per ft (lbm/ft)
- Rate per ft (bpm/ft)

When rules of thumb are used, little consideration is given in the design of water fracs to reservoir permeability (K), and its relationship to fracture conductivity (K_{fw}) and conductivity

HALLIBURTON EXHIBIT 2012

Profrac Holding Corporation and U.S. Well Services, LLC v. Halliburton Energy Services, Inc.

IPR2023-01318, page 1

ratio (C_{fd}). This lack of connection between the reservoir and water frac design lead the authors to look for a different design approach.

A New Methodology

In this paper, a water frac is defined as a low-viscosity (10 cP or less), water-based fracturing fluid. Average proppant concentrations are 0.5 lbm/gal or less. Guar gel concentrations vary from 0.5 lbm/1,000 gal to 20 lbm/1,000 gal. The gel is primarily used as a friction reducer, not as proppant transport. Other additives include long-chained polymer friction reducers at concentrations of 0.5 to 2.0 gal/1,000 gal, with surfactants, biocides, and clay-stabilizers.

The intent of this water-frac design methodology was to use existing methods of coupling fracture design and reservoir quality (Kgh) to highlight the specific characteristics unique to water fracs. The following list includes some of these characteristics:

- Low formation permeability
- Large treatment intervals
- Large treatment volumes
- Low-viscosity fluids
- Poor proppant transport
- Narrow fracture width
- High injection rates
- Complex fracture geometry

The basis for frac design is not new. Frac designs have been chronicled in SPE Monograph Volume 12. This monograph is the basis for most of the basic water-frac design correlations used in this investigation.

During the search for the “rocket science behind water-frac design,” the authors found that they were in a minority of those who expected the science to exist. From literature searches and conversations with other operators, they gathered that the basic fracture design methodology had not been aggressively applied to water fracs. This lack of frac design application to water fracs may be because of the suspected complex geometry indicated by microseismic imaging and uncertainty of proppant deposition in thin fluids. The lack of water frac design could also exist because water fracs may have been considered a low technology completion practice, used mainly in reservoirs with marginal production capability. The comment most often made when the authors asked about water-frac design was, “This ain’t rocket science.”

However, the authors were determined to find that science. They attempted to uncover the design methodology by reviewing past water-frac treatments. Most designs were based on “close-ology,” that is, “do what worked on the nearest offset.” The authors decided to go back to square one and walk through the basics of frac design to see what caveats water frac had on the design process. The search began in September 2001 at a panel discussion sponsored by the Fort Worth section of SPE. The panel, an assembly of some of the world’s experts on water fracs, discussed the subject of “Low Proppant Concentration Stimulations.”¹

Numerous operators and service company engineers gave presentations about the success of water-frac stimulation over conventional gel fracs in specific areas or fields. Various

academic authors discussed reasons for water-frac success and operators and service company representatives discussed typical water-frac designs. One presentation, “A Unified Fracture Design,” given by Michael Economides, provided the team with a starting point for uncovering the rocket science behind water-frac design.

Case Study

A microseism-mapped Cotton Valley Lime (CVL) well in north Personville Field, Limestone County, Texas, was used as the calibration well in the dataset. After the calibration, a second microseism-mapped Cotton Valley Sand water-frac well in Panola County, Texas, was used as a test for the model. The model was then compared to a 10-well Barnett shale microseism-mapped water-frac study performed for Mitchell Energy.²

Purpose of Study. Unfortunately, most water-frac designs seem to be based on the answers to questions, like the following, that are not related to the reservoir or productivity after stimulation:

- How big a pit can I dig on my location and still have room for frac equipment?
- How many frac tanks can I fill before pump time?
- How fast can I pump down the production casing before I reach 80% of burst?
- How much money can I spend while staying within budget?

Although practical, these design considerations lack any linkage to the reservoir and its response to stimulation. The authors decided to attempt a systematic process to design water fracs.

After past water-frac designs and their results were reviewed, the following revised questions were posed to the group:

- What design methodology is used to develop a completion procedure for water fracs?
- Can we develop an easy-to-use field design tool to produce a frac design schedule?
- Can we link this design to reservoir and rock properties data specific to each well?
- Can we do this without complicated input-intensive frac models or expensive reservoir description tools?

These questions led to a review of various pre-computer-assisted fracture design methods. These methods are not as intricate as state-of-the-art 3-D fracture models built on ½-ft grid rock properties and fluid-flow proppant transport capabilities. However, after the team reviewed the microseism events of the wells in the data set and observed the apparent complex fracture geometry, the decision was made to make our design fracture geometry simple yet general enough to cover the observed microseismic shapes.

Some water frac designs used field rules of thumb to help determine treatment volume (gal/ft) and proppant amount (lbm/ft). However, little design consideration was given to reservoir quality (Kgh) or mechanical factors such as the following:

- Volume required to attain designed proppant fracture half-length (X_f), and designed fluid fracture half-length (L_f)
- Proppant sieve size to meet conductivity and frac width constraints
- Proppant concentration in lbm/ft^2 or lbm/ft to achieve adequate conductivity
- Rate required to place job, or generate sufficient width

Job Size and Proppant Concentration. While the term “water frac” implies that no proppant is pumped, most jobs involve pumping light concentrations of various sieve sizes. Usually the size and amount of proppant is based on the amount of conductivity required in the fracture to yield a stimulated response from the fracture. The size and amount is also based on the ability to move this proppant a sufficient distance through the fracture (X_f) without screening out.

First, the formation permeability, or at least its order of magnitude, must be known. For the calibration well, the permeability estimates from production-history matching ranged from a low of 0.007 md to 0.06 md, with an average permeability of 0.03 md.

Next, the value of dimensionless conductivity ratio necessary to obtain a significant stimulated effect should be calculated. Fracture production increase is directly related to dimensionless conductivity ratio, which is the ratio of fracture proppant-pack permeability to formation permeability and frac half-length (X_f).

Dimensionless conductivity ratio as defined by Prats is:

$$C_{fd} = \frac{K_f w}{K X_f} \dots \dots \dots \text{Eq. 1}$$

Where:

$K_f w$ = Fracture conductivity (md-ft)
 K = Formation permeability (md)
 X_f = Fracture half-length

Prats concluded that for a specific fracture volume V_p , the optimum fracture would have a dimensionless conductivity of approximately $C_{fd} = 1.6$.³

The fracture width (w) and fracture half-length (X_f) used here are the dimensions of the conductive path after closure has occurred on the deposited proppant pack. In water fracs, portions of the created width and fracture half-length may contain no proppant and yet remain open after closure. That the open portions of the fracture will contribute to the overall conductivity of the system is understood. However, unless the incremental increase in conductivity that can result from the amount and extent of possible open fractures is known, only the proppant-filled conductivity in the model is used.

For this investigation, the liquid fracture volume V_L is defined as an ellipsoid with the major axis as the fracture half-length and the minor axis as the fracture height (**Fig. 1**).

Fig. 2 is an illustration of the fracture geometry using oilfield nomenclature for the dimensions.

Using the authors' terminology, the proppant fracture volume V_p is described as a simple ellipsoidal shape with the following equation:

$$V_p = 4/3 \pi abc \dots \dots \dots \text{Eq. 2}$$

Where:

$a = w/2$
 $b = X_f$
 $c = h/2$

These variables are substituted into the volume equation:

$$V_p = 1/3(\pi w X_f h_p) \dots \dots \dots \text{Eq. 3}$$

If Eq. 3 is solved for w and this solution is substituted in Eq. 1, the result is an optimized value for fracture half-length (X_f) in feet.

$$X_f = [(3K_f V_p)/(k h_p C_{fd} \pi)]^{1/5} \dots \dots \dots \text{Eq. 4}$$

And if Eq. 3 is solved for X_f and this solution substituted in Eq. 1, the result is an optimized value for width (w) in inches.

$$w = 12 [(3C_{fd} V_p k)/(h_{gross} K_f \pi)]^{1/5} \dots \dots \dots \text{Eq. 5}$$

Where:

k = Formation permeability (md)
 K_f = Proppant permeability (md)
 V_p = Volume of propped fracture ft^3
 h_{gross} = Gross fracture height (ft)
 h_p = Proppant height at wellbore (ft)
 X_f = Proppant fracture half-length (ft)
 w = Fracture width (ft)
 C_{fd} = Fracture dimensionless conductivity ratio

The value of $C_{fd} = 1.6$ suggested by Prats is used in this design methodology to provide a target for values of X_f and w . However, these values are not always practical and should be modified to adjust for the realities of job execution and proppant placement.

Optimum Width and Fracture Half-Length. Calculating optimum X_f and w with Eqs. 4 and 5 is fine from a theoretical standpoint. However, when normal treating conditions are applied, the calculated optimized width (w) and the optimum proppant fracture half-length (X_f) are sometimes unpractical or unattainable.

Table 1 lists the estimated conductivity of the proppant vs. lbm/ft^2 in the fracture and the corresponding optimum fracture half-length and width for 20/40 sand. **Table 2** lists the same data for 40/60-mesh sand. The problem with optimum width for $C_{fd} = 1.6$ is that 20/40-mesh proppant is going to require more than 0.1 lbm/ft^2 to achieve an optimum width of 0.367 in. Conversely, 2 lbm/ft^2 of 20/40-mesh proppant cannot fit into the recommended 0.068-in. frac width. For 40/60-mesh sand, the optimum width for 0.1 lbm/ft^2 is 0.485 in., but the amount of proppant present will not support this width at closure.

Practical Proppant Size Selection. While operators cannot always design for the ideal or optimum combination of X_f and w , some practical considerations exist for selecting the proppant sieve size. The primary consideration is finding the minimum fracture width (w) required to allow the proppant to flow through without hindrance.

Laboratory findings indicate that perforation diameter should be at least six times the maximum proppant particle diameter.⁴ In this study, that rule was extended to include fracture width. **Table 3** lists the minimum, maximum, and median diameters of proppant at various sieve sizes. The suggested fracture width size and amount of proppant in lbm/ft² required for a monolayer to exist are also listed. The width requirement of six times the median proppant diameter was used to design the rate requirement for the model fracture stimulation.

Practical Fracture Half-Length (X_f). The previous discussion illustrates the fact that optimization based on formation permeability and dimensionless conductivity ratio (C_{fd}) alone can produce results that are not practically achievable. When the optimum X_f calculated is obviously unattainable, selecting a proppant fracture half-length that would best drain the area specified by the drilling pattern is considered.

In the data set, the estimated drainage radius (r_e) is approximately 160 acres or less ($r_e = 1,320$ ft). The design fracture half-length was set at 50% of drainage ($X_f = 660$ ft) based on a productivity chart (**Fig. 3**) from McGurie and Sikora.⁵ The average proppant concentration for a typical water frac in our data set is 0.5 lbm/ft². This average places the x-axis location at $(wk_f/k)(40/A)^{1/2} = 10,000-14,000$ in **Fig. 3**.

In this case, L_f/r_e greater than 50% does not yield a substantial incremental production increase for this conductivity range.

Frac Rate. Next, the frac rate necessary to generate width that will allow proppant to flow through was determined. To answer this question, the width generated at a specific rate (q_i) was calculated for a specific set of rock properties (Eq. 6).

The rate was then adjusted to generate a width wide enough for the fracture to accommodate proppant of a specific sieve size. **Table 4** lists the results of this calculation using average rock properties and fluid properties of the calibration well. Width at closure is listed in **Table 5** for various concentrations of proppant.

PKN width equation:

$$W = 0.3 [(q_i \mu (1-v) L_f) / G]^{1/4}$$

Width at wellbore.....Eq. 6⁶

$$W = 0.3 [(q_i \mu (1-v) L_f) / G]^{1/4} (\pi/4) (\gamma)$$

Average width.....Eq. 7⁴

$$W_p = (12 C_p) / (1 - \phi_p) \rho_p$$

Width at closure.....Eq. 8⁴

Where:

q_i = Injection rate (bbl/min)

μ = Frac fluid viscosity (cP)

G = Elastic shear modulus (psi) = $(YM)/(2(1+v))$

YM = Young's Modulus (psi)

γ = Geometric factor = 0.75

w = Width (in.)

v = Poisson's ratio

C_p = Proppant concentration lbm/ft²

ϕ_p = Porosity of proppant pack (+/- 30%)

ρ_p = Bulk density of proppant (100 lbm/ft³ for sand)

Simple Calculation of Fracture Dimensions. The microseismic measurements taken during the fracture treatments in the data set indicate that the calculations of fracture dimensions resemble the gross shape of the total fracture field. This shape may be the geometry created by the liquid volume injection. In this case, the geometry was assumed to be an ellipsoid.

The authors chose to use a set of equations from a text by Economides and Nolte.⁴ This set of equations suggests a relationship between injection rate and injection time to created area and volume of the liquid-filled fracture. Other methods are documented by D.E. Nierode.⁷ The intent was to keep the calculations simple so that a spreadsheet calculation of fracture geometry and resulting pump schedule could be created using a few hard facts and an equal amount of engineered estimates.

Fracture Height Estimation. From the start of this project, the calculations were to be kept as simple as possible. Most 3-D fracture simulators use detailed rock properties to determine fracture height as a function of stress difference between pay and barrier and expected bottomhole pressure increases during the job. However, in the study data set, rock properties data was not often collected.

The 3-D fracture-simulated fracture heights predicted vs. the actual fracture height mapped in the M-Site work done by Warpinski⁸ was reviewed. After this review, fracture height calculations were found to be beyond the scope of this effort.

In the data set of microseism mapped fractures, the authors noticed that the fracture height tended to stay contained to the gross zone height. Little downward growth was detected below the lower perforation. Upward height growth was limited to 30–40 ft. In addition, the authors' experience with frac tracer logs has indicated the same results. The authors decided to make their best engineering estimate of gross fracture height using logs and the location of perforations.

Created Fracture Volume. With the gross fracture height estimated, the design fracture fluid volume $V_L = (Q_i t_i)$ was adjusted to generate a proppant fracture half-length (X_f) with a designed lbm/ft² proppant concentration to attain the required conductivity. This adjustment sets the proppant amount and rate required to generate a width (w) sufficient to allow proppant to flow through the fracture without hindrance.

Remember the liquid fracture volume $V_L = (Q_i t_i)$ should be greater than or equal to the propped fracture volume V_p that

HALLIBURTON EXHIBIT 2012

Profrac Holding Corporation and U.S. Well Services, LLC v. Halliburton Energy Services, Inc.

IPR2023-01318, page 4

was calculated in Eq. 3. The liquid volume required is strongly dependent on the fluid leakoff and the permeable surface area exposed to the frac fluid. This fluid leakoff is accounted for with a fluid efficiency factor made in the next section. The fluid efficiency also sets the volume of pad required to place the job.

The material balance equation used combines the created fracture volume, leakoff, and total injected volume:

$$V_L = Q_i \cdot t_i = \frac{w \cdot A_f}{2} + \frac{[(K_L C_L A_f r_p)(t_i)^{1/2}]}{2} \text{ in bbl} \dots \text{Eq. 9}^4$$

Where:

Q_i = Injection rate (bbl/min)

t_i = Injection time (min)

$Q_i \cdot t_i$ = Injected volume (bbl)

V_L = Liquid volume pumped in bbl (multiply by 5.61 to convert to ft³)

A_f = Total area of both frac faces = $2 (\pi L_f h_f/2)$ for ellipsoid

L_f = Liquid fracture half-length (ft)

r_p = Ratio of net pay to gross pay = $h_{\text{net}}/h_{\text{gross}}$

$C_L = C_{\text{eff}}$ Leakoff coefficient (ft/min^{1/2})

η = Fluid efficiency = fracture volume/injected volume

K_L = Volume to width factor, varies from 2.7 to 3.14 assume (2.92)

$$K_L = (8/3) \eta + \pi(1-\eta) \dots \text{Eq. 10}^4$$

Fluid Efficiency Tests (FET). Fluid efficiency tests help determine the volume required to achieve the designed fracture half-length. Fluid efficiencies of the data set averaged 55%. This number was found by pumping approximately 20,000 gallons ahead of the frac and measuring the time required to reach closure. This small injection volume is approximately 1/30th to 1/50th the size of the design frac volume. This fluid efficiency should be corrected for the expected fracture area exposed during the actual job. The fluid efficiency was corrected using a correlation proposed by Mike Smith.⁹

$$\eta = E_{f1} (t_2/t_1)^{-(1-E_{f1})/3} \dots \text{Eq. 11}^7$$

Where:

E_{f1} = Fluid efficiency calculated from pump-in test

t_1 = Pump time for pump-in test

t_2 = Pump time for main frac

η = Corrected fluid efficiency for main frac volume

Using $t_2/t_1 = 30$ and $E_{f1} = 0.55$

$\eta = 0.33$ or 33%

Therefore, $\eta = 33\%$ in Eq. 10 was set for most of the calculations. This result set $K_L = 3.094$ for the width calculations in Eq. 9.

Even with this modification to fluid efficiency, the model predicted a much larger fracture volume than was suggested by the microseism mapping of the calibration well. The authors suspected that the cause of this discrepancy was the

complex fracture network observed in all of the mapped examples in the data set. They concluded that an additional leakoff component was not being considered and was evident from the microseism events occurring orthogonal to the main fracture plane.

To honor the average pay permeability of 0.03 md, and make the model-predicted volume match the apparent created volume in the calibration well, a multiplier of 4.6 was used with the leak-off coefficient. This modifier increased the calculated leakoff coefficient of $C_{\text{eff}} = 0.0046 \text{ ft/min}^{1/2}$ to $C_{\text{eff}} = 0.0216 \text{ ft/min}^{1/2}$. This increase in fluid leakoff could be attributed to the pressure-dependent nature of leakoff described by Barree.¹¹

Fig. 4 is an example injection and fall-off with closure picked from the GdP/dG curve on the calibration well. The upward hump in the GdP/dG curve indicates pressure-dependent leakoff caused by fissure opening.

In the material balance equation, the multiplier of 4.6 is used on the value C_L in Eq. 9. This multiplier remained constant for all other examples and is in the range reported by Barree¹⁰ and Mayrhofer.¹¹

Using the adjusted C_{eff} , the authors vary rate (q_i) and pump time (t_i) and solve Eqs. 7 and 9 simultaneously until the widths are equal. This method produces the pump rate and injection time necessary to develop a sufficient frac width and the fluid volume pumped (V_L) using the modified leakoff coefficient.

Proppant Distribution in Fracture. Initially, an even distribution of proppant across the entire fracture area and fracture half-length (L_f) was assumed. This distribution is probably not what actually occurs. Because the fluid is thin (± 1.0 cP), proppant fallout will be high. The area of highest proppant concentration should be near the wellbore and should decrease as it extends out to the fracture tip (**Fig. 5**). This deposition should yield a maximum proppant half-length ($X_{f_{\text{max}}}$) deposited at the bottom of the fracture, a maximum near-wellbore proppant height (h_p), with a resulting average proppant half-length (X_f) occurring somewhere in the pay section (**Fig. 5**).

For the design calculations, a proppant deposition is assumed to be triangular like that in **Fig. 5**, with the base of the triangle equal to the maximum proppant length ($X_{f_{\text{max}}}$), and the height of the triangle equal to the wellbore proppant height (h_p). Maximum proppant length ($X_{f_{\text{max}}}$) is calculated using the proppant volume (V_p) in ft³, the calculated fracture width (w) at design rate, and the maximum proppant height (h_p) at the wellbore. Then $X_{f_{\text{max}}}$ is calculated using the following relationship:

$$X_{f_{\text{max}}} = 12(V_p)/(h_p)(w) \text{ in ft} \dots \text{Eq. 12}$$

And

$$X_f = \frac{1}{2}(X_{f_{\text{max}}}) \text{ in ft} \dots \text{Eq. 13}$$

An average lbm/ft² can then be calculated using the following relationship:

$$\text{Average lbm/ft}^2 = (V_p \rho_p)/(h_p)(X_{f_{\text{max}}}) \dots \text{Eq. 14}$$

Where:

V_p = Volume of proppant (ft³)

ρ_p = Bulk density of proppant (lbm/ft³)

Designing a Pump Schedule

First, a pad volume must be calculated (again using equations from Economides):

$$\text{Pad} = V_L (1-\eta)/(1+\eta) \text{ in gal.} \dots \text{Eq. 15}^4$$

Where $V_L = (q_i)(t_i)(42)$ in gal (Eq. 9)

and

$$\eta = 33\% \text{ (Eq. 10)}$$

The clean fluid slurry volume V_s can then be calculated from the following equation:

$$V_s = (V_L - \text{Pad}) \text{ in gal.} \dots \text{Eq. 16}$$

If a minimum concentration is set to start or ramp or stair-step a proppant schedule, the end concentration required to place the desired amount of proppant volume ($V_p \rho_p$) in the clean slurry volume available can be calculated.

Let

PC_i = Proppant concentration initial (lb/gal)

PC_f = Proppant concentration final (lb/gal)

Then

$$PC_f = [(2) (V_p \rho_p) / (V_s)] - (PC_i) \dots \text{Eq. 17}$$

The following inputs are entered into an input data sheet:

1. L_f = Liquid fracture half-length (ft)
2. Gross and net height (h)
3. Formation permeability (md)
4. C_{fd} = Desired conductivity ratio
5. η = Estimated fluid efficiency
6. ϕ = Porosity
7. μ = Frac fluid viscosity (cP)
8. G = Elastic shear modulus (psi) = $(YM)/2(1+\nu)$
9. ν = Poisson's ratio
10. ρ_b = Bulk density of proppant (100 lbm/ft³ for sand)
11. PC_i = Minimum initial proppant concentration

Pump rate and pump time ($Q_i t_i$) are adjusted to satisfy width requirements and volume requirements in the material balance equation for the specified L_f (Eqs. 7 and 9). The spreadsheet generates a pump schedule and summary design sheet (Tables 6 and 7).

Design Versus Reality

Critics of this design methodology may contend that the authors have not developed anything new. They may contend that the authors have simply dusted off old frac design principles, used well published equations to describe fracture geometry, coupled that to a material balance equation, inserted it to a spreadsheet calculator, and now call it "rocket science."

To this contention, the authors humbly reply, "Yes, that is correct." However, evidence indicates that the simplified approach explained in this paper can give predictable results.

The model was calibrated using a water frac that was monitored with microseismic receivers installed in two offset wells.¹² The events recorded during the frac treatment indicate that a fracture network was created (Fig. 6):

- The microseism mapped fracture fluid half-length (L_f) = 720 ft
- Gross height (h_{gross}) = 260 ft
- Net height (h_{net}) = 33 ft
- Fluid volume pumped (V_L) = 3,300 bbl
- Proppant volume (V_p) = 302.8 ft³
- Frac rate (Q_i) = 60 bbl/min
- Pump time (t_i) = 55 min

Microseismic measurements indicate a fracture network:

- Frac height = 260 ft
- Fracture half-length (L_f) = 720 ft
- Width = 300 ft (Width here is defined as the maximum distance between microseismic events that occur transverse to the main fracture plane in our calibration well).

The frac height developed in the first 20 minutes of the treatment and then grew slowly for the next 35 minutes (Fig. 7).

The fracture length grew rapidly for the first 20 minutes, stabilized for 10 minutes, and then grew at a slower rate for the next 12 minutes. Growth remained relatively flat for the last 13 minutes of pumping (Fig. 8). Note the rapid development of both fracture height and length in the early pump times. This development is followed by relatively flat periods. Pump time was converted to volume, and a graph was generated to show the relationship between job size (gallons) and fracture half-length from microseismic imaging (Fig. 9).

Using the data from the microseismic imaging, the authors plotted job size vs. fracture half-length calculated from the model and the half-length indicated from microseismic imaging (Fig. 10). Again, note that the leakoff coefficient had to be adjusted to make the dimensions from the model match the microseism length and height. In addition, because they calibrated to microseism events for length and height, the authors have inferred that fluid has traveled to those event sites.

The calibration well was a water frac on a Cotton Valley Lime in Limestone County, Texas. The test well was a water frac on a Cotton Valley Sand in Panola County, Texas. The additional test of the model was an average of 10 Barnett shale water fracs that were microseism mapped in Wise County, Texas. The results of the model-estimated volumes compared to actual volume pumped are provided in Table 8. This table indicates that the model fracture volume V_1 predicted is very close to the actual frac volume pumped to create a specific mapped geometry.

Conclusions

This paper outlines a water-frac design methodology using standard correlations taken from the fracturing literature. The

HALLIBURTON EXHIBIT 2012

Profrac Holding Corporation and U.S. Well Services, LLC v. Halliburton Energy Services, Inc.

IPR2023-01318, page 6

following conclusions were reached when the described methodology was used:

- This model is based on simple applications of width vs. pump rate and material balance relationships developed years before complex computer models were available.
- This model varies from the conventional fluid-loss coefficient used in the material balance equation with the application of a fluid-loss multiplier. This multiplier may be necessary because of the pressure-dependent leakoff exhibited by most of the analyzed injection data.
- This model is highly sensitive to permeability, net permeability height (kh), gross to net height, and porosity (ϕ).
- A reasonable height estimate must be made to attain a designed fluid volume for a desired fracture half-length.
- This model does not contain a direct proppant transport correlation, but uses a simplifying assumption made for proppant deposition in a thin fluid. The proppant distribution is assumed to be approximately triangular with the proppant height at the wellbore as its base.
- Because this model was calibrated to microseismic events, the authors are implying that fluid has penetrated to these event sites. This may or may not be true.
- This model appears able to predict the liquid volume required to achieve a specific fluid fracture half-length (L_f) as interpreted from microseismic mapping in two separate cases.

Summary

The purpose of writing this paper was to demonstrate that a methodology, or “rocket science,” can be applied to water-frac design. Water-frac design does not have to be a thoughtless, “rule of thumb” or cookie-cutter process. Certainly, additional investigation is required for water-frac design, to explain why these methods work and how to couple 3-D fracture models with fracture mapping results.

Acknowledgements

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Table 1—Optimum Width and Half Length^a

20/40 Sand	6,000 psi Closure	200°F	With Nondarcy Effects	
lbm/ft ²	Perm Darcy	Perm Darcy With Nondarcy Effects	Optimum Xf Cfd = 1.6 (ft)	Optimum w Cfd = 1.6 (in.)
0.1	50	0.7	446	0.367
0.5	67	5.4	1238	0.132
1	72	11	1768	0.092
2	77	20	2384	0.068
3	75	26.1	2723	0.06
4	74	30.6	2949	0.055

^aWith Cfd = 1.6 k = 0.03 md for various fracture conductivities**Table 2—Optimum Width and Half Length^a**

30/50 Sand	6,000 psi Closure	200°F	With Nondarcy Effects	
lbm/ft ²	Perm Darcy	Perm Darcy With Nondarcy Effects	Optimum Xf Cfd = 1.6 (ft)	Optimum w Cfd = 1.6
0.1	15	0.4	337	0.485
0.5	17	2	753	0.217
1	18	3.8	1039	0.157
2	18	6.4	1348	0.121
3	18	7.9	1498	0.109
4	17	9	1599	0.102

^aWith Cfd = 1.6 k = 0.03 md**Table 3—lbm/ft² Required to Attain a Monolayer**

Proppant Size	Median Diameter (in.)	Min. Grain Diameter (in.)	Max. Grain Diameter (in.)	Min. Frac Width = 6X Median DIA (in.)	Required for a Monolayer (lbm/ft ²)
50/70	0.01	0.008	0.012	0.06	0.17
40/60	0.014	0.01	0.017	0.084	0.19
30/50	0.017	0.011	0.023	0.102	0.21
20/40	0.025	0.017	0.033	0.15	0.28
16/30	0.035	0.023	0.047	0.21	0.41
12/20	0.049	0.033	0.066	0.294	0.58

Table 4—Width Calculation Results^a

μ = 1.0 cP Water	YM = 5,000,000 psi	v = .25	G = 2,000,000 psi
Rate (bbl/min)	w at Wellbore (in.)	Avg w (in.)	Suggested sieve size
25	0.078	0.045	50/70
50	0.092	0.054	40/60
75	0.103	0.06	30/50
100	0.11	0.064	30/50
125	0.116	0.067	30/50
150	0.122	0.071	30/50
175	0.127	0.074	30/50
200	0.131	0.076	30/50

^aUsing average rock and fluid properties of the calibration well.**Table 5—Width at Closure**

lbm/ft ²	Width at Closure (in.)
0.1	0.0171
0.5	0.0857
1	0.171
1.5	0.257
2	0.342
3	0.514
4	0.685

Table 6—Pump Schedule

Stage	Fluid	Stage Vol. (gal)	lb/gal	lb per stage	% of Total
1	Pre pad	20,000	—	—	—
2	FET test	—	—	—	—
3	Pad	66,615	—	—	43.12
4	Slurry	6,568	0.05	328	4.25
5	Slurry	6,568	0.24	1,563	4.25
6	Slurry	6,568	0.43	2,798	4.25
7	Slurry	6,568	0.61	4,032	4.25
8	Slurry	6,568	0.80	5,267	4.25
9	Slurry	6,568	0.99	6,502	4.25
10	Slurry	6,568	1.18	7,736	4.25
11	Slurry	6,568	1.37	8,971	4.25
12	Slurry	6,568	1.55	10,206	4.25
13	Slurry	6,568	1.82	11,934	4.25
14	Flush	2,203	—	—	1.43
—	Total	154,503	—	—	100.00

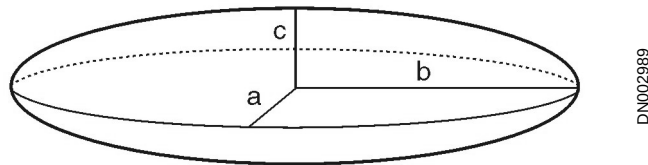
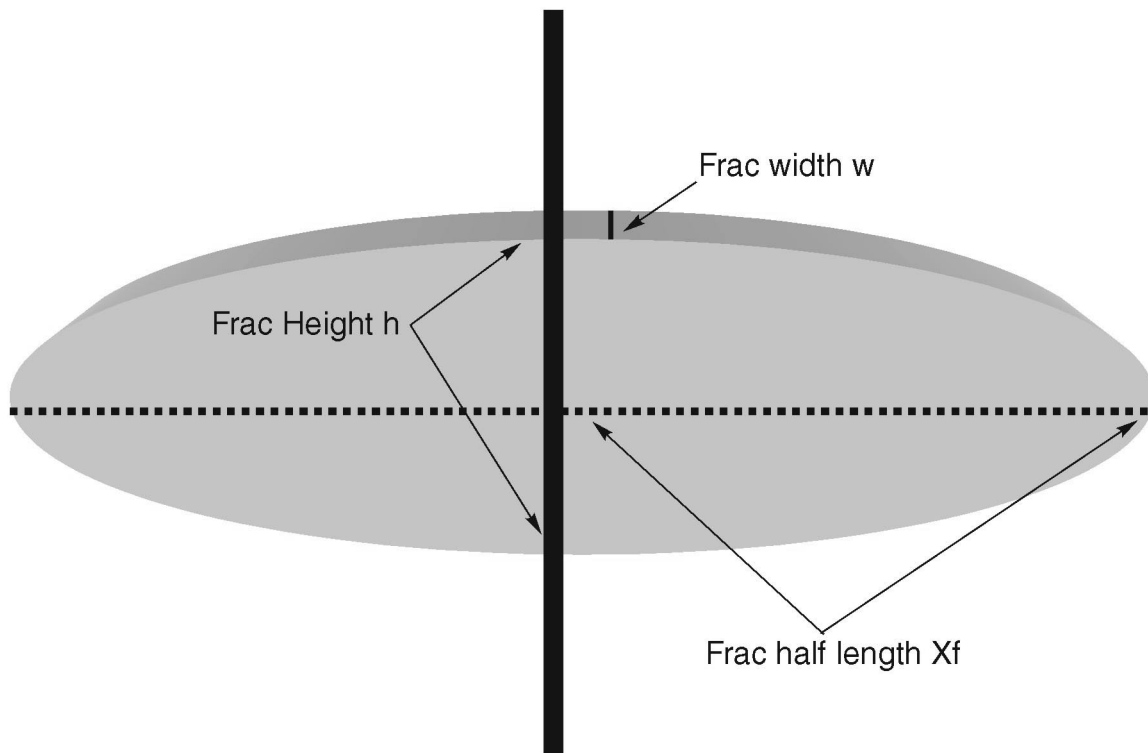
Table 7—Summary Design Sheet

Gross height	260 ft
Width at closure	0.076 in.
Lf	720 ft
Xf	179 ft
Area of frac	294,054 ft ²
Average lbm/ft ²	0.63 lbm/ft ²
Volume of proppant	58,811 lb
Pad volume	66,615 gal
Slurry clean volume	63,003 gal
Slurry dirty volume	65,685 gal
Pad + slurry clean	132,300 gal
Created width	0.129 in.
Volume created frac	2,010 ft ³
Volume created frac	15,033 gal
Fluid efficiency	55.00%
Rate	60 bbl/min
Total frac fluid minimum	3,679 bbl
Pump time	1.02 hr
Tanks	8.2 (500 bbl)

Table 8—Actual Volume^a

Measurement	Calibration Well	Test Well	10-Well Barnett Average
Lf from microseism (ft)	720	770	1,155
h gross from microseism (ft)	260	144	278
h net (ft)	33	60	278
Average permeability k (md)	0.03	0.01	0.002
Average porosity f	12%	8%	6%
Ceff (ft/min ^{1/2})	0.00422	0.0021	0.0008
Ceff multiplier	4.6	4.6	4.6
Rate (bbl/min)	60	30	55
Actual volume (bbl)	3,300	4,797	17,455
Model volume (bbl)	3,150	4,560	17,985

^aActual volume compared to model predicted volume for a given height and fracture half length

Fig. 1—Volume of the ellipsoid = $(4/3 \pi abc)$.Fig. 2—Estimated fracture volume showing dimensions of fracture height (h), fracture half-length (X_f) and fracture width (w).

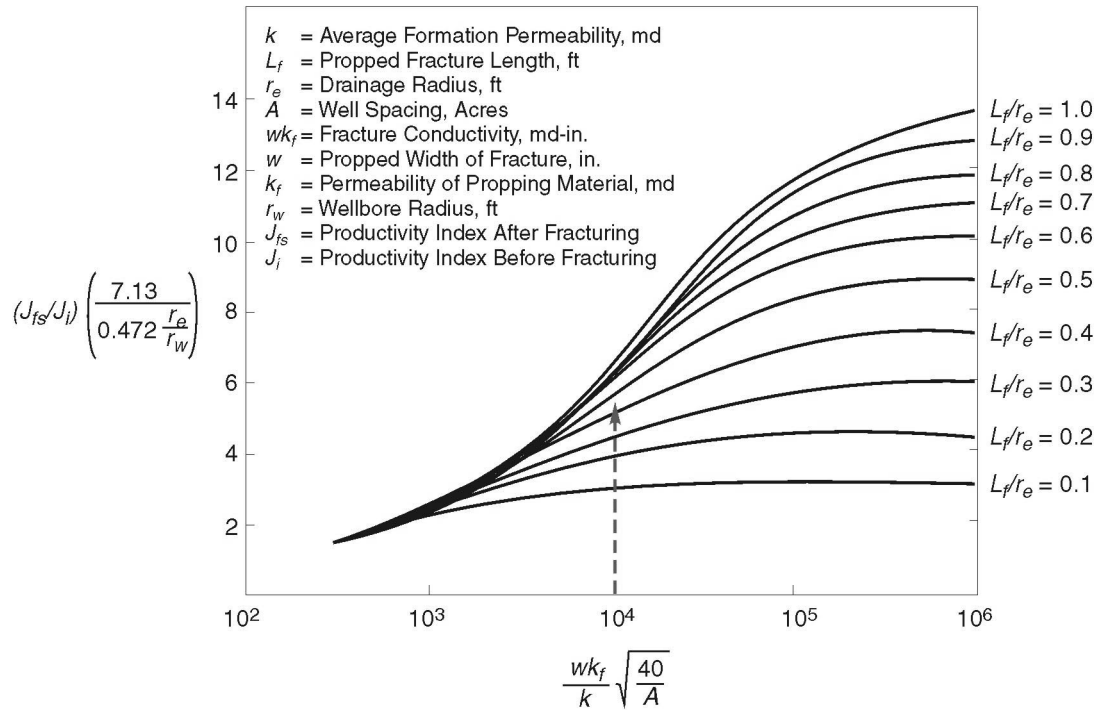


Fig. 3—Chart from McGurie and Sikora and the project's optimum conductivity ratio ($C_{df} = 1.6$).

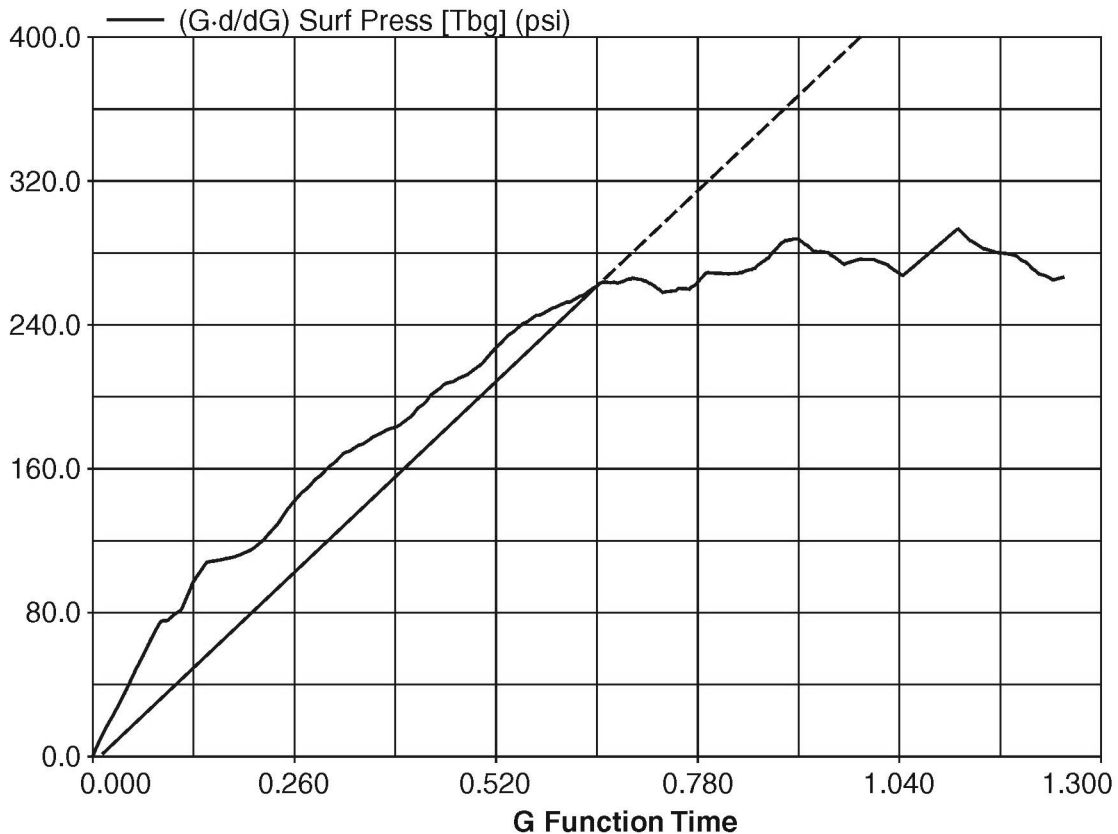


Fig. 4—Example pressure falloff from minifrac injection.

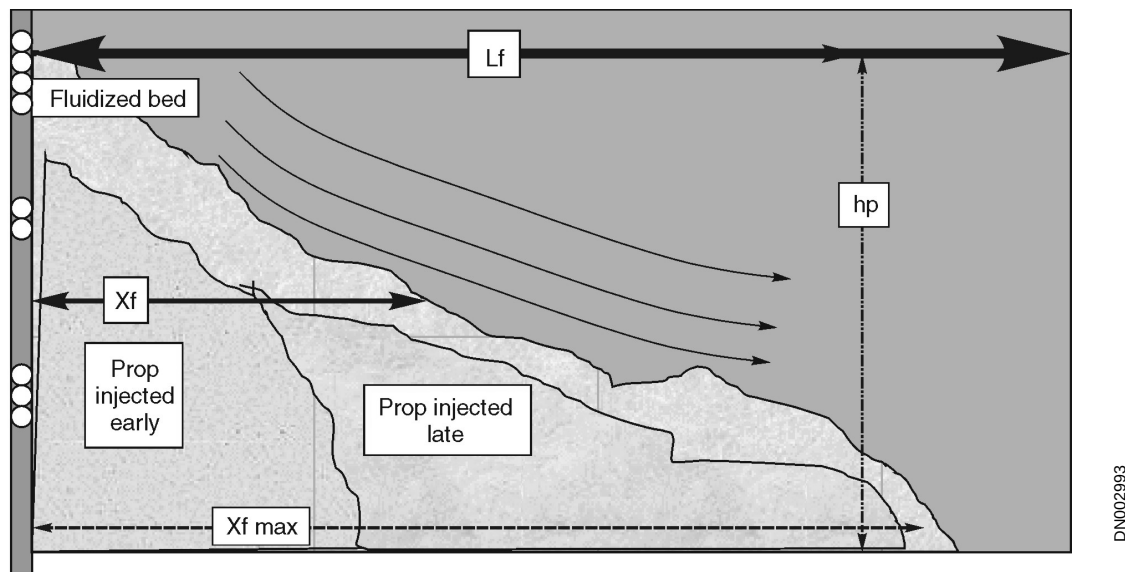


Fig. 5—Illustration of proppant fallout from the wellbore to the fracture tip.

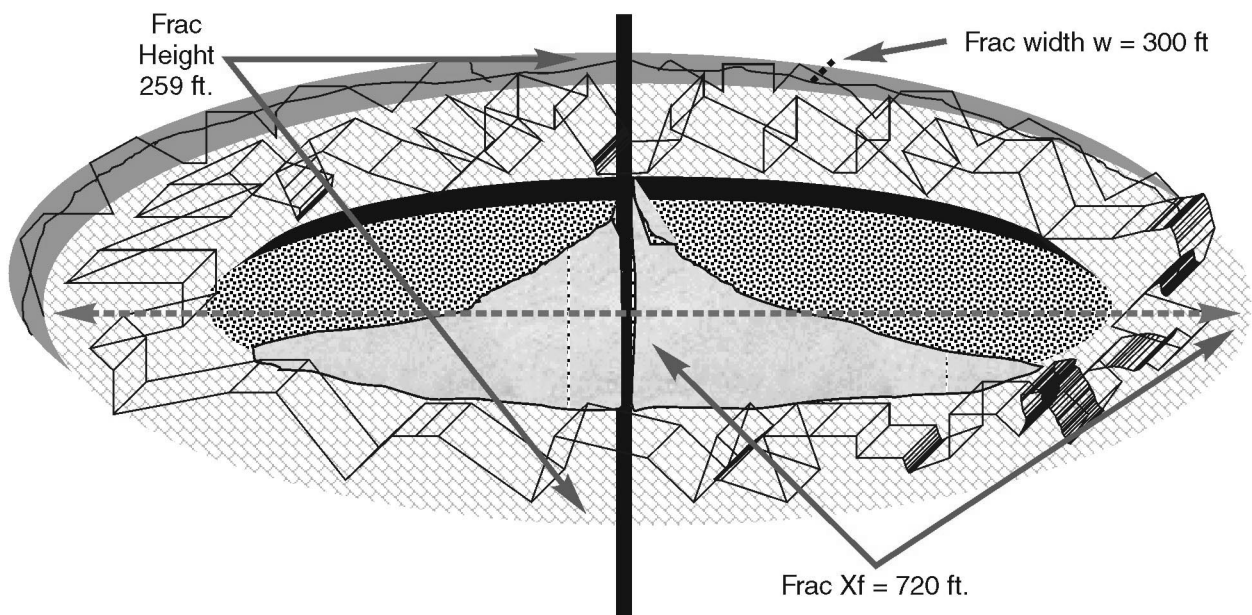


Fig. 6—Illustration of fracture network indicated by microseismic imaging of the calibration well.

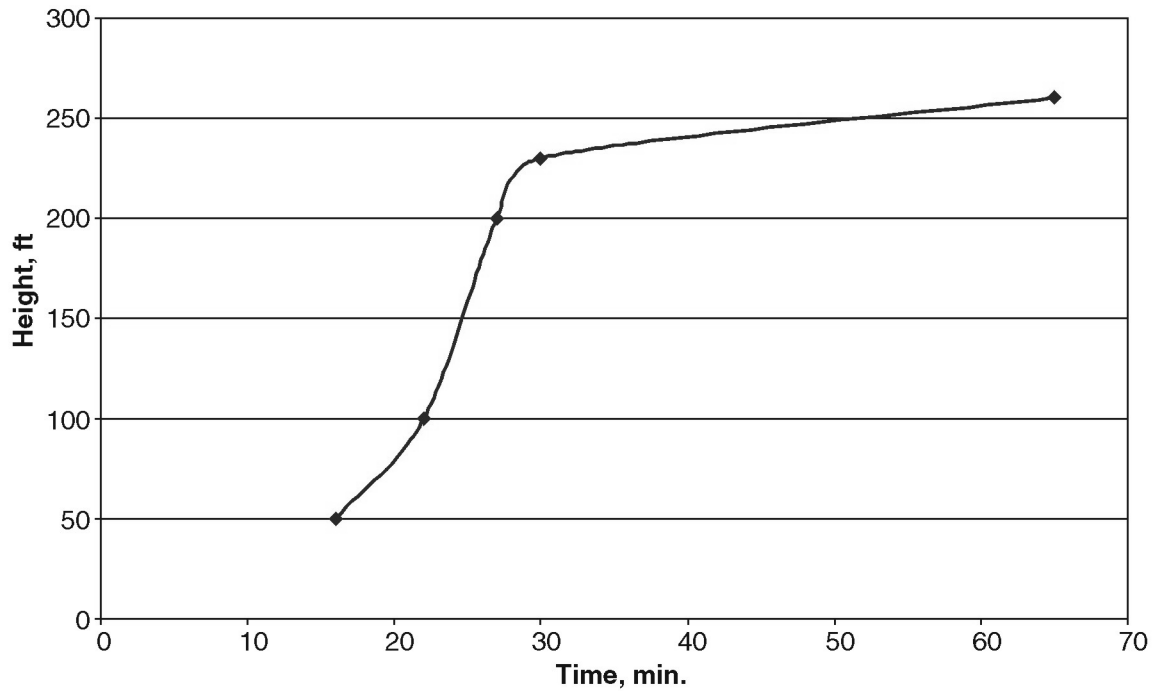


Fig. 7—Plot of fracture height versus time from microseismic imaging calibration well.

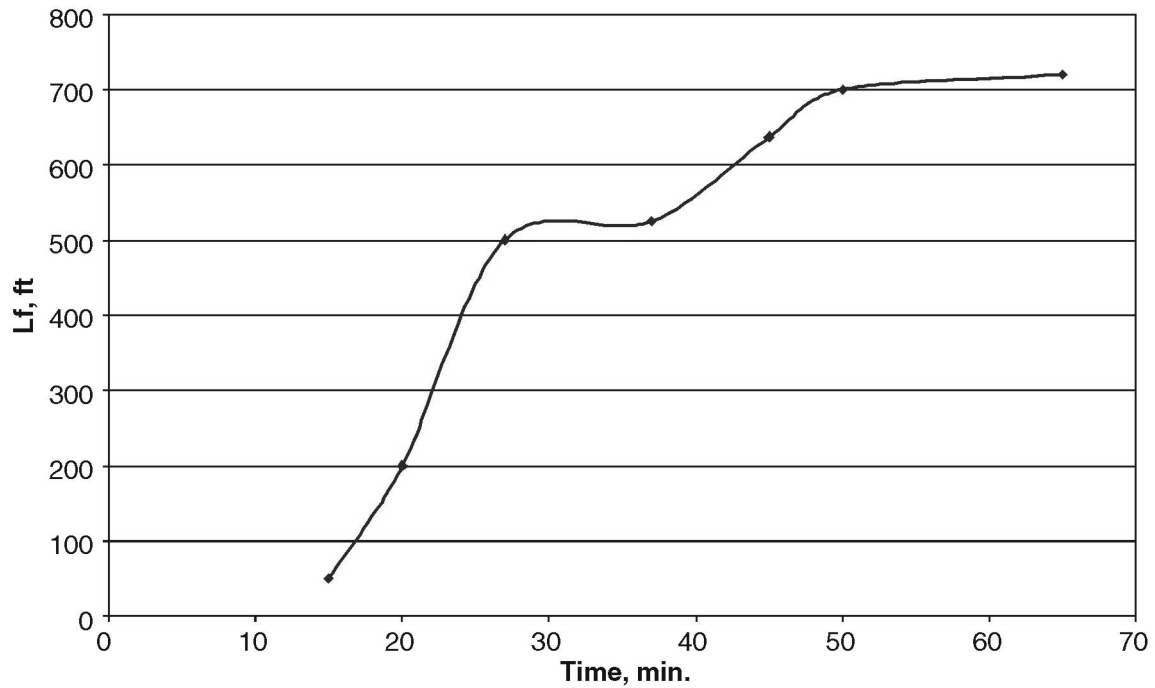


Fig. 8—Plot of fracture half-length versus time from microseismic imaging calibration well.

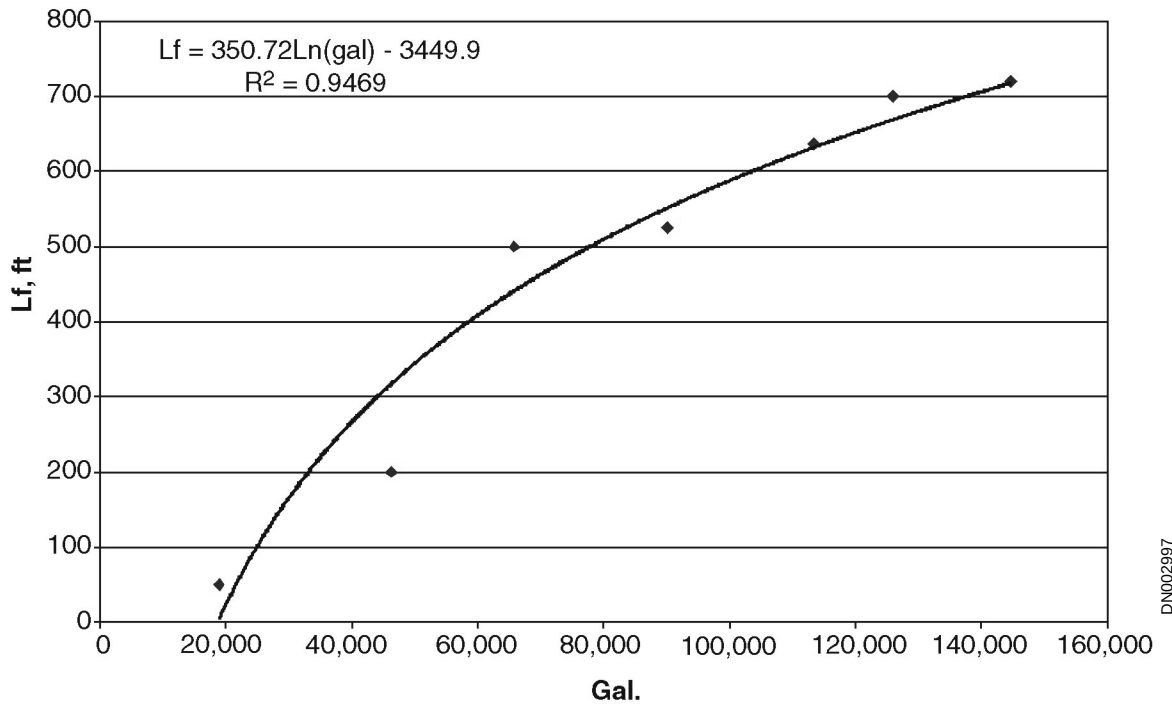


Fig. 9—Plot of fracture half-length versus gallons from microseismic imaging calibration well.

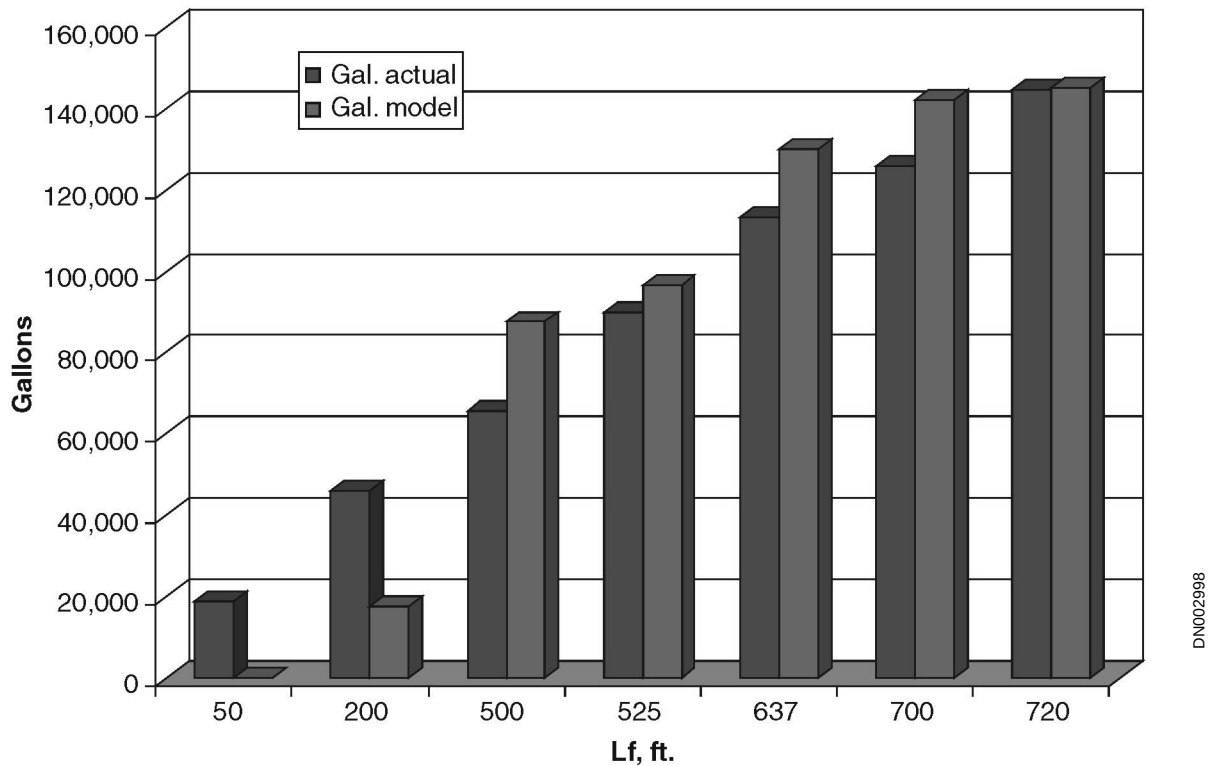


Fig. 10—Model volume calculated to achieve fracture half-length (L_f) versus actual gallons required to reach fracture half-length ($L_f=720$ ft) from microseismic imaging.