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FRANCISCO BRUNO XAVIER TELES

A SIMPLIFIED DESIGN OF A HYDRAULIC FRACTURING JOB IN A TIGHT GAS RESERVOIR

FORTALEZA

2017

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Monography presented to the Petroleum Engineering course of the Universidade Federal do Ceará in 2017, as a partial request for obtaining the title of Bachelor of Petroleum Engineering.

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To God.

To my parents, grandmother, and friends.

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“The best preparation for tomorrow is doing your best today.”

H. Jackson Brown, Jr.

ABSTRACT

Hydraulic fracturing is a well stimulation technique very efficient for low to moderate permeability reservoirs. In the last decades, this method has been intensively used for exploring unconventional reservoirs in many regions of the world. This technique consists on pumping fluid with additives in a high pressure into the formation, this pressure must be high enough to break the rock and propagate. Once the fracture is created, fluid with the stabilizer agent, also called proppant, which has the function of keeping the fracture opened and conductive is pumped in a slurry stage. This process provides a permeable channel in the formation, making the flow of the formation fluids easier, and leading to a more productive interest zone. In this work, using STIMPLAN, a hydraulic fracturing design was developed for a gas reservoir, in which its properties, type of materials, and operational parameters were considered. Based on some reservoir physical properties, obtained from logs and pressure data information, a proppant and fluid injection agenda were proposed for two volumetric limitations aiming to obtain an optimum fracture design. As result, an optimum design with the desired fracture propped length and non-dimensional conductivity was obtained.

Keywords: Well Stimulation. Hydraulic Fracturing. Unconventional Reservoirs. Fracture. Tight Gas.

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ABBREVIATIONS

FOI	Folds of Increase
API	American Petroleum Institute
KCl	Potassium Chloride
PKN	Perkins-Kern-Nordgren

SYMBOL DESCRIPTION

%	Percentage
F_{CD}	Non dimensional fracture conductivity
°C	Degree celsius
mD	Milidarcy
in	Inches
m	Meters
m^3	Cubic meters
t	Tons
min	Minutes
psi	Pounds per square inch
lb	Pounds
gal	Gallons
s	Skin factor
r_e	Drainage radius
r_w	Well radius
P_{bd}	Breakdown pressure
P	Reservoir pressure
σ_H	Maximum horizontal tension
σ_h	Minimum horizontal tension
T_0	Rock tension
P_{net}	Net pressure
P_{surf}	Surface pressure
P_{hyd}	Hydraulic pressure
P_{fric}	Friction pressure
Δ_{perf}	Perforation pressure
σ_1	In-situ stress
k	Formation permeability
k_f	Fracture permeability
w	Fracture width
x_f	Fracture half length
$r_{w'}$	Effective well's radius

SUMMARY

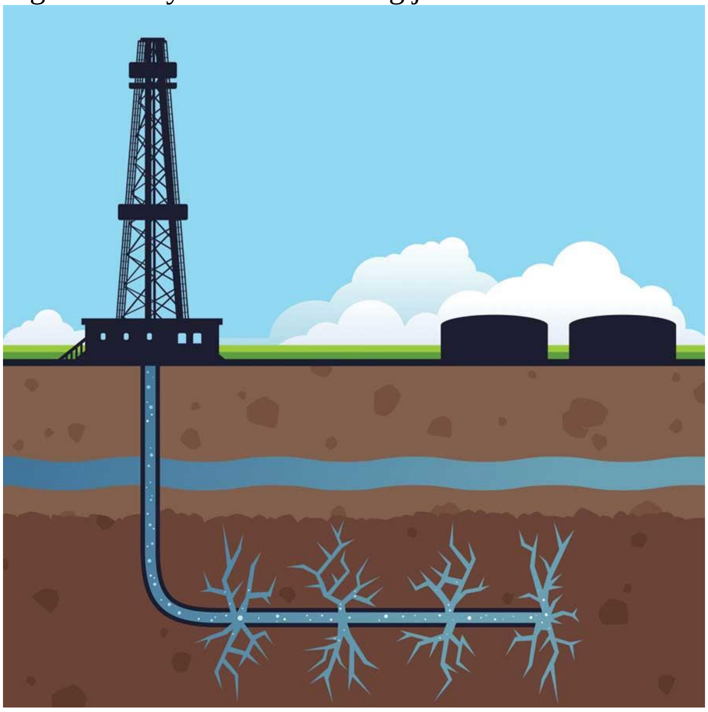
1 INTRODUCTION

According to the International Energy Agency (IEA), fossils fuels are responsible for supplying most of the world's energy demand when compared to other energy resources. However, nowadays conventional resources of oil are not enough to supply the future demand of energy if energy consumption continues at the same level. This leads to the search for ways of increasing hydrocarbon production from unconventional reservoirs.

The unconventional reservoirs are oil and gas deposits that cannot be produced due to their low porosity and permeability, or when the produced volume without a stimulation is not economically viable. In the past years, horizontal drilling together with hydraulic fracturing allowed to get very high volume of shale gas and oil, which were not produced in a profitable way (GOMAA *et al*., 2014).

Fracking job consists on high-pressure injection of fluids, generally water with additives, in oil or/and gas reservoirs. This pressure must be high enough to create fractures on the rock. When the breakdown pressure is reached the rock opens and fluid is still being injected so the fracture can propagate. To keep the fracture opened and conductive, and thus permeable, after the treatment, proppant agent is injected with the fluid (DANESHY, 2010). Figure 1 shows a good illustration of how this process occurs.

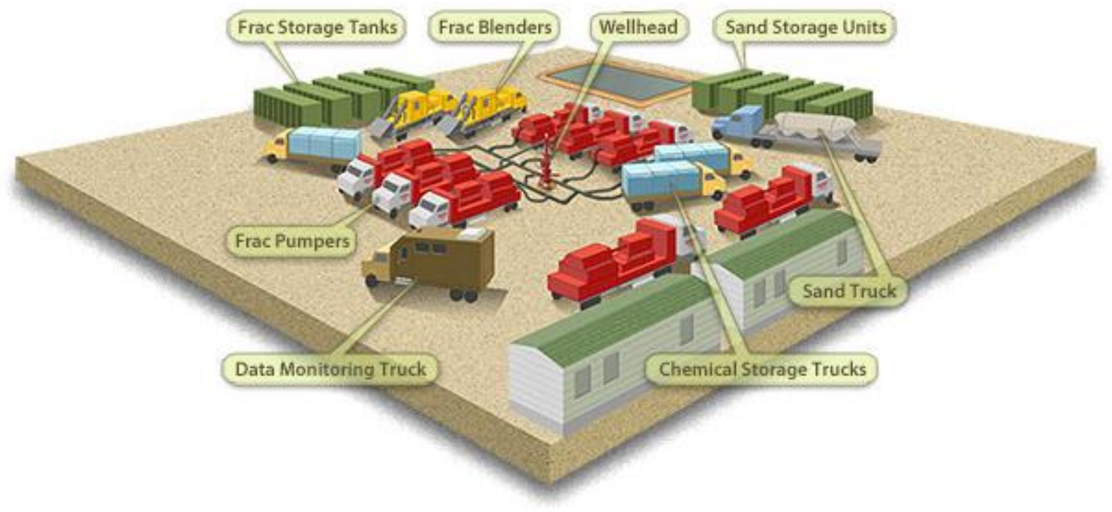
Figure 1 – Hydraulic fracturing job illustration



Source: Mother Earth News accessed on 11th July, 2017.

A well-executed fracking design can reach a vast stimulated area and get a permeability six times greater than the original one (ECONOMIDES, 1994). Because of that, hydraulic fracturing is one of the most complete methods for stimulating an oil or natural gas reservoir. Figure 1 shows a scheme with equipment and materials in a fracking treatment.

Figure 1 – Hydraulic fracturing job equipment overview



Source: Frac Focus Chemical Disclosure Registry accessed on 2th July, 2017.

We can see on the figure below, the storage tanks and units where the fracking fluids, chemicals, and proppants are stored. Some of the trucks pump the fluids and materials into the wells. In addition, there is a data monitoring truck, where all the frac job is monitored and operated by the engineers and technicians.

Along with high growth in the use of hydraulic fracturing in the last decade, there are some concerns involving the environmental impacts caused by this stimulation method. Among them, there is the issue of large volume of water used in the process, the variety of chemicals used being some of them potentially contaminating. In case of spills, it can contaminate the soil, surface water, and ground water. Besides that, there are some evidences of earthquakes caused by the injection of fracking fluid underground. Nevertheless, there are some uncertainties about this: the association of earthquakes and hydraulic fracturing has not been proved.

2 LITERATURE REVIEW

2.1 Conventional and unconventional reservoirs

The difference between conventional and unconventional resources is related to the type of formation that makes up the reservoir and how easy or hard it is to explore. Both conventional and unconventional reserves refer to an amount of hydrocarbons that is economically feasible to be extracted. Therefore, some reservoir properties as permeability and porosity are what mainly differs these type of reservoirs.

Conventional resources encloses high permeability reservoirs that can be produced by standard methods, being these resources easy and less expensive to produce. According to Castro (2015), reservoirs with permeability higher than 1mD are categorized as conventional reservoirs. On the other hand, unconventional resources are those with permeability lower than 1mD, including low-permeability (<0.1 mD) sandstones and self-sourcing reservoirs (ZOU *et al*., 2015). Unconventional reservoirs have properties that made them extremely difficult to produce oil or gas. Therefore, these unconventional reservoirs need high technology and the use of stimulation techniques to be recovered in a viable way.

In order to simplify the understanding of different types of unconventional oil and gas resources, Wang (2016) established some definitions and classification criteria for all types of unconventional resources. Table 1 shows a short version of the definition proposed in his study.

Table 1 – Definition of unconventional resources

Resource type	Definition
Heavy oil	Refers to the crude oil that is difficult to or cannot flow at reservoir pressure.
Oil sand	Refers to sandstone or other rocks composed of asphalt, sand, water, clay, and other minerals.
Tight oil	Refers to a kind of oil accumulating in tight sandstone, tight carbonatite, and other reservoirs.
Oil shale	Refers to combustible shale with high ash content and high organic matter content.
Shale gas	Refers to that natural gas that occurred in rich organic shale

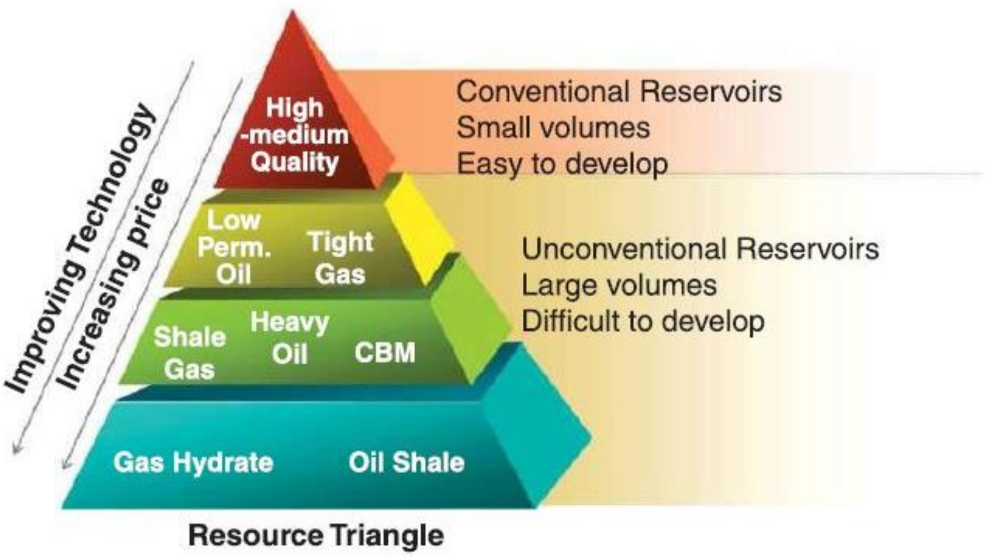
	reservoir in free and adsorbed states.
Tight gas	Refers to natural gas accumulated in tight sandstone and other reservoirs. The tight gas resources have a methane content of more than 85%.
Coalbed methane	Refers to hydrocarbon gas occurring in coal seam.

Source: Adapted from Wang (2016).

To better understand the particularities of conventional and unconventional resources, Old *et al*. (2008) and Dong *et al.* (2012) suggested that these reservoir types can be assigned to various resources classes in a triangle, and their positions in the triangle reflect the reservoir quality, abundance, and technology required for recovery.

The diagram, shown on Figure 3, illustrates what was previously mentioned. According to the literature, this triangle demonstrates that approximately 10% of the total recoverable hydrocarbon resources are conventional oil and gas (red region described by the small volumes and easy to develop resources), whereas 90% of the recoverable hydrocarbons are from unconventional resources, with larger volume and difficult to develop reservoirs, as displayed by the base of the triangle.

Figure 3 – Triangle resource



Source: Dong *et al.* (2012)

The formation types closer to the triangle bases, have lower permeability or/and contain more viscous fluids. More complex unconventional reservoirs will be more expensive to explore and obviously, the cost of produced fluids should pay off the investment in development and production of the reservoir. Holditch and Lee (1987) affirm that unconventional reserves are much greater than conventional ones. This high energy capacity should be explored and, for this purpose, a significant field of study about new technology and production methods is required.

2.2 Unconventional resources in the world

Wang *et al*. (2016) performed an assessment study to evaluate unconventional oil and gas resources around the world. They evaluated the recoverable potential of 346 basins around the world. This study revealed that the global unconventional oil resources capacity is 4,421x10^8 t, being 1,267x10^8 t of heavy oil, 641x10^8 t of oil sands, 414x10^8 t of tight oil, 2,099x10^8 t of shale oil. Besides that, the global recoverable unconventional gas resources are estimated in 227x10^{12} m^3, being 161x10^{12} m^3 of shale gas, 17x10^{12} m^3 of tight gas, and 49x10^{12} m^3 of coalbed methane.

The assessment presented by Wang *et al*. (2016) also says recoverable unconventional oil resources are mainly concentrated in 54 countries, and the first 10 countries on the list are United States, Russia, Canada, Venezuela, Brazil, China, Belarus, Saudi Arabia, France, and Mexico, accounting for 82.4% of the global total. Unconventional gas resources are mainly concentrated in 37 countries, and the first 10 countries on the list are United States, China, Russia, Canada, Australian, Iran, Saudi Arabia, Argentina, Libya, and Brazil, with resources totalizing 76.8% of the global total.

Table 2 and 3 show the assessment of recoverable oil and gas volumes distribution in each region of the world, respectively.

Table 2 – Assessment of recoverable resources of global unconventional oil

Region	**Resources (10^8 t)**				
	Heavy oil	**Oil sand**	**Tight oil**	**Oil shale**	**Unconventional oil**
North America	318	395	91	699	1503
Russia	88	156	77	570	891
South America	409	0	68	150	627
Europe	82	18	26	354	480
Asia	130	48	79	120	377
Middle East	177	0	13	102	292

Africa	63	24	42	68	197
Oceania	0	0	18	36	54
Total	**1267**	**641**	**414**	**2 099**	**4 421**

Source: Adapted from Wang *et al*. (2016).

Table 3 – Assessment of recoverable resources of global unconventional natural gas

Region	**Resources (10^{12} m^3)**			
	Shale gas	**Tight gas**	**Coalbed methane**	**Unconventional Gas**
North America	34	5	17	56
Asia	26	9	14	49
Russia	15	0	15	30
Middle East	21	0	0	21
Africa	19	0	0	19
South America	19	0	0	19
Europe	16	1	0	17
Oceania	11	2	3	16
Total	**161**	**17**	**49**	**227**

Source: Adapted from Wang *et al*. (2016).

2.3 Hydraulic fracturing

2.3.1 Fracture materials (Proppant and Fluid)

The main materials in a hydraulic fracturing process are the fluid and the proppant agent. To keep the fracture opened and ensure it will have an acceptable conductivity, proppant must be carried by the fluid through the formation. The most common fluid in this process is a mix of water and some additives. The presence of additives is important to improve proppant transport, to adjust flow in the formation and to reduce friction during the treatment. However, in water sensitive formations, oil based fluid (such as kerosene and diesel) should be used.

The most common fracking treatment fluids are the water based ones due to the low cost and abundance of water. Approximately 98% of the treatment fluid is composed by water and proppant. As said before, water is responsible for carrying the proppant agent, and the latter is responsible for keeping the fractures opened and conductive. The other 2% of the fracking fluid consist of a series of additives, each one with its specific function. Table 4 describes some additives that may be present in the hydraulic fracturing fluid and their respective function.

Table 4 – Fluid treatment additives

Product	**Description of purpose**	**Results in the well**
Acids	Help on mineral dissolution and on the induction of fractures on the reservoir rock. Cleans up perforation intervals of cement and drilling mud prior to fracturing fluid injection.	Reacts with minerals present in the formation, producing salt, water and neutralized carbon dioxide.
Bactericide agent	Eliminates bacteria that are present in the water, preventing them from producing corrosive sub products.	Reacts with organisms that can be present on the treatment fluid and/or in the formation.
Breakers	Retard the breaking of the treatment gels.	In the formation, it reacts with the crosslinker and gel making it possible the recovery of the fracturing fluid.
Clay stabilizer	Prevents swelling of clays in the formation clays, which could block pore spaces.	Reacts with the clays present in the formation through the ionic exchange of Sodium and Potassium.
Corrosion inhibitor	Prevents corrosion on the metallic equipment present in the wells.	Connects to the metallic surfaces as tubes and other bottom-hole equipment.
Crosslinker	Keeps the fluid viscosity in the treatment when the temperature increases.	Combined with the breaker in the formations, it forms salts that returns to the surface with the water.
Friction reducer	Lubricates the water minimizing the	Stays in the formations where

	pressure loss. It also, allows fracture fluids to be injected at optimum rates.	in the presence of high temperatures and some chemicals it can be consumed by organisms.
Iron control	Prevents the precipitation of carbonates and sulfates which could plug off the formation.	Reacts with minerals in the formations, creating salts, carbon dioxide and water.
pH adjusting agent	Adjusts and controls the pH to keep the effectiveness of other additives such as crosslinkers.	Reacts with acid agents in the treatment fluid keeping the pH neutral.
Fouling Inhibitor	Prevents the fouling deposition on bottom hole and surface equipment.	Connects to bottom-hole equipment preventing from fouling deposits.
Surfactant	Reduces fracturing fluid surface tension and increases the fluid treatment viscosity.	Keeps the fluid viscosity high until to breaker becomes active.

Source: Adapted from Oliveira (2012).

According to Wieland (1971), fluids that are more viscous are better for transportation and suspension of proppant. The use of such fluids leads to longer fractures and higher proppant concentration, in other words, they are capable to generate fractures with a higher flow capacity. Though, many times it is better to use fluids with low viscosity, since they are cleaner, meaning they will not leave residues that can affect its conductivity in the fracture.

The choice of transport fluid in a design is an important step: every formation has its own peculiarities and, depending on the desired results, there is the best treatment fluid to be chosen. The mechanism of proppant transport of slickwater, a common fluid for fracturing in shale reservoirs, is different from standard water. Since slickwater has only small concentration of polymers, it does not require high viscosity or elasticity to keep the proppant in suspension. In this case, if the design requires a higher fluid suspension capacity, it is better to use a hybrid fracturing treatment fluid system, in which the injection of slickwater and gelled fluids are alternated creating complex fracture network in tight formations (CHONG *et al.*, 2010).

The proppants are solid materials, basically sand, treated sand or man-made ceramic materials, bauxite, resin, whose main function is to keep the fracture opened during and after the treatment. Figure 4 shows how some of these materials look like, in this case a ceramic proppant is shown. Besides the material type, the size of proppant is very important in a hydraulic fracturing job. These agents are divided in different sizes, generally between 8 and 140 mesh. The mesh size is the number of openings across one square inch of screen (LIANG *et al*., 2015). Thus, high mesh sizes lead to high number of openings, which means small proppants.

Figure 4 – Ceramic proppant illustration

Source: Adapted from Saldungaray and Palish (2013).

Besides the type of material and size, another important characteristic of proppants is their resistance. Proppants made of sand are the most used due to their low cost and abundance, however they are not very resistant and their closing pressure is below 6000 psi. On the other hand, sand treatment with resins leads to more resistant proppants, which have a higher closing pressure. Table 5 shows some proppants and their densities and closing pressures.

Table 5 – Density and closing pressure by type of proppant

Type of proppant	**Density (g/cm^3)**	**Closing pressure (psi)**
Pure sand	2.65	< 6000
Sand with treated resin	2,55	< 8000
Intermediary resistance ceramic	2.7 – 3.3	5000 - 100000
High resistance ceramic	3.4 or higher	> 100000
Bauxite	2.0	> 7000

Source**:** Castro (2015).

2.3.2 Fracture mechanics and propagation.

The in-situ stresses in a formation are classified in three main stresses, generally the first is the highest stress resulted from the pressure of the underlying layers. In this environment, the fracture direction is normal to the least stress. So, the fracture opens against the three smaller stresses and grows in the direction of the lowest. In most of the cases, the minimum horizontal stress is the smallest one, creating vertical fractures.

As fluid is injected with a high flow rate, the pressure increases until it reaches the breakdown pressure. This pressure depends on the reservoir pressure, formation mechanical properties, the three main stresses and the formation tensile strength (DANESHY, 2010). According to Terzaghi (1923), the breakdown pressure for vertical wells is given by the following equation:

$$P_{bd} = 3\sigma_H - \sigma_h + T_0 - P \qquad [1]$$

where, σ_h and σ_H are the minimum and maximum horizontal tension, respectively; T_0 is the rock tension and P is the reservoir pressure.

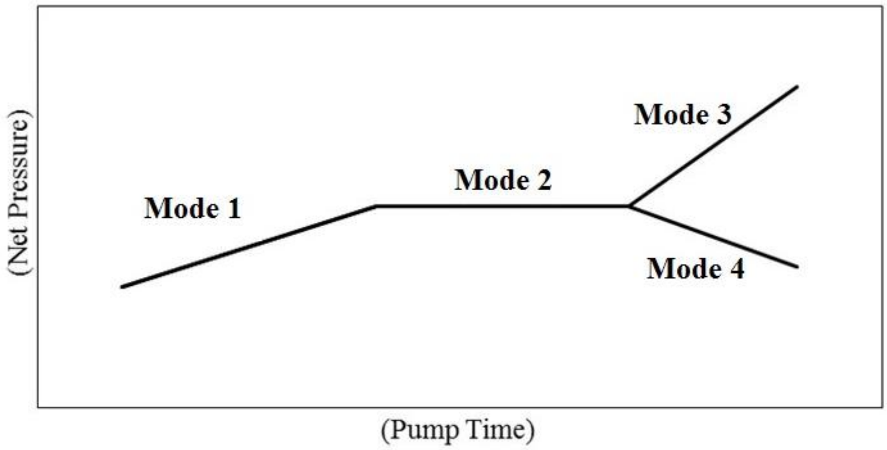
The fracture geometry is controlled by the net pressure exerted in the formation. This pressure is responsible for opening the fracture and for its propagations, and it consists of the difference between the fracture propagation pressure and the fracture closing pressure.

According to Kim e Wang (2011), the calculation of the net pressure can be given by the bottomhole pressure, which depends on the surface pressure, hydrostatic pressure and fluid friction pressure drop, subtracted by the perforation pressure drop and in-situ tension, as shown on Equation 2:

$$P_{net} = P_{surf} + P_{hyd} - P_{fric} - \Delta P_{perf} - \sigma_1 \qquad [2]$$

The analysis of the net pressure is an important step during a hydraulic fracturing job. A logarithm diagram performed by Nolte and Smith (1981) represents the behavior of the net pressure as a function of injection time. This diagram is a powerful tool for the interpretation of the fracture geometry over the process. Nolte and Smith (1981) divided the process into four distinct modes, which describe different behaviors over the operation, as shown on Graph 1.

Graph 1 – Nolte-Smith Diagram



Source: Adapted from Britt (2015).

Mode 1 represents the period the height is confined only in the perforated region. The fracture grows only in length as fluid is injected. This mode is represented on the graph by a curve with slope between 1/8 and 1/4.

Mode 2 is the region where the curve has a zero slope, indicating a constant net pressure during a certain amount of time. There is a stable height growth and fluid loss to the formation due to the presence of natural fractures. The fluid injection pressure being compensated by the fluid loss characterizes this constant net pressure.

Mode 3 is represented by the unit slope curve. In this region, the net pressure growth is proportional to injection time, which can be due to the fact that fracture reached its maximum length or because it reached a high tension zone, as a shale content region.

In contrast, the fracture can change from Mode 2 to Mode 4, where the curve has a negative slope. A characteristic of this region is a fast and uncontrolled height growth due to it reaching a low tension region, it can also be a consequence of a screen-out due to fluid loss in Mode 2.

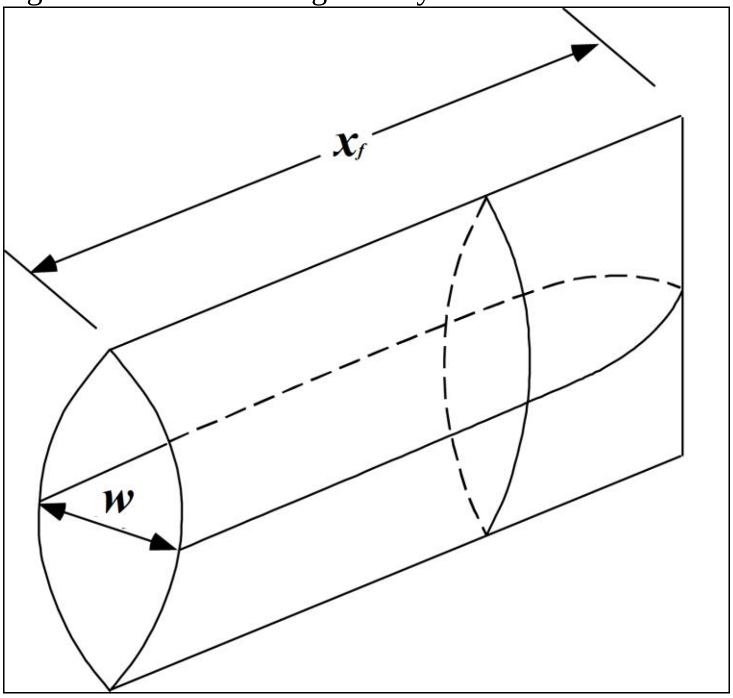
2.3.3 Optimum fracture and geometry

The critic parameters to get an effective fracture are the length and its conductivity. The length, as previously explained, is the fracture extension tip to tip, and its conductivity is the ability of the fracture of carrying fluids. Length and conductivity should be analyzed in each scenario to determine which one will most affect the design. However, there should be a balance between length and conductivity, in order to obtain a design that can result in a reasonable increase of productivity after the treatment. The dimensionless fracture conductivity (F_{CD}) can be calculated with Equation 3, which relates the formation capacity to feed fluid to the fracture kx_f and the fracture capacity to carry fluid $k_f w$.

$$F_{CD} = \frac{k_f w}{k x_f} \qquad [3]$$

where k_f is the fracture permeability (after the treatment), w is the fracture width, k is the formation permeability and x_f is the fracture half length. Some of these fracture properties is illustrated on the Perkins-Kern-Nordgren (PKN) geometry, shown in Figure 5, which is normally used when the fracture length is much greater than the fracture height.

Figure 5 –PKN fracture geometry



Source: Adapted from PetroWiki. Accessed on 5th July, 2017.

According to Britt (2015), the optimum F_{CD} for an oil reservoir fracturing (steady state flow) is 2, and for a gas reservoir (transient flow) the optimum F_{CD} is 10.

2.3.4 Fracture Design

The design is the most important step in a fracking process. This step consists on the calculation of fluid volume to be injected in each stage, choice of proppant, determination of flow rate and injection pressure. The fracture properties are the fracture height, width and half-length. It is important to mention that the fracture length is divided in two components, the hydraulic length and the propped length. Creating a fracture with the longest possible length with proppant is the goal of all hydraulic fracturing jobs.

Each stage of a hydraulic fracturing job has its own operational conditions, as volume, type of proppant, type of fluid and injection flow. In the first stage, called pad, only fluid is injected in the well to fracture the formation. After this fracture has been propagated, the slurry stage starts. In this stage, the flow is mixed with sand (proppant) and it is injected in the fracture opened by the pad stage (GUO, 2007).

More details about each stage in a hydraulic fracturing treatment are discussed below:

- **Pad:** in this stage fracturing fluid is injected without proppant agent. The pressure must be higher than the formation fracture pressure, so the fracture can propagate until the desired radius.
- **Slurry:** in this stage, there is a gradual mix of proppant in the injection fluid. The injection of the slurry (fluid and proppant) must follow the pump schedule performed for this design.
- **Flush:** after all fluid from the pad stage has been lost to the formation, a fluid is pumped to clean up the path created by the fracture.

Equation 4 shows in a simplified way how productivity increases after the treatment is related for steady state flow, for moderate to high permeability formations (between 2 and 5 mD). Folds of Increase (FOI) is given by the ratio of post treatment production and pretreatment production (Darcy Equation) and relates the well's effective radius after the treatment with the damages before the formation has been fractured, the skin factor.

$$FOI = \frac{\ln(r_e/r_w) + S}{\ln(r_e/r_{w'})} \qquad [4]$$

where r_e is the drainage radius, r_w is the actual wellbore radius, $r_{w'}$ is the effective well radius and S is the skin factor.

2.4 Formation evaluation and logs

Important parameters to the reservoir characterization for hydraulic fracturing and hydrocarbon recovery include porosity, permeability, saturations, and lithology of the formations. All these parameters are used to estimate net pay, amount of hydrocarbons in place, pre and post fracture rate of recovery.

Two of the most important aspects of formation evaluation are geological and core analysis. The evaluation of the formation material and measurement of the physical and chemical properties are crucial to a comprehensive formation evaluation (HOLDITCH; ROBINSON; WHITEHEAD, 1987). Core analysis is the best technique for obtaining some rock properties as Young's modulus and Poisson's ratio. The Young's modulus of the formation is the only fracturing parameter that can be directly measured through compression tests. This measurement improves the analysis of other geomechanical parameters.

The orientation and geometry of hydraulic fracturing can be determined by making an azimuthal gamma ray measurement (SIMPSON and GADEKEN, 1993; CHEN *et al.*, 2017). These radioactive log measurements are also important for determining where to frac, since it provides an indication of lithology. The Dipole Sonic Log provides critical information in defining the closure stress beds for determining fracture height growth parameters.

2.5 Reservoir considerations

In a hydraulic fracturing design, many factors that may directly influence the characteristic of the fracture should be considered. Reservoir properties as porosity, permeability, saturation and net pay must be analyzed in a project. Such properties, except the permeability, can be estimated through well logging analyses. The permeability and reservoir pressure can be obtained through well testing.

Another factor also controlled by formation properties is the fluid loss. This loss strongly affects the volume and fluid selection, so it should be considered during the project development as well. Geomechanical data from well testing and completion data must also be considered.

2.6 Objectives

2.6.1 General objectives

The goal of this work was to elaborate a computational design of a hydraulic fracturing job using the software STIMPLAN, developed by NSI Technologies. For this purpose, a pump schedule was designed, using real data from a tight gas (low permeability) reservoir. All parameters mentioned before were considered, objecting to obtain a fracture with optimum F_{CD} and acceptable drainage area.

2.6.2 Specific objectives

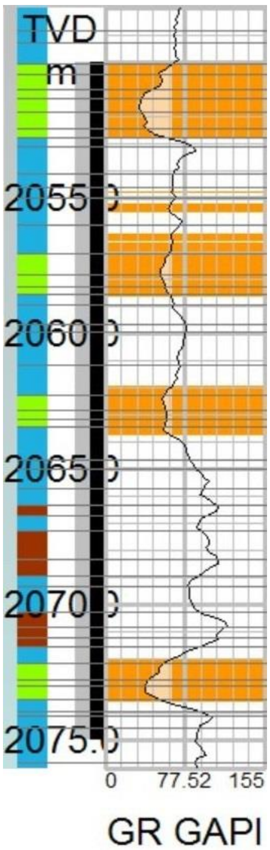
- To find the net pay zone;
- To find the reservoir pressure and permeability by well testing analysis;
- Design pump schedule for two different scenarios: first for injection of 15000 BBL and then for 2000 BBL;
- Provide a pump schedule with an acceptable F_{CD};

3 METHODOLOGY

This design was developed from real data of a vertical well and formation of the field located in Chile. The reservoir properties are: perforation depth between 2050 and 2075 m, porosity of 17.6%, water saturation of 51.3%, drainage radius of 160 acres, and bottom-hole temperature of 92°C. These properties were previously provided and obtained from log measurements and core tests data. Other reservoir properties were obtained after importing formation logs and pressure data to the software, and then the STIMPLAN could provide the well testing analysis and formation evaluation through logs. It was specified that the area of interest is a glauconite formation.

To identify the desired layer for the input of the software, a lithology log (Gamma Ray) was used. The formation zones to be fractured are where the gamma ray logs are below 65 °API. Figure 6 shows the gamma ray measurements by depth, the net pay for the formation is the lighter orange part, being the total net pay height of 7.6 m. The injection pressure data, measured on the surface was imported to the software as well, and from them it was determined some reservoir properties, minimum horizontal stress and breakdown pressure.

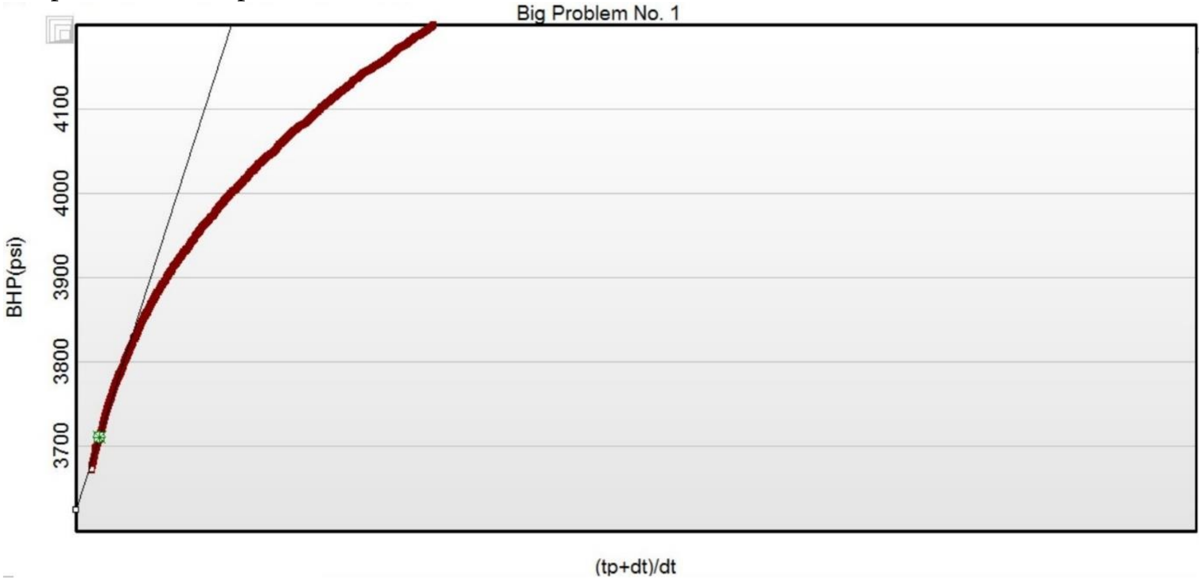
Figure 6 – Gamma ray measurements by depth in meters



Source: author.

The bottom-hole pressure was determined by adding the well hydrostatic pressure to the surface pressure available. For this, it was considered a density of 9.0 lb/gal for the completion fluid. The reservoir pressure and permeability were obtained from analyses of the bottom-hole pressure versus time (build-up test), using the Horner Plot graph in STIMPLAN. Graph 2 shows this plot, from where these reservoir properties were obtained.

Graph 2 – Horner plot



Source: author.

The geomechanical profile from the logs and reservoir data obtained from the well tests, were used, first, to develop a design limited to 15,000 barrels of fluid volume. Then a second design was proposed, but limited to 2,000 barrels of fluid volume. For both designs, it was considered two fluids for the fracking: slick water (water containing a low concentration of polymers) and cross-linked gel (50 X-Link_HPG), this latter was chosen due to its high viscosity which makes it good to carry proppant.

Many options for the pump schedule were considered in the design, objecting to obtain a reasonable F_{CD} and fracture length. For the first scenario, it were necessary nineteen stages, being four stages with 610.5 barrels for the pad, and more fifteen stages with 847.2 barrels each one with proppant (Ottawa Sand 20/40). The pumping flow rate for each stage varied from 20 to 50 barrels per minute.

For the second scenario, five stages were necessary, being one stage with 325 barrels for the pad, and more four stages with 418.6 barrels each one with proppant (Ottawa Sand 20/40). The pumping flow rate for each stage varied from 20 to 45 barrels per minute

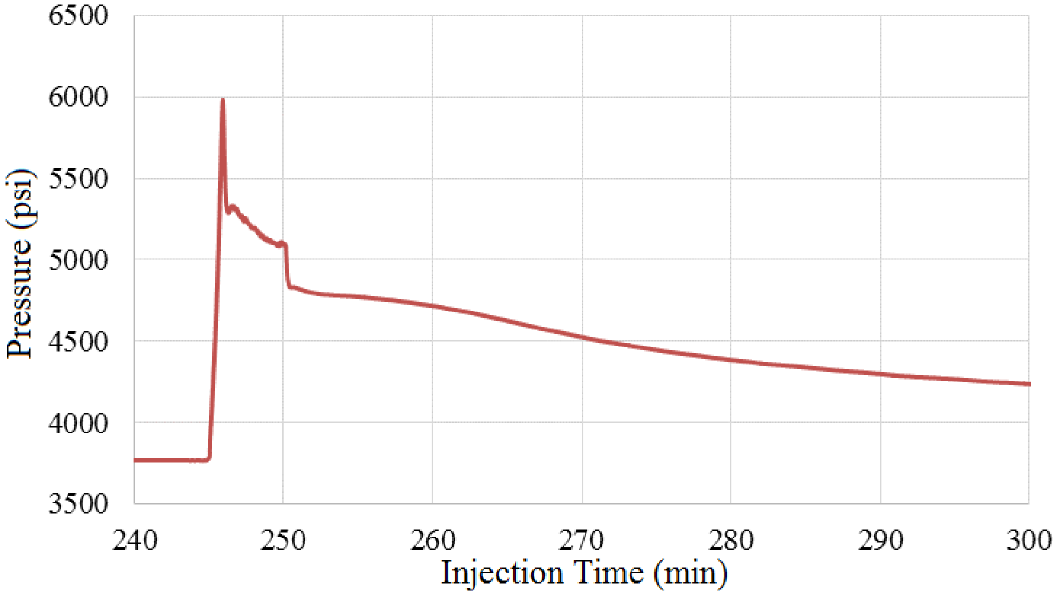
4 RESULTS AND DISCUSSION

4.1 Results for Design 1

For this design, the hydrostatic pressure for a depth of 2062.3 meters (mid perforation depth), was 3220.7 psi. Through well testing analyses (build-up test), the values obtained for reservoir pressure and permeability were 3622.3 psi e 0.0128 mD, respectively. This value of permeability is low, and according to the literature, the optimum fracture should be long.

From the real pressure versus injection time data plotted in Graph 3, the breakdown pressure was determined by the peak of the curve, being approximately 5920 psi.

Graph 3 – Bottom-hole pressure versus injection time



Source: author.

Table 6 presents the results obtained for this fracture. It can be noted that due to the high fluid volume injected, the fracture is long. In this case, the fracture propped length was approximately the same as the hydraulic length. On the other hand, the maximum fracture height is relatively high, being extended until an upper area to the perforation area. This shows the tendency of the formation to develop higher fractures.

It is important to say that when high viscous fluids, as the cross-linked gel, are used, the height growth is greater. In this case the best solution to reduce this effect is to use water (slick water) as pad.

Table 6 – Results for design 1

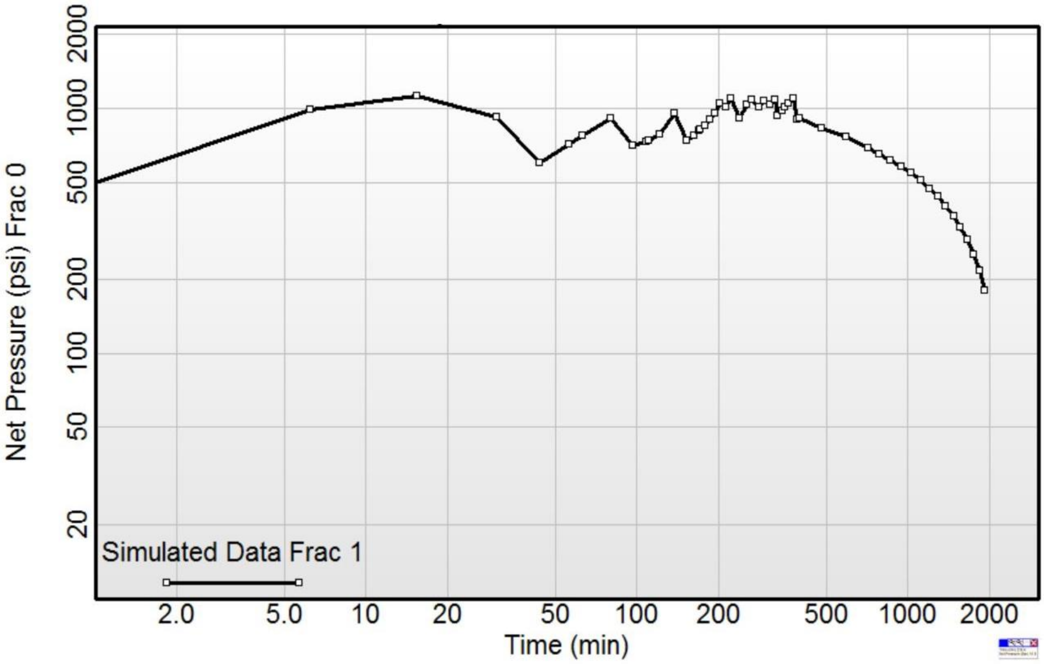
Properties	Value
Half length (m)	2173
Propped length (m)	1893
Fluid loss (bpm)	7.92
Maximum height (m)	155.3
Average width (in)	0.19
F_{CD}	9.52

Source: author.

For this design, the obtained F_{CD} was 9.52, which is very close to the optimum value for gas reservoirs that is 10.

On Graph 4, the behavior of the net pressure versus injection time for this project is shown. We can note the behavior of Mode 1 of Nolte and Smith (1981) diagram in the first seventeen minutes. Then, there is an uncontrolled height growth following by oscillations of grow in height and length as shown between seventeen and approximately four hundreds minutes. Finally, after this, just an uncontrolled height growth is present, when a low-tension region is reached, characterizing Mode 4.

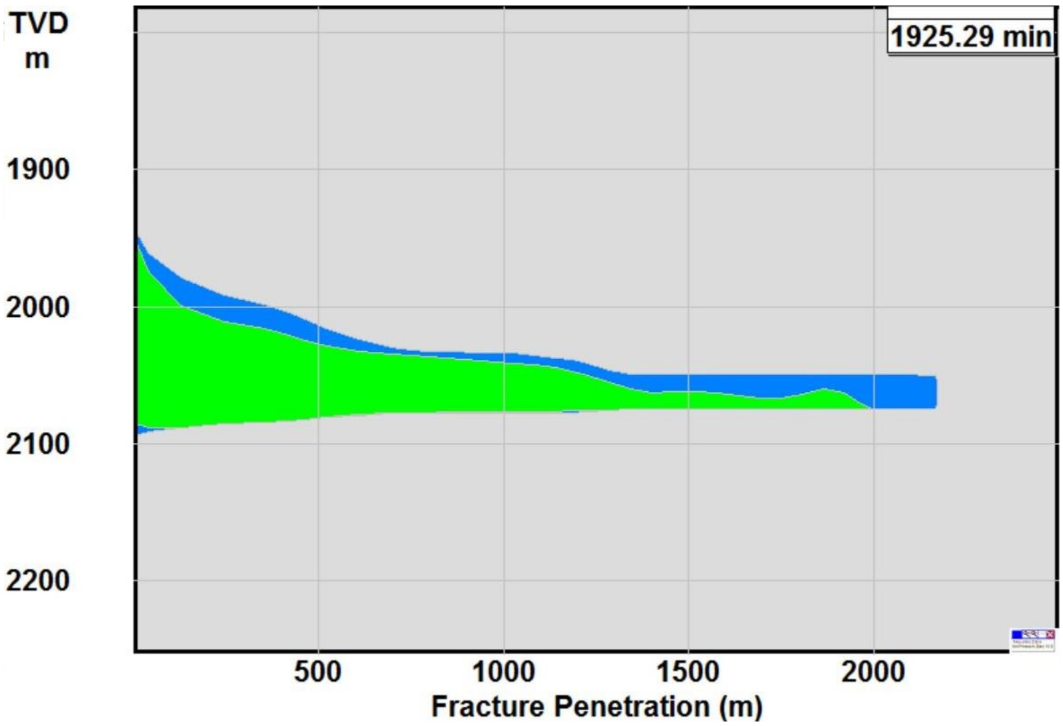
Graph 4 – Nolte-Smith diagram for design 1



Source: author.

On Figure 6, we can observe the fracture propagation and its bi-dimensional geometry, if this design was executed on the field. The blue region corresponds to the pad region, and the green region is the slurry region, in which the proppant agent is present. Looking at Figure 7, it can be noted that the increase on fluid viscosity (by changing from pad stage to slurry stage) contributed to an increase in fracture height, making it to extend beyond the perforation zone, as it was expected.

Figure 7 – Two-dimensional representation of the fracture obtained in the simulation for injecting 15,000 BBL (blue region: pad; green region: slurry)



Source: author.

4.2 Results for Design 2

Table 7 presents the results obtained for the fracture when injecting only 2,000 barrels of fluid. For this design, it was noted that the fracture is smaller, due to the lower fluid volume injected, extending just for 658 meters. For this volume, the fracture propped length was approximately the same as the hydraulic length, as on Design 1. The maximum fracture height is relatively high as in the other design, but it is still being extended until an upper area to the perforation zone.

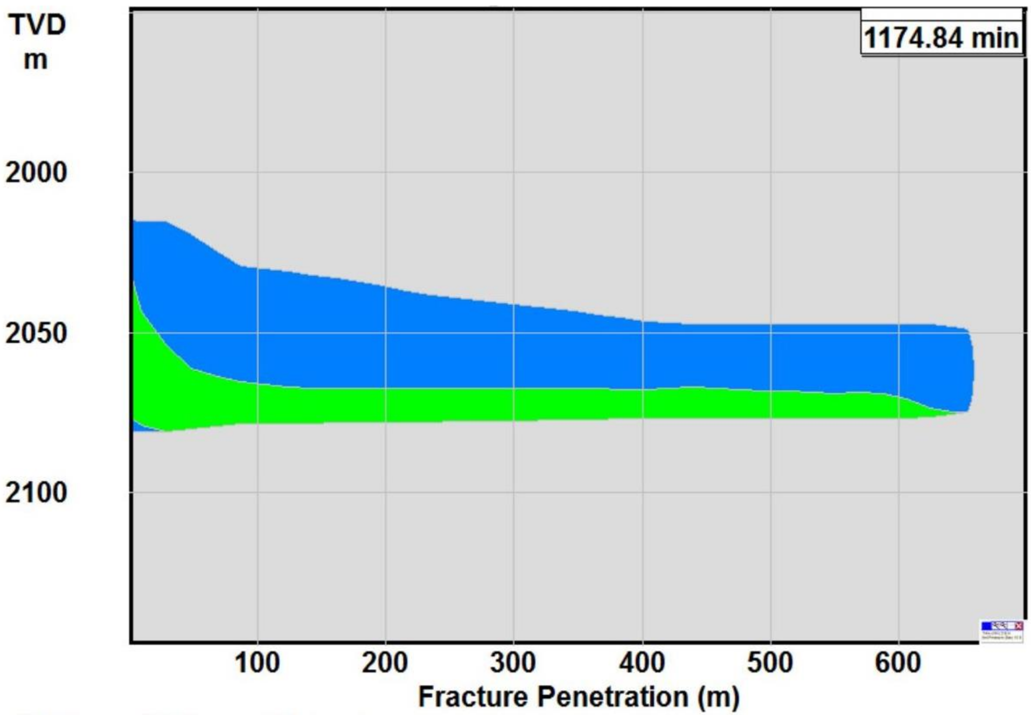
Table 7 – Results for design 2

Properties	Value
Half length (m)	658
Propped length (m)	596
Fluid loss (bpm)	2.25
Maximum height (m)	66.6
Average width (in)	0.21
F_{CD}	9.18

Source: author.

On figure 8, it is possible to observe the fracture propagation and its bi-dimensional geometry. By looking at this figure, it can be noted that the increase on fluid viscosity (by changing from pad stage to slurry stage) did not contributed to an increase of the fracture height as in design 1. In addition, we can see that for this design the proppant agent did not spread for almost all pad area. This could be due to the used proppant concentration or the treatment fluid. Probably, for the design with only 2,000 barrels of injection fluid, the more viscous fluid should be used, so it can carry the proppant to a larger area.

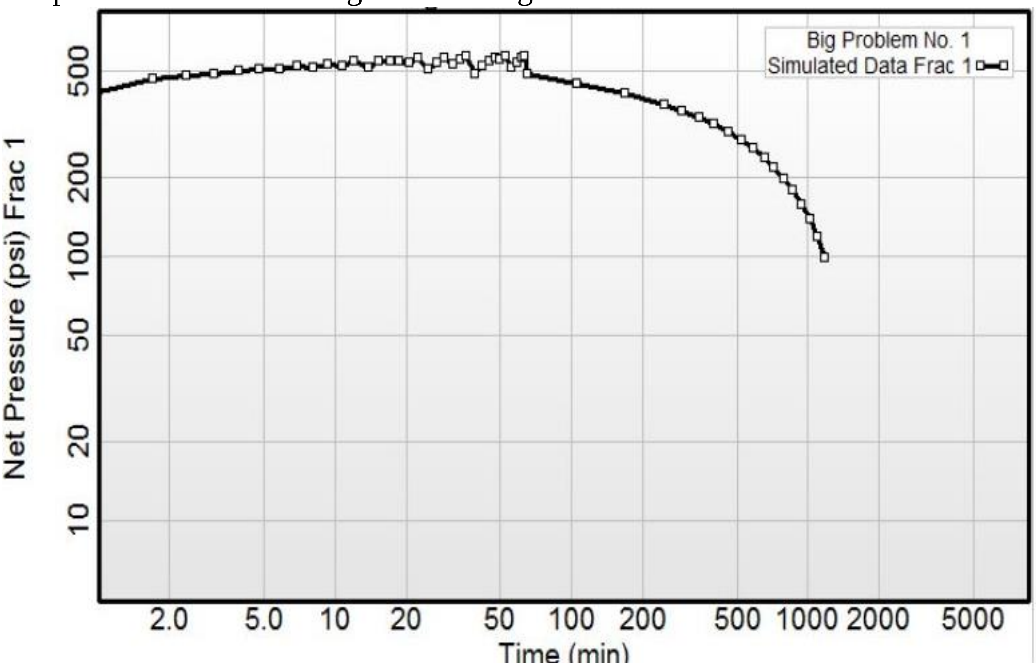
Figure 8 – Two-dimensional representation of the fracture obtained in the simulation for injecting 2,000 BBL (blue region: pad; green region: slurry)



Source: author.

Graph 5 shows the behavior of the net pressure versus injection time when injection 2,000 BBL with the proposed pumping schedule. We can note the behavior of Mode 1 of Nolte and Smith (1981) diagram in the first ten minutes. Then, the critical pressure is presented between ten and twenty three minutes, when the curve slope is zero. Finally, after 65 minutes of injection time, a low-tension region is reached, where the fracture behavior is characterized by Mode 4, in which uncontrolled height growth happens.

Graph 5 – Nolte-Smith diagram for design 2



Source: author.

5 CONCLUSION

It can be concluded that the two presented designs showed good results for fracking of this formation. The obtained fractures have a long length, which, according to the literature, is a good geometry for low permeability gas reservoir. However, it is better to use the larger volume design since it provides a longer fracture. The resulted F_{CD} was close to the optimum value for gas reservoirs, which shows a good relationship between fracture conductivity and length in both designs.

Through logging analysis on the software, it was possible to estimate the height of the interest zone and then put this value as input. The well testing analysis was very helpful, being essential to find the reservoir permeability and pressure.

Another point to mention is the fact that the geometry for the designed fracture confirms the behavior of Nolte-Smith diagram, which evidences its importance in a data analyses for a project.

It was possible to confirm that the use of more viscous fluids affects the fracture geometry, as shown for injection of cross-linked fluid, which made the fracture grows quickly in height, more than if only slick water was used. However, the use of this fluid made it possible to get a longer propped length, as proppant agent was distributed over a reasonable part of the fracture. We can conclude the used technique brought interesting results for this reservoir, showing that the hydraulic fracturing is a good method to maximize the production in low permeability reservoirs.

For future works, the recommendations are: to perform an economic analyses for both design (2,000 BBL and 15,000 BBL), to provide a new pumping schedule using a lower viscous fluid and lower proppant concentration. It would be interesting to create a new pumping schedule with a flush stage and see the effect on the propped length and F_{CD}.

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