METHODOLOGIES AND NEW USER INTERFACES TO OPTIMIZE HYDRAULIC FRACTURING DESIGN AND EVALUATE FRACTURING PERFORMANCE FOR GAS WELLS

A Thesis

by

WENXIN WANG

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

December 2005

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee, Peter Valko
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Wayne Ahr
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ABSTRACT

Methodologies and New User Interfaces to
Optimize Hydraulic Fracturing Design and Evaluate Fracturing Performance
for Gas Wells. (December 2005)

Wenxin Wang, B.S. Southwest Petroleum Institute

Chair of Advisory Committee: Dr. Peter Valko

This thesis presents and develops efficient and effective methodologies for optimal hydraulic fracture design and fracture performance evaluation. These methods incorporate algorithms that simultaneously optimize all of the treatment parameters while accounting for required constraints. Damage effects, such as closure stress, gel damage and non-Darcy flow, are also considered in the optimal design and evaluation algorithms. Two user-friendly program modules, which are active server page (ASP) based, were developed to implement the utility of the methodologies. Case analysis was executed to demonstrate the workflow of the two modules. Finally, to validate the results from the two modules, results were compared to those from a 3D simulation program.

The main contributions of this work are:

- An optimal fracture design methodology called unified fracture design (UFD) is presented and damage effects are considered in the optimal design calculation.
- As a by-product of UFD, a fracture evaluation methodology is proposed to conduct well stimulation performance evaluation. The approach is based on calculating and comparing the actual dimensionless productivity index of fractured wells with the benchmark which has been developed for optimized production.
- To implement the fracture design and evaluation methods, two web ASP based user interfaces were developed; one is called Frac Design (Screening), and the other is Frac Evaluation. Both modules are built to hold the following features.
    - Friendly web ASP based user interface

- Minimum user input
- Proppant type and mesh size selection
- Damage effects consideration options
- Convenient on-line help.

DEDICATION

This thesis is dedicated to Yanlin Qian, my wife, who gives me love and support all of the time. I also want to dedicate this thesis to my happy, shining daughter, Shangshang, and to my parents, Guiying Yu and Haichao Wang, in China, who supported me throughout this study.

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CHAPTER I

INTRODUCTION

This research develops and presents methods of optimal hydraulic fracture design and post-fracture evaluation for gas wells. To make the methods and algorithm more valuable for practical application, Active Server Page (ASP) based user interfaces (UI) were created.

The first section of this chapter provides some hydraulic fracturing background. Next, comparison of fracture stimulation for high permeability and low permeability reservoirs is presented. In the third section an optimal fracture design methodology called unified fracture design (UFD) is discussed. The fourth section provides a literature review, presenting non-Darcy effects, which are significant in optimal fracture design. The last section of this chapter introduces the objectives of the research and the expected results.

1.1 Background on Hydraulic Fracturing

Hydraulic fracturing is a technique used to allow oil and natural gas to migrate more freely by generating a high conductivity conduit from the rock pores to a producing well. The technology was developed in the late 1940s and has been continuously improved and applied since that time. More than 100,000 wells have been hydraulically fractured in the U.S. in the past 15 years, an estimated 50 percent of natural gas wells and 30 percent of oil wells employ this technique to improve recovery. Application of hydraulic fracturing to increase recovery is estimated to account for 30 percent of U.S. recoverable oil and gas reserves and has been responsible for the addition of more than 7 billion barrels of oil and 600 trillion cubic feet of natural gas to meet the nation's energy needs.[1]

Hydraulic fracturing involves injecting fluids into a reservoir at pressure that is high enough to part the formation. To keep the fracture open after the injection pressure

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This thesis follows the style of *Journal of Petroleum Technology* .

is relieved, a granulated material called "proppant", which ranges from natural sand to expansive synthetic, is pumped into the created fracture.

The proppant-filled fracture generates a narrow but very conductive or high permeability flow path toward the wellbore. The propped permeability is normally five to six orders of magnitude greater than the reservoir permeability. "Typical intended propped widths in low permeability reservoirs are on the order of 0.25 cm (0.1 in.), and the length can be several hundred meters. In high permeability reservoirs, the targeted fracture width is much larger, perhaps as high as 5 cm (2 in.), while the length might be as short as 10 meters (30 ft)."[2]

The primary goal of hydraulic fracturing is to increase the productivity of a well by removing damage in the vicinity of the wellbore or by inducing a highly conductive pathway in the formation. Increasing of productivity can either improve the production rate or decrease the pressure drawdown.

The relation between production rate and drawdown pressure can be expressed by the following equation:

$$q = J\Delta p \qquad (1)$$

where J is the productivity index (PI).

The general form of the constant-rate solution of diffusive equation is:

$$q = \frac{1}{141.2}\frac{kh\Delta p}{\mu}\frac{1}{p_D} \qquad (2)$$

Therefore, the expression of productivity index can be obtained from comparing Eq.(1) and (2).

$$\mathrm{J} = \frac{q}{\Delta p} = \frac{1}{141.2}\frac{kh}{\mu}\frac{1}{p_D} \qquad (3)$$

where q is the flow rate, h is reservoir net pay thickness and μ is the fluid viscosity; Δp is pressure drawdown and p_D is dimensionless pressure.

For pseudo-state flow, the drawdown and dimensionless pressure function are given by

$$\Delta p = \overline{p} - p_{wf} \qquad (4)$$

and

$$p_D = \ln \frac{0.472 r_e}{r_w} \quad \text{.......} (5)$$

where $\bar{p}$ is average reservoir pressure, p_{wf} is flowing bottomhole pressure, r_e is outer boundary radius and r_w is wellbore radius.

Because of the radial nature of flow, most of the pressure drop occurs near the wellbore[2], and any damage in this region may significantly increase the pressure loss. The impact of damage near the well can be represented by the skin factor, *s,* added to the dimensionless pressure in the expression of the PI:

$$J = \frac{1}{141.2} \frac{kh}{\mu(p_D + s)} \quad \text{.......} (6)$$

Eq. 6 reveals that a positive skin factor implies a restriction to flow, which in turns reduce production rate. Positive skin factor may be caused by a variety of factors. One of the main components of total skin effect is the damage skin, which may be the result of the drilling, completion and workover operations on a well. Another component of total skin effect is mechanical skin, which may be due to partial completion and slant and perforation skin effect. Phase and rate dependent skin effects are collectively classified as 'pseudo-skins'.

Opposite to positive skin, a negative skin factor implies that the near-wellbore pressure drop is less than would be expected under normal reservoir flow conditions (zero damage), therefore, negative skin effect would increase the well productivity.

Hydraulic fracturing is one of such method that intends to improve the skin factor (negative skin factor). Ideally, a hydraulic fracture creates a highly permeable pathway connecting the formation and the well, thus bypassing the near-well damage.

1.2 Hydraulic Fracturing in Low and High Permeability Reservoirs

1.2.1 Low Permeability (Tight Gas) Fracturing

Well performance can be determined by the rate and pressure behavior of a well throughout its productive life. This performance can be estimated through various methods, most of which are based on the constant rate solution of the radial diffusivity equation, as shown below,

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial p}{\partial r}\right)=\frac{\phi\mu c_t}{k}\frac{\partial p}{\partial t} \quad \text{.......} \quad (7)$$

where ($\phi\mu c_t / k$) is the hydraulic diffusivity term that determines the speed that production or injection impulses (transients) travel radially through the formation. Hydraulic diffusivity is sufficiently low in most low permeability gas reservoirs that well stimulation is usually desired to speed the recovery of reservoir fluid, and well stimulation is usually achieved by a hydraulic fracture treatment. The purpose of the treatment therefore, is to extend a high conductivity "tunnel," normally vertical in orientation, from the wellbore into the reservoir rock.

When fracturing treatments are successful, the increased reservoir flow area created by the fracture can greatly increase the production capacity of the well in addition to any benefit enabled by the mitigation of near-wellbore formation damage. To enhance this effect, the flow capacity of the fracture must be significantly great compared to that of the native reservoir exposed to the fracture.

It is generally recognized that the fracture length requirements depend greatly on reservoir permeability and fracture conductivity. For low permeability formations, fracture length is normally much greater than that of high permeability reservoirs, but with narrower width.

1.2.2 High Permeability Fracturing (Frac and Pack)

Traditionally, hydraulic fracturing has been used predominantly for the stimulation of low permeability reservoirs. Widespread misunderstanding has limited the use of hydraulic fracture in high permeable reservoir based on the belief that the excessive fluid leakoff and difficulties arising from the unconsolidated sands often associate with this kind of formation would render the treatment ineffective.

In recent years, however, techniques for successfully fracturing high-permeability and poorly consolidated reservoir have been developed and improved, leading to an increasingly popular method for the stimulation and control of sand production in these reservoirs. The key technique that enabled the use of hydraulic fractures in high permeability reservoirs is tip screenout (TSO). This involves arresting the lateral propagation of the created fracture; subsequent inflation and packing of the fracture provides the required width (conductivity). The treatment may thus be split into two parts: 1) the TSO stage, and 2) the fracture inflation and packing (FIP) stage. The resulting fracture is much shorter and much wider than a traditional low-permeability hydraulic fracture.

This two-in-one combination treatment is often called a frac and pack treatment. Similar to conventional (low permeability) fracturing, frac and pack treatments by-pass near wellbore damage, providing effective stimulation when acidizing may not be successful. By reducing the pressure drawdown and fluid flux in the reservoir, these treatments also provide effective sand control. In addition to this indirect sand control via reduction in near-wellbore pressure gradients and flow velocities, frac and packs also help control sand production in a more direct manner. This is achieved by increasing effective stresses acting on the formation, in effect compacting and stabilizing the sandface, as well as by exerting a physical filtering effect similar to conventional gravel packs. Frac and pack treatments have been shown to provide superior sand control without the loss in productivity associated with conventional sand control methods. In additional to the initial increased productivity compared to gravel packs, frac and pack treatments often experience an improvement in productivity with time whereas conventional gravel pack completions deteriorate with time[3-7].

Frac and pack treatments offer other advantages besides sand control and stimulation. Drawdown-related problems such as asphaltene or wax deposition can be reduced or eliminated, and non-Darcy flow well effects may be reduced. Frac and packs also allow for more complete zonal coverage, which is can be very beneficial in laminated reservoirs and non-perforated zones.

The first isolated attempts at combining stimulation and sand control took place three decades ago in Venezuela. A small number of frac and pack completions were performed in the early 1980's, and the number of completions increased in the late 1980's and early 1990's experienced a marked increase in frac and pack completions and the technique continues to gain popularity, with successful implementations in various petroleum regions including Gulf of Mexico, Prudhoe Bay in Alaska, Indonesia, Nigeria, Australia and the North Sea[4,8,9].

1.3 Optimal Fracture Design

As a result of the success of massive hydraulic fracturing (MHF), the average size of a typical treatment has been increasing during the last several decades. For tight gas reservoir, it is common that with the fracture length increasing, the flow rate and ultimate recovery from a well are usually increased. This does not mean, however, that the bigger the fracture treatment the better. Holditch *et al*.[10] realized that for any given set of reservoir parameters, an economic optimum fracture length can be calculated. If the induced fracture actually created in a well is greater than the economic optimal length, the well performance may be better but the profit from the well can be reduced. Holditch *et al*[10] proposed that three factors need to be considered to determine the optimum fracture length (or treatment size): 1) fracturing cost; 2) the well performance; and 3) net present value economic. After the corresponding calculations are made, one can construct the graphs of present value profit (NPV) versus fracture length for various wells, such graphs can be used to determine the optimum economic values of well spacing and fracture length for given reservoir.

This optimization procedure though, is very time consuming and tedious because it requires a large number of sensitivity runs. The inordinate number of required runs is a result of having three key unknowns that directly affect the ultimate production response, which includes dimensionless fracture conductivity, fracture length and fracture conductivity. The number of necessary runs is further exacerbated because the method lacks an initial starting point to begin the sensitivity analysis for each of the key parameters[11].

A method called unified fracture design can dramatically reduce the number of required sensitivity runs, and the next section is a brief introduction of the method. The details and the algorithm will be discussed in following sections.

1.3.1 Unified Fracture Design

Valkó *et al.*[2] realized that performance of a fractured well cannot be properly described if one forecasts the production of oil, gas, and even water as a function of time elapsed after the fracturing treatment, since post-treatment production is influenced by many decisions that are not part of the treatment design itself. To solve this problem, they introduce a dimensionless variable called pseudo-steady state productivity index; this variable describes the actual effect of the propped fracture on well performance.

The goal of unified fracture design, therefore, is to reach the maximum pseudo-steady state productivity index, based on the determined treatment size and specific reservoir information. The philosophy of the methodology is that if the petrophysical information of a reservoir is known, and if the amount and the type of proppant intended to inject into the formation have been determined, then one can make the optimal compromise between fracture width and length, where fracture width implies the fracture conductivity and the length implies the fracture penetration. The proppant volume puts a constraint on the two parameters. To handle the constraint easily, a new dimensionless parameter is introduced, which is called proppant number, expressed as:

$$N_{prop} = \frac{2k_f V_{prop}}{kV_{res}} \qquad (8)$$

where, k_f is the fracture permeability, V_{prop} is the propped volume, k is the reservoir permeability, and V_{res} is the bulk volume.

Based on the determined proppant number, one can find a unique fracture conductivity that corresponds to the maximum productivity. With the two known parameters, proppant number and fracture conductivity, the optimal fracture geometry can be calculate.

1.4 Calculation of Non-Darcy Effects

It has been suggested that tight-gas-well performance is hindered significantly by non-Darcy flow effects.[12-14] Gas wells with finite-conductivity fractures producing at high flow rates, the non-Darcy effect is created within the fracture. High pressure drop in the presence of high flow velocities might be reflecting both turbulence and inertial resistance.

Vincent *et al*.[13] realized that in designing fracture treatments non-Darcy effects should not be assumed to apply only to high-rate wells; the effects also are significant even in wells considered to be low rate by current industry standards. According to the author, ignoring these effects will often lead to inaccurate production forecasts, suboptimal fracture design, and selection of an inappropriate proppant type. These mistakes result in lost revenues which can exceed $2 million per fracture treatment for typical gas and oil well fracture treatments conducted in North America.

Richardson[11] proposed a methodology for fracture design and optimization considering the effects of closure stress, temperature, embedment, gel damage, non-Darcy turbulent flow, and non-Darcy multiphase flow. The optimal length is selected on the basis of an economics analysis of fracture length versus net present value (NPV), and then the required fracture conductivity is calculated for a dimensionless fracture conductivity of 30.

Barree *et al*. [15] identified that proppant selection as a key factor to guarantee a successful stimulation and field development. They corrected proppant conductivity for field conditions by considering damage mechanisms that might occur during fracturing and production. Finally, their simulator includes the effects of closure stress, embedment, filtercake deposition, and bulk gel damage.

Lopez-Hernandez *et al*.[16] realized that the Barree *et al*. methodology did not address the reliability of the estimation of the β-factor and its effects on the outcome. So they used unified-fracture-design methodology[2], which is based on a new dimensionless number called *proppant number* to optimize the hydraulic fracture design. Their approach can also be applied to the situation where non-Darcy flow through the propped fracture is significant. In their project, they evaluated β-correlations obtained from different sources for various proppants.

Lopez-Hernandez's[16] methodology is an easy way to solve the problem of optimal fracture. The methodology was implemented in the design of 11 fractures treatments of 3 natural tight gas wells in south Texas. Results show that optimal fracture design might increase the expected production with respect to design that assumes Darcy flow though the propped pack.

Lopez-Hernandez *et al*.,[16] however, did little to apply the method and algorithm to practical field analysis due to their complexity and inflexibility. This research developed a web based user interface connecting with reservoir and proppant database, which can greatly simplify the input and calculation procedure, hence, make the approach more valuable for application. Also, more case investigation could improve the practicality of the methodology.

1.5 Objectives of This Research

This research hinges on how to optimize the hydraulic fracture treatment parameters based on the given treatment size and petrophysical condition to maximize well productivity; an optimal fracture design methodology called unified fracture design (UFD) is presented.

The methodology will be improved to suit practical fracture design work for gas wells by considering effects such as gel damage, closure stress and non-Darcy flow. Gel damage in this research is taken into account as a percentage of retained permeability; whereas closure stress resulting in compaction and consequently some reduction in proppant permeability is evaluated by looking up the behavior of proppant pack permeability versus closure stress for the proppant. This research will utilize an algorithm for non-Darcy effect calculation developed by Lopez-Hernandez *et al*[16]. In the algorithm, non-Darcy flow is described by the β factor method. Evaluation and selection of appropriate β factor correlation is a key in the approach, so the introduction of several typical β correlations will be also included in the research.

In addition, a fracture evaluation methodology is developed to conduct well stimulation performance evaluation. The approach is based on calculating and comparing the actual dimensionless productivity index of fractured well with the benchmark which has been developed for optimized production. Therefore, the key factor of this method is the actual productivity index. The calculation for this parameter will be based on the actual skin factor, and production analysis is the necessary procedure to get reliable skin.

The secondary objective of this research is to develop web (ASP) based user interfaces to implement the methods and simplify the calculation procedures. Two computer program modules will be developed corresponding to the fracture design and evaluation methodologies. Both modules should include following features.

- Web (ASP) based user interface is friendly
- Program minimizes user input by connecting with reservoir database
- User is able to select the proppant type and mesh size from the interface
- User has the opportunity to consider the effect of gel damage and non-Darcy flow from the interface
- User manual is linked to the user interface page, providing on-line help

An investigation on a stimulated well will be conducted in the last stage of the research to demonstrate and validate the methodologies and computer modules. Finally, the calculated results will be compared with those from a 3D fracture simulation program, FracPro, which was developed by Pinnacle Technology.

CHAPTER II

METHODOLOGIES AND ALGORITHM

2.1 Unified Fracture Design (UFD)

Unified fracture design or proppant volume technique was first proposed by Valkó and Economides in 2002. The name "unified fracture design" suggests "the connection between theory and practice, but also that the design process cuts across all petroleum reservoirs— low permeability to high permeability, hard rock to soft rock. And indeed, it is common to all"[2].

2.1.1 Concept of Proppant Number

The performance indicator of a stimulated natural gas well is the pseudo-steady state productivity index (J)[2], which can be expressed by following equation.

$$J = \frac{q_{g\,sc}}{p_{res} - p_{wf}} = \frac{2\pi k_g h_p}{\alpha_1 B_g \mu_g} J_D \quad \ldots\ldots (9)$$

where J_D is called the dimensionless productivity index.

The effect of the hydraulic fracture on the well performance appears in the variable J_D. Dimensionless fracture conductivity (C_{fD}) and penetration ratio ($I_x = 2x_f/x_e$) are the two primary variables that control J_D. The dimensionless fracture conductivity, C_{fD}, is the ratio between the flowability of produced fluid in fracture and ability of the fracture to gather fluids from the formation:

$$C_{fD} = \frac{k_f w_{fp}}{k_g x_f} \quad \ldots\ldots (10)$$

The proppant number is a combination of the two dimensionless variables:

$$N_{prop} = I_x^2 C_{fD} \quad \ldots\ldots (11)$$

Substituting the definition of penetration ratio and dimensionless fracture conductivity into Eq. 11 we obtain the final form:

$$N_{prop} = \frac{2k_f}{k_g}\frac{V_{p-2w}}{V_{res}} \quad (12)$$

Therefore, the proppant number is the ratio of the propped volume (volume of proppant in the pay, in the two wings) to the reservoir volume, weighted by the permeability contrast. The proppant number determines the maximum achievable dimensionless productivity index, as seen in **Figs. 1** and **2**. For a specific N_{prop}, the maximum J_D occurs for a well defined value of C_{fD}. For example, optimum C_{fD} is 1.6 for N_{prop} below 0.1 (Fig. 1). However, for N_{prop} larger than 0.1, the optimal C_{fD} increases with proppant number (Fig. 2). It happens because the I_x cannot exceed unity.

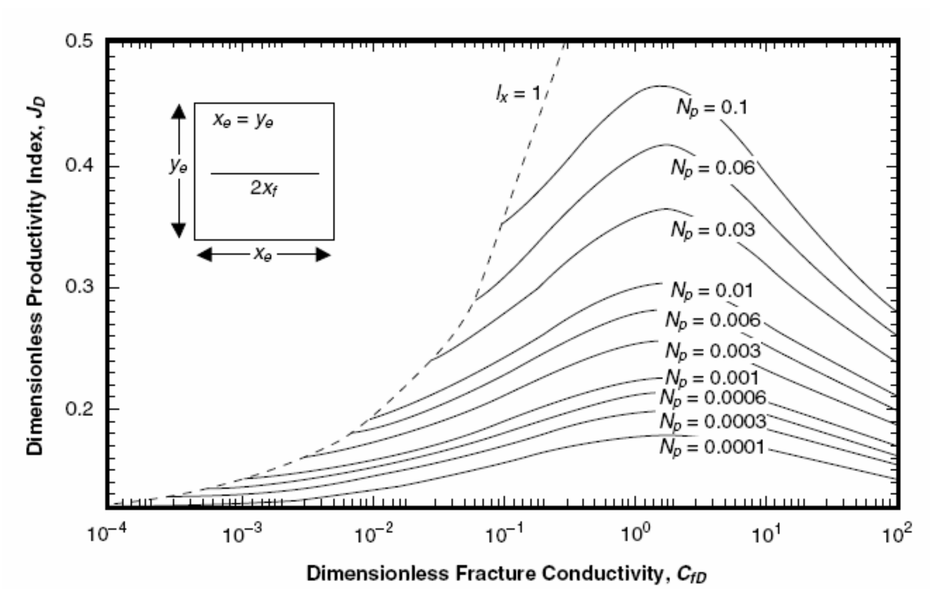


Fig. 1 Dimensionless productivity index as a function of the proppant number less than 0.1 and dimensionless productivity index[2]

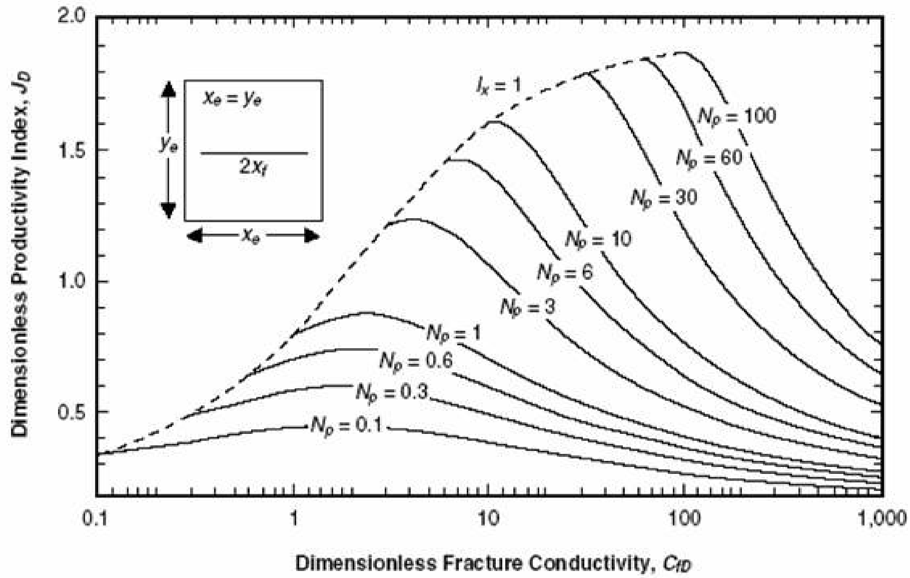


Fig. 2 Dimensionless productivity index as a function of the proppant number above 0.1 and dimensionless productivity index[2]

For all proppant numbers, the optimum fracture dimensions can be obtained from:

$$w_{fp} = \left(\frac{C_{fDopt} k_g V_{p-1w}}{k_f h_p} \right)^{1/2} \quad \text{.......} \quad (13)$$

$$x_f = \left(\frac{k_f V_{p-1w}}{C_{fDopt} k_g h_p} \right)^{1/2} \quad \text{.......} \quad (14)$$

Once the spacing of the wells in the reservoir has been defined, the proppant number will depend on propped fracture permeability (k_f) and volume of proppant reaching the pay ($V_{p\text{-}2w}$).

Volume of proppant reaching the pay is set based on economics (mass of proppant to inject). Finally, the ultimate proppant number will depend on effective propped pack permeability at *in-situ* conditions. Laboratory tests,[14] well modeling and simulation,[17] and post fracture well evaluations[11] have shown that propped fracture permeability of natural gas wells may be significantly reduced by:

- closure stress;
- non-Darcy Flow;

- gel damage;
- multiphase flow;
- embedment;
- proppant crushing; and
- fines migration

The method of optimal fracture design in this research considers the effects of closure stress, non-Darcy flow and gel damage upon proppant effective permeability.

2.1.2 Closure Stress

A hydraulic fracture grows normal to the plane of minimum principal in situ stress (**Fig. 3**). In a homogeneous formation the minimum principal stress is equal to closure stress. However, lithology typically varies with depth. Therefore, minimum principal stress varies in magnitude and direction over the gross pay interval. In this case, closures stress represents the stress at which created fracture globally close (i.e. global average for the interval). Techniques commonly used to determine closure stress are the step-rate test, shut-in decline and flowback analysis.[18]

Fracture fluid (i.e. pad and slurry) is injected at high pressures into the formation to overcome closure stresses, create and propagate a hydraulic fracture. When fluid injection ceases, stresses acts to close the fracture and confine proppant. The effective stress acting on the proppant is

$$\sigma_{eff} = P_c - P_{fracture} \quad (15)$$

Effective stress (σ_{eff}) results in compaction and consequently some reduction in proppant permeability, which is then magnified by crushing of the grains (**Fig. 4**). Reservoir pressure depletion decreases the net closure stress (P_c).[19] On the other hand, flowing pressure within the fracture ($P_{fracture}$) typically decreases with time, increasing the net closure stress. In general, the most critical condition is when pressure within the fracture is 0 psi. It is the case assumed in this research where P_c is calculated from Eq. 16.

$$P_c = FG \cdot MoP \quad (16)$$

where, *FG* is fracture gradient of the interval, and *MoP* is the middle of perforation of the interval.

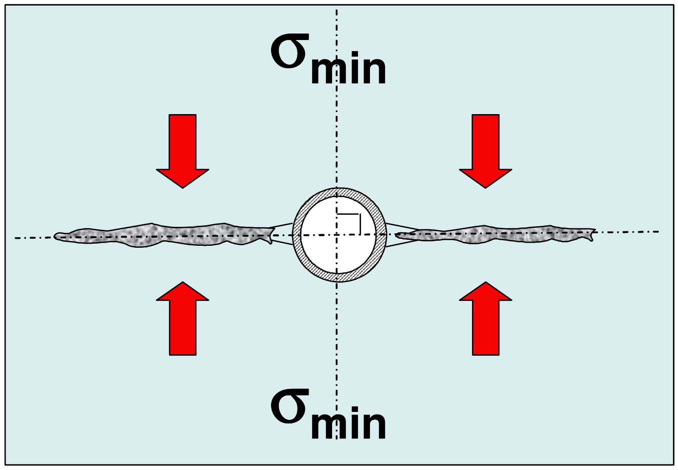


Fig. 3 Orientation of created fracture with respect to principal stresses[16]

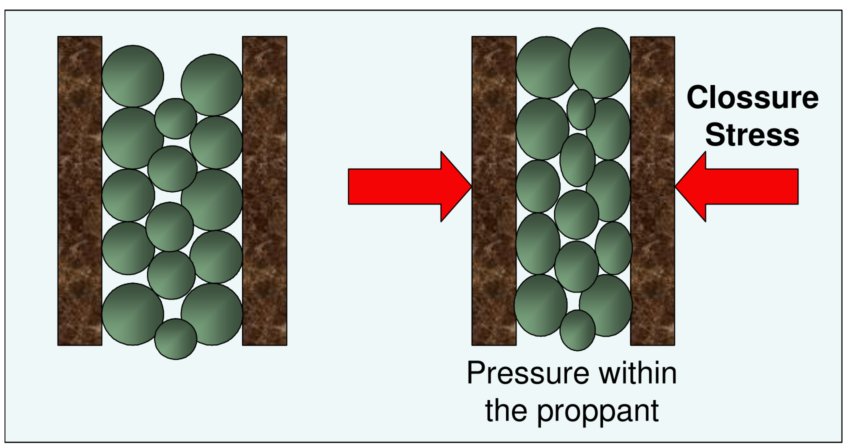


Fig. 4 Closure stress compacts the propped pack reducing the initial permeability of fracture[16]

The behavior of proppant pack permeability versus closure stress for proppants is presented in Appendix A.

2.1.3 Non-Darcy Flow

Darcy´s law describes laminar flow through porous media where the pressure gradient is directly proportional to flow velocity

$$\frac{\Delta P}{\Delta L} = \frac{\mu_g v}{k_f} \quad \text{...} \quad (17)$$

When flow velocity increases, an additional pressure drop is caused by the frequent acceleration and deceleration of the particles of the moving fluid. These inertial effects[21,26] are described by Forchheimer equation:

$$\frac{\Delta P}{\Delta L} = \frac{\mu_g v}{k_f} + av^2 \quad \text{...} \quad (18)$$

Cornell and Kartz[20] rewrote the constant a as the product of the β factor (also called non-Darcy flow coefficient, inertial flow coefficient, and turbulent factor) and the fluid density:

$$\frac{\Delta P}{\Delta L} = \frac{\mu_g v}{k_f} + \beta \rho_g v^2 \quad \text{...} \quad (19)$$

Manipulating Eq. 18 and 19 we can get an expression of $k_{f\text{-eff}}$ describing the non-Darcy flow effects. Geertsma[21] first suggested the parameter called Reynolds number (N_{Re}), which is presented in Eq. 21.

$$k_{f-eff} = \frac{k_f}{1 + N_{\mathrm{Re}}} \quad \text{...} \quad (20)$$

$$N_{\mathrm{Re}} = \frac{\beta k_f \rho_g v}{\mu_g} \quad \text{...} \quad (21)$$

β factor is a property of the porous media.[22,23] Empirical correlations, based on proppant lab data, have been developed to estimate this factor[24]. β factor correlations considered in this research were selected based on evaluations performed by Lopez, Valkó and Pham[16].

2.1.3.1 Typical β Correlations

Cooke

Cooke's equation was the first equation developed to estimate the β factor of proppants.[25] Brady sand was used in the lab experiments. Five sand sizes and various stress levels were considered. Fluids used were brine, gas and oil. Cooke observed no difference results among fluids evaluated. All curves followed Eq. 22. Coefficients are shown in **Table 1.**

$$\beta = \frac{a}{k_f^{\,b}} \quad \text{(22)}$$

Table 1. Constants *a* and *b* of Cooke's Equation

Sand Size (mesh)	*a*	*b*
8/12	3.32	1.24
10/20	2.63	1.33
20/40	2.65	1.54
40/60	1.10	1.60

Martins *et al.*

Tests were conducted for different type of proppants (i.e. intermediate strength proppant, sand) and mesh size (i.e. 16/20 and 20/40) at confining stresses of 2,000, 4,000 and 5,000.[26] Martins *et al*. observed that at high rates all results are very similar irrespective of the type of sand and mesh, and so they proposed Eq. 23 as general equation for proppants.

$$\beta = \frac{2.1E-01}{k_f^{\,1.036}} \quad \text{(23)}$$

Penny and Jin

Penny and Jin plotted β factor vs. permeability for different types of 20/40 proppants (i.e. northern wide sand, procured resin coated white sand, intermediate strength ceramic products and bauxite).[27] Their final equation has the same form as

Cooke´s equation (Eq. 22) where the coefficients *a* and *b* depend on type of sand. These coefficients are shown in **Table 2**. The correlation provides the so called dry β factor because the authors propose to correct it for multiphase flow (when water or condensate is also flowing).

Table 2. Constants a and b of Penny & Jin's equations for 20/40 mesh

Type of proppant	a	b
Jordan Sand	0.75	1.45
Precurred Resin-Coated Sand	1	1.35
Light Weight Ceramic	0.7	1.25
Bauxite	0.1	0.98

Pursell *et al.*

Three type of proppants (i.e. Brady sand, Interprop and Carbolite) were evaluated injecting nitrogen at constant closure stress and pore pressure, at different flow rates. Pursell *et al.* [22] concluded that the relationship between permeability and β factor is only a function of mesh size and proppant permeability and is independent of proppant type. They developed two equations, with the same form as Cooke's equation for 12/20 and 20/40 mesh size. Their coefficients *a* and *b* are shown in **Table 3**.

Table 3. Constants a and b in Pursell's equation

Mesh	a	b
12/20	1.144	0.635
20/40	1.123	0.326

2.1.4 Gel Damage

Fracturing fluids are one the most important components of a successful fracture treatment. The main functions of these fluids are to transmit the hydraulic pressure from the pumps to the formation and transport proppant along the created fracture.[2,18]

Water-based systems are the most widely used fracturing fluids. In this case, polymers are added to proportionate viscosity to the fluid. Guar gum and its derivatives such as hydroxypropil guar (HPG) and carboxymethyl-hydroxypropyl guar (CMHPG) are the polymers typically used as gelling agents.

During the treatment polymer deposits a filter cake on the fracture wall due to the leakoff of the fracturing fluid into the formation.[28] Gel concentration within the fracture increases with time as an effect of the fluid leakoff as well. Deposited cake is subject to erosion and part of the polymer within the fracture comes out in the flowback. However, most of the polymer remains in the fracture (**Fig. 5**). Final effect is a reduction of the cross sectional area of flow, which decreases fracture permeability.

Gel damage is taken into account in this research as a percentage of retained permeability (Eq. 16). Flowers, Hupp and Ryan[23] mentioned that usually engineer designing hydraulic fractures includes a damage of 50% or more to proppant permeability as a consequence of damage by polymers.

$$k_{f-eff} = k_f \cdot \%damage \quad \text{...} \quad (24)$$

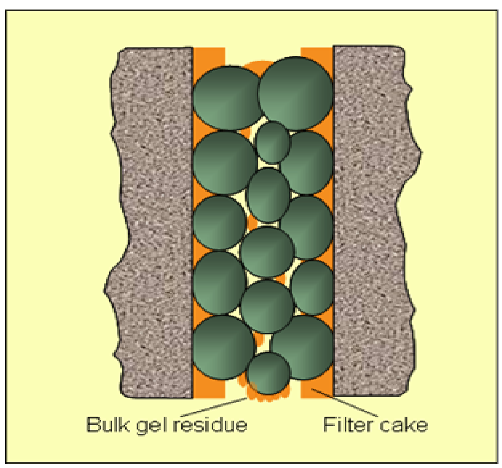


Fig. 5 Polymers within the fracture reduce cross sectional area of propped pack[16]

2.2 Algorithm of Fracture Design Incorporating Damage Effects

Lopez *et al.*[16] developed an algorithm for optimal fracture design, which incorporates non-Darcy flow effect. The algorithm can be illustrated by a flow chart shown in **Fig 6**. The detail of the procedure is described as following:

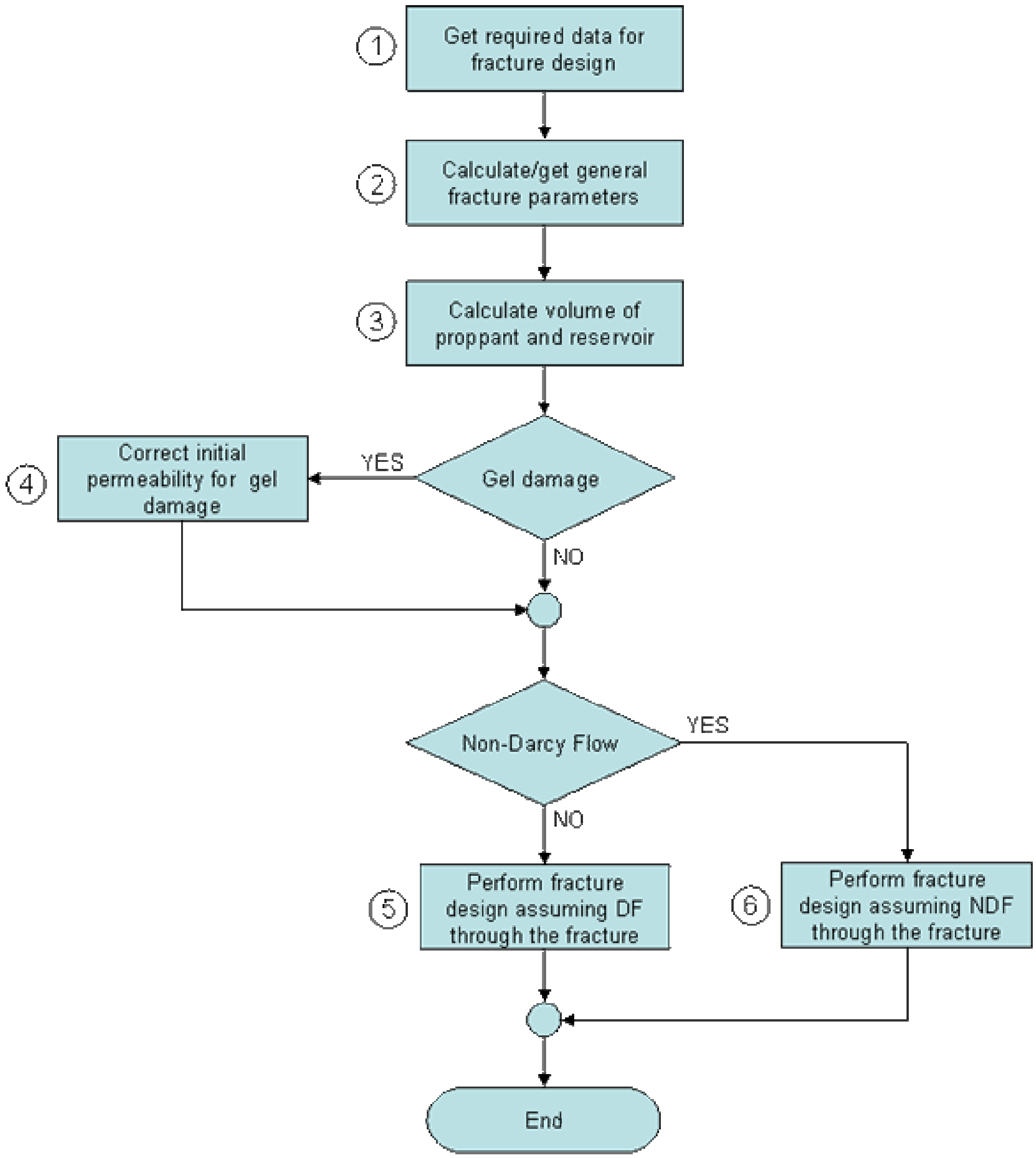


Fig. 6 Flow chart of the fracture design algorithm[30]

2.2.1 Calculate General Fracture Parameters

- Estimate closure pressure (p_c)

$$p_c = f_g \cdot mop \qquad (25)$$

- Obtain k_f based on closure pressure, selected proppant type and mesh size
- If AR is the method selected for fracture height calculation then initialize h_f to 100 ft; Else h_f is the one specified by user.

2.2.2 Calculate Volume of Proppant and Reservoir

- Calculate drainage radius (r_e)

$$r_e = \sqrt{\frac{area}{\pi}} \qquad (26)$$

- Reservoir volume (V_{res})

$$V_{res} = \pi \cdot r_e^{\,2} \cdot h_p \qquad (27)$$

- Volume of proppant injected (V_i)

$$V_i = \frac{0.016 \cdot m}{(1 - pp) \cdot sgp} \qquad (28)$$

2.2.3 Correct Initial k_f due to Gel Damage

- $k_f = k_f \cdot (1 - gd/100)$ $\qquad$ (29)
- Initialize error to 100

2.2.4 Fracture Design Assuming Darcy Flow through the Propped Pack

- Set $h_{fnew} = h_f$
- Volume of proppant reaching the pay (V_2)

$$V_2 = V_i \cdot \frac{h_p}{h_{fnew}} \qquad (30)$$

- Proppant number (N_{prop})

$$N_{prop} = \frac{2 \cdot k_f}{k_g} \frac{V_2}{V_{res}} \quad \text{(31)}$$

- Calculate optimal dimensionless fracture conductivity (C_{fdop}) and optimal dimensionless productivity index (J_{dop}) from algorithm to calculate these two parameters for a given proppant number,

- Proppant volume in one wing of the net pay (V_1)

$$V_1 = \frac{V_2}{2} \quad \text{(32)}$$

- Optimal fracture half length (x_f)

$$x_f = \left(\frac{k_f \cdot V_1}{C_{fdop} \cdot k_g \cdot h_p} \right)^{1/2} \quad \text{(33)}$$

- $h_{fold} = h_{fnew}$

- If aspect ratio option is selected, then $h_{fnew} = \frac{2 \cdot x_f}{4}$; Else continue

- Calculate Error

$$Error = \frac{\left| h_{fnew} - h_{fold} \right|}{h_{fold}} \cdot 100 \quad \text{(34)}$$

- If Error < 0.01 continues; else go back to Eq. 30 and repeat its following steps again.

- Calculate gas production (q_g)

$$q_g = \frac{k_g \cdot h_p \cdot (m(pres) - m(fbhp))}{1{,}424 \cdot (T_{res} + 460)} J_{dop} \quad \text{(35)}$$

2.2.5 Perform Fracture Design Considering Non-Darcy Effect

- Calculate z-factor (Z_{fbhp}) at flowing bottomhole pressure

- Calculate gas formation volumetric factor (b_g)

$$b_g = 0.0282 \frac{Z_{fbhp} \cdot T_{res}}{f_{bhp}} \quad \text{……………………..………………...…. (36)}$$

- Molecular weight of the mixture (m_g)

$$m_g = 29 \cdot sgg \quad \text{…………………………….……………………. (37)}$$

- Density of the gas (g_{asd})

$$g_{asd} = \frac{f_{bhp} \cdot m_g}{Z_{fbhp} \cdot 10.732 \cdot T_{res}} \quad \text{……………………...………………… (38)}$$

- Beta factor (*beta*)

$$\beta = \frac{a}{k_f{}^b pp^c} \quad \text{………………...………………………………….... (39)}$$

- Initialize Reynolds number (r_{new}) $r_{new} = 10$

- Calculate effective permeability due to NDF (k_{feff})

$$k_{feff} = \frac{k_f}{1 + r_{new}} \quad \text{………………………………...……….……… (40)}$$

- Volume of proppant reaching the pay (V_2)

$$V_2 = V_i \cdot \frac{h_p}{h_f} \quad \text{………...…………...……………………..……... (41)}$$

- Proppant number (N_{prop})

$$N_{prop} = \frac{2 \cdot k_{feff}}{k_g} \frac{V_2}{V_{res}} \quad \text{……………..………………….……….…..... (42)}$$

- Calculate optimal dimensionless fracture conductivity (C_{fdop}) and optimal dimensionless productivity index (J_{dop}) based on a given proppant number,
- Calculate proppant volume in one wing of the net pay (V_1)

$$V_1 = \frac{V_2}{2}$$

- Calculate optimal fracture half length (x_f) by using following equation

$$x_f = \left(\frac{k_{feff} \cdot V_1}{C_{fdop} \cdot k_g \cdot h_p} \right)^{1/2} \quad \text{……………………...……………………….. (43)}$$

- If aspect ratio option is selected, then $h_f = \frac{2 \cdot x_f}{4}$; else continue
- Evaluate the optimal propped width (w_f)

$$w_f = \left(\frac{C_{fdop} \cdot k_g \cdot V_1}{k_{feff} \cdot h_p} \right)^{1/2} \quad \ldots\ldots \text{(44)}$$

- Calculate gas production rate (q_g)

$$q_g = \frac{k_g \cdot h_p \cdot (m(pres) - m(fbhp))}{1{,}424 \cdot (T_{res} + 460)} J_{dop} \quad \ldots\ldots \text{(45)}$$

- Calculate gas velocity within the fracture (v)

$$v = \frac{500 \cdot b_g \cdot q_g}{h_f \cdot w_f} \quad \ldots\ldots \text{(46)}$$

- Set $r_{nold} = r_{new}$
- Calculate gas viscosity (v_{fbhp}) at flowing bottomhole pressure
- Calculate Reynolds number (r_{new})

$$r_{new} = 1.83 \times 10^{-16} \frac{\beta \cdot k_f \cdot gasd \cdot v}{v_{fbhp}} \quad \ldots\ldots \text{(47)}$$

- Compute Error of Reynolds number

$$Error = \frac{|r_{new} - r_{nold}|}{r_{new}} \cdot 100$$

- If Error < 0.01 continues; else go back to the step of effective permeability calculation.

2.3 Fracture Performance Evaluation

The methodology of fracture performance evaluation is based on calculating and comparing the actual dimensionless productivity index of fractured well with the benchmarks which have been developed for optimized production. From the comparison, one can evaluate the fracturing performance and make decisions such as re-fracturing and improvement of future treatments.

To estimate the actual productivity index, one can use the equation applied to calculate the dimensionless pseudo-steady state productivity index, which is given as:

$$J_D = \frac{1}{\ln 0.472 \frac{r_e}{r_w} + s} \quad \text{(48)}$$

Therefore,

$$s = \frac{1}{J_D} - \ln(0.472 \frac{r_e}{r_w}) \quad \text{(49)}$$

where, J_D is the actual dimensionless productivity index, r_e is the drainage radius, r_w is the well radius, and s is the measured skin factor.

The comparison between the two dimensionless productivity indexes is presented as the percentage of optimal productivity index achieved.

$$pi_{ach} = \frac{J_{act}}{J_{opt}} \times 100\% \quad \text{(50)}$$

The key factor of this application is the input actual skin factor, which may come from other production analysis methodology such as Fetkovich decline curve analysis. Success of fracture evaluation greatly depends on how reliable this skin factor is.

CHAPTER III
ACTIVE SERVER PAGE USER INTERFACE

Two methodologies, unified fracture design and fracture evaluation, were presented in the previous chapter. In reality, however, they are rarely put in practical use due to the complex algorithm. This research is trying to solve the problem by creating user interfaces of fracture design and evaluation to simplify the input and calculation procedures. Two computer modules were developed based on the methods, one is called Frac Design (Screening), and the other is Frac Evaluation.

3.1 Fracture Design (Screening) Module

Frac Design (Screening) is a web based application for the design of hydraulic fractures mainly for natural gas wells. Design methodology is based on proppant number approach (UFD). The application considers the effects of closure stress, non-Darcy flow and gel damage upon the effective propped pack permeability performance. It results in more realistic fracture designs for maximizing gas well deliverability.

Frac Design (Screening) was designed to minimize number of parameters to be entered by user. Then, most of the design input process consists on various selections, based on which, data required by application is obtained from those already created by the production company in South Texas and from new databases (i.e. database of proppant and beta factor) constructed in this research.

One of the most important features of Frac Design (Screening) is the possibility to use any commercial proppant in any of its available mesh size. Proppants have been classified by type. Only a few commercial products have been initially included in the database, but it can be extended to include more proppant in the futures.

The several typical proppant beta correlations have been included in Frac Design (Screening). Based on user selection of proppant type and mesh size, the program will pick the most appropriate correlation for actual case. Gel damage is accounted as percentage of proppant permeability reduction.

3.1.1 Input Data

Frac Design (Screening) has been designed to minimize the number of parameters to be entered by user. Most of required data is obtained from existing real reservoir databases and new databases we created for this application (i.e. database of proppant and beta correlations databases). Entries basically consist on the selections from lists and checkboxes displayed in input window. For the information which are not given in the database, default values are set for the entries and marks "**" following the data name.

3.1.1.1 Well Data Input and Interval Selection

Basic information of the selected well is displayed at the top of Frac Design (Screening) main page (**Fig. 7**), which includes operator information, well name, field name, reservoir information and the well location.

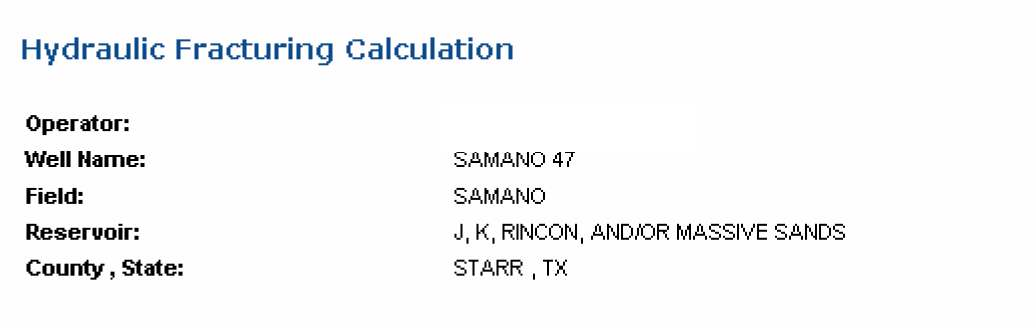


Fig. 7 Basic data of well to be fractured

The intervals in this well are presented in a combo box list (**Fig. 8**). It corresponds to intervals that are already included in the reservoir databases. One interval might be selected from this list.

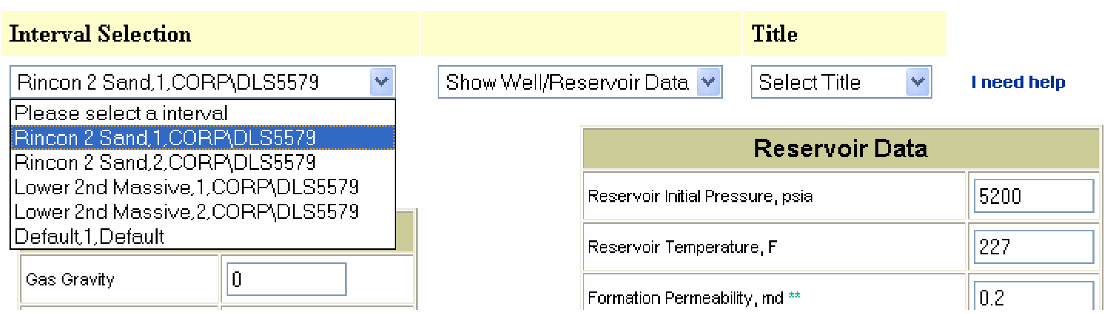


Fig. 8 Interval to be fractured in one stage

All intervals selected must be in a range of maximum 300 ft (**Fig. 9**). It is because only one fracture treatment can be designed at a time and maximum expected fracture height is 300 ft.

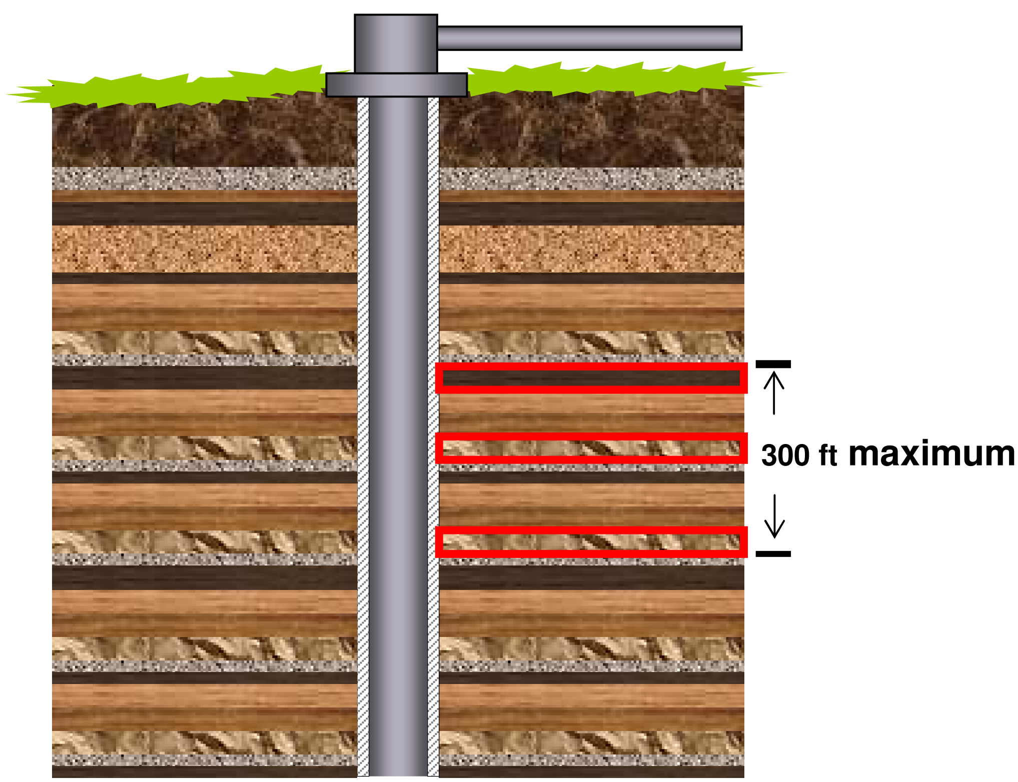
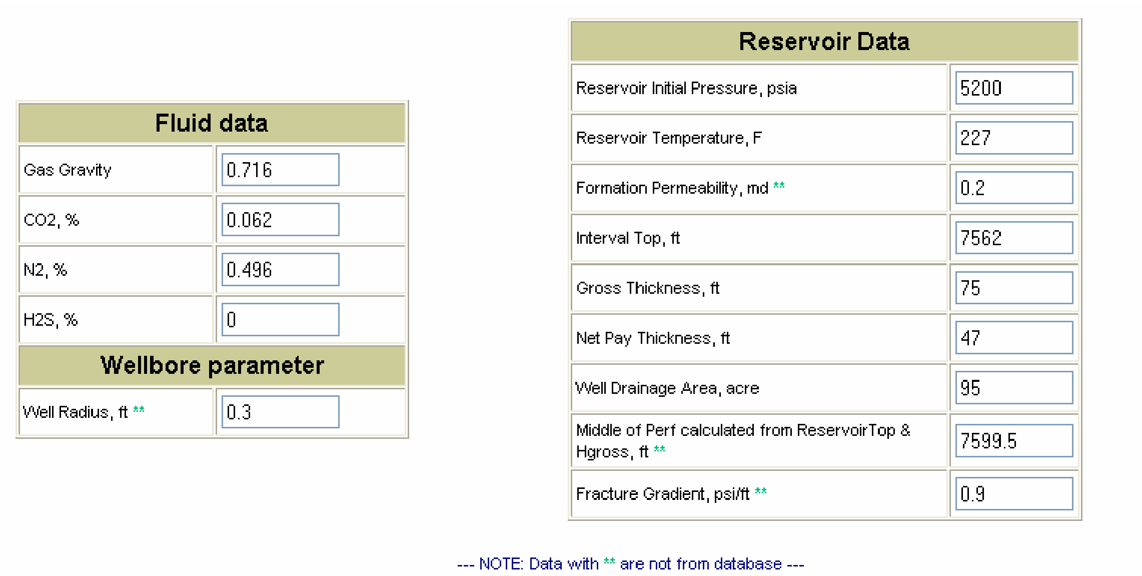


Fig. 9 Intervals selected to be fractured in one stage should be in a range of 300 ft[30]

3.1.1.2 Reservoir and Fluid Data

These data read from the reservoir databases will be displayed in "Fluid data" and "Reservoir Data" forms (**Fig. 10**), right below the "Well data" and "Interval selection" sections after an interval is selected.



Fluid data	
Gas Gravity	0.716
CO2, %	0.062
N2, %	0.496
H2S, %	0
Wellbore parameter	
Well Radius, ft **	0.3

Reservoir Data	
Reservoir Initial Pressure, psia	5200
Reservoir Temperature, F	227
Formation Permeability, md **	0.2
Interval Top, ft	7562
Gross Thickness, ft	75
Net Pay Thickness, ft	47
Well Drainage Area, acre	95
Middle of Perf calculated from ReservoirTop & Hgross, ft **	7599.5
Fracture Gradient, psi/ft **	0.9

--- NOTE: Data with ** are not from database ---

Fig. 10 Fluid/reservoir data collecting from the reservoir databases

The input data of this section includes three parts i.e. fluid data, wellbore parameters and reservoir data, which are described as following.

3.1.1.3 Fluid Data

- *Gas gravity*. The specific gravity of the gas, this information might be obtained from lab or field measurements
- *%*N_2. Percentage of nitrogen (mass) present in the gas mixture. It is obtained from lab measurements.
- *%*CO_2. Percentage of carbon dioxide (mass) present in the gas mixture. It is obtained from lab measurements.

- *$\%H_2S$*. Percentage of hydrogen sulfide (mass) present in the gas mixture. It is obtained from lab measurements.

3.1.1.4 Wellbore Parameter

- *Well radius*. Normally this information can not be collected from reservoir database, so a number of 0.3 (ft) is set as default input.

3.1.1.5 Reservoir Data

- *Reservoir initial pressure.* The initial pressure of the reservoir
- *Reservoir temperature.* Average formation temperature
- *Formation permeability.* Formation effective permeability to gas. Normally this value can not be obtained directly from database, but from log, well test or from production analysis
- *Interval Top.* Depth of the interval top
- *Gross Thickness.* Total gross thickness of the interested intervals
- *Net Pay Thickness.* The effective thickness of the reservoir
- *Well drainage radius*. It is obtained from drainage area assuming reservoir is circular (Eq. 18)

$$r_e = \sqrt{\frac{43{,}560 \cdot Area}{\pi}} \quad \text{......} \quad (51)$$

where, r_e is in ft and Area in acres.

- *Middle depth of the perforations*. It is calculated from the interval top plus the half of gross thickness.
- *Fracture gradient*. This value is calculated in stead of read out from database. Since instantaneous shut-in pressure (ISIP) data can be obtained from fracture operation database, fracture gradient can be computed by following equations:

$$BHP = P_h + ISIP \quad \text{......} \quad (51)$$

$$FG = BHP / MoP \quad \text{......} \quad (52)$$

where, BHP is bottomhole pressure, P_h is hydrostatic pressure, *FG* is fracture gradient and *MoP* is middle of perforation.

3.1.2 Proppant Selection & Treatment Size

One of the most important steps in the hydraulic fracturing design, to be performed in any well, is the selection of proppant to be injected into the formation. It determines in part the maximum dimensionless productivity index we might expect from fractured well. In this section of the input window user can choose the type of proppant, commercial product, mesh size and mass of proppant to inject. Proppants available in Frac Design (Screening) are those included in a Microsoft Access database developed for this application. Then, this database can be extended as needed to include more proppant products. Data included in the Access file is shown in Appendix A.

- *Proppant type*. Because of recent advances in composite material and manufacturing technologies, many new men-made proppants are available. Type of proppant has to be selected based on in-situ stress conditions (i.e. Closure pressure), long term goals, etc. Types available in Frac Design (Screening*)* are included in the list next to label "Prop Type" (**Fig. 11**). The type of proppants initially included in Frac Design (Screening) are:
    - Low Weight Ceramic (LWC)
    - Heavy Weight Ceramic (HWC)
    - Sintered Bauxite (SB)
    - Resin Coated Sand (RCS)
    - Resin Coated Bauxite (RCB)
    - Sand (Sand)
- *Proppant name*. It is the list of commercial proppants available in Frac Design (Screening) for type of proppant selected in previous step. If user changes the type of proppant to be used proppant name list should be changed too. (Fig. 11).
- *Mesh size*. List displayed next to label "Mesh Size" corresponds to sizes available for proppant selected in previous step. It is automatically updated when user change proppant to be used. (Fig. 11).

- *Mass of proppant*. The mass of proppant to be injected into the formation in the textbox. It is in *lbm* (Fig. 11).

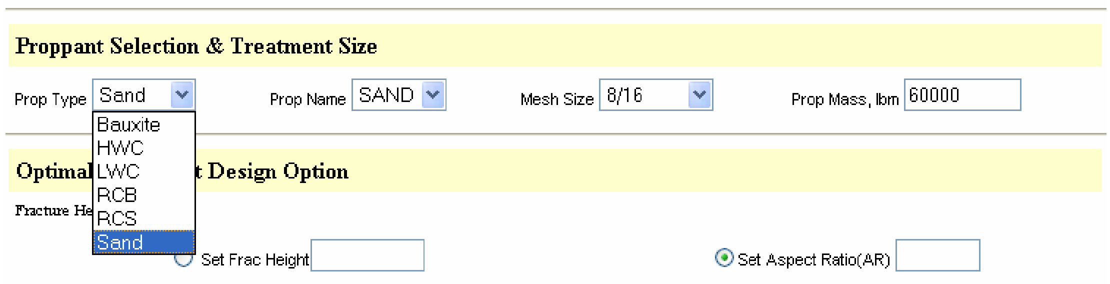


Fig. 11 Selection of proppant to be considered in the design and mass of proppant to inject into the formation

3.1.3 Optimal Treatment Design Options

In this section, the user has to complete several input that will be necessary for determining final optimal fracture geometry.

3.1.3.1 Fracture Height

Final fracture height is determined by injection pressure, in-situ stresses and mechanical properties of interested and adjacent layers (i.e. strength contrasts). Frac Design (Screening) includes two options to set this parameter based on data available and uncertainties.

- Known *fracture height*. This option is recommended when final fracture height can be estimated from logs. It is the case of thick pays with high strength contrast where it can be assumed that fracture will be contained in the pay of interest (**Fig. 12**).

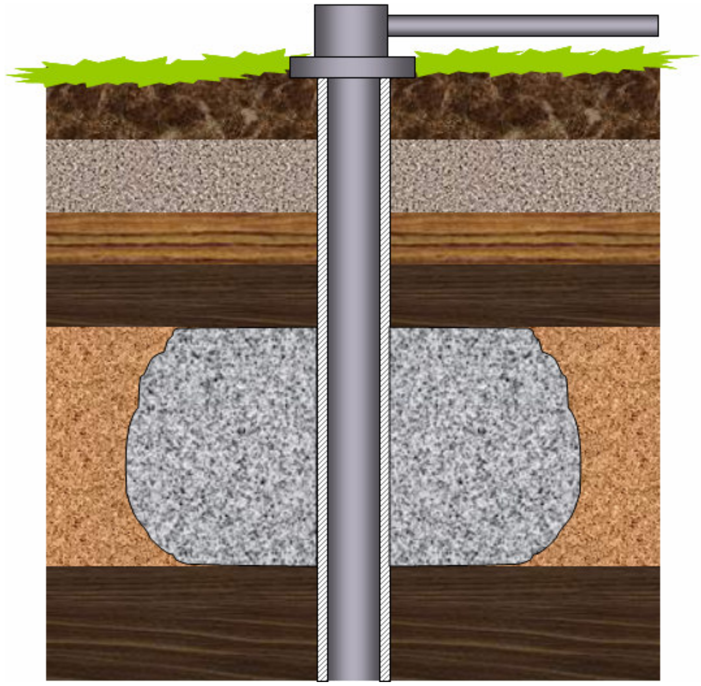


Fig. 12 Fracture contained by two adjacent shales[30]

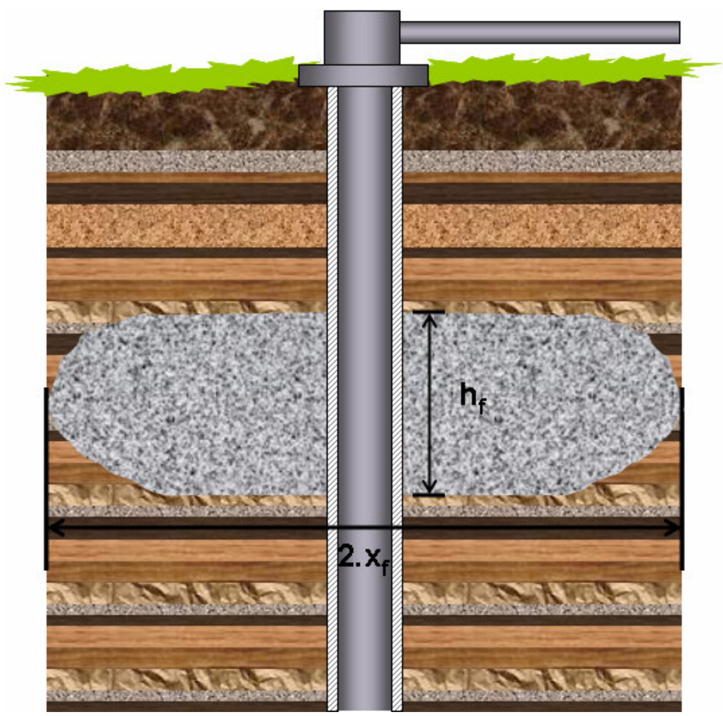


Fig. 13 Fracture height estimation in multilayered reservoirs[30]

- *Aspect ratio*. This option is recommended when the uncertainties in fracture containment is high. It is the case of laminated reservoirs (**Fig. 13**) where it is difficult to predict where the fracture height growth will stop. Aspect ratio is defined as the ratio of total fracture half length to fracture height (Eq. 51). Valkó suggests setting this value to 4 based on numerous observations where both parameters were measured.

$$AR = \frac{2 \cdot x_f}{h_f} \quad \text{...} \quad (53)$$

Finally, select the appropriate method for fracture height calculation by clicking on the option that corresponds to the method (**Fig. 14**)

Fig. 14 Fracture height estimation method selection

3.1.3.2 Correct Prop Permeability

In this section user has the opportunity to consider the effects of gel damage and non-Darcy flow upon the effective permeability of the propped pack. It is recommended to consider the effects that are likely to be presented. It will result in real optimal fracture designs.

- *Gel damage*. To consider this effect just click on the check box next to the label with the same name. This option is active only when a checkmark appears in the check box (**Fig. 15**). Then, user has to input a percentage of gel damage in the textbox next to the checkbox (Fig. 15). Several authors recommend setting this parameter to 50% for design purposes.

- *Non-Darcy flow*. This effect is always likely to be presented at field conditions. Therefore, it should always be considered during the design process. Check the box next to the label with the same name if non-Darcy effects are considered (**Fig. 15**).

In this section the user can check the beta correlation and nominal proppant permeability being used, which are based on the proppant selection in the previous step.

Fig. 15 Selection of damage factors

3.1.3.3 Beta Correlation

There are four β correlations available in Frac Design (Screening). Two of these correlations were developed for a specific proppant type and mesh size. These are Penny & Jin and Cooke. These correlations will appear in the combo box if and only if the proppant type and mesh size corresponds to one of the combinations presented in **Table 4**. If it is the case, select either one of these correlations as the correlation of choice. Otherwise, either Pursell *et al.*[23] or Martins *et al.*[25] can be used for other type of proppant and mesh size.

Table 4. Correlations developed for specific types of proppants and mesh size

Correlation	Type of proppant	Mesh size
Penn & Jin	Bauxite	20/40
	LWC	20/40
	RCS	20/40
	Sand	20/40
Cooke	Sand	8/12
	Sand	10/20
	Sand	20/40
	Sand	40/60

3.1.3.4 Optimize Pseudo-Steady State Design

In this section user must set the bottomhole pressure and average formation pressure in order to calculate the flow rate corresponding to the optimal fracture design.

- *Flowing bottomhole pressure.* This parameter should be entered by user in the text box next to the label with the same name (**Fig. 16**). This parameter is used to calculate the flow rate based on the optimal design scenario.

- *Formation average pressure.* This parameter also should be input by user associated with the practical condition. It should be estimated as best as possible, since the final optimal design is affected by this parameter (**Fig. 16**).

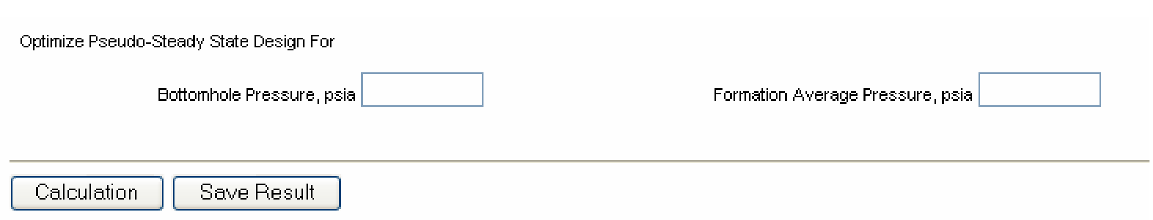


Fig. 16 Input of the bottomhole pressure and formation average pressure

3.1.4 Run Calculation

After all data required have been entered and selections have been made, click on the "Calculation" button (**Fig. 16**) to execute the designing calculation. If any parameter is missing, a warning message will be displayed indicating what parameter to enter or correct (**Fig. 17**).

Fig. 17 Warning message indicating that some parameter value is missing or out of the range

3.1.5 Results

Optimal fracture design, important parameters associated to this design and expected well performance is presented in the *Calculation Results* section (**Fig. 18**) at the bottom of Frac Design (Screening) window. Calculation results are presented below.

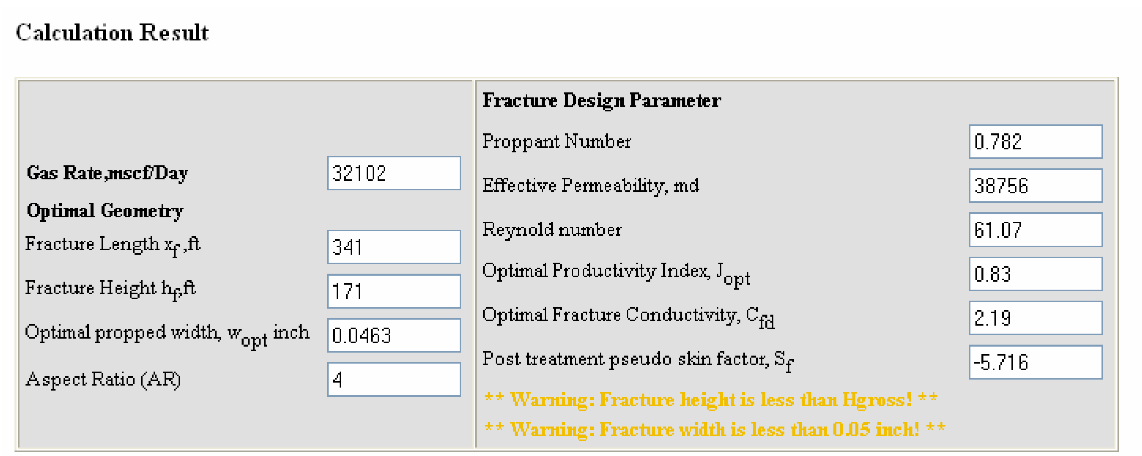


Fig. 18 Results window

3.1.5.1 Gas Rate

It is the expected gas production in Mscf/day coming from actual stage. It is calculated using the gas pseudo pressure function. It can be considered as a reference which depends on reservoir and well data as well as selected proppant and other conditions affecting propped pack permeability. Uncertainties in any of these parameters should be considered appropriately.

3.1.5.2 Optimal Fracture Geometry

It is the set of dimensions fracture should have in the reservoir to produce the amount of gas reported previously.

- *Fracture height* (h_f) **Fig. 19**
- *Fracture half length* (x_f) **Fig. 19**
- *Fracture width* (w_p) **Fig. 19**
- *Aspect ratio*

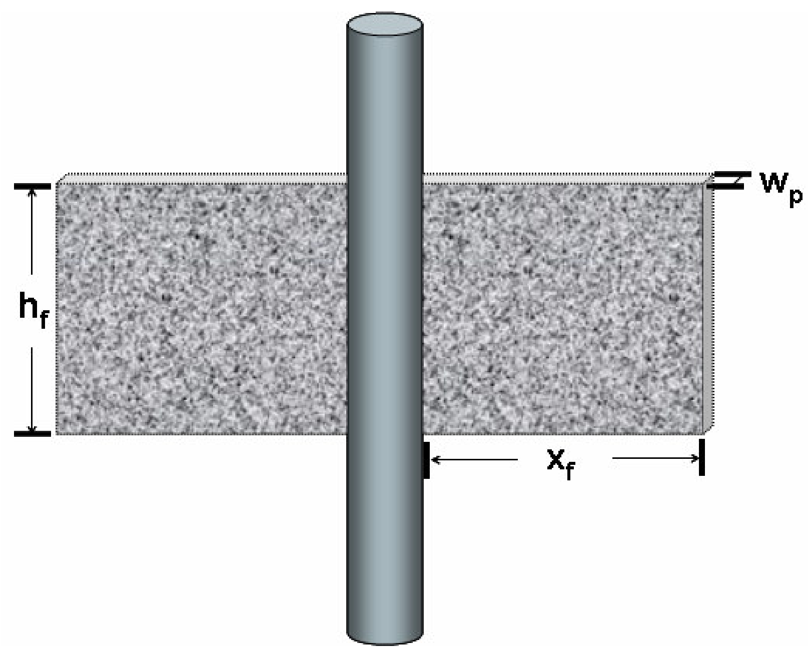


Fig. 19 Optimal fracture dimensions reported in Frac Design (Screening)[30]

3.1.5.3 Fracture Design Parameters

It corresponds to the set of parameters that might be of interest to the user for further analysis.

- *Proppant number*
- *Effective propped pack permeability*
- *Reynolds number*
- *Optimal dimensionless productivity index*
- *Optimal dimensionless fracture conductivity*

3.1.5.4 Treatment Size vs. Production Rate/Productivity Index Plot

The plots of treatment size (proppant mass) vs. production rate and treatment size vs. productivity index **(Fig. 20, Fig. 21)** show how much optimal production rate/productivity index one can reach for certain amount of proppant mass. The red dot in the graphic indicates the production rate/productivity index corresponding to the user-input proppant mass. Note that there is an absolute maximum achievable dimensionless productivity index, which is $6/\pi$ (around 1.909), this PI corresponding to perfect linear flow in a square reservoir.

The range of the proppant mass in the plot is from half of the value user input to the amount of proppant reaching to the design maximum productivity index (1.909). So one can find out from the plot that how much more proppant he/she should inject in order to achieve the maximum production rate (productivity index), if it is possible.

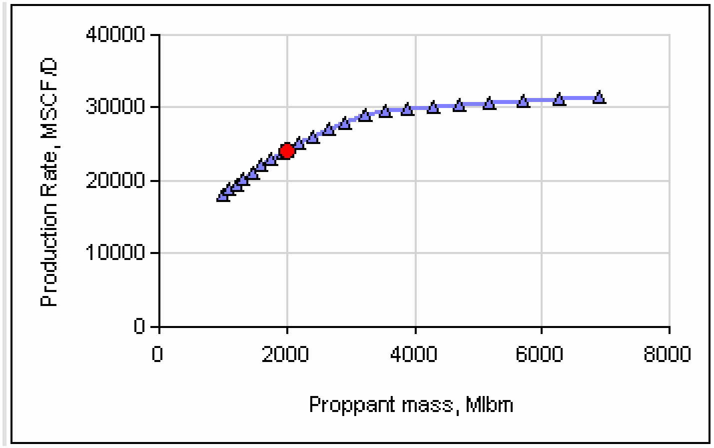


Fig. 20 Relation between treatment size and production rate

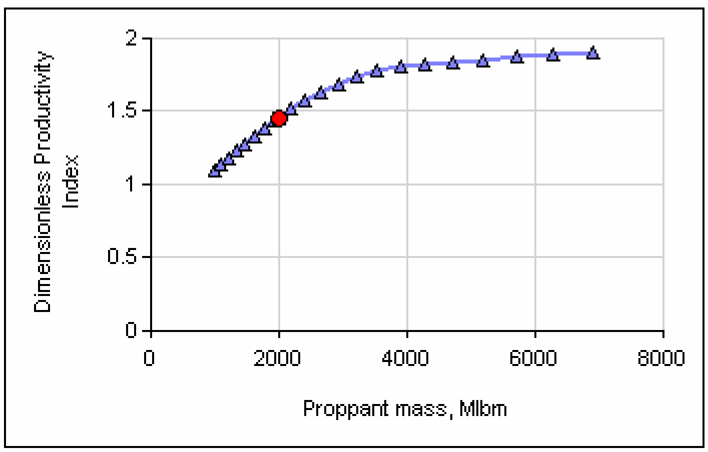


Fig. 21 Relation between treatment size and dimensionless productivity index

3.2 Fracture Evaluation Module

Frac Evaluation module is also a web based application for the evaluation of hydraulic fracturing performance. The methodology in this module is based on calculating and comparing the actual dimensionless productivity index of fractured well against the benchmarks which has been developed for optimized. Based on the comparison, one can evaluate the fracturing performance and make decisions such as re-fracturing and improvement of future treatments.

Similar to Frac Design (Screening), optimal parameter calculation in this application still considers the effects of closure stress, non-Darcy flow and gel damage upon the effective propped pack permeability performance. The key factor of this application is the input actual skin factor, which may be estimated from well test or from the production data by applying methodology such as Fetkovich analysis. The success of the evaluation greatly depends on how reliable this skin factor is.

3.2.1 Input Data

It is similar to Frac Design (Screening), the input sections in Frac Evaluation module also includes PVT data, fluid data and reservoir data. One difference between the two modules is that since fracture evaluation considers the wells which have already been performed fracture treatment, one can get sufficient completion operation information for these wells, to make it easier for user checking the treatment information, a section called “Fracture operation summary” is added in the user interface. The other difference of the input sections between the two modules is there is an extra input item in Frac Evaluation called actual skin factor, and productivity index can be calculated based on this information **(Fig. 22)**.

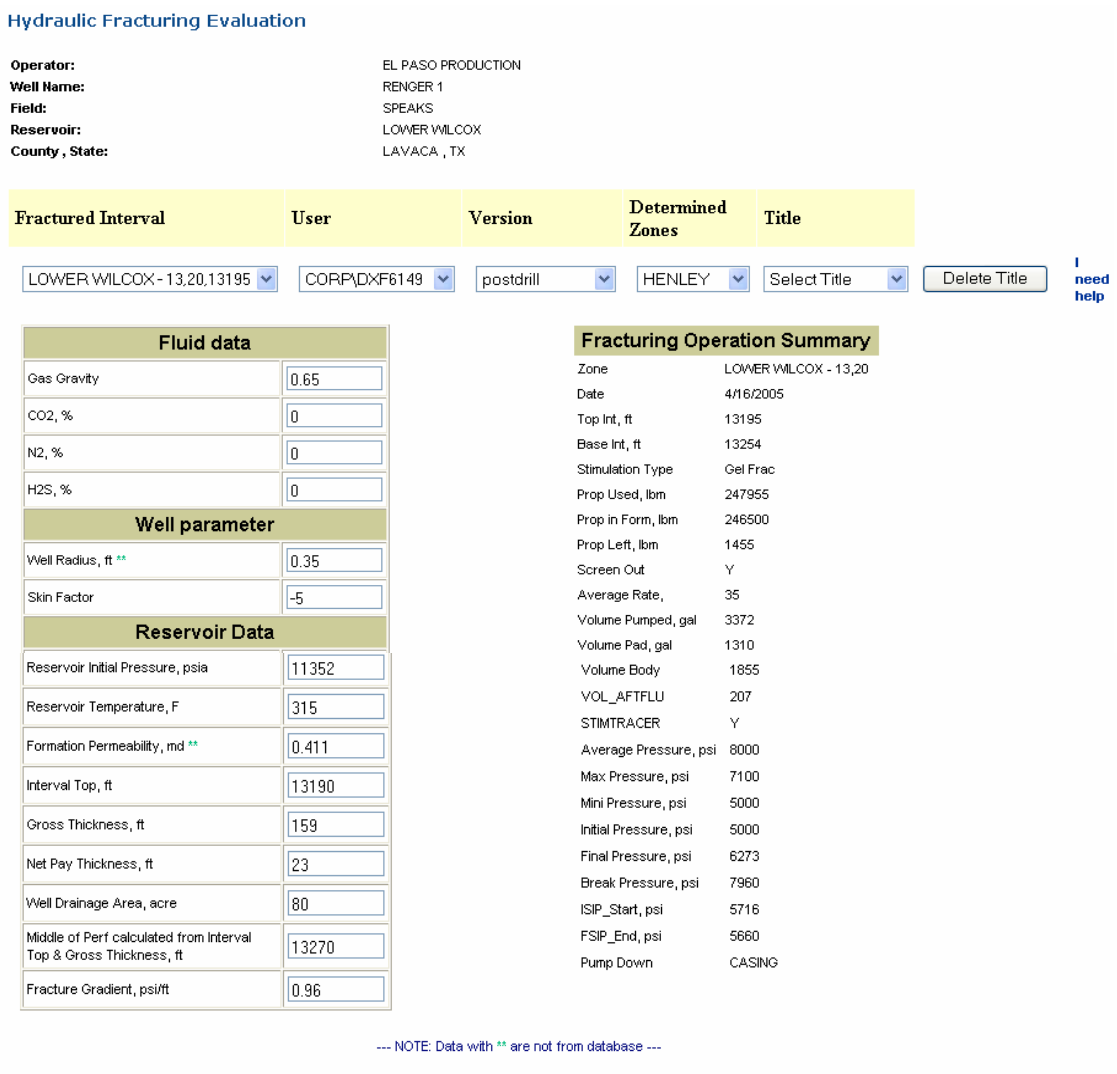
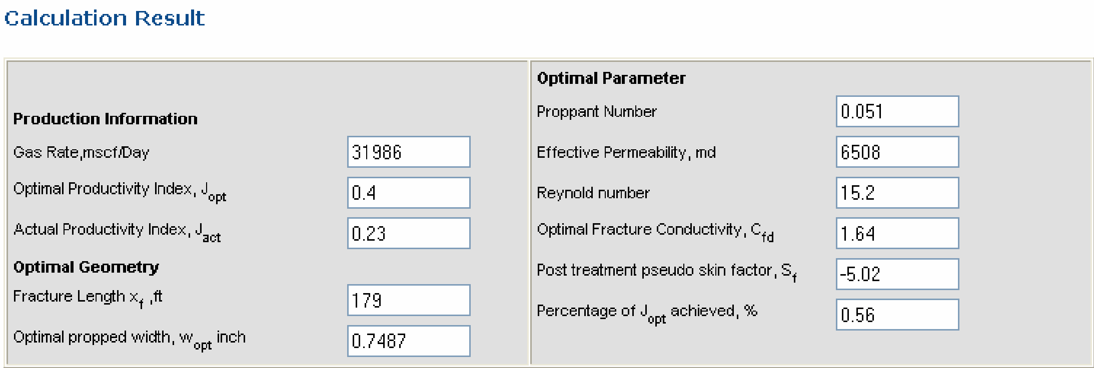


Fig. 22 Input sections of Frac Evaluation module

3.2.2 Results

Optimal fracture parameters and actual dimensionless productivity index are presented in the Calculation Results section (**Fig. 23**) at the bottom of Frac Evaluation window. Calculation results are shown below.



Calculation Result

Production Information		Optimal Parameter	
Gas Rate,mscf/Day	31986	Proppant Number	0.051
Optimal Productivity Index, J_{opt}	0.4	Effective Permeability, md	6508
Actual Productivity Index, J_{act}	0.23	Reynold number	15.2
Optimal Geometry		Optimal Fracture Conductivity, C_{fd}	1.64
Fracture Length x_f ,ft	179	Post treatment pseudo skin factor, S_f	-5.02
Optimal propped width, w_{opt} inch	0.7487	Percentage of J_{opt} achieved, %	0.56

Fig. 23 Results window of Frac Evaluation module

3.2.2.1 Optimal and Actual PI

These are two dimensionless parameters indicating the expected and actual well performance respectively. The fracture performance evaluation is based on the comparison between this two productivity indexes (percentage ratio).

3.2.2.2 Percentage of Optimal Productivity Index Achieved

This value indicates how close the actual fracture performance to that of optimal fracture. The closer this value is to 100%, the better the fracture performance is, vice versa.

CHAPTER IV
CASE ANALYSIS

In this chapter a well named RG #1 located at Texas Golf Coast is investigated as an example to show how the two methodologies and the computer modules (Frac Design (Screening) and Frac Evaluation) work. Also as validation, the results from Frac Design and Frac Evaluation to those from 3D frac simulation software, which is named FracPro, developed by Pinnacle Technology Company, will be compared.

To perform fracture design and evaluation analysis, first step and also one of the most important steps is to collect the data regarding the necessary input. Most of the data in this case are from Halliburton's post job report, since the information of this well has not been sufficiently established in the database. Petrophysical data are also quoted to confirm the information obtain from the report.

Based on the collected treatment information, it is clear that the stimulation operation includes three stages; the location of each stage is shown in following table (**Table 5**). Notice that the second stage was abandoned due to the aquifer involved.

Table 5. Top and bottom depth of RG #1 stages[31]

Stage	Top Depth, ft	Bottom Depth, ft
Stage #1	13,195	13,354
Stage #2	13,550	13,573
Stage #3	14,282	14,631

4.1 Fracture Design

4.1.1 Treatment Stage 1 of RG #1

Table 6 shows the basic information of RG #1 first stage.

Table 6. The basic information of the first stage of RG #1[31]	
Customer	PRODUCTION COMPANY
Well Name	RG #1
Stage	1
Well Number	1
Start Time	23-Feb-05 08:21:54
County	Lavaca
State	Texas
Country	United States of America
H2S Present	Unknown

4.1.1.1 Input Data

Fluid Data

The gas gravity value is obtained from reservoir database, the number is around 0.65, also it is clear that any reasonable assumptions for impurity composition will not greatly affect the calculation results, so it is fine if one sets the three impurity components (CO_2, H_2S and N_2) to zero. The detail of fluid data set is shown in **Table 7**.

Table 7. Fluid data of RG #1[31]

Fluid Properties	Value	Data Source
Gas Gravity	0.65	Reservoir database
CO2, %	0	Assumption
N2, %	0	Assumption
H2S, %	0	Assumption

Well Data

Fig. 24 shows the wellbore schematic of RG #1, from which one can estimate the well radius, the number is around 0.3 ft.

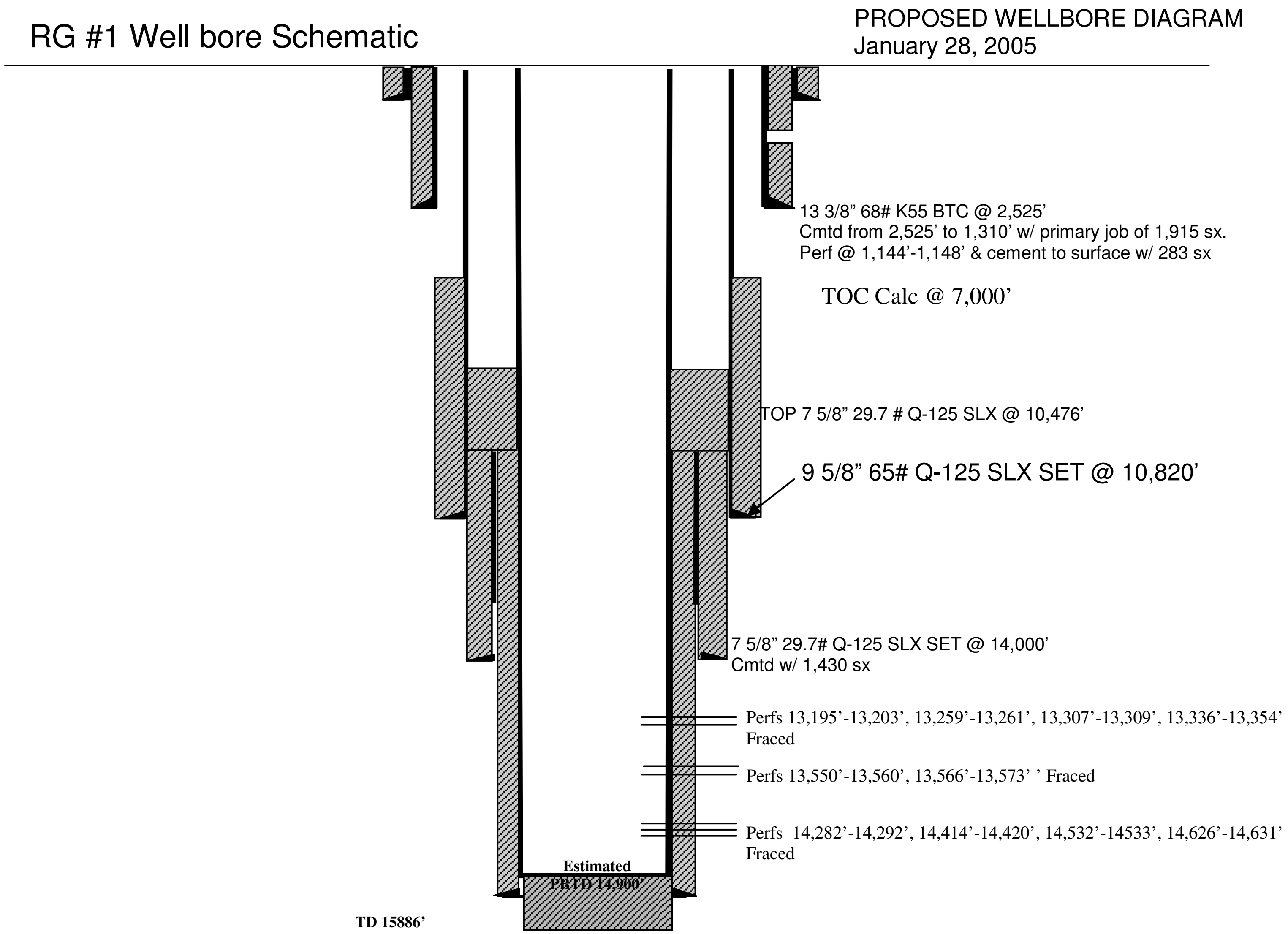


Fig. 24 Wellbore schematic of RG #1

Reservoir Information

Following (**Table 8**) is the corresponding reservoir data quoted from the Halliburton's post job report.

Table 8. Reservoir information[31] of RG #1 stage 1

Bottomhole temperature @ 14457 ft, F	338
Surface temperature @ 0 ft, F	73
Young's Modulus, psi	3,000,000
Poisson's Ratio	0.25
Total Compressibility, 1/psi	0.00008
Fluid viscosity, cp	0.03
Reservoir Pressure, psi	12,553
Reservoir Permeability, md	0.1

Tables 9 and **10** show the pipe and perforation interval information of RG#1 stage 1.

Table 9. Pipe information[31] of RG #1 stage 1

Equipment Name	Top MD ft	Bottom MD ft	OD in	ID in	Grade	Weight lb/ft
Casing	0.0	10,820	9.875	8.559	Q-125	65.10
Casing	10,476	14,000	7.625	6.875	HCQ-125	29.70
Casing	0.0	15,070	7.625	6.875	Q-125	23.20

Table 10. Perforation intervals[31]

Top MD ft	Bottom MD ft	Total Gross Thickness ft	Number of shots	Perf Density spf	Perf Phasing
14,282.0	14292.0	339	61	6.0	60
14,414.0	14420.0		37	6.0	60
14,532.0	14533.0		13	6.0	60
14,626.0	14631.0		31	6.0	60

Also the reservoir data are collected from petrophysic summary, which is shown in **Table 11**.

Table 11. RG #1 stage 1 petrophysic summary	
Zone Name	Meine
Top Depth, ft	14,282
Bottom Depth, ft	14,631
Gross Thickness, ft	339
Net Pay, ft	58.5
Net to Gross, ft	0.17
Average Reservoir Permeability, md	0.1033
kh, md-ft	6.04
Porosity, %	14
Water Saturation, %	39.9

Drainage Area

The drainage area is necessary information to estimate the reservoir volume which in turn is used to calculate the proppant number. However, this data is missing in both petrophysic summary and Halliburton's report, so one must take advantage of other methodologies to evaluate this parameter. Before this research is conducted, a module called Fetkovich Advanced DCA (Decline Curve Analysis) has been developed by a reservoir technology group in the production company. This case investigation just directly applies the results by running the module. The value of drainage area gained from Fetkovich analysis is around 40 acres.

Fracture Gradient

Mini-frac was conducted before the treatment, **Table 12** shows the ISIP and fracture gradient measured in three different phases, which include 1) well loaded; 2) the fluid efficiency test (FET); and 3) end of treatment. As an input, the average of the fracture gradient from the three phases is taken, which is around 0.98 psi/ft.

Table 12. ISIP table[31]				
Test Number	ISIP psi	Hydrostatic psi	Fracture Gradient psi/ft	Test Phase
1	7,875	6,360	0.985	Load Well
2	7,797	6,357	0.979	PET
3	7,464	6,660	0.977	End of Treatment

Depth of Middle of Perforation

The depth of middle of perforation is calculated by adding up top and bottom of interval and divide the summation by two.

$$D_{middle} = (D_{top} + D_{bottom}) / 2 \qquad (54)$$

Summarizing the information above, one can reach the input and resource for the optimal fracture design calculation as shown in **Table 13**.

Table 13. Data input set for optimal fracture design calculation		
Reservoir Parameter	Parameter Value	Data Source
Initial Reservoir Pressure, psi	11,352	Post job report
Reservoir Temperature, F	338	Post job report
Formation Permeability, md	0.1	Post job report & Log interpretation
Depth of Interval Top, ft	14,282	Log interpretation
Gross Thickness, ft	339	Log interpretation
Net Pay, ft	58.5	Log interpretation
Drainage Area, acre	40	Fetkovich Analysis
Depth of Middle of Perforation, ft	14,456	Calculation based on Reservoir top and gross thickness
Frac Gradient, psi/ft	0.98	Post job report

Proppant Selection and Treatment Size

Again one can get the proppant information from the post job report prepared by Halliburton. The treatment consisted of 144,682 gal carrying 222,140 lbs of 20/40 Bauxite coated with Expedite 350 at an average treating rate and pressure of 30.9 bpm and 8,218 psi. The maximum pressure encountered during the treatment was 9,177 psi. The total liquid load to recover is 137,519 gal. **Table 14** gives the summary of proppant injection job information.

Table 14. Proppant injection job summary[31]

Start Time	10:57:49
End Time	13:58:26
Pump Time, min	126.87
Max Treating Pressure, psi	9,177
Average Treating Pressure, psi	8,218
Max Slurry Rate, bpm	46.2
Average Slurry Rate, bpm	30.9
Clean Volume, gal	137,384
Slurry Volume, gal	144,668
Proppant type	Bauxite
Mesh size	20/40
Proppant Mass, $\times 100$ lbm	2117.51
BH Proppant in Formation, 100 * lbm	2060.37

Fracture Height

It is clear from log analysis that this is a laminated reservoir where it is difficult to predict where the fracture height growth will stop. Therefore, aspect ratio concept is used to determine the fracture height. In this case analysis, the value of aspect ratio is set as 4 based on the rule of thumb.

Non-Darcy Effect

Since it is a gas well, non-Darcy effects can not be ignored in the fracture design calculation.

<u>Driving Force</u>

To calculate the optimal flow rate, the average formation pressure and flowing bottomhole pressure have to be input, both of the parameters should be estimated as best as possible, because final optimal design is affected by these parameters due to the effects of non-Darcy flow, the higher kh product is the more important a good estimation is. This case is dealing with low permeability reservoir, so the input will not impact greatly on the optimal fracture geometry and productivity index. The average reservoir pressure and flowing bottomhole pressure are set to 9000 psi and 7000 psi respectively.

4.1.1.2 Design Parameters Calculation Results

Table 15 shows the calculation results of optimal fracture design based on the input data discussed above.

Table 15. Optimal fracture design parameter for RG #1 stage 1

Gas Rate, mscf/D	4,800
Fracture Length, ft	494
Fracture Height, ft	247
Optimal propped width, inch	0.076
Aspect Ratio (AR)	4
Proppant Number	2.25
Nominal Proppant Permeability, md	166,000
Effective Permeability, md	31,331
Reynold Number	1.65
Dimensionless Optimal Productivity Index	1.1
Optimal Fracture Conductivity	4.01
Post Treatment Pseudo Skin Factor	-6.16

4.1.1.3 Comparison with 3D Simulation

Fig. 25 is the 3D simulation result for fracture design, the solid and dash double-arrow lines indicate the simulation fracture length and UFD fracture length respectively. Note that it only consider the simulation fracture length with proppant concentration over 1 lb/ft^2. The comparison shows no substantial deviation between the two results from the modules (494 ft versus 500 ft).

In additional, it is clear from the simulation results that the effective fracture height (180 ft) is much less than the gross thickness (339 ft), that may lead the actual production rate lower than the optimal flow rate.

4.1.2 Stage 3

The third stage of the treatment is located at 13,195 ft to 13,354 ft, the detail of the input data are described as following.

4.1.2.1 Input Data

Fluid Data

It assumes that the fluid property independent on depth, therefore the same fluid data as shown in stage 1 (**Table 8**) is still used in stage 3.

Reservoir Data

The following table (**Table 16**) shows the basic information in the third stage of the fractured well.

Table 16. Treatment information[31] of RG #1

Well Name	RG # 1
Stage	3
Well Number	1
Start Time	15-Apr-05 07:09:11
County	Lavaca
State	Texas
H2S Present	Unknown
CO2 Present	Unknown

Reservoir Information

Table 17 shows the reservoir data for RG #1 treatment stage 3, which are also collected from Halliburton's post job report.

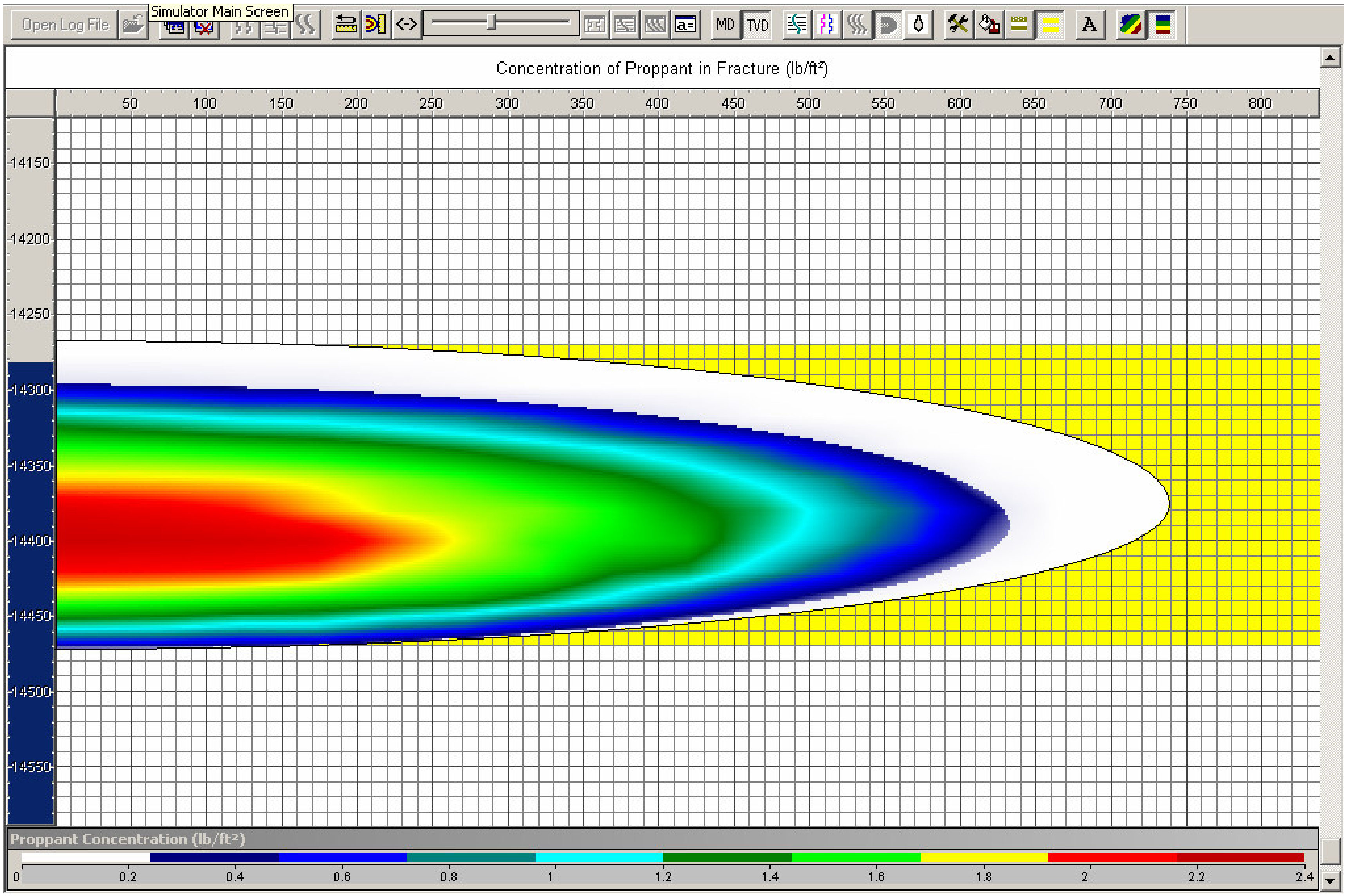


Fig. 25 Result comparison between Frac Design (Screening) and 3D simulation for treatment stage 1 of well RG #1

Table 17. Reservoir information[31]	
Bottomhole temperature @ 14457 ft, F	315
Surface temperature @ 0 ft, F	65
Young's Modulus, psi	3,000,000
Poisson's Ratio	0.20
Total Compressibility, 1/psi	0.00009201
Fluid viscosity, cp	0.03
Reservoir Pressure, psi	10,833
Reservoir Porosity, %	18
Reservoir Permeability, md	0.1

Table 18 and **19** show the pipe and each perforation interval information

Table 18. Pipe information[31]

Equipment Name	Top MD ft	Bottom MD ft	OD in	ID in	Grade	Weight lb/ft
Casing	0.0	15070.0	5.000	4.044	Q-125	23.20

Table 19. Perforation intervals[31]

Top MD Ft	Bottom MD ft	Total Gross Thickness, ft ft	Number of Shots shots	Perf Diameter, in in
13195.0	13203.0	159	49	0.320
13259.0	13261.0		13	0.320
13307.0	13309.0		13	0.320
13336.0	13354.0		49	0.320

Table 20 shows the reservoir data from petrophysic summary for RG#1 stage 3.

Table 20. RG #1 stage 3 log interpretation[31]	
Top Depth, ft	13,195
Bottom Depth, ft	13,354
Gross Thickness, ft	159
Net Pay, ft	23
Net to Gross, ft	0.14
Average Reservoir Permeability, md	0.4113
kh, md-ft	9.46
Porosity, %	15.9
Water Saturation, %	36.7

Fracture Gradient

Mini-frac test result are shown in **Table 21**. The fracture gradient is calculated by taking the average of three phases, which is around 0.95 psi/ft.

Table 21. ISIP table [31]

Test Number	ISIP psi	Hydrostatic psi	Fracture Gradient psi/ft	Test Phase
1	6,849	5,862	0.958	Load Well
2	6,860	5,866	0.959	PET
3	5,716	6,827	0.945	End of Treatment

Summarizing the information getting above; the necessary input for the optimal fracture design calculation can be reached as shown in the **Table 22**.

Table 22. Data input set of optimal fracture design calculation for RG # 1 stage 3		
Reservoir Parameter	Parameter Value	Data Source
Initial Reservoir Pressure, psi	10,833	Post job report
Reservoir Temperature, F	315	Post job report
Formation Permeability, md	0.4113	Post job report & Log interpretation
Depth of Interval Top, ft	13,195	Log interpretation
Gross Thickness, ft	159	Log interpretation
Net Pay, ft	23	Log interpretation
Drainage Area, acre	40	Fetkovich Analysis
Depth of Middle of Perforation, ft	13,274	Calculation based on Reservoir top and gross thickness
Frac Gradient, psi/ft	0.95	Post job report

<u>Proppant Selection and Treatment Size</u>

Table 23 gives the summary of proppant injection job information of stage 3.

Table 23. Proppant injection job summary	
Start Time	10:35:01
End Time	14:47:37
Max Treating Pressure, psi	9,476
Average Treating Pressure, psi	7,671
Max Slurry Rate, bpm	40.2
Average Slurry Rate, bpm	36.41
Slurry Volume, gal	144,668
Proppant type	Bauxite
Mesh size	20/40
Proppant Mass, 100 * lbm	2479.55
BH Proppant in Formation, 100 * lbm	2465.00

<u>Fracture Height</u>

The value of aspect ratio is still set to 4 based on the rule of thumb.

<u>Driving Force</u>

For this stage, it still assumes the average reservoir pressure and flowing bottomhole pressure are 9000 psi and 7000 psi respectively.

4.1.2.2 Design Parameters Calculation Results

Table 24 shows the calculation results of optimal fracture design based on the input data discussed above.

Table 24. Optimal fracture design parameter for RG #1 stage 3

Gas Rate, mscf/D	6,266
Fracture Length, ft	420
Fracture Height, ft	210
Optimal propped width, inch	0.1258
Aspect Ratio (AR)	4
Proppant Number	0.939
Nominal Proppant Permeability, md	192,404
Effective Permeability, md	38,224
Reynold Number	1.52
Dimensionless Optimal Productivity Index	0.87
Dimensionless Optimal Fracture Conductivity	2.32
Post Treatment Pseudo Skin Factor	-5.92

4.1.2.3 Comparison with 3D Simulation

Same as what has been done for stage 1, comparison between design results and those from 3D simulation is conducted. **Fig.26** shows the fracture geometry generated by simulation program, again, the solid and dash double-arrow lines indicate the simulation fracture length and UFD fracture length respectively. It is clear from the comparison that optimal fracture geometry from UFD and that from real data 3D simulation are similar (420 ft versus 480 ft, for fracture length and 210 ft versus 200 ft for fracture height).

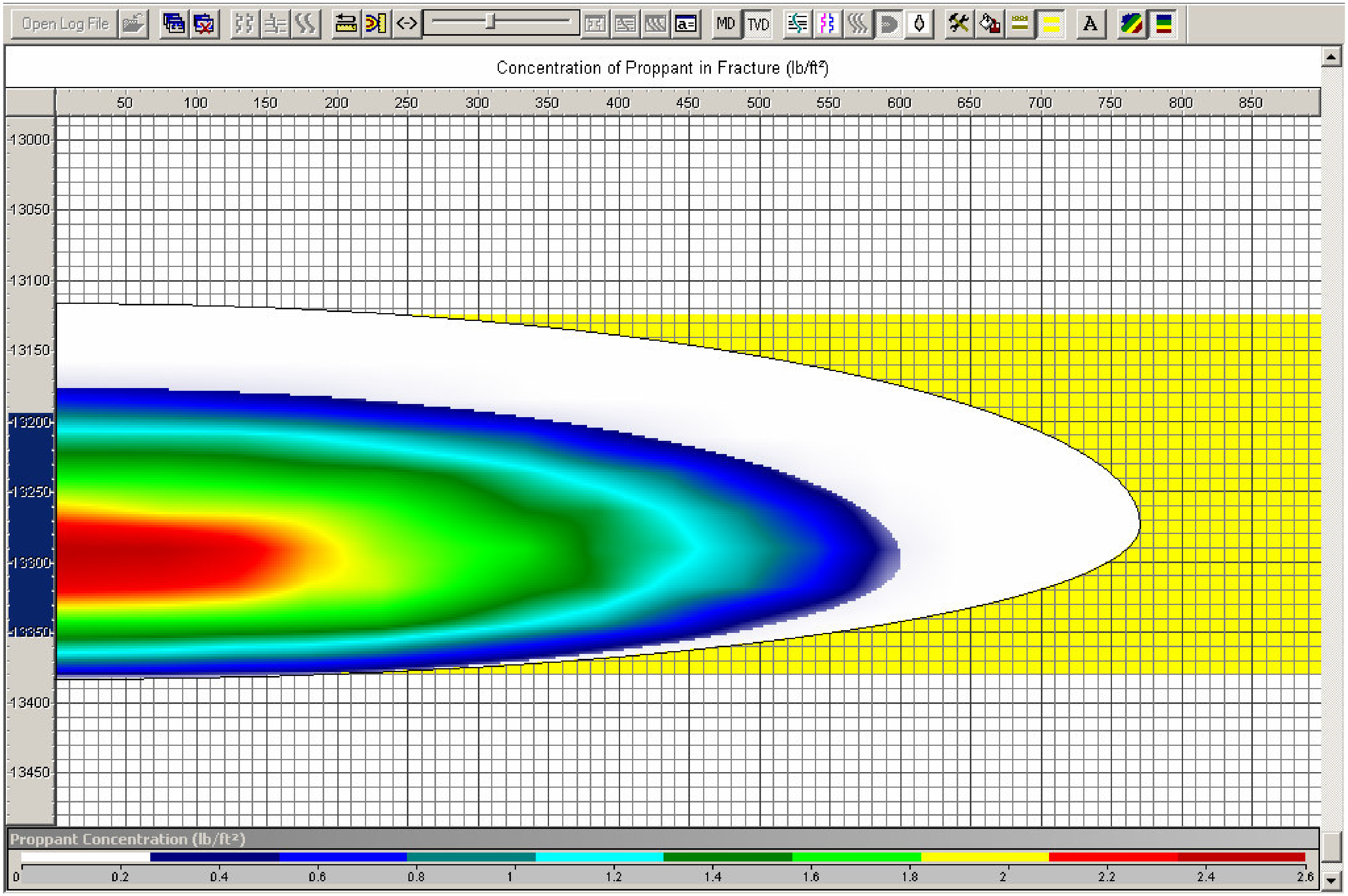


Fig. 26 Result comparison between Frac Design (Screening) and 3D simulation for treatment stage 3 of well RG #1

4.2 Fracture Evaluation

Just as being mentioned in the previous chapter, the key factor of this application is the input actual skin factor, which may be estimated from the production data by applying methodology such as Fetkovich analysis. The success of the evaluation much depends on how reliable this skin factor is. The analysis result from Fetkovich Advanced DCA module is about -2.

4.2.1 Fracture Evaluation Analysis

The fracture evaluation analysis is done separately for the two individual treatment stages (stage 1 and stage 3). Since the Fetkovich analysis module is not allowed to conduct production allocation, it has to make the assumption that the skin factor is constant for the two stages. Of cause, this is not an accurate call, but for time being, and just for the method test purpose, it assumes the assumption is correct.

4.2.2.1 RG #1 Stage 1

The input of Frac Evaluation module for RG #1 stage 1 is listed in **Table 25**.

Table 25. Basic input of fracture evaluation for RG #1 stage 1

Gas Gravity	0.65
CO2, %	0
N2, %	0
H2S, %	0
Well Radius, ft	0.3
Skin Factor	-2
Initial Reservoir Pressure, psi	11,352
Reservoir Temperature, F	338
Formation Permeability, md	0.1
Depth of Interval Top, ft	14,282
Gross Thickness, ft	339
Net Pay, ft	58.5
Drainage Area, acre	40
Depth of Middle of Perforation, ft	14,456
Frac Gradient, psi/ft	0.98
Proppant Type	Bauxite
Mesh Size	20/40
Treatment Size, lbm	206,000
Fracture Height, ft	247

The calculation results from Frac Evaluation module are shown in **Table 26**.

Table 26. Frac Evaluation results for RG #1 stage 1	
Gas Rate, mscf/Day	4801
Optimal Productivity Index	1.1
Actual Productivity Index	0.2
Fracture Length, ft	494
Optimal Propped width, inch	0.076
Proppant Number	2.25
Nominal Proppant Permeability, md	166,000
Effective Permeability, md	31,331
Reynolds Number	1.65
Optimal Fracture Conductivity	4.02
Post Treatment Pseudo Skin	-6.16
Percentage of Optimal PI Achieved, %	17.94

It is clear that the actual productivity index is significant low comparing to the optimal PI, i.e. only 17.94% of optimal PI achieved. The primary reason leading to the result is that in the first stage, reservoir is partial opened – gross thickness is 339 ft while only 130 ft of that height is covered, which confirms the pre-conclusion that the actual productivity is less than the optimal productivity drawn from Frac Design (Screening) analysis and the result comparison to 3D simulation.

Therefore, by running Frac Evaluation module, it can easily find out the "bad" performance stimulation job based on the reliable input skin factor, thus one can look back by checking the petrophysic data and 3D simulation results, to search for the gap, finally gives such suggestions as re-fracturing and improvement of fracture treatments.

CHAPTER V
SUMMARY AND CONCLUSIONS

5.1 Summary

Unified fracture design (UFD) or constant proppant volume technique is an efficient methodology to determine the optimal fracture parameters for hydraulic fracturing treatment. The name implies that it connects theory and practice, and that the design process cuts across all petroleum reservoirs – low permeability to high permeability, hard rock to soft rock.

The goal of unified fracture design is to reach the maximum pseudo-steady state productivity index, based on the determined treatment size and specific reservoir information. In the methodology, a new dimensionless parameter called proppant number is introduced. From this parameter one can always find a unique fracture conductivity that corresponds to the maximum productivity index. Then with the two known parameters, proppant number and fracture conductivity, the optimal fracture geometry – fracture width and fracture length can be calculated.

On the other hand, Non-Darcy effects in fracture treatment design are significant, it can not be ignored especially for gas well (high flow velocity). In the UFD methodology non-Darcy effects are considered as reduction to the proppant permeability, thus, effective permeability is computed from the nominal permeability divided by 1 plus Reynolds number. Reynolds number is significantly impacted by the β factor. This research presents several typical correlations which are developed from lab experiment to evaluate this β factor.

As a by-product of unified fracture design technique, fracture evaluation algorithm is developed in this research for the evaluation of hydraulic fracturing performance. The methodology is based on calculating and comparing the actual dimensionless productivity index of fractured well with the benchmarks which has been developed for optimized production. From the comparison, one can evaluate the fracturing performance and make decisions such as re-fracturing and improvement of future treatments. The key factor of this application is the input actual skin factor, which may be estimated from the production data by applying methodology such as Fetkovich analysis.

Nevertheless, the methodologies introduced above are impractical for field applications due to their complexity and inflexibility, so an active server page (ASP) based user interfaces is developed in this research. Two modules were developed. One is Frac Design (screening), and the other is Frac Evaluation.

The two computer modules consider the effects of closure stress, non-Darcy flow and gel damage upon the effective propped pack permeability performance. It results in more realistic fracture designs for maximizing gas well deliverability. The modules were designed to minimize number of parameters to be input by the user. Then, most of the design process consists of these selections, based on which, data required by application is obtained from existing reservoir databases and proppant databases.

One of the most important features of *Frac* Design (Screening) and Frac Evaluation is the possibility of using any commercial proppant in any of its available mesh size. Proppants have been classified by type. Only a few commercial products have been initially included in the database, but the database can be extended to include more proppant.

5.2 Conclusions

5.2.1 Optimal Fracture Design and Evaluation Methodologies

Formal approaches to optimize fracture design and evaluate post-fracture performance for gas well have been introduced. Some of the advantages and highlights of these methodologies are as follows:

- Compared with NPV versus fracture length optimization procedure, unified fracture design methodology needs much less input and computer running time.
- Just as its name implies, unified fracture design connects theory with practice; also, it implements design process that is relevant to all petroleum reservoirs – low permeability to high permeability, hard rock to soft rock.

- The methodologies consider gel damage, closure stress and non-Darcy effects, which make the optimal fracture design calculation more realistic.
- Fracture evaluation is a handy approach to identify the stimulated well failed to implement the expected (optimal) performance; the drawback of this method is that it greatly depends on the reliability of input skin factor.

5.2.2 User Interface

Two computer modules, Frac Design (Screening) and Frac Evaluation were developed to implement the optimal fracture design and evaluation methodologies. The user-friendly program is built on a VB script and Java script platform, and has following useful features.

- The applications consider the effects of closure stress, non-Darcy flow and gel damage upon the effective propped pack permeability performance.
- The programs are designed to minimize number of parameters to be input by users. Most of the design input process consists on various selections, based on which, data required by application is obtained from reservoir database and proppant database.
- Some useful information, such as in the Frac Design (Screening) module, typical proppant beta correlation being used for the fracture design, and the nominal permeability based on the reservoir fracture gradient are shown in the user interface. In the Frac Evaluation module, fracture operation summary is displayed on the user interface, to give the user the basic information of the practical operation.
- Two plots are shown in the design and evaluation module respectively, which are treatment size versus flow rate and treatment size versus dimensionless productivity index. The plots reveal that based on certain amount of proppant mass how much optimal production rate/productivity index can be reached. Referring to this information, the user can get clear picture of the relationship between treatment size and the expected well productivity.

- User guideline called "I need help" is included in the interface, which is a link to the user manual, and the documentation gives sufficient details about the methodology and the guideline of the user interface.

5.2.3 Case Analysis

This research has looked at an example of fracture design and evaluation based on the actual reservoir and treatment data. It was confirmed by comparing with 3D simulation software that Frac Design (Screening) and Frac Evaluation can work well for gas well fracture design and evaluation analysis.

In the example, a gas well named RG #1 from a production company in South Texas is investigated. Based on the data interpretation, fracture design and evaluation analysis, following observations and suggestions can be obtained.

- Two stages of hydraulic fracturing stimulation are performed for well RG #1.
- The results of optimal fracture length calculated from UFD for both of the two stages are close to those from 3D simulation program.
- Fracture height is much less than the gross pay thickness in the first stage thus, the actual calculated productivity is substantially lower than the optimal one, fracture evaluation analysis can confirm this point.
- Re-fracturing suggestion may be issued for the interval from depth 14,282 ft to 14,631 ft (first stage) regarding the poor percentage of optimal productivity index reached, and the decision should be made combining the consideration from economic analysis.

5.3 Recommendation for Future Work

The scheme presented in this research provides two useful methodologies for optimal fracture design and evaluation for gas wells, and these approaches and the related computer modules have already been put into practical use, incorporating real reservoir and production data, but post jobs are still required to further improve the function of the modules:

- Investigate more cases to validate the tools

- Integrate to the fracture design module with 2D gas simulator to conduct the production forecast based on the calculated optimal fracture parameters.
- Improve the Fetkovich DCA module to implement production allocation, which can make the frac evaluation analysis for each individual stage more reliable.

NOMENCLATURE

a = numerator of β equation

AR = aspect ratio

b = power of proppant permeability in β equation

c_t = total compressibility, psi^{-1} [kPa^{-1}]

B_g = gas formation volumetric factor, RCF/SCF [m^3/m^3]

C_{fD} = dimensionless fracture conductivity,

C_{fDopt} = optimal dimensionless fracture conductivity

FG = fracture gradient, psi/ft [kPa/m]

h_f = fracture height, ft [m]

h_p = net pay, ft [m]

I_x = penetration ratio

J = well productivity index, MSCF/D/psi [m^3/s/kPa]

J_D = dimensionless productivity index

k_g = reservoir gas permeability, md [m^2]

k_f = initial or nominal proppant permeability, md [m^2]

$k_{f\text{-}eff}$ = effective proppant permeability, md [m^2]

ΔL = differential length in pressure drop calculation, ft [m]

MoP = mid of perforation, ft [m]

N_{Re} = Reynold number

N_{prop} = proppant number

$\overline{p}$ = average formation pressure, psi [kPa]

ΔP = pressure drop, psi [kPa]

P_c = closure pressure, psi [kPa]

$P_{fracture}$ = Pressure within the fracture, psi [kPa]

p_{res} = reservoir pressure, psi [kPa]

p_{wf} = flowing bottomhole pressure, psi [kPa]

q_{gsc} = gas rate production at standard conditions, MSCF/D [m^3/s]

r_e = outer boundary radius, ft [m]

r_w = wellbore radius, ft [m]

s = skin factor

v = gas velocity, ft/D [m/s]

V_{p-2w} = volume of proppant in the net pay, ft^3 [m^3]

V_{p-1w} = volume of proppant in pay in one wing, ft^3 [m^3]

V_{res} = reservoir volume, ft^3 [m^3]

w_{fp} = propped fracture width, ft or in [m]

x_e = reservoir length, ft [m]

x_f = fracture half- length, ft [m]

α_1 = conversion units constant

β = non-Darcy flow coefficient, 1/ft [1/m, atm-sec^2/gr]

μ_g = gas viscosity, cp

σ_{eff} = effective in situ stress, psi [kPa]

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APPENDIX A

PROPERTIES OF PROPPANT AVAILABLE IN DATABASE

Properties of proppants available in Database [30]

PROPPANT NAME	TYPE	SG	Closure Stress psi	Mesh Size Permeability (md)			
CARBOECONOPROP	LWC	2.70		20/40	30/50	40/70	
			2,000	340,000	230,000	78,000	
			4,000	300,000	190,000	65,000	
			6,000	230,000	150,000	51,000	
			8,000	150,000	100,000	41,000	
			10,000	85,000	70,000	28,000	
CARBOLITE	LWC	2.71		12/18	16/20	20/40	
			2,000	2,003,000	1,288,000	570,000	
			4,000	1,325,000	955,000	480,000	
			6,000	570,000	510,000	340,000	
			8,000	293,000	276,000	210,000	
			10,000	141,000	150,000	120,000	
CARBPROP	HWC	3.27		16/30	20/40	30/60	40/70
			2,000	1,050,000	385,000	174,000	140,000
			4,000	800,000	345,000	152,000	110,000
			6,000	640,000	290,000	128,000	80,000
			8,000	420,000	250,000	104,000	65,000
			10,000	300,000	200,000	69,000	50,000
			12,000	190,000	150,000	49,000	40,000
			14,000		100,000		
CARBOHSP	Bauxite	3.56		12/18	16/30	20/40	30/60
			2,000	2,742,000	1,207,000	539,000	254,000
			4,000	2,395,000	939,000	440,000	224,000
			6,000	1,609,000	721,000	370,000	197,000
			8,000	894,000	515,000	302,000	167,000
			10,000	409,000	393,000	246,000	134,000
			12,000	284,000	298,000	204,000	99,000
			14,000	194,000	232,000	166,000	73,000
CERAMAX-P	RCB	3.43		16/30	20/40		
			2,000	604,000	233,000		
			4,000	568,000	218,000		
			6,000	523,000	195,000		
			8,000	400,000	166,000		
			10,000	289,000	138,000		
			12,000	212,000	112,000		
			14,000	156,000	96,000		
AcFrac® SB Excel	RCS	2.59		16/30	20/40		
			2,000	357,000	249,000		
			4,000	270,000	211,000		
			6,000	158,000	133,000		
			8,000	88,000	61,000		

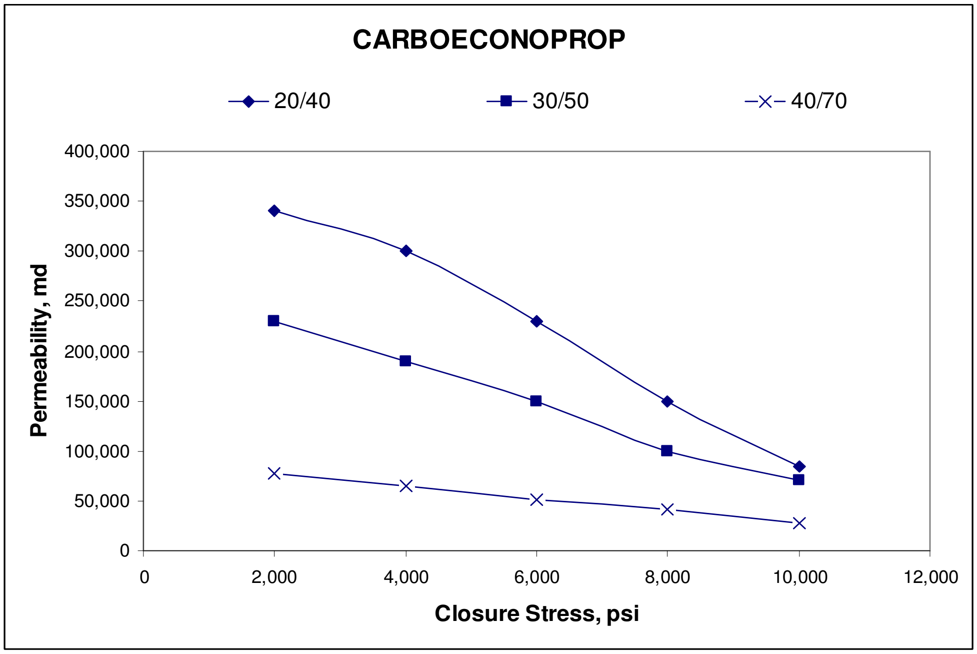

Fig. A-1 Closure Stress versus Proppant Permeability for CARBOECONOPROP (LWC)[30]

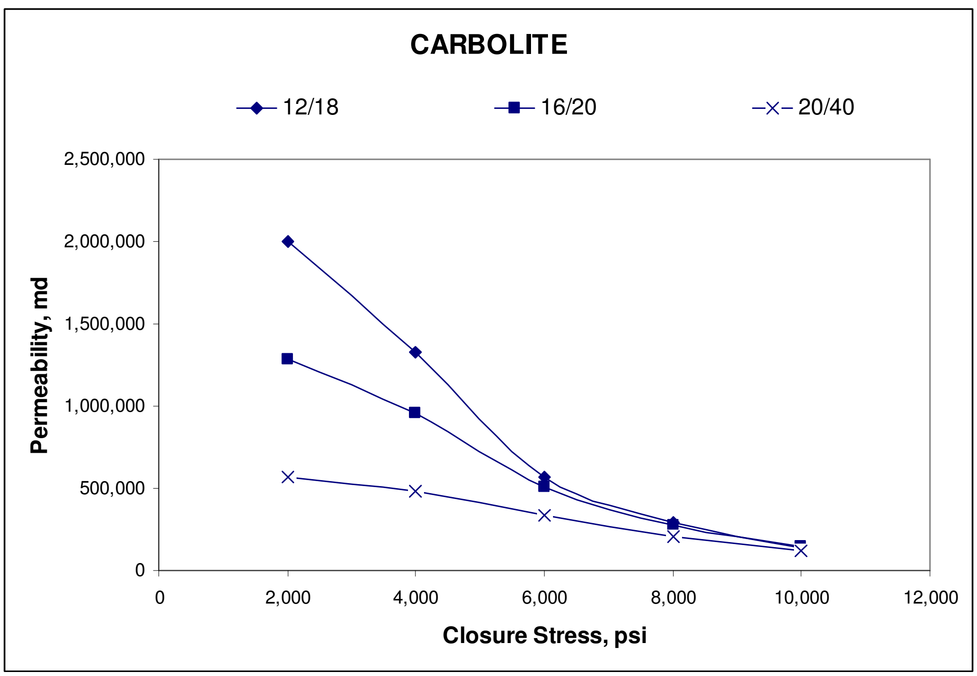

Fig. A-2 Closure Stress versus Proppant Permeability for CARBOLITE (LWC)[30]

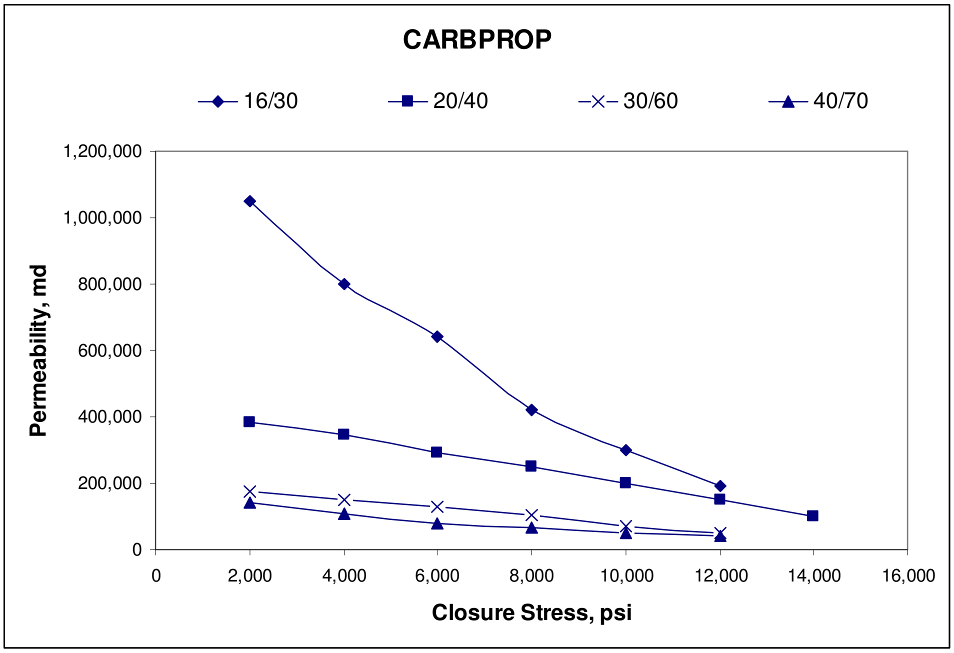

Fig. A-3 Closure Stress versus Proppant Permeability for CARBPROP (HWC)[30]

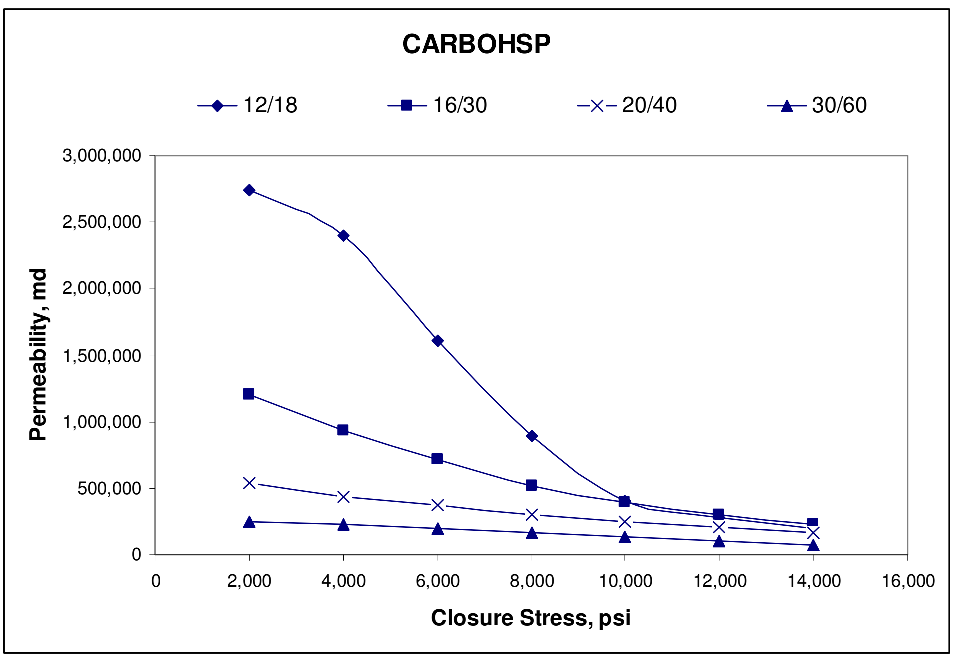

Fig. A-4 Closure Stress versus Proppant Permeability for CARBOHSP (Bauxite)[30]

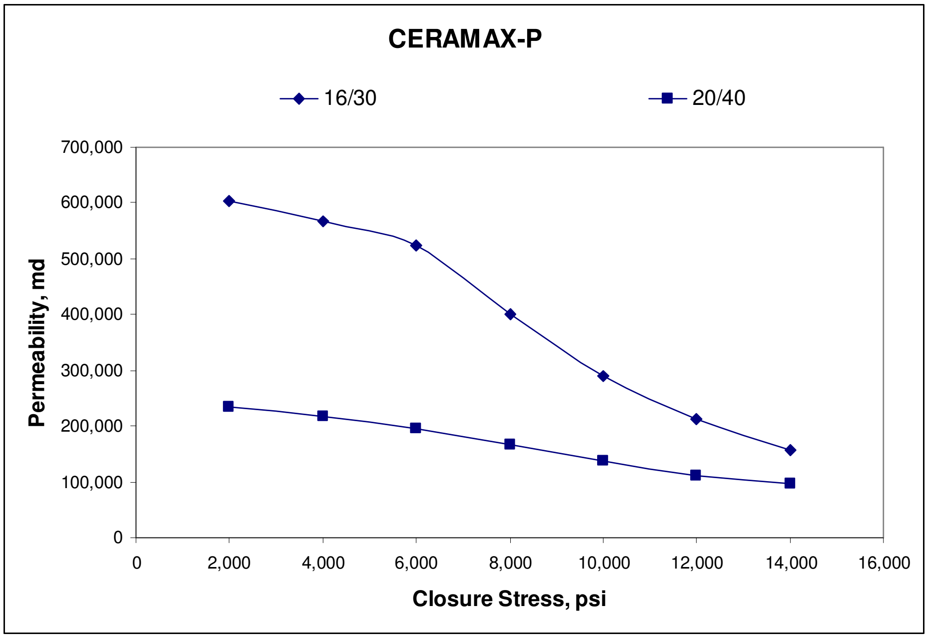

Fig. A-5 Closure Stress versus Proppant Permeability for CERAMAX-P (RCB)[30]

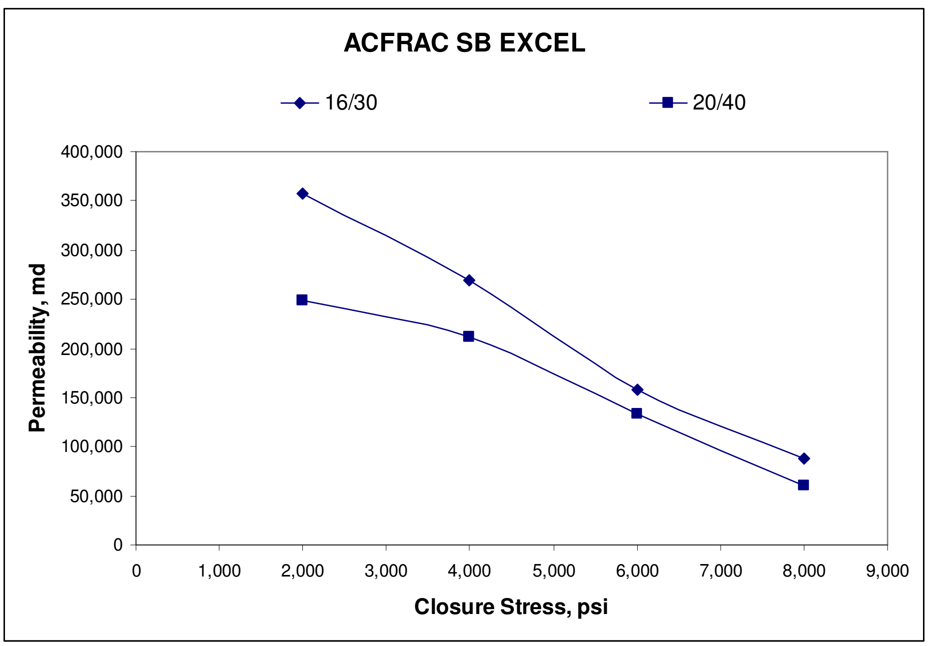

Fig. A-6 Closure Stress versus Proppant Permeability for ACFRAC SB EXCEL[30]

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