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Presented by:

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- THEME –

Innovative Platform Proposal (Website) for Hydraulic Fracturing Calibration Test Analysis

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DEDICATION

My Loving FAMILY & My Dear FRIENDS,

Thank you, from the bottom of my heart.

Akram Abdelmouez BOUAISS.

My Adored FAMILY & My Treasured FRIENDS,

Thank you, from the bottom of my heart.

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My Beloved FAMILY & My Dearest FRIENDS,

Thank you, from the bottom of my heart.

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ABSTRACT

Hydraulic Fracturing involves injecting a high-pressure mixture of water, sand, and chemicals to fracture rock formations and increase hydrocarbon flow. At Sonatrach, multiple tests are conducted during this process to develop an improved fracturing model and schedule. However, analyzing these test results was challenging due to the lack of a specialized software platform, forcing reliance on expensive expert services.

To address this, the FRACTO comprehensive software/website solution was created to optimize fracturing processes by integrating tools to bridge theory and practice. Requirements were gathered through collaboration with fracturing engineers, following a well-defined methodology to systematically program the platform. The results demonstrated that the main fracturing schedule generated by the FRACTO Platform for the MD689 well was accurate and effective, providing a solid foundation for successful execution.

Key words: Hydraulic Fracturing, HF Tests, Sonatrach, FRACTO, Platform.

RÉSUMÉ

La Fracturation Hydraulique implique l'injection à haute pression d'un mélange d'eau, de sable et de produits chimiques pour fracturer les formations rocheuses et augmenter le flux d'hydrocarbures. Chez Sonatrach, de nombreux tests sont effectués au cours de ce processus afin de développer un modèle et un calendrier de fracturation améliorés. Cependant, l'analyse de ces résultats de test était un défi en raison du manque d'une plateforme logicielle spécialisée, obligeant à faire appel à des services experts coûteux.

Pour résoudre ce problème, la solution logicielle et site web complet FRACTO a été créée pour optimiser les processus de fracturation en intégrant des outils permettant de faire le lien entre la théorie et la pratique sur le terrain. Les exigences ont été recueillies grâce à la collaboration avec des ingénieurs en fracturation hydraulique, suivant une méthodologie bien définie pour programmer systématiquement la plateforme. Les résultats ont démontré que le calendrier principal de fracturation généré par la plateforme FRACTO pour le puits MD689 était précis et efficace, fournissant une base solide pour une exécution réussie.

Mots-clés : Fracturation Hydraulique, HF Tests, Sonatrach, FRACTO, Plateforme.

ملخص

تتضمن عملية الكسر الهيدروليكي حقن خليط عالي الضغط من الماء والرمل والمواد الكيميائية لكسر تكوينات الصخور وزيادة تدفق الهيدروكربونات. في شركة سوناطراك، يتم إجراء العديد من الاختبارات خلال هذه العملية لتطوير نموذج كسر وجدول زمني محسنين. ومع ذلك، كان تحليل نتائج هذه الاختبارات يمثل تحديًا بسبب عدم وجود منصة برمجية متخصصة، مما اضطر إلى الاعتماد على خدمات شركات خبيرة باهظة الثمن.

لمعالجة هذا الأمر، تم إنشاء منصة فراكتو (برنامج/موقع إلكتروني) لتحسين عمليات الكسر الهيدروليكي من خلال دمج الأدوات لربط النظرية بالممارسة العملية. تم جمع المتطلبات من خلال التعاون مع مهندسي الكسر الهيدروليكي، واتباع منهجية محددة جيدًا لبرمجة المنصة بشكل منهجي. وأظهرت النتائج أن جدول الكسر الرئيسي الذي أنشأته منصة FRACTO لبئر MD689 كان دقيقًا وفعالًا، ووفر أساسًا متينًا للتنفيذ الناجح.

الكلمات المفتاحيّة: التكسير الهيدروليكي، اختبارات التكسير الهيدروليكي، سوناطراك، فراكتو، منصَّة.

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LIST OF ABBREVIATIONS

SEM = Scanning Electron Microscope,

TCV = Control Vehicle,

KH = Permeability Horizontal,

HCL = Hydrochloric Acid,

ISIP = Instantaneous Shut-in Pressure,

PIFB = Pump in Flow Back,

POOH = Pull Out of the Hole,

CFD = Dimensionless Fracture Conductivity,

FOI = Folds of Increase,

PKN = Perkins Kern Nordgren,

KGD = Khristianovic Geertsma de Klerk,

TVD = True Vertical Depth,

MD = Measured Depth,

ISIP = Instantaneous Shut-in Pressure,

DFIT = Diagnostic Fracture Injection Test,

BHTP = Bottom-hole Treating Pressure,

GENERAL INTRODUCTION

The natural exploitation of an oilfield involves bringing hydrocarbons to the surface via natural depletion. However, as energy decreases, permeability and well productivity reduce. For reservoirs with significant remaining reserves, new recovery techniques are employed to improve well potential and characteristics. Among the most commonly used are stimulation methods that create new channels in the rock formation, allowing easier oil and gas flow. Their main goal is to bypass near-wellbore damage and create highly conductive pathways within the formation, thereby enhancing well productivity.

Hydraulic fracturing is one of the treatment processes most frequently used to overcome the problem of low productivity. This technique has been steadily developing with the evolution of technology, especially over the last decade, when it was reserved for compact reservoirs. In addition to increasing production, it is important to be able to predict the expected results of a hydraulic fracturing operation. This knowledge is useful in planning an economically reliable treatment and in achieving the desired production levels for the well.

To ensure the successful execution of fracturing operations, several calibration tests are conducted. These tests are crucial for developing an improved Hydraulic Fracturing Model (Executable Main Frac Schedule). However, the analysis of these tests has been hindered by the lack of a specialized platform within the National Company SONATRACH. Consequently, SONATRACH is compelled to incur expenses by engaging expert services companies in the field for this analysis, resulting in a waste of costs and time.

As part of our final year dissertation project, we were faced with the challenge of studying and creating a new platform; FRACTO, for the Hydraulic Fracturing Calibration Test Analysis; a comprehensive website and software solution designed to optimize hydraulic fracturing processes. This final brief consists of two parts:

- The theoretical part contains two chapters:
  - The first chapter provides General Hydraulic Fracturing Fundamentals,
  - The second chapter provides Fracture Pressure Analysis & Perforation Design.

  The practical part is dedicated to the realization of platform proposal (Website & Software) for Hydraulic Fracturing Calibration Test Analysis.

CHAPTER I

General Hydraulic Fracturing Fundamentals

I. Introduction

During the life of a well, it is exposed to different types of damage causing problems caused by (Scales, swelling clays, water block...) and may occur from drilling to any time during the life of a well, the evidence of damage is made by the observation of a decline in well flow or by the decline in the productivity index which requires a matrix treatment by stimulation.

Among the treatment processes most commonly used to overcome the problem of low productivity is hydraulic fracturing (Economides Michael, 1993).

Hydraulic fracturing has been, and will remain, one of the primary technological tools for improving well productivity by artificially creating a drain with a very high conductivity compared to that of the reservoir, on either side of the well up to a certain distance from it. In its most common application, a threefold increase in the productivity index is a very good result.

II. Definition of Hydraulic Fracturing

Hydraulic Fracturing is the targeted dislocation of low-permeability geological formations by means of high-pressure injection of a fluid designed to crack and micro-fracture the rock. Fracturing can be carried out close to the surface, or at great depth (over 1 km, or even over 4 km in the case of shale gas), using vertical, inclined or horizontal wells.

It is carried out by fracturing the rock by mechanical "stress" using a fluid injected under high pressure from a surface borehole, to increase its macro-porosity and to a lesser extent its micro-porosity (Boubekri, 2013).

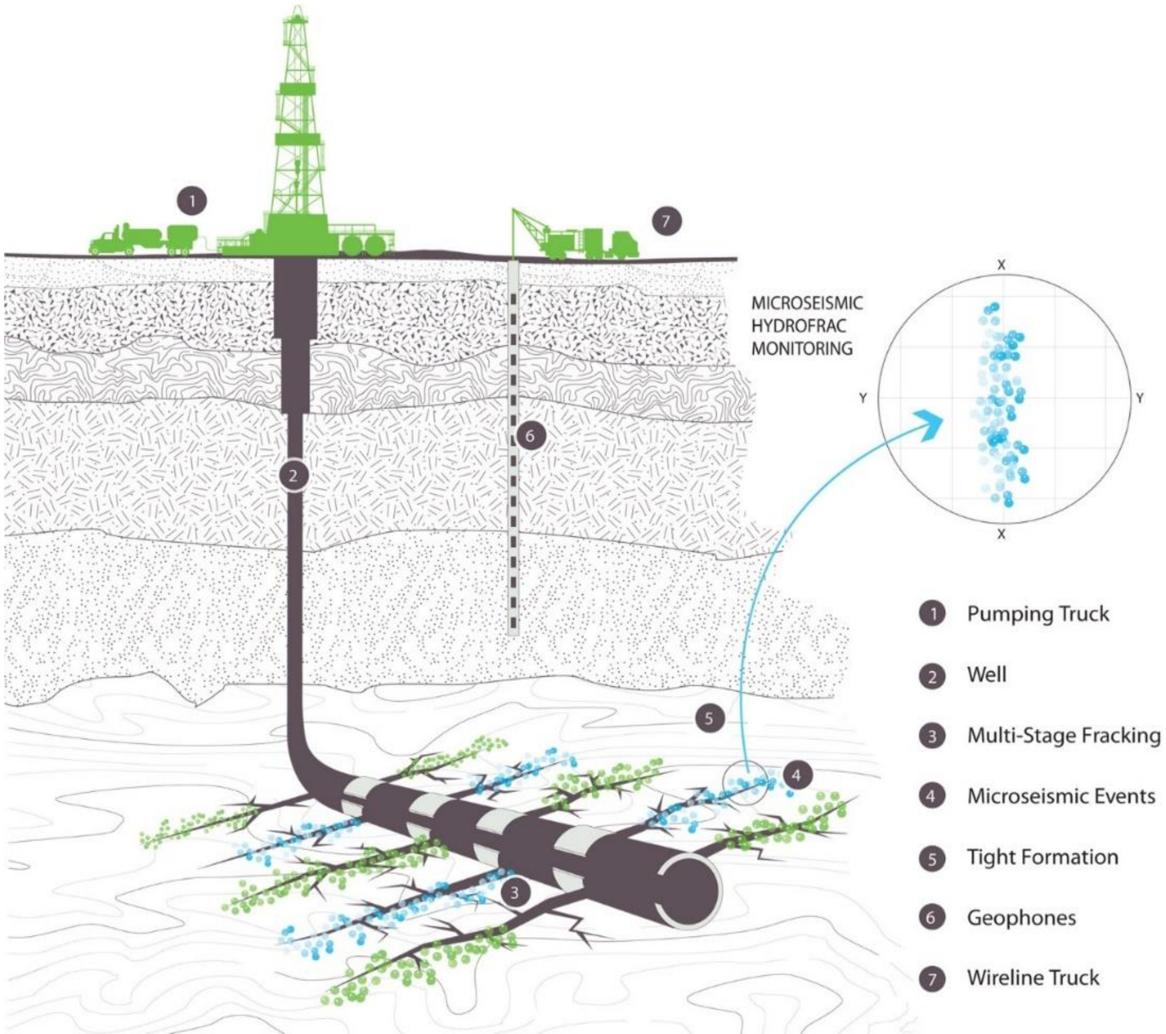


Fig I.1: *Hydraulic Fracturing information's*

The main use of these technique is to "stimulate" the speed and extent of gas or oil drainage by a well, in low-permeability rock "reservoirs" (e.g., shale) which would otherwise produce almost nothing.

When hydrocarbons are trapped within the rock matrix, fracking facilitates access to a larger part of the deposit. Combined with other techniques involving a cocktail of chemicals added to the fracking fluid, it also facilitates the desorption and recovery of gas or oil that has been trapped for millions of years in the rock matrix itself (Boubekri, 2013).

III. Goals of Hydraulic Fracturing

In general, hydraulic fracture treatments are used to increase the productivity index of producing wells. The productivity index defines the rate at which oil or gas can be produced at a given pressure differential between the reservoir and the well-bore, while the injectivity index it's the rate at which fluid can be injected, at a given pressure differential (BBG, 2022).

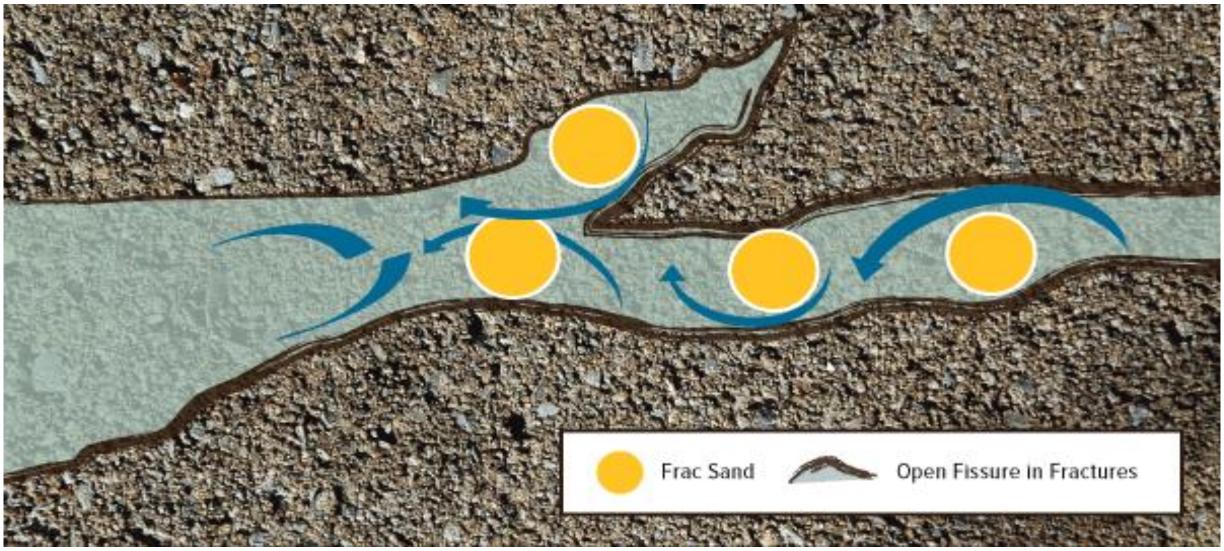


Fig I.2: *Fracture shape*

There are many applications for hydraulic fracturing. Hydraulic fracturing can:

- Increase the flow rate of oil and/or gas from low-permeability reservoirs,
- Increase the flow rate of oil and/or gas from wells that have been damaged,
- Connect the natural fractures and/or bond in a formation to the well-bore,
- Decrease the pressure drop around the well to minimize sand production,
- Improving the placement of gravel sand,
- Decrease the pressure drop around the well to minimize problems with asphalting and/or paraffin deposition,
- Increase the area of drainage or the amount of formation in contact with the well-bore,
- Connect the full vertical extent of a reservoir to incline or horizontal well. There could be other uses, but most of the treatments are pumped for these reasons,
- Increase to productivity index (IP) which is; A commonly used measure of the ability of the well to produce is the Productivity Index.

IV. Process of Hydraulic Fracturing

A. Design Considerations for Fracturing

There are many considerations that should be focused upon before performing a hydraulic fracturing operation such as geologic considerations, petrophysical and well testing considerations and these are combined to get a complete description of the reservoir.

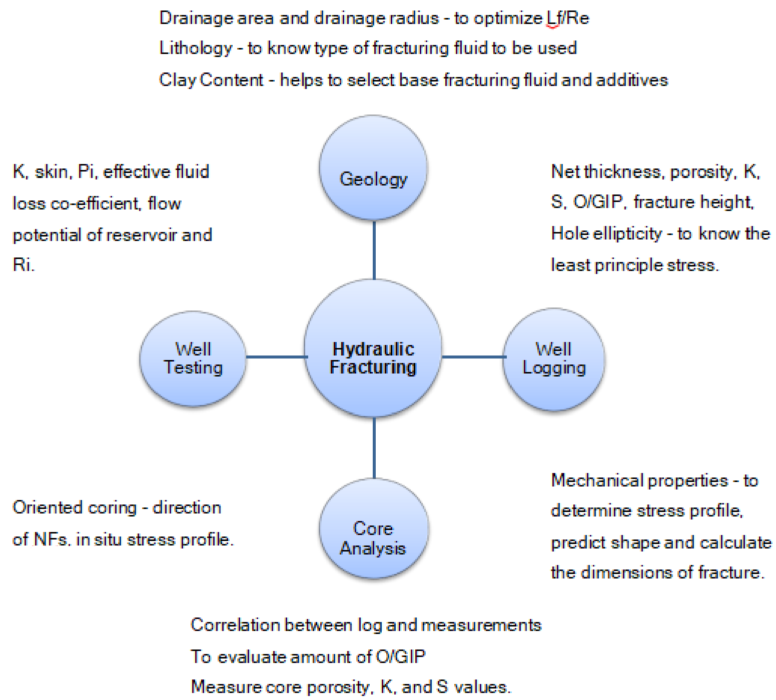


Fig I.3: *Major sources of data*

1. Geologic Considerations

There are many aspects which should be considered during geologic evaluation of the candidate formation/reservoir (Hoss, 2017). These aspects / parameters are:

a. Drainage area. b. Lithology. c. Clay Content. d. Fault patterns.

Drainage Area

Understanding the complexity of the geologic deposition patterns is important before designing a fracture treatment. Not only is it important to understand whether a formation is blanket or lenticular, gas bearing or water bearing, but it is also important to determine the probable size of the reservoir before designing the stimulation treatment.

For designing the treatment in blanket reservoirs, the engineer must determine optimum values of fracture half-length and drainage radius.

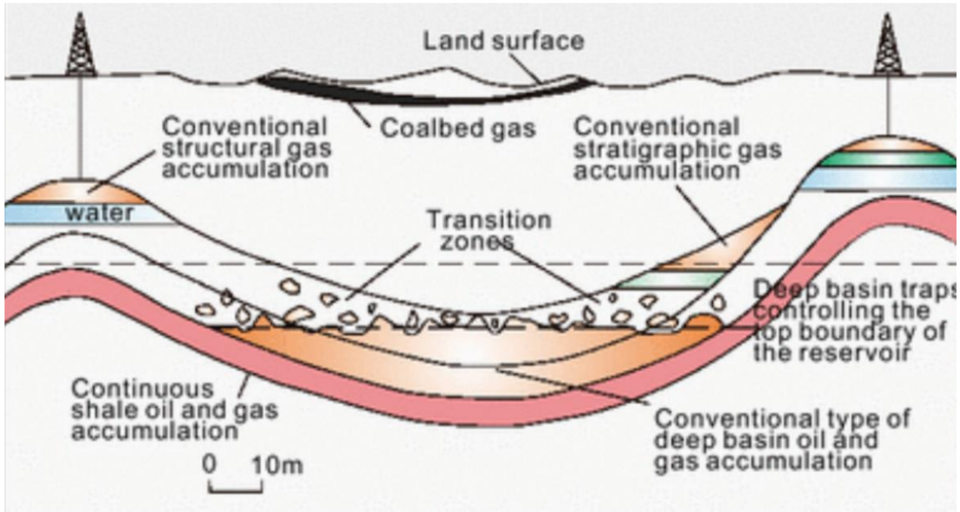


Fig I.4: *General distribution of water and gas in conventional*

However, in lenticular reservoirs, the probable size and shape of the reservoir is estimated and then optimum fracture length is determined from the most probable reservoir size.

Lithology

A geologic characteristic which is important to know before designing a hydraulic fracturing treatment. For a sandstone reservoir, a water or oil-based fracturing fluid will probably be selected. In shallow carbonate reservoirs, sometimes acid based fluid is feasible.

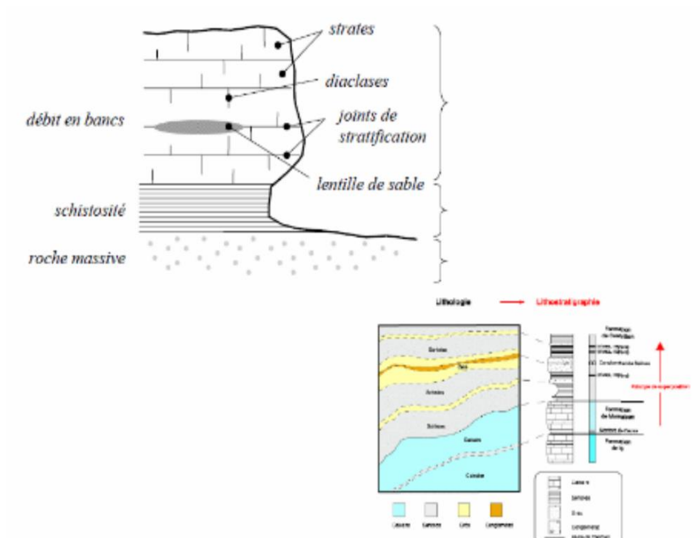


Fig I.5: *Sedimentary Rock Architecture*

The basic lithology of a reservoir is an important factor for the analysis of open hole geophysical logs as well. Other lithological characteristics can also be important depending upon certain geologic environment.

Clay Content

It is important to know the type and distribution of material that fills the pores in a particular formation. It is well known that many low permeability reservoirs contain large amount of clay material in the pore space. Geologic studies that include core descriptions, use of scanning electron microscope (SEM's) and X-ray diffraction analysis can be very helpful to understand the type of clay and its distribution in a particular formation. Different types of clays affect and reduce the permeability of a sandstone reservoir as shown in the **Fig I.6**.

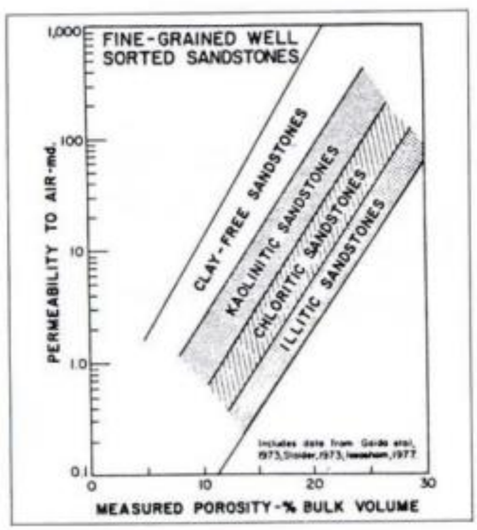


Fig I.6: *Porosity/permeability relationship of clay free and clay bearing sandstones*

A pore filling clay reduces the permeability to a higher extent than a pore lining clay. The type of minerals and their location in the rock matrix can be of vital importance to interpret well logs and reservoir behavior (Heru Irianto).

Fault patterns

The geologic study will be incomplete without the knowledge of regional and local stress patterns in an area.

The knowledge of in-situ stresses is very important in designing the fracturing treatments. One way to investigate the stresses is to examine the regional and local fault systems.

Hubbert and Wills explained that localized and regional stress patterns in an area are controlling factors in determining the orientation of hydraulic fractures and that the state of stress underground is not hydrostatic but depends on tectonic conditions. They further concluded that hydraulically induced fractures are formed approximately perpendicular to the least principal stress (Heru Irianto).

2. *Logging Considerations*

An accurate analysis of these geophysical logs is a crucial part for better formation evaluation provides the values of porosity, water saturation and net thickness of hydrocarbon zone. The values obtained from well logging and PVT properties obtained from laboratory measurements of the reservoir fluid, can be used to have a good estimation of oil and gas in place by the volumetric method as explained below:

$$OOIP = A * h * \varphi * (1 - Sw)/\beta$$

Where:

OOIP = Original oil in place,

A = Drainage area,

h = Net pay thickness.

β = Geometric factor,

φ = Porosity,

Sw = Water saturation,

Small errors in porosity or saturation can cause a big difference in the estimation of reserves. Therefore, an accurate well log analysis is very important to determining the shale content, fluid content and borehole irregularities.

Well logging helps us to obtain the values of following parameters.

Shale Content Analysis

This analysis should be performed for better description of conventional as well as unconventional reservoirs. A good combination of logs consisting on gamma ray, spontaneous potential, induction, neutron, density and acoustic logs should be used for accurate formation evaluation (Heru Irianto).

Dual water model and Waxman Smits methods are probably the best methods to perform shaly sand analysis. For simplicity only Archie’s equation is presented below;

$$Rt = \frac{a * Rw}{\varphi^m S_w^n}$$

$$S_w^n = \frac{a * Rw}{\varphi^m R_t}$$

$$S_w^n = \frac{F * Rw}{R_t}$$

$$S_w^n = \frac{Ro}{R_t}$$

Where:

m = Cementation exponent,

Sw = Formation water saturation,

Rw= Formation water resistivity,

Rt= True formation resistivity,

F = Formation Resistivity Factor,

F = a/φ^m

n = Saturation exponent,

a = Lithology or tortuosity factor.

This equation is based upon the assumption that 100% of the current is transmitted through the fluids into the pore space from the resistivity logging tool. For clean and uniform size sands: a = 1 and m = 2.

Rock Mechanics

The knowledge of mechanical properties of a producing formation as well as the surrounding formations is extremely important to predict the shape and to calculate the dimensions of hydraulic fractures. These mechanical properties include; Young's modulus, Shear modulus, Poisson's ratio, Bulkmodulus and Compressibility. The following equations can be used to calculate the mechanical properties of a formation.

Young's modulus: $\mathrm{E} = \mathrm{G}(1 + \mathrm{v})$

Shear modulus: $\mathrm{G} = 1.34 * \frac{10^{10}\rho_b}{\Delta t_s^2}$

Poisson's ratio :

$$\mathrm{v} = \frac{0.5\mathrm{R_v^2} - 1}{\mathrm{R_v^2} - 1}$$

$$R_V = \frac{V_c}{V_s} = \frac{\Delta t_s}{\Delta t_c}$$

Where:

$\boldsymbol{Vc}$ = Compressional wave velocity,

$\boldsymbol{Vs}$ = Shear wave velocity,

$\Delta\boldsymbol{tc}$ = Compressional wave travel time,

$\Delta\boldsymbol{ts}$ = Shear wave travel time.

Bulk modulus : $K = 1.34 * 10^{10} \rho_b \left(\frac{1}{\Delta t_c^2} - \frac{4}{3\Delta t_s^2}\right)$

Compressibility: $C_b = \frac{1}{K}$

Where:

E = Young's modulus, ***Rv*** = velocity ratio,

G = shear modulus, ***ρb*** = bulk density.

v = Poisson's ratio,

The best values of shear wave velocity and compressional wave velocity are obtained by recording a full wave form sonic signal from a downhole acoustic transmitter.

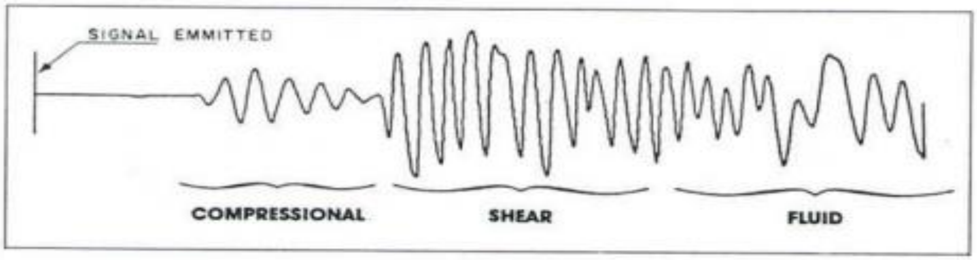


Fig I.7: *Typical sonic waveform in borehole*

The key to accurate determination of mechanical properties is an accurate measurement of shear wave travel time in the formation.

The relationship between compressional wave and shear wave travel time for a number of different lithologies and fluid saturations.

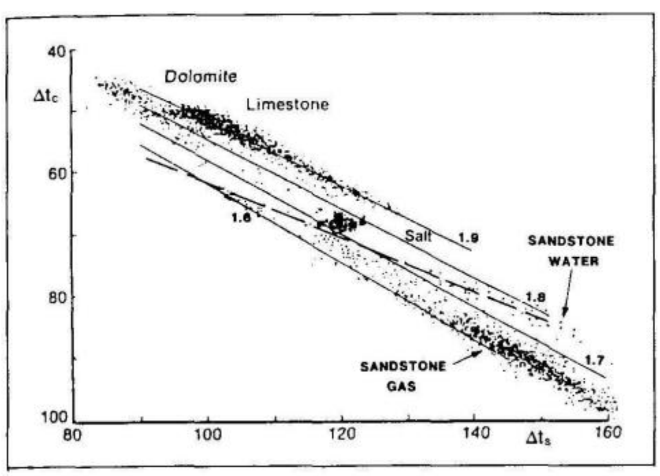


Fig I.8: *Well log examples, $\Delta t_c/\Delta t_s$ cross plots*

Table I.1: *Velocity rations from* ***Fig I.8***

Lithology	$\Delta t_s/\Delta t_c$
Sandstone/Water	1.78
Sandstone/Gas	1.60
Dolomite	1.80
Limestone	1.90

It can be concluded from this relationship that, if one can determine the amount of dolomite, limestone, shale and probable fluid content then an estimation of shear wave travel time is possible from compressional wave travel time. Once velocity ratio is estimated then the values of Poisson's ratio and moduli can be calculated (Tilioua, 2020).

Stress Profile

One of the most important uses of mechanical properties data is to determine the stress profile in a formation containing multiple layers.

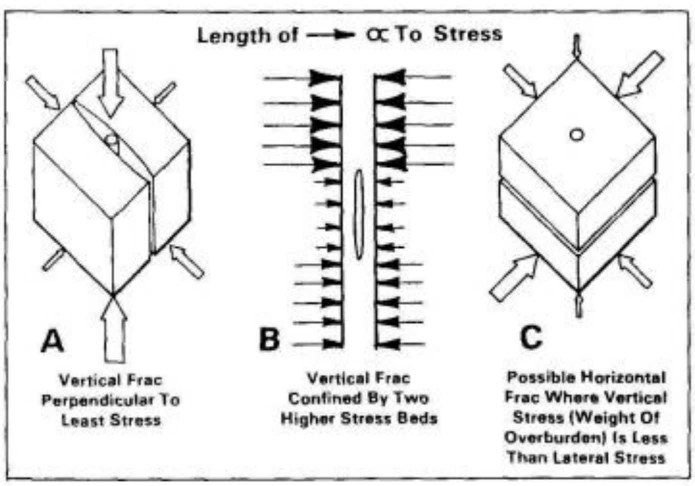


Fig I.9: *Effect of stress field on fracture propagation*

The knowledge of in-situ stresses and stress profile is crucial in designing a fracture treatment which is confined within the productive interval. Effect of stress field on fracture propagation is presented in **Fig I.9**.

This equation illustrates that the total horizontal stress can be calculated if Poisson's ratio, total overburden stress, pressure and externally generated stresses are known.

$$\sigma_x = \left({}^{v}/_{1-v}\right)(\sigma_2 - p) + p + \sigma_E$$

Where:

$\boldsymbol{\sigma x}$ = the total horizontal stress,

$\boldsymbol{v}$ = Poisson's ratio,

$\boldsymbol{\sigma z}$ = overburden stress,

$\boldsymbol{p}$ = reservoir fluid pressure or pore pressure,

$\boldsymbol{\sigma E}$ = externally generated stress.

Temperature Log Base Profiles

Temperature logs in combination with gamma ray logs can be used to determine where fluid enters or exits the casing. These logs can also provide information about flow channels behind the casings. Many engineers also try to determine the fracture height after stimulation treatment with gamma ray/temperature logs. However, the measurements of fracture height from well logs can be misleading (Boubekri, 2013).

Fracture Height

This is perhaps the most difficult parameter to measure during hydraulic fracturing design. Fracture height can be calculated if one can obtain complete description of all layers in the reservoirs by using a reliable three-dimensional model.

For most situations, one should consider only (1) thick, clean shales, (2) thick, dense formations and (3) coal seams as potential barriers to fracture growth. The best method of estimating created fracture height from the log is to start at the perforated interval and search until shale or dense streak is found that appears thick enough to be a barrier to fracture growth.

It is observed that the size of fracture treatment, the viscosity of fracturing fluid, and the injection rate will influence the value of created fracture height. To design a fracture treatment with current technology, one must estimate fracture height from logs.

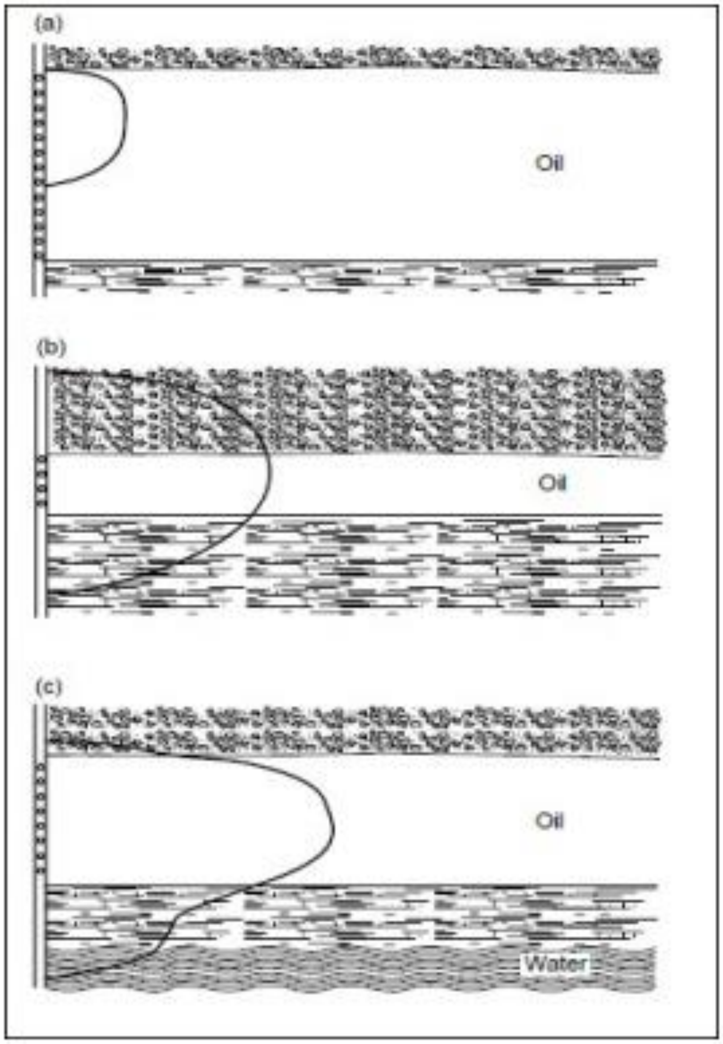


Fig I.10: *The importance of fracture height*

- In **Fig I.10-a**, the fracture is initiated near the top of the interval, and h_f is not large enough to contact the entire zone, which is clearly an important reservoir concern.
- In **Fig I.10-b**, the fracture grew out of the zone and contacted mostly no reservoir rock, diminishing x_f relative to the treatment volume pumped.
- In **Fig I.10-c**, the fracture grew downward past the oil/water contact and if propped would possibly result in unacceptable water production.

In all these cases, fracture height growth is controlled by rock mechanics considerations such as in- situ stress, stress gradients, stress magnitude differences between geologic layers.

The reservoir thickness can be calculated from the well log (Economides Michael, 1993).

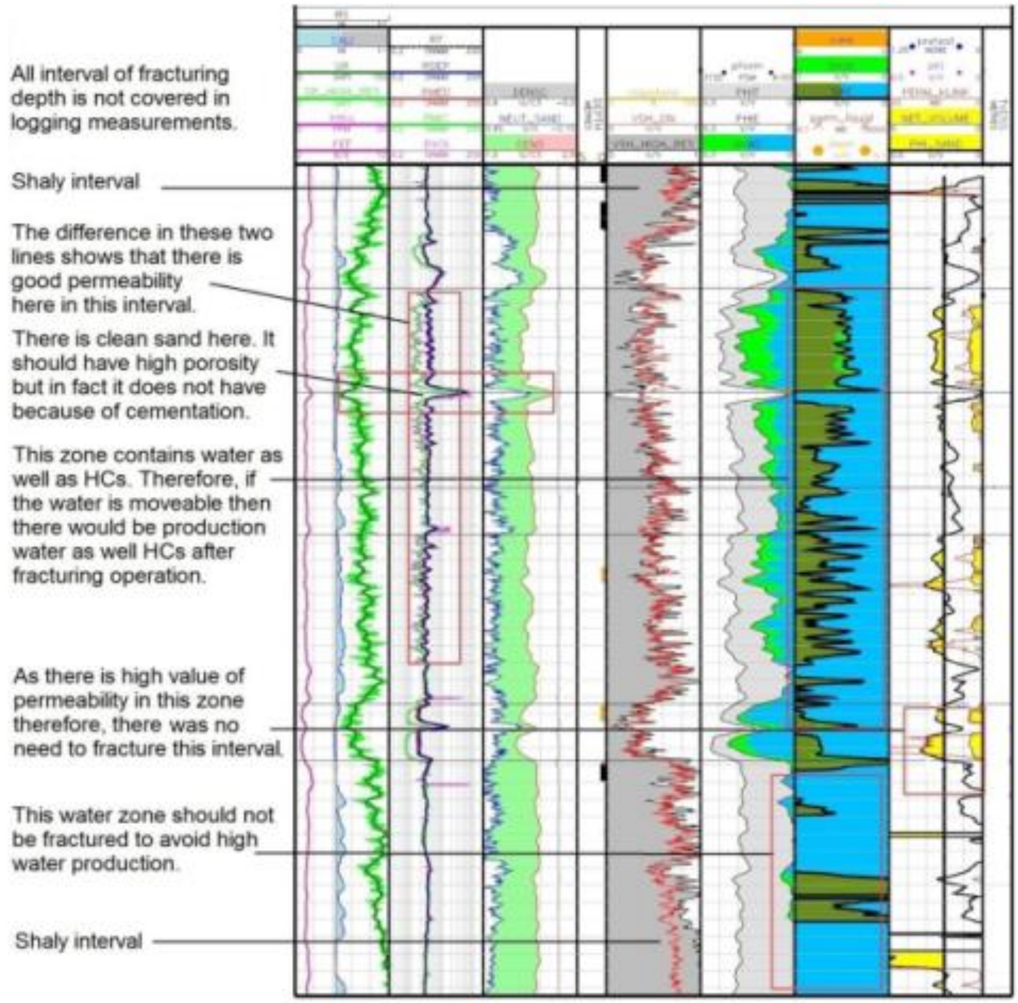


Fig I.11: *Well log analysis*

3. Core Analysis

The description of layers surrounding the productive interval is important to design the hydraulic fracture treatment. The main purpose of taking the cores is to evaluate the amount of oil and gas in place, to determine the effective permeability values and to obtain correlations between core and log readings.

Conventional core analysis is usually performed to calculate the values of porosity, permeability and water saturation at atmospheric conditions. The measurements are made at room temperature and moderate pressure after removing hydrocarbons and drying the core sample in an oven. This type of analysis has been useful in conventional reservoirs; however, it is not useful for unconventional tight gas reservoirs (Senina).

Fig I.12: *Geological Core Sampling*

In addition to measuring the rock and fluid properties, it is also extremely important to run special tests to determine the possible interaction of fracturing fluid and proppants with the formation. It's because, fracturing fluid can play an important role in altering the formation characteristics such as wettability.

Oriented coring technique is useful in order to determine the direction of natural as well as hydraulically induced fractures and stress patterns. Special coring equipment is used to obtain an oriented core. Knowing the core orientation can be quite useful in planning the location of development wells in blanket reservoirs (Hoss, 2017).

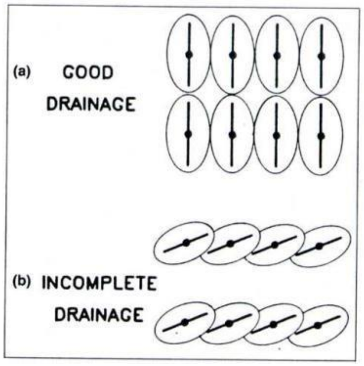


Fig I.13: *Optimum recovery (a), Inefficient recovery (b)*

It is illustrated in the **Fig I.13-a** that when fracture orientation is known, the wells can be drilled to obtain adequate drainage area in the reservoir. But if the well spacing and location are not properly planned, the reservoir would not be drained sufficiently as can be seen in the **Fig I.13-b**. Optimum selection of infill well locations depend upon the orientation of propped fractures in low permeability reservoirs.

4. *Well Testing*

Once the decision has been made those hydrocarbons are present in commercial quantities in the reservoirs depending upon the analysis of geological, log and core data, a series of pre-fracture well test should be designed, executed and analyzed for further evaluation of the formation (Lake, 2006).

The main purpose of well test is to estimate the dynamic reservoir permeability, skin factor and initial reservoir pressure along with some other properties such as in-situ stresses and effective fluid loss coefficient. Skin factor is a quantitative measure of the extent of damage of a formation. It is difficult to analyze post-fracture well tests, optimize fracture length and to design the optimum proppant for the fracture treatment if the correct value of in-situ permeability is not known from pre-fracture well test.

B. Fluids and Equipment Overview

1. *Fluids*

A fluid injected into a well as part of a stimulation operation. Fracturing fluids for shale reservoirs usually contain water, proppant, and a small amount of no aqueous fluids designed to reduce friction pressure while pumping the fluid into the wellbore. A wide variety of chemical additives are used in hydraulic fracturing fluids; chemical additives typically might make up just 1/2 to 2 percent of the fluid. The remaining 98 to 99 1/2 percent of the fluid is water. Proppants such as sand, aluminum shot, or ceramic beads are frequently injected to hold fractures open after the pressure treatment is completed (Salman, 2015).

Fig I.14: *Fracturing gel*

Fracturing fluids currently on the market fall into two groups, known as conventional fluids, they include:

- Water-based gels,
- Oil-based gels, which are used less and less frequently.

For water-based fluids, we distinguish two types of gels: linear and cross-linked.

a. Linear gels: these gels are made up of long polymer chains, one next to the other, with no links to each other. The viscosity of such gels is less than 100 Cp. They are used to displace cross-linked gels.

b. Cross-linked gels: these are made up of long polymer chains, but this time, strong bonds, due to a cross-linking agent, exist between the polymer chains, creating a viscosity in excess of 100 Cp.

Table I.2: *Summary of Fluid Types*

Base Fluid	Fluid type	Main Composition	Used For
Water Based	Linear Fluids	Gelled Water, GUAR < HPG, HEC, CMHPG	Short Fractures, Low Temperatures
	Crosslinked Fluids	Crosslinker + GUAR, HPG, CMHPG, CMHEC	Long Fractures, High Temperatures
Foam Based	Water Based Foam	Water and Foamer + N2 or CO2	Low Pressure Formations
	Acid Based Foam	Acid and Foamer + N2	Low Pressures, Water Sensitive Formations
	Alcohol Based Foam	Methanol and Foamer + N2	Low Pressure Formations with Water Blocking Problems
Oil Based	Linear Fluids	Oil, Gelled Oil	Water Sensitive Formations, Short Fractures
	Crosslinked Fluids	Phosphate Ester Gels	Water Sensitive Formations, Long Fractures
	Water External Emulsions	Water + Oil + Emulsifier	Good For Fluid Loss Control

Additives

Chemicals are most often added to water to transform it into a highly viscous, low-friction fluid capable of carrying the proppant and withstanding the rigors associated with the journey to the zone of interest and subsequent return to the surface. The number of chemicals and their content when added to the proppant suspended in the fluid can vary considerably, depending on the specific properties of the reservoir, once combined their content will generally not exceed 1% of the total volume of the fluid-proppant mixture (Campos, 2018).

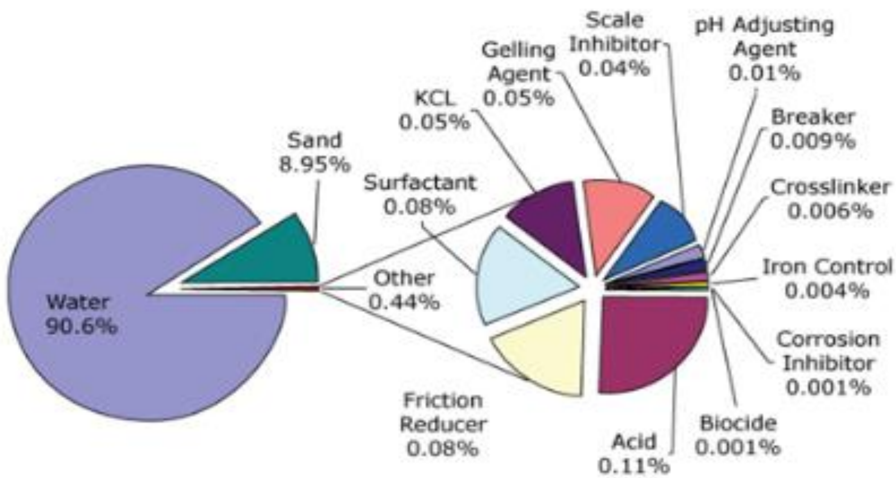


Fig I.15: *Volumetric composition of a fracturing fluid*

- Gelling agents: serve to increase the viscosity and suspension capacity of propellants and act as lubricants, they include;
  - Guar gum: creates a chain of natural polymers, high viscosity,
  - Polyacrylanide: used to make the water used in the frac process slippery.
- Friction reducers: complement the friction-reducing action of gelling agents.
- Cross-linked polymers: used to join polymers together:
  - Boron, Zirconium, Titanium or Iron: they increase the degree of viscosity of the liquid by binding the polymers.
- Clay controller: used in formations characterized by their instability to water, to prevent swelling of clay particles, we have;
  - Potassium chloride: reduces reservoir damage by preventing certain dry minerals from reacting with water.

- Interrupting agents: break the polymer chain created by the gelling agent:
  - Oxidant: reduces the degree of polymer viscosity and allows fluids to flow back to the surface,
  - Enzyme: consumes polymers created by guar gum.
- Surfactants: act to reduce the surface tension of the frac fluid.
  - Discharge additives: facilitate drainage of the fluid once the treatment.
- Biocides: prevent the introduction of sulfate-reducing bacteria:
  - Natural and manufactured biocides: prevent the introduction of bacteria that can produce hydrogen sulfide or other chemicals of a corrosive or fouling nature.
- Activating agents: gases used to activate or foam fluids for fracturing treatment purposes:
  - Carbon dioxide: used to enhance fluid recovery capacity while reducing the risk of formation damage. It is sparingly soluble in water and highly soluble in oil when under pressure,
  - Nitrogen: very abundant in the atmosphere and improves the recovery capacity of fluids used in stimulation operations.

Table I.3: *Types and functions of additives*

Additive Type	Main Compound(s)	Functions
Diluted Acid (15%)	Hydrochloric acid or muriatic acid	Help dissolve minerals and initiate cracks in the rock
Biocide	Biocide	Eliminates bacteria in the water that produce corrosive by-products
Breaker	Ammonium per sulfate	Allows a delayed break down of the gel polymer chains
Corrosion Inhibitor	n-dimethyl form amide	Prevents the corrosion of the pipe
Crosslinker	Borate salts	Maintains fluid viscosity as temperature increases
Friction Reducer	Polyacrylamide	Minimizes friction between the fluid and the pipe
	Mineral oil	
Gel	Guar gum or hydroxyethyl cellulose	Thickens the water in order to suspend the sand
Iron Control	Citric acid	Prevents precipitation of metal oxides

KCI	Potassium chloride	Creates a brine carrier fluid
Oxygen Scavenger	Ammonium bisulfite	Removes oxygen from the water to protect the pipe from corrosion
pH Adjusting Agent	Sodium or potassium carbonate	Maintains the effectiveness of other components, such as crosslinkers
Proppant	Silica, quartz sand	Allows the fractures to remain open so the gas can escape
Scale Inhibitor	Ethylene glycol	Prevents scale deposits in the pipe
Surfactant	Isopropanol	Used to increase the viscosity of the fracture fluid

Proppants

These are solid particles suspended in the fracturing fluid and injected into the fractures. Their purpose is to keep the fractures open, creating and maintaining a conductive "path" for the fluids (gas, oil, water) to move easily to the extraction well. To improve well productivity, a fracture must have a higher permeability than the permeability of the reservoir matrix.

Non-compressible material (usually sand or ceramic beads) is added to the fracturing fluid and pumped into open fractures to prevent them from closing in on themselves when the pressure drops at the end of treatment (Guenaoui, 2021).

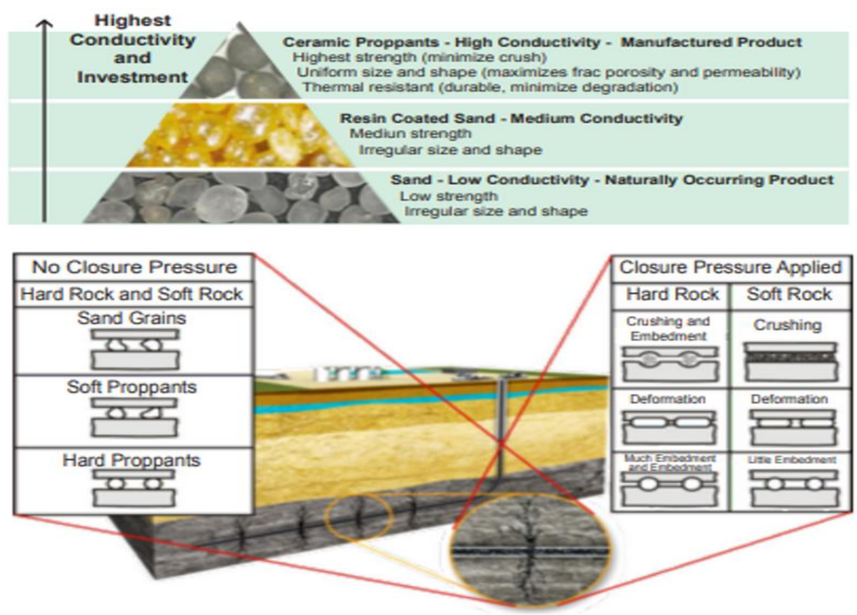


Fig I.16: *Types of Proppants*

There are a number of properties that need to be adequately assessed when selecting underpinning materials. Strength is one of the main properties to be taken into account, as it defines service life and the limit of closure stress.

The strength of the proppant is also linked to its porosity, which in turn is linked to its density. The production method determines the quality of the format (sphericity and roundness) and the size of the final product *(Verisokin, 2021)*.

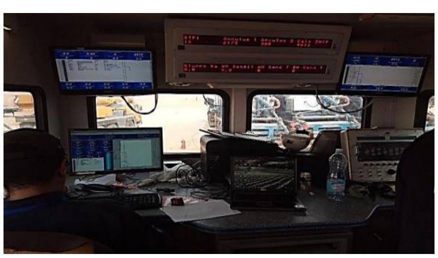
Table I.4: *Selection of the support agent based on depth*

Depth (m)	**The support agent**
1000 à 1500	Sand
1500 à 2000	ISP (Intermediate Strength Proppant)
≥ 2000	HSB (Heigh Strength Bauxite)

2. *Equipment*

The success of a technical operation such as either is only achievable by the necessary appropriate equipment and highly qualified personnel *(BBG, 2022)*.

Table I.5: *Equipment Requirement*

	8		8
High Pressure Frac Pump		Frac tank	
	1		1
Control Vehicle (TCV)		Sand truck / Sand Chief	

 High Pressure Manifold	1	 POD Blender	1
 Wellhead Isolation Tool (Tree Saver)	1		

Where:

- High Pressure Pumps: Most high-pressure pumps used in hydraulic fracturing are of the triplex variety, which can reach 20000 psi.
- Frac tank: To store treated water used for frocking gel preparation.
- Control Vehicle (TCV): The fracturing treatment will be controlled from this facility. The Frac Supervisor, the Frac Engineer and the Company Man can sit in relative comfort and quiet, making treatment-critical decisions, based on the data that is being collected and displayed.
- Sand truck / Sand Chief: Is a storage propping agent, its capacity can go up to 2500 ft3. It divided into five (5) rooms allowing putting the different types of proppants.
- High Pressure Manifold: is a set of valves that collects mixtures and can with stand pressures of 20000 Psi for a flow of 75 (bbl/min).
- POD Blender: This device is used to mix and send to the high pump pressure whatever is necessary for the fracturing fluid (fluids, proppants, and additives).

- Wellhead isolation tool (Tree-saver): It is a device that allows the wellhead to with stand high pressures. He is used to avoid the change of the wellhead which cannot withstand critical pressures. He serves to protect the wellhead at:
  - High pressures,
  - The abrasive and corrosive effect of fluids and additives. The tuning of this tool is done without killing the well.

C. The Execution of the Operation

1. Preparation of the well (Pre-Frac Phase)

Preliminary tests on the well:

These operations, although optional, are however of great interest.

The interpretation of well tests provides information on the current (KH) of the well and the depletion state (case of old wells).

The flow meter makes it possible to compare the profile of flow recorded with the (KH) of the well (according to the permeability's on cores, if they exist).

Mechanical cleaning of the well:

We carry out a control of the well with the cable (wire line) in order to locate the top sediment and any anomalies in the completion (fish, collapse, dislocation, etc.).

Cleaning the well with acid:

If the well is not unequipped, the cleaning of the casings by circulation of hydrochloric acid (HCl), added with a powerful surfactant is desirable, and then the acid is disgorged from the well in order to avoid damaging completion equipment.

2. Calibration Test

Calibration test is the most commonly used technique in unconventional shale reservoirs to determine various completions and reservoir properties for optimum fracture design.

The idea is to create a small fracture by pumping 10-100 BBLs of water at 2- 10 bpm and monitor pressure falloff for a specific period of time. The time of shut-in after pumping will be dependent upon the formation permeability and the pump time, which in turn translates into the time it takes to reach pseudo-radial flow.

After pumping, enough monitoring time should be allowed to reach pseudo-radial flow to determine various reservoir properties.

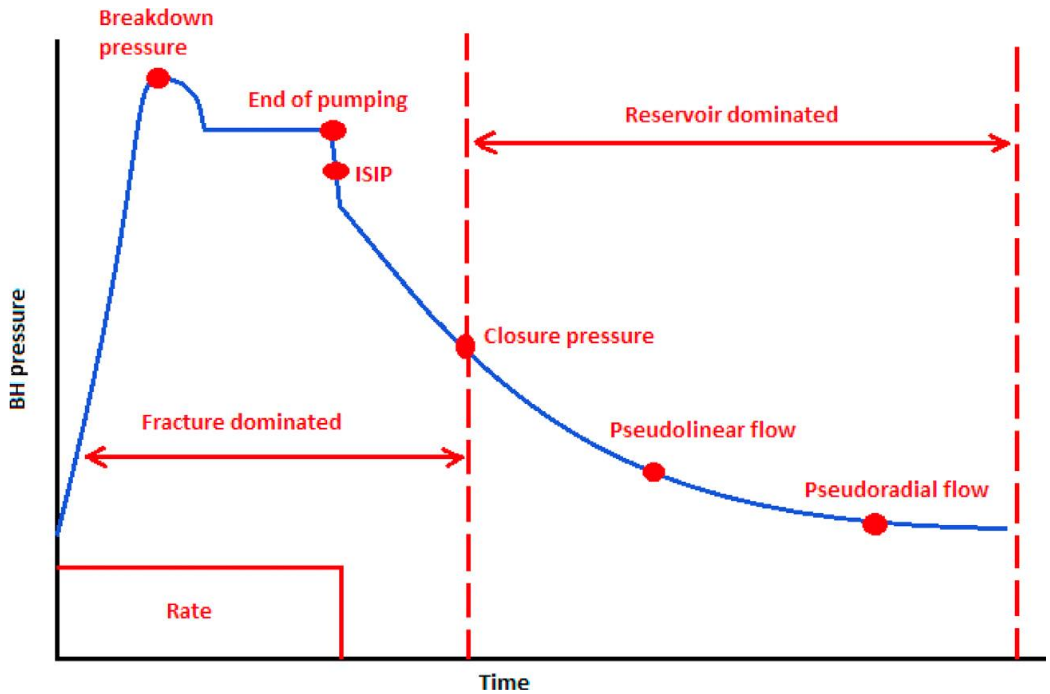


Fig I.17: *Typical fracture Injection test*

Some of the completions properties that can be obtained from calibration test are instantaneous shut-in pressure (ISIP), fracture gradient, net extension pressure, fluid leak-off mechanism, time to closure, closure pressure The main purpose is to contact the whole net pay to get accurate completions and reservoir properties (Senina).

Break down Test (Injection Test) procedures

It consists of injecting a fluid; treated water, brine or crude in a fracturing regime for:

- Check if the formation absorbs fluid (hence the name of the Injection Test),
- Determine the fracturing gradient and consequently the head pressure (no or few fractures on the same field, very heterogeneous reservoirs at great depths in particular...),
- Test the bottom and surface equipment.

This test is still very useful if the well is blocked. If necessary, a prior injection well and significantly reduces the apparent fracturing gradient.

- When hydraulic fracturing is commonly practiced in the field, the injection test immediately precedes the treatment itself, with the same pumping equipment and at the rate intended for this treatment.
- In the case of deep or heterogeneous reservoirs or where the fracturing gradient is not well known, it will be useful to carry out an injection test before deciding on the choice of hydraulic fracturing treatment.

Mini-Frac Test (Data Frac)

The Mini frac is a set of consecutive tests carried out on the formation which makes it possible to initiate an unsupported fracture for a sufficient period of time so as to allow, through their analysis, to provide the necessary information on the conditions prevailing at the bottom of the wells, so to work out our fracturing operation, this test includes several tests such as:

Step Rate Test

This test is conducted solely to estimate the pressure of extension or propagation of the fracture by injecting the base fluid (treated water) at a low flow rate, then increasing it gradually by increments, these flow rates are maintained at each stage. For a sufficient time until the pressure stabilizes (approximately 5 to 10 min). This injection must be accompanied by a continuous recording of the pressure, and a curve of the following form is obtained:

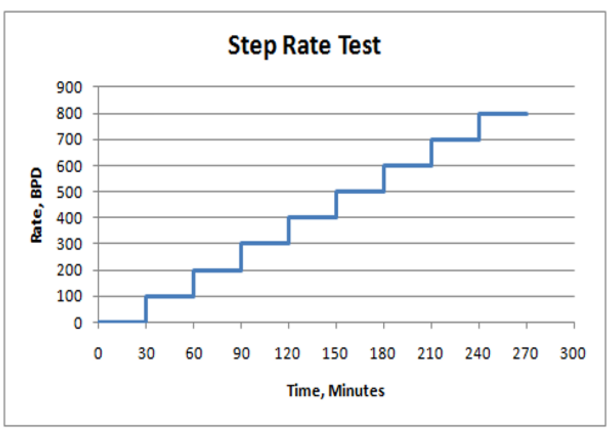


Fig I.18: *Step Rate test*

Pump in Flow Back Test (PIFB)

This is a test that is used to determine the fracture closing pressure (Pc).

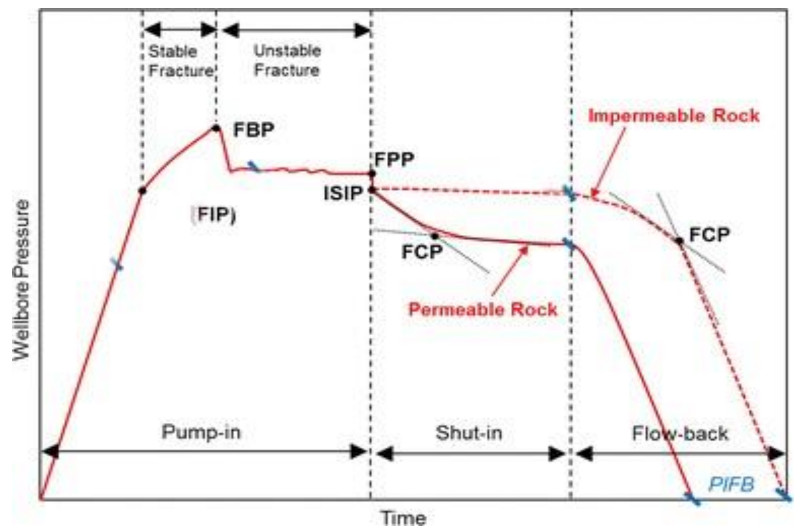


Fig I.19: *Pump in Flow-back test*

It comes directly after the Step Rate Test, requiring the use of the same fluid as the previous test, and it is divided into two stages:

- The pump in step,
- The flow back stage.

3. Main Fracturing Job

Main Job stages

The 2 operation is done in 6 phases (BBG, 2022):

01st Phase: Tests on surface installations.

02nd Phase: Injection of volume pre-pad: This initial stage is also referred to as an acid or it involves injecting a mix of water with diluted acid, such as hydrochloric acid. This serves to clear debris from the wellbore, providing a clear pathway for fracture fluids to access the formation. The acid reacts with minerals in the rock, creating starting points for fracture development.

03rd Phase: Volume pad injection: Consists of injecting viscous water (Slickwater) without proppant. This fluid, once pumped into the well, is intended to initiate and open fractures under very high pressure greater than the fracturing pressure (5,000 psi to 13,000 psi) to allow routing and placement proppants. The pressure required to reopen the fracture is called the fracture reopening pressure and is usually less than the fracture pressure established during MiniFrac testing.

04th Phase: Injection of the slurry: Consists of pumping the proppant coated in a very viscous fluid (gelled water). This proppant is either perfect balls of calibrated sand, or ceramic or zirconium balls. Its role is to fill and keep open the fractures once the hydraulic pressure of fracturing is released. The concentration of proppant is increased as you approach the end of the stage. Indeed, a low concentration of proppant is injected at the very beginning of the stage, this is to clear and clean the route.

05th Phase: Flushing Stage: Drive out the fluid carrying the proppant and keep the proppant to maintain open fractures by pumping a volume of industrial water (linear gel) sufficient to displace the excess slurry remaining in the tubing or in the perforations. The flush volume must always be estimated based on the size of the completion.

06th Phase: Flow back: The moment of disgorging is determined by the evolution of the pressure at the wellhead after the treatment. Wells are opened when the pressure is stable.

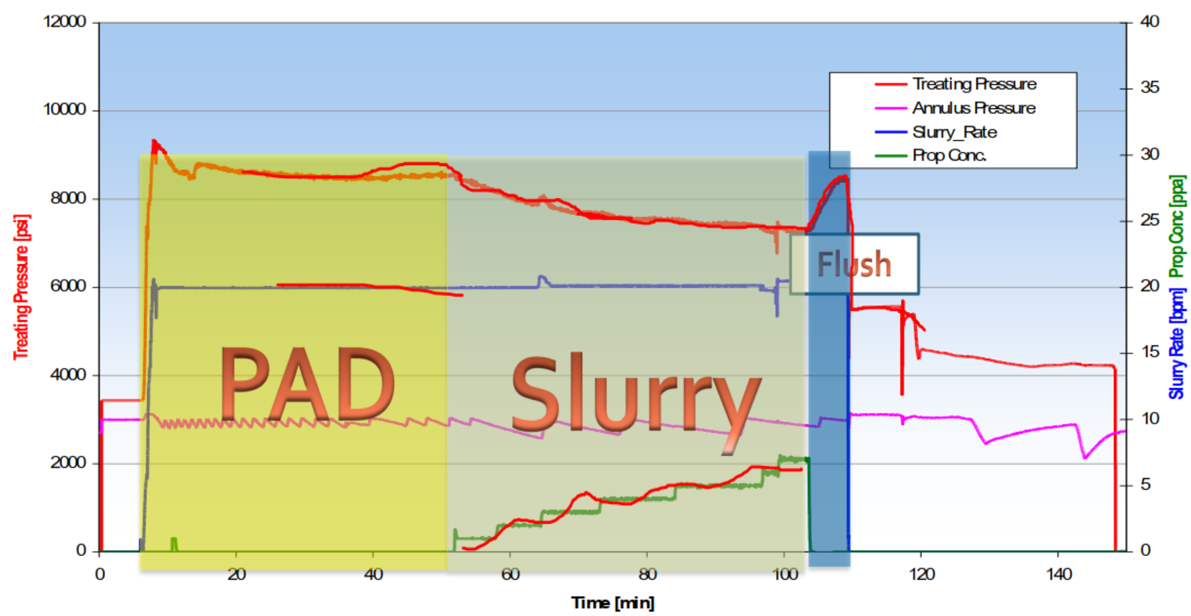


Fig I.20: *Main Fracturing Job stages*

4. *The clean-out by Coiled Tubing (CT)*

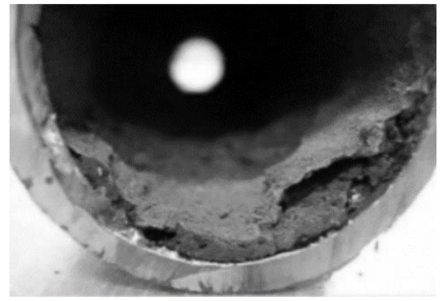


Fig I.21: *Formation of a proppant crust at the bottom of the inner surface of a horizontal wellbore*

One of the most effective technologies for production stimulation is hydraulic fracturing. Frequently, well development after hydraulic fracturing leads to an active flow of proppant from the formed fractures in the reservoir. The proppant, together with the undistorted gel, settles in the wellbore. In order to conduct a successful well development, it is necessary to limit the magnitude of the reservoir depression, flow rate, and pressure gradients. During the operation of the well, complications may appear that makes it difficult to remove the proppant crust by flushing. The crust is a proppant layer with reduced permeability (Li, 2006).

A decrease in permeability occurs only in the presence of smaller impurities (sand, suspension in solution, the use of bound polymers without breakers, carbonate chips). The reasons for crust formation are geological and technological factors. The crust is formed as a result of the precipitation of small proppant particles, mechanical impurities from the working fluids of hydraulic fracturing.

In the formation of a hard-to-break crust, carbonate, clayey rocks, not destroyed under the influence of reservoir temperature, hydraulic fracturing reagents, and mineral salts act as a cementing material. In some cases, viscous oil emulsions and resins are the “cement” for crust formation.

The process includes running CT into the well whilst circulating fluids using a nozzle with a “high energy” jetting action pointing forwards down the well to stir up the particulate solids and allow the CT to reach a target depth or bottom of the well.

When the bottom or desired depth is reached, the hole can then be cleaned either by circulating a fluid while keeping the CT stationary (circulation stage) or by pulling the CT out of the wellbore with continuous circulation (wiper trip stage), or by a combination of these stages (Li, 2006).

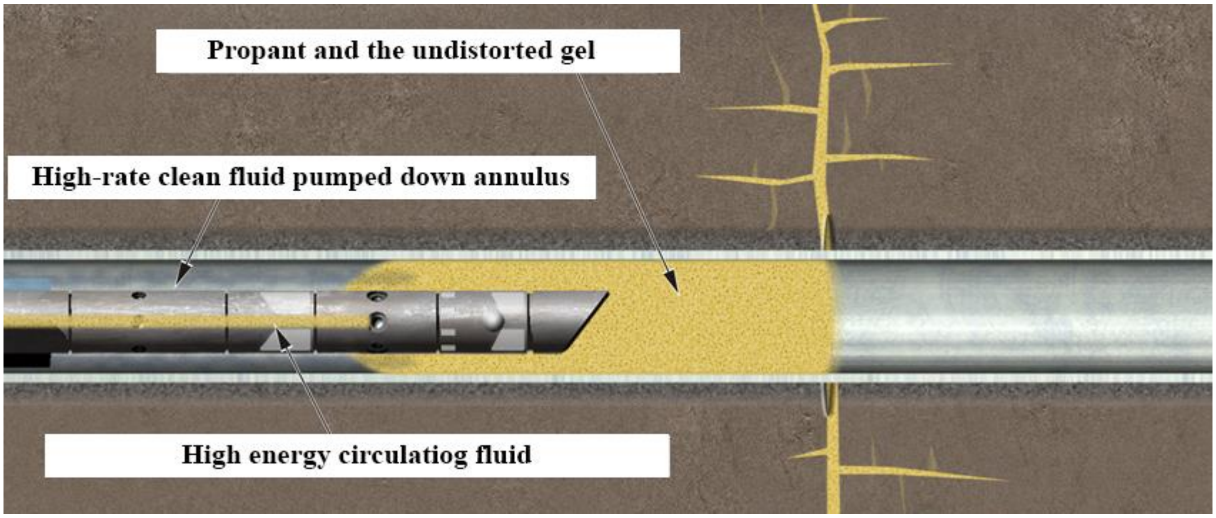


Fig I.22: *Clean out by Coiled Tubing*

In the wiper trip mode, a reversing jetting nozzle with low energy is used to circulate the fluids and to create a particle re-entrainment action to enhance agitation of the solids and then entrain the particulates in suspension for transport out of the wellbore while pulling the CT out of the hole. The reverse jetting action along with a controlled pump rate and POOH speed can produce a solids transport action which cleans the hole completely by keeping the solids in front (upward) of the end of the CT in continuous agitation.

The low energy nozzles have a low pressure drop which allows for higher flow rates which results in improved cleanout efficiency (Li, 2006).

V. Evaluation of the Main Fracturing Job

Evaluating the performance of hydraulic fractures by using production data and well testing strategies are the most widely used techniques to give a clear idea about the dimensions and properties of the created fractures (Economides Michael, 1993).

There are many factors that the engineer must consider when analyzing the behavior of a well after it has been fracture treated. The engineer should analyze the productivity index of the well both before and after the fracture treatment.

Other factors of importance are ultimate oil and gas recovery and calculations to determine the propped fracture length, the fracture conductivity, and the drainage area of the well.

Post-fracture treatment analyses of the fracture treatment data, the production data, and the pressure data can be very complicated and time consuming. However, without adequate post-fracture evaluation, it will be impossible to continue the fracture treatment optimization process on subsequent wells.

A. Productivity Index Increase

Many of the early treatments in the 1950s were designed to increase the productivity index of damaged wells. These treatments were normally pumped to break through damage in moderate- to high-permeability wells (Lake, 2006).

The productivity index of an oil well, $J = \frac{q_0}{(P_e - P_{wf})}$

The productivity index for a gas well, $J = \frac{q_g \bar{\mu} \bar{z}}{(Pe^2 - P_{wf}{}^2)}$

Where $\bar{z}$ and $\bar{\mu}$ are evaluated at the average pressure of, $\overline{P} = \frac{(P_e + P_{wf})}{2}$

Where:

q_o = Oil rate,

q_g = Gas rate,

μ = Viscosity,

P =Average pressure,

Pwf = Pressure of the well,

Pe = Drainage pressure.

J is the productivity index in terms of *barrels per psi per day* or *mcf-cp per psi squared per day*. Viscosity and compressibility are included in the equation describing the productivity index of a gas well, because they are pressure dependent.

McGuire and Sikora published a procedure that was the first tool a fracture-treatment design engineer could use to determine the fracture length and fracture conductivity required to achieve a certain fold of increase in the productivity index (Lake, 2006).

The McGuire and Sikora graph can be used to draw the following conclusions;

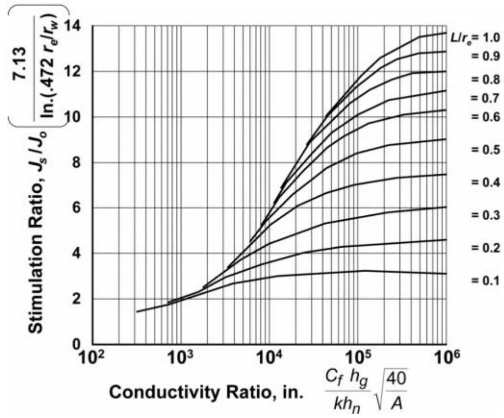


Fig I.23: *The McGuire and Sikora graph*

For high-permeability reservoirs, fracture conductivity is more important than fracture length.
For low-permeability reservoirs, fracture length is more important than fracture conductivity.
For a given fracture length, there is an optimum value of conductivity ratio.
Most Fracture treatments in undamaged formations should result in stimulation ratios of 2 to 14.

These conclusions have allowed engineers to design successful fracture treatments for more than 40 years. At approximately the same time as the classic McGuire and Sikora paper was published, Prats published another classic paper.

Assuming *J* is the productivity index for a fractured well at steady-state flow, and Jo is the productivity index of the same well under radial flow conditions, Prats found that;

$$\frac{J}{J_0} = \frac{\ln(\frac{r_e}{r_w})}{\ln(\frac{r_e}{0.5L_f})}$$

Where:

r_e = Drainage radius, meter,

r_w = Radius of the well, meter,

L_f = Half-length.

For a well containing an infinite conductivity fracture whose fracture half-length is *Lf*. Prats explained that a well with a fracture half-length of 100 ft will produce as if the well had been drilled with a 100-ft diameter drill bit (Lake, 2006).

In other words, the hydraulic fracture, if conductive enough, acts to extend the wellbore and stimulate flow rate from the well. If the dimensionless fracture conductivity, C_{fD} is equal to 10 or greater, the hydraulic fracture will essentially act as if it is an infinitely conductive fracture.

B. Ultimate Recovery for Fractured Wells

Hydraulic fracturing should always increase the productivity index of a well; and, under certain circumstances, the hydraulic fracture can increase the ultimate recovery. **Fig I.24** and **Fig I.25** illustrate the differences that sometimes occur between low-permeability and high-permeability reservoirs. In **Fig I.24**, when a high-permeability well is fracture treated, the drainage volume and the recovery efficiency in the reservoir are not significantly altered.

The fracture treatment increases the flow rate, increases the decline rate, and decreases the producing life of the well. The ultimate recovery is not changed. The same reserves are recovered in a shorter period of time, which reduces overall operating costs (Lake, 2006).

Accelerating the recovery of a fixed volume of reserves is often beneficial. If the well is located in the Arctic or offshore in deep water, where operating costs are very high, then recovering the reserves sooner is very advantageous.

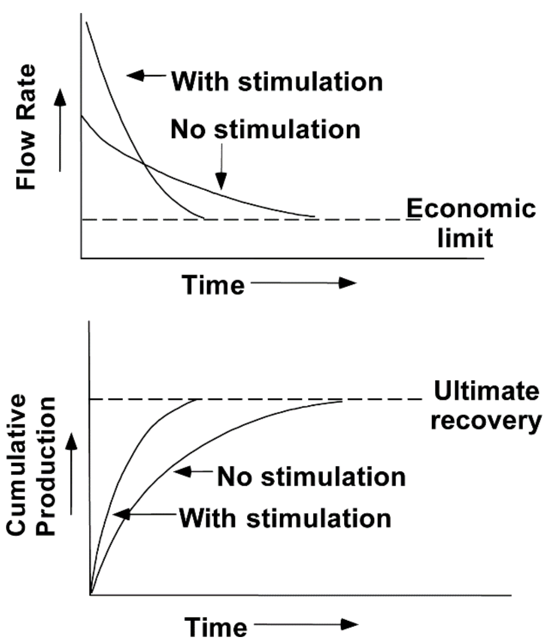


Fig I.24: *Production behavior in a high-permeability formation*

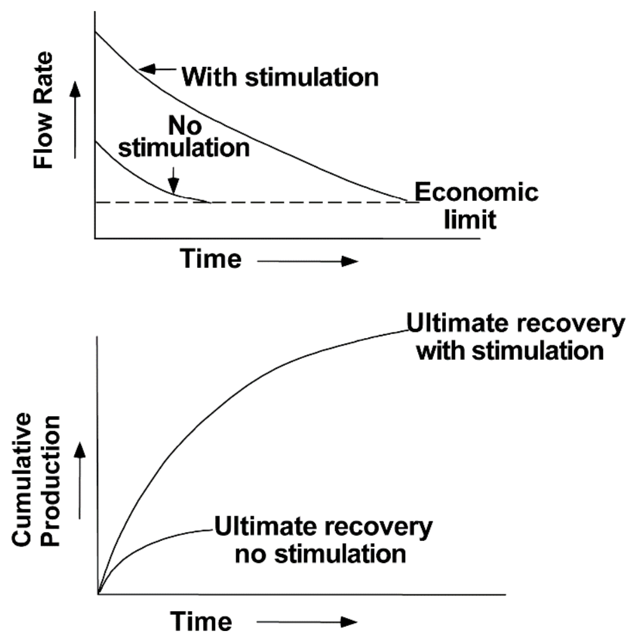


Fig I.25: *Production behavior in a low-permeability formation*

Fig I.25 illustrates the normal situation in low-permeability reservoirs. Without a fracture treatment, most low-permeability wells will flow at low rates and recover only modest volumes of oil and gas before reaching their economic limit.

By definition, a low-permeability well will not be economic unless a successful fracture treatment is both designed and pumped into the formation. When the stimulation treatment is successful, the flow rate will increase, the ultimate recovery will increase, and the producing life will be extended. In fact, many low-permeability wells will produce for 40 or more years, given adequate product prices and minimal operating costs.

It is usually very easy to justify fracture treatments in low-permeability wells when the fracture treatment substantially increases the ultimate recovery (Lake, 2006).

C. Post-Fracture Well-Test Analyses

Post-fracture well-test analyses are used to compute estimates of the propped fracture length, fracture conductivity, and drainage area of the formation. It is important to keep good records of the flow rates of oil, gas, and water, as well as the flowing pressures after the fracture treatment. If possible, a pressure-buildup test should be run after the well cleanup following the fracture treatment (Campos, 2018).

Lee, presented a complete discussion on how to analyze production and pressure data after a fracture treatment to estimate fracture properties.

1. The folds of increase (FOI)

The folds of increase can be defined as the post-fracture increase in well productivity compared with pre-fracture productivity:

$$FOI = \frac{\ln(r_e/r_w)}{\ln\left(\frac{r_e}{r_w{}'}\right) + s}$$

Where:

$\boldsymbol{r_e}$ = Drainage radius,

$\boldsymbol{r_w}$ = Wellbore radius,

$\boldsymbol{s}$ = Pre-fracture skin,

$\boldsymbol{r_w{}'}$ = Equivalent wellbore radius.

Values for *FOI* can vary from 1, no stimulation, to values > 10 for very stimulated.

2. Dimensionless Fracture Conductivity

Dimensionless fracture conductivity is defined as fracture conductivity, $k_f\, w$ (md-ft), divided by reservoir permeability (k) multiplied by the fracture half-length, x_f (ft).

$$F_{cd} = \frac{k_f\, w}{\mathrm{k}\, x_f}$$

It provides a means of optimizing the amount of conductivity in a fracture for varying permeability and fracture length (Guenaoui, 2021).

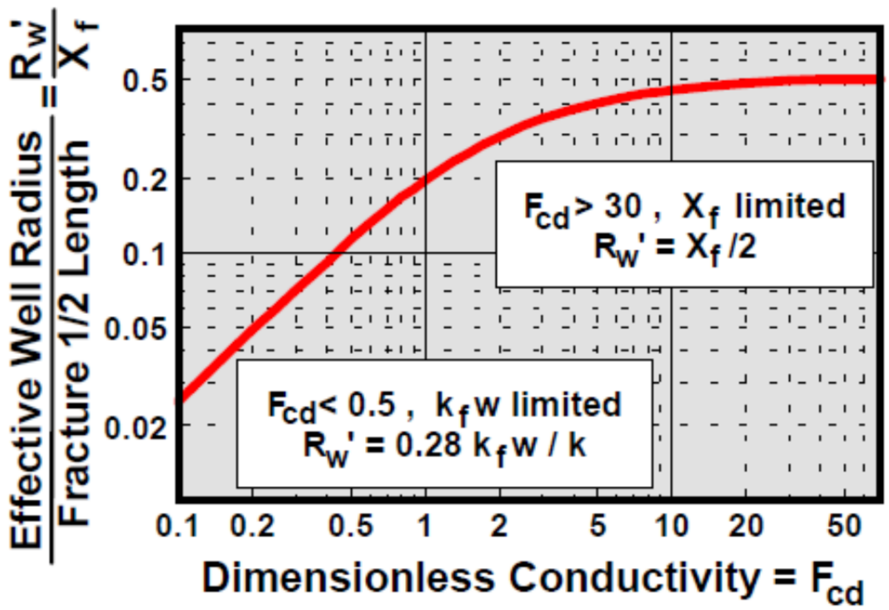


Fig I.26: *Equivalent wellbore radius as a function of dimensionless fracture conductivity and fracture length*

It can be shown mathematically that for pseudo-radial & pseudo-steady-state conditions, the optimum value for well productivity occurs at F_{cd} of about 2. For a given amount of proppant, two different types of fractures can be generated, a short fat fracture can be created with a high value of $k_f\, w$ or a longer, narrow fracture can be created with a lower value of $k_f\, w$.

Fracpacks in high permeability zones (>1 md) deal with the short fat fractures with a high $k_f\, w$, and in low permeability zones (<1 md), a long, lower conductivity fracture is desired.

Assessing production performance after hydraulic fracturing is crucial not just for primary production scenarios, but also when implementing waterflooding techniques and maintaining reservoir pressure (Guenaoui, 2021).

CHAPTER II

Fractur Pressure Analysis &

Perforation Design

I. Introduction

To optimize the fracturing process and ensure effective fracture propagation, it is crucial to calibrate and analyze the fracturing parameters accurately. One of the critical components of this analysis is the calibration test, which is conducted to determine the appropriate fluid properties, proppant concentrations, and pump rates for the specific formation conditions.

The calibration test typically involves pumping a small volume of fracturing fluid into a well under controlled conditions, while monitoring various parameters such as pressure, flow rates, and fluid properties. This test provides valuable data that can be used to calibrate and validate the hydraulic fracturing models and simulations, ensuring that the subsequent fracturing operations are designed and executed effectively (Sikonja, 2019).

In this analysis, we will explore the process of conducting a calibration test for hydraulic fracturing and the data interpretation techniques. We will also discuss the importance of accurate calibration in optimizing the fracturing process and enhancing hydrocarbon recovery.

II. Analytical Techniques for Fracture Geometry

Following the fracture initiation, additional fluid injection would result in fracture propagation. The geometry of the created fracture can be approximated by models that take into account the mechanical properties of the rock, the properties of the fracturing fluid, the conditions with which the fluid is injected (rate, pressure), and the stresses and stress distribution in the porous medium (Economides Michael, 1993). In describing fracture propagation, which is a particularly complex phenomenon, two sets of laws are required:

- Fundamental principles, such as the laws of conservation of momentum, mass, and energy,
- Criteria for propagation, i.e., what causes the tip of the fracture to advance. These include interactions of rock, fluid, and energy distribution.

A. Hydraulic Fracture Width with the PKN Model

The PKN Model has an elliptical shape at the wellbore. The maximum width is at the centerline of this ellipse, with zero width at the top and bottom. For a Newtonian fluid the maximum width, when the fracture half-length is equal to x_f, is given by;

$$w_{max} = 2.31\left[\frac{q_i \mu (1-\nu) x_f}{G}\right]^{1/4}$$

Where *G* is the elastic shear modulus and is related to Young's modulus, E, by: $G = \frac{E}{2(1+\nu)}$

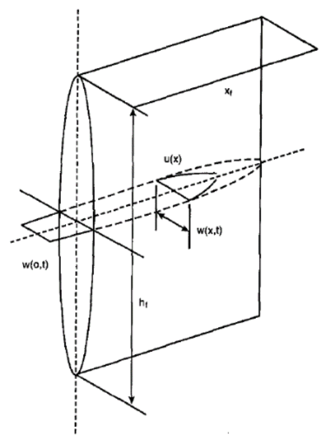


Fig II.27: *The PKN model geometry*

B. Fracture Width with the KGD Model

The KGD model, depicted in Fig. 16-8, is a 90° tum of the PKN model and is particularly applicable to approximate the geometry of fractures where *ht* >> x_f. Thus, it should not be used in cases where long fracture lengths are generated (Hoss, 2017).

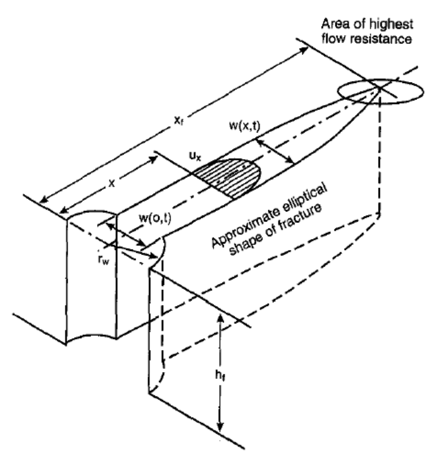


Fig II.28: *The KGD model geometry*

III. Nolte and Smith Analysis

The Nolte-Smith analysis was introduced in 1981 and it has been used to interpret net pressure when 2-D models were broadly used for fracture design and most fractures were vertically contained during fracture propagation (Kim, 2010).

Based on PKN fracture geometry (Perkins and Kern, 1972), KGD (Khristianovich and Geertsma and de- Klerk, 1969) and radial models, Nolte and Smith analyzed the fracturing pressure response, and then predicted fracture behaviors based on the pressure response. The interpretation of fracture growth is explained as slopes of net pressure as seen in **Fig II.29**.

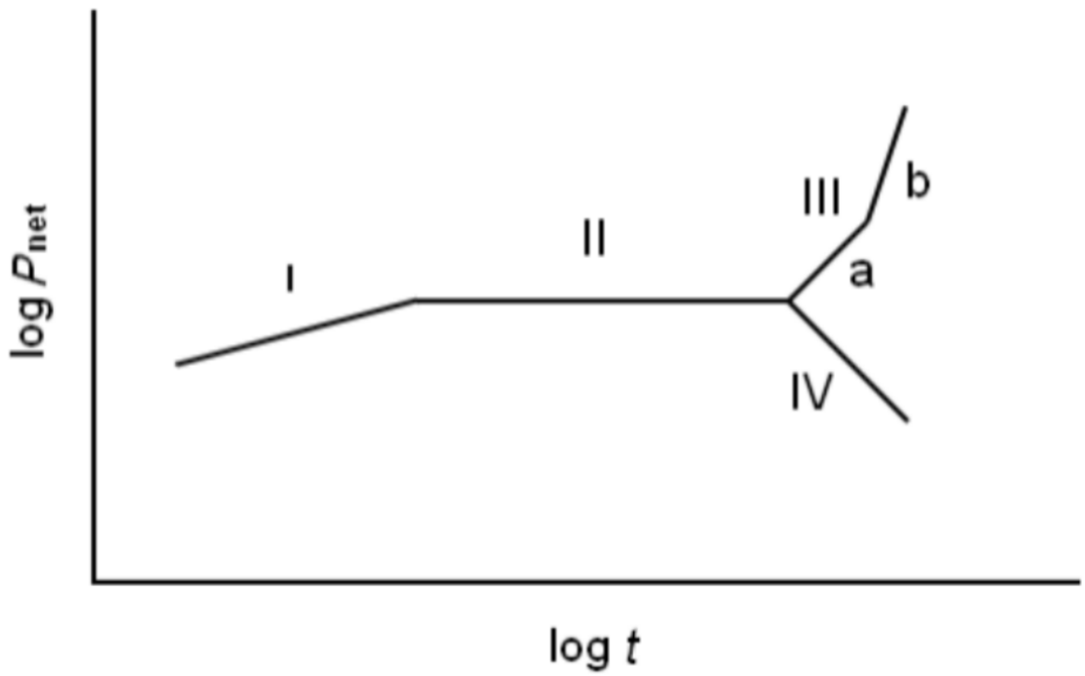


Fig II.29: *Nolte-Smith analysis pressure response plot*

In the Nolte-Smith analysis, the fracture fluid pressure will increase as the fracture propagates. Fracture growth was put into four different modes based on the slope of net pressure vs. time. Detailed descriptions of each mode are shown in **Table II.6**.

Table II.6: *Nolte-Smith analysis pressure response modes*

Mode	Behavior
I	Propagation with PKN fracture geometry. Slope is equal to *e* for constant fracture fluid rheology.
II	Constant gradient. Height growth in addition to length growth, or increase in fluid loss, or both.
III. a	Unit slope P_{net} is now directly proportional to time. This behavior is usually associated with additional width growth such as during a tip screenout.
III. b	Slope is higher than 2. Screenout, usually a near-wellbore event with a very rapid rise in pressure.
IV	Negative slope. Represents rapid height growth. Potentially KGD or radial fracture geometry.

PKN model assumes constant height growth of fractures and that the fluid pressure required to extend the fracture will increase with time. In other words, net pressure is a function of time, $P_{net} \propto t\ e$. This pressure relationship can be expressed as:

$$\log Pnet = e \log t + constant$$

This means that fractures displaying PKN fracture geometry would have a straight line with a slope of e on a plot of log P_{net} against log t. This stands for Mode I on the Nolte-Smith plot in **Fig II.29**. In power law fluid systems, the time exponent, *e*, is defined with upper and lower boundaries as:

$$\left(\frac{1}{4n' + 4}\right) < e < \left(\frac{1}{2n' + 3}\right)$$

These upper and lower boundaries are the outcome of solving a polynomial equation. This means that for practical values of n’, the lower boundary of e will be between 0.25 and 0.125, while the upper boundary will be from 0.333 to 0.2. Those values are obtained when we put n’=0 and n’=1 into the previous equation. So, any straight line on a Nolte-Smith plot with a gradient between 0.333 and 0.125 possibly indicates very good height containment. For Newtonian fluids (n’=1), the range of the exponent becomes 0.125 < *e* < 0.2.

A. Small Positive Slope (Mode I)

As a result, the initial portion of the curve in **Fig II.29**, denoted as Mode I, indicates confined height, constant compliance, and unrestricted extension of fracture length. The interpretation could be made that the fracture is propagating normally.

B. Constant Pressure (Mode II)

This portion of the curve is the most difficult to provide a definitive physical description. However, this portion is potentially the most important. According to the Nolte-Smith analysis, this mode indicates larger increase in fluid loss, height, or compliance than with respect to the desired small positive slope mode.

In general, the constant pressure region preceded an undesirable height growth or rapid increases in pressure.

C. Unit Slope (Mode III)

A unit log-log plot, denoted as Mode III. a, implies that the pressure is proportional to time or, more significantly, the incremental injected-fluid volume. It also implies that an obvious flow restriction has occurred in the fracture like proppant screenout.

The difference between Modes III. a and III. b is determined by the distance from the wellbore. If the distance is large, a screenout probably occurs near the tip and can be used to estimate the propped penetration. But if the distance is small, the screenout likely occurs near the wellbore with abnormal fluid loss.

D. Negative Slope (Mode IV)

The negative slope indicates a rapid increase in fracture height growth. The fundamental concept in this area is that a notable decline in fracture pressure likely stems from unstable fracture height growth. A considerable increase in fluid loss is possible but improbable when pressure decreases. Therefore, the most plausible cause of a significant pressure drop must be a substantial increase in fracture height.

IV. Calibration Test analyses methods

Calibration tests are an essential part of mini-frac analysis, as they ensure the accuracy and reliability of the measured data. The analysis of calibration test data is crucial for interpreting the formation's geo-mechanical properties, fracture geometry, and fluid flow behavior. Several methods are employed to analyze the pressure and time data obtained during these tests, including: Square Root Plot, Log-Log Plot, G-function Analysis, and Horner Plot.

These calibration tests analysis methods are typically used in combination with other techniques, such as numerical modeling, micro-seismic analysis, and well log interpretation, to obtain a comprehensive understanding of the fracture propagation behavior and formation characteristics (Economides Michael, 1993).

The accurate interpretation of calibration test data is crucial for optimizing fracturing designs, predicting well performance, and maximizing hydrocarbon recovery from hydraulic fracturing operations.

A. Square Root Plot

A square root plot is commonly used to determine the closure pressure. When the square root of time (x-axis) versus the bottom-hole pressure (y-axis) is plotted, the linear portion of the plot will lie along a straight line going through the origin.

The point at which deviation from the straight line occurs on the superposition plot (second derivative) is referred to as closure pressure.

Every square root plot will have three main curves: pressure curve, first derivative, and second derivative (also referred to as superposition). Deviation from the straight line on the pressure curve is used to define minimum closure pressure.

In addition, deviation from the smart line going through the origin on the second derivative curve is referred to as fracture closure.

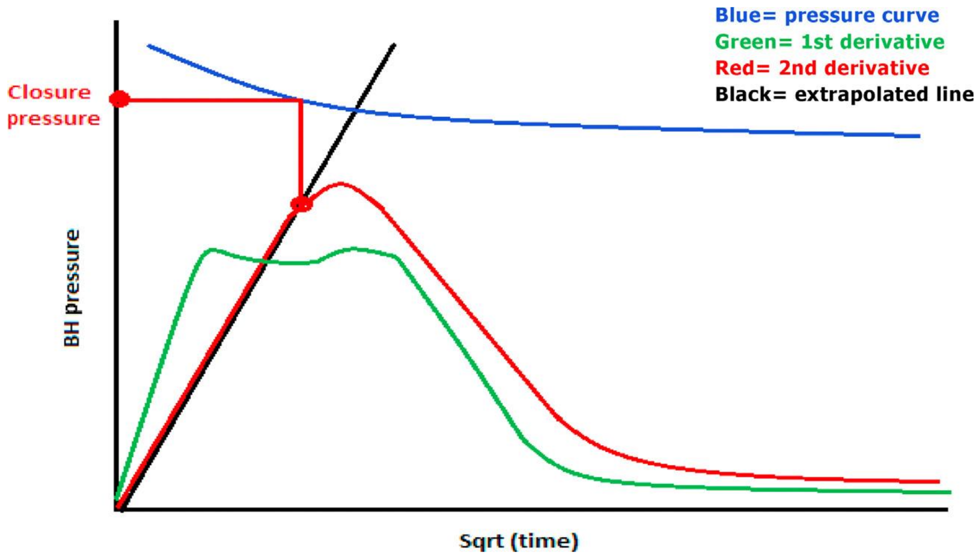


Fig II.30: *BHP versus square root of time*

In **Fig II.30**, the blue curve (dark gray curve in print version) is the pressure curve, the green curve (light gray curve in print version) is the first derivative curve, and the red curve (gray curve in print version) is the second derivative (superposition curve). To identify fracture closure, a linear extrapolated line from the origin is drawn on the second derivative curve (black line). Fracture closure can be approximated when the second derivative curve deviates from the linear line. After identifying fracture closure on the second derivative curve, draw a vertical line from the fracture closure point until the pressure curve is intersected as shown in red (gray in print version). After intersecting the pressure curve, closure pressure can be read on the y-axis.

B. Log-Log Plot (Log (BH ISIP-BHP) Versus Log (Time))

A log-log plot is derived from a square root plot. This plot should be sufficient to identify closure and various flow regimes before and after closure (Tilioua, 2020). Various flow regimes on the second derivative of the log-log plot can be determined:

Before-closure analysis:

- Half-slope line (1/2 slope) = Corresponds to linear flow regime.
- Quarter-slope line (1/4 slope) = Corresponds to bilinear flow regime.

After-closure analysis:

- Negative half-slope line (21/2) = Corresponds to linear flow.
- Negative three-fourth (23/4) = Corresponds to bilinear flow.

- Negative unit slope (21) = Corresponds to pseudo-radial flow.

The log-log plot shows a positive 1/2 slope on the second derivative curve before closure. In some rare instances, it shows a positive 1/4 slope on the second derivative before closure. Closure occurs by the change in slope from positive to negative on the second derivative curve. Pseudo-linear flow is indicated when the second derivative curve shows a negative 1/2 slope in conjunction with a negative 1.5 slope on the first derivative curve (Senina).

Pseudo-radial flow is indicated when the second derivative curve displays a negative unit slope in conjunction with a negative 2 slope on the first derivative curve.

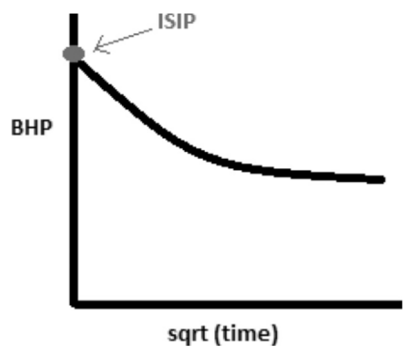


Fig II.31: *Instantaneous pressure drop "ISIP"*

$$y = m_x + b$$

$$BHP = m\left(\sqrt{time}\right) + ISIP$$

$$BHP - ISIP = m\sqrt{time}$$

$$\Delta P = m \times time^{\frac{1}{2}}$$

$$log\Delta P = \log(m \times time^{1/2})$$

$$\log(\Delta P) = \frac{1}{2}\log(time) + log(m)$$

In the log-log plot example shown in

Fig II.32, the blue curve (dark gray curve in print version) represents delta pressure, the green curve (light gray curve in print version) represents the first derivative, and the red curve (gray curve in print version) represents the second derivative. As can be seen on the second derivative, the slope of the curve changes from being positive to negative.

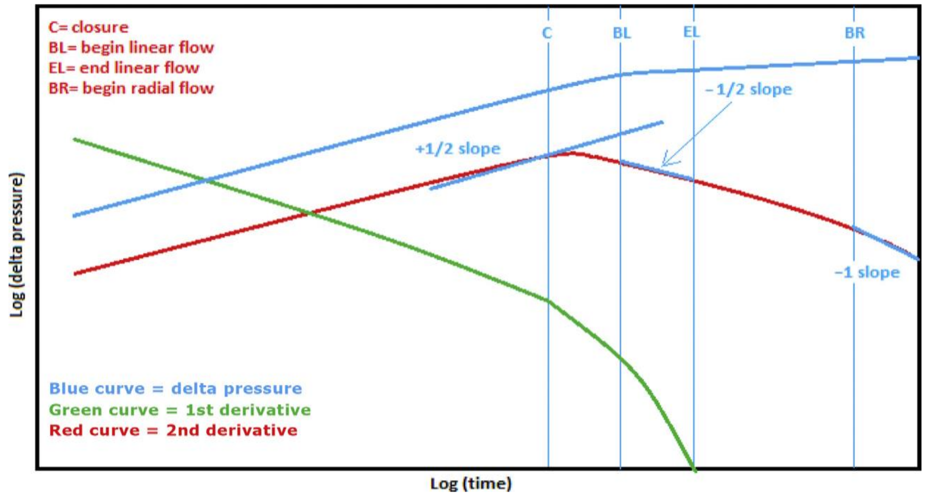


Fig II.32: *Log-log plot*

The slope of the open fracture line on the second derivative is 1/2. Any derivation from this 1/2 slope line means the fracture would have changed or in this case closed. This represents closure occurrence and that point can be picked as the fracture closure pressure. Negative 1 slope (unit slope) on the second derivative is also an indication of pseudo-radial flow. When pseudo-radial flow is reached, more confidence is obtained when calculating various reservoirs properties, especially pore pressure (Tilioua, 2020).

C. G-function Analysis

G-function is a variable related to time. G-function (x-axis) versus BHP (y-axis) can be plotted to determine various fracture and formation properties such as fracture closure, fluid efficiency, effective permeability, and leak-off mechanism. G-function assumes constant fracture height, constant pump rate, and stoppage of fracture propagation when pumping stops (Hoss, 2017). The next equation can be used to approximate G-function time:

$$G(\Delta t_D) = \frac{4}{\pi}[g(\Delta t_D) - g_0]$$

$$g(\Delta t_D) = \frac{4}{3}(1 + \Delta t_D)^{1.5} - {\Delta t_D}^{1.5}; \qquad \beta = 1.0$$

$$g(\Delta t_D) = (1 + \Delta t_D)\sin^{-1}(1 + \Delta t_D)^{-0.5} + {\Delta t_D}^{0.5}; \qquad \beta = 0.5$$

$$\Delta t_D = \frac{t - t_p}{t_p}$$

Where:

t = Shut-in time, minutes;

$\mathbf{t_p}$ = Total pump time, minutes.

A β value of 1.0 refers to tight formations with low fluid leak-off, while a β value of 0.5 refers to high-permeability formations with high leak-off. It is important to note that the G-function at shut-in (ISIP) is zero. For example, if total pump time is 5 minutes (tp55 min), t at ISIP will be equal to 5 as well. Therefore, G-function at ISIP is equal to zero. G-function time starts at ISIP. The following steps can be used to find closure pressure on the G-function time:

1. Look for local maximum on the first derivative,
2. Look for deviation from the straight line on the pressure curve,
3. Look for deviation from the straight line going through the origin on the second derivative curve,
4. Closure occurs where the second derivative curve deviates from the straight line.

Fracture closure occurs when the second derivative deviates from the straight line going through the origin. Once that point is identified on the G-function plot, draw a vertical line until the pressure curve is intersected. After the intersection of the pressure curve with the vertical line (as shown in red (gray in print version)) is identified, closure pressure can be read on the y-axis. Closure pressure is regarded as the minimum horizontal stress (GUENAOUI, 2022).

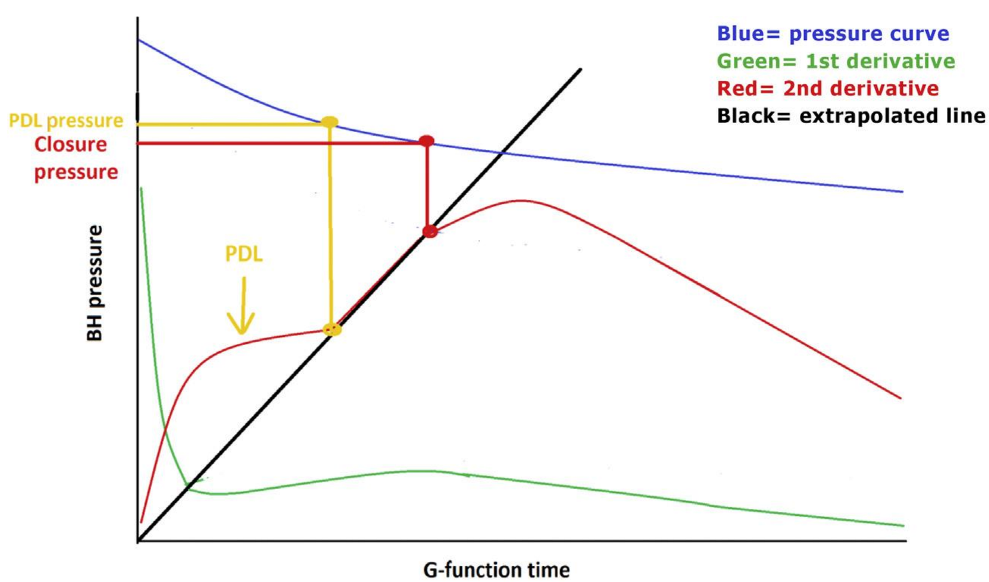


Fig II.33: *Pressure-dependent Leak-off*

D. Horner Plot

Horner analysis uses the log of Horner time on the x-axis versus bottomhole pressure on the y-axis to calculate pore pressure and reservoir permeability. Note that the y-axis is plotted on the Cartesian axis and logarithmic scale is applied to the x-axis (GUENAOUI, 2022).

Horner time is defined;

$$\text{Horner time} = \frac{t_p + \Delta t}{\Delta t}$$

Where:

t_p = Fracture propagation time, minutes,

Δt = Elapsed shut-in time, minutes.

As shut-in time increases, Horner time decreases. As shut-in time approaches infinity, Horner time approaches 1. A straight-line extrapolation to the y-intercept (at Horner time of approximately 1) yields reservoir pressure (pore pressure). One of the biggest limitations with a Horner plot is that pseudo-radial flow must be reached or Horner analysis is not recommended to be used. Once pseudo-radial flow is identified, the slope of the straight extrapolated line is referred to as mH. The point at which the extrapolated line reaches the y-intercept (as shown below) is pore pressure. The slope of the Horner plot (mH) can be used to estimate reservoir transmissibility (kh/μ) and subsequently reservoir permeability using this equation;

$$\frac{kh}{\mu} = \frac{162.6(1440)q}{m_H}$$

Where:

kh/μ = Reservoir transmissibility, md.ft/cp,

k = Reservoir permeability, md,

h = Net pay height, ft,

μ = Far-field fluid viscosity (not injected fluid viscosity), cp,

mH = Slope of the Horner plot, psi,

q = Average injected fluid rate, bpm.

By assuming a far-field fluid viscosity and net pay height, reservoir effective permeability can be calculated by **Fig II.34**.

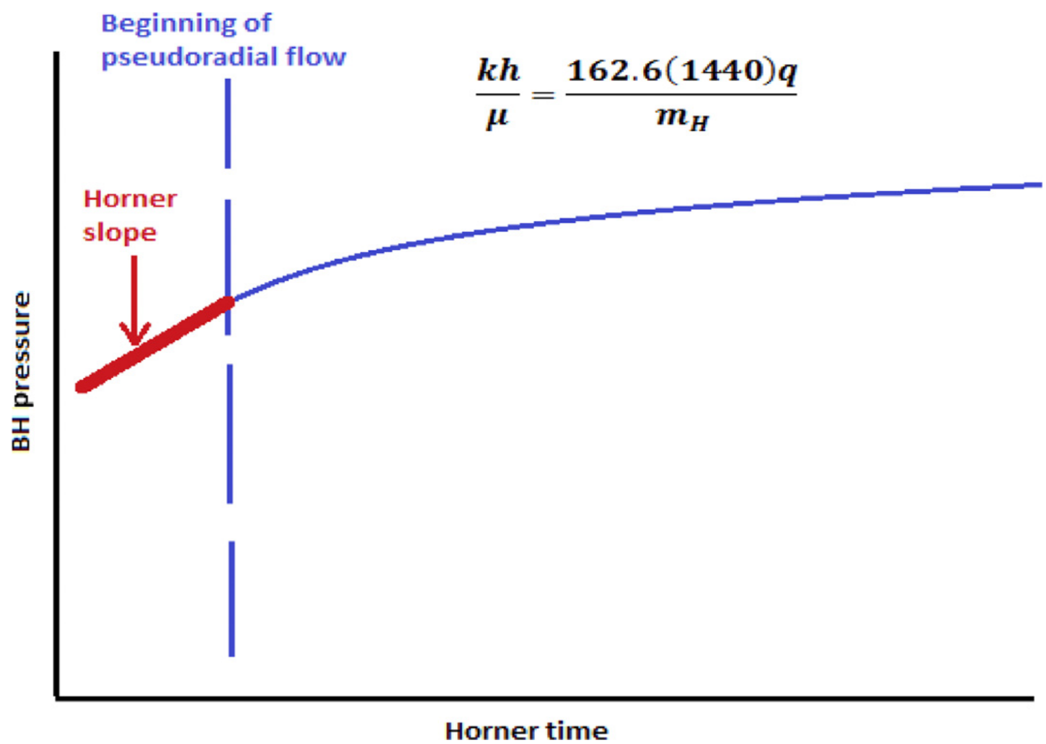


Fig II.34: *Horner analysis*

E. After closure analysis

1. Linear Flow-Time Function Versus Bottom-Hole Pressure

Reservoir pressure can be determined from the linear flow-time function (x-axis) versus BHP (y-axis). Linear flowtime function is described by this equation;

$$F_L(t, t_c) = \frac{2}{\pi} \sin^{-1} \sqrt{\frac{t_c}{t}} \qquad for\ t \geq t_c$$

Where:

t_c = Time to closure, minutes,

t = Total pump time, minutes.

A straight-line extrapolation from the linear flow yields an estimated pore pressure from the linear flow-time function plot. In other words, once after-closure pseudo-linear flow is observed during shut-in, the intercept of the extrapolated straight line through the pseudo-linear flow data provides an estimate of the pore pressure (GUENAOUI, 2022).

Reservoir pore pressure extrapolation is valid and no direct information of transmissibility can be obtained from this analysis. If pseudo-radial flow is not obtained from DFIT analysis, this plot can be used to estimate the reservoir pressure;

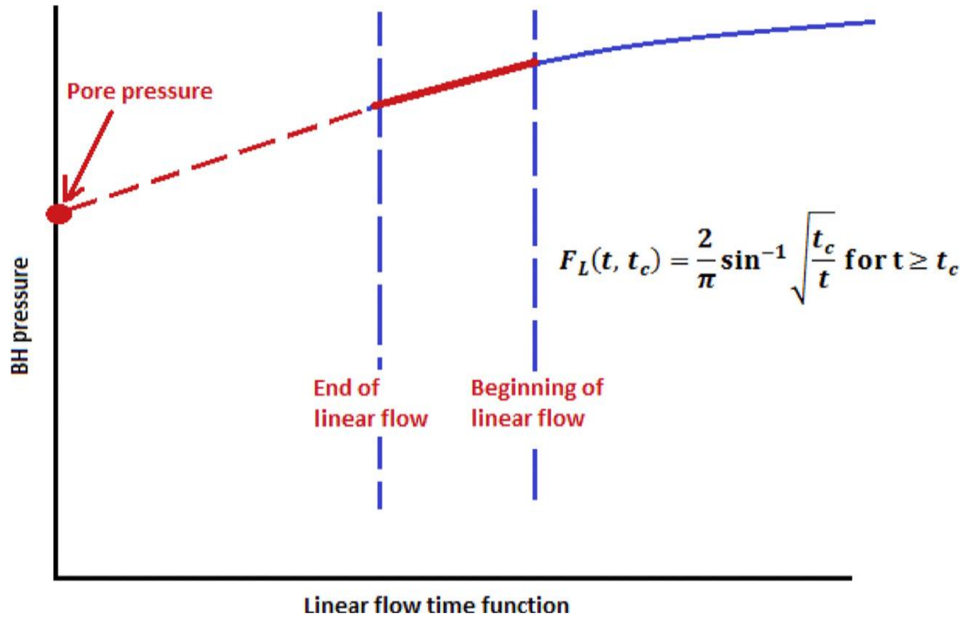


Fig II.35: *Linear flow-time function plot*

1. Radial Flow-Time Function Versus BHP

Radial flow-time function can also be used to calculate reservoir pressure along with transmissibility when true pseudo-radial flow is identified. Radial flow-time function is defined;

$$F_R(t, t_c) = \frac{1}{4} \ln\left(1 + \frac{X t_c}{t - t_c}\right), \qquad X = \frac{16}{\pi^2} \cong 1.6$$

Where:

t_c = Time to closure, minutes,

t = Total pump time, minutes.

In addition to reservoir pressure, when the pseudo-radial flow period is properly identified, far-field transmissibility can also be calculated by knowing the slope of the extrapolated line, time to fracture closure, and total volume injected during the test. Transmissibility using a radial flow-time function plot (**Fig II.36**) can be obtained using this equation;

$$\frac{kh}{\mu} = 251{,}000 \frac{V_i}{m_R t_c}$$

Where:

V_i = Injected fluid during the test, BBLs,

m_r = Derived slope, 1/psi,

t_c = Time to closure, minutes,

h = Net pay, ft,

μ = Far-field fluid viscosity, cp.

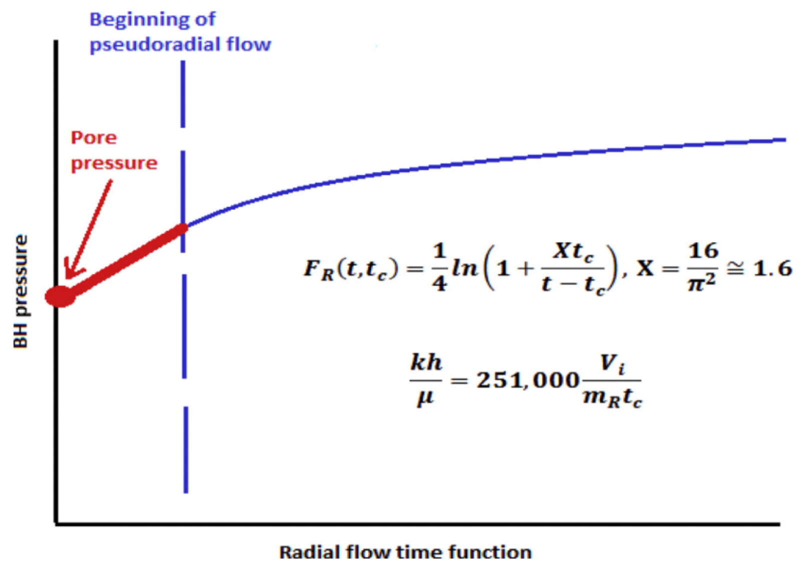


Fig II.36: *Radial flow-time function plot*

V. Design Parameters for Hydraulic Fracturing

F. Net Fracturing Pressure

The creation of a two-dimensional crack, with one dimension of largely infinite extent and the other of finite extent, *d*, has been described by Sneddon and Elliot (1946). The maximum width of the crack, which is proportional to this characteristic dimension, is also proportional to the net pressure (p_f - σ_{min}) and inversely proportional to the plane strain modulus, E'.

The maximum width is given by; $w_{\max} = \frac{2(p_f - \sigma_{\min})d}{E'}$

Where: $E' = \frac{E}{1-\nu^2}$

The average width, $\overline{w}$, is; $\overline{w} = \frac{\pi}{4} \gamma w_{max}$

For the PKN model the characteristic dimension d is the fracture height, h_f, while for the KGD model it is equal to the fracture length, tip to tip, $2x_f$. The value of γ is 0.75 for the PKN model and 1 for the KGD model (Hoss, 2017).

For a fracturing operation with efficiency $\eta (= V_f / V_i) \longrightarrow 1$

The volume of the fracture, V_f, must be equal to the volume of fluid injected, Vi, and therefore; $\bar{w} A_f = q_i t$

Where A_f is the fracture area and equal to $2x_f \, h_f$.

For $\eta \rightarrow 0$ $A_f = \frac{q_i \sqrt{t}}{\pi C_L r_p}$

Where C_L is the leakoff coefficient and r_p is the ratio of the permeable height to the fracture height. In a single-layer formation the permeable height is the net reservoir thickness, h.

For $\eta \rightarrow 1$ $x_f \bar{w} = \frac{q_i t}{2h_f}$

G. Fluid Volume Requirements

A hydraulic fracturing operation involves distinct fluid stages serving specific purposes. The pad fluid initiates and propagates the fracture without carrying proppant, allowing controlled fluid leak-off to create a filter cake on the fracture walls. Proppant-laden slurry is then injected with increasing concentrations until reaching a predetermined level based on the fluid's proppant transport ability and the reservoir's capacity (Rafik, 2015).

Excessive fluid leak-off due to reservoir heterogeneities or fracture height migration can cause slurry dehydration and screen-outs, preventing further fracture growth. The propped fracture length is limited by the point where the fracture width becomes too narrow (less than three proppant diameters) for proppant transport.

The total fluid volume requirement relates to the pad volume based on the fluid efficiency.

$$V_{\text{pad}} \approx V_i \left(\frac{1 - \eta}{1 + \eta} \right)$$

Flush is intended to displace the slurry from the well into the fracture. It should be less than well volume, because over displacement would push the proppant away from the well and a “choked” fracture would result after the fracturing pressure dissipates and the fracture closes.

This should be a major concern of the stimulation treatment and should be avoided at all cost. A material balance between total fluid injected, created fracture volume V_f, and fluid leakoff V_L can be written: $V_i = V_f + V_L$

And it can be expanded further by introducing constituent variables:

$$q_i t_i = A_f \bar{w} + K_L C_L (2A_f) r_p \sqrt{t_i}$$

Where q_i is the injection rate, t_i is the injection time, A_f is the fracture area, C_L is the leakoff coefficient, and r_p is the ratio of the net to fracture height (h/h_f). The variable K_L is related to the fluid efficiency, and also Nolte has shown that:

$$K_L = \frac{1}{2}\left[\frac{8}{3}\eta + \pi(1-\eta)\right]$$

The fracture area in the leak-off term is multiplied by 2 to account for both fracture faces. The fracture length can be calculated assuming a fracture model and known fracture height, leak-off coefficient, and fluid efficiency.

This involves solving a quadratic equation for the positive square root of time, which gives the total injection time. Multiplying this time by the injection rate yields the total required fluid volume. Since the pad volume fraction is known, the onset time for proppant slurry addition can be determined from the calculated total volume and injection rate.

$$t_{\text{pad}} = \frac{V_{\text{pad}}}{q_i}$$

H. Proppant Schedule

Proppant addition, its starting point, and at what concentrations it is added versus time depend on the fluid efficiency. In the previous section the onset of proppant addition was determined after the pad volume was estimated. Nolte (1986) has shown that, based on a material balance, the continuous proppant addition, “ramped proppant schedule” versus time, should follow a relationship expressed by:

$$c_p(t) = c_f \left(\frac{t - t_{\text{pad}}}{t_i - t_{\text{pad}}} \right)^{\epsilon}$$

Where $c_p(t)$ is the slurry concentration in pounds per gallon (ppg), c_f is the end-of-job (EOJ) slurry concentration, and t_{pad} and t_i are the pad and total times, respectively (Li, 2006).

The variable ϵ depends on the efficiency and is given by; $\epsilon = \frac{1-\eta}{1+\eta}$

These equations simply denote the appropriate proppant addition mode so that the entire hydraulic length coincides with the propped length. This is not entirely realistic, since the fracture length, beyond the point where the hydraulic width is smaller than three proppant diameters, cannot accept proppant; it will bridge (Note: Bridging can also occur at widths larger than three proppant diameters, which is the absolute minimum.)

Hence, in designing a hydraulic fracture treatment, this type of criterion may be used as a check for the total mass of proppant that can be placed. Another consideration for the end-of-job slurry concentration, c_f, is the proppant-transporting ability of the fracturing fluid. Certainly, in all cases the calculated average propped width cannot exceed the average hydraulic width.

I. Propped Fracture Width

In addition to the length, the propped width of the fracture describes the fracture geometry that controls posttreatment production. The fracture conductivity is simply the product of the propped width and the proppant pack permeability. The width in that expression is the propped width of the fracture. As should be obvious from the last two sections, the relationship between hydraulic width and propped width is indirect; it depends greatly on the fluid efficiency and especially on the possible end-of-job proppant concentration (Verisokin, 2021).

Assuming that a mass of proppant, M_p has been injected into a fracture of half-length x_f and height h_f and the proppant is uniformly distributed, then;

$$M_p = 2x_f h_f w_p (1 - \phi_p) \rho_p$$

Where the product $2x_f h_f w_p (1 - \phi_p)$ represents the volume of the proppant pack and is characteristic of the proppant type and size.

The density ρ_p is also a characteristic property of the proppant.

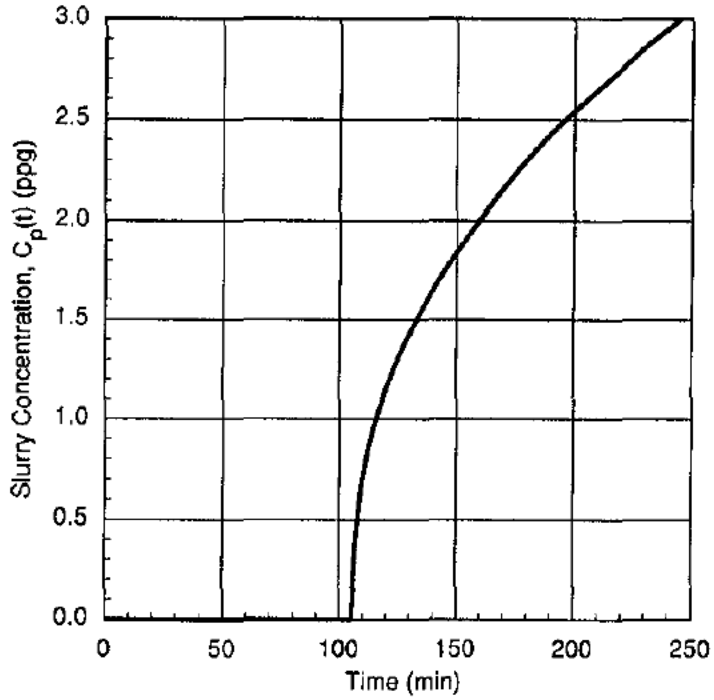


Fig II.37: *Onset of proppant slurry and continuous proppant addition*

A frequently used quantity is the proppant concentration in the fracture, C_p, defined as;

$$C_p = \frac{M_p}{2x_f h_f}$$

And the units are lb/ft^2. Traditionally, a good proppant pack concentration in a fracture would be 2 lb/ft^2.Therefore, the last equation, rearranged for the propped width, w_p, leads to;

$$w_p = \frac{C_p}{(1-\phi_p)\rho_p}$$

To calculate the mass of proppant it is necessary first to integrate the ramped proppant schedule expression from t_{pad} to t_i and to obtain an average slurry concentration;

$$c_p(t) = c_f\left(\frac{t-t_{\text{pad}}}{t_i-t_{\text{pad}}}\right)^{\epsilon} \qquad \bar{c}_p = \frac{1}{t_i-t_{\text{pad}}}\int_{t_{\text{pad}}}^{t_i} c_f\left(\frac{t-t_{\text{pad}}}{t_i-t_{\text{pad}}}\right)^{\epsilon} dt$$

Leading to; $\bar{c}_p = \frac{c_f}{\epsilon+1}(1-0) = \frac{c_f}{\epsilon+1}$

The mass of proppant would then be; $M_p = \bar{c}_p\left(V_i - V_{\text{pad}}\right)$

VI. Parameters excluded from Calibration Test analysis

A. Different pressures encountered

In hydraulic fracturing, it is common to refer to a large number of different pressures encountered during operations and their analysis (Economides Michael, 1993).

Each of these pressures has its own name (or usually more, several common names) referring to where that pressure is being measured or what it is doing:

1. Hydrostatic pressure, Ph

Hydrostatic pressure is the pressure of the fluid column exerted in static condition. Hydrostatic pressure is one of the most important concepts that must be learned by heart. Hydrostatic pressure depends on the weight of fluid (ppg) and true vertical depth (TVD) of the well. In addition, 0.052 is a constant for conversion to psi.

One of the most common mistakes that beginners make is using measured depth (MD) instead of TVD to calculate hydrostatic pressure in the wellbore. Measured depth can be used for volume calculation; however, TVD has to be used for hydrostatic pressure calculation. The hydrostatic pressure can be calculated using;

$$P_{\mathrm{h}} = 0.052 \times \rho \times \mathrm{TVD}$$

2. Initiation pressure, Pbd

This is the pressure at which the fracture is initiated.

3. Instantaneous pressure drop, ISIP

ISIP stands for instantaneous shut-in pressure, and is the pressure at which all of the pumps come offline following a hydraulic fracturing stage treatment or diagnostic fracture injection test (DFIT). ISIP can be obtained using a surface-treating pressure graph after each hydraulic fracture stage treatment.

ISIP is extremely important to calculate for new exploration areas where hydraulic fracturing will take place in order to ultimately calculate the estimated surface-treating pressure.

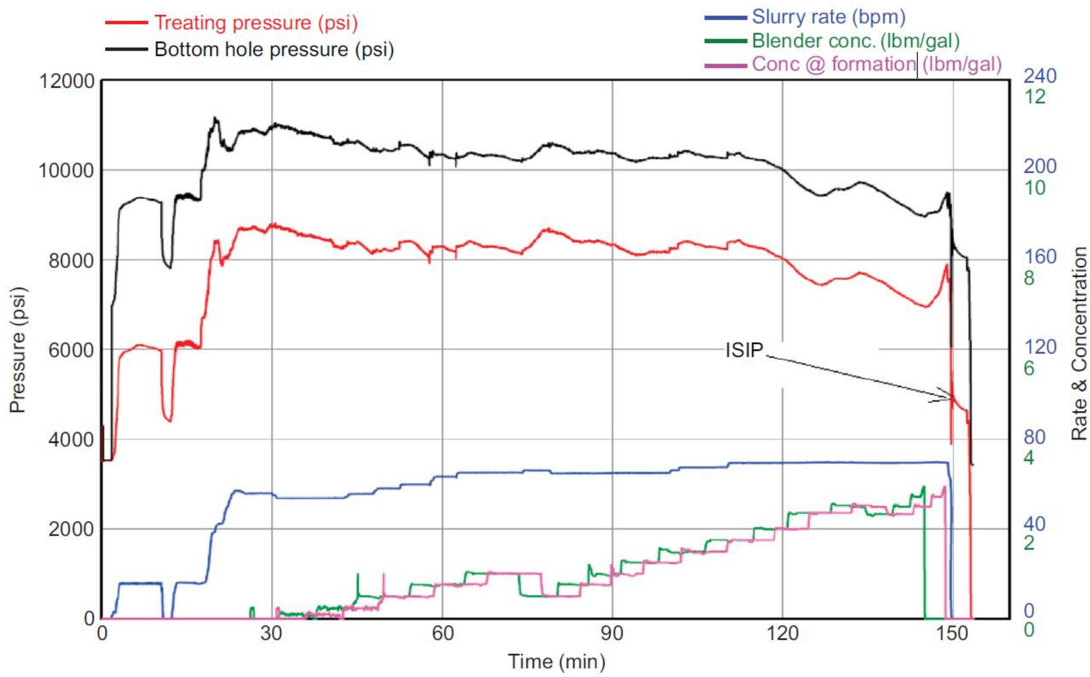


Fig II.38: *ISIP illustration*

Treating pressure, calculated bottom hole pressure, slurry rate, blender, and formation sand concentrations. ISIP in **Fig II.38** is the pressure as soon as all of the pumps are offline (i.e., the slurry rate goes to 0). In this figure, ISIP is approximately 4900 psi.

ISIP can also be calculated using:

$$\mathrm{ISIP} = \mathrm{BHTP} - P_{\mathrm{h}}$$

4. Bottom-hole treating pressure, BHTP

Bottom-hole treating pressure (BHTP) is the amount of pressure required at the perforations to cause fracture extension during hydraulic fracture stimulation. BHTP is the pressure along the fracture face that keeps the fractures open (Economides Michael, 1993).

BHTP is also referred to as bottom-hole frac pressure (BHFP). Correct estimation of BHTP is essential when preparing the estimates of surface-treating pressure and ultimately a frac job. BHTP can be calculated using;

$$\mathrm{BHTP} = \mathrm{FG} \times \mathrm{TVD} \quad \text{or} \quad \mathrm{BHTP} = \mathrm{ISIP} + P_{\mathrm{h}}$$

5. Total friction pressure, FPt

There are various types of friction pressures that must be considered and calculated before and after treatment to derive perforation efficiency and optimum design.

Friction pressures during a frac job are pipe friction pressure, perforation friction pressure, and tortuosity pressure. Total friction pressure after each frac stage can be calculated using;

$$FP_T = \text{Avg surface treating pressure} - \text{ISIP}$$

6. Pipe friction pressure, Ppipe friction

Pipe friction pressure can be calculated excluding FR impacts. However, it is much more important to obtain the pipe friction pressure after FR is added to the fracturing fluid pumped in the well. This calculation depends on the type of FR provided by the service company.

There are various tools that can be used to approximate pipe friction pressure depending on the type of FR used.

Service companies typically perform lab tests to understand the impact of their particular FR product on pressure, and to quantify the pressure reduction caused by the FR.

The pressure reduction of each friction reducer varies depending on the type and manufacturer of the product.

7. Perforation friction pressure, ΔPpf

In addition to pipe friction pressure, which is one of the main considerations in hydraulic fracturing treatment design, perforation friction pressure is another important parameter in hydraulic fracturing design that needs to be calculated and considered.

Perforation friction pressure can be calculated if optimum perforation friction pressure for a particular area is known:

$$\Delta P_{pf} = 0{,}2369 \frac{q^2 \rho_S}{N_{perf}^2 D_p^2 C_d^2}$$

Where:

ρ_s = suspension density (ppg),

q = total flow rate (bpm),

N_{perf} = number of perforations (so q/Nperf is the flow rate per perforation),

D_p = perforation diameter (in),

C_d = discharge coefficient.

8. Tortuosity pressure, ΔPtort

Also known simply as tortuosity, this is the loss of pressure by the fracturing fluid as it passes through a restricted flow region between the perforations and the fracture(s) itself.

9. Friction around the well, NWBF or ΔP_{NWB}

This is the total head loss due to the effects of the well surroundings, and is equal to the sum of perforation friction pressure and tortuosity.

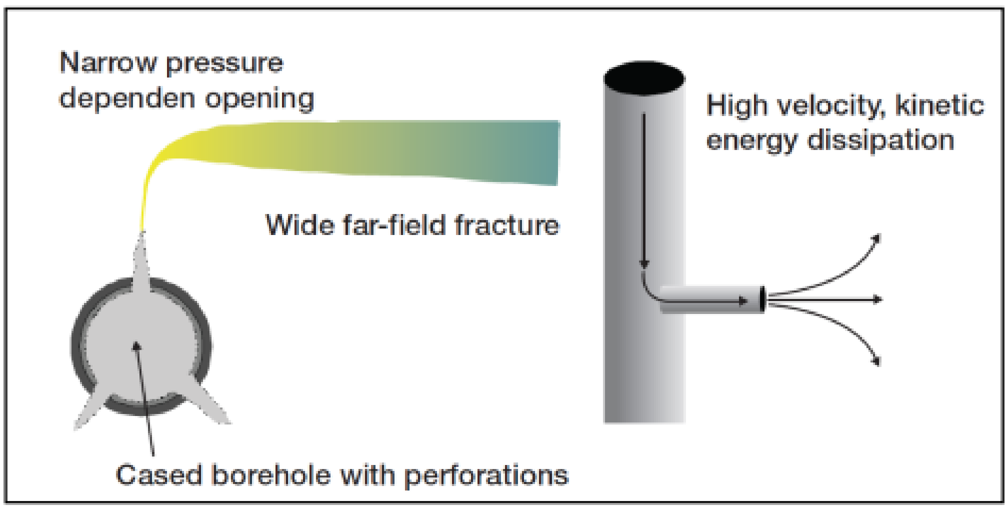


Fig II.39: *The different parts of energy dissipation (ΔP_{pf}, ΔP_{tort}, ΔP_{NWB})*

10. Fracture extension pressure, Pext

Fracture extension pressure is referred to as the pressure inside the fracture(s) that makes the fractures grow as pumping continues. In other words, fracture extension pressure is the pressure required to extend the existing fractures.

In order to keep the fractures open while gaining length, height, and width, the fracture extension pressure must be greater than the closure pressure of the formation.

Fracture extension pressure can be thought of as bottom hole treating pressure (BHTP). These terms are used interchangeably.

$$\text{Fracture extension pressure} = \text{Frac gradient} \times \text{TVD}$$

11. Fracturing fluid pressure, Pf

Although used in a variety of situations, strictly speaking, this pressure is the pressure of the fracturing fluid inside the fracture body itself, after it has passed through the perforations and any tortuosities.

The pressure of the fracturing fluid may not be constant within the fracture entirely due to friction (Hoss, 2017).

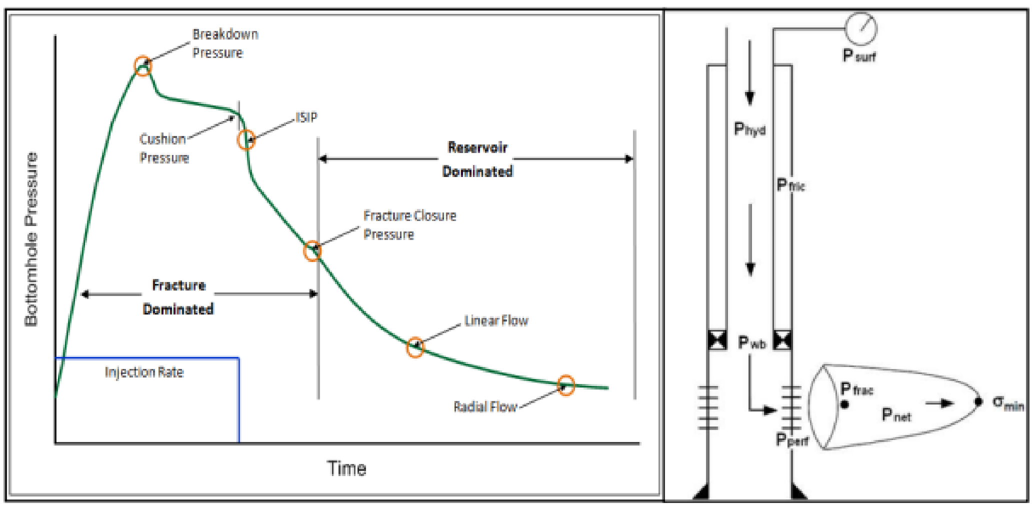


Fig II.40: *Examples of different pressures related to hydraulic fracturing*

a. *On the graph BHP = f(t).* ***b.*** *In the well.*

12. Closing pressure, Pc

Closure pressure is the minimum pressure required to keep the fractures open. In other words, closure pressure is the pressure at which the fracture closes without proppant in place. For example, during a hydraulic fracturing treatment, closure stress in the pay zone must exceed the BHTP in order to grow an existing fracture. This means that BHTP has to be greater than the pay zone’s closure stress (Economides Michael, 1993).

13. Net pressure, Pnet

Net pressure is one of the most important pressures to consider in hydraulic fracturing. Net pressure is the energy required for propagating fractures and creating width during the frac job and refers to the excess pressure over the frac pressure required to extend the fractures.

Net pressure is essentially the difference between the fracturing fluid pressure and the closure pressure and is the driving mechanism behind fracture growth. The more pressure inside a fracture, the more potential there is for growth.

The term net pressure is only used when the fracture is open. If the fracture is closed, net pressure is equal to 0. Net pressure depends on various parameters such as young's modulus, fracture height, fluid viscosity, fluid rate, total fracture length, and tip pressure;

$$P_{net} = P_f - P_c \quad \text{and} \quad P_{net} = P_{iw} - \Delta P_{pf} - P_{tort} - P_c$$

Virtually all analyses involving fracture geometry use net pressure as the common variable linking all parts of the mathematical model.

Pnet values are interpreted as follows:

- Pnet ≤ 0: The fracture is closed, no propagation possible,
- 0 < Pnet ≤ Pext: Fracture is open with Wf proportional to Pnet. No propagation possible,
- Pnet > Pext: Fracture is open with Wf proportional to Pnet and pressure generates sufficient to propagate the fracture.

14. Surface treating pressure, STP

Surface-treating pressure (STP), also known as wellhead treating pressure (WHTP) is the pressure at the surface during a hydraulic fracturing treatment. STP during a hydraulic fracturing treatment is the real-time pressure obtained from the surface pressure transducer on the main line. A transducer uses pulsation to get the real-time pressure during a hydraulic fracture treatment. Surface-treating pressure can be estimated using;

$$\mathrm{STP} = \mathrm{BHTP} + \mathrm{P_f} - \mathrm{P_h} + \mathrm{P_{net}}$$

Where:

BHTP = Bottom-hole treating pressure, psi,

Pf = Total friction pressure, psi,

Ph = Hydrostatic pressure, psi,

Pnet = Net pressure, psi.

B. Fluid Leak-off

Leak-off is the loss of energy by the fracturing fluid: the total energy available for fracture propagation is equal to the net pressure multiplied by the fracture volume. A high leak-off indicates a low fracture volume and vice versa (Sikonja, 2019).

Consequently, increasing leak-off fluid tends to decrease thickness, height and length, whereas if the leak-off is low, the fracture dimensions will be large.

1. Leak-off coefficient (CL)

This coefficient can be approximated by calculating three components of the fluid leak-off and then combining these to form the overall leak-off coefficient, as described by Howard and Fast (1970). These three components are:

- The coefficient of controlled viscosity (Cv),
- The coefficient of controlled compressibility (Cc),
- The coefficient of controlled wall construction (Cw).

C. Efficiency (η)

Fluid efficiency is a concept used in many fracturing applications and is relatively simple. At any given time, fluid efficiency is given by:

$$\eta = \frac{V_f}{V_i} = \frac{V_i - V_L}{V_i} = 1 - \frac{V_L}{V_i}$$

Where:

$\mathbf{V_i}$ = total volume of fluid injected into the fracture,

$\mathbf{V_f}$ = fracture volume,

$\mathbf{V_L}$ = leak-off volume.

Thus, the higher the fluid efficiency, the greater the fracture volume and the smaller the leak-off. Efficiency depends on fracture size and treatment flow rate, and generally refers to the value at the end of fluid injection or pumping, ηp. However, efficiency can be defined at any time the fracture is open (i.e., Pnet > 0) (Economides Michael, 1993).

Efficiency is highly variable and depends not only on fluid and formation characteristics, but also on fracture zone, differential pressure, pumping time and several other variables. This means that for two pumping treatments in identical formations, significantly different fluid efficiencies can be observed by changing only the pumping rate or the volume injected.

VII. Softwares related to Hydraulic Fracturing

Different numerical simulators are used nowadays to evaluate and predict the location, direction and extend of the hydraulic fractures. Simulations range from two to fully three dimensional depending on the degree of complexity of the wellbore and fracture geometries, the required accuracy of predictions (Mukhamedzianova, 2017).

The three main fracture simulation models used in the oilfield today are FracPro, FracproPT and MFrac. They are used in 90% of all treatments currently performed. Other simulators, such as StimPlan, GOHFER and the proprietary simulators produced by Schlumberger, Halliburton, Shell and others, are available, *but their use is limited mainly to engineers who work for the actual company that produced the simulator*.

GOHFER® Fracture Modeling Software

Building upon the foundation laid by industry-leading software like GOHFER from Halliburton, which stands for Grid Oriented Hydraulic Fracture Extension Replicator.

Fig II.41: *GOHFER Logo from Halliburton*

Due to intellectual property rights and copyright restrictions, we are unable to share any specific images, screenshots, or detailed technical information about Halliburton's proprietary GOHFER software. However, we can provide a general overview of GOHFER's capabilities and its significance in the hydraulic fracturing based on publicly available information and our understanding of the software's role in fracture design, analysis, and optimization workflows.

GOHFER employs advanced numerical models and simulations to predict fracture propagation, proppant transport, and fluid flow behavior within reservoirs during hydraulic fracturing operations. These simulations help optimize fracture designs by determining ideal parameters such as injection rates, fluid volumes, and proppant concentrations (Halliburton).

The software integrates geological data, wellbore trajectories, and fracture simulations to assist in well planning and design. It helps identify suitable well locations, optimize stage and cluster spacing, and ensure efficient fracture placement within the target formation.

GOHFER includes tools for analyzing data from calibration tests. These tests provide valuable information about formation properties, such as rock stresses, fluid leakoff characteristics, and fracture initiation pressures, which are crucial for accurate fracture modeling.

During fracturing operations, GOHFER can interface with real-time monitoring systems to track and analyze data from various sensors, enabling operators to make informed decisions and adjustments based on actual conditions.

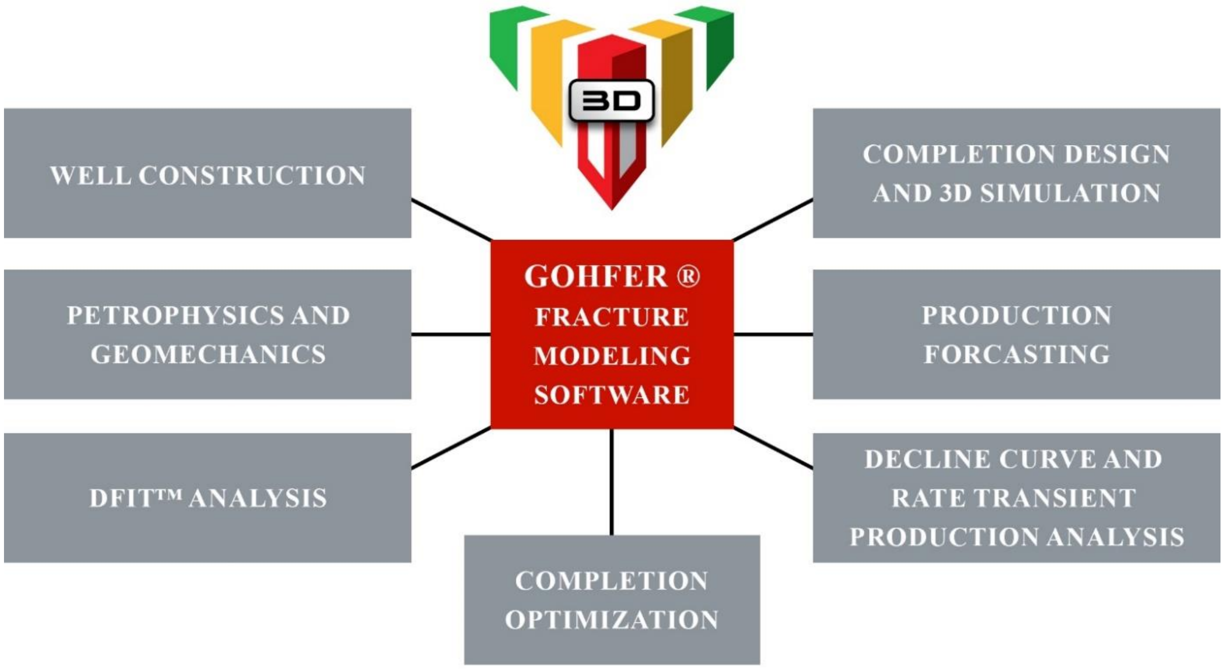


Fig II.42: *GOHFER Fracture Modeling Software Capabilities (Halliburton)*

With the help of this simulator, we developed a new specialized platform for analyzing calibration test data in hydraulic fracturing. This platform is a result of our collaboration with experienced hydraulic fracturing engineers and a programmer; aims to enhance the calibration test data analysis process, ultimately contributing to more accurate fracture designs and optimized well performance; *improved Executable Main Frac Schedule*.

CHAPTER III

FRACTO PLATFORM DEVELOPMENT

I. Introduction

In the Hydraulic Fracturing Process, we conduct multiple tests to develop an improved Hydraulic Fracturing Model (*Executable Main Frac Schedule*). However, we encountered an issue with the analysis of these tests due to the lack of specialized Platform (Software & Website) for the National Company SONATRACH. This last is obligated to cover the expenses incurred by expert Services Companies in the field, for this analysis.

So, how we thought to assist SONATRACH in circumventing this issue and enhancing the hydraulic fracturing operation process?

We focused on creating a new platform; **FRACTO**, for the *Hydraulic Fracturing Calibration Test Analysis;* a comprehensive website and software solution designed to optimize hydraulic fracturing processes.

FRACTO, plays a pivotal role in field development optimization. It provides valuable insights into fracture behavior, empowering operators to make informed decisions during hydraulic fracturing operations. By seamlessly integrating various tools and functionalities, FRACTO enhances our understanding of fractures and significantly contributes to efficient and effective oil and gas extraction processes.

Fig III.43: *Designed logo of FRACTO*

FRACTO is a powerful tool for the oil and gas industry, bridging the gap between theory and field practice. Its impact extends beyond individual wells, contributing to sustainable resource management and energy production.

For our project, we conducted a thorough needs assessment to analyze the challenges faced by the National Company SONATRACH in Hydraulic Fracturing Calibration Test Analysis. Additionally, we collaborated with Hydraulic Fracturing Engineers to gather functional and technical requirements for the platform.

A comprehensive methodology encompasses a well-defined sequence of interconnected steps, each contributing to the programming of the platform.

II. Methodology

D. Design of FRACTO

We outlined the design of FRACTO, focusing on user experience, scalability, and integration with existing systems.

1. User Experience (UX) Design:
   FRACTO's UX design offers a seamless and positive experience for users, ensuring intuitiveness, efficiency, and enjoyment.
2. Scalability:
   FRACTO's scalability ensures a platform can handle increased load, users, or data without compromising performance, allowing it to adapt to changing demands and accommodate growth.
3. Integration with Existing Systems:
   FRACTO's integrating with existing systems enables seamless data exchange and functionality, streamlining processes, avoiding duplication of effort, and enhancing overall efficiency.

In summary, a well-designed platform considers user experience, scalability, and integration to create a robust and effective system that meets user needs and business goals.

E. Development of FRACTO

Our development strategy is a two-phased approach. In the first phase we will focus on *Web Development* to establish a strong online presence and ensure that FRACTO is accessible and user-friendly. The selection of programming languages for the FRACTO's web development is influenced by a variety of factors such as project specifications, our team's proficiency, and the particular functionalities we aim to incorporate.

2. Web development

Programming languages

We have opted for the following technologies: React for user interface; allowing us to create interactive and responsive components, TypeScript for provide robust scripting capabilities, enhancing code quality and maintainability, and CSS for ensure consistent styling and a visually appealing user experience. Let's dive into more details about the technologies we've chosen for our project.

React

React is a way to build user interfaces. It is only concerned with what we see on the front-end. React makes user interfaces very easy to build by cutting each page into pieces. We call these pieces components. Here is an example of cutting a page into components:

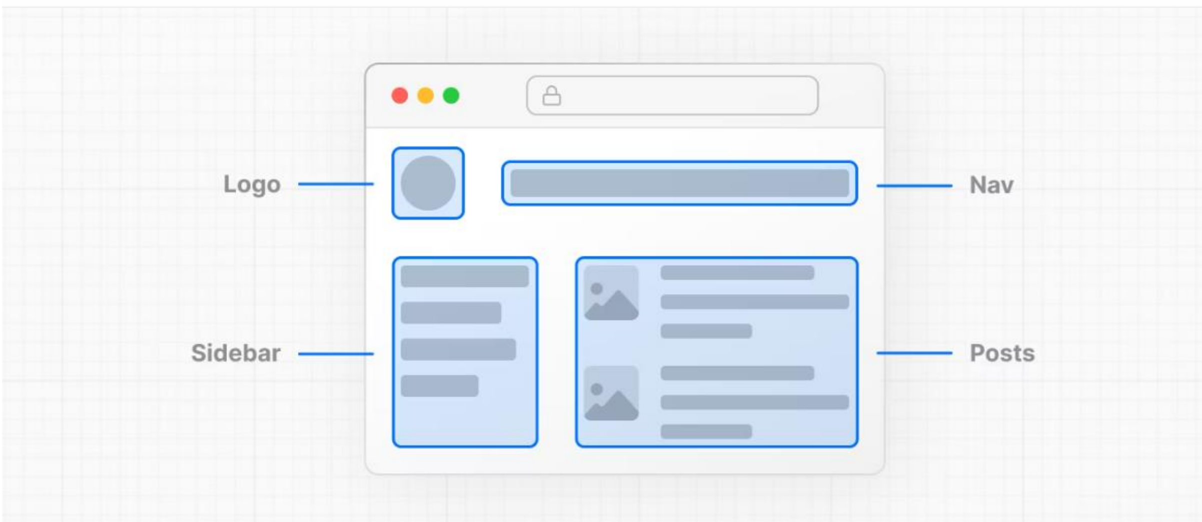


Fig III.44: *React Components*

A React component is a bit of code that represents a piece of the page. Each component is a TypeScript or JavaScript function that returns a piece of code that represents a piece of a web page. React uses a language called *TSX* or *JSX* that looks like HTML but works inside TypeScript or JavaScript, which HTML usually doesn't do.

TypeScript

TypeScript is a programming language developed by Microsoft. It is a typed superset of JavaScript, and includes its own compiler. Writing TypeScript with React is very similar to writing JavaScript with React. The key difference when working with a component is that we can provide types for our component's props. These types can be used for correctness checking and providing inline documentation in editors.

React apps are made out of components. A component is a piece of the UI (user interface) that has its own logic and appearance. A component can be as small as a button, or as large as an entire page. React components are TypeScript functions that return markup:

```
function MyButton() {
  return (
    <button>I'm a button</button>
  );
}
```

Fig III.45: *TypeScript code with React*

We can add a type describing the *title* for the button. Notice that *<MyButton />* starts with a capital letter. That's how we know it's a React component. React component names must always start with a capital letter, while HTML tags must be lowercase. Have a look at the result in the **Fig III.47**.

App.tsx Reset Fork TypeScript Playground

```
function MyButton({ title }: { title: string }) {
  return (
    <button>{title}</button>
  );
}

export default function MyApp() {
  return (
    <div>
      <h1>Welcome to my app</h1>
      <MyButton title="I'm a button" />
    </div>
  );
}
```

Fig III.46: *Minimal React Component code*

Fig III.47: *React Component code rendered in the browser*

The type describing our component's props can be as simple or as complex as we need, though they should be an object type described with either a *type* or *interface*.

The type definitions from *@types/react* include types for the built-in *Hooks*, so we can use them in our components without any additional setup. They are built to take into account the code we write in our component, so we will get inferred types a lot of the time and ideally do not need to handle the minutiae of providing the types. However, we can look at a few examples of how to provide *types* for *Hooks*.

- *useState*

The *useState Hook* will re-use the value passed in as the initial state to determine what the type of the value should be. For example:

```
// Infer the type as "boolean"
const [enabled, setEnabled] = useState(false);
```

Fig III.48: *useState Hook*

This will assign the type of *boolean* to *enabled*, and *setEnabled* will be a function accepting either a *boolean* argument, or a function that returns a *boolean*. If we want to explicitly provide a type for the state, we can do so by providing a type argument to the *useState* call:

```
// Explicitly set the type to "boolean"
const [enabled, setEnabled] = useState<boolean>(false);
```

Fig III.49: *Providing type of the useState Hook*

This isn’t very useful in this case, but a common case where we may want to provide a type is when we have a union type. For example, *status* here can be one of a few different strings:

```
type Status = "idle" | "loading" | "success" | "error";

const [status, setStatus] = useState<Status>("idle");
```

Or, as recommended, we can group related *state* as an object and describe the different possibilities via object *types*:

```
type RequestState =
  | { status: 'idle' }
  | { status: 'loading' }
  | { status: 'success', data: any }
  | { status: 'error', error: Error };

const [requestState, setRequestState] = useState<RequestState>({ status: 'idle' });
```

- *useEffect*

The *useEffect Hook* lets us perform side effects in function components:

```
import React, { useState, useEffect } from 'react';

function Example() {
  const [count, setCount] = useState(0);

  // Similar to componentDidMount and componentDidUpdate:
  useEffect(() => {
    // Update the document title using the browser API
    document.title = `You clicked ${count} times`;
  });

  return (
    <div>
      <p>You clicked {count} times</p>
      <button onClick={() => setCount(count + 1)}>
        Click me
      </button>
    </div>
  );
}
```

Fig III.50: *UseEffect Hook Code*

Note: there is quite an expansive set of *types* which come from the *@types/react* package, we covered a few of the more common *types* here.

CSS

In React, we specify a CSS class with *className*, then we write the CSS rules for it in a separate file, with the *.css* file extension, and we must import it in the *.tsx* file.

```
* {
  box-sizing: border-box;
  margin: 0;
  padding: 0;
}
body {
  font-family: "Segoe UI", sans-serif;
  line-height: 1.4;
  color: #000;
  background: #fff;
  height: 100vh;
  font-weight: 400;
}
```

Development Tools

Visual Studio Code (VS Code)

During the development of the FRACTO platform, we employed Visual Studio Code (VS Code), a powerful and versatile open-source code editor developed by Microsoft. VS Code provided a flexible and extensible environment that streamlined our coding workflow and significantly increased productivity throughout the project's lifecycle.

One of the standout features of VS Code that greatly benefited our development process was its robust extension ecosystem. The vast collection of extensions available in the VS Code Marketplace allowed us to tailor the editor to our specific needs, enhancing its functionality and integrating various tools and utilities seamlessly into our workflow.

The built-in terminal within VS Code enabled our developers to run command-line tools, scripts, and build processes without leaving the editor's interface. This seamless integration eliminated the need to constantly switch between different applications, resulting in a more focused and productive coding experience.

In addition to its core functionality, VS Code's extensibility allowed us to integrate various development tools and utilities specific to our project's requirements. For example, we incorporated debugging tools, task runners, and code analysis tools, all within the familiar VS Code interface. This level of customization and integration streamlined our development workflows, enabling us to work more efficiently and effectively.

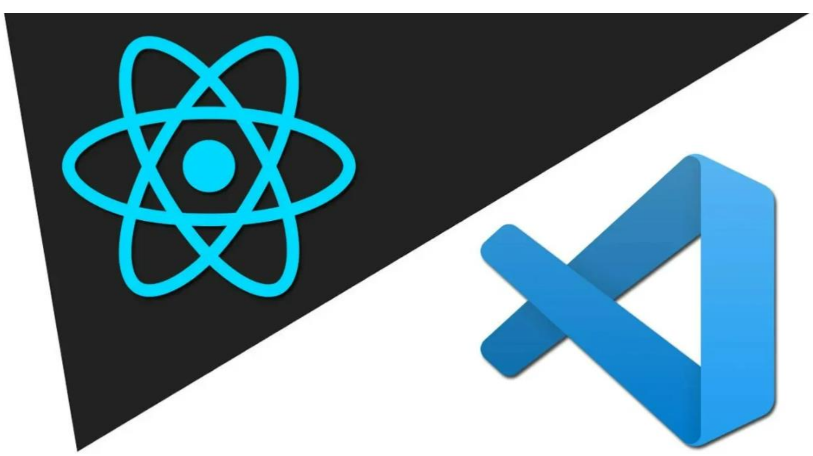


Fig III.51: *Visual Studio Code for the React Development*

Node.js

In addition to leveraging Visual Studio Code as our primary code editor and development environment for the React-based frontend, we also utilized Node.js as the runtime environment for the server-side components of the FRACTO platform.

Fig III.52: *Node.js logo*

VS Code's native support for Node.js and its ecosystem proved invaluable during the development process. The built-in Node.js debugger and integrated terminal facilitated efficient debugging, testing, and deployment of our server-side code. Furthermore, the extensive collection of Node.js extensions available in the VS Code Marketplace enabled us to incorporate various tools and utilities seamlessly into our workflow.

FRACTO Website

After presenting an overview of the programming languages and development tools that formed the backbone of the FRACTO platform, it is pertinent to shift our focus to the practical aspects of the platform's implementation. In the following sections, we will examine the FRACTO's architecture, Data handling and Storage.

FRACTO's architecture

Back-end

Welcome to the backend code repository for FRACTO's architecture website. This repository houses the server-side code responsible for powering the website that showcases FRACTO's robust and scalable software architecture.

Within this next repository, you'll find portions of the source code for various components, including database integration, and content management system. Each component is organized into separate modules, enabling easy navigation, collaboration, and future enhancements.

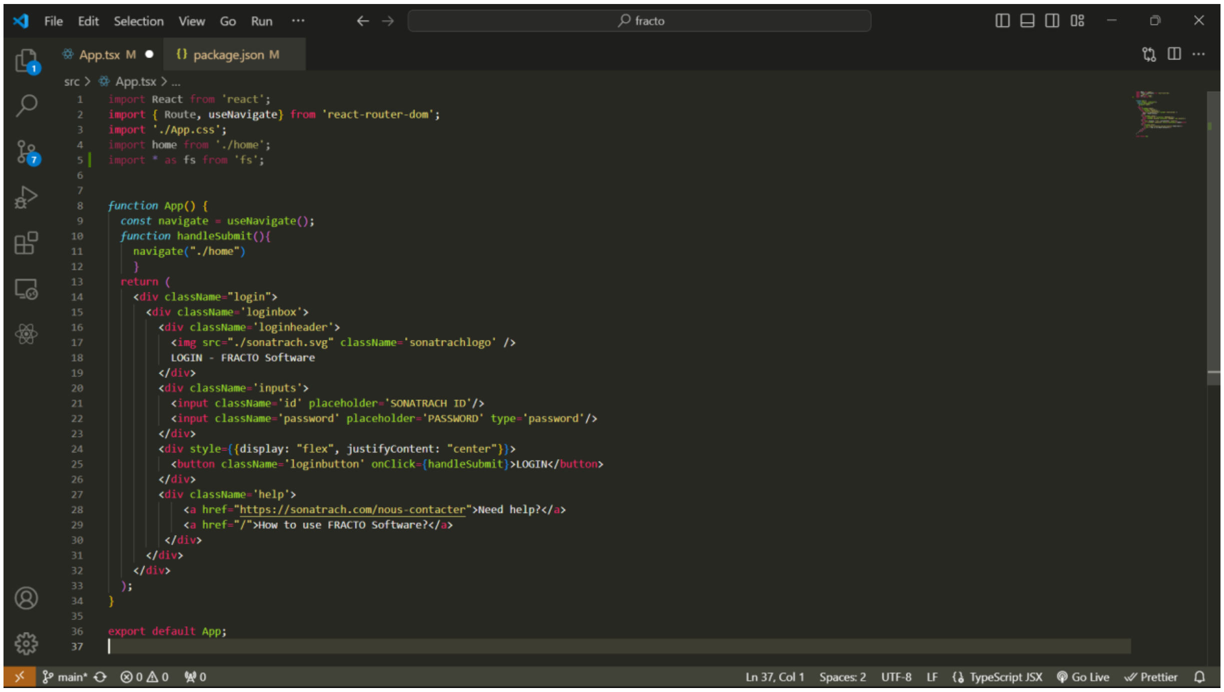


Fig III.53: *Login Page, Private React with Typescript Code*

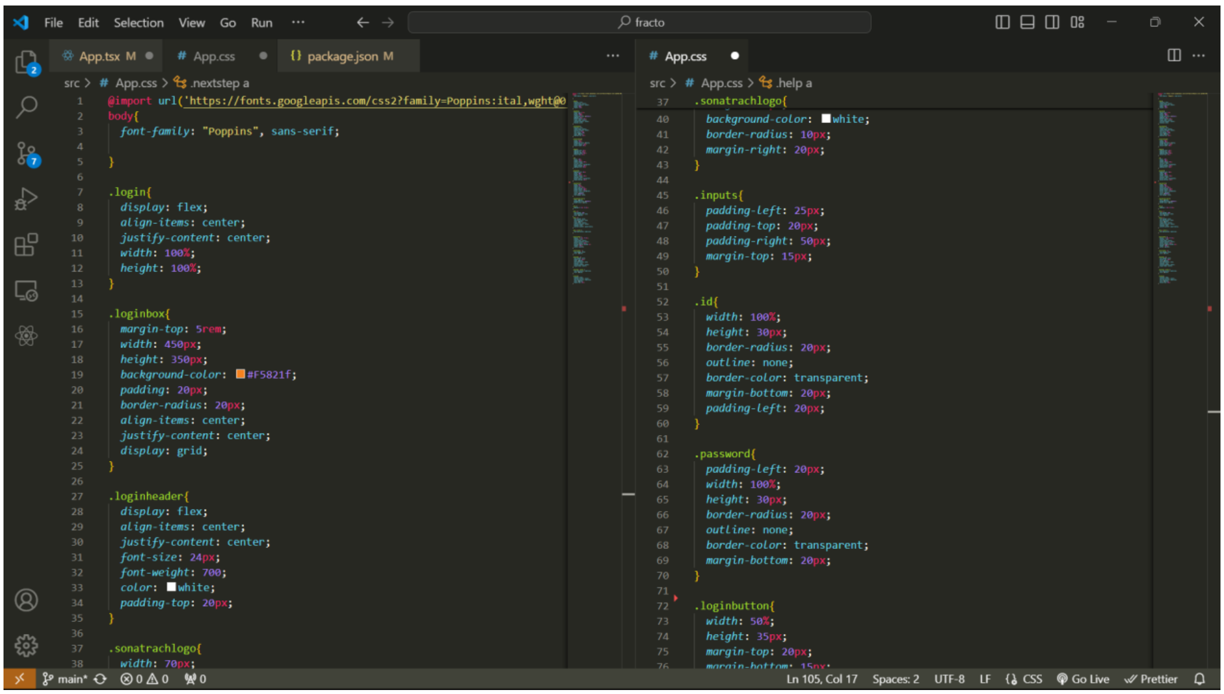


Fig III.54: *Login Page, Private Styling Code*

We built a login page using React components and leverage TypeScript's static type-checking to ensure type safety and catch potential errors during development.

We use CSS to style the login page components according to FRACTO's design.

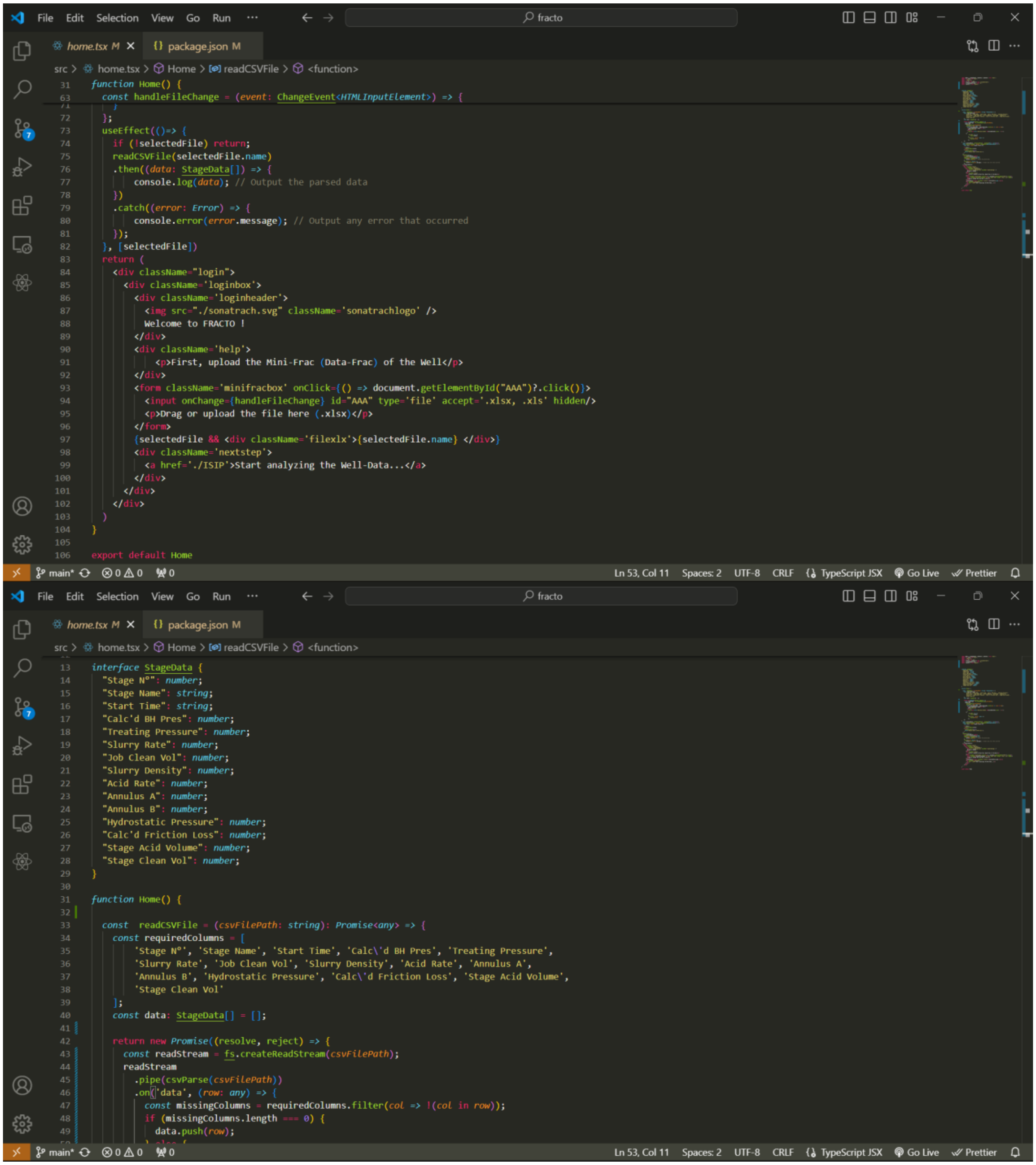


Fig III.55: *Data Upload Page, Private React with Typescript Code*

Calibration test data upload page in a FRACTO’s website is a user interface component that allows users to select files or data from their local machine and upload them to a server or cloud storage. The *handleFileChange* function is called when the user selects a file, updating the file state with the selected file object. The component uses the *useState Hook* to manage the state for the selected file and upload progress.

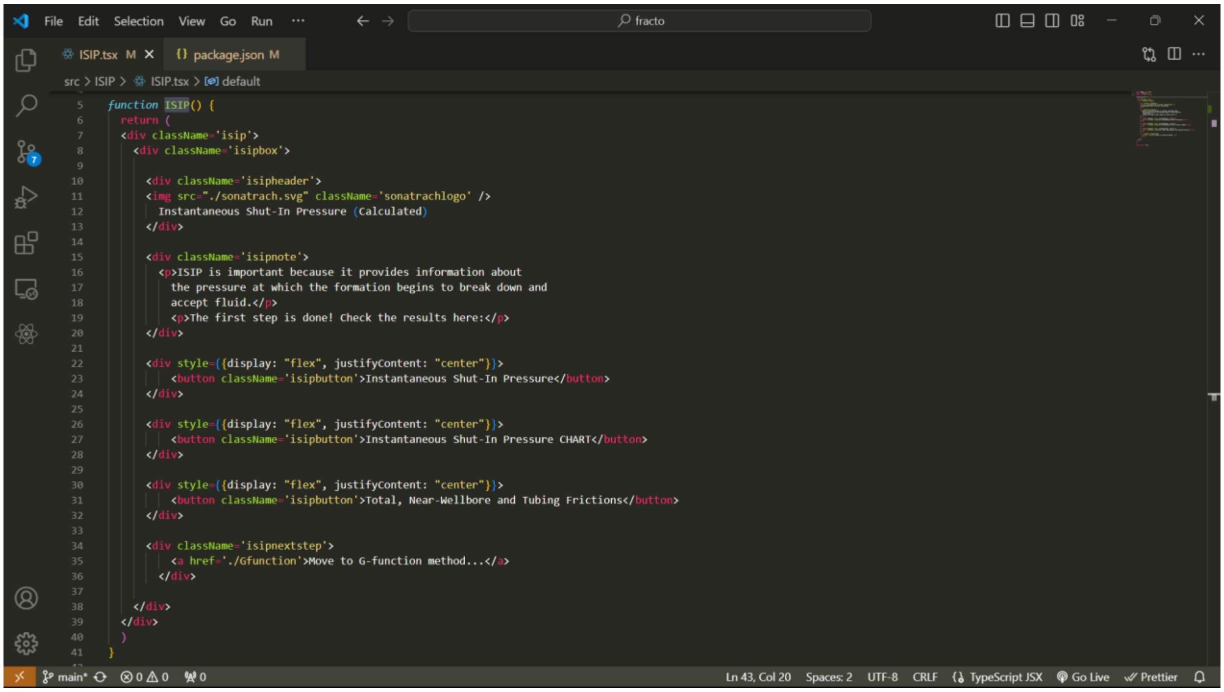


Fig III.56: Calculated ISIP Page, Private React with Typescript Code

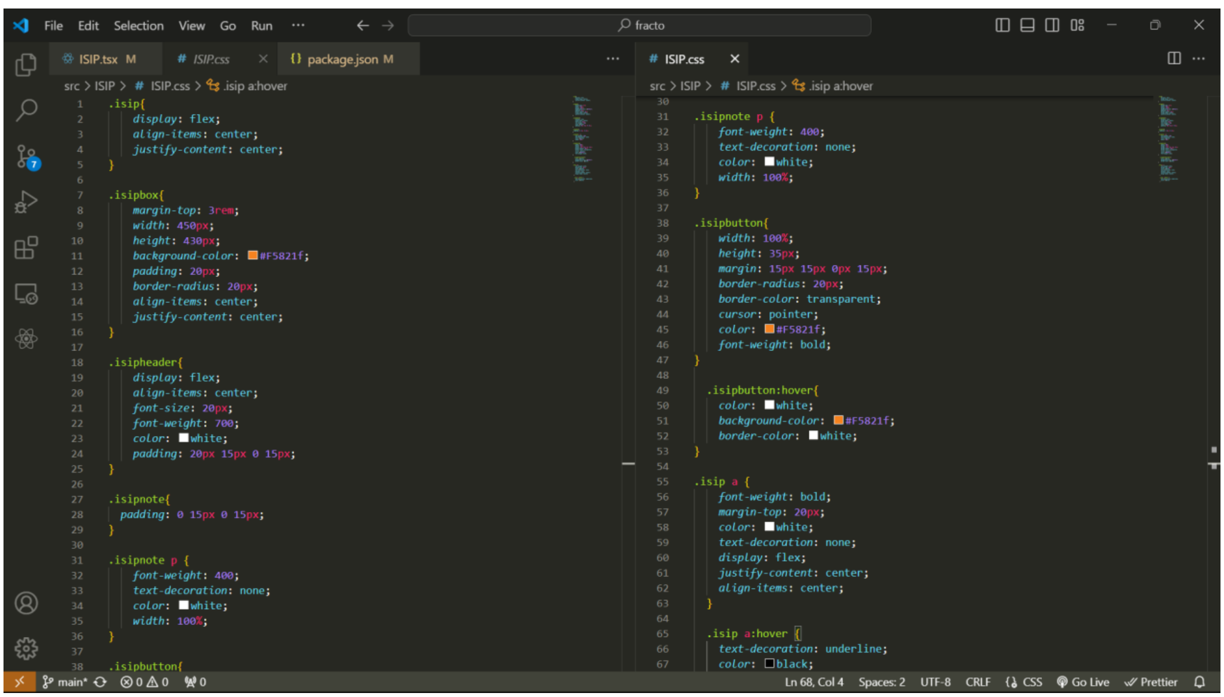


Fig III.57: Calculated ISIP Page, Private Styling Code

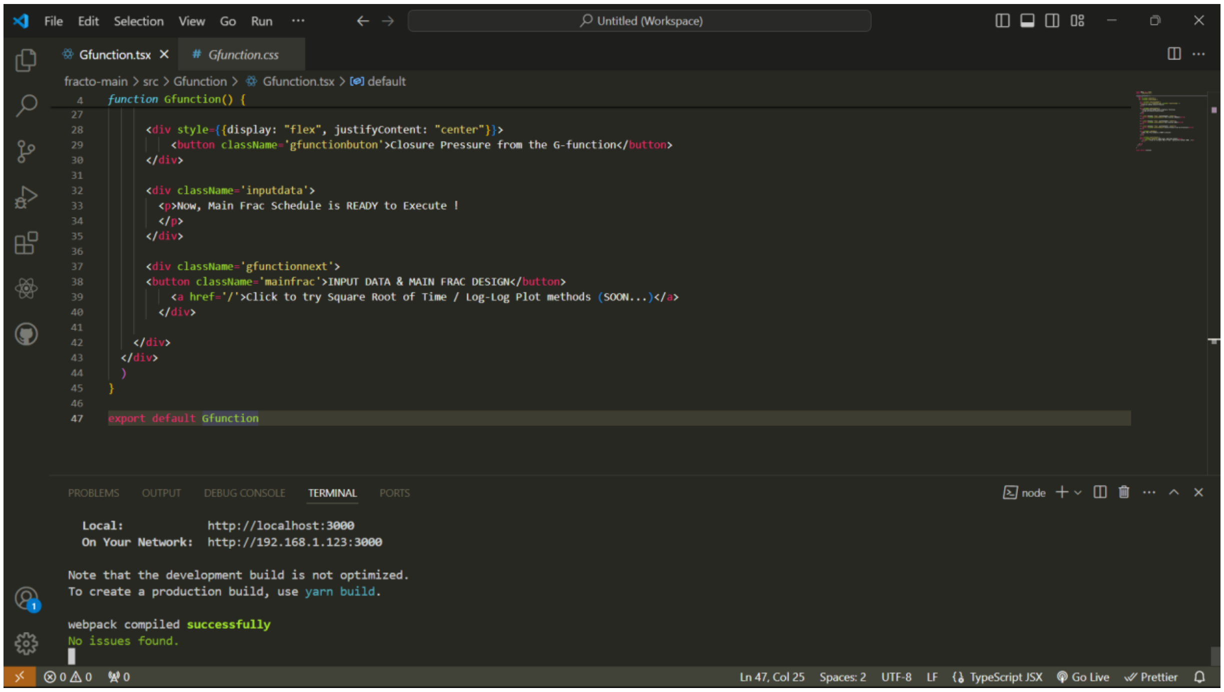


Fig III.58: *G-function Page, Private React with Typescript Code*

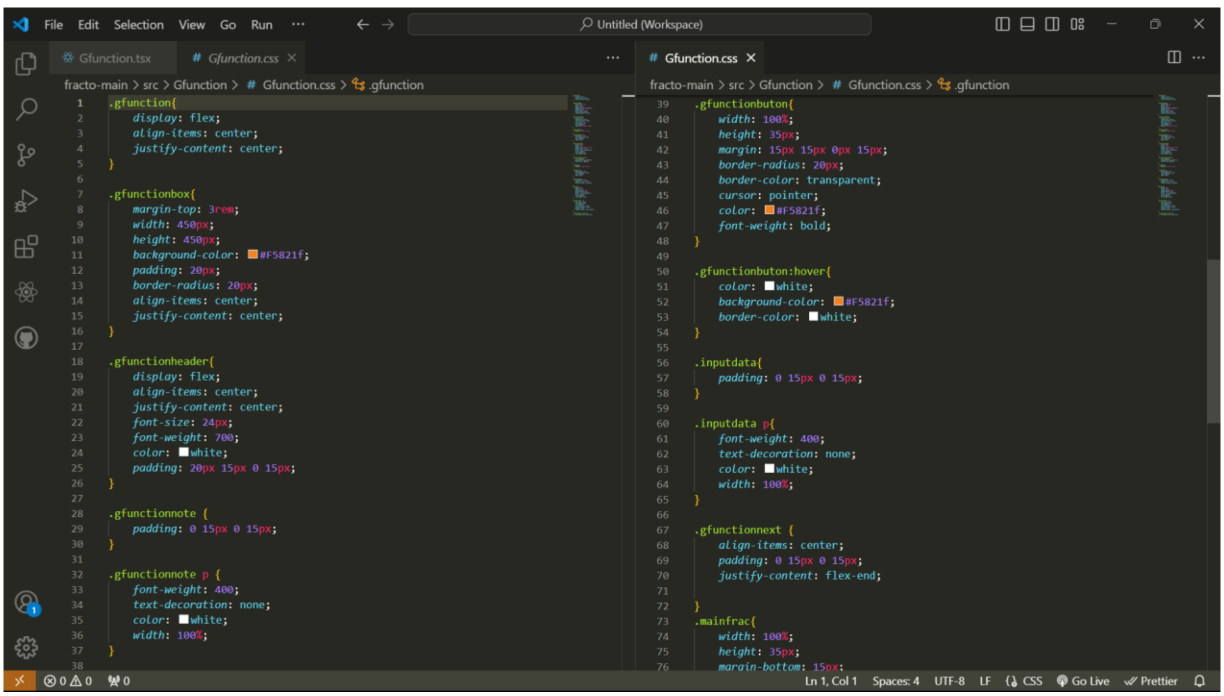


Fig III.59: *G-function Page, Private Styling Code*

Please note that we cannot provide the complete private codebase due to intellectual property considerations. However, we can share some general details about the website platform's front-end, and technical approach without disclosing the code itself.

Front-end

Welcome to the frontend code repository for FRACTO's website. In the subsequent figures, you will see the user interfaces of the FRACTO website.

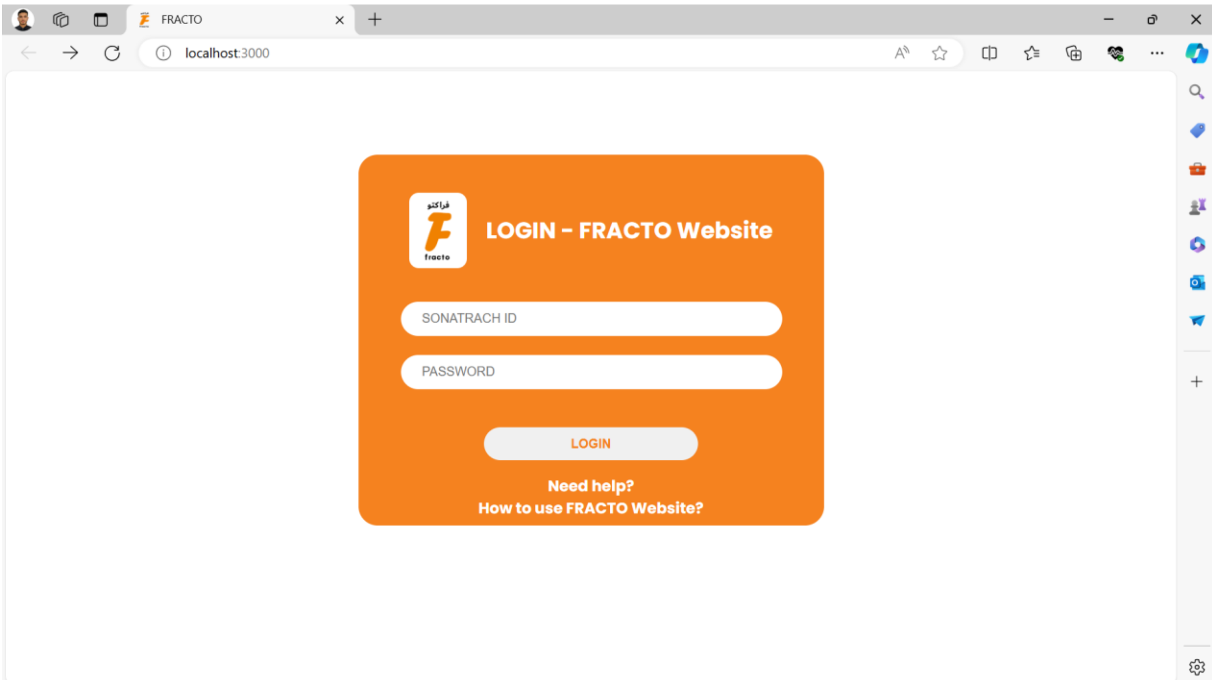


Fig III.60: *Login Page (UIs)*

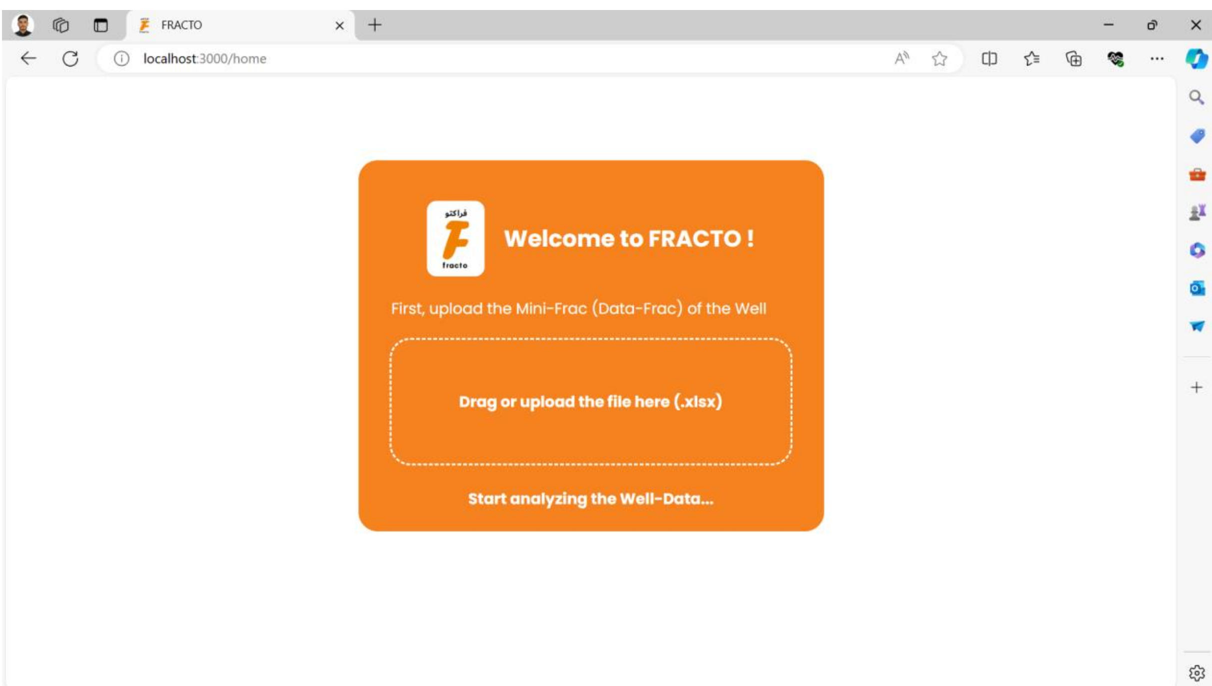


Fig III.61: *Data Upload Page (UIs)*

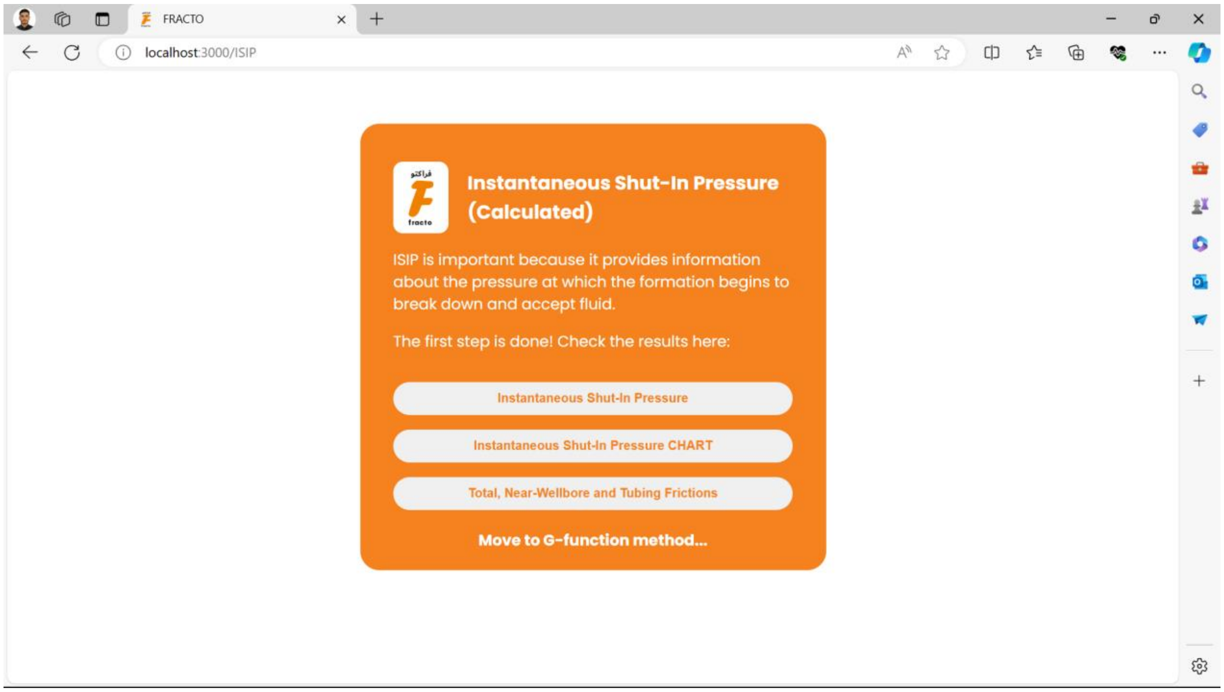


Fig III.62: *Calculated ISIP Page (UIs)*

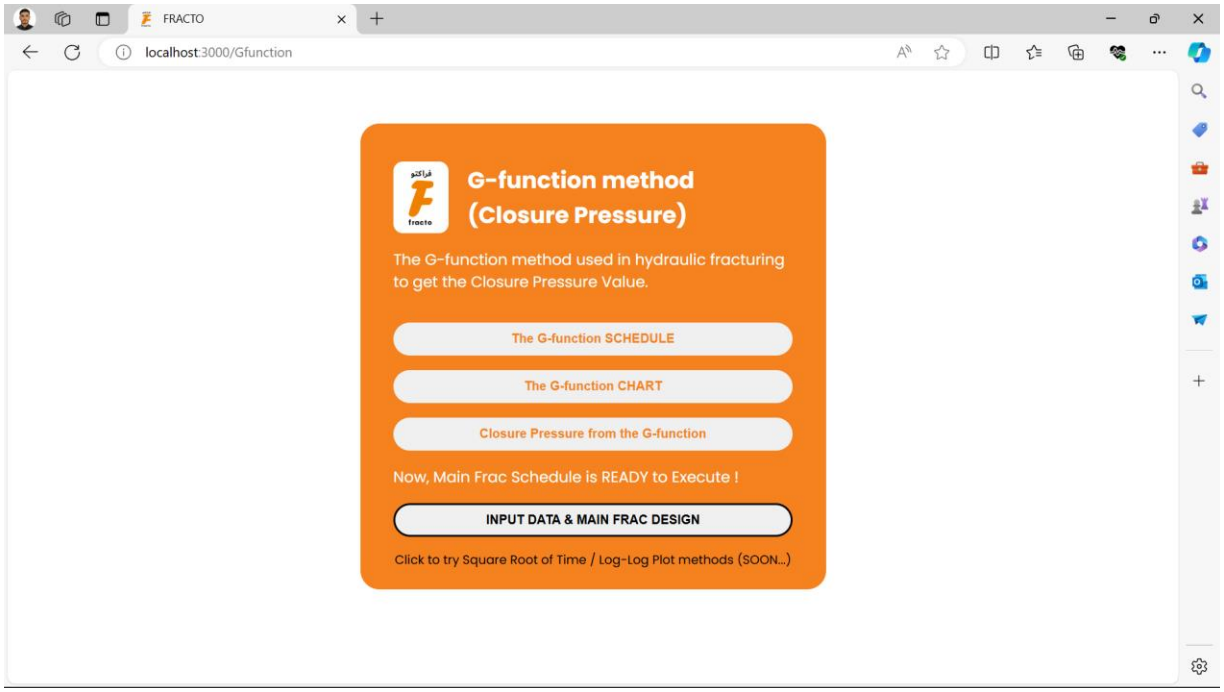


Fig III.63: *G-function Page (UIs)*

After calculating the closure pressure, the main hydraulic fracturing schedule stands ready for execution, enabling the targeted formation to be effectively stimulated and enhancing hydrocarbon production.

Data Handling and Storage

React Components interact employed

While the FRACTO platform employs React components for the frontend development, the specific implementation details and interactions between these components are part of our proprietary work and cannot be disclosed in this dissertation due to confidentiality concerns.

So, we hope you understand the need to protect this sensitive information.

Database management systems employed

The choice of database management system(s) depends on factors such as data volume, velocity, variety, and the specific requirements of the FRACTO platform. It is common to employ a combination of different database systems to cater to various data storage and processing needs.

The FRACTO platform utilizes robust and scalable database management systems to handle the storage and management of hydraulic fracturing data. However, the specific details of the database technologies employed cannot be disclosed as this information is considered proprietary and confidential to protect the intellectual property and competitive advantage of the platform. We hope you understand the need for this confidentiality.

3. Software development

In the first phase of this project, the focus was on web development aspects of the FRACTO Platform. The second phase involved working on the development of the software's user interface (UI).

The shift from web development in the first phase to the software development work in the confidential second phase was enabled through the use of an Electron extension, which allowed the web application to be packaged as a cross-platform desktop application.

What is Electron?

Electron is a popular framework that allows developers to build cross-platform desktop applications using web technologies such as HTML, CSS, and JavaScript. By combining Electron with React, a powerful Typescript library for building user interfaces, we can create feature-rich desktop applications that feel and behave like native applications on Windows, macOS, and Linux.

Using Electron allowed us to leverage our existing web skills and codebase, while transforming it into a desktop software product during the second phase. However, due to the proprietary nature of this latter stage of development, we cannot publicly disclose or include specific technical details in this dissertation. As we're the owners and developers of this intellectual property, it is crucial for us to protect the confidentiality and maintain the security and integrity of the FRACTO Platform.

While we cannot delve into the implementation specifics, we can provide a high-level overview of the goals and outcomes of this private phase, for creating beautiful looking desktop app with Electron and React we used *Electron Forge* - A complete pipeline for creating and shipping Electron app. It also provides an easy way to setup React with Electron.

Electron Forge

Electron Forge is an all-in-one tool for packaging and distributing Electron applications. It combines many single-purpose packages to create a full build pipeline that works out of the box, complete with code signing, installers, and artifact publishing. For advanced workflows, custom build logic can be added in the Forge lifecycle through its Plugin API.

F. Training and Documentation

We created a comprehensive documentation designed to instruct users on the effective use of the Platform. The documentation aims to provide clear and concise instructions to users, guiding them through the various features and functionalities of the platform. It will cover the entire process, from initial setup and configuration to advanced usage scenarios.

The documentation is supplemented with visual aids, such as screenshots, diagrams, and flowcharts, to enhance understanding and provide visual references for users. Additionally, code snippets and examples are included where relevant to illustrate concepts and facilitate practical implementation.

Throughout the documentation, particular emphasis is placed on ensuring clarity, consistency, and adherence to best practices in technical writing. The language used is straightforward and accessible to users with varying levels of technical expertise.

The documentation is structured in a logical and user-friendly manner, with separate sections dedicated to different aspects of the platform. These sections include:

4. ***Introduction and Overview***

- Overview of the platform's purpose, key features and benefits,
- Description of target users/industries and use cases,
- High-level architecture.

5. ***Getting Started***

- System and browser requirements,
- Account login process (for website),
- Software installation and setup guides.

6. ***Mini Frac Data Upload***

- Uploading Mini Frac Data file from local storage,
- Data import options and configurations.

7. ***Reporting***

- Exporting analysis results and visualizations,
- Collaboration and sharing.

8. ***Troubleshooting and FAQs***

- Common issues with data uploads and analysis,
- FAQs on data formats, analysis techniques, and more.

The comprehensive documentation for the FRACTO Platform, detailing its data analysis capabilities and features, is attached as an appendix to this dissertation.

III. Validating the FRACTO Platform: A Comprehensive Testing

In the case of the FRACTO Platform, while we cannot provide testing details for the confidential software itself, we can offer a comprehensive test plan for validating the website.

This comprehensive website test plan aims to validate the specific sections and features of the FRACTO Website, by the **MD689 Well Calibration Test Data**. By rigorously testing these components, we can identify any issues before users access and interact with this critical data.

A. Account login

The testing of the FRACTO Platform website's login page and user access controls is crucial. This will ensure that only authorized expert users from Sonatrach National Company can successfully log in and gain access to view and analyze this sensitive data.

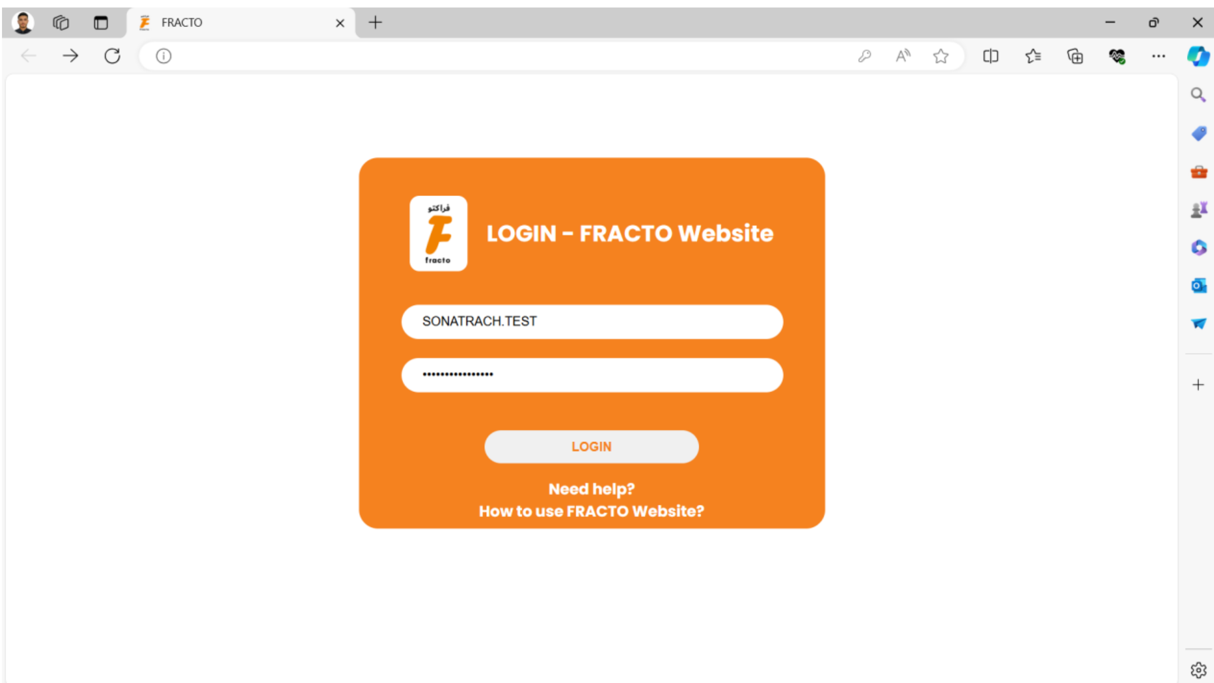


__Fig III.64:__ Approved Account Login Test for the FRACTO Website

B. MD689 Well Data Uploading and Treating

To proceed, you will need to provide a file containing Mini Frac Data from your local computer. This file must be in Microsoft Excel format (.xlsx or .xls). The Mini Frac Data file should contain the necessary information and measurements. Please ensure that the file is accessible and ready for upload before start analyzing.

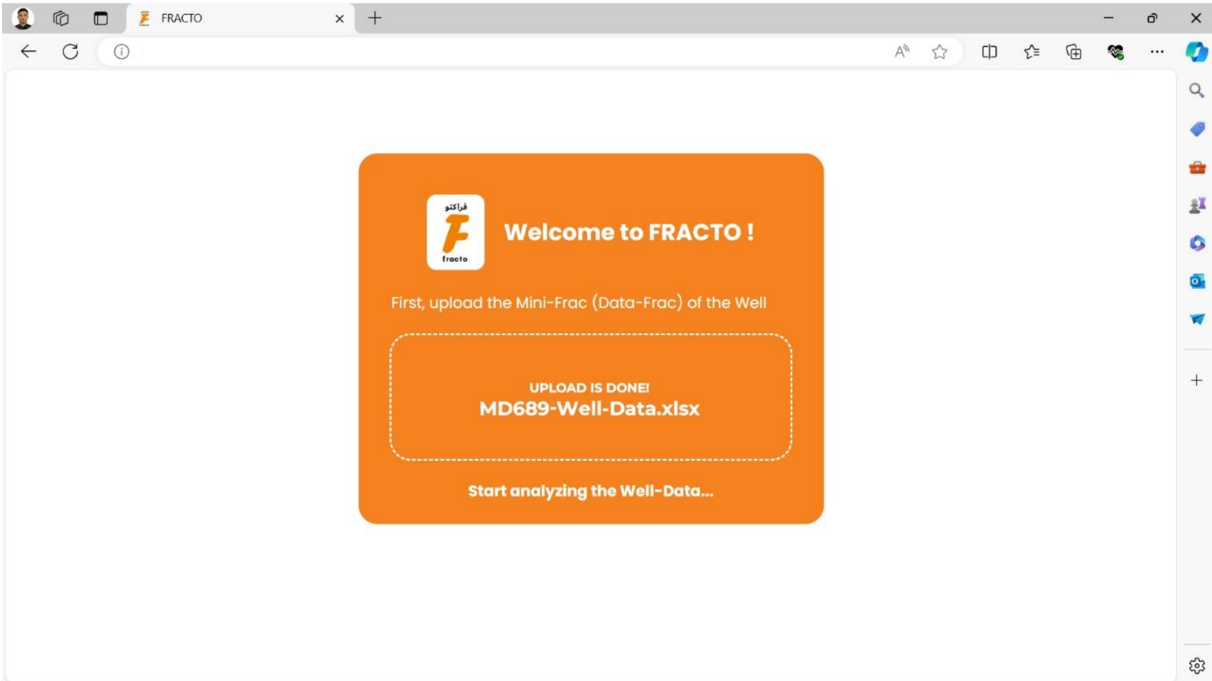
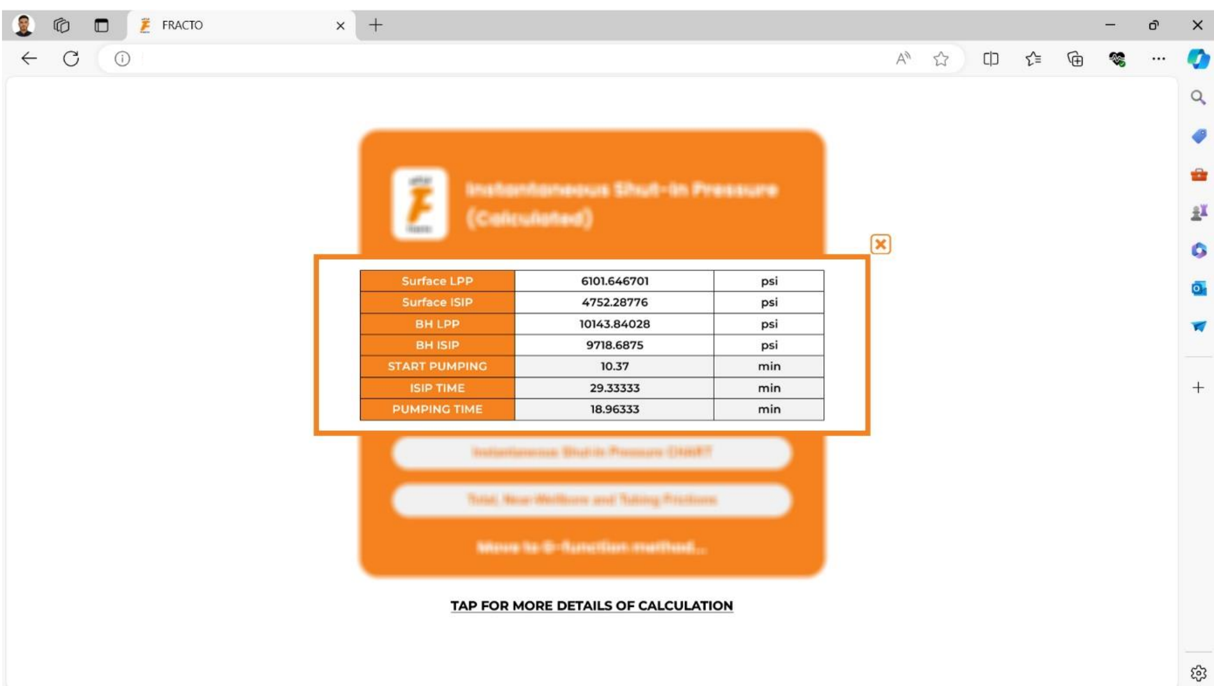


Fig III.65: Test of Uploading MD689 Well Data for Analyzing

C. ISIP Calculation for MD689 Well

After the data from a calibration test is uploaded, such as pressure trends, pump rates, fluid volumes, etc., FRACTO can process this data to determine various important parameters.



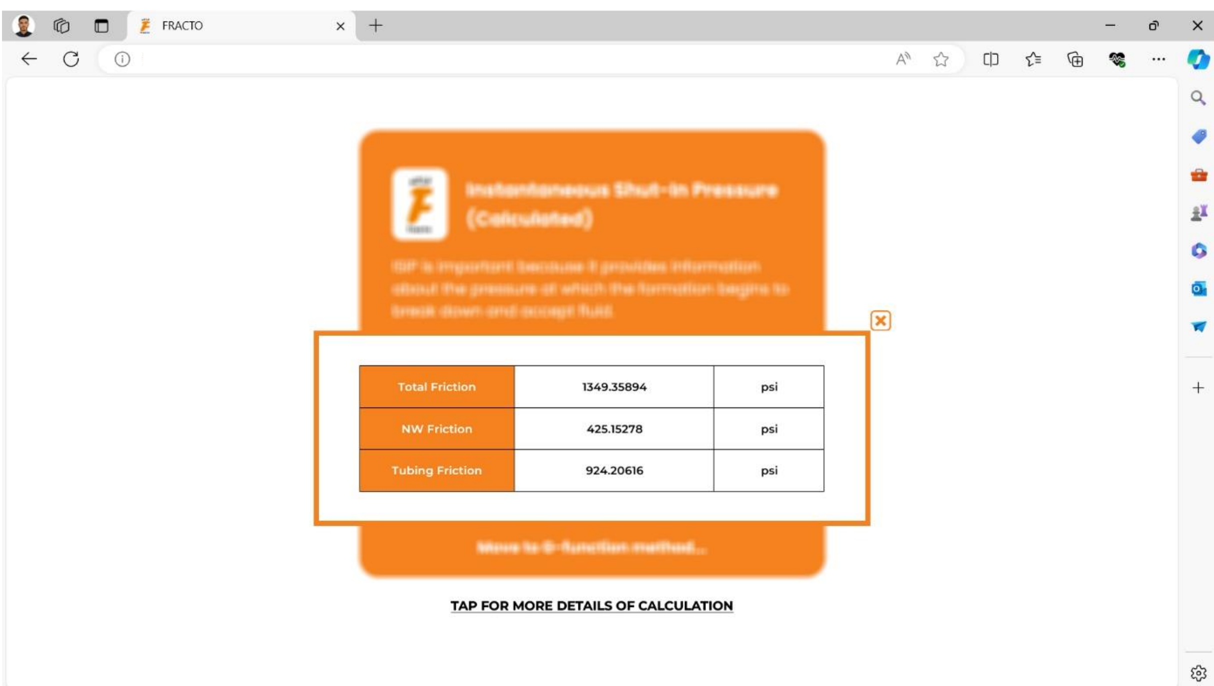
Surface LPP	6101.646701	psi
Surface ISIP	4752.28776	psi
BH LPP	10143.84028	psi
BH ISIP	9718.6875	psi
START PUMPING	10.37	min
ISIP TIME	29.33333	min
PUMPING TIME	18.96333	min

Fig III.66: Calculated ISIP and other Parameters

One key parameter it calculates is the ISIP. This is the pressure measured at the exact moment pumping is stopped and the well is shut-in after the fracturing treatment. FRACTO identifies this pressure point from the uploaded pressure/time data.

Fig III.67: *ISIP Chart*

Some other critical parameters FRACTO can analyze include:



Total Friction	1349.35894	psi
NW Friction	425.15278	psi
Tubing Friction	924.20616	psi

Fig III.68: *Calculated Frictions*

FRACTO uses physics-based and empirical models to interpret this fracturing data and calculate the key parameters. These outputs allow optimization of future frac designs and provide insights into the hydraulic fracturing job effectiveness. The next step is often to analyze the results using what is known as the G-function

D. G-function method for MD689 Well

The G-function, also called the G-curve or storage/loss ratio plot, is a diagnostic tool widely used in hydraulic fracturing analysis.

Fig III.69: *G-function Chart*

The G-function allows diagnosis of the fracture propagation behavior, leak-off characteristics, and determination of key parameter, the closure pressure - the pressure where fractures start to close after shut-in.

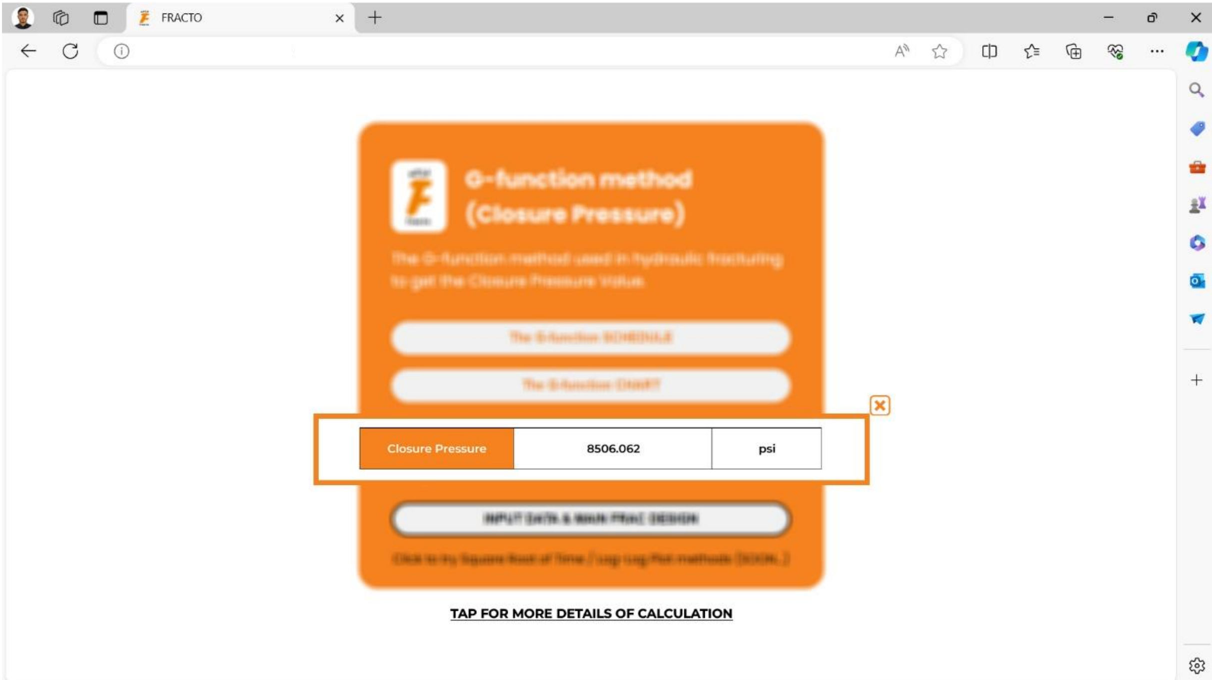


Fig III.70: *Closure Pressure from G-function method*

Once the closure pressure is obtained from interpreting the G-function plots and type curve matching, we can move to generating an executable fracturing schedule for future treatments of the MD689 Well.

E. Input Data & Main Frac Schedule for MD689 Well

The executable schedule essentially programs the optimal pumping sequence and parameters to achieve the desired fracture dimensions and conductivity. After getting all inputs, just click on the button of Main Frac Design to provide the Schedule.

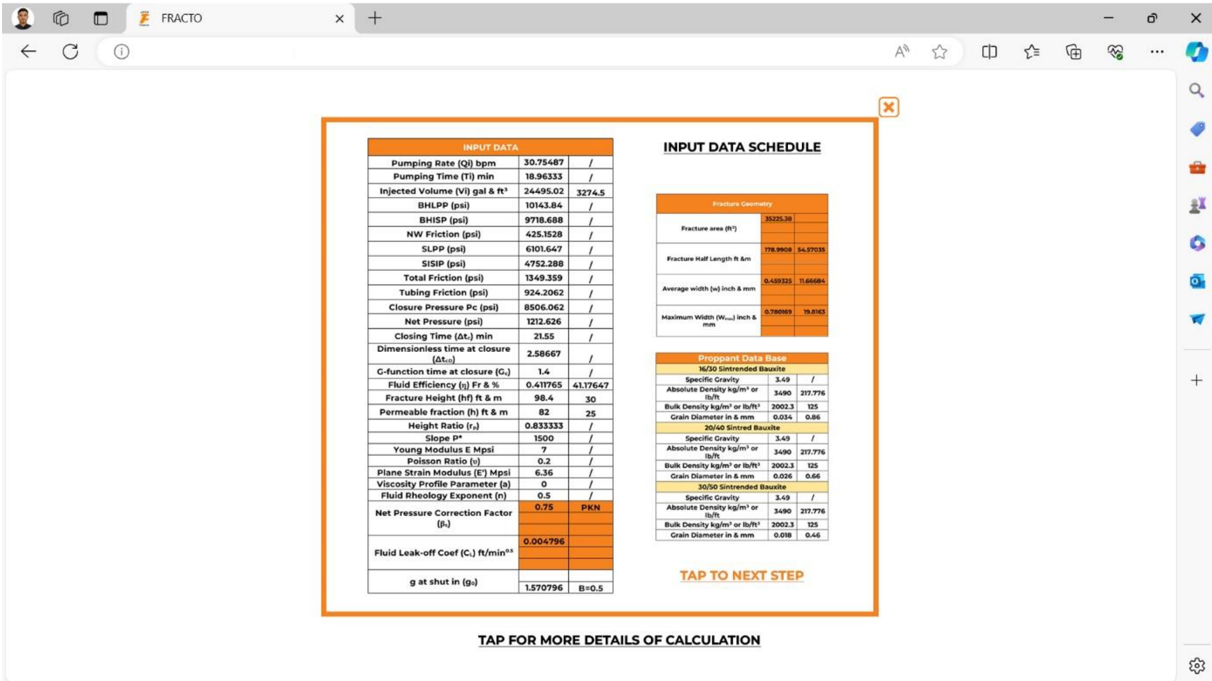


Fig III.71: *Input Data for MD689 Well*

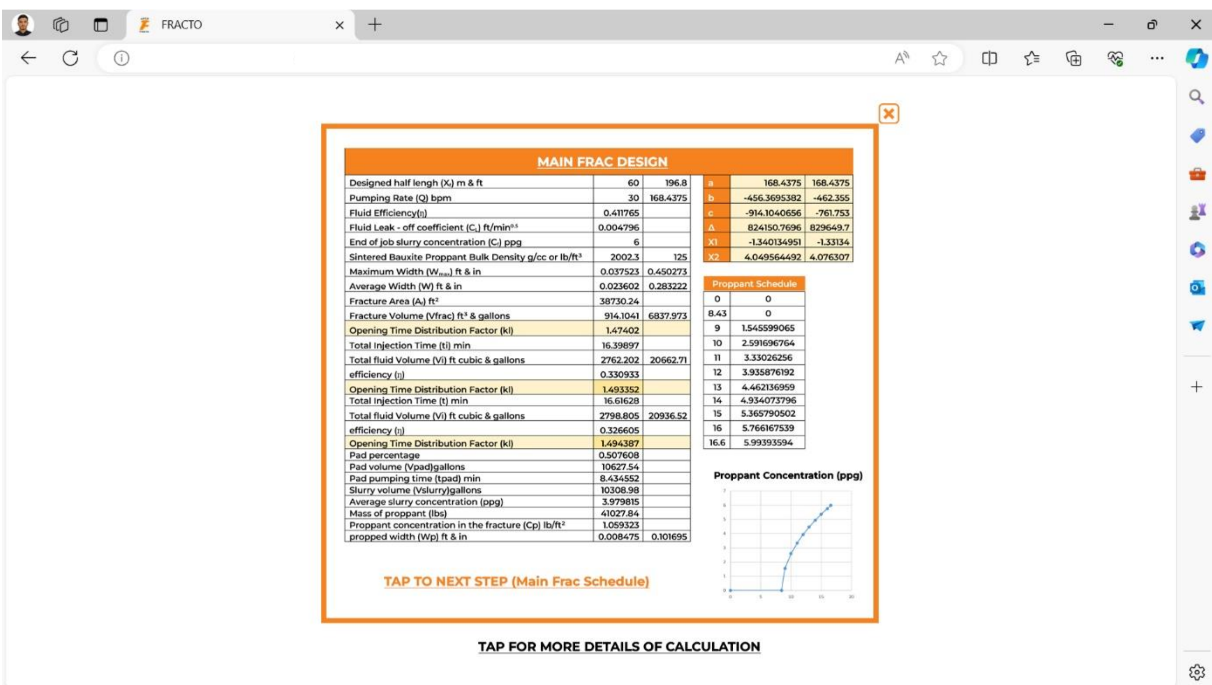
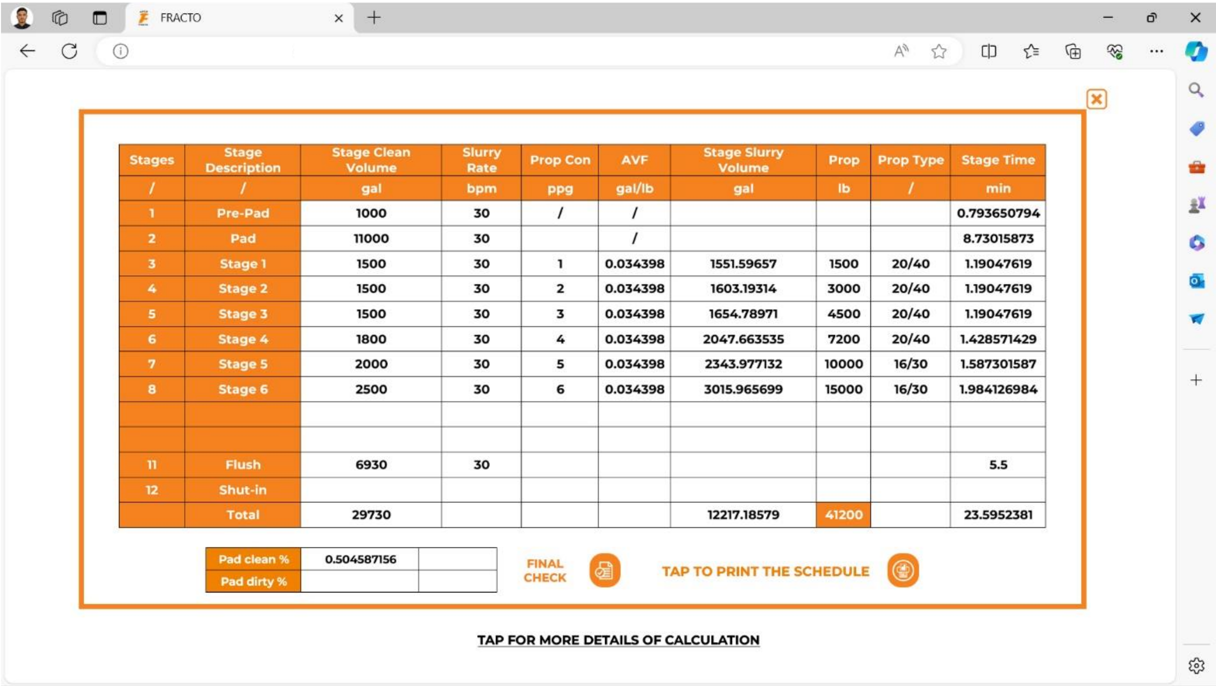


Fig III.72: *Main Frac Design for MD689 Well*

After extensive data analysis, fracture modeling, and fracture design work, a detailed main frac schedule was generated for the hydraulic fracturing treatment on the MD689 well. This frac schedule specified all the key pumping parameters.



Stages	Stage Description	Stage Clean Volume	Slurry Rate	Prop Con	AVF	Stage Slurry Volume	Prop	Prop Type	Stage Time
/	/	gal	bpm	ppg	gal/lb	gal	lb	/	min
1	Pre-Pad	1000	30	/	/				0.793650794
2	Pad	11000	30		/				8.73015873
3	Stage 1	1500	30	1	0.034398	1551.59657	1500	20/40	1.19047619
4	Stage 2	1500	30	2	0.034398	1603.19314	3000	20/40	1.19047619
5	Stage 3	1500	30	3	0.034398	1654.78971	4500	20/40	1.19047619
6	Stage 4	1800	30	4	0.034398	2047.663535	7200	20/40	1.428571429
7	Stage 5	2000	30	5	0.034398	2343.977132	10000	16/30	1.587301587
8	Stage 6	2500	30	6	0.034398	3015.965699	15000	16/30	1.984126984
11	Flush	6930	30						5.5
12	Shut-in								
	Total	29730				12217.18579	41200		23.5952381

Pad clean %	0.504587156	
Pad dirty %		

Fig III.73: *Main Frac Schedule for MD689 Well*

To validate that the main frac schedule achieved its objectives, several key data streams were closely monitored and analyzed, including treatment pressures, volumes pumped, post-frac well data, production logs, and hydrocarbons rates over time.

Additionally, an Excel file containing the full execution program as pumped on location was provided. This allows for a direct comparison between the designed main frac schedule parameters and the actual pumping program implemented during the MD689 stimulation.

Based on the comprehensive analysis and comparison of the execution program file against the actual pumping data, pressure trends, and production results from the MD689 well, it is evident that the main frac schedule generated by the FRACTO Platform proved to be accurate and effective. The key design parameters and objectives specified in the schedule were successfully achieved when executing the fracturing treatment on location. With the validation of the fracto platform's schedule design capabilities now confirmed, future main frac schedules provided by the software can be implemented with confidence, optimizing stimulation efforts and enhancing production from subsequent wells.

The FRACTO Platform has demonstrated it delivers true and field-ready frac schedules through its robust fracture modeling, analysis, and schedule generation workflows.

GENERAL CONCLUSION

Hydraulic fracturing has proved to be the best method for improving the productivity of reservoirs. It is a very delicate operation that can fail as a result of a negligible and insignificant incident. But it can change the petrophysical properties of the fractured level when the execution of the latter is carried out according to the rules of art.

This method is not only applicable to reservoirs with poor petrophysical characteristics, but it can also be applied to tanks that already have a good productivity.

The calibration tests aimed to ensure the optimization of the hydraulic fracturing “the execution part of the program of main frac” and due to the time taken for the analysis of these tests and the cost that the national company SONATRACH is forced to endure we thought to have developed FRACTO to avoid this gap and tried the chance to the national company to improve the frac operation of this side.

In this study, the results obtained from the platform clearly demonstrate that the main fracturing schedule generated by the FRACTO Platform was accurate and effective, providing a solid foundation for the successful execution for MD689 well.

The validation of the FRACTO Platform's schedule design capabilities through this research is a significant milestone. The results confirm that future main fracturing schedules generated by this platform can be implemented with confidence, optimizing stimulation efforts and enhancing production from subsequent wells. The platform's proven accuracy and effectiveness will undoubtedly contribute to the success of future projects in this field.

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فراكتو
fracto

FRACTO PLATFORM

A COMPLETE DOCUMENTATION GUIDE
TO USE THE **WEBSITE**

DATE : June 23rd, 2024

WHAT IS FRACTO, WEBSITE?

FRACTO, for the Hydraulic Fracturing Calibration Test Analysis; A comprehensive website solution designed to optimize hydraulic fracturing processes.
FRACTO is a powerful tool for the oil and gas industry, bridging the gap between theory and field practice. Its impact extends beyond individual wells, contributing to sustainable resource management and energy production.

GETTING STARTED

Accessing the FRACTO Website
FRACTO Platform is a web-based application accessible through modern internet browsers. Open Browser, launch your preferred web browser, and type the **FRACTO website**.
Account Login Process
The picture shows two input fields labeled "**SONATRACH ID**" and "**PASSWORD**" respectively. FRACTO Platform website's login page and user access controls is crucial. This will ensure that only authorized expert users from Sonatrach National Company can successfully log in and gain access to view and analyze this sensitive data.

MINI FRAC DATA UPLOAD

The main element in the shown picture is an upload area to drag or upload a file with a "**.xlsx**" extension, which likely refers to an **Excel Spreadsheet** file containing Well Data or a "Mini Frac" dataset.
It's essential to ensure that the uploaded Excel file contains the **Required Columns**.
These necessary columns are: **Stage Name**, **Start Time**, **Calc'd BH Pres**, **Treating Pressure**, **Slurry Rate**, and **Hydrostatic Pressure**. Proper validation of the uploaded Excel file is crucial to ensure accurate data processing in FRACTO Website.

REPORTING

Instantaneous Shut-In Pressure (Calculated)
The next step after analyzing the data from the uploaded file is to creating a **Chart** to determine the Initial Shut-In Pressure (ISIP) **automatically**.
The interface shows the ISIP calculation process, and it displays the key results - the calculated ISIP value itself, an ISIP chart, and values for Total, Near-Wellbore and Tubing Frictions which are inputs feeding into the overall ISIP analysis.
G-function method (Closure Pressure)
G-function is a variable related to time. It can be plotted to determine the closure pressure and other fracture properties.

After calculating the closure pressure, the **Main Hydraulic Fracturing Schedule** stands ready for execution, enabling the targeted formation to be effectively stimulated and enhancing hydrocarbon production. You will see how this schedule is designed and prepared for execution.

Stages	Stage Description	Stage Clean Volume	Slurry Rate	Prop Con	AVF	Stage Slurry Volume	Prop	Prop Type	Stage Time
/	/	gal	bpm	ppg	gal/lb	gal	lb	/	min
1	Pre-Pad								
2	Pad								
3	Stage 1								
4	Stage 2								
5	Stage 3								
6	Stage 4								
7	Stage 5								
8	Stage 6								
11	Flush								
12	Shut-in								
	Total								

Pad clean %		
Pad dirty %		

FINAL CHECK

TAP TO PRINT THE SCHEDULE

FRACTO PLATFORM TEAM
SIGNATURE

www.fracto.com
contact@fracto.com