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-THÈME / TITLE-

Case study of Depleted Reservoir Hydraulic Frac. Simulating OMP-742 Frac with Energizing Fluid.

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Summary

Abbreviation List

A_f	Fracture surface	ft^2
B_g	Oïl volumetric factor	$m^3/stdm^3$
B_0	Volumetric factor	m^3/stm^3
C	Compressibilty	Psi^{-1}
C_f	Fracture coefficient	ft/psi
C_L	Filtration coefficient	$ft/\sqrt{min}$
Cpf	Final concentration in proppant	ppg
C_p	Concentration of proppants (Proppant)	lb/ft^2
$\overline{Cp}$	Average concentration in proppant	ppg
E	Young's modulus	Mpsi
E'	Plane deformation modulus	Mpsi
F_{CD}	Dimensionless conductivity	/
FOI	Folds Of Increase	/
G	Shear modulus	Psi
G_F	Fracturing gradient	Psi/ft
GOR	Gas flow rate compared to oil	m^3/m^3
H	Layer height	(ft) ou(m)
h_f	Fracture height	(ft) ou(m)
$ISIP_S$	Surface hole instantanus shuting pressure	psi
ISIP	Instantanus shuting pressure	Psi
$ISIP_{BH}$	Bottom hole instantanus shuting pressure	Psi
K	Permeability of formation or pristine area	Darcy
K_f	Permeability of Fracture	Darcy
Kh	Conductivity	md.ft
K_L	Efficiency-dependent coefficient	/
Ks	Permeability around the well or damaged area	Darcy
LLP_{BH}	Bottom hole last pressure pumping	Psi
LPP_S	Surface hole last pressure pumping	Psi
$m_{proppant}$	Mass of proppant	Klbs
Pe	Well drainage limit pressure	atm / psi
σ_{eff}	Effective stress	Psi
Φ_p	Proppant porosity	%
τ	Shear stress	τ

P_{ext}	Fracture extension pressure	Psi
P_f	Fracturing pressure	Psi
P_g	Deposit pressure	Psi
P_{HB}	Bottom hole pressure	Psi
P_{Inj}	Injection pressure	(psi)
P_{net}	Net pressure in the fracture	Psi
P_p	Pore pressure	Psi
P_{wf}	Pressure at the well wall	(atm) ou (psia)
ΔP_{BH}	Pressure drops around the well (Near wellbore)	Psi
$\Delta P_{Pipefriction}$	Friction losses	Psi
ΔP_{Total}	Total pressure drop	Psi
Q_{inj}	Injection rate	bbl/min
	Production flow before fracturing	(m^3/h) ou (bbl/j)
	Production rate after fracturing	(m^3/h) ou (bbl/j)
ΔQ	Gain in production	m^3/h
r_e	Drainage radius	(cm) ou (ft)
r_s	Damage radius	(cm) ou (ft)
r_w	Real well radius	Ft
R_w'	Effective well radius	Ft
S	Skin factor	/
S_o	Oil saturation	%
S_w	Water saturation	%
T	Recording time	min
t_p	Pumping time	min
t_{pad}	Pad injection time	min
V_f	Fracture volume	ft^3
V_i	Total volume injected	bbl
V_{pad}	PAD volume	ft^3
W_f	Fracture width	(ft) ou (m)
Pc	Fracture closure pressure	Psi
$\overline{W}_f$	Largeur moyenne de la fracture	in
W_{fp}	Width suported by the proppant	in
X_f	Half lengh of the fracture	(ft) ou (m)
β	Geometric Factor	/
ε	Deformation	/
η	Fluid efficiency	%
υ	Poisson ratio	/
ρ	Density	g/cm^3
ρ_p	Density of the proppant	lb/ft^3

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Resume

Our study aims at the selection of a candidate well (OMP742) for stimulation treatment by a Conventional Hydraulic Fracturing as well as considering the benefits of the foam as energizing fluid in order to simulate the Frac operation for same well. Selection of the well candidate is made according to determined criteria, such as good petro-physical characteristics, location of the well, its completion, importance of reservoir damage, flow rate history and expected improvement of oil production post frac to ensure good economics for gaining much more daily oil production by saving time. Then, converting the same well to Gas-Lift mode a year after the frac job will help sustain the daily production longer enough.

Since most formation experience an uneven depletion of the reservoir pressure, hence new improvements in hydraulic fracturing to increase fracture conductivity are actively discussed. One of them is fracturing with foam, as topic on which we focus in this study.

This document will be structured, step-by-step, starting with generalities on Hydraulic Facturing, clarifying its different parameters, in addition fluid proprieties additives, and proppant concentration. At this level we will include the foam as behavior during the frac job.

The process of hydraulic fracturing by enumeration its different sequences was considered also, including interpretation and analysis of pressure curves decline. Followed with Hydraulic Fracturing Design with the illustration of results calculated compared to stimulated ones by FracCad software,

Because of shortage of Nitrogen pumping equipments in Algeria at present time,(needed daily at Hassi Messaoud for Coiled Tubing activity) a design scenario using a foam as energizing fluid for the contain of nitrogen (N2) gas was applied for OMP742 as simulation only, including performing pumping schedule with simulator, to show the benefit of this operation compared to the conventional fluid: using less fluid which leads to less damaging to the fracture conductivity, better fluid efficiency and good rheological performance at reduced polymer loading ,therefore improving the productivity of OMP742 well.

Résumé

Notre étude vise à sélectionner un puits candidat (OMP-742) pour un traitement de stimulation par une fracturation hydraulique conventionnelle ainsi qu'à considérer les bénéfices de la mousse comme fluide énergisant afin de simuler l'opération Frac pour le même puits. La sélection du puits candidat est faite selon des critères déterminés, tels que de bonnes caractéristiques pétro-physiques, l'emplacement du puits, sa complétion , l'importance des endommagements au niveau de réservoir, l'historique du débit et l'amélioration attendue de la production de pétrole post-frac pour assurer une bonne économie et un meilleur gain de production quotidienne de pétrole en gagnant du temps. Ensuite, la conversion du même puits en mode Gas-Lift un an plus tard, décidée par Sonatrach, aidera à maintenir la production quotidienne suffisamment longtemps.

Étant donné que la plupart des formations subissent un épuisement naturel ou parfaois irrégulier de la pression du réservoir, de nouvelles améliorations de la fracturation hydraulique pour augmenter la conductivité de la fracture sont activement discutées. L'un d'eux est la fracturation avec de la mousse, sujet sur lequel nous nous concentrons dans cette étude.

Ce document sera structuré, étape par étape, en commençant par des généralités sur la Fracturation Hydraulique, en clarifiant ses différents paramètres, en plus des propriétés des fluides additifs, et la concentration de l'agent de soutènement. À ce niveau, nous inclurons la mousse décrivant son comportement pendant l'opération de fracturation.

Le processus de fracturation hydraulique par ses différentes séquences a également été pris en compte, notamment l'interprétation et l'analyse des courbes types de pression. Suivi de la conception de fracturation hydraulique avec l'illustration des résultats calculés par rapport à ceux simulés par le logiciel FracCad,

En raison de la pénurie d'équipements de pompage d'azote en Algérie à l'heure actuelle, (Exigés quotidiennement pour l'activité coiled Tubing à Hassi Messaoud) un scénario de conception utilisant une mousse comme fluide énergisant pour contenir du gaz azote (N2) a été appliqué pour l'OMP742 à titre de simulation uniquement, y compris l'exécution du programme de pompage avec simulateur, pour montrer l'avantage de cette opération par rapport au fluide conventionnel: utiliser moins de fluide ce qui conduit à une moindre dégradation de la conductivité de la fracture, un meilleur rendement du fluide et de bonnes performances rhéologiques à chargement de polymère réduit, améliorant ainsi la productivité de l'OMP742.

تلخيص

تهدف دراستنا إلى اختيار بئر مرشح للعلاج التحفيزي بواسطة التكسير الهيدروليكي التقليدي. يتم اختيار البئر المرشح وفقًا لمعايير محددة وهي الخصائص البتر وفيزيائية الجيدة، وموقع البئر، واكتمالها، والجلد المرتفع في حفرة البئر.

نظرًا لأن معظم التكوين يواجه استنفادًا غير متساوٍ لضغط الخزان، وبالتالي تتم مناقشة التحسينات الجديدة في التكسير الهيدروليكي لزيادة موصلية الكسر، أحدها هو التكسير بالرغوة والذي سيكون موضوعًا نركز عليه في هذه الدراسة.

سيتم تنظيم الدراسة خطوة بخطوة بدءًا من العموميات على التكسير الهيدروليكي مع توضيح المعلمات المختلفة التي تضيف إلى ذلك خصائص المائع والمواد المضافة وتركيز مادة الدعم، وفي هذا المستوى سنقوم بتضمين الرغوة كسائل تكسير ثم شرح ما هو الرغوة التكوين والتخزين مزيد من خصائصه وسلوكياته خلال عملية التكسير الهيدروليكي.

مع الانتهاء من العموميات، سنكشف عن طريقة تحقيق التكسير الهيدروليكي من خلال تعداد تسلسله المختلفة، ثم سننتقل لشرح تفسير وتحليل علاجات الضغط، وما أن يتم فهم الطريقة فسوف نطبق الطريقة الهيدروليكية تصميم الكسر مع الرسم التوضيحي للنتيجة المحسوبة مقارنة بتلك المحفزة بواسطة برنامج .FracCad

سنفترض فقط أن سيناريو التصميم باستخدام سائل الرغوة هو نيتروجينN_2 بسبب نقص معدات الضخ سيتم تنفيذ جدول الضخ باستخدام المحاكاة، الفائدة من هذه العملية هي تحقيق ما يتم تنفيذه عند استخدام السوائل التقليدية، ولكن مع استخدام كمية أقل من السوائل يعني ضرر أقل لموصلية الكسر، وكفاءة مائع أفضل وأداء ريولوجي جيد عند تقليل تحميل البوليمر ، وبالتالي تحسين الإنتاجية من البئر.

General Introduction

Reservoir stimulation and artificial lift are the two main activities of the production engineer in the petroleum and related industries. The main purpose of stimulation is to enhance the property value by the faster delivery of the petroleum fluid and/or to increase ultimate 6economic recovery. So, matrix stimulation and hydraulic fracturing are intended to remedy, or even improve, the natural connection of the wellbore with the reservoir, which could delay the need for artificial lift. What we are going to focus on in our study subject is hydraulic fracturing with foams as energizing fluids.

Hydraulic fracturing is a particularly complicated enterprise. The purpose of hydraulic fracturing is the placement of an optimum fracture of a certain geometry and conductivity to allow maximum incremental production (over that of the unstimulated well) at the lowest cost. This process combines the interactions of fluid pressure, viscosity and leakoff characteristics with the elastic properties of the rock. Accomplishing this, while taking into account all the presented technology, requires significant attention to the treatment execution involving optimized completion and perforating strategies, appropriate treatment design, control and monitoring of rate, and pressure and fluid characteristics.

The history of the use of foams in the production of oil and gas shows that foams are very versatile fluids with specia1 properties, making them outstanding candidates for some applications. In 1966, Anderson, Harri son and Hutch; son1 reported the development of foams for drilling and wellbore cleanout. They found the following features particularly interesting in well completion fluids, which supply much less hydrostatic head than conventional drilling fluids, thus differential pressure into the producing interval is lower. Lower differential pressure causes less fluid loss and less formation damage due to fluid invasion. These features were very helpful when drilling and completing wells in low-pressure zones (depleted reservoir) which is the case of our well study OMP-742.

The fluid characteristics of foams are in some ways quite different from ge1led liquids. Foams have relatively low viscosities, which make them similar to linear gels. On the other hand, they have very low particle-settling rates similar to crosslinked gels.

The rheological properties of foams are sufficient to open and extend fractures. Low particle settling rates, and, therefore, good particle transport properties, are responsible for foam being able to carry large amounts of proppants through a fracture.

Foams contain a very large amount of potential energy in the high-pressure gas they contain. When a foam-fractured well is put on production, most of the energy of compression is available for removing fluids and solids from the wellbore. By "energizing" the produced fluids, a high percentage of the treating liquids is blown from the well, thus achieving a rapid cleanup of treating fluids.

This study is divided into five chapters where we try to organize, expose and explain clearly step by step the process of hydraulic fracturing starting by a general view on the conventional and foam fracturing fluids to the realization and analysis of pressure decline curves passing by the practical study on OMP-742 well using the conventional fluid adding Methanol and Fiber as a new additives. To finish with a design scenario using a foam fluid (N2 with deferent qualities as an energizer) performed with simulator.

Chapter I : Hassi Messaoud field

Introduction :

Hassi Messaoud field is one of the most complex fields in the world. During geological history, this field underwent on the one hand, an intense tectonic evolution characterized by compressive and distinctive phases. On the other hand, by the diagenetic transformation in the reservoir during its burial during geological time, until the deposit has taken shape as represented by the current configuration. These events can sometimes improve the petrophysical parameters (creation of natural fractures…) as they can deteriorate them (decreasing porosity …)

This chapter gives a view of the field of Hassi Messaoud on different aspects (geographic situation, geological location and reservoir characteristic). In addition describes the stratigraphic structure and lithology of OMP-742 well.

I.1 Geographic location of Hassi Messaoud field:

The Hassi Messaoud field contributes for more than 50% of Algerian production. It is located in the vast desert of the Algerian Sahara, north of the African continent. It is also located 700 km southeast of the capital Algiers, 350 km from the Algerian-Tunisian border, as well as approximately 80 km southeast of the city of Ouargla and 176 km south of Touggourt (figure 1) its location in Lambert South Algeria coordinates:

X = 790,000 - 840,000 Est,

Y = 110,000 - 150,000 North.

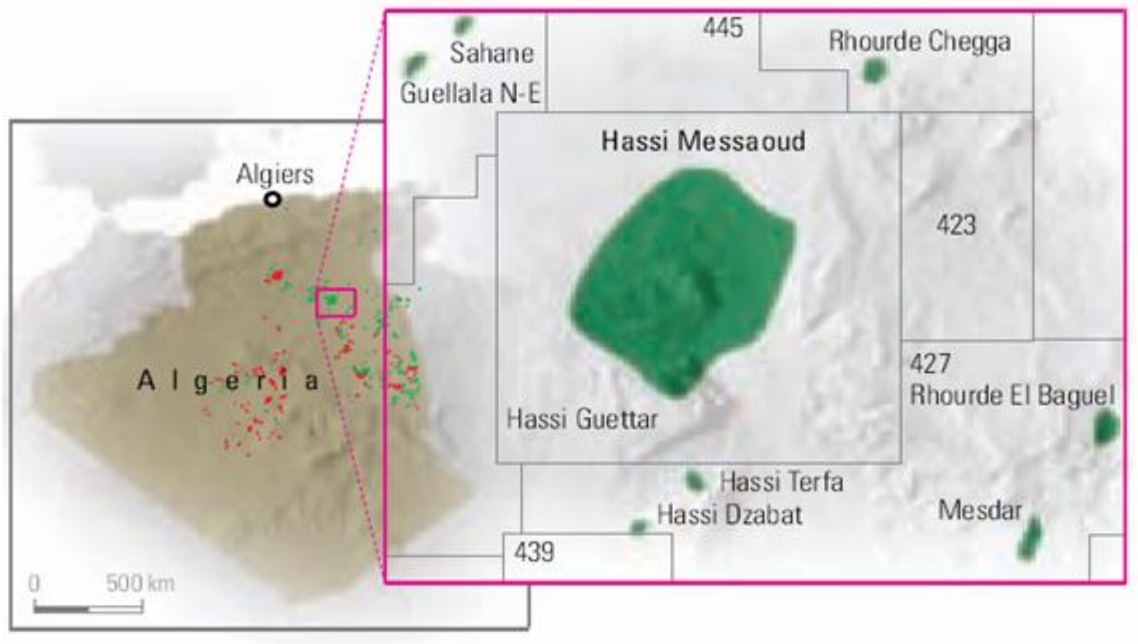

Figure I.1: Location of Hassi Messaoud Oil Field.

I.2 Geological situation of Hassi Messaoud field:

The Hassi Messaoud field is located in the northern part of the Sahara Platform which is situated in the south of Algeria .The Hassi-Messaoud field occupies the central part of the Triassic province. It is considered one of the most important and noticeable field in the world. Also it positions close to 800 km south east of Algiers as illustrated on figure 1.1, it extends an area of 2000 Km2 (50 × 40 Km) which has a multi-billion oil field discovered in 1956.

It is also limited by the following deposits (see Figure 1.2):

- To the West by the Guellala, Ben-Kahla and Berkaoui deposits;
- In the North-West by the Ouarsenis N, Zidane Lakhar and Boukhezana deposits;
- In the Northeast by the Rh. Chegga deposit;
- In the Southeast by the Rhourde El Baguel and Mesdar deposits;
- In the Southwest by the El Gassi, Zotti and El Agreb deposits.

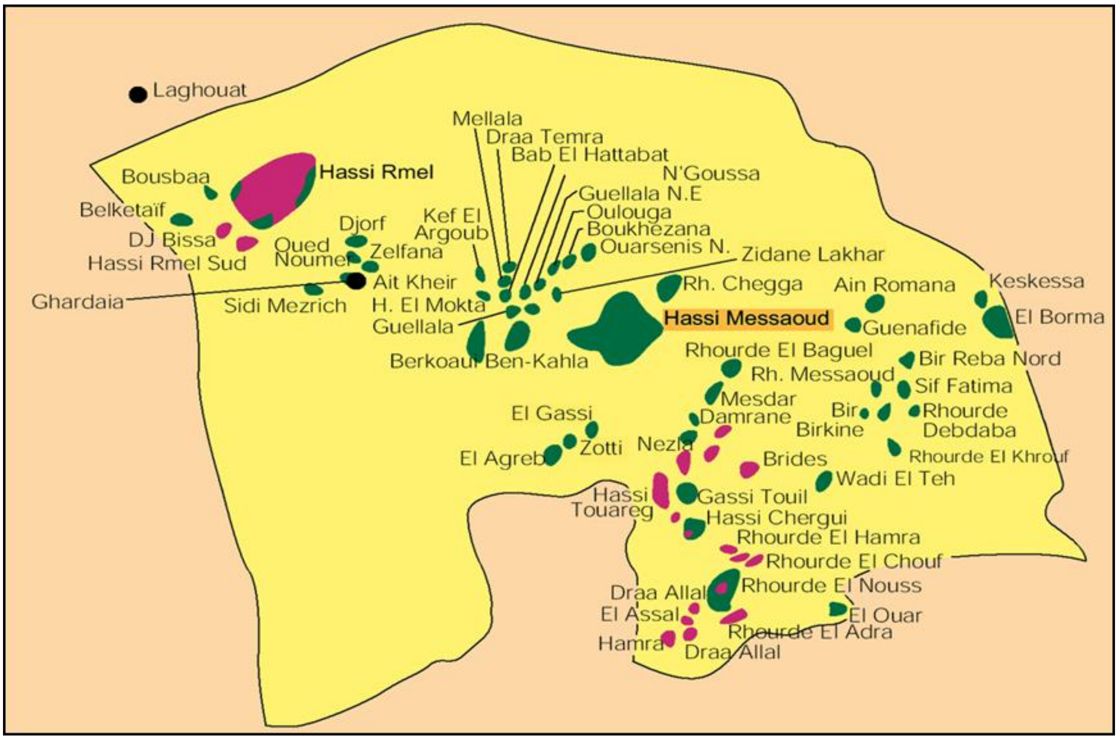

Figure I.2: The deposits surrounding the HMD field.

I.3 Zones and numbering of wells in the field of HMD:

The evolution of well pressures as a function of production made it possible to subdivide the Hassi Messaoud deposit into 25 zones, known as production zones, of variable extension. These zones are relatively independent and correspond to a set of wells communicating with each other and not with those of the neighboring zones. Each zone has its own behavior from the point of view of reservoir pressure. Wells in the same area jointly drain a well-established amount of oil in place. However, it is important to emphasize that the pressure factor cannot be the only criterion for characterizing the zones (Figure I.3).

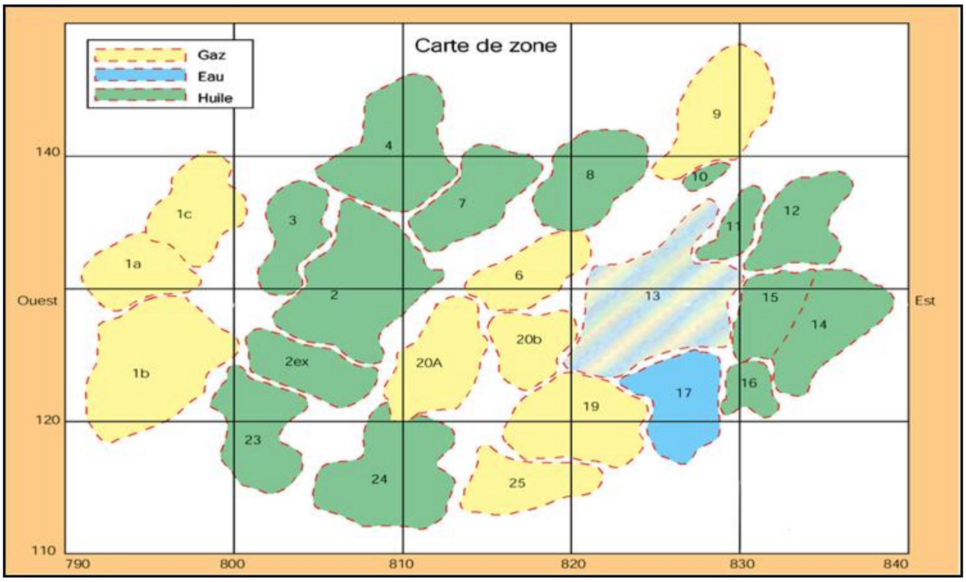

Figure I.3: Well zones and numbering.

The Hassi Messaoud field is divided into two distinct parts: the North zone and the South zone, also each zone has its own numbering established by the first companies detecting the field.

- **North field:** includes a geographical numbering supplemented by a chronological numbering, example: Omn 43

  O: Uppercase, Ouargla's license.

  m: Tiny, 1600 km2 square

  n: Tiny, 100 km2 square

  4: abscissa, and 3: ordinate

- **South field:** It is mainly chronological supplemented by a geographical numbering based on abscissas and ordinates of interval equal to 1.250 km and harmonized with the Lambert coordinates, Example: Md10 (33) - (15)

It is important to note that the current subdivision is not satisfactory because the same zone can be divided into sub zones. (Ex: 1a, 1b, 1c).

I.4 Description and characteristics of the reservoir of HMD field:

I.4.1 Drain and reservoir subdivisions:

The Hassi-Messaoud sandstones were subdivided at the start of the exploration of the deposit into four Zones: Ri, Ra, R2 and R3.

- **Zone Ri** or isometric sandstones, usually very compact: D5 or (R70 – R 90), subdivided into three sections.
- **Ra zone** or anisometric sandstone, consisting from bottom to top of the following drains:
  - **D1**: Coarse sandstone with dominant oblique arched stratifications, well marked and often micro-conglometric, with absence of tigillites.
  - **ID:** Thinner levels and greater frequency of silty levels, with local presence of tigillites. It marks a very gradual passage between D1 and D2.
  - **D2**: Coarse but well classified sandstones with dominant tabular oblique stratifications forming mega-ripples, with the presence of some intercalations of silts with fine bioturbations.
  - **D3:** It corresponds to the fine median zone of HOMER (smaller particle size). The main characteristic of this drain is the abundance of silty interbeds and fine sandstones with very strong bioturbations (tigillites in particular). The marine character of this drain is well marked; it could correspond to an environment of an infra-coastal platform, made up of bioturbated silty-clay levels in which marine bars with tidal influence or storms develop.
  - **D4:** It corresponds to the upper coarse area of L'HOMER. These are sandstones with frequent tabular oblique stratifications forming mega-ripples one to more than two meters thick.

- **Zone R2:** Zone of quartzite sandstone, more clayey presenting and rarely reservoir qualities in its upper part (R200-R300), R2 ab (R200-R250).

- **Zone R3:** Very coarse zone with very clayey micro-conglomerates, without any petroleum interest (R300-R400). (Figure I.4)

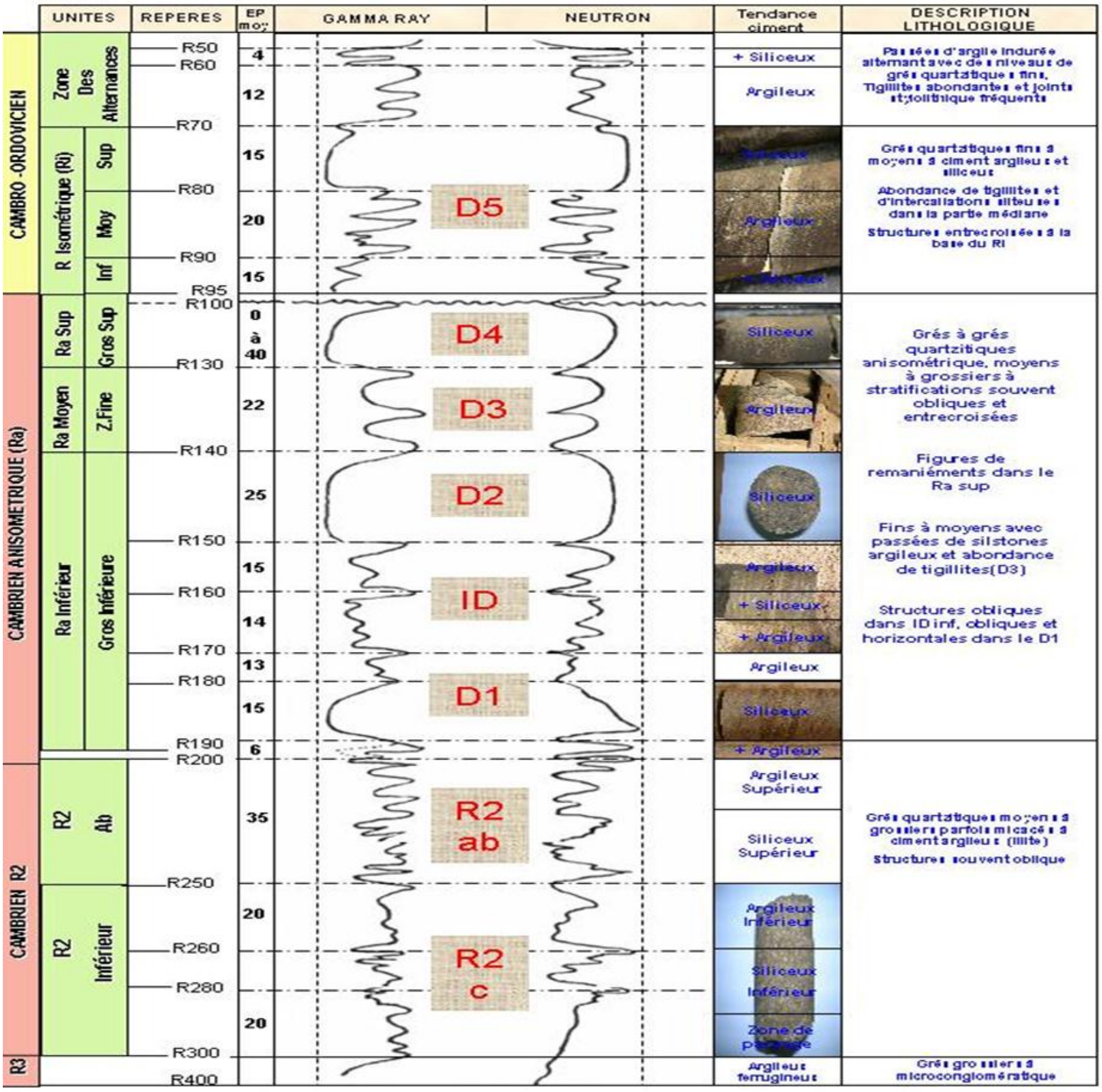

Figure I.4: Drains of the Cambrian of Hassi Messaoud.

I.4.2 reservoir characteristics:

The reservoir is located under the Hercynian unconformity, it is protected by an important clay-salt cover from the Triassic.

The deposit water is salty saturated with various dissolved salts (360-370 g / l) and has a density of 1.21 g / cm2, its viscosity is 0.45 cp. The oil / water contact was originally at 3380 m (Sw = 100%) and partially invaded a good part of the R2. The aquifer is not active.

The Hassi Messaoud sandstones are made up mainly of anisometric sandstone, only the Ra zone of around one hundred meters has the best petrophysical characteristics, it is the most productive of the Cambrian reservoir located around 3300 m to 3500 m deep. The characteristics of the reservoir rock vary widely according to their classification, their degree of quartzification and their clay content, we can mention:

- Heterogeneity is very important on a vertical and on a plane.
- The porosity is low from 5 to 10%.
- The permeability is very low of average 1 –2 mdarcy.
- The oil is light, it has an average surface density of 0.8 (45 ° API), thus increasing the rate of recovery by gas injection.
- The oil viscosity is approximately 0.2 cp.
- The background volumetric factor Bo is m3 / stdm 3 and the Bg is 0.0005 m3 / stdm 3;
- The average total compressibility on oil (oil + water + rock) is equal to 3.63.10 - 4 (kg / cm2) -1
- Oil saturation is 80% to 90% maximum
- The deposit pressure is variable from 120 to 400 kg / cm2.
- The bubble pressure is 140 to 200 kg / cm2.
- The temperature is around 118 ° C.
- The wells show G.O.R. with an average of 219 m3 / m3 (except for pierced wells where the G.O.R can exceed 1000 m3 / m3 and more)
- The thickness of the productive area can reach 120 m but can also be zero.
- Reference elevation is 3200 m.

I.5 Specific information related to OPM-742 well :

I.5.1 Geological information on the well: OMP-742 Z13 (central zone HZN):

Coord. plate forme : Xpf = 828106.13 (Lambert sud algerie) Ypf = 135590.84	Altitude : Zsol :135.48 m Zt :146 m	LONGITUDE: 6Â° 9'49.22" E LATITUDE :31Â° 45'37.58" N	DEBUT DU FORAGE :14/09/2008 FIN DU FORAGE :03/03/2009 APPAREIL :R265

T O P S D E S F O R M A T I O N S

ETAGES->	T.ARGILEUX	T.GRESEUX	T.ERUPTIF	Q.HAMRA	G.E.A	A.E.G	Z_ALT	Cm Ri	Cm Ra	Cm R2	Cm R3	FOND
TOIT (m)	3174	3321	3336						3345	3421		3432.5
Cte Abs(m)	-3028	-3175	-3190						-3199	-3275		-3286.5
Epais. (m)	147	15	09						76	11.5		

Table I.1: Geological informations on OMP-742 well.

- Albien : 1059 m A 1387 m Epais = 328 m
- LD2 : 2584 m A 2635 m Epais = 51 m
- TS3 : 2972 m A 3174 m Epais = 202 m

I.5.2 Structural comments:

The OMP-742 well is located in the NE part of the HASSI MESSAOUD field. it belongs to a local monoclinal plunging to the North-Est.

This part of the field is crossed by several normal faults. Direction approximately NN-SSW, the others either direction NE-SW.

The Hercynian erosion was very accentuated in this well where the deposits of the Triassic are deposited in discordance at the level of the drain D2.

I.5.3 Comments on reservoir:

The description of the cores shows that the most important interval at the level of this well given its granulometry and the large and very frequent vertical splitting is the intervals between 3368m to 3381m, 3386.5m to 3401.1m. 3410m to 3416m this corresponds to the base of the inter-drain and the D1 drain

the best porosity values are recorded at these levels and are of the order of 6 to 7% with low values of clays and low water saturation

I.5.4 petrophysical characteristic of reservoir:

According to the interpretation of the ELAN, the best reservoir qualities are carried by the D1 and the ID with good porosities and fairly low water saturations.

Conclusion :

The Hassi Messaoud field (sandstone reservoir) is characterized by heterogeneity which results in extreme variations in petrophysical properties resulting the variation in production from one zone to another and from one well to another. The extent of this field implies variability in production in its different parts. This is clearly evidenced by the history of cumulative production to date.

Chapter II: Generalities on Hydraulic Fracturing with conventional and foam fluids

Introduction:

The productivity of the well measured may turn out to be too low due to the petrophysical characteristics specific of reservoir, or to the well damage for following drilling operations so, the natural exploitation of a petroleum deposit to bring the hydrocarbons to the surface with favorable conditions by its natural depletion it is not capable once this energy does not meet the production constraint. The poor flow of the oil from the deposit can however be improved by means of stimulation methods, new recovery techniques are introduced in order to improve the potential, the productivity as well as the characteristics of the wells such as acidification or hydraulic fracturing. These techniques require multidisciplinary work involving geology, petrophysics, geomechanics and reservoir engineering.

II.1 Definition and principle of hydraulic fracturing:

Hydraulic fracturing is an operation that consists of creating, after breaking the rock, a permeable drain extending as far as possible into the formation in order to facilitate the recovery of hydrocarbons. This method is applicable in the case where the flow rate of a well is insufficient, when natural permeability of the matrix is low or in case of damage.

The principle of hydraulic fracturing consists of injecting a more or less viscous fluid with great pressure to crack the reservoir rock, and it is often accompanied by solid (Support agents), At the end of the injection, when the pressure is released, the fracture opened by the fluid tends to close. In order to prevent the resulting fracture from closing, a granular material of natural or synthetic origin, called proppant (support agent) , is added to the fracturing fluid during pumping to keep the fracture open and that the fluid can flow more easily between the reservoir and the well (producing well) or between the well and the reservoir (injecting well).

There are three possible fracture orientations: horizontal, vertical, or any tilt between these two limits.

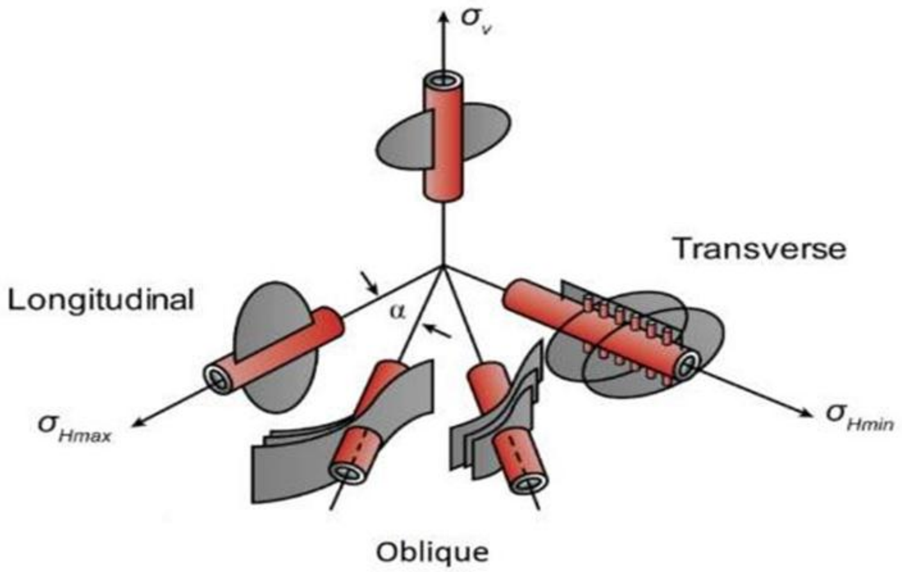

Figure II.1: Wellbore and Fracture Orientation.

- **Longitudinal fracture:**

This mode of fracturing generally exists in horizontal wells where the fracturing develops in parallel when the well is drilled in the direction of maximum horizontal stress.

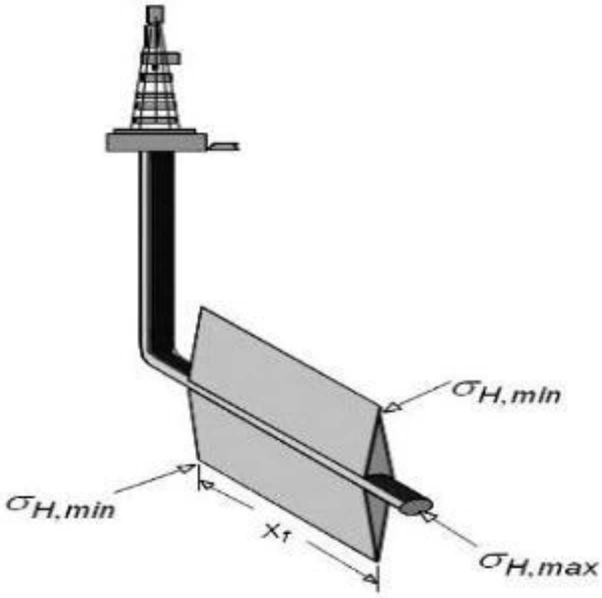

Figure II.2: Longitudinal fracture.

- **Transverse Fracture:**

The transverse fracture is created perpendicularly when the well is drilled in the direction of minimum horizontal stress.

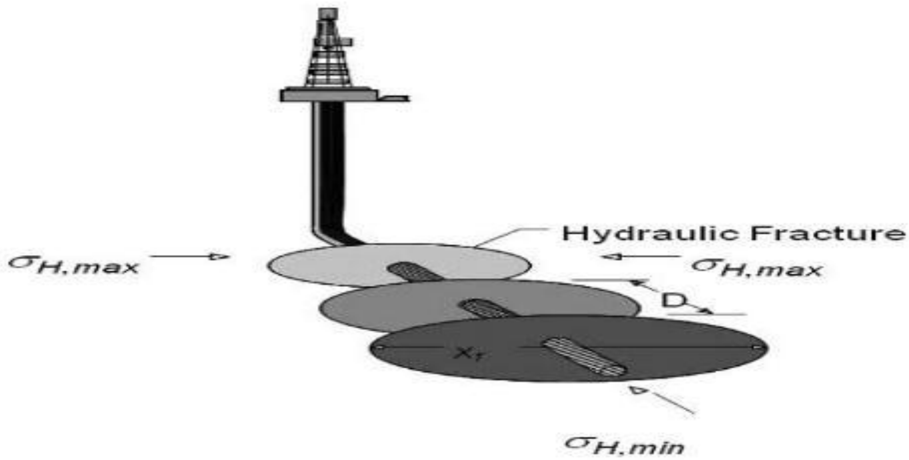

Figure II.3: Transverse fracture.

II.2 Objectives of hydraulic fracturing:

The main features of a hydraulic fracturing operation are logically deduced:

- Hydraulic fracturing is a highly developed process among the most effective techniques for stimulating wells and improving oil recovery. It is a delicate operation in which we try to increase the productivity index of the well by decreasing its skin value.

The desired objective of an H.F is to create by breaking the rock a very permeable drain (artificial permeability) extending on either side of the well.

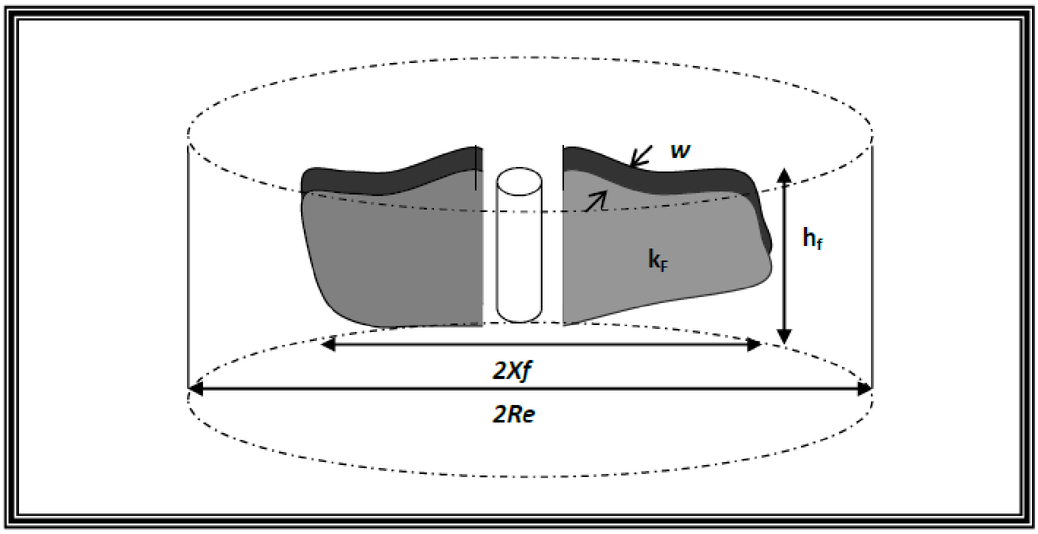

Figure II.4: The drain created by hydraulic fracturing.

The productivity index of the well will then increase because of the decrease in reduction of the pressure and the increase in flow thus the gain will be defined:

$$\boxed{Gain = Ip(ap) / Ip(av)}$$

The productivity index of a well with a skin (S) can be expressed:

$$I_P = \frac{2\pi Kh}{\mu B_0 (\ln(r_e / r_w) + S)} \qquad Q = I_P \, \Delta P$$

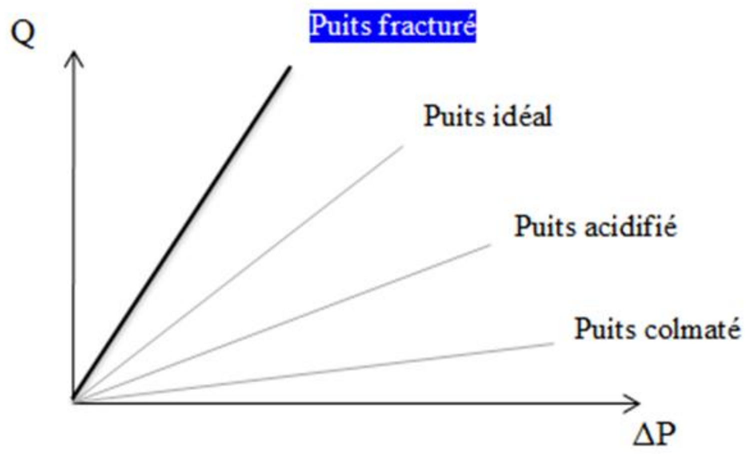

Figure II.5: Q curves as a function of ΔP for different categories of wells.

The fictitious radius method consists of replacing the real well with radius r_w and skin S with a fictitious well of radius r'_w and zero skin (figure), by imposing ΔP from r_s to r_w in real case = ΔP from r_s to r'_w in fictitious case.

The effective radius is given by the following formula:

$r'_w = r_w e^{(-s)}$ (expression valid regardless of S).

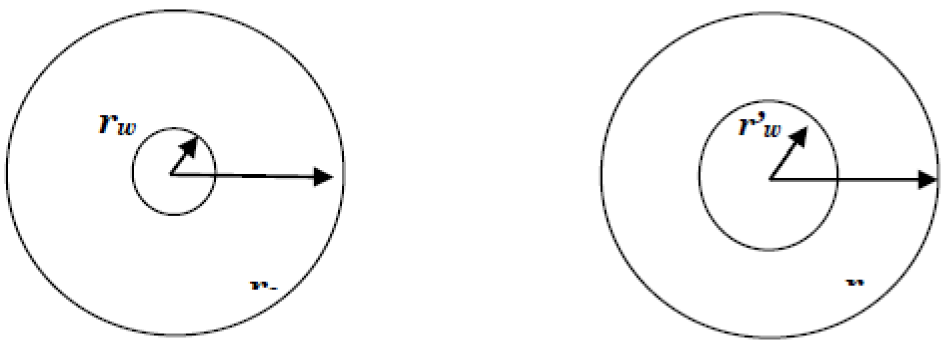

Figure II.6: Radius before and after frac.

If S<0 $r'_w > r_w$

If S>0 $r'_w < r_w$

So in reality, increasing the effective radius of the well to eliminate any risk of entrapment near the well, so we can assimilate a fractured well of radius (r_w) to a well of fictitious radius (xf) with a zero skin if the conductivity of the fracture is infinite.

So the increase in reservoir productivity by:

- Increased flow capacity;
- The creation of an effective radius of the upper well (r'w> rw);
- Increase in the contact surface between the reservoir and the well.

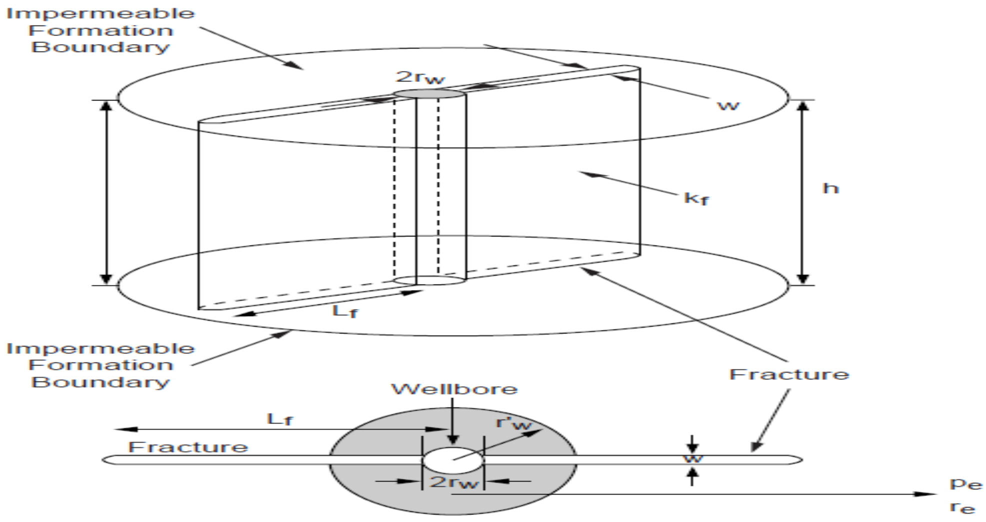

Figure II.7: the contact surface increased by hydraulic fracturing.

- Rupture of the rock by pressurizing a fluid in the well.
- Development of the fracture under the effect of the pressure exerted by the injected fluid, which must be much greater than the minimum stress in place of the rock.
- Keeping the fracture open.
- Create a connection between the formation and hole to bypass the skin.
- The increase in the speed of recovery thanks in particular to an improvement in the productivity index.
- Increased recovery time.
- Decrease the pressure difference around the well in order to eliminate the problem of paraffin and asphaltene deposition.
- Mining of certain deposits.
- Hydraulic fracturing has long been used as a method of improving the performance of water wells in aquifers. it is widely used for domestic wells in many parts of the USA (Texas, Washington).
- Hydraulic fracturing is carried out in the coal seams allowing the production of methane.
- Heat recovery in deep geothermal energy.

II.3 Fracture proprieties:

II 3.1 Parameters to know:

- Constraints in general, the formations are subjected to different stresses which combine to maintain these rocks in states of compression.
- the permeability of the land.
- the porosity of the formation.

- mechanical properties of rocks:
  a. Young's modulus (E)
  b. Poisson's ratio (v)
  c. Stiff modulus or shear modulus (G)
  d. Module de compressibilité (Bulk modulus) C_b
  e. Interfaces : WOC and GOC (water oil contact, gas oil contact)

❖ **Relation between (E), (K), G) and Poisson's ratio (v)**

The four main elastic constants: Young's modulus, the modulus of shear, the compressibility modulus and the Poisson's ratio are related in such a way so that the knowledge of two constants makes it possible to deduce the other two:

$E = 3K(1-2\upsilon)$	$G = E/2(1+\nu)$	$G = E/2(1+\nu)$	$\upsilon = (3K-E)/6K$

II 3.2 Parameters to choose:

- Injection rate
- Fracturing fluid
- Surfactant agent

II 3.3 Parameters to obtain:

➢ **Development or extension of the fracture:** Field experiments show that hydraulic fracturing is developed along horizontal or vertical planes. For depths less than 600 m, it is possible to obtain fractures in the horizontal planes. The fracturing gradient is then generally of the order of 0.23 bar/m (1psi/ft).
At greater depths For depths greater than 600 m and beyond 1000m, the fracture generally develops only in the vertical planes because of the weight of the sediments. The fracturing gradient is then generally less than 0.23bar / m, its average value being considered to be 0.16 bar/m (0.7psi/ft), and this is the case in Hassi Messaoud.

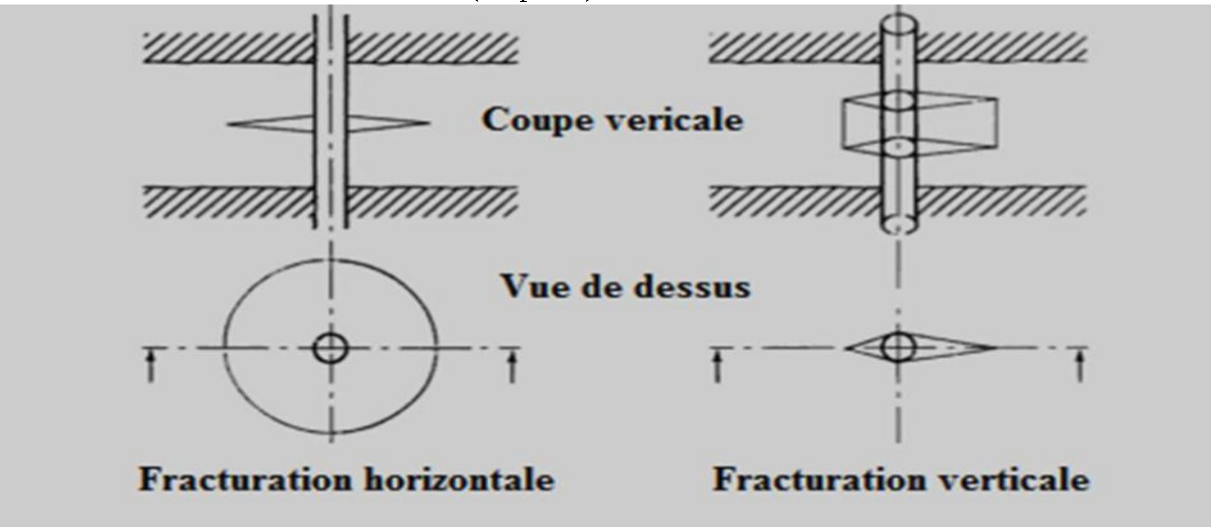

Figure II.8: Geometry of the fractures.

- **The geometry of the fracture:**

- **Dimensions of a Fracture:**

The vertical fracture is assumed symmetrical to the well, and it is characterized by length, thickness and height.

a. **The length (L_f):** is the distance between the well and the point located at the end of the fracture.
b. **The width (W_f):** is the distance between the two vertical faces of the fracture.
c. **The height (h_f):** is the distance along the vertical between the two points associated with a zero thickness.

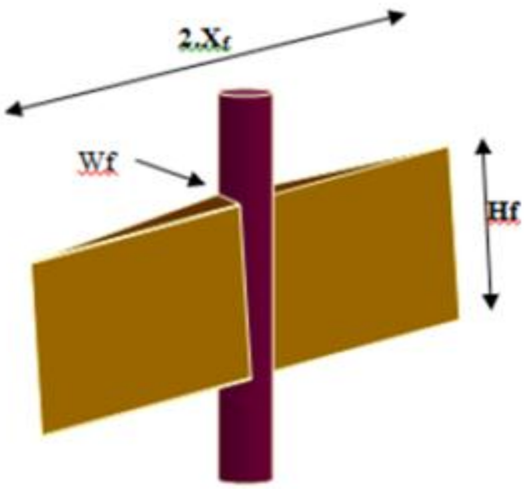

Figure II.9: Dimensions of a Fracture.

II 3.3.2 Fracturing pressure (PF):

Fracturing Pressure (PF) is a function of:

- The state of stress exerted on the reservoir.
- Boundary conditions.
- The mobility of the injected fluid.

$$P_F = P_{inj} + P_{Hyd} + P_{friction}$$

P_{inj}: injection pressure at the head (psi).
P_{hyd}: Hydrostatic pressure (psi).
PF: Pressure drops which can have two components of losses in the tubing or / and perforation level (Psi).

II 3.3.3 Fracturing gradient (GF):

By definition, the fracturing gradient is equal to the fracturing pressure ratio (PF) in (Psi) and the formation depth (H) in (ft):

$$G_F = P_F/H$$

- **Evolution of ideas on the orientation of fractures and the fracturing gradient:**

The following empirical rules relating to the gradient of fracturing and orientation of the fracture.

$$\begin{cases} G_F < 0.16 \text{ bar/m } (0.7\text{psi/ft}) \longrightarrow \text{Fracture verticale} \\ G_F > 0.23 \text{ bar/m } (1\text{psi/ft}) \longrightarrow \text{Fracture horizontale} \end{cases}$$

Currently, it is accepted, more and more commonly, that a value of the gradient

lower than the geostatic gradient (0.23 bar/m to 0.25bar/m) corresponds to a fracture vertical.

A gradient greater than 0.280bar/m almost reflects an anomaly that can be explained often by clogging of the formation.

II 3.3.4 Dimensionless conductivity of the fracture:

The dimensionless conductivity of the fracture (F_{CD}) is represented by the ratio:

$$F_{CD} = \frac{K_f . W_f}{K . L_f}$$

L_f or X_f: Extension of the fracture (the half-length) (ft).

W_f: Fracture thickness (ft).

K: The permeability of the formation (md).

K_f: The patency of the fracture (md).

- **Optimization of hydraulic fracturing:**

For the fracturing to be optimal, it suffices that: FCD> 2.

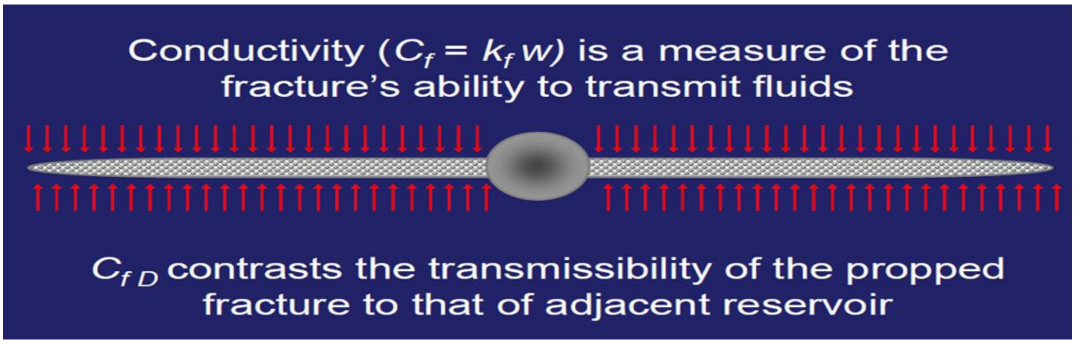

Figure II.10: Productivity of a fractured well.

- $K_f W_f$: The capacity of the hydraulic fracture to conduct the fluid towards the well.
- KX_f : The capacity of the formation to transmit the fluid to hydraulic fracturing.

The conductivity of a fracture increases by:

- Increasing the width of the fracture W_f.
- Increased permeability of proppants (large, more spherical;proppant grains have high permeability).
- Minimization of the damage to the permeability of the proppant caused by freezing (Polymer) Fracturing Fluid.

The most important parameters affecting the conductivity or flow capacity in the fracture:

- The physical properties of the proppants (permeability of the proppant).
- The concentration of proppant in the fracture.
- The closing pressure.
- The width of the fracture after closure.
- Contaminants (presence of insoluble residues of the fracturing fluid).

II 3.4 Fracture calculation models:

II. 3.4.1 2D fracture models:

There are three main models in this category:

- **The model (GDK):** developed by Geerstma, Kristianovitch and Klerk.
- **The model (PKN):** developed by Perkins, Kern and Nordgren.
- **The radial model.**

The GDK model is based on the following assumptions:

- Monodimensional flow in one direction (L),
- Constant fracture height along the length and over time,
- The fracture has an elliptical section in the horizontal plane,
- The section of the fracture in the vertical plane is rectangular,
- Same thickness any distance from the well.

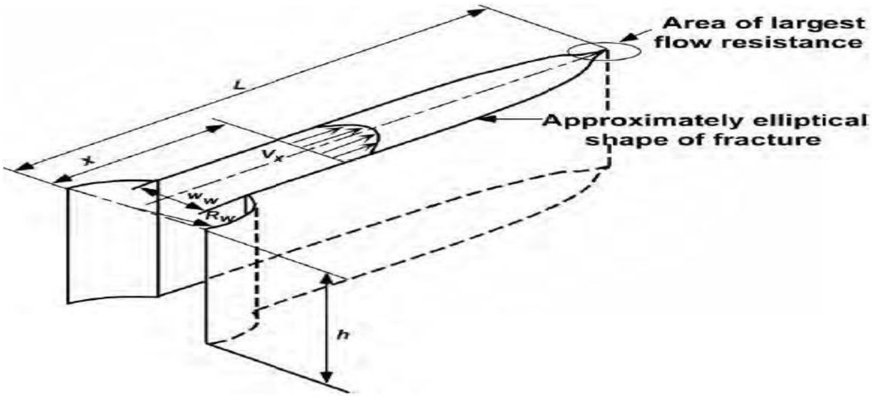

Figure II.11: Representation of fracture propagation according to the GDK model.

The PKN model is based on the following assumptions:

- The flow in the fracture is one-dimensional
- Constant fracture height along the length and over time.
- The cross section of the fracture is assumed to be elliptical,
- The section of the fracture in the vertical plane is assumed to be elliptical.

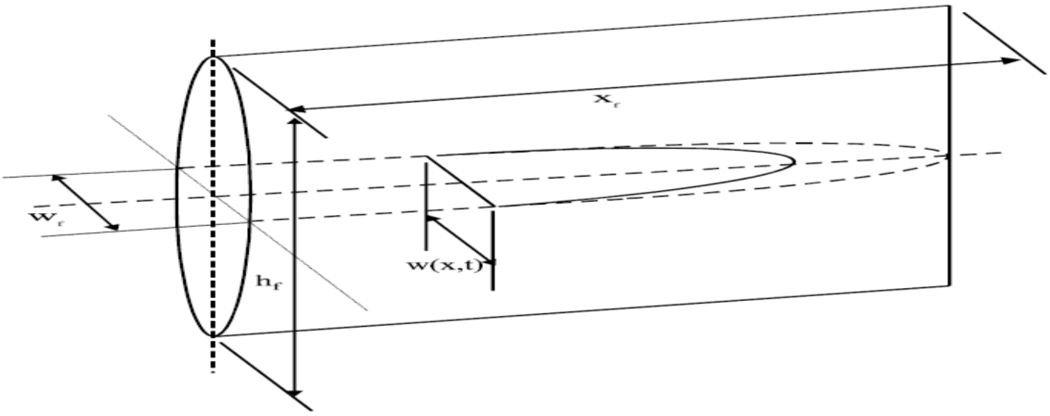

Figure II.12: Representation of fracture propagation according to the PKN model.

a) Radial model

The radial model is characterized by a circular profile in the vertical plane with an elliptical section (figure below).

It is used when the permeable area is small and has only weak barrier intercalations. In this case a low formation height is perforated (the perforated interval should be relatively small), so the fracture is assumed to initiate at one point and develop radially.

The calculation method is based on the following assumptions:

- The height of the fracture varies according to the length.
- The vertical section is assumed to be elliptical.
- The fracture develops radially.

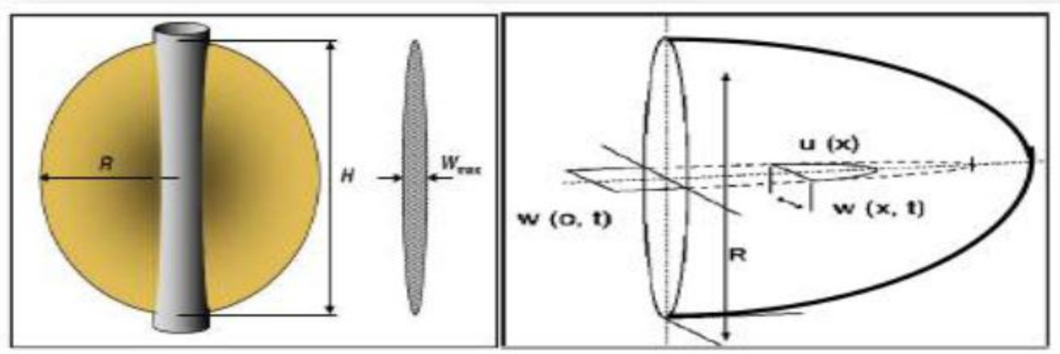

Figure II.13: Representation of fracture propagation according to the Radial model.

II.3.4.2 2D and pseudo-3D fracture models:

The 2D models examined in the previous section are obtained using empirical assumptions. Although their accuracy is limited, they are useful in the design of hydraulic fracture growth.

The major disadvantage of 2D models is the requirement to specify the fracture height. It is not always obvious, from log data, to affirm the constancy of the height, for example. In fact, the height generally varies between the well and the end of the fracture, depending on the pressure development.

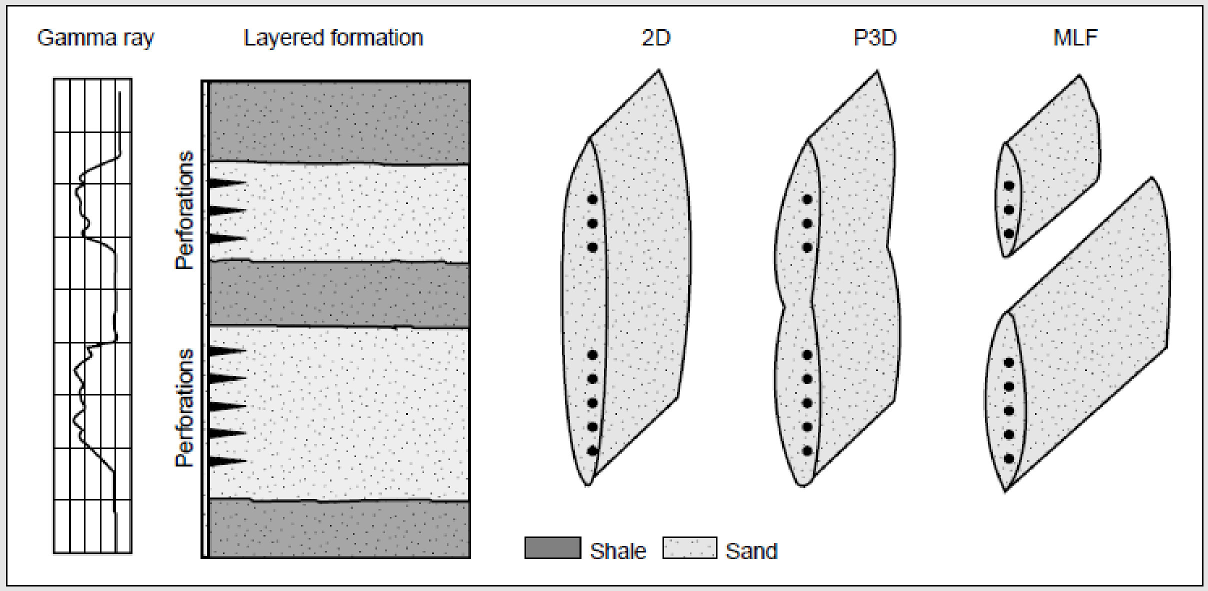

Figure II.14: Fracture geometry of 2D, P3D and MLF models.

II 3.5   Estimation of the extension of fractures:

The estimation of the extension of fractures is done by several techniques are:

- **Thermometry:**

Thermometric recordings generally provide precise indications of the vertical extension of the fracture in the immediate vicinity of the well, it can be applied in cased and perforated wells as well as in open wells. Recordings should be made at different times and started approximately four hours after the end of pumping.

- **Flowmeter:**

Flowmetry is not very commonly used to locate fractures induced by hydraulic fracturing. However, its use after an injectivity test makes it possible to supplement the information given by the thermometric records.

- **Diameter (Caliper):**

The diameter gauge is essential in open wells to interpret the continuous flowmeter. Thus to provide useful indications in the cased wells, if there is rupture, obstruction, bursting, ... of the casing.

- **Radioactive tracers:**

The use of a tracer with support makes it possible to determine the vertical or horizontal orientation of the fracture and to control its vertical extension, by comparison with a reference recording.

- **Recording of sonic logs:** The sonic logic makes it possible to record the amplitude of the shear wave before and after the stimulation, this leads to detect by comparison, the presence of an induced fracture and its extension when it is vertical.

II.4 Conventional Fracturing Fluid, Additives Chemistry and Proppants :

The fracturing fluid is a critical component of the hydraulic fracturing treatment. Its main functions are to open the fracture and to transport propping agent along the length of the fracture. Consequently, the viscous properties of the fluid are usually considered the most important. However, successful hydraulic fracturing treatments require that the fluids have other special properties. In addition to exhibiting the proper viscosity in the fracture, they should break and clean up rapidly once the treatment is over, provide good fluid-loss control, exhibit low friction pressure during pumping and be as economical as is practical. Characterization of these performance properties is addressed in this chapter.

This section describes the chemistry of commonly used fracturing fluids, additives and proppants.

II 4.1 Fracturing fluids:

Fracturing fluids are fluids injected under high pressure into a geological formation, in order to crush hard and poorly permeable rocks, in order to release the hydrocarbons (gas, oil) that they trap.

The fracturing fluid will be chosen according to several criteria such as: its availability, safety, ease of mixing and use, its compatibility with the formation, possibility of disgorging and their cost.

However, it is not enough to fracture in good conditions, it is also important that the reservoir does not remain damaged by the injected fluid, which can have various origins and serious consequences.

II 4.1.1 The ideal fluid:

This should have the following characteristics:

- Filter as little as possible.
- Transport the proppants well and do not allow them to settle in the event of an unforeseen shutdown.
- Be clean as a base of fluid.
- Easy to pump.
- Be compatible with the tank.
- Disgorging easily.
- Not to be dangerous.
- Do not pollute.
- Be economical as possible

II 4.1.2 Properties of fracturing fluids:

The main qualities and required properties demanded of a fracturing fluid are as follows:

- An adequate viscosity favoring a large "W_f" width and a significant extension of the fracture while ensuring good transport capacity (do not allow them to settle in the event of an unforeseen stoppage) as well as a good placement of the agents of important).
- Low friction to limit the pumping power required during injection.
- Good compatibility with rock and formation fluids, low content of insoluble solids and creation of a minimum of insoluble reaction products so as not to damage the formation.
- Filtration as low as possible (all that filters being lost to the fracture).
- Easy to move by the hydrocarbons in place in the reservoir, low viscosity after degradation (during disgorging) and low density to facilitate disgorging and production start-up.
- Low in insoluble solids.
- Adapted to the temperatures encountered during the operation to be carried out (in particular the viscosity strongly depends on the shear stresses, the duration and the temperature).
- Profitable (availability, low cost), is not dangerous, non-polluting.

II 4.1.3 Main roles of fracturing fluids:

The fluid used has several roles to fulfill during the fracturing operation:

1. He must open and develop the fracture. For this, this fluid must have:

- A high viscosity to obtain a sufficient width of the fracture for the penetration of proppants.

- The smallest possible filtrate, that is to say the volume of liquid that has not filtered, or as large as possible.

2. It should also transport proppants from the surface to the bottom of the fracture.

II 4.1.4 The choice of fracturing fluids:

The choice of fluid, its preparation on site, the choice of its injection rate and certain modalities, contributes in an essential way to the results of hydraulic fracturing. The choice of fracturing fluids is made according to several criteria such as:

Availability, safety, ease of mixing and use, compatibility with training and possibility of bleeding as well as their costs.

II 4.1.5 Preparation Of gel on site:

The preparation of a gel can be roughly divided into three steps:

a) Dispersion

Consists of adding the base polymer (WG-11) containing a pH control agent, to the medium, usually a 2% KCl solution. The critical points to be observed are:

- Add the polymer to as much water as possible without circulating gelling water.
- To circulate long enough so as to obtain a homogeneous dispersion, without lumps or clumps of polymers.

b) Hydration

Consists of the chemical reaction of the polymer in water. By controlling the chemistry, molecular mass, particle size of the polymer as well as the nature of the pH, it is possible to adjust the rate of hydration.

The problems encountered in the field are usually due to poor control of the pH, the mixing water or the temperature of the latter.

c) Crosslinking:

Consists of creating bonds between the polymer molecules which considerably increases the viscosity of the fluid and thus facilitates the transport of proppants.

II 4.1.6 Composition of fracturing fluids:

- **Water-based fluids:**

Due to their low cost, availability, high efficiency, good support transport, minimum pumping power, job safety (fire, explosion, pollution) and ease of handling (easily treatable with additives); water-based fluid is the most widely used fracturing fluid. A large number of water-soluble polymers can be used to obtain a viscous solution capable of keeping the proppant in suspension at room temperature. Among the water-based fluids used, we can distinguish:

- Linear gel.
- Cross-linked gel.

Its viscosity is increased thanks to an additive at low concentration which allows its gelation. This can be "linear", that is to say made up of long chains next to each other but without links between them. The addition of a crosslinking agent changes from linear mode to a threedimensional semi-rigid structure; said crosslinked, where the bonds between the molecules are very strong, which allows perfect control of the sedimentation of the support and increased control of filtration.

Disgorging can be difficult if the reservoir pressure is low and, on the other hand, increasing water saturation by filtration reduces the relative permeability to the oil. It is important to pay attention to the amount of water (content of chlorides, baking soda, iron, insoluble solids, bacteria). We distinguish :

a. **Linear gel:** Polymer + Water

.Slick water: 10 - 20 lbs / 1000 gal (initiation and propagation).

. Gelled water: 30 - 80 lb / 1000 gal (transport).

b. **Cross-linked gel:** Polymer + Water + Cross linker (high density of proppants, has low friction, used in deep wells).

- **Oil-based fluid:**

To a lesser extent oil-based fracturing fluids are also used (crude oils, gelled oils, etc.). They have the advantage of better compatibility with formation fluids (remains their main asset), the absence of solid residues, a good stability and good gel transport capacity, low density favor the disgorgement. Conversely, their costs are high, they pose job security problems and pollution, they require higher pumping power. Therefore, they are now only used in formations which are known to be extremelysensitive to water. The oil-based fluids that are used are:

- crude oil.
- Cross-linked oil.

- **Multiphase Fluids:**

There are situations in which the properties of standard water-base, oil-base or acid-based fluids can be enhanced by incorporating a second phase into the fluid. Foams are created by adding gas to the fluid, nitrogen or carbon dioxide, these are generally recommended for shallow or medium depth tanks and preferably gas tanks, low/very deep tanks low permeability and/or depleted (easy disgorgement) and formations sensitive to water.

An emulsion is a dispersion of two immiscible phases such as oil in water or water in oil stabilized with a surfactant. Emulsion-based fracturing fluids are highly viscous solutions with good transport properties. The higher the percentage of the internal phase, the more resistance there is to droplet movement, resulting in a higher viscosity.

II 4.2 Fracturing fluid additives:

A fracturing fluid is generally not simply a liquid and viscosifying material, such as water and HPG polymer or diesel oil and aluminum phosphate ester polymer. Various additives are used to break the fluid once the job is over, control fluid loss, minimize formation damage, adjust pH, control bacteria or

improve high-temperature stability. Care must be taken when using multiple additives to determine that one additive does not interfere with the function of another additive. Among the additives used we can mention:

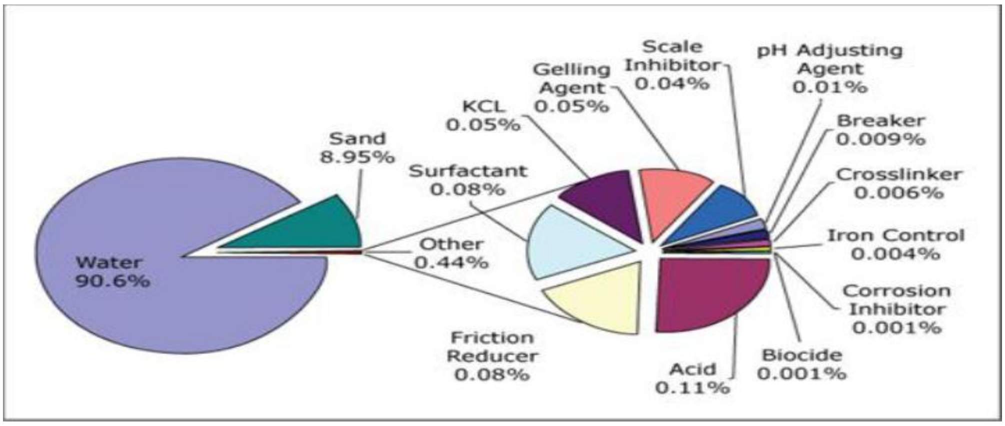

Figure II 15: Volumetric composition of a fracturing fluid.

a. Gelling agent

Whose role is to develop the viscosity of the fracturing fluid. Example: WG-11, WG-18.

b. Filtrate reducers:

Increase the efficiency of the fluid by reducing the filtrate of the fluid in the formation. (Please note, because filtrate reducers are in fact clogging, insoluble products, their use in excess can cause damage to the formation).

c. Friction reducer:

Reduce pressure drops and thus save power. Example: SGA-HT, FR-26 LC, FR-5.

d. Anti-foaming:

During gel penetration, due to certain additives used (sea water, surfactants, etc.) foam may form. This must be eliminated to avoid the risk of deactivating the pumps. Example: LOSURF-300.

e. Crosslinker:

The purpose of this additive is to create bonds between the different polymer chains. Borate, Zirconate and Titanate Example: CL-28M, K-38.

f. Activator:

This additive is added at the outlet of the blender and makes it possible, by modifying the pH, to accelerate the phenomenon of crosslinking. Example: CAT-3, CAT-4.

g. Surfactants:

Used in water-based fluids and in acid. Facilitate the disgorging of these fluids, and thus avoid leaving a matrix that is too highly saturated with water. In this category we can include de-emulsifying agents which prevent the appearance of emulsions which can form between the water of the fracturing fluid and the forming oil.

h. Clay stabilizers (ClayFix):

The high flow rate injection of a large amount of water can destabilize a highly clayey matrix, causing swelling or migration of clay platelets. Example: Clayfix II, Clayfix.

i. Bactericides:

In some isolated locations, the water used to make the gel can be more or less brackish. It is therefore necessary to purify it before injecting into the formation. To do this, bactericides are used, the role of which will be to destroy any organic component that could modify the properties of the gel, or generate a bacterial development in the formation. Example: BE-3S.

j. Barrier agent (Inverter and Diverter):

- **Invertfrac:** is a new technique to control and limit the vertical development of a fracture. The technique involves developing an artificial barrier in the upper part of the fracture by injecting a product with a density lower than that of water. This avoids the extension upwards (gas zone).

- **Divertfrac:** Like invertfrac, divertfrac prevents vertical extension of the fracture. The technique this time involves developing an artificial barrier in the lower part of the fracture by injecting a product that solidifies temporarily. This avoids the extension downwards (water zone).

II 4.3 Support agent (Proppant):

In the field of oil, gas or hydraulic drilling, proppants (or propping agents) are solid products (natural or synthetic) which are injected into the fractures and micro fractures caused in the rock during hydraulic fracturing operations. . Their role is to produce a layer that is both permeable and strong enough to keep the microcracks open after entering them. This layer creates and maintains a “draining path” within which fluids (gas, oil, water) easily move to the well.

The success of hydraulic fracturing often depends on proppants, which must meet two conditions:

- Being strong enough to keep the fracturing open.
- Allow the fluids to flow to the production well.

The behavior of proppants in the fracture depends on the related characteristics:

- To the using of materials (Type of agents).
- To the constituent rock which has the fracture (soft rock ,hard rock,..).
- On the state of the constraints reigning in the reservoir.

II 4.3.1 Nature of proppants:

There are a wide variety of proppants used for hydraulic fracturing.

a.Elastic-brittle support agents (brittle fracture)

- The sands.
- Glass beads (high resistance).
-

b. Elasto-plastic proppant

- Walnut shells (less and less used).
- Certain polymers (difficult to use above 80-100 ° C).
- Aluminum balls (practically abandoned).
- Steel balls (which could be considered with the use of very viscous fluids).

II 4.3.2 The properties of the proppant:

The properties that an ideal support should have to meet these requirements are:

- A good grain size and a shape capable of generating good conductivity and compatible with the width of the fracture.
- High mechanical resistance to in-situ stresses in operation (resistance to plastic deformation and breakage).
- Chemical resistance under background conditions over time (corrosion, erosion, temperature, dissolution by effluent, aging).
- A density compatible with optimum transport (sedimentation).
- No deterioration of the installations during pumping.

II 4.3.3 Main proppants:

These are generally calibrated ceramic balls, sand or bauxite, with a particle size of 8/12, 12/20, 16/30, 20/40, 40/70 and their permeability varying between 100 and 800 and even up to to 1000 Darcy. In Algeria, mainly agents (0.033-0.017 in) (20-40 mesh) are used.

Many materials have been tested in the field. These include: aluminum balls, nut shells, steel balls, glass balls, rilsan-type polymers. For various reasons (densities, poor temperature resistance, dissolution, clogging after breakage), they were more or less quickly abandoned, a classification was established based on resistivity, we quote:

a. **Sand (LSP: Low Strength Proppant)**
b. **Intermediate proppants (Ceramic Proppant or ISP)**
c. **High strength proppants (HSP or HSB)**

Figure II.16: The different grain sizes of proppants.

II 4.3.4 Choice of proppant:

The choice of a proppant depends on economic and practical considerations.The selection criteria for proppants of type, size and concentration are based on fracture flow capacity and formation permeability to provide the highest production rates compatible with economy. The selection is based on the following physical properties: stiffness, sphericity, density and grain size as well as depth.

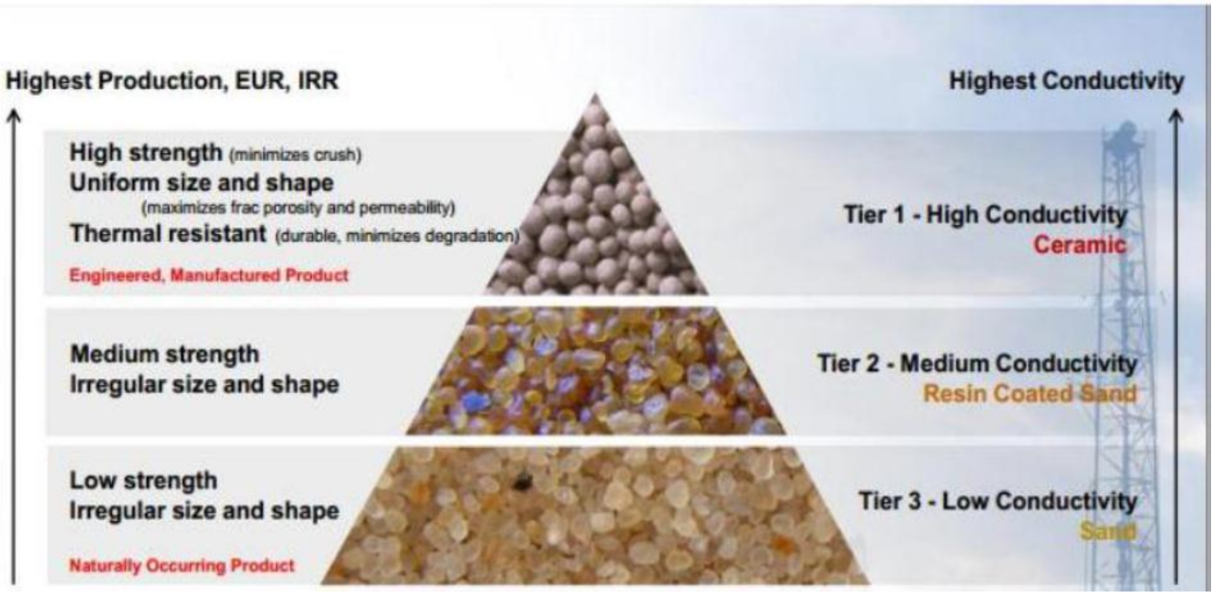

Figure II 17: Properties of Proppant (Prepared by CARBO ceramics).

II 4.3.5 Transport of proppants:

The transport capacity depends on:

- The viscosity of the transport fluid, hence the use of possibly crosslinked gels.
- The density of the proppant.

And the filling also depends on the concentration of these agents in the fluid to be injected, the concentration is expressed as a ratio of proppant weight to the volume of liquid (example: ppg is pounds per gallon).

- **Equipments needed in Conventional Fluid Fracturing Operation:**

Figure II.18: Equipments of Conventional Hydraulic Fracturing.

II.5 Foam Fracturing Fluid Chemistry and Proppants :

II 5.1 Foams:

A foam is a stable mixture of liquid and gas. To make the mixture stable, a surface-active agent (surfactant) is used. The surfactant concentrates at the gas/liquid interface and lowers the interfacial tension. The surfactant stabilizes thin liquid films and prevents the cells from coalescing. Pressurized gas (nitrogen or carbon dioxide) in a foam expands when the well is flowed back and forces liquid out of the fracture. Foams accelerate

the recovery of liquid from a propped fracture and thus are excellent fluids to use in low-pressure reservoirs. Also, the liquid phase is minimal because foams contain up to 95% by volume gas. In the case of a water-base fluid, foaming the fluid significantly decreases the amount of liquid in contact with the formation. Therefore, foams perform well in water sensitive formations. Foams yield pseudo plastic fluids with good transport properties.

They provide good fluid-loss control in low-permeability formations where the gas bubbles are approximately the size of the rock pore openings.

Foams are described by their quality:

$$foam\ quality = \frac{gas\ volume}{foam\ volume} \times 100\,.$$

Originally, foam quality was considered to range from 52% to 95%. Above 95%, the foam usually changes to a mist, with gas as the continuous phase. Below 52%, a stable foam does not exist because there are no bubble/bubble interactions to provide resistance to flow or to gravity. Above 52% gas, the gas concentration is high enough that the bubble surfaces touch. Stable dispersions of gas in liquid can be prepared with qualities less than 52% .It may not be appropriate to call them foams, but they can be used effectively as energized fluids.

. Nitrogen and carbon dioxide are used as energizing gases. N2 is less dense than CO2. CO2 creates a denser foam and, consequently, lower surface treating pressures because of the increased hydrostatic head in the wellbore. Lower treating pressures reduce pumping costs. On the other hand, because CO2 is much more soluble in oil and water than N2, it takes more CO2 to saturate the liquid and to create the foam. Reductions in pumping costs may be offset by increases in material costs.

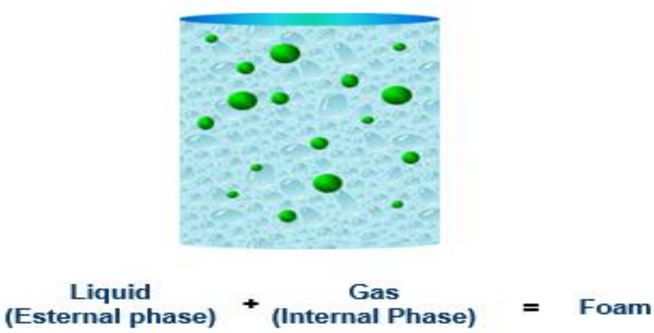

Figure II.19: Faom Phases.

II.5.2 Foam Fracturing Fluid Design:

Water is not commonly used as the liquid phase because of limited stability. Enhanced stability can be achieved by adding a polymer, increasing the polymer concentration and by crosslinking the polymer.

Nitrogen and carbon dioxide are the gas most commonly used in foam fluids. Formation characteristics, fluid compatibility and economics are major factors in the selection of the gas phase type.

Selection of a foaming agent is usually determined by the type of foam fracturing fluid design and the foaming agent compatibility with the formation fluid. So fracturing fluid foam design as:

The liquid phase

- Linear gel
- Crosslinked gel
- Hydrocarbons and alcohols

The gas phase

- Nitrogen
- CO2

Foaming agents

- F109 for StableFOAM/SuperFOAM
- F107 for ThermaFOAM and methanol containing foams

II.5.2.1 The liquid phase

a. Linear Gels in Foams

The use of polymers in linear gel will increase the foam viscosity and reduce leakoff. The greater the viscosity, the less drainage of liquid from the bubble and therefore the more stable the foam. Enhanced stability of the foam results in improved proppant transport.

- Increase foam viscosity
- Reduce leakoff
- More stable foam
- Improve proppant transport

➢ **Effect of Polymer Loading on Foam Viscosity:**

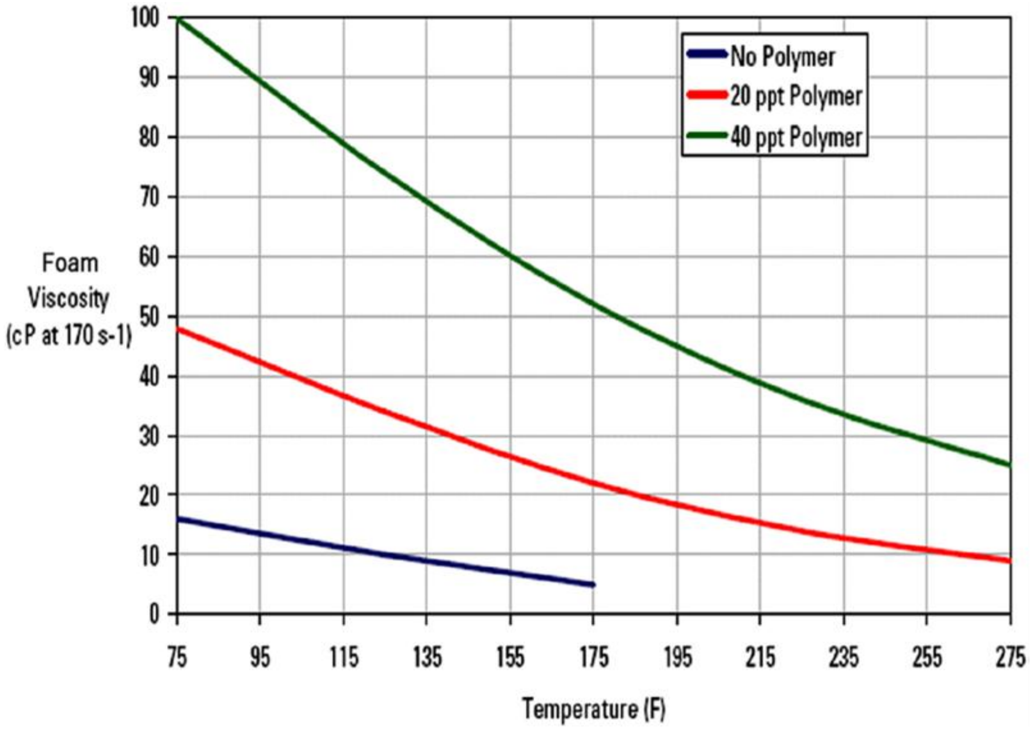

Figure II.20: Polymer Loading on Foam Viscosity.

- **Effect of Various Polymers on Foam Stability**

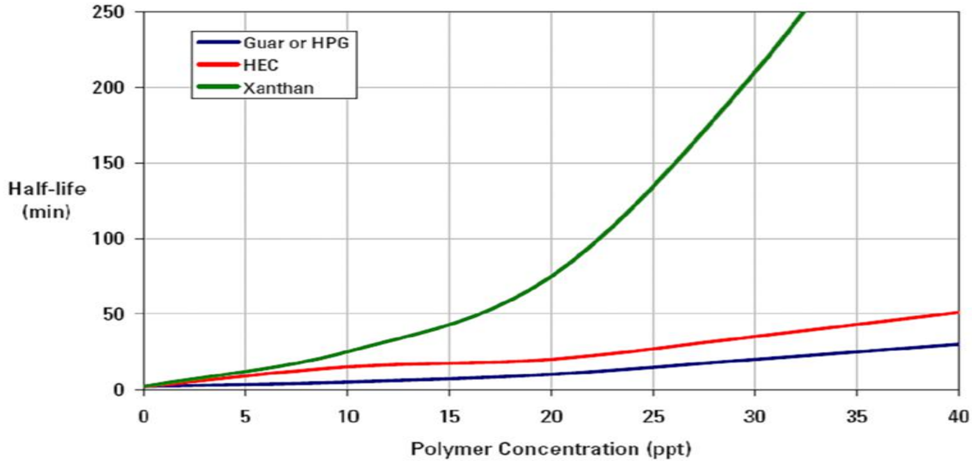

Figure II.21: Various Polymers on Foam Stability.

- Guar, HPG, HEC and xantham gum are the most commonly used polymers. Different polymers result in different foam stability.
- The half life of a foam is the time required for one half of the liquid phase to break out of the foam. It is used as stability indicators is the laboratory.
- A 75% quality foam without polymers has a half life of less than 5 minutes.
- Xantham gum (J312) is by far the most efficient.

b. Cross-linked Polymers in Foams:

A crosslinked gel in the liquid phase allows the gas content to be decreased which result in:

- Higher hydrostatic pressure (lower treating pressure).
- Higher proppant concentration.

The increased friction pressure drop in the pipe due to higher viscosity may reduce some of the benefits of the lower, treating pressure.

The major advantage is the ability to achieve higher proppant concentration in the fracture. Treatment design may allow a lower foam quality in later stages of a treatment to achieve higher proppant concentrations.

Assuming maximum proppant concentration at blender=20PPA. In uncrosslinked 70% quality foam, the maximum BH proppant concentration ~ 6 PPA. Because gas content is lower in a crosslinked foam, e.g. ~30% quality, the BH proppant concentration can be as high as 14 PPA. Some treatments still pump crosslinked 70% foam due to reservoir properties, not viscosity properties.

Foams made with crosslinked fluids are usually thought of as being stable at any quality, because of the high viscosity. The crosslinked structure may resist being disrupted by a large bubble concentration and will separate additional gas from the foam. A 70% quality foam appears to be the maximum for most crosslinked foams.

➢ **Stability of Foamed Crosslinked Gel**

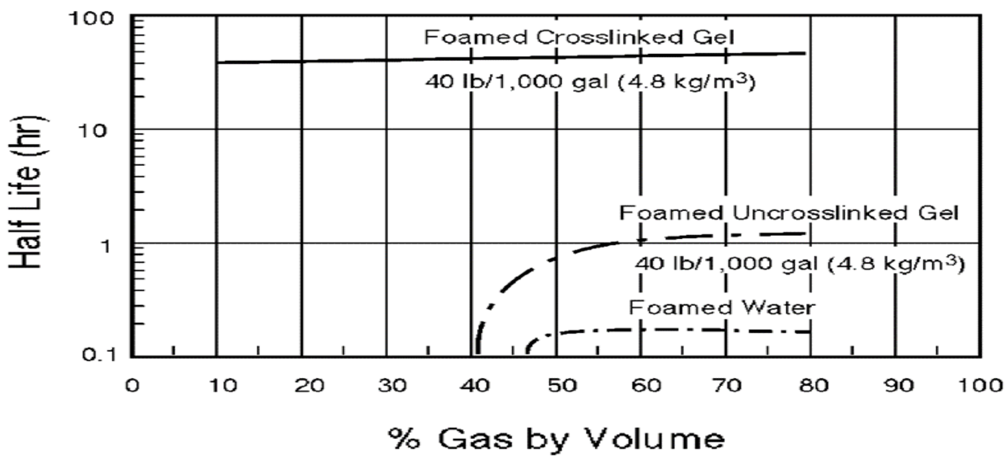

Figure II.22: stability of foamed Crosslinked Gel.

- A comparison of half-life vs. gas content for foamed water, foamed linear gel and foamed crosslinked gel, shows that the latter exhibit a much more stable foam.
- Fluid must be foamed and then crosslinked to avoid trapping of large bubbles. (Use a delayed x linker).
- For quality less than 50%, the crosslinking/foaming timing may not be so critical.

Hydrocarbons foamed with CO_2

- Impractical due to high solubility of CO_2

Hydrocarbons foamed with N_2

- Expensive, requires fluorocarbon surfactants

Foamed alcohols

- Used in dry gas reservoir to avoid relative permeability problems
- Max alcohols content: 40% of aqueous phase

II.5.2.2 The gas phase (N2/CO2) :

Both CO_2 and N_2 can be used to foam different fluid. Nitrogen is an inert gas and is frequently used because it is versatile. CO_2 is more soluble in water so more CO_2 is required to create the foam. CO_2 may have an advantage in certain applications: greater hydrostatic pressure (lower treating pressure), more expansion during flowback (aids in cleanup) and may remove or prevent water blocks. CO_2 is not compatible with: YF100, YF100D, YF200, YF200D, YF500HT, YF600LT and YF600HT. CO_2 will interfere with the crosslinking mechanism.

N2: Nitrogen gas:

a. **Nitrogen Production:**

Air is liquefied by compression **and** cooling processes.

Decreasing the pressure will free some vapor which is rich in nitrogen, the same happens when heat is added.

The remained unboiled liquid is rich in oxygen

With repeating boiling and condensing processes all gases contained in the air are separated.

b. Nitrogen N2 :

- Normal boiling point - 320o F
- Critical pressure 492.3 psi
- Critical temperature - 232.87o F
- Chemical symbol N2
- Triple point - 345.9o F @ 1.82 psi
- 1 gallon of LN2 = 93.12 SCF of gas

The basic idea is to liquefy air, then separate the liquid by fractional distillation.

- Liquid air boils at - 317^{o} F
- Liquid nitrogen boils at -320^{o} F
- Liquid oxygen boils at - 297^{o} F
- Nitrogen starts to evaporate leaving oxygen rich liquid
- By repeating **boiling** and **condensing** processes high purity of liquid nitrogen up to 99.98 % can be obtained
- Different gases are extracted in the same way.

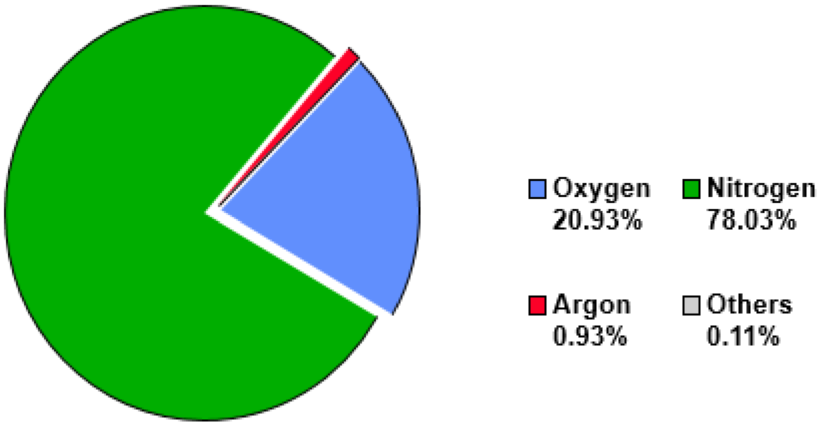

Figure II.23: Nitrogen in air.

a. Nitrogen Volume Factor:

A term is used to reflect the number of SCF occupy one barrel volume at a certain conditions of pressure and temperature.

It can be obtained from precalculated tables in the nitrogen manual when pressure and temperature values are available.

For conditions out of the tables range, It is obtained by the above formula.

Absolute temperature (Rankine) = T deg.F + 460

Standard cubic feet per barrel of space

$$\text{SCF} = \frac{(198.6 * P)}{(Z*T)}$$

P = Pressure, PSI

T = Temperature, absolute Rankine (T degF + 460)

Z = Compressibility factor

Accurate BHP is critical in foam calculations

b. Compressibility Factor:

This is a graph shows the values of Z as related to pressure and temperature.

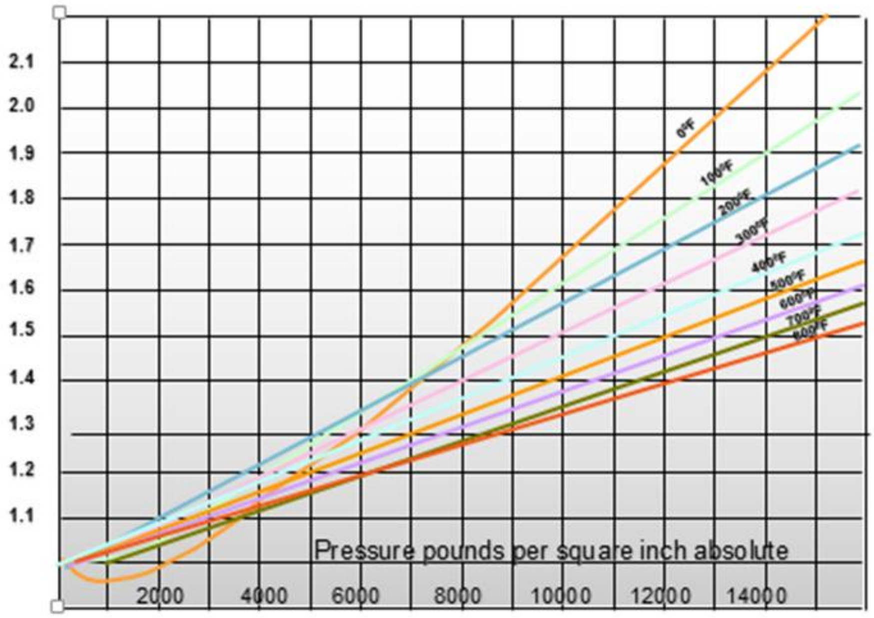

Figure II.24: Z factor compressibility related to pressure and temperature.

c. Nitrogen storage:

Because of the extreme low temperature (–320 degF [–196 degC]) of liquid nitrogen, caution must be exercised to ensure that the liquid does not contact the carbon steel material normally used in the construction of pumping equipment. Contact with mild steel like A-36 or other common steel plate will cause the steel to distort and crack. Load bearing members of a truck or trailer will crack and ultimately fail if exposed to liquid nitrogen.

Any activity or procedure that allows the liquid nitrogen to absorb heat will directly affect the inventory. Because of its low temperature, liquid nitrogen is constantly picking up heat from the atmosphere. Because of the insulated cryogenic tank the amount of heat transferred is limited, assuming the vacuum has been maintained properly. This limited heat transfer results in reduced losses of liquid nitrogen. Any activity during which the liquid nitrogen is moved outside the insulated storage vessel affects inventory management. The exposure to noncryogenic temperatures will convert some

of the liquid to gas, and this process cannot be reversed. Activities that can introduce heat into the system are:

- transferring liquid from the suppliers

- transport to the storage tank

- transferring from a storage tank to a transport

- building pressure in the vapor space of any storage tank or transport.

- leaving liquid in a tank for long times

-,not maintaining vacuums at the manufacturer's recommended levels

- cooling down the transfer centrifugal pump (C-pump) at the district

- cooling down transfer hoses in preparation to move fluid

- cooling down cold ends and the C-pump on the pumping unit

- cooling down C-pump on any transport

-cooling down and filling of a nitrogen tank that has not been used in a long time.

-conditioning of the fluid in preparation for cooldown and prime-up of pumping units.

An industry guideline assumes that it takes from a 1/2 to 1 galUS of liquid nitrogen to cool down 1 lbm of metal. This estimate is highly dependent on the ambient temperature of the metal being cooled down, but the important point is that a lot of liquid nitrogen can be lost in the cooldown process alone.

Because of the extreme low temperature of LN2, the liquid nitrogen boils and evaporates at room temperature (70 to 80 degF [21 to 27 degC]). Thus, it is necessary to store the liquid nitrogen in containers that are insulated. The design of the insulation will be somewhat similar to that of a vacuum thermos bottle used to keep fluids hot or cold. The main difference will be the extent to which the vacuum is pulled and the insulating material used in the space between the inner and the outer shells. A vacuum works by removing the molecules of air that would transfer heat from the outer surface of the tank to the liquid stored in the inner tank. As more molecules of air are removed from the space between the two tanks, the ability of heat to migrate to the liquid is reduced. High-capacity vacuum pumps are used for pulling these vacuums.

There are several contributors to the total amount of liquid loss on a monthly basis. This is just one of them. Nitrogen losses cannot be stopped, but every effort should be made to limit the total loss of liquid to between 5 and 10%.

When the transformation from liquid to gas has taken place, the process cannot be reversed in Schlumberger equipment. The only solution is to remove the heat from the liquid by blowing down the tank.

Different sizes 2000, 4000 for on shore and off shore usage, 7200 trailer mounted, 13000vertical yard storage.

Different working pressures but Dowell uses only low pressure type for safety.

Two layers tank equipped with minimum of three pressure relief devices.

Heat transfer is too low in vacuumed environment.

Skid mounted and crash frames for protection and lifting purposes.

Figure II.25: Equipments needed in the storage of Nitrogen.

Different sizes to suit the application:

- Stainless steel inner vessel
- Mild steel outer jacket
- Insulation filling and vacuum
- Safety pressure relief devices
- Low or high pressure (40 -300 psi)

d. Applications for Nitrogen:

- Flow back - Best to pump N2 with the fluid not ahead, gas functions by expansion toward the well bore and reduces the hydrostatic psi.
- Energized acid – reduced time in clean up, swabbing may not be possible - tapered string, gas aids in leak off, high flow back velocity in the critical matrix, determine if the perfs are open before treatment.

- Atomized acid- small droplets allow better coverage at low bottom hole injection pressure, speeds clean up, low water content, N2 extremely dry gas.
- Displacement for completion – commonly used when formation pressure is not adequate to lift hydrostatic column of completion fluid.
- Corrosion inhibition – inhibitor evenly dispersed over the tubing and pore spaces, can be used to place scale inhibitors
- Abrasive – sand laden fluid gets much better penetration when energized.
- Formation test – used to reduce the high differential pressures across the packer helps to prevent tool failure and formation caving.
- Setting Hydraulic packers – the tubing is displaced 1,000' to 500' above the packer, ball is dropped and allowed to seat, pressuring up set the packer, continuing to build until the ball shears.
- PSI Test / Pipe line – BOP's, flow lines, and other surface equipment Lines purged for repairs, pigging, cleaning.
- Gaseous drilling – 30% mixture for air is explosion proof, can be used with air drilled holes
- Differential perforating – can be used in both over and under balanced perforating.
- Drilling – N2 used to reduce the hydrostatic psi of the mud ahead of the cement, increasing cement fill and reducing formation damage.
- Industrial & Marine applications – inert and cool reactors, catalyst system drying, ship purging, LNG and boiler purging
-

CO2: Carbon Dioxide gas:

a. Carbon Dioxide production

- Unrefined gas may be obtained from:
  - Combustion of coal
  - Coke
  - Natural gas, oil - Carbonaceous fuels
- Generated in the fermentation process
- By-product gas from ammonia plant, lime kilns, carbine furnaces
- Natural springs and wells
- By repeating boiling and condensing processes high purity of liquid carbon dioxide up to 99.98 % can be obtained

b. CO2 Production

- 1 gal liquid CO2 @ 0o F	8.51 lb/gal
- Critical pressure	1,070 psi
- Critical temperature	87.8o F
- Chemical symbol	CO2
- Triple point	- 69.9o F @ 60.43 psi
- 1 gallon of LCO2	= 73 SCF of gas

c. CO2 pressurization:

Why we need to pressurize CO2…?

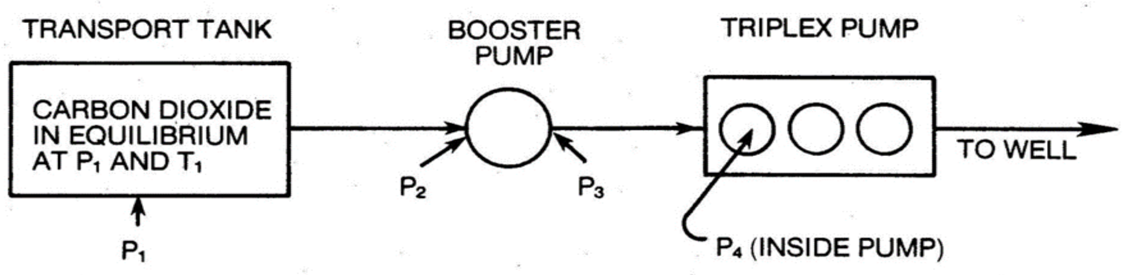

Figure II.26: CO2 pressurization.

- P1 > P2 but only slightly, will allow some gas out of solution
- P3 is the "boost" pressure to the triplex pump
- The sequence of events in the triplex is the main reason for the boost in discharge psi.
- Carbon dioxide is pumped at the wellhead in liquid form Triple point – the point on a phase diagram at which the three states of matter: gas, liquid, and solid coexist
- Critical point – the point on a phase diagram at which the substance is indistinguishable between liquid and gaseous states

When the triplex plunger completes its forward stroke, the discharge valve closes. Then the plunger starts its backward stroke, the pressure inside the pump is reduced. When the pressure is reduced to pressure P4, the pressure inside the triplex will be less than the pressure in the triplex suction header and the suction valve will open and allow the triplex fluid chamber to fill as the plunger completes its backward stroke. If the CO2 pressure decreases below P1 the tank pressure, gas will be evolved and occupy a portion of the chamber causing the pump to "knock". If this gas bubble is not expelled it will grow larger with each succeeding stroke of the plunger and soon the pump will become gas-locked. Gas-locking occurs when the pressure of the gas "bubble" is high enough to prevent the suction valves from opening and the volume of the gas is too large for it to be compressed enough to open the discharge valves. When gas-locking occurs, we must open the bleed valve on the triplex so that we can discharge the gas in the triplex fluid chamber to the atmosphere and reprime the triplex. Now you understand the necessity of pressurizing the triplex.

d. Foamed Hydrocarbons and Alcohols:

Hydrocarbons foamed with CO2:

- Impractical due to high solubility of CO2

Hydrocarbons foamed with N2:

- Expensive, requires fluorocarbon surfactants.

Foamed alcohols:

- Used in dry gas reservoir to avoid relative permeability problems.
- Max alcohols content: 40% of aqueous phase.

II 5.3 Foam stability:

Stability maintains the dispersion of the gas in the liquid, which in turn controls the rheology and fluid loss properties of the foam.

Factors affecting stability:

- Surfactant type & concentration
- Foam quality
- Polymer type & concentration
- Mixing energy

II 5.4 Foam Quality:

At less than 52% quality, the spherical bubbles are free to segregate and move. There is no bubble/bubbles interaction to provide resistance to flow considered unstable. The fluids are classified as energized fluids.

From 52% to 74% quality, the spherical bubbles contact each other and are no longer free to move. From 74% to 96% quality, the bubbles sides flatten and there is a more rigid structure. The fluids are classified as foamed fluids.

At greater than 96% quality, a gas outside phase and liquid inside phase are formed resulting in a mist. The fluids are classified as atomized fluids.

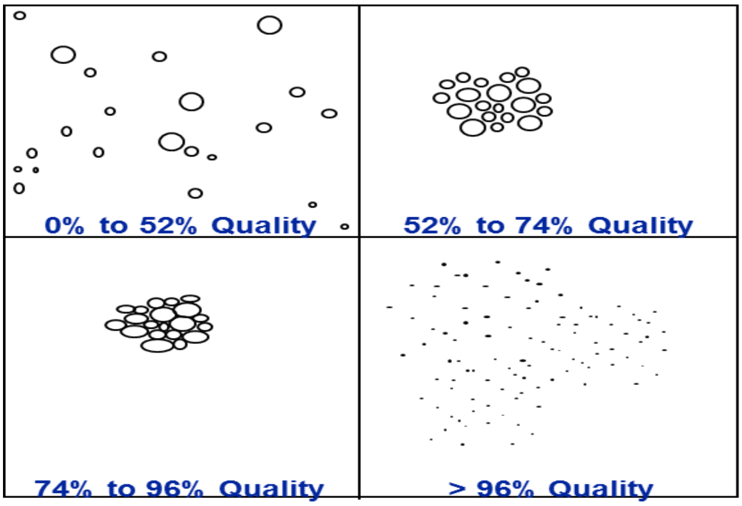

Figure II.27: Nitrogen Quality.

- Less than 52% quality: energized fluid
- From 52% to 74% quality: regular or wet foamed fluid
- From 74% to 96% quality: compressed or dry foam
- Greater than 96% quality: atomized fluids

II 5.4.1 Adjusting Foam Quality

This constant foam quality method is usually the chosen method. Constant bottom hole foam quality is often assumed in the design of foam fracturing treatment.

Gas rate adjustment: reducing the gas pump rate as the liquid volume decreases and the proppant volume increases. The blender discharge is constant, the total pump rate will decrease.

Liquid rate adjustment: Increasing liquid rate to compensate for the liquid volume displaced by the proppant. The total pump rate will increase.

The total rate and foam quality will remain constant by simultaneously adjusting the gas and liquid rate.

The foam quality can also be reduced to accommodate higher proppant concentration.

II 5.4.2 Proppant Concentration vs. Foam Quality:

The most significant drawback to high foam qualities is the difficulty in achieving high proppant concentrations. A slurry concentration of 20 ppa at the blender would yield a concentration of 2 ppa in a 90% quality foam.

Foams made with crosslinked fluids are usually thought of as being stable at any quality, because of the high viscosity. The crosslinked structure may resist being disrupted by a large bubble concentration and will separate additional gas from the foam. A 70% quality foam appears to be the maximum for most crosslinked foams.

High foam qualities may be desirable for:

- Improved proppant transport, higher viscosity, better fluid loss control, less conductivity damage.

Drawback to high quality foam:

- Low proppant concentration.

Crosslinked foam:

- Maximum quality = 70%.
- No advantage to crosslink a foam unless $Q < 52\%$.

II 5.5 Foam Rheology:

Leak off of foam to the formation, controlled by formation permeability, foam texture and polymer loading will play a large role in whether a treatment is successful.

Foam quality affects the shape and strength of the bubble interface structure which in turn affects the viscosity.

Many factors affect the rheology of foam:

- Liquid phase composition.
- Foam mixing/texture.

- Foam quality.
- Temperature.

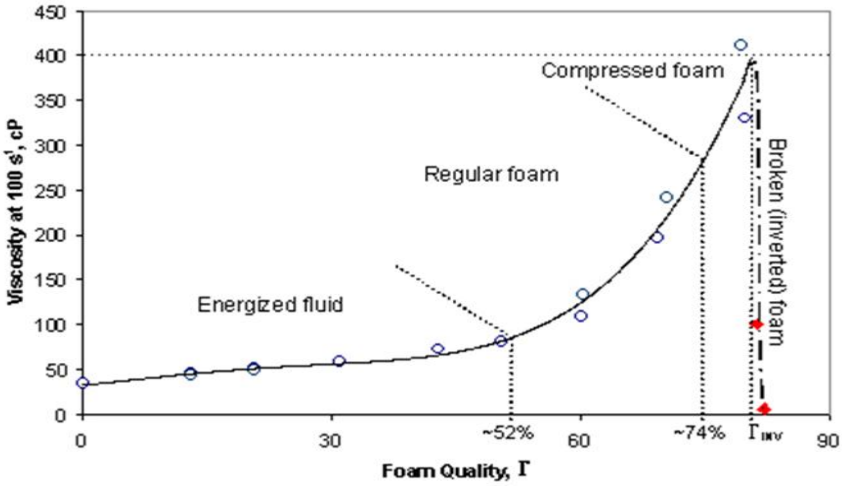

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Figure II.28: Foam Rheology.

II 5.6 Foam Texture:

- Texture is an important factor in determining rheology and fluid-loss properties.
- In general, a foam containing small bubbles is more viscous than the same quality larger bubbles.
- Likewise, a foam containing a narrow range of bubble sizes is more viscous than a foam containing a wide range of bubble sizes.

II 5.7 Foam Fluid Loss Properties:

The two phase effects help control fluid loss by increasing the flow resistance through the matrix of the rock. The deformation of the bubbles when flowing into formation creates resistance to leakoff.

The two phase fluid loss control mechanism is lost once the pore throat size exceeds the bubble size.

A foam containing a polymer can control fluid loss by filter cake deposition in the fracture face. However, wall building properties that contains high quality foam or low concentration of polymer are slow to develop.

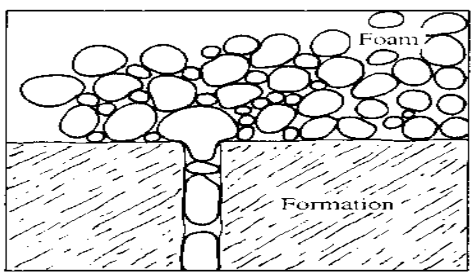


Figure II.29: Foam fluid loss in formation.

Two phase behavior:

- Increased flow resistance help control fluid loss.
- Poor fluid loss control when pore throat size > bubble size (above 30 md).

Wall building effects:

- Polymer filtercake deposition.
- Low quality foam.
- High concentration of Polymer.

Use Cw for preliminary fracture design:

- Low permeability (< 1 md): Foam quality has little effect on Cw.
- High permeability: Cw decreases as quality increases.

II 5.8 Foam Conductivity Damage:

- Proppant pack may be damaged by polymer
  - High post closure polymer concentration
- Foam has minimal conductivity damage
  - Low polymer concentration

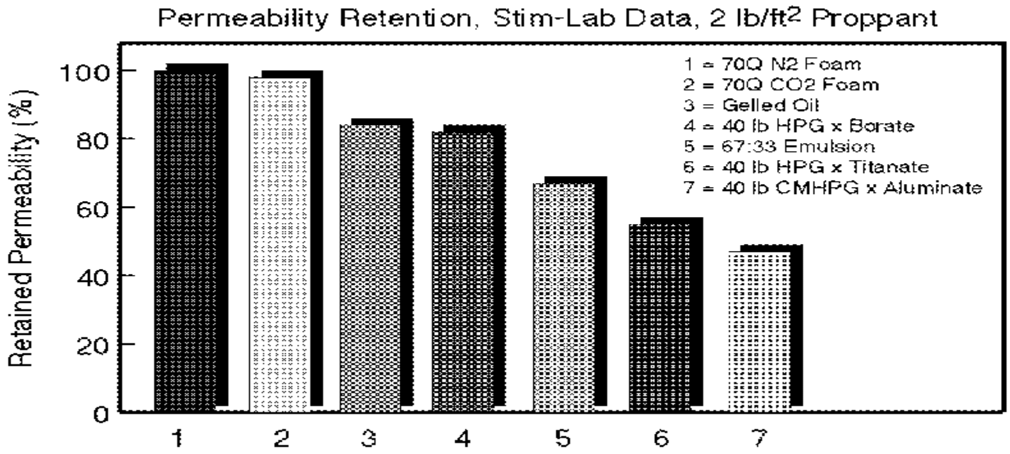


Figure II.30: diagram shows Foam conductivity damage.

Permeability of proppant pack may be damaged by the polymer. The final post closure polymer concentration can easily reads 10 to 15 times the initial concentration. This high concentrated polymer is the primary cause of the conductivity damage.

Foam is considered to be very good at minimizing conductivity damage caused by high post closure polymer concentration. This is due to low polymer concentration in the foam and less liquid-phase volume.

Results from stim-lab testing have shown the following retained proppant pack permeabilities (2 lb/ft2):

Quality	Gas	Polymers	Retained pIIIermeability
70%	N2	30# Xantham	98%
70%	CO2	30# HPG	98%
70%	N2	30# HPG	82%

II 5.9 Foam Fracturing Fluids advantage and disadvantage:

- Foams provide low leakoff and good solid suspending properties.
- Enhanced cleanup will be obtained because of the high energy of the gas during the clean-up stage.
- Foams are excellent fluids to use in low pressure reservoirs to achieve rapid cleanup.
- Foams also perform well in water sensitive formations since the liquid phase of the foam is minimal.
- Pumping pressures will be large compared with water based gel, due to low hydrostatic pressure. Another disadvantage is that it is difficult to get high sand concentrations in foam fracturing.

II 5.10 Foam Fractures and Application:

- Foams provide clean up energy for depleted reservoir.
- Water sensitive formations: Foams minimize the amount of water into the formations.
- Tight gas wells: Good fluid loss control provides extended fracture length which is important in low permeability reservoirs.

II 5.11 Proppant Addition to Foam:

As proppant is added to the foam, the quantity of liquid required decrease due to the additional volume taken up by the proppant. The proppant will behave as a higher quality foam. The purpose of the compensation is to allow increasing proppant concentration while maintaining adequate but not excessive viscosity.

The advantage of no compensation is that it is operationally simple. As the proppant concentration at the blender increases, the total slurry rate increases.

One of the following methods is generally used when compensating for the proppant volume

- No compensation
- Constant bottom hole quality
- Decreasing bottom hole quality
- Constant internal phase (CIP)

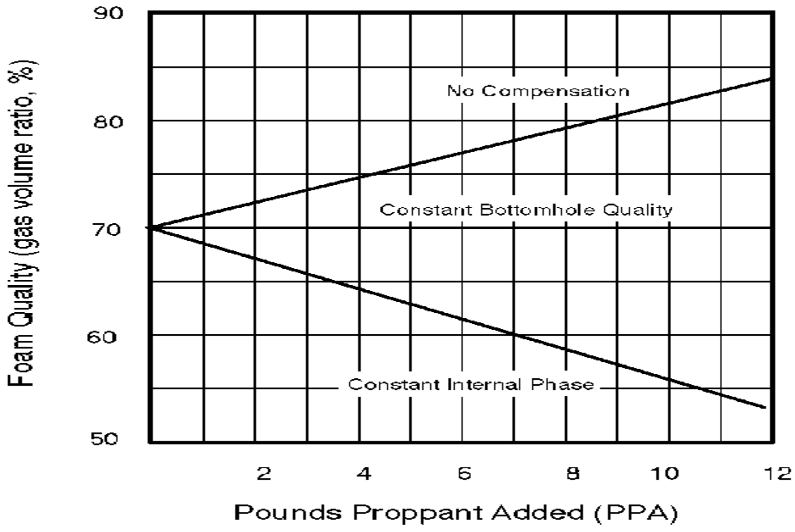


Figure II.31: Proppant compensation in foam quality.

II 5.12 Calculation of Foam Parameters:

- **Foam pressure calculation:**

  Hydrostatic pressure of liquid phase:

  - PLH = 0.433 SGL dL Dp

  Hydrostatic pressure of gas phase:

  - Pgh = dg (Piw - Pwh)

  Total pressure:

  - Pfh = PLH + Pgh

  Surface pressure at the wellhead:

  - Pw = Piw - Pfh + Ptf + Ppf

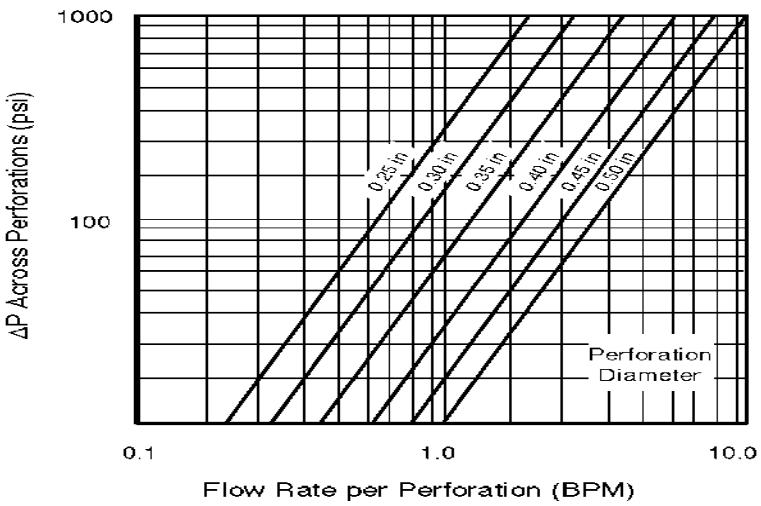


Figure II.32: Foam rate per perforation. VS across ΔP perforations.

Where:

- SGL = S.G. of liquid
- Dp = Vertical depth (ft)
- dL = Liquid ratio (fractional) dg = Gas ratio
- Piw = Fracturing pressure = Fracture gradient x depth (psi)
- Pwh = Wellhead pressure (psi) (from Nitrogen Engineering Handbook)
- Ptf = Tubular friction pressure (psi) (from Fracturing Material Manual - Fluids)
- Ppf = Perforation friction pressure (psi) (from figure)

➢ **Equipment Calculations:**

Liquid Phase Rate

- qL = qdL - qf

Horse power requirement for liquid phase:

- HHP = 0.0245 Pw qL

Gas phase pump rate:

- qg = q dg (BPM)

For Nitrogen:

- Rate (scf/min)= Qg (bpm) x BN2 (scf/bbl)

(Volume factor BN2 is obtained from the Nitrogen Engineering Handbook

Where:

- dL = Liquid ratio
- dg = Gas ratio
- qf = Foa mer pump rate (BPM)
- Pw = Surface pumping pressure

The number of N2 pumpers required is determined by dividing Nitrogen pump rate (SCF/min) by rate per pumper.

➢ **Material Requirements:**

Liquid phase volume:

- = foam volume x liquid ratio

Nitrogen volume (SCF):

- = foam volume x gas ratio x BN2 x 0.0238

CO2 volume (gal):

- = foam volume x gas ratio

Foamer volume:

- = foamer concentration x liquid phase volume x 0.001

Foam volume in gal.

Foamer concentration in gal/1,000 gal.

II 5.13 Execution Considerations:

- Equipment limitations
- Foam generation
- Proppant compensation method

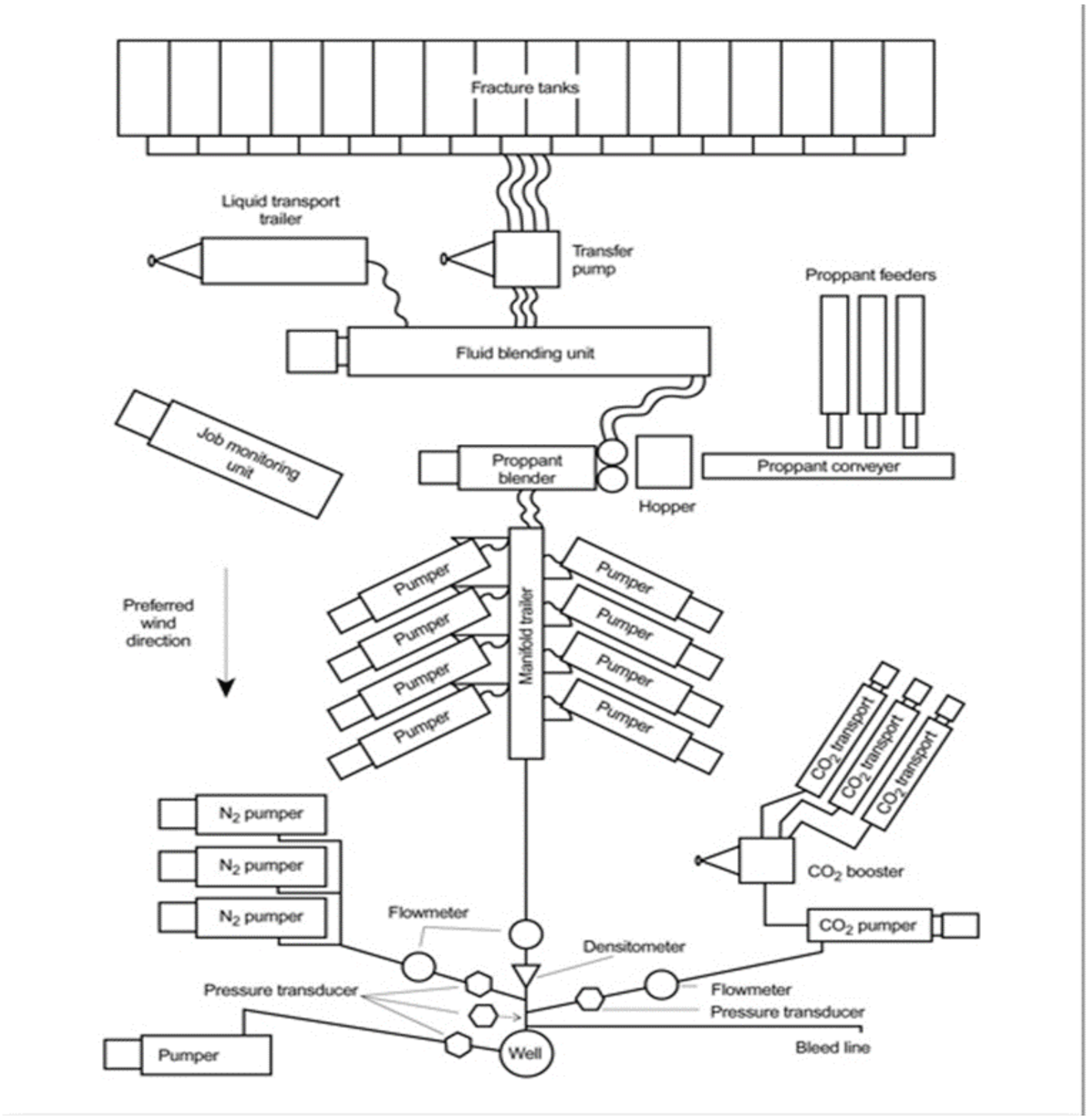


Figure II.33: Operation job consideration.

Executing a foam fracturing job requires a significant amount of equipment and pump schedule coordination. Foam quality may be limited because of available equipment.

II 5.14 Additional Considerations:

Pressure Measurement:

- Surface pressure
- As long as density in constant

- Dead string tubing
- Downhole BHP sensor

Proppant Concentration:

- Inability to mix high proppant concentration
- POD Blender can control up to:
    - PA (sand)
    - 32 PPA (ISP)

Flush Fluids:

- Do not use foam: Foam will heat up and expand, may overflush

The inability to mix and meter high proppant concentration in high quality foams is a limitation in foam fracturing treatments because of dilution effects of the gas phase.

Some places do flush with foam, but they flow the wells back immediately to overcome any expansion or over-displacement.

II 5.15 Foam Generation:

Sufficient mixing turbulence is required Foam fluid in laminar flow:

- A foam generator is required

Foam generator:

- A Frac cross containing a disperser
- Recommended for all foam fracturing treatments

Surfactant

- Affect foam texture

A foam generator is required if the foamed fluid will be in laminar flow. A foam generator is a frac cross containing a disperser comes with various hole sizes and arrangement.

Surfactant also affect the foam generation. Insufficient or contaminated surfactant may have a poor foam texture.

Generally, turbulence is achieved in oilfield conditions; however, if a base fluid is particularly viscous, turbulence may not be achieved, and in this case, a foam generator is highly recommended.

II 6 Equipment needed in foam fracturing design:

The same equipments used in conventional hydraulic fracturing are used in foam operation but the deference is in using the N2 gas with foam. The N2 gas has it's specific pumps due to the high pressure it needs to pump to the well, here it is a clearly explanation of N2 pump following pumping steps.

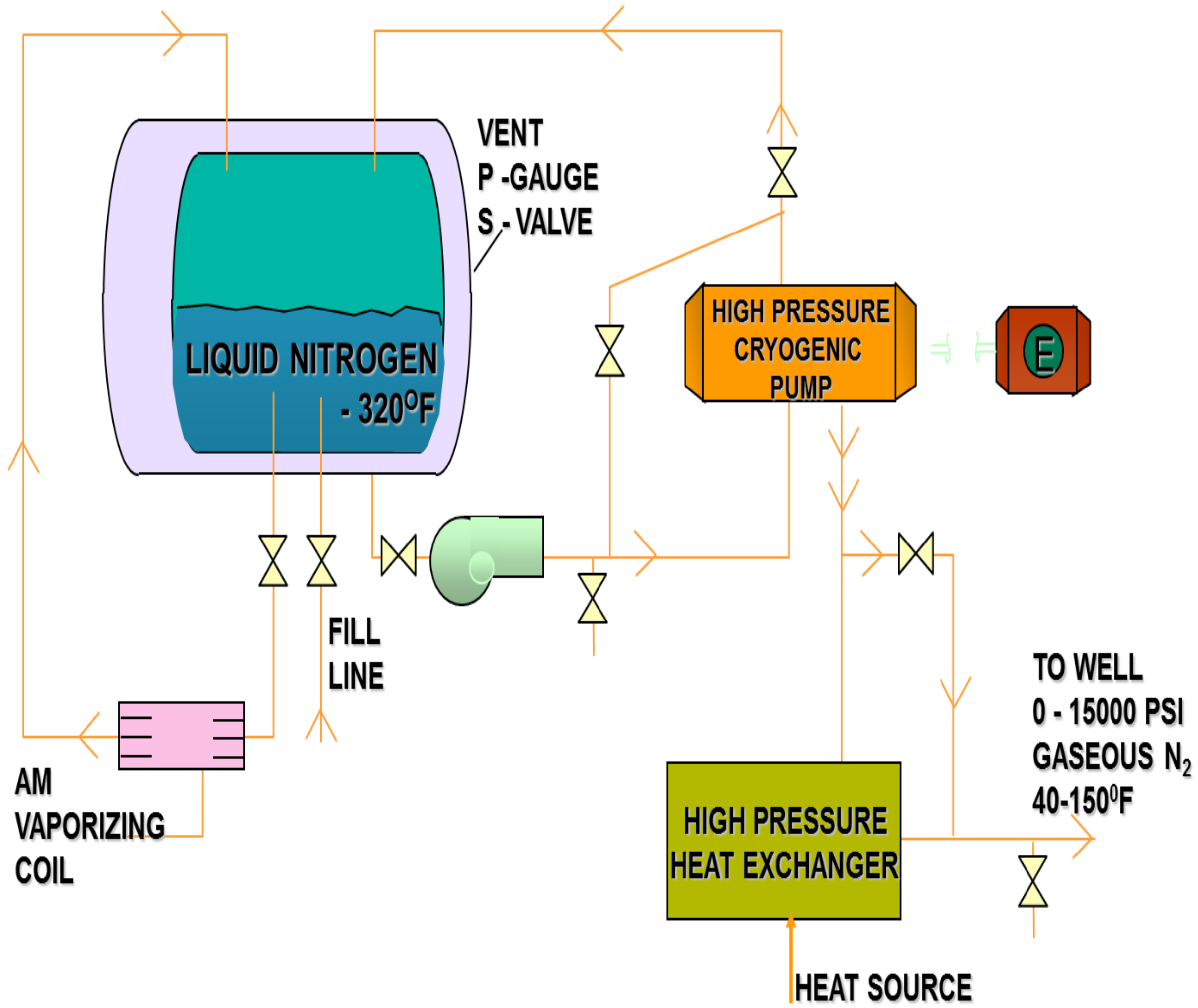


Figure II.34: N2 Pump.

LN2 flows from a supply tank into a boost C‑pump, which boosts the LN2 pressure.

For a pump to operate at the rated capacity, the suction must be charged with fluid at the net positive suction head required. If the pump is not properly charged on the suction side, the triplex will be starved of source fluid and cavitation will occur. This priming is done with a C-pump. The potential for cavitation is higher when LN2 is being pumped because of the entrained gas in the liquid. Because of the LN2 temperature, volatility of the liquid, and the entrained gas, proper priming and use of the LN2 C-pump is essential to successfully pumping LN2. The cryogenic C-pump comes in various sizes, depending on the flow rate and discharge pressure required. There are no shortcuts to cooling down the C-pump (Fig. 5‑10). All of the heat in the metal components of the C‑pump must be removed so that the LN2 remains liquid and the pump can maintain prime with LN2. The pump is cooled down by allowing LN2 from the tank to flow through the C-pump and out the ground vent valve to the atmosphere (Fig. 5-10). As long as the discharge of the ground vent valve is surging because of the GN2, the C‑pump is not completely cooled down.

A centrifugal booster pump is pressurizing the liquid in order to help overcome line losses and to provide the additional head required for an efficient unit operation.

Vent valve to speed with cooling down the booster pump.

Return to tank line valve for circulation back to tank and cool down.

A high pressure triplex pump pressurizes the LN2 to the required pressure and passed through a high pressure vaporizer where liquid is converted to a warm gas.

The required heat energy comes from a burner, engine coolant, engine exhaust, and other sources depending on the design (rate) of the unit.

High quality stainless steel piping and fittings for both high and low pressure systems.

Gas temperature control by pass valve or burner temperature to adjust discharged gas temperature.

Proper cool down should be done prior operating pumps. Failure to do so will result in parts damage as all component are cooled and lubricated by liquid nitrogen.

Conclusion

In the one hand this chapter gives an overview on hydraulic fracturing with the conventional fluid and the several parameters to know and to choose for successful operation (constraints, permeability, porosity of the formation, young’s modulus poisson modulus, the injection rate, fracturing fluid….) to obtain the fracture extansion Xf, thincknessWf, supported height Hf and the conductivity(Kf.Wf).In the other hand fracturing with foam as an energized fluid especially in depleted reservoir which is our OMP-742 well cas, in addition exposes.

Chapter III: Best practices for performing Hydraulic Fracturing Operation

Introduction :

A test program, before hydraulic fracturing is necessary to prepare and ensure consistency in the main treatment processes, the test data and the analysis of the latter must be studied and observed, with great seriousness on the one hand and a certain finesse on the other hand. In this chapter we present the most common tests and their interpretations as well as the main course of hydraulic fracturing.

III .1 Selection criteria for wells to be fractured:

III . 1 .1 Characteristics of the reservoir to be fractured:

- Nature of the reservoir
- Fluid interface in place
- Nature of the fluid in place
- Permeability of the reservoir
- Static pressure of the tank

III .1 .2 State of wells to be fractured :

- History of well
- Completion of well
- Condition of the perforations

III .2 design of hydraulic fracturing:

Hydraulic fracturing is only suitable for sufficiently consolidated formation like... sand limestone..as opposed to plastic-formation like clay sand very little-consolidated.

this process applies to the case where the flow from the well is insufficient due to the low natural permeability of the rock

.also in heavily damaged formation or-production always remains weak or because of clogging difficult to remove with acidification.in order to have sufficient conductivity contrast between the fracture and formation it is therefore normal to want to increase the reservoir productivity. by the creation of a well formation bond.which-will have a permeability clearly superior than that of the matrix for the first case and of go beyond the damage in the second case.

III .3 Preparation of the well for hydraulic fracturing (Pre-Frac Phase):

III .3.1 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 flowmeter makes it possible to compare the profil of flow recorded with the (kh) of the well (according to the permeabilities on cores, if they exist.

III .3.2 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.).

III .3.3 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, then the acid is disgorged from the well in order to avoid damaging completion equipment.

III .4 Realization of hydraulic fracturing:

III .4.1 Injectivity tests:

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

- Check if the formation absorbs fluid (hence the name of the Injectivity 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 reduce the apparent fracturing gradient.

III .4.1.1 Procedure for the injectivity test:

- When hydraulic fracturing is commonly practiced in the field, the injectivity 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 injectivity test before deciding on the choice of hydraulic fracturing treatment.

III .4.1.2 Nature and volume of fluids injected:

The injectivity test is performed with conventional fracturing fluids:

- Water or brine gelled (transformed into gel) or not.
- Crude or diesel.

To bring the gel to the surface after the operation, a chemical is used"Breaker gel". The total volume to be injected depends on the recordings provided. We will proceed to different flow rates if necessary, in order to obtain the flow rate curve (Qinj) according to the injection pressure (PInj), allowing to know perfectly the extension pressure of the fracture.

III .4.1.3 Interpretation of the results of the injectivity test:

- Determination of the fracturing gradient (Gf) and its evolution with the extension of the fracture.

- An abnormally high gradient is generally the clogging index of the well. Further acidification with a few cubic meters of acid can significantly reduce the gradient.

- Determination of the pressure drops in injection, with estimation if possible of the pressure drops to be expected at a different (generally higher) flow rate during the main treatment.

- Verification of the behavior of the well equipment (The quality of the cementation and the behavior of the downhole equipment).

- Orientation and location of the fracture specified by thermometries in particular. All of this information makes it possible to decide whether or not to continue - and under what conditions - the treatment of the well by hydraulic fracturing.

III .4.1.4 General information deduced from the injectivity tests:

The initial pressure of the vertical fracture may or may not pass through a maximum, depending on:

- The degree of filtration of the fluid injected into the formation.
- The ratio of the main horizontal stresses.
- The actual distribution of stresses in the immediate vicinity of the well.

Most often, a maximum of the background pressure is not observed, especially if the injected fluid filters normally through the formation. Analysis of the flow-pressure curve provides information on the development of the induced fracture:

- A large and extensive fracture results in a very sharp elbow.
- on the contrary, if the fracture is poorly developed, and therefore not very open, the pressure increases slightly with the increase in flow.

If the indications for the injectivity test are not entirely satisfactory, the execution of the main treatment should be postponed to investigate the causes of the abnormalities observed.

III .4.2 Shadow Frac (Data Frac or Mini frac):

The Data FRAC is a set of tests intended to provide essential information for carrying out a fracturing operation with the best chance of success.

III .4.2 .1Objective of the FRAC Data:

The goal is first to obtain accurate or at least realistic data from in situ measurements. So it is a powerful technique that makes it possible to determine the parameters necessary for the study and design of a hydraulic fracturing operation by:

- Estimate the minimum stress (Closing pressure).

- Measure the net pumping pressure (choose the most appropriate model).

- Measure efficiency.

- Evaluate the fractured height (thermometry after 4 hours of stopping pumping).

- Calculate the geometry of the fracture: length, width, mechanical properties.

- Calculate the values of the filtration coefficients.

III .4.2.2 Types of Data Frac tests:

a) Step Rate Test SRT

In fact, there are two different tests, the step-up rate test and the step-down rate test (step-down rate test), the first is selected to determine the extension pressure (propagation) of the fracture (Pext), the second concerns the evaluation of pressure drops around the well and to evaluate the influence of the state of the perforations and / or the tortuosity effect of the fracture on the interpretation

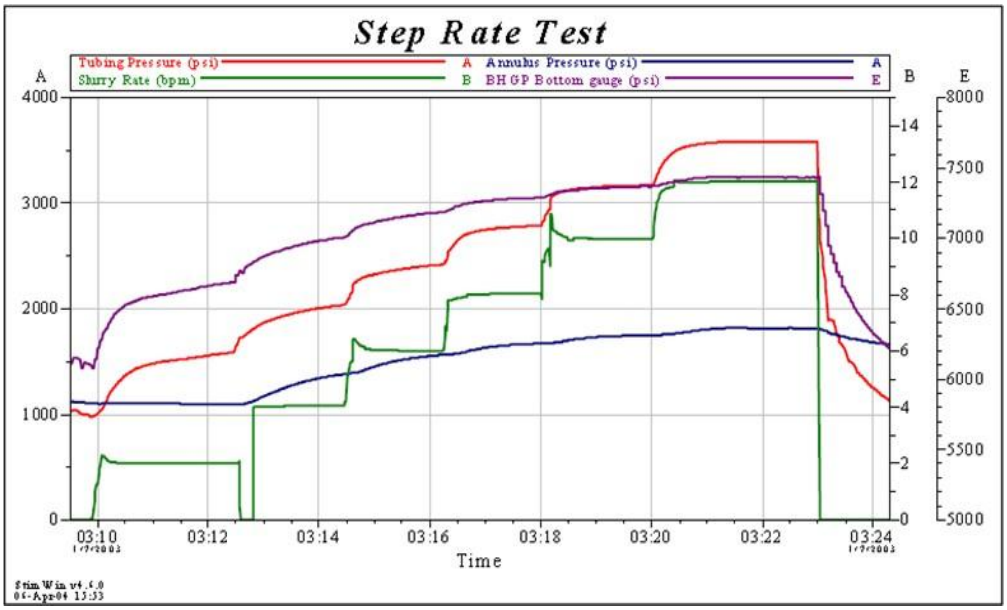


Figure III .1: Diagram of a real SRT (Step up rate test) graph.

- **Step-Up Rate Test (test in increasing flow steps)**

Essentially, it is the recording of the flow rate and the pressure during pumping, this test is used to determine the propagation pressure of the fracture. So from the SRT we get:

- The pressure of propagation (extension) of the fracture (Pext).

- The rate of fracture extension.

N.B: the last level must last long enough (05 to 10 min) to establish a sufficiently large fracture volume in order to obtain appreciable results from a possible flow back test.

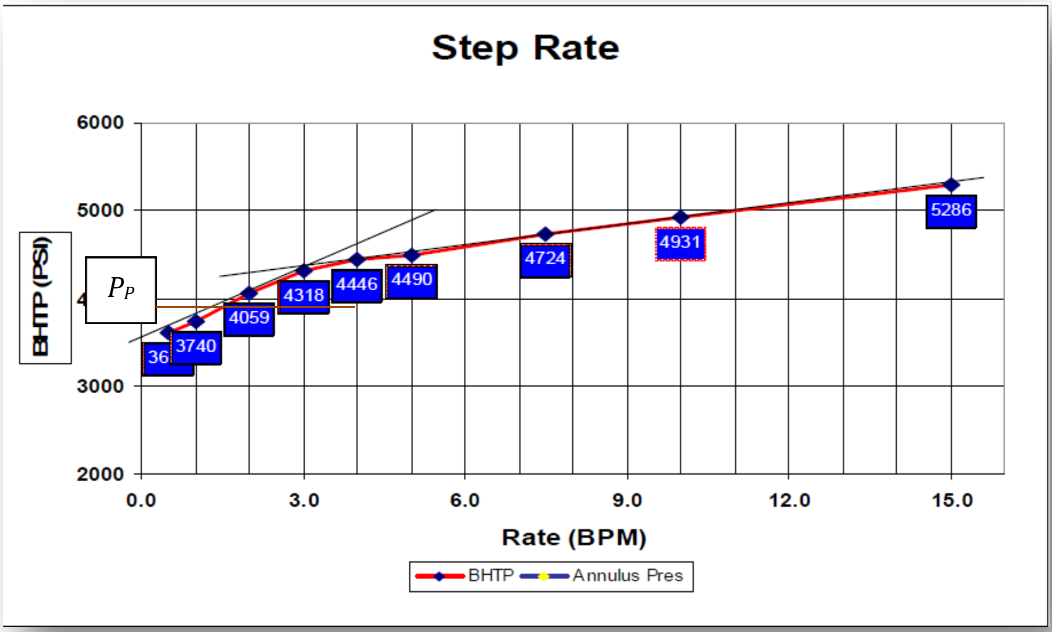


Figure III.2: Estimation of propagation pressure by plotting BHTP as a function of flow rate.

- **Step-Down Rate Test (test in decreasing flow steps)**

The decreasing rate SRT test determines the influence of the fracture around the well. This test is also useful for quantifying the efficiency of perforations and providing a rough estimate of the number of clean perforations.

The figure below shows an SRT test with decreasing flow rate carried out on the same well before and after perforation,the first test reveals rather significant pressure drops generated mainly by more or less blocked perforations. This is characterized by the concave shape of the curve, while the second test represents pressure drops around the well generated mainly by the tortuosity of the fracture and it’s this reflected by a convex aspect of the curve, the decision to re-perforate can be made based on this test.

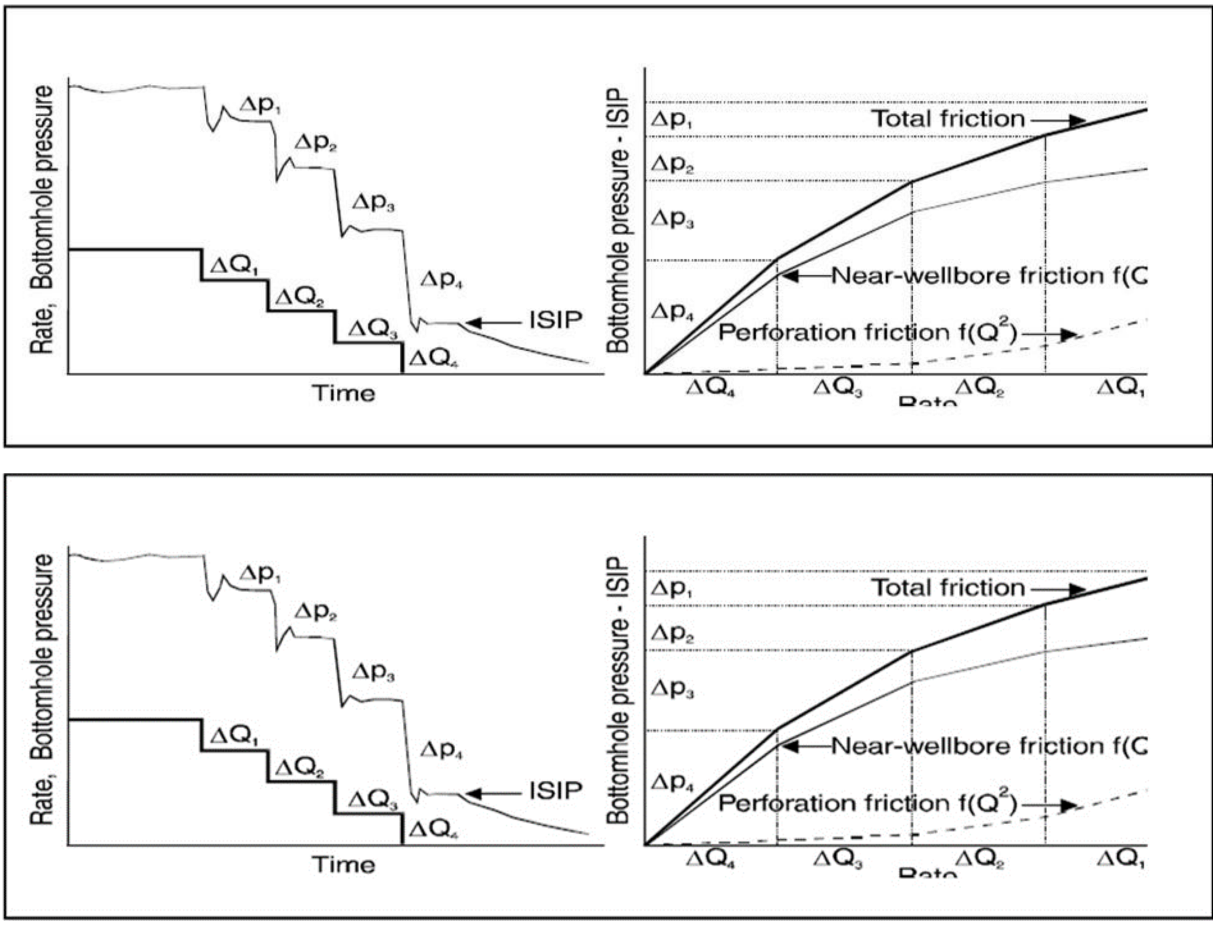


Figure III.3: Step down test before and after perforation.

b. Pump in Flow back Test (PIFB)

This is a test that is used to determine the fracture closure pressure (Pc), it comes directly after the Step Rate Test, requiring the use of the same fluid as the previous test.

The figure below shows the influence of the flow back flow on the pressure response, the three curves represent the pressure responses for low, ideal and high flow. The correct rate is usually ⁄ of the last injection rate.

vs. Fluid efficiency test, (pump-in / shut-in test or fluid efficiency test FET):

This test consists of creating a mini-fracture in the formation with the same fluid as that proposed for the main treatment. It is divided into two stages:

• Minifrac step, which makes it possible to determine the propagation model.

• Fall-off stage or pressure drop after Minifrac.

The pressure must be recorded in both phases in order to obtain, after the curve analysis, the following information:

- The efficiency of the fluid.

- Fluid filtration.

- The geometry of the fracture (width and length).

- The closing pressure (Pc).

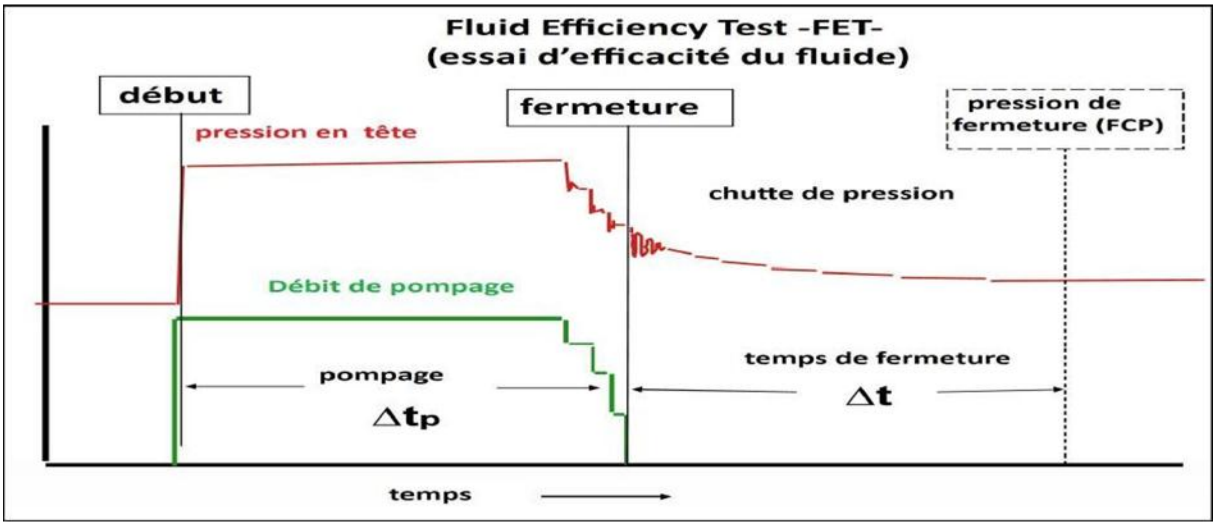


Figure III.4: Fluid Efficiency Test -FET-.

III 4.3 Main treatment:

III 4.3.1 Phases of the main treatment:

It subdivides into six (06) stages:

- **1st phase:A series of tests on the installations**

Equipment and facilities must withstand the pressures reached during fracturing. The main installations that need to be tested are:

- pipes; - the pumps ; - the well head; - the Tree-Saver;

- the annular space; - The Packer; - tubing;

- the discharge valves and the pump control valves.

- **2nd phase: Acid stage**

Consists of pumping several tens of thousands of liters of acid solution diluted in water (hydrochloric acid) in order to clean the cement and drilling mud debris remaining in the notches created by the perforations before the injection of the fluid. fracking.

- **3rd phase: Pad stage**

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.

- **4th phase: Injection of the slurry (Fluid + Proppant: Gelled water or Cross-linked gel)**

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.

Note: Usually the proppant is not injected until it is certain that:

- the width of the fracture is open enough to accept the intrusion of proppants.

- The length obtained approaches the expected length.

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.

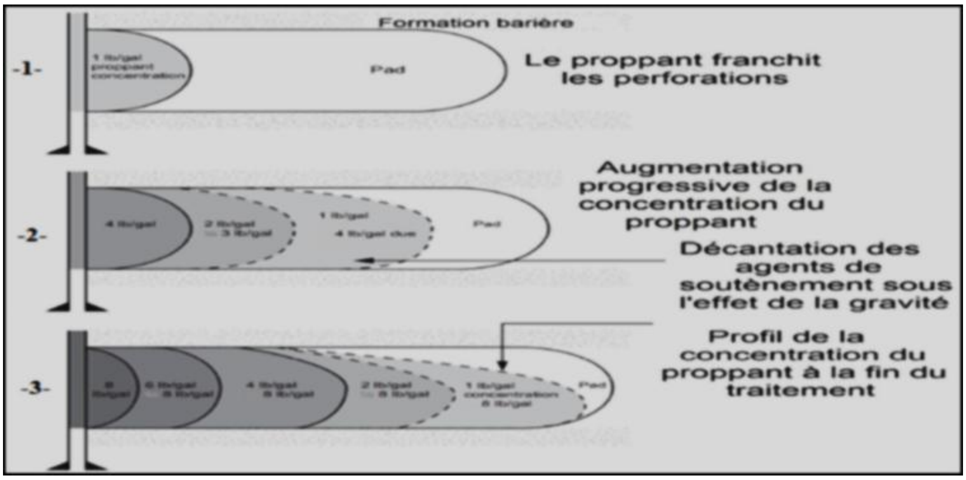


Figure III.5: Proppant concentration profiles during injection.

- **5th phase: Flushing Stage**

Consists of pumping a volume of industrial water (linear gel) sufficient to displace (disgorge) 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.

- **6th phase: Flow back (Fluid Return)**

We must try to evacuate as well as possible not only the treatment fluid contained in the well and in the fracture, but also the fluid that has filtered into the formation.

III 4.3.2 Duration of well closure after treatment:

The duration of well closure after the end of treatment varies according to the operators:

- Some recommend disgorging the well 24 hours after the end of treatment.

- Others limit this wait to 8am only.

The closing time will also obviously vary from one well to another, depending on the permeability of the reservoir and the nature of the fluid injected:

- The use of a temporary sealant, sparingly soluble or insoluble in the effluent, sometimes considerably delays the lowering of the head pressure after treatment.

- The action of the acid in a carbonate reservoir is practically neutralized within a few minutes. The well will be disgorged as soon as the injection is complete.

III 4.3.3 Manner of cleaning the well:

Opinions also differ according to the operators on the discharge rate. In reality, it is desirable to unclog the well by gradually increasing the flow rate, so as to avoid sudden variations in the effective stresses in the formation and to safeguard the resistance of the proppants in the fracture.

III 4.3.4 Duration of disgorging:

It is always useless to want to eliminate all the fluids injected during disgorging.

III 5 Problems of hydraulic fracturing:

Among the hydraulic fracturing problems we can mention:

III 5.1 Clogging:

The reduction OF permeability in the fracture can result from several factors which are:

- Support agent: the wrong choice of support agents can cause clogging, for example crushing of the"Proppant" in the formation due to the low resistance of the latter can cause reduction in conductivity and therefore clogging.
- Fracturing fluid: filtration of fracturing fluid and insoluble residues are two factors that can influence permeability:
- Insoluble residues that form from the breakdown of fracturing fluid may remain in the fracture or in the pores causing clogging.
- The filtration of the fracturing fluid causes an increase in the viscosity of the fluid in the formation which will act as an obstacle in front of the passage of the formation fluid.

III 5.2 Cementing:

For bad cementation, the fracturing fluid will penetrate into areas of low resistance. To solve this problem, we inject the "proppant-slug" to close (plug) the channels behind the casing.

III 5.3 The thickness of the wall (cover layers):

Usually the producing layer is located between two covering layers (which are waterproof); allowing a good seal against the migration of the fluid in place.

In the event that the thickness of its barriers is low; there is the risk of total loss of fluid or of receiving unwanted fluids.

III 5.4 Tortuosity:

The phenomenon of tortuosity causes the width of the fracture to be restricted, which will cause pressure drops and blocking (screen out) because the width becomes smaller than the dimensions of the proppants.

III.5.5 Perforations:

The type of perforation and their density as well as the distribution play a very important role for the success of the fracturing; and to avoid certain problems:
To avoid the tortuosity problem, the perforations must be in the direction of the maximum horizontal stress.
To avoid this problem. It is necessary to facilitate the passage of the balls and for this it is necessary that the diameters of the perforations are large enough.

III.5.6 Configuration of the well head:

In general, the series of heads of the producing wells is 5000 psi while during the treatment we easily exceed 5000 psi at the head, but the problem has been solved by putting a device which by passes the head of the well and which is anchored in the casing called "Treesaver".

III .6 Fracturing with Foam:

The steps to realize a foam fracturing (injection test , calibration test , main treatment, annular pressure test) are similar than the conventional .therefore the deference will be noticed in the pumping part (field operation) , and the specific equipment used . also including the efficiency of the energizer on the flow back section .

III .6 .1 Field operations

During foam frac treatment, water from tank is continuously mixed with sand in a blender, at sand-water ratio progressively increasing to as high as 8 lbs/gallon.

A surfactant, or foaming agent is then proportioned into this slurry at a ratio of 2% to 1%, and the resultant fluid blend is transferred to a high-pressure triplex pumper. High-pressure nitrogen gas is manifolded into the discharge line of the triplex, and it is at this point that the foam is developed. KCL, gellants,or other chemacl trating agents may be added to the base water if required to improve its compatibility with the reservoir rock or fluids. Figure schamtically shows this process.

The blender and high-pressure pumper are conventional oilfield service equipment, modified to accurately proportion the high sand ratios pumped at slow discharge rates. The high-pressure N2 gas is also available from conventional oilfield and to service unit

the foam injection rates and volumes are in the order of 4to 5 times thoese of the liquid pump rates and volumes at the blender because of the expansion by introduction of N2.these total volumes and rates are increased by factor F as follows :

$$F= \frac{1}{(1-(FQ(T,P))}$$

F: expansion factor for foam volume compared to fluid volume.

$FQ_{(T,P)}$: Foam quality at Temperature T and pressure P.

For example using a 75% foam quality ,the foam injection rate will be 4 time the field pump rate at the blender.also, because of the sand must be mixed in the water before foaming, sand ratio of 8 lb/ gal at the blender is required to developed the equivalent of 2 lb/gal in the foam

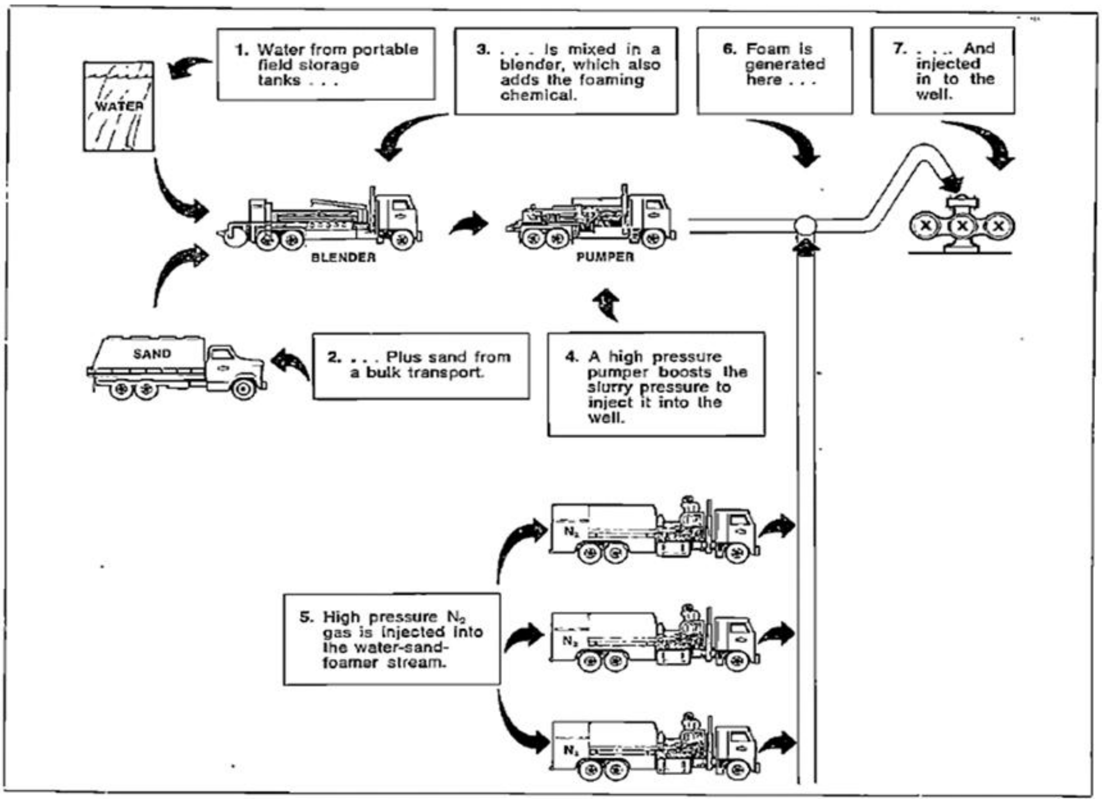


Figure III 6: schematic Diagram of the foam frac operation.

III 6.2 Load fluid flow back procedure:

Due to the extremely low fluid leak-off coefficient of foam, the well pressure generally bleeds off very slowly after a fracture treatment. In one measured case, the wellhead still recorded a shut -in pressure of 200 psi above, the frac closure pressure 24hours after the treatment was finished .these observation. And the sand return observation, led to the institution of the specific flowback procedure required after the use of Foam as fracturing fluid.

Immediately following completion of the treatment, the flareline is connected to the wellhead and the well is flowed back through a chock nipple at a very slow controlled rate,

This slow rate is maintained until the calculate bottom -hole pressure is approximately 200 psi below the frac closure pressure. The objective is to keep the Foam velocity in the fracture at a low rate until overburden pressure can gripe the propping material .at the point; the well flow rate increased with a wider choke to cleanup load fluids and evaluate the treatment because N2 ratios are determined on the basis of injection pressures ,considerable expansion of nitrogen occurs during flow back of the well .

this gas expansion increases the foam blows as mist (FQ sup 95% 98%) the resultant decrease in hydrostatic head not only causes the well to flow without swabbing ,but in fact increases the bottom-hole formation -to- wellbore pressure differential for important for improved load fluid recovery from the formation .

Conclusion

In this chapter, we have first presented the criteria of selecting wells for the hydraulic fracturing operation, then we have explain in a clear way, the techniques and how a main treatment is conceived, at the end of the chapter, we have summaries the operation of foam fracturing and it's efficiency in the flow back. finally we finished with the problems most often encountered in a treatment of hydraulic fracturing.

Chapter IV: Analysis and Interpretation of pressure decline curves (Analysis and interpretation of the Mini FRAC test)

Introduction:

In order to check the efficacy of the treatment to improve the performance of the next operation, it is therefore necessary to evaluate and analyze the results.

This analysis can be expressed in two parts:

The first part concerns the analysis of fracturing data such as the fall-off recording. This analysis helps us estimate certain property of rock and fracturing fluid.

The second part concerns the interpretation of well tests carried out after fracturing to confirm whether the operation was successful or not.

IV .1 Analysis and interpretation of the Mini FRAC test):

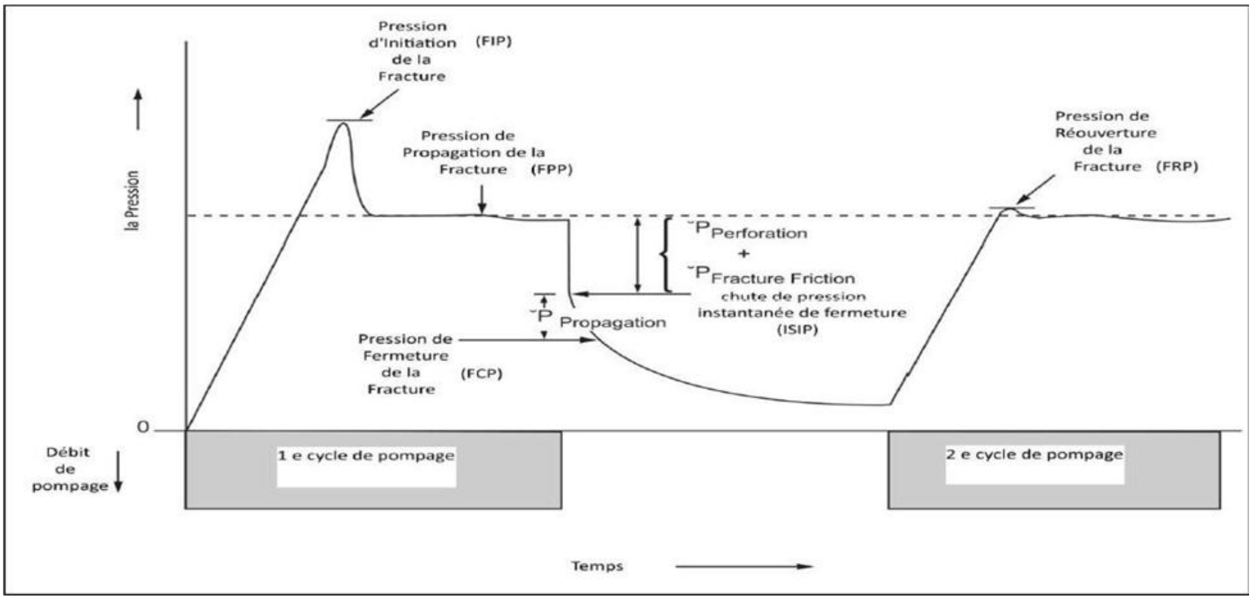


Figure IV.1: Recordings of the pressure development during the operation.

As soon as the pumps start to operate, an increase in the pressure at the bottom of the well is recorded. this increase lasts until the fracture initiation pressure (FIP) is reached. Then the pressure curve falls and stabilizes for an interval of time, this corresponds to the pressure of propagation of the fracturing (FPP).

The pumps are stopped when the intended volume is pumped and the propagation of the fracture is complete. At this moment the pressure drops rapidly, it is called the instantaneous closing pressure drop (ISIP):

$$\text{ISIP} = \text{FPP} - \Delta P_{perforations} - \Delta P_{fracture\ friction}$$

Where: the sizes are in [practical US unit]

Δ: pressure drop across the perforations

Δ: pressure losses between the perforations and the end of the fracture.

The fracture is still open during the instantaneous closing pressure drop (ISIP) and losses continue until the fracture is completely occluded.

Complete fracture closure is only observed when the pressure equals the minimum in-situ stress (), the fracture closure pressure (FCP) is recorded at this point.

$$\text{ISIP} = \text{FCP} + \Delta P_{fracture\ propagation}$$

Where: Δ is the pressure difference necessary to overcome the stresses.

The fracture closure pressure (FCP) is taken from the part of the curve where this

last change of slope.

The fracturing reopens during the second pumping cycle. The fracture reopening pressure (FRP) is usually lower than the fracture initiation pressure (FIP).

Note that the test is done in two stages with injection first and closing or stopping the injection second. each of the steps extracts useful data and parameters.

a-The injection (pump-in):

From this phase, we can determine the following parameters:

FIP: Fracture initiation pressure.

FPP: Fracture propagation pressure and fracture propagation model.

B-The shutdown (shut-in / fall-off):

From this phase, we can determine the following parameters:

L'ISIP: The fluid treatment efficiency (ŋ), the filtration coefficient (C_L), the filtration coefficient fracture closure pressure (FCP).

IV.2 fracturing data analyses:

From fracturing data analysis, we will determine:

- Instantaneous closing pressure drop (ISIP)
- The pressure drops (Δ
- Closing pressure (minor horizontal constraint) (σn min).
- The net pressure in the fracture (Pnet)
- Fluid efficiency (η).
- Identification of the propagation model [PKN, GDK, or radial].
- Compliance.

- Filtration coefficient.
- Geometry of the fracture.
- Δ (Near wellbore Friction).

the pressure drops around the well are the result of several processes: drilling, sediment deposits along the production of the well, in situ stresses, tortuosity.

IV .2.1 Instantaneous closing pressure drop (ISIP):

IV .2.1.1 Definition:

The ISIP: (instantaneous shut-in pressure) is recorded instantly when the pumps are stopped, the advantage of this measurement is that at this moment all the frictions are zero. This value gives us the static BHTP (background pressure measured in static state).

IV .2.1.2 Determination of the ISIP:

The determination of the instantaneous ISIP closing pressure, this is done by drawing a vertical line from the point corresponding to the injection stopping time of the fluid.

Then the stabilized pressure drop line is extrapolated, the point of intersection of the two lines corresponds to ISIP

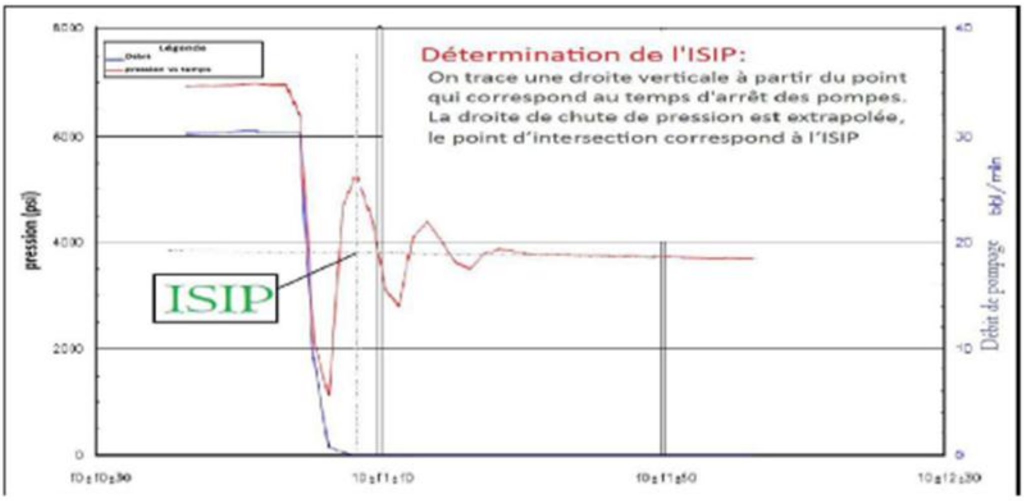


Figure IV.2: ISIP Reading Method.

IV .2.2 The pressure losses ($\Delta P_{friction}$) :

($\Delta P_{friction}$) : different type of pressure encountered

There are three main levels of friction: the tubular, the perforations and the area around the well.

$$\boxed{\Delta P_{friction} = \Delta P_{pipe} + \Delta P_{perf} + \Delta P_{NWF}}$$

ΔP_{Pipe}: the value of this parameter depends mainly on:

- Flow regime (laminar or turbulent ↗)
- Dimension of tubulars and roughness of internal walls.
- The state of cleanliness of the tubulars.

ΔP_{perf} : the parameters on which the value of the pressure drops at the perforation level depends remain relatively simple:

- The rheological properties of the fluid.
- The injection parameters (flow and pressure).
- The orientation of the perforations.
- The number of perforations.

- The diameter of the perforations.
- Constraints in situ.

ΔP_{NWF} (Near wellbore Friction):

pressure drops around the well are the result of several processes: drilling, sediment deposits along the production of the well, in situ stresses, tortuosity

IV.2.3 Fracture closure pressure:

IV .2.3.1. Definition:

his is the pressure that most closely corresponds to the minimum horizontal principal stress, it is an average of the value of the stress acting perpendicular to the fracture surface. from a hydrodynamic point of view the closing pressure is defined as the pressure where the flow becomes bilinear and no longer linear.

From the graph, we can have a qualitative value of the fracture closing pressure (FCP).

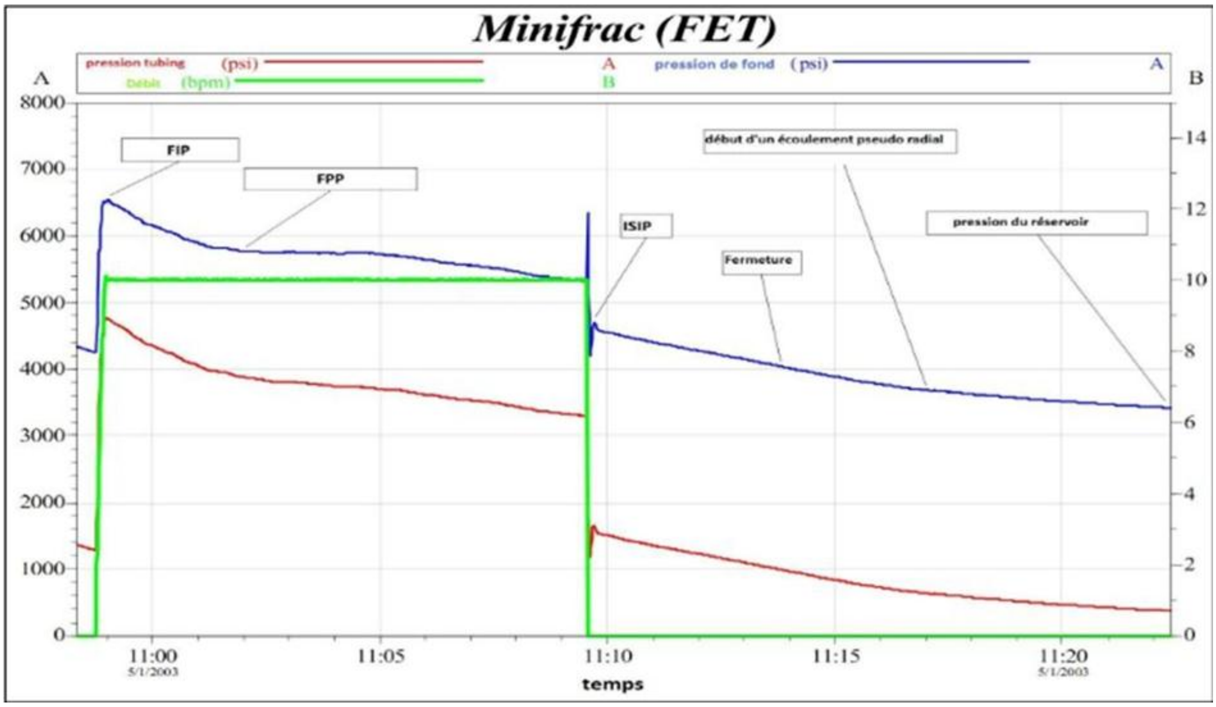


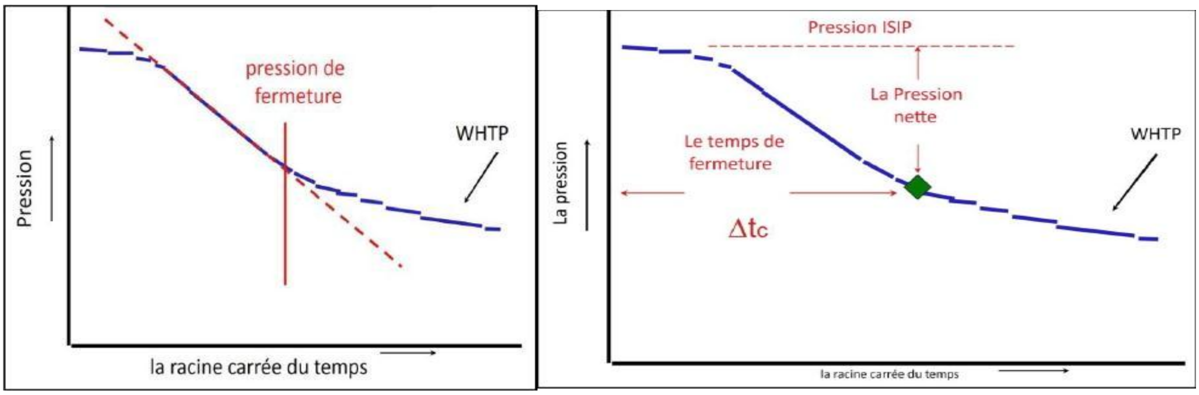
Figure IV.3: Mini-frac diagram.

The closing time and pressure can be determined by looking at different graphs The interpretation of each chart is different and each can indicate a different closing pressure. Knowledge of the terrain and experience of the staff, are required to assess the correct one. value, or take average values by combining those obtained from the different charts. the first step is to restrict a pressure interval, in fact the closing pressure (FCP) is limited by the pressure of propagation of the fracture (FPP) and the pressure known as the instantaneous closing pressure drop (ISIP).

IV 2.3.2 Closing pressure evaluation methods (FCP):

IV 2.3.2.1. The square root of time method:

The closing pressure can be determined from the data of the Minifrac. the pressure decline from the stopping of the pumps is analyzed as a function of the square root of time. it is assumed that during the pressure drop, the equation governing the pressure decline is linear with the square root of the closing time. inflections or changes in the slope of the curve may indicate fracture closure. however, the main difficulty with this technique is identifying the right straight line (see Fig.V-13)



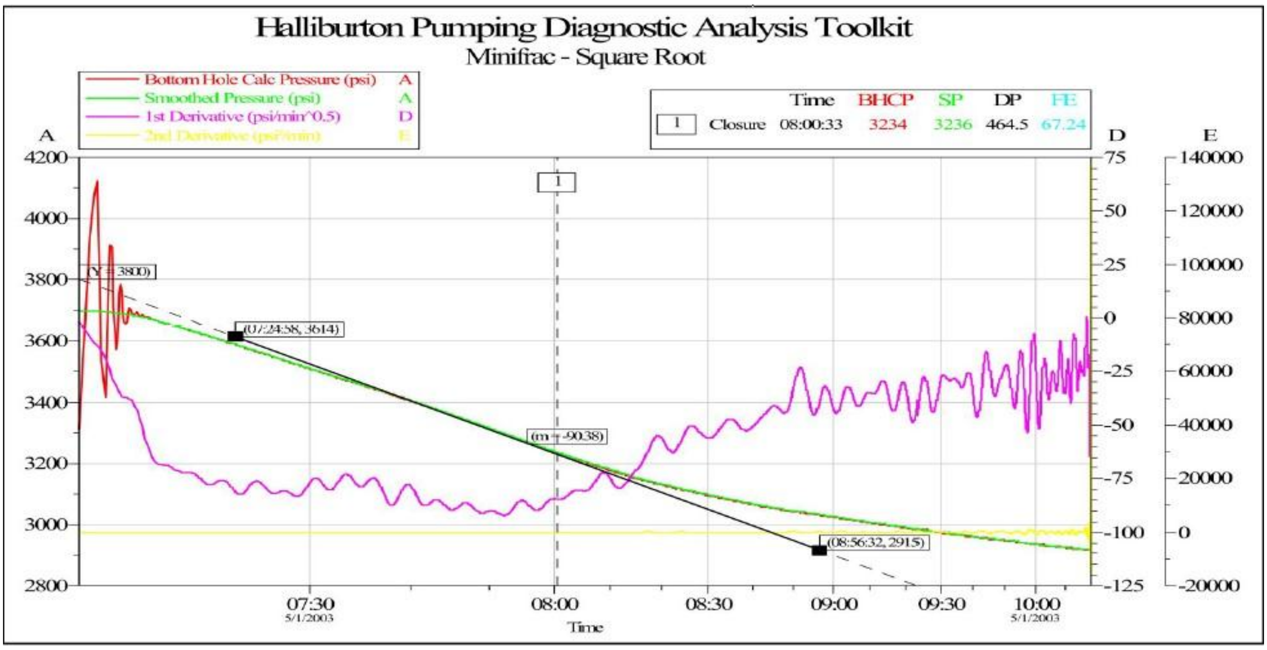


Figure IV.4: pumping Diagnostic Analysis Toolkit Mini-frac Root.

IV .2.3.2.2 The method of the G-function:

The G-function, is a dimensionless mathematical model which translates a combination of the stopping time and the pumping time; the following equations analytically clarify the G-function:

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

$$g(\Delta t_D)=\frac{4}{3}\left[(1+\Delta t_D)^{1,5}-\Delta t_D^{1,5}\right] \text{ pour } \alpha=1$$

$$g(\Delta t_D)=\left[(1+\Delta t_D)\sin^{-1}(1+\Delta(1+\Delta t_D)^{-0,5}\right]+\Delta t_D^{1,5} \text{ pour } \alpha=0,5$$

$$\Delta t_D=(t-t_p)\,/\,t_p$$

The analysis of the pressure decline after closing can be done using the G-function.We can distinguish two borderline cases for the G-function are the case where α = 1.0, i.e. for weak

fluid losses, in this case the fracture is still open after stopping and the fracture area varies approximately linearly with time. The equation for α = 0.5 indicates high fluid losses; however the area of the fracture varies with the square root of the time after stopping the injection. The value of is the value of g calculated when pumping is stopped.

The basic G-function calculations are conducted with the above equations. One of the key variables identified by Nolte is the difference between high efficiency (upper limit) and low efficiency (lower limit). However, we notice the low impact of these two

Latest situations on the qualitative shape of curves.

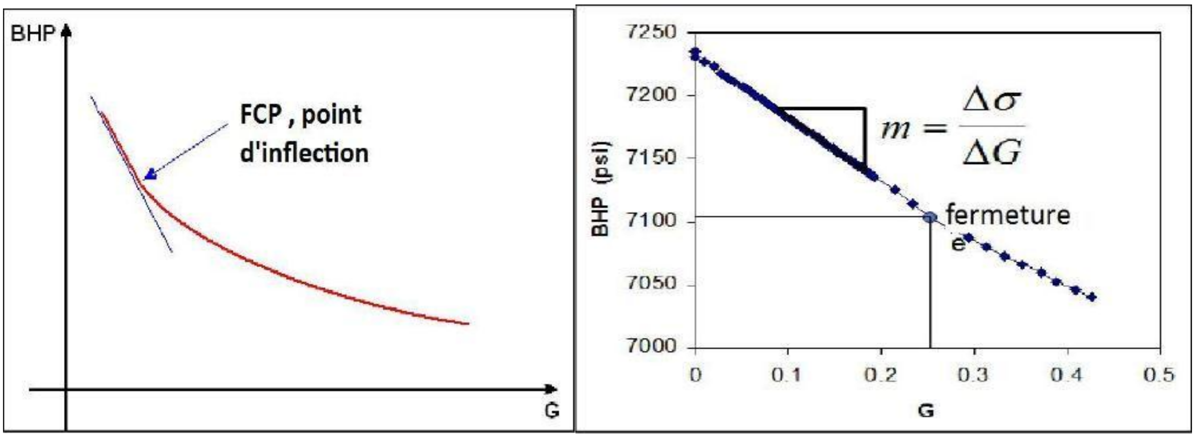


Figure IV.5: plot of the pressure vs the G function.

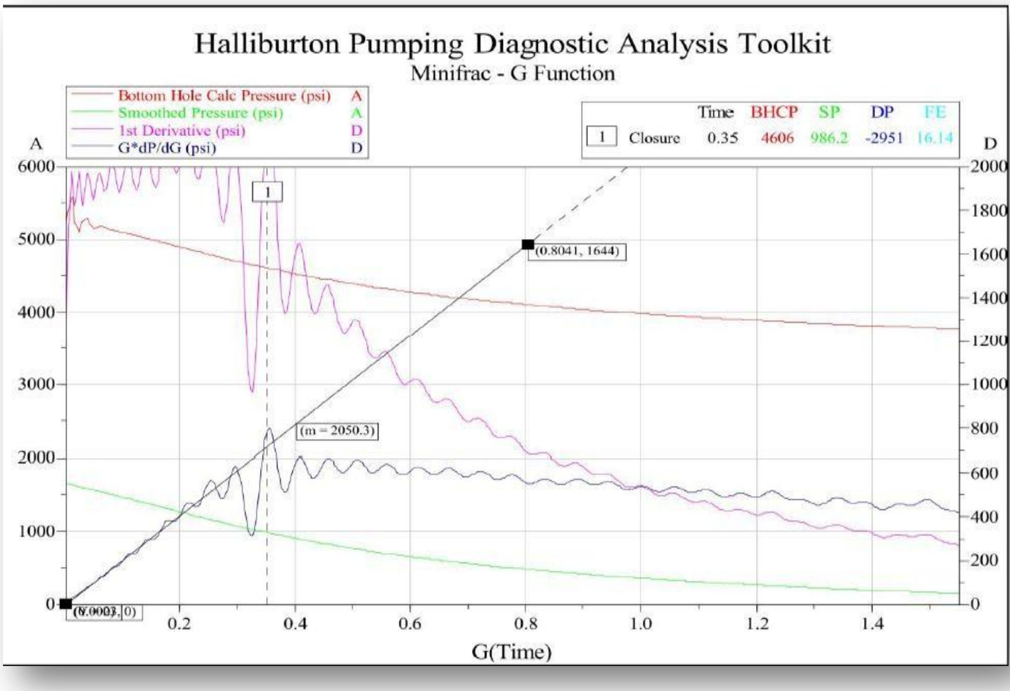


Figure IV.6: determination of the FCP with the frac pro PT.

IV 2.4 The net pressure in the fracture (Pnet):

The net pressure is the excess pressure required above the minimum principal stress to keep the fracture open.

The net pressure is determined by the equation below:

$$P_{Net} = ISIP_{BH} - P_C$$

IV.2.5. Fracturing Fluid Efficiency:

The efficiency of fracturing fluid can be evaluated following using these three methods:

A- By directly using the following formula:

$$\eta = \frac{g(\Delta t_{cD}) - g_0}{g(\Delta t_{cD})}$$

By using the graph of G-function we will draw the value of Δt_Dwhich corresponds to the fracture closing pressure which is Δt_{cD} and we also draw the value of g which corresponds to the value of Δt_{cD}.

B-

$$\mathbf{F.E} = \eta = \frac{\boldsymbol{volume\ du\ fluide\ dans\ la\ fracture}\ (\text{à}\ \boldsymbol{T=t})}{\boldsymbol{volume\ du\ fluide\ pompé}\ (\text{à}\ \boldsymbol{T=t})}$$

C- The formula for calculating the most eminent efficiency is that formulated by Nolte:

$$\mathbf{FE} = \frac{(1+\frac{T_C}{T_P})^{1,5} - (\frac{T_C}{T_P})^{1,5} - 1}{(1+\frac{T_C}{T_P})^{1,5} - (\frac{T_C}{T_P})^{1,5}}$$

IV **2.6 Identification of the propagation model and log.log analysis:**

The Log-Log graph of net pressure against time represents a conceptual analysis for the different types of graph slope.

These slopes are characteristic for the different types of propagation modes, this is why the Log-Log graph and these associated slopes are granted as a diagnostic plot.

The basis of interpretation of this diagram can be summarized as sequences:

An initial pressure decline before fracturing is influenced by the effect of the barriers (see fig.) The time of this phenomenon is generally small for a zone of small thickness.

• For this part the propagation model chosen is either the GDK or radial model, the theoretical order of the slopes is given by the following formula:

$$\left.\begin{aligned} m &= -M'/(2(\rho'+1)) \rightarrow (\eta \rightarrow 0) \\ m &= -M'/(n'+2) \rightarrow (\eta \rightarrow 1) \end{aligned}\right\} GDK$$

$$\left.\begin{aligned} m &= -3n'/8(n'+1) \rightarrow (\eta \rightarrow 0) \\ m &= -n'/(n'+2) \rightarrow (\eta \rightarrow 1) \end{aligned}\right\} Radial$$

• after the fracture is confined with the barriers, the pressure increases where the fracture propagates in a similar way to the PKN models with slope whose theoretical order is given by:

$$\left.\begin{aligned} m &= 1/4(n'+1) \quad (\eta \rightarrow 0) \\ m &= 1/(2n'+3) \quad (\eta \rightarrow 1) \end{aligned}\right\} \text{PKN}$$

• For a Newtonian fluid is of the order of 1/8 for low efficiencies and of 1/4 for high efficiency.

• The increase in pressure can reach the forming capacity, so there is a need for a regulating effect (to keep the pressure almost constant). The pressure is regulated by accelerating filtration in the area near the well where the pressure is maximum.

• If the pressure decreased due to the propagation of the development through the barriers, then there is an increase in height.

• A significant increase in pressure (slope> 1), indicates a restriction of the extension of the fracturing what is called screen out close to the fracture, and if the slope is >>> 1, we have a screen out close to the well because of the great resistance of the formation.

• The different types of slopes associated with their interpretation are presented in the following table:

Types	La pente de Log-Log Plot approximatif	interprétation
I	1/8 à ¼	- Restriction de lahauteur.
II	0	- Développement suivant la hauteur ouverture desfrisent.
IIIa	1	- Restriction de l'extension suivant la longueur. (deux ailesactifs)
IIIB	2	- Restriction de l'extension suivant la longueur (un seul activeaile).
IV	Négative	- Pas de restriction suivant lahauteur

Table IV.1: Interpretation of the Nolte pressure curve.

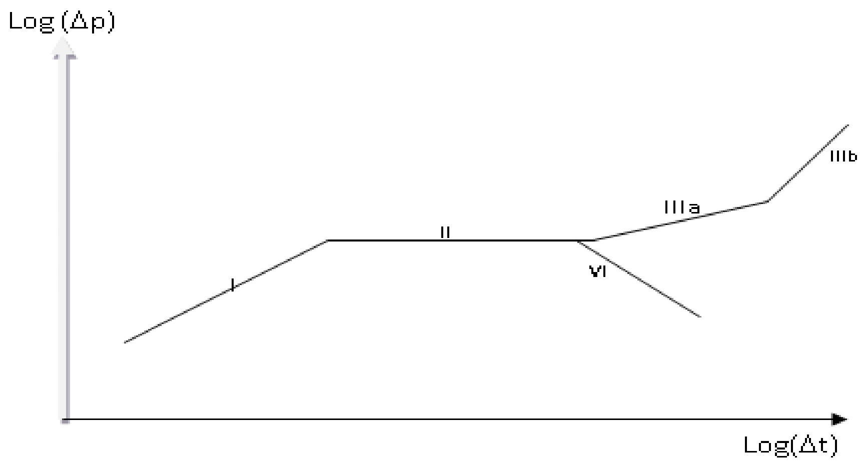


Figure IV.7: Ideal pressure evolution for different models.

IV.2.7 Compliance:

Nolte a represents a relation in a general form between the pressure and the width of the fracture using the notion of complacency: Where:

$$w = c_f \Delta p$$

Where:

$$c_f = \frac{\pi\beta}{2E'} \begin{cases} h_f & \text{PKN} \\ x_f & \text{GDK} \\ 32/3M^2R & \text{RADIAL} \end{cases}$$

With:

$$\beta = \begin{cases} (2n'+2)/(2n'+3+a) & \text{PKN} \\ 0{,}9 & \text{GDK} \\ 3M^2/32 & \text{RADIAL} \end{cases}$$

• n ': rheological exponent of the faith of the fluid.

• $E' = E/(1-\nu^2)$

• α: the coefficient of degradation of fluid.

And β is defined as the ratio between the average value of the net pressure used to determine the average width and the net pressure Filtration coefficient:

It is a coefficient which characterizes the volume filtered in the formation through the faces of the fracture, it is given by the following relation:

$$C_L = \frac{m_p \beta_s}{r_p \sqrt{t_{inj}} E'} X$$

Where: βs geometric factor:

$$\beta_s \begin{cases} \frac{2n'+2}{2n'+3+a} = 0.75 & PKN \\ 0{,}9 & KGD \\ \frac{3\pi^2}{32} = 0{,}92 & radial \end{cases}$$

X: depends on the model considered

$$X = \begin{cases} h_f & PKN \\ 2x_f & KGD \\ \frac{32R_f}{3\pi^2} & radial \end{cases}$$

IV.2.8. Geometry of the fracture:

IV.2.8.1. length: it is given for the different propagation models by:

Where: Vi this is the volume of the pad injected

IV.2.8.2. The surface of the fracture A$_f$:

a- $$A_f = \frac{(1-\eta)\ V_{pad\ inj}}{2\ g_0\ r_p \sqrt{t_p}\ C_L}$$

b- $$A_{frac1} = \frac{(1-\eta)\ V_{pad\ inj}}{2g(\Delta t_D=0)(C_L r_p \sqrt{t_{inj}}\ )}$$

c- $$A_{frac1} = \begin{cases} 2X_f h_f & PKN \\ 2X_f h_f & KGD \\ \pi R_f^2 & Radial \end{cases}$$

IV.2.8.3. Fracture volume:

$$V_{fp} = 2\ C_L\ r_p\ A_f \sqrt{t_p}\ [g(\Delta t_{CD}) - g_0]$$

IV.2.8.4. width:

Two methods were used to calculate the width of the fracture:

a – $$W_f = \frac{\eta\ V_{pad\ inj}}{A_f} = \frac{V_{pad\ qui\ reste\ la\ fracture}}{surface\ de\ fracture}$$

b- $$W_f = \frac{2g(\Delta t_D=0)(C_L\ r_p \sqrt{t_{inj}})\eta}{1-\eta}$$

c- $$w = c_f\left(p_f\left(\Delta t_f = 0\right) - p_f\left(\Delta t_D = \Delta t_{cD}\right)\right)$$

IV.2.8.5. the height:

It is generally determined by thermometer or by radioactivity.

Conclusion

In this chapter, we have presented how to calculate the essential parameters for hydraulic fracturing.

Chapter V: Frac Job applied on OMP742 & Foam Simulation related to same well

Introduction :

This chapter is split in two parts where the first is for the study and evaluation of hydraulic fracturing with the uses of the conventional fluid; therefore, in the second part we will introduce a new technique on the field of Hassi Messaoud witch is successfully applied in the whole word.

And for the first time this technique has been achieved in ALgeria on Tin **Essameid Est -3(TDE-3)** well in South EST Ilizi , the 10th december,2015

According to this example of treatment wich is considered to be representative of typical result of the foam frac process , a design senario of foam fracturing with an energizer fluid (N2) is supposed to be applied on OMP 742 but due to the N2 low pumping capacity this operation is hold on until 2021 waiting for specific pumping equipment .

V.1 Overview:

OMP-742 is a vertical well drilled in on 03/03/2009 and sidetracked after some issues during the drilling phase. The well is completed with LCP: covering D2, ID, D1, Zalt and R2, the LCP is perforated in D2 , ID and D1 that have a good potential .despite the damage, the DST rate measured was 3,2 m^3 /h

Since the damage introduced to the well when drilling and after completion, the well failed to produce despite the numerous attempts with acid intervention and Gas lift. The production was not sustained, and the well was closed since 2017 due to low profitability. Thewell was selected for hydraulic fracturing treatment in order to stimulate the reservoir and recover its production rate.

Several design scenarios and job sizes were explored in order to develop a final fracturing design that meet the objective.

V.2 Objectives:

The well was selected for hydraulic fracturing treatment in order to stimulate the reservoir and recover its production rate.

V.3 Well Data:

V.3.1 well location:

OMP-742 is vertical well situated in the North-Est of HassiMessaoud field with coordinates X :82106.13 Y:135590.84

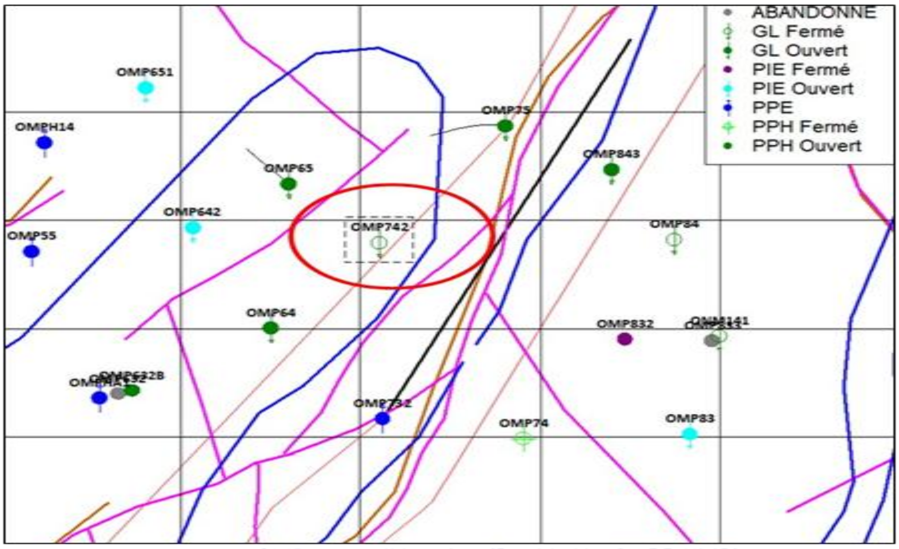


Figure 1: OMP-742 well location, (Provided by SH-DP-HMD)

Figure V.1: OMP-742 well location.

V.3.2Geological information:

V.3.2.1 About the reservoir:

The description of the cores shows that the most important interval at the level of this well, from the granulometry and the important frequent vertical cracks are the intervals between

3368 m to 3381m, 3386.5 m to 3401.5m, 3410m to 3416 mr. This corresponds to the base of the inter drain and the drain D1.

The best porosity values are recorded at this levels in the order of 6% TO 7% with low clay values and low water saturation.

V.3.2.2 Petro physical Data:

- The D1 and ID carry qualities with good porosities and fairly low water saturations.
- The theoretical water level is at 3466 m (-3320 m abs).
- The intervals are characterized by a **K**=2.83md and **ø**=6-7% with a weak water saturation.

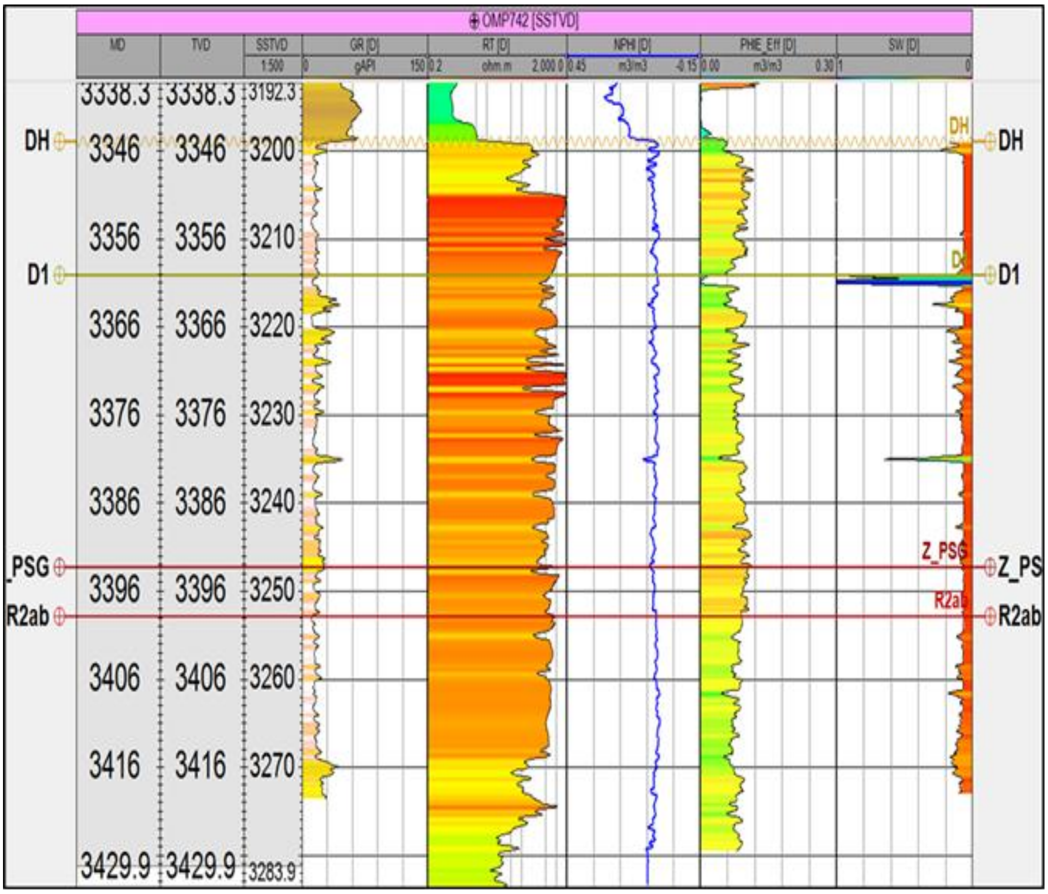


Figure 3 OMP-742 Petrophysical Data (Source SH-DP-HMD)

Figure V.2: OMP742 petrophysical Data.

Field Name	Hassi Messaoud
Well type	Oil Producer
Target Formation	ID and D1 intervals
Permeability	2.83mD (well test)
Saturation	Sw= 6-7 %
Porosity	6-7%
Skin	2.44
Net effective pay (m)	34 m
Rock type	Sandstone
Reservoir Pressure at Top Perforations	2223 psi
BHST	120°C

TableV.1 Field Overview Summary.

V.3.3 Well completion:

End of drilling and completed	05 January 2016
Initial Well Depth MD (m)	3440m
Deviation	Sidetrack @3302 m
Casing	Casing 9"5/8 TC-P P110 47-53.5 #/ft 3268m
Casing	Casing 7" NV 29-32 #/ft P110 3240m
Tubing/ cemented	4"1/2 New Vam P110 13.5# 3555 m
Tubing	4"1/2 New Vam N80 13.5# 3440 m
Packer	Hallib Packer 7'' 32-38# @3235.7 m P.deff = 10000 psi & Liner Packer-linear Hanger @ 3244m
Interval Perforation	3349 m - 3361 m 3364 m - 3366 m 3373 m - 3380 m 3382 m - 3385 m 3394 m - 3404 m

Table V.2: Well completion summary.

V 3.3.1 Condition of casing cementation:

CBL From 7" to 12/02/2005		CBLFrom 4"1/2 to 26/02/2005	
From 3295 to 3115 m From 3115 to 3005 m From 3005 to 2715 m From 2715 to 2695 m From 2695 to 2525 m	Good to average Bad Average to bad Good Good to medium	From 3425 to 3345 m From 3345 to 3275 m From 3275 to 3270 m From 3270 to 3250 m From 3250 to 3243 m From 3243 to 3241 m	Very good. Average to bad Good Average to bad Good Bad (TOL)

Table V.3: Condition of casing cementation.

V 3.4 Current state:

- Cumulative production 20.4K m3
- Pg = 157.67 KG / cm2, (PFS 06/20/2019).
- State: well closed

V.3.5- Pressure test :

Test	Date	PG (kg/cm²)	PFD (kg/cm²)	PT (kg/cm²)	Rate (m/h)		IP	HKL (Hw * Kyz)	Skin	Remarque
DST	23/11/2008	149.46	133.88	47.8	Huile	3.2	.26	198	-2.43	Vertical well DSTrealize @ 3410m.
PFS	21/05/2011	139.28	--	--	--	--	--	-	-	PFS
PFS	29/06/2019	157.67	--	1.04	--	--	--	-	-	Static level 952.21 m

Table V.4: Pressure Test (DST).

The field pressure development shows that there is pressure support coming from the OMP642 water injection well, which is 1000m above the OPM742.

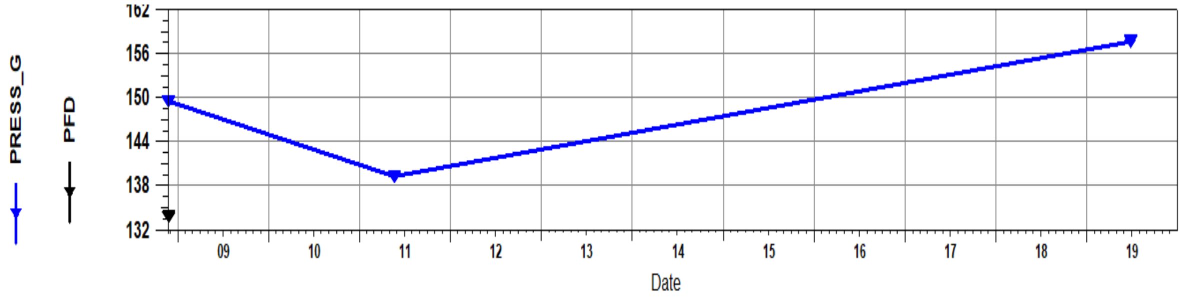
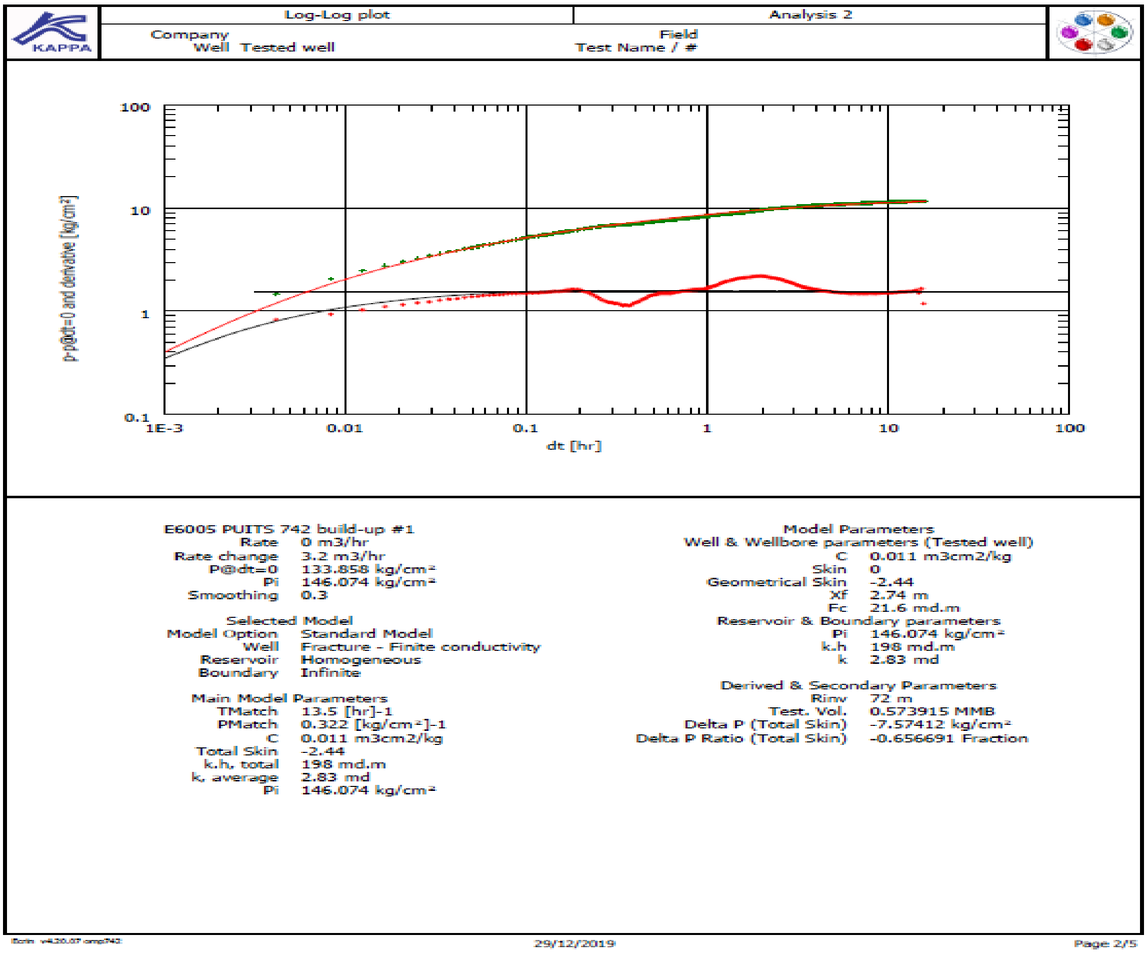


Figure V.3: Data DST Interpretation.

The DST (open hole) interpretation of 11/31/2008 shows that the reservoir model is infinite homogeneous over an investigation radius of 72 m, no fault detected around the wells. The interpretation also shows that the average permeabilities are in the order of 2.83md.



FigureV.4: Well Test interpretation.

V.3.6 Production Test:

The following table represents the well gauges:

well : OMP742							
Date Measure	Diam.duse (mm)	Rate (m³/h)		GOR	Water rate (l/h)		
		Oil	Gaz		Press. Head	Recovered	Injected
22/11/2008	9.53	3.2	1117.68	350	47.8	0	0
19/12/2014	18	0		0	17	142	0
20/12/2014	18	0.22	1066.85	4840	12.5	0	0
28/03/2015	12.7	2.2	1471.17	669	23.6	0	0
26/08/2015	12.7	0.2	1312.23	6713	17	0	0
06/10/2015	12.7	0.82	1008.10	1228	16	0	0
06/04/2016	15	0.1	573.74	5737	20	0	0

Table V.5: Well gauges.

V.3.7 Neighboring wells:

The following table represents the neighboring wells of the OMP-742 over a radius of 2000m, among the 13 wells surrounding the OMP-742, 05 wells are closed, two for a reason of significant water production, one, following a subsidence of wellhead and one for load reduction, all located in zone 11 and one in the HZN for pending abandonment.

Two injection wells in service in Zone 13 and HZN and one shut down in Zone 11 following the breakthrough in neighboring wells.

Most of the wells are gas lift, 05 fractured wells in this area and 2 wells converted to short radius.

Wells	Status	Zone	SR	FH	Radius	Last Test			Last gauges				
						Type	Date	PG(kg/cm^2)	Date	Rate (m^3/h)	GOR	w/rec(m^3/h)	Wcut(%)
OMP65	GL	13	01/11/10	23/04/00	651.33	PFD	22/08/19	--	14/11/19	3.67	533	0	0
OMP64	GL	13	---	14/12/99	844.2	SBU	05/06/10	--	26/12/19	5.08	462	0	0
OMP642	PIE	13	---	---	1046.52	FO	21/10/10	--	--	--	--	--	--
OMP75	GL	HZN	17/04/05	---	1074.09	DST	03/03/05	166.45	11/09/19	1.47	675	0	0
OMP843	GL	11	---	28/10/01	1390.23	SBU	05/04/02	135.86	06/12/19	1.2	952	6.5	84.4
OMP832	PIE	11	---	---	1520.65	--	--	--	--	--	--	--	--
OMP74	PPH	11	---	---	1572.03	PFS	06/07/19	252.38	00/01/98	Closed(important production of watter)			
OMP84	GL	11	---	---	1642.83	PFS	30/05/19	205.22	22/08/17	Closed (Load reduction)			
OMP651	PIE	HZN	---	---	1687.75	FO	15/02/17	367	--	--	--	--	--
OMP632B	PPH	13	---	14/07/96	1714.51	SBU	20/06/07	147.02	20/12/19	7.88	375	0.4	4.8
OMP73	GL	11	---	---	1769.57	PFS	04/05/19	249.06	00/05/03	Closed (important production of watter)			
OMP761	GL	HZN	---	22/06/99	1783.51	PFS	05/05/19	259.98	06/05/10	Closed after SNB			
ONM141	GL	11	---	---	1999.41	PFS	27/05/19	277.06	09/09/99	Closed (wellhead sag)			

Table V.6: Neighbor well situation.

The following graphs show the development of deposit pressure in the neighboring wells of OMP-742 over a radius of 2000m, showing that the latter is in good communication with the wells of zone 13 and some wells of the HZN.

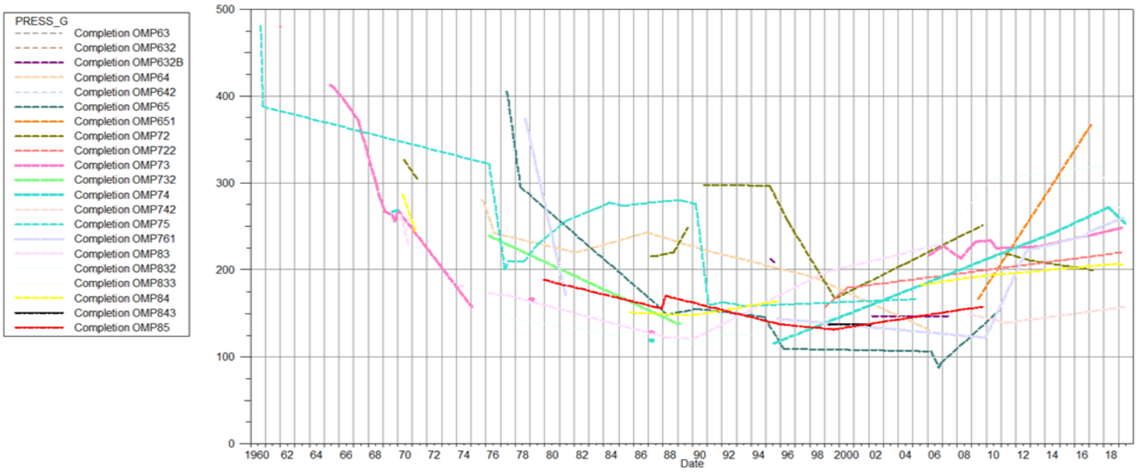


Figure V.5: development of deposit pressure in the neighboring wells of OMP-742.

V 3.8 Fractured wells:

Puits	Status	Zone	FH	Rayon (m)	Date	Direction	Proppant (livres)	Qo(Av) M3/h	Qo (Ap) M3/h	Obs
OMP65	GL	13	23/04/00	651.33	23/04/00	NO	147954	1.98	2.57	ouvert
OMP64	GL	13	14/12/99	844.2	14/12/99	SO	24444	7.25	18.57	ouvert
OMP843	GL	11	28/10/01	1390.23	28/10/01	NE	21464	5.66	15.02	ouvert
OMP632B	PPH	13	14/07/96	1714.51	14/07/96	SO	104676	20.01	27.90	ouvert
OMP761	GL	HZN	22/06/99	1783.51	22/06/99	N	59375	3.8	8.89	Fermé

Table V.7:Fractured well in zone 13.

- The majority of the fractured wells are in Zone 13 and have given positive results after fracturing.

V.3.9 Water injector well :

Puits	Status	Zone	Rayon	Direction	Qinj Mm3/j	Obs
OMP642	PIE	13	1046.52	O	0.172	Ouvert, Débit recommandé 0.7Mm3/j
OMP832	PIE	11	1520.65	SE	0	Fermé
OMP651	PIE	HZN	1687.75	NO	0.651	Ouvert, Débit recommandé 0.7Mm3/j

Table V.8 : Injector wells.

No injection water breakthrough is reported in the wells close to the active injectors except in those close to the OMP832, hence the decision to stop the injection into the latter.

V.3.10 History of operations:

The following table summarizes all the operations carried out on the well.

29/06/2019	29/06/2019	WIRELINE	Pressure measure PFS
28/09/2018	04/10/2018	SNUBBING	-----
30/11/2016	30/11/2016	WIRELINE	Pressure measure PFS
09/03/2015	06/03/2015	OPERATION_SPECIALE	Acid Martix 2nd Day
08/03/2015	08/03/2015	OPERATION_SPECIALE	Tube Clean Pulsonix
27/02/2015	14/03/2015	SNUBBING	-----
01/11/2014	08/11/2014	SNUBBING	-----
03/10/2014	03/10/2014	DIAGRAPHIE	-----
02/10/2014	02/10/2014	DIAGRAPHIE	-----
29/08/2014	16/10/2014	WORKOVER	-----
11/08/2014	11/08/2014	OPERATION_SPECIALE	Kill Well
12/07/2014	12/07/2014	WIRELINE	Control
09/07/2014	09/07/2014	DIAGRAPHIE	-----
20/01/2014	20/01/2014	WIRELINE	Control
02/05/2013	03/05/2013	SNUBBING	-----
21/05/2011	21/05/2011	WIRELINE	Pressure measure PFS
09/06/2009	09/06/2009	OPERATION_SPECIALE	KICK OFF
09/05/2009	09/05/2009	OPERATION_SPECIALE	KICK OFF
23/04/2009	23/04/2009	OPERATION_SPECIALE	Underwatter treatment
27/02/2009	27/02/2009	COMPLETION	-----
25/02/2009	25/02/2009	DIAGRAPHIE	-----
19/02/2009	20/02/2009	DIAGRAPHIE	-----
07/11/2008	07/11/2008	DIAGRAPHIE	-----
31/10/2008	01/11/2008	DIAGRAPHIE	-----
08/10/2008	08/10/2008	DIAGRAPHIE	

Table V.9: history operation of the OMP 742 well.

V.3.11 Stress profile :

The stress profile is carried out according to the correlation of computed field stresses of Hassi Messaoud according to the recording of mec.V.

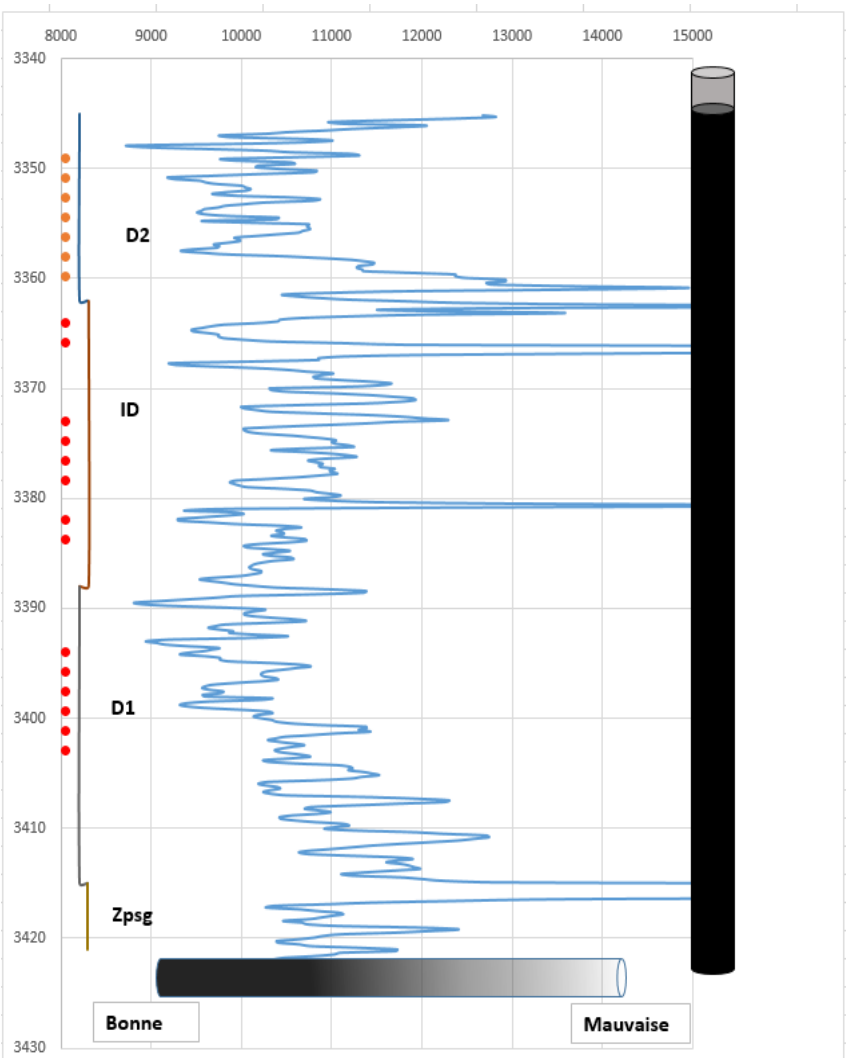


Figure V.6: Stress profile.

Discussion and recommendations:

- During the drilling of the well, the reservoir was drilled with a mud of 1.42 despite the low reservoir PG, the first hole was missed due to the jamming and the inability to recover the fish which increased the exposure time of mud tank.
- Despite the strong damage caused by the drilling fluid, the well gave a flow rate of 3.2m^3/h during DST.
- After completion, the well did not start despite the start-up attempts made.
- The gas lift supply through CCE installed with SNB from 2013 fails to start the well.
- The damage becomes more and more serious after the WO of 2014 (for change of completion).

- Acidification followed by gas lift injection in 2015 brought the well into production with a low flow rate of 0.2m3/h, but not for long. The well has been closed since 2017 for load reduction.

From the previous discussion and the analysis of the well data, the OMP742 is a candidate for a hydraulic fracturing operation of the `` tip screen out '' type of average size of the order of 95k lbs of HSP 20 proppants / 40 and 16/30 has a high concentration of the order of 10PPA.

V.4 Major Criteria taken for selecting OMP 742 as candidate well for Frac.

- According to the core, the reservoir has a good petro-physical characteristics, and from **Elan** interpretation the D1 and ID carry the best reservoir properties.
- OM-P742 is located in a good area looking at the production of neighboring wells, and it occupies an intermediate position comparing to the neighboring wells.
- The completion of wells and the cementing state of the casings allow the candidacy of wells for fracturing.
- The theoretical Cambrian of water level is 62m from the bottom perforations, and the stress profile shows barriers at the bottom of D1 and Zpsg and at the top of D2.
- No production of injected water recorded in neighboring wells, which are in communication with our well.
- A deposit pressure drop
- A very high skin in wellbore

V.5 Fracking program:

V.5.1Well preparation:

- ✓ Clean tube well cleaning with intensive washing of the perforated interval
- ✓ Annular test before fracking

<table>
<tr><td rowspan="2">Production tubing 4’’1/2 13.5# P110</td><td>écrasement (psi)</td><td>Eclatement (psi)</td><td>80% écrasement (psi)</td><td>80% éclatement (psi)</td></tr>
<tr><td>10690</td><td>12410</td><td>8552</td><td>9928</td></tr>
<tr><td>Pression différentielle de packer de production</td><td colspan="4">Halliburton Packer AWR 7" 32-38#
P.deff = 10000 psi</td></tr>
<tr><td>Completion fluid density</td><td colspan="4">Brine d=1.20</td></tr>
</table>

Table V.10: production tubing pressure test.

Steps	Annular pressure A (psi)	Max. Allowable pumping pressure (psi)
Injectivity test and data frac	2500	11000
Main frac	2500	9500

Table V.11: annular pressure test.

- **The data of the OMP-742 well:**

Module de YOUNG (E)	8.10^6 Psi
Coefficient de poisson (ν)	0.2
Indice de comportement de fluide (n’)	0.6

Table V.12: Data related to OMP-742 Reservoir.

V 5.2 Well Operation

V 5.2.1 Injectivity test

Fluid: treated water 3% + HCL 15%

- Fill the wells with treated water to homogenize the hydrostatic column.
- Perform a breakdown test with treated water at 1-10 bmp until breakdown appears.
  - Switch to 15% HCL at low flow then move the 15% HCL with treated water in frac regime (10-15 bpm).
  - Once all the volume of acid has been moved, increase the injection rate gradually until reaching the maximum pumping rate designed for the mini frac. Each injection flow should be maintained for a sufficient period (1 minute) to allow injection pressure stability.
- If the pumping pressures are high, a STEP DOWN TEST with ET can be performed.
- Stop pumping, close surface valves.
- The flow rate of the mini-frac can be changed after analyzing the injectivity test results and combining the stress profile.

Wellbore Fill up chart OMP742:

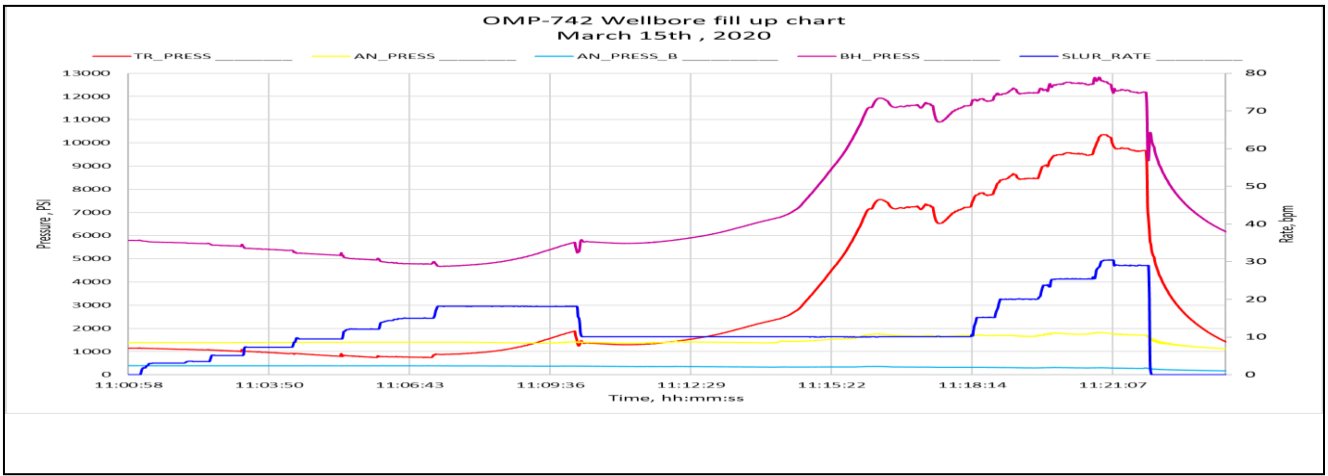


Figure V.7: OMP742 Wellbore fill up chart.

Acid HCL 15 % pumping chart :

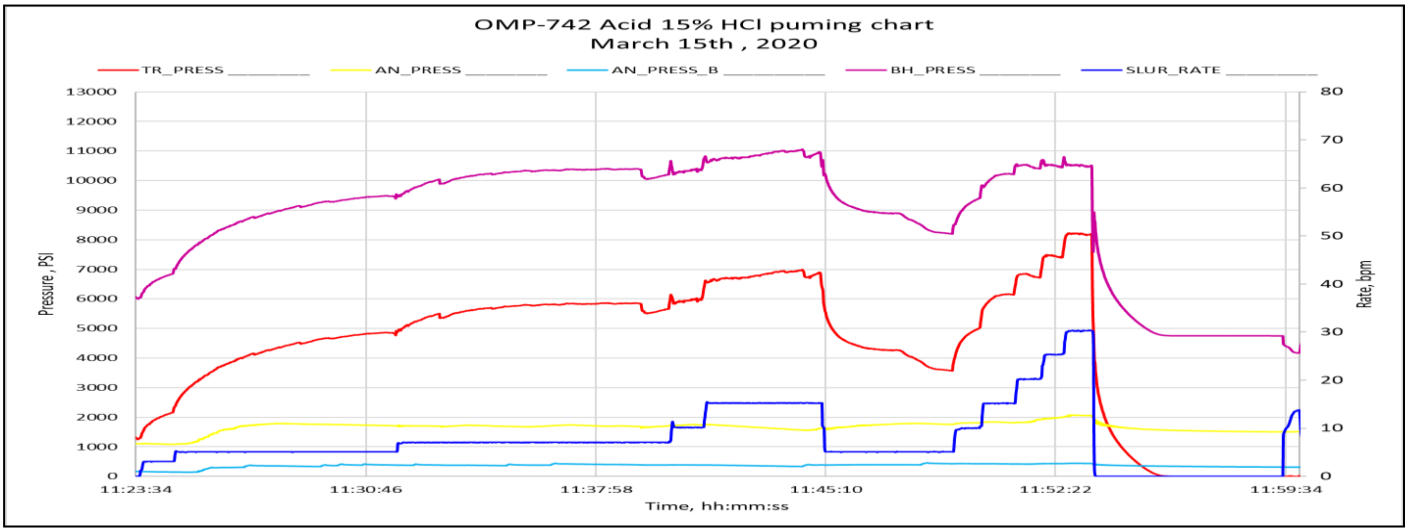


Figure V.8: Acid HCL pumping chart.

V 5.2.2 Shadow Frac

- **Injection and Calibration Test**

Prior to the calibration test a breakdown injection will be performed with treated water in order to identify the breakdown which is considered as the upper bound of the closure.Schlumberger strongly recommend the MinifallOFF test in order to evaluate the formation transmissibility and evaluate more adequately the job size. A Step Rate test is be considered as well. A Step Down test is recommended to identify the closure pressure lower boundary.

A total PAD volume of 20.000 gallons of YF135HTD to be injected into the formation, then over flushed by additional 5bbl to the displacement volume with linear Gel. The result obtained from this test include fluid efficiency, closure pressure and identification of any non-ideal behavior. The formation mechanical properties will be calibrated by performing a pressure match. This will allow re-designing an optimized treatment.

OMP-742 is characterized by having depleted reservoir pressure .therefore, the **methanol K46** well be used .in order to lowers the surface tension of water and reduces capillary pressure with results in lower energy required to move the water a cross boundaries and through the formation matrix, in addition of being a good fluid stabilizer in high temperature well.

An optimum re-design for the treatment .recommended logging procedure are announced hereafter.

The table below summarizes the recommended pump schedule of DataFrac steps with the total fluid volumes:

	Fluid	Rate (bpm)	Volume (gal)	Volume (bbl)
Break down	Treated Water	1-10	10000*	238
Shut down – and pressure decline recording				
Acid	15%HCl	0-7	3990	95
Flush	Treated Water	15	6888**	164
Shut down – and pressure decline recording				
SRT	Treated Water	0-3-5-8-10-20-30-35	7000*	166
Shut down				
PrePAD	WF135HTD+ 2%Methanole	0-35	1,000	24
PAD	YF135HTD+ 2%Methanole	35	20,000	476
Flush	+2%Methanol	35	6888**	164
Shut down				

Table V.13: DataFRAC Sequence.

Fluid Name	Total (gal)	Total (bbl)
Treated Water	30,888	375.4
WF135 + 2%Methanol	7,888	187.8
YF135HTD+ 2%Methanole	20.000	476.2

Table V.14: DataFRAC Totals.

A plot of the dataFrac pumping chart recorded during the diagnostic is shown below:

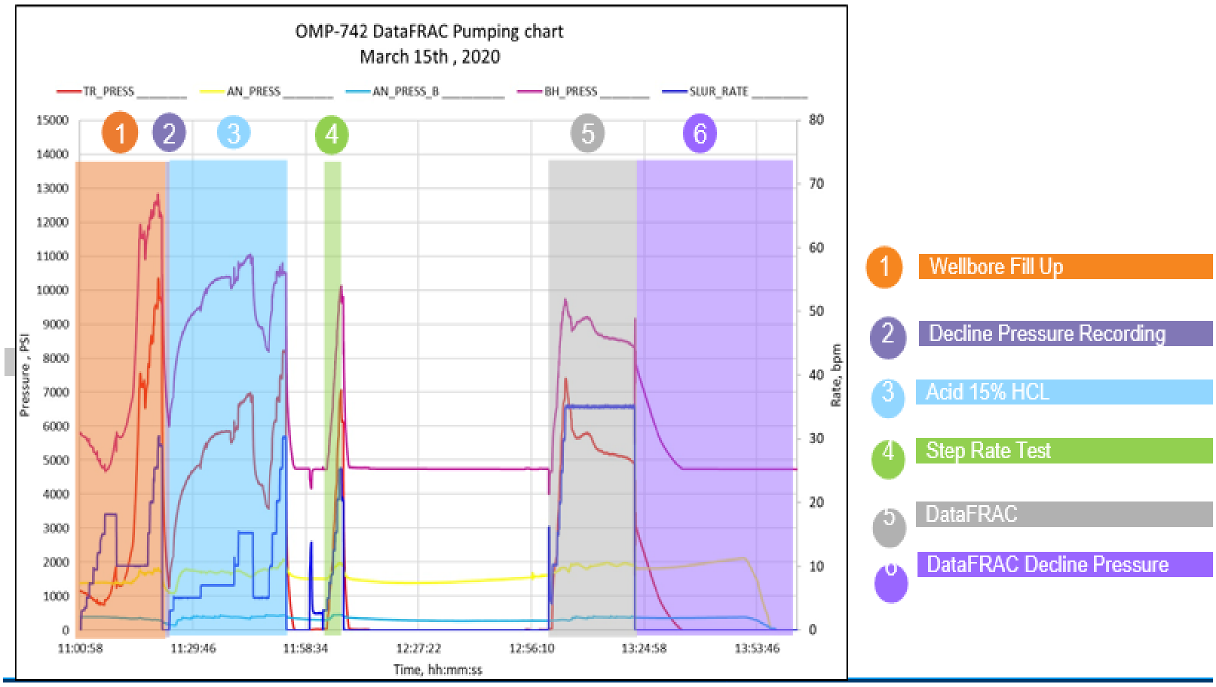


Figure V.9: DataFrac pumping chart.

V.6 Temprature log :

A temperature log was run four hours after the shadawfrac to estimate the fracture height and calibrate the fracture model

important operation note :

- ✓ temperature surveys will not indicate the proppant height but rather the toltal fracture height
- ✓ in case of sand plug .proppant fill below the perforated interval prevents the tool from reading below this depth the temperature anomaly will be lost by the time wellbord is cleaned out .
- ✓ any fluid movement prior to temperature logging or during logging may cause the interpretation   to be difficult or even impossible .care should be taken to prevent fluid from floming back prior to or during logging .
- ✓ because the tool is measuring the temperature of the fluid in the pipe , there may be a portion of fluid below the perforations will give the typical kick to the right showing heat-up to the base curve .many times this is erroneously picked us the bottom of fracture .a fracture that is in this area must have some time to influence the temperature inside the pipe .this is only seen when a successive   temperature runs are made and is finally seen below theperforations .indicating that the fracture finally had a temperature impact on the casing fluid .

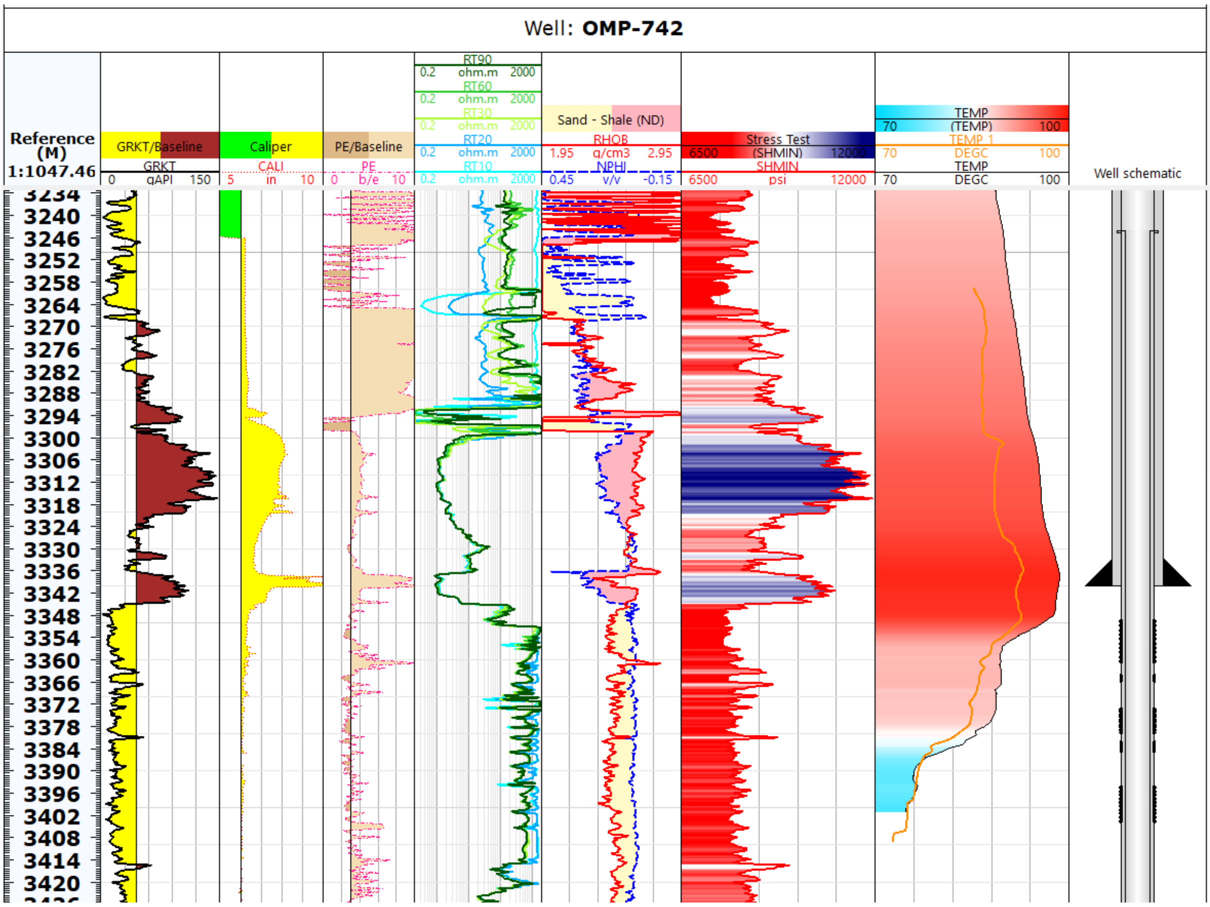


Figure V.10 : well Thermolog result.

V.6.1 Well Thermolog results 1st & 2nd Pass down :

- Cool down starts at **3348 m**
- The 1stpass down shows a fracture growth in height
- The top of the Fracture is taken at **3,348 m**
- The bottom of the Fracture is taken at **3,402 m**

- **The frac height : H_f=54m**

$$\boxed{H_f = \frac{54}{0.3048} = 177 \text{ ft.}}$$

V.7 Interpretation of pressure decline curves (analysis of mini frac test):

The mini frac pressure data was analyzed to determine the instantaneous closure pressure fracture closure pressure ;net pressure fluid efficiency and its filtration coefficient (leak off)

OMP-742 DATAFRAC pressure match Result:

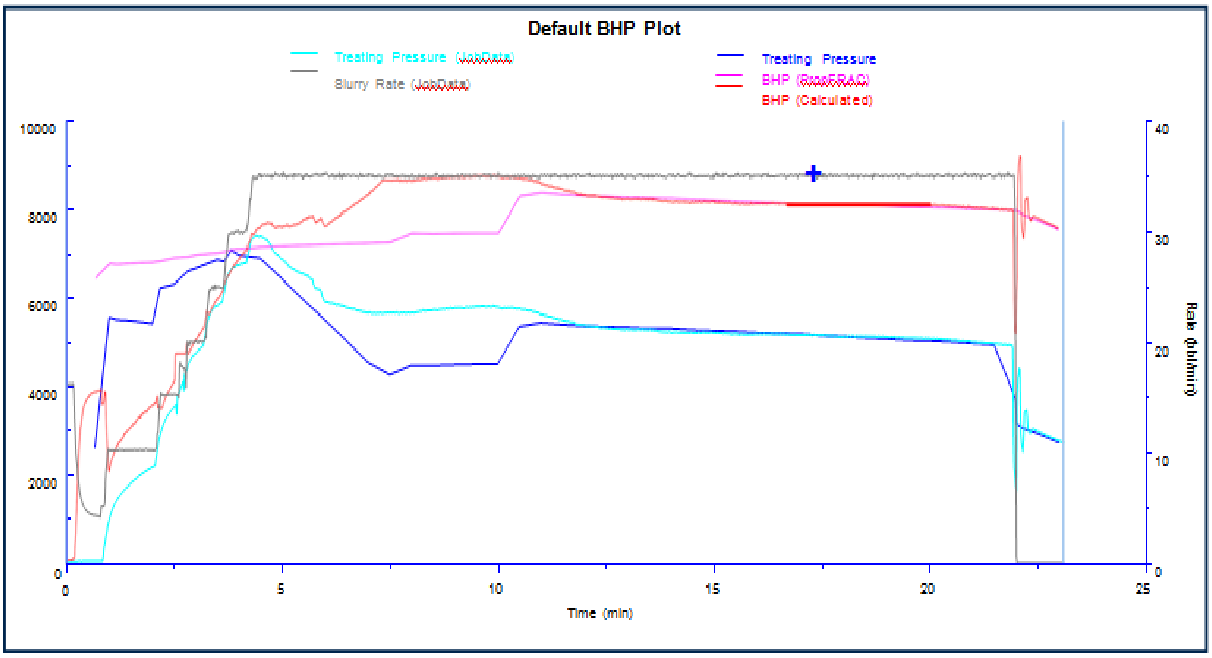


Figure V.11: Pressure during the Shadow FRAC OMP-742.

V.7.1 Calculation of pressure losses:

the total pressure drop is the sum of the losses at the perforation around the well and that of the tubing the pressure drops are calculated by determining ISIP and LPP (surface and bottom) from the curve showing the change in the bottom pressure Pwf and the surface after shut in as a function of time

)Determination of ISIP the determination of the instantaneous ISIP closing pressure is done by drawning a vertical line from the point corresponding to the injection stopping time of the fluid then stabilized pressure drop line is extrapolated ;the point of intersection of the two lines corresponds to the ISIP.

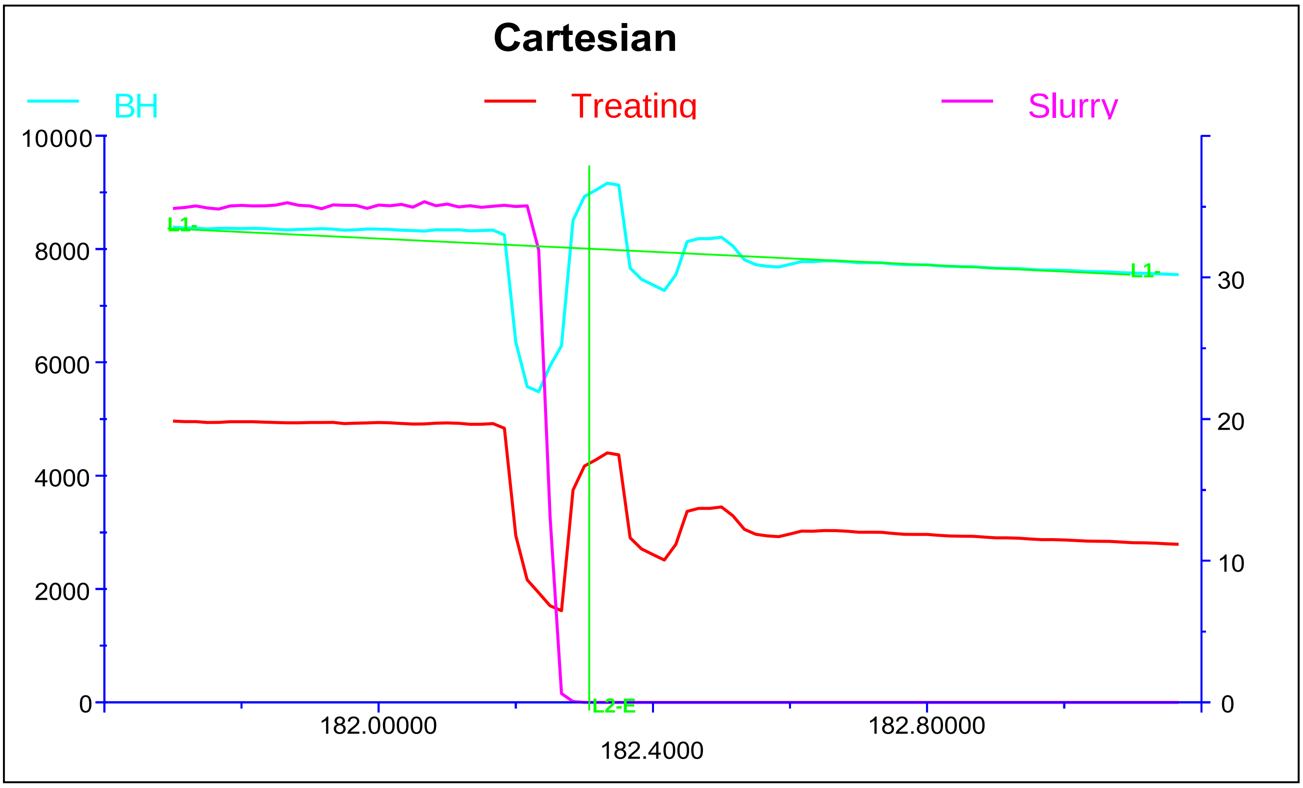


Figure V.12: Determination of ISIP DataFRAC OMP-742.

From the graph above :

- **Determination of pressure drops around the wellbore :**

ΔP_{NWB}= LPP_{BH}-$ISIP_{BH}$

LPP_{BH}= 8336psi ; $ISIP_{BH}$= 8005

$$\boxed{\Delta P_{NWB}= 331psi}$$

- **LLP** $_{BH}$ bottom hole last pressure pumping (psi).
- **ISIP**$_{BH}$ bottom hole instantaneous shutting pressure (psi).

- **Determination of total pressure drops ΔP_{total}:**

ΔP_{total}= LLP_S-$ISIP_S$

From the grave above :

LPP_S = 4921 psi ; $ISIP_S$= 3254 psi

$$\boxed{\Delta P_{total}=1667\ psi}$$

- **LLPs** surface hole last pressure pumping(psi).
- **ISIPs** surface hole last pressure pumping (psi).

- **Determination of friction losses ΔP PIPE FRICTION :**

$\Delta P_{tot=}\Delta P_{NWB}$ $+\Delta P_{pipe\ frction}$
$\Delta P_{pipefriction}$ $= \Delta P_{tot}$ $-\Delta P_{NWD}$
ΔP_{total}=1667 psi ; ΔP_{NWB}=331psi

$$\boxed{\mathbf{\Delta P_{pipefriction} = 1336\ psi}}$$

Pressure Parameter	Pressure value (psi)
Total Friction @ 25 bbl/min	1,667
Calculated NWF (Near wellbore friction)	331
Tubing Friction	1,336

V.7.2 Determination of closing pressure (pc) :

the calculation of the closing pressure is essential, in fact it corresponds to the minimum horizontal principal stress (σ_h).the value of (σ_h) is essential to determine the parameters of the fracture .

V.7.2.1 G-function Method:

The determination of the closing pressure (PC) is done by analyzing the pressure decline after stopping the pumping can be done.
The G-function defined by formulas below:

$$G(\Delta t_D) = \frac{16}{3\pi}\left[(1+\Delta t_D)^{\frac{3}{2}} - (\Delta t_D)^{3/2} - 1\right]$$

$$G(\Delta t_D) = \frac{4}{\pi}\left[(1+\Delta t_D)\sin^{-1}(1+\Delta t_D)^{-\frac{1}{2}} + \Delta t_D^{\frac{1}{2}} - \frac{\pi}{2}\right]$$

With

$$\Delta t_D = \frac{t - t_P}{t_p} = \frac{\Delta t}{t_P} \text{ et } \Delta t = t - t_P \text{ : Time after shut-in.}$$

After stopping the pumping, the plot is made: PBH = f (G (ΔTD)).
With:

- t : recording time
- t_P: Pumping time.

After stopping the pumping, the plot is made: PBH = f (G (ΔTD)).

N.B:

Injection (Pump-in): From this phase we can determine the following parameters: fracture initiation pressure, fracture propagation pressure and the fracture propagation model.

Closure (shut-in / fall-off): This phase we can determine the parameters according to ISIP, the efficiency of the treatment fluid (η), the filtration coefficient (CL) and the fracture closing pressure (Pc).

In our case the fluid efficiency is low we have high leek off, the closing pressure (Pc) will be determined by G-Function (Lower terminal).

• Closing time (Tc)

- **Tc = 4 minutes**

• Pumping time (Tp) or injection (Tinj)

- **Tp = 28.4minutes**

on the graph the choice of the closing pressure is made according to the graph Gdp / dG, by drawing the tangent to the curve, the point on which the curve Gdp / dG begins to shift respecting to the tangent represents the point of closing

CP = 6450 Psi, which corresponds to a slope:

$\mathbf{m_p = \Delta \mathit{P/G}}$

$\boxed{\boldsymbol{m_p = 5097\ psi.}}$

From the graph bellow of G function, we get:

- $g(\Delta t_D)$ =1,71 1.91 from the graph of (G function): $G(\Delta t_D) = f[g(\Delta t_D)]$.
- Δt_D= 0,28 from the graph of (G function) : $g(\Delta t_D) = f(\Delta t_D)$.

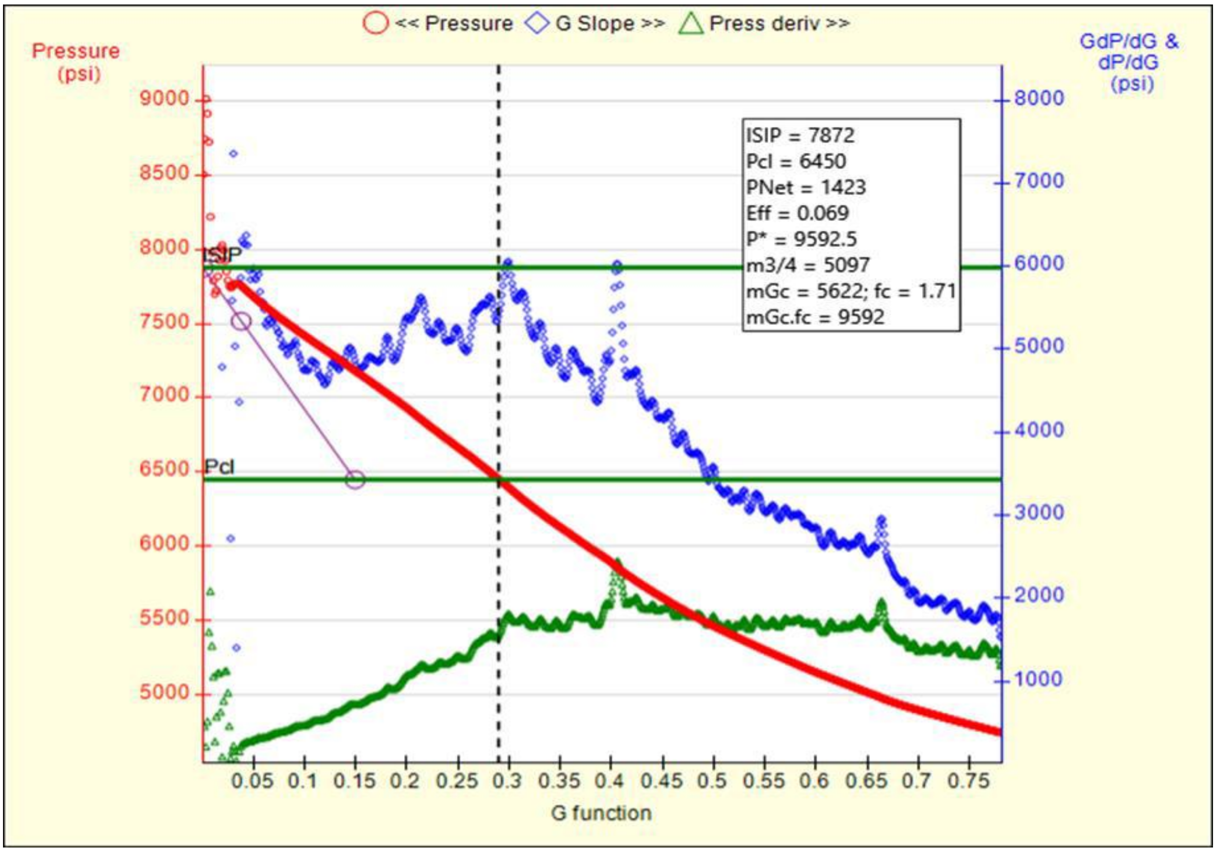


Figure V.13: DataFRAC Analysis with G function.

From the graph above :

- **BH ISIP**: 7,872 psi 0.71psi/ft
- **Closure pressure**: 6,450 psi **Gf**= 0.58 psi/ft at **H= 3,376.5 m** (depth in the middle of the perforated interval)
- **Pnet**: 1,423 psi
- **Efficiency: 7% calculated using ¾ method.**

✓ **The net pressure (Pnet):**

The net pressure is determined by the equation below:

- $P_{Net} = ISIP_{BH} - P_C$
- Pnet = 7872- 6450 = 1423 psi

$\boxed{\textbf{Pnet = 1423 psi}}$

✓ **Calculation of the closing time:**

From Δt_D found, we calculate the closing time Δtc.

$$\Delta t_D = \frac{\Delta Tc}{Tp} \quad \Rightarrow \quad \Delta t_D \,.\, \Delta t_C = 0{,}28 \,.\, 28{,}4 \approx 8$$

$\boxed{\Delta t_D \approx 8 \text{ min.}}$

- ✓ **Efficiency:**

From the graph

$\eta = f(\Delta t_D)$ we get $\eta = 0,069$ it's $\eta = 6,9\ \% \approx 7\%$

Using equation:

$$\eta = \frac{g(\Delta t_D) - g_0}{g(\Delta t_D)}$$

$$\eta = \frac{1.71 - \frac{\pi}{2}}{1;71} = 0.081$$

$$\boxed{\eta = 8\%}$$

- ✓ **Estimation of the fracturing gradient (GF):**

The fracturing gradient can therefore be estimated using the following expression (Gf):

$$Gf = CP / H$$

Where:

- H = Depth (in the middle of the perforated interval) H = 3376.5m = 11077.7 ft
- Closure pressure =6450Psi.

$$\boxed{\mathbf{Gf = 0.58\ psi/ft}}$$

V 7.2.2 Determination of Closure pressure from Square Root Function:

From the graphs bellow the closure pressure can be also determinated using square Root function:

Note: the results found by the G function method are confirmed by the SQRT method.

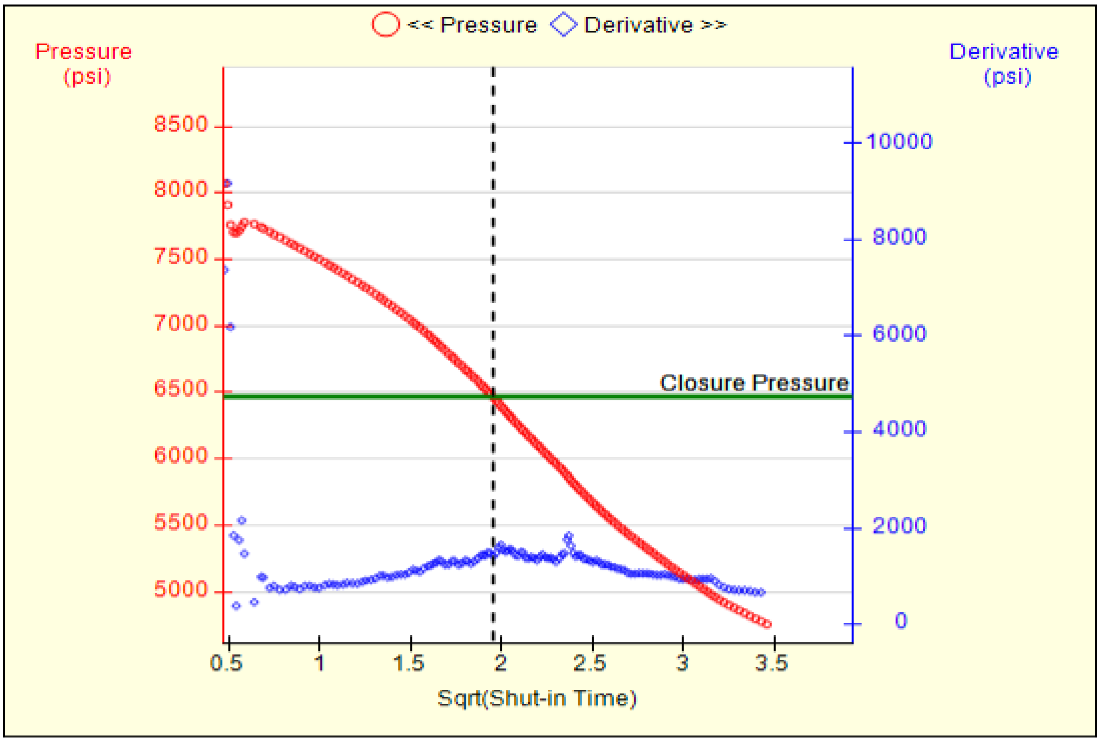


Figure V.14: Square Root Shut-in.

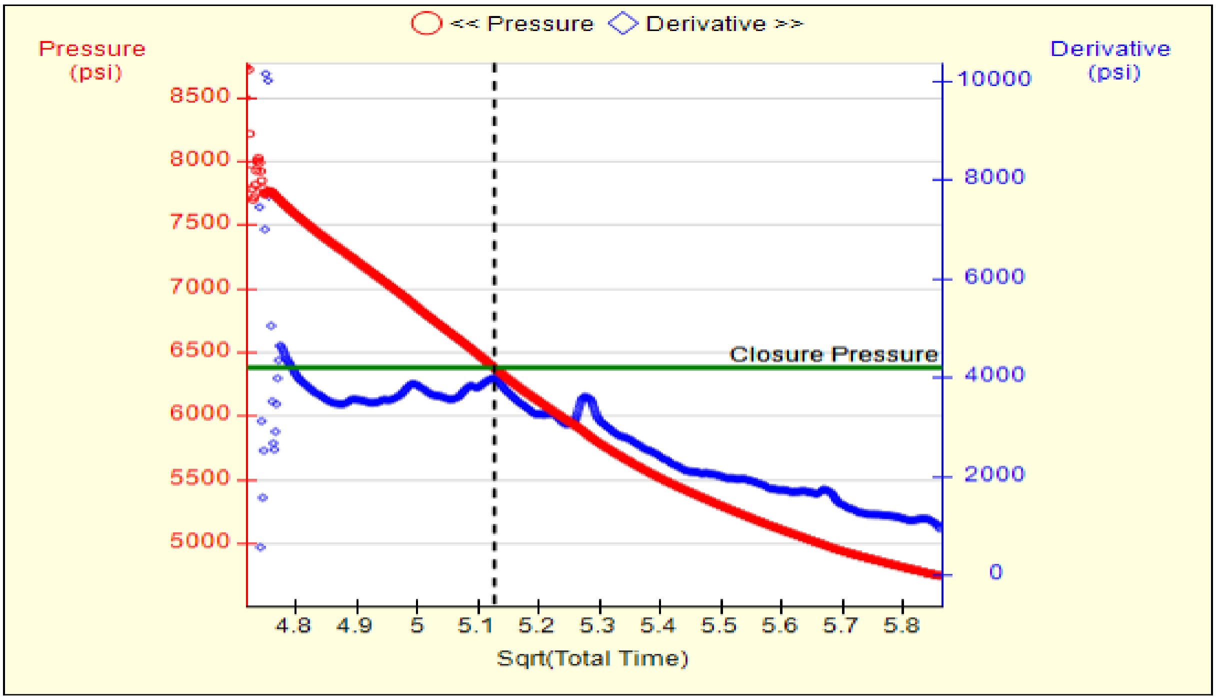


Figure V.15: Square Root Total.

V 7.3 Identification of the propagation model and log.log analysis:

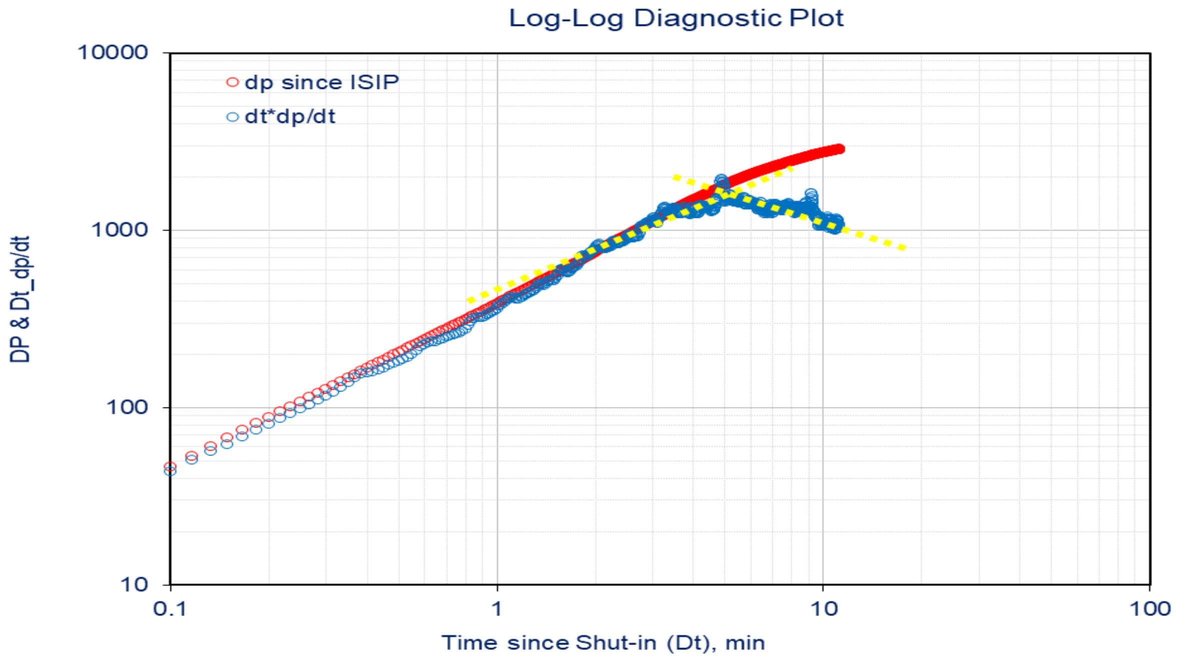


Figure V.16: Propagation model and log log analysis.

The level of the derivative half unit slope line is half that of the pressure.
The Fracture seems to close very fast 4m after stop pumping pressure and derivative responses on log-log scales Infinite conductivity fracture was observed only in the initial few minutes after shut down The open frac bi-linear flow stopped completely after 4min sign of frac closure
After closure Analysis ACA:

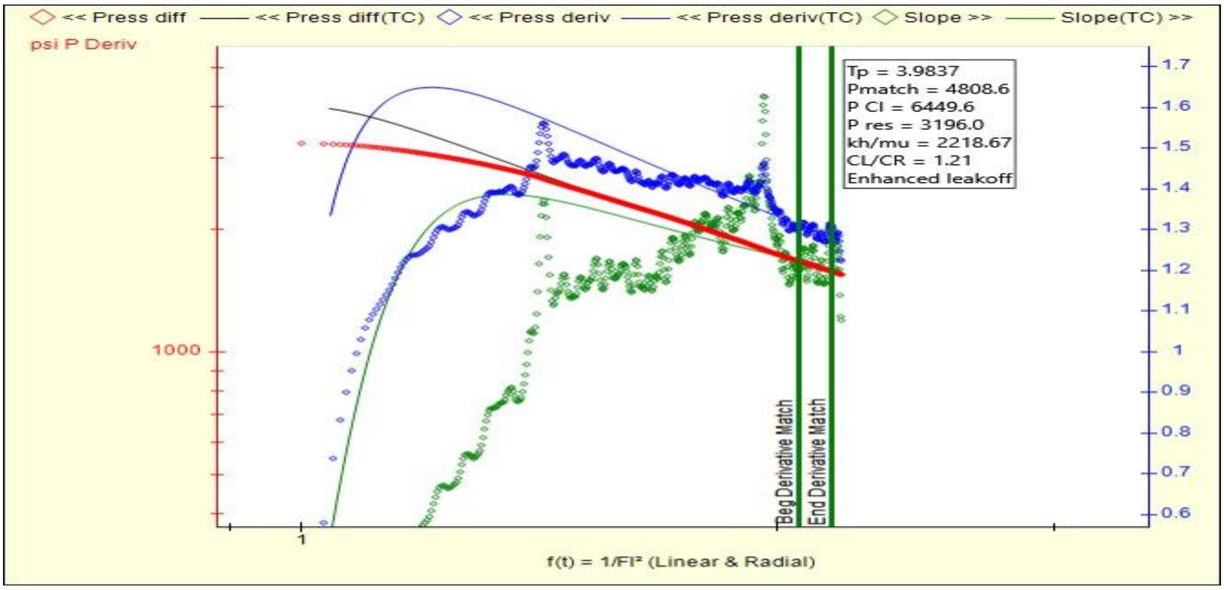


Figure V.17: After Closure Analysis on the pseudo radial flow.

- The After closure analysis on the **Pseudo radial flow** show high leak off formation

CL/CR = 1.21

- However The formation shows good transmissibility on the reservoir **2218 md-ft/cp.**
- The reservoir pressure is very low and the well will need artificial lifting post frac.

V.7.4 Compliance calculation:

- We calculate compliance with the following equation:

$$C_f = \frac{\pi \ \beta s}{2\,E'} H_f$$

- In this equation we are missing the plane strain modulus E ’:

$$E' = \frac{E}{\left(1-\nu^2\right)}$$

$$E' = \frac{8.10^6}{1-0{,}2^2} = \frac{8.10^6}{0{,}96} = 8{,}33\ .\ 10^6$$

$$\boxed{\mathbf{E' = 8{,}33\ .\ 10^6\ psi.}}$$

Where: H_f is the length of the fracture.

$$C_f = \frac{3{,}14\ .\ 0{,}9}{2\ .\ 8{,}33\ .\ 10^6} \cdot 177{,}16 = 3{,}0051270101\ .10^{-5}.$$

$$\boxed{\mathbf{Cf = 3{,}0051270101\ .10^{-5}\ ft/psi.}}$$

V.7.5 Calculation of the filtration coefficient CL:

$$C_L = \frac{m_p \beta_s}{r_p \sqrt{t_p} E'} 2X_f$$

With X_f: the half length of the fracture.

$$X_f^2 = \frac{(1-\eta) Vpad\ E'}{2\,g_0\,\beta_s\,m_P} \cdot \frac{1}{4 * h_f}$$

$$Xf^2 = \frac{(1-0{,}08)\ .\ 5242{,}10\ .\ 8{,}33\ .\ 10^6}{2.\frac{\pi}{2}.0{,}9.5097} \cdot \frac{1}{4.177{,}16} = 3964{,}85\ ft^2$$

$$Xf = \sqrt{3964{,}85} = 62{,}96\ ft$$

$$\boxed{\mathbf{Xf = 19{,}9\ m}}$$

Calculation of the filtration coefficient CL:

$$r_p = \frac{hutil}{hfracture} \qquad C_L = \frac{m_p \beta_s}{r_p \sqrt{t_p} E'} 2X_f$$

$r_P = \frac{3376,5}{3356,81} = 1.066$

$C_L = \frac{5097 \,.\, 0,9}{8,33 \,.\, 10^6 \,.1,006\sqrt{28,4}} . 2. 62,69 = 1,3 \,.\, 10^{-2}$

$$\boxed{\mathbf{CL = 1,3 \,.\, 10^{-2}\ ft/\sqrt{min}.}}$$

V.7.6 Calculation of the area of the fracture Af:

$$A_f = \frac{(1-\eta)V_{slurryinj}}{2g_0 r_P \sqrt{T_P} C_L}$$

$A_f = \frac{(1-0,08).5242,10}{2 .\frac{\pi}{2}.\ 1,006.\sqrt{28,4}.\ 1,3.\ 10^{-2}} = 22320,76$

$$\boxed{\mathbf{A_f = 22320.76\ ft^2}}$$

Verification:

$A_f = 2\ X_f\ .\ H_f$

$H_f = \frac{Af}{2.Xf} = \frac{22320,76}{2\ .\ 62,96} = 177.26$

$$\boxed{\mathbf{H_f = 177.26\ ft = 54.02\ m}}$$

V.7.7 Calculation of the fracture volume:

$$V_{fP} = 2C_L r_P A_f \sqrt{t_P}\,[g(\Delta t_{CD}) - g_o]$$

$V_{fP} = 2.\ 1,3\ .10\text{-}2\ .\ 1,006.\ 22320,76\sqrt{28,4}\ .\ (\ 1,71\text{-}\frac{\pi}{2}\ ) = 433,23$

$$\boxed{\mathbf{V_{fP} = 433,23\ ft^3.}}$$

V 7.8 Calculation of the fracture width:

To calculate the width of the fracture two methods were used:

1st method: from the surface

$$w_f = \frac{\eta V_i}{A_f} = \frac{V_f}{A_f}$$

$W_f = \frac{0,08\,.\,5220,10}{22320,76} = \frac{433,29}{22320,76} = 0,019$

$$\boxed{\mathbf{W_f = 0,019\ ft = 0,2\ in.}}$$

2nd method:

$$w_f = C_f \Delta P = C_f (ISIP - P_c)$$

$$\boxed{\mathbf{Wf = 0.043\ ft = 0.5\ in.}}$$

V 7.9 Volume of slurry and pad injected (Vinj):

Knowing the injection rate and time (pumping), we deduce the volume injected by:

Qinj = 35 bbl/min (Qmax during pupming).

Tinj = 28,4 min.

Vinj = 35 . 28,4 = 994 bbl = 5300.16 ft^3.

$$\boxed{\mathbf{Vinj = 5300.16\ ft^3 = 39648\ gallon.}}$$

- **Pad volume (VPad):**

Calculation of pad percentage:

$$Vpad = \frac{1-\eta}{1+}.Vinj \qquad \%pad = \frac{1-\eta}{1+\eta}$$

$\%pad = \frac{1-0,08}{1+0,08} = 0,85$

$$\boxed{\mathbf{\%pad = 85\ \%.}}$$

Pad volume (VPad) is given by the formula below:

$$Vpad = \frac{1-\eta}{1+}.Vinj$$

$Vpad = \frac{1-0,08}{1+0,08}.\,5300.16 = 4440,48$

$$\boxed{\mathbf{Vpad = 4505.13\ ft^3 = 33701\ gallon.}}$$

V 7.10 Procedure for selecting proppants:

The proppant selection is primarily governed by the desired conductivity for a desired flow rate, in relation to the permeability and the concentration of proppants in the fracture. It is also based on the main side of in-situ stress, and on the other side of the diameters of the perforations in addition to their availability and cost. The selection procedure is as follows:

- The closing pressure is determined in (psi).
- By using the abacus, the permeability of the proppant is determined as a function of the closing pressure.
- We calculate the dimensionless fracture conductivity.
- The concentration of the proppant in the fracture.
- The mass of proppant required

✓ **Dimensionless fracture conductivity**

$$F_{CD} = \frac{K_f \cdot W_f}{K \cdot X_f}$$

K_f : permeability of proppant.
K: permeability of the formation (K = 2.83md).
W_f: Fracture width.
X_f : Length of the fracture.

✓ **The permeability of the proppant:**

The proppant permeability determination chart ”gives us for Pc = 6450 psi and for High Strength proppants an approximate permeability is 366000 mdarcy.

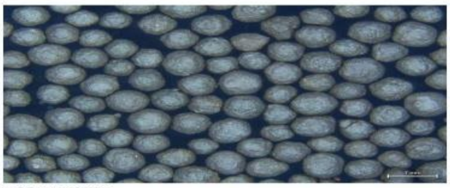
2.4. Proppant Proprieties

Schlumberger

Technical Data Sheet

S542-2040

Mesh Size: 20/40
Proppant Type: HSP



Properties	
Absolute Density, g/cm^3	3.64
Apparent Density, g/cm^3	-
Bulk Density, g/cm^3	2.04
Roundness	0.90
Sphericity	0.90
GSD, In Size wt %	95.98
Acid Solubility*, %	4.36
Turbidity, NTU	70.00
LOI, wt %	-
UCS, psi	-
Mass Absorption Coefficient, cm^2/g	0.07560

*Performed in 12/3 Mud Acid for 30 minutes at 150 degF [66 degC]

Crush Test (ISO13503-2)

Stress, psi	Fines, wt %
13000	2.66
21000	9.15

Sieve Analysis

Mesh	wt %
16	0.00
20	3.93
25	37.22
30	52.02
35	6.55
40	0.19
50	0.08
pan	0.01
Mean Size, mm	0.708

Conductivity and Permeability

Stress, psi	Conductivity, mD-ft	Permeability, D
2000	6864	492
4000	5886	427
6000	4977	366
8000	4035	302
10000	3113	237
12000	2419	187
14000	1955	155

Test conditions: ISO 13503-5
Ohio Sandstone; 250 degF [121 degC]; 2 lbm/ft^2 (9.8 kg/m^2);
50 hours; 2 wt % (167 lbm/1,000 galUS (20 kg/m^3) KCL.

Product specification range can be found here: http://ocpqa.slb.com

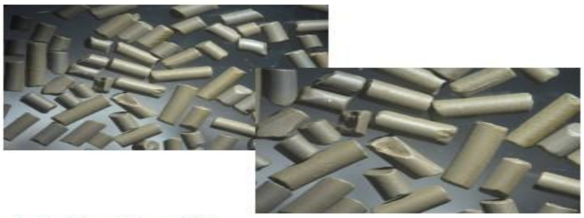
Figure 4 HSP 20/40 Technical Data Sheet

Figure V.18: HSP 20/40 Technical Data sheet.

Schlumberger

Technical Data Sheet

S810



Properties

Absolute Density, g/cm^3	3.64
Apparent Density, g/cm^3	-
Bulk Density, g/cm^3	2.18
Rod Straightness	0.91
Rod Roundness / Spherisity	0.78
Average rod Length	2.83
Average rod Diameter	1.50
Length distribution 1.51 to 3.76 mm, % fraction	83.97
Length distribution < 1.51 mm, % fraction	2.15
Length distribution > 3.76 mm, % fraction	13.88
Turbidity, NTU	63.00
Mass Absorption Coefficient, cm^2/g	0.07560

Conductivity and Permeability

Stress, psi	Conductivity, mD-ft	Permeability, D
2000	52512	3307
4000	26046	1733
6000	13431	930
8000	8099	582
10000	4651	346
12000	1985	154
14000	369	30

Test conditions: ISO 13503-5
Ohio Sandstone; 250 degF [121 degC]; 2 lbm/ft^2 (9.8 kg/m^2);
50 hours; 2 wt % (167 lbm/1,000 galUS (20 kg/m^3) KCL

Crush Test (ISO13503-2)

Stress, psi	Fines, wt %
5000	-
7500	-
10000	-
12500	-
15000	20.00

Figure 6 RodShape proppant Technical Data Sheet

Figure V.19: Rod Shape proppant Technical Data Sheet.

C : retained permeability factor (the gel that remains in the fracture decreases the permeability) C = 0.5.

$$F_{CD} = \frac{Kf\,.\,Xf}{K\,.Hf} = \frac{366.10^3.\ 0,5\,.\ 0,019}{2,83\,.\ 177} = 6.94$$

$$\boxed{F_{CD} = 6.94}$$

V 7.11 Results obtained from the "Frac cad" simulator:

Hydraulic fracturing is an extremely complex operation, and it is impossible to guarantee the success of the operation. The use of the computer tool gives a new vision of the operation and revolutionizes the practices of hydraulic fracturing.

The graphic below is the complete recording of the minifrac test. This graph is generated by the Fraccad software:

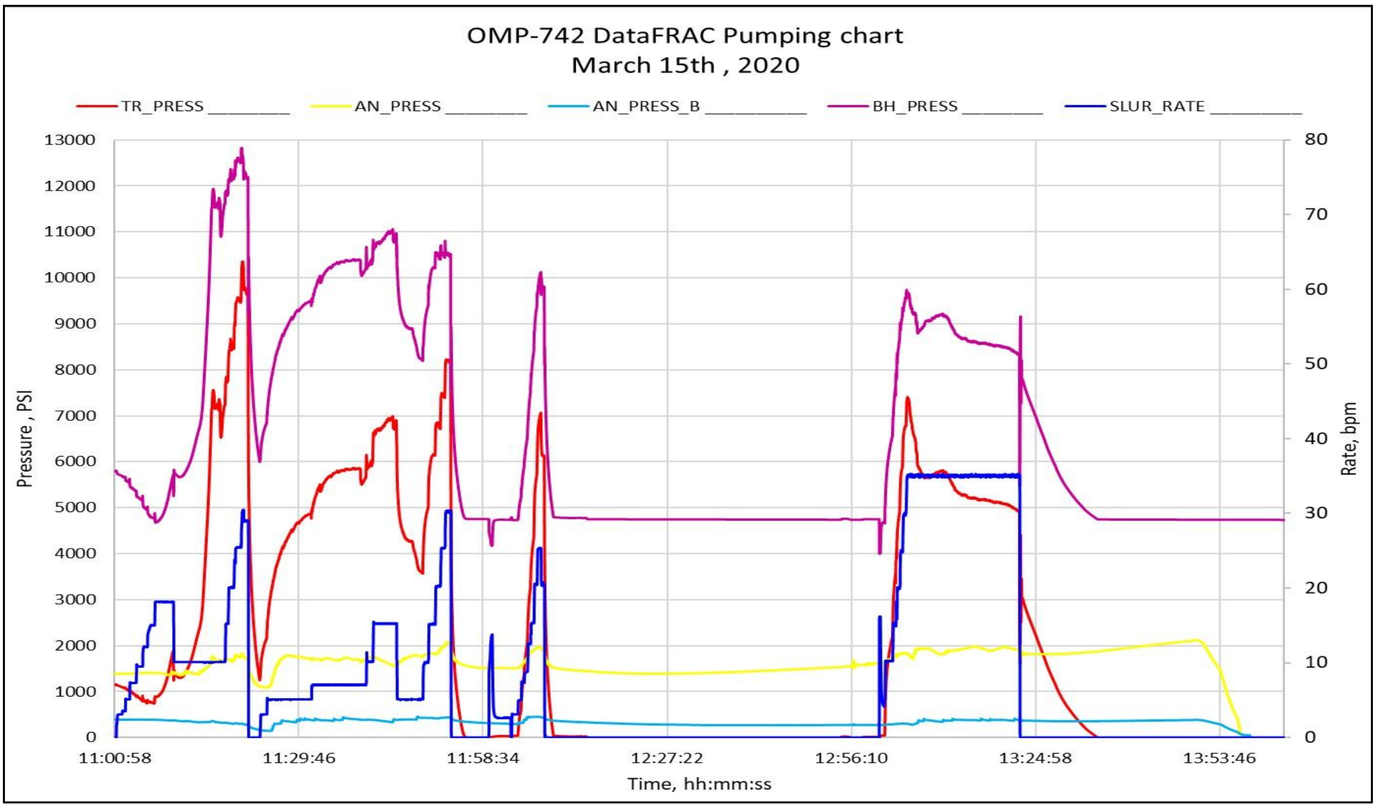


Figure V.20: DataFrac pumping chart OMP-742.

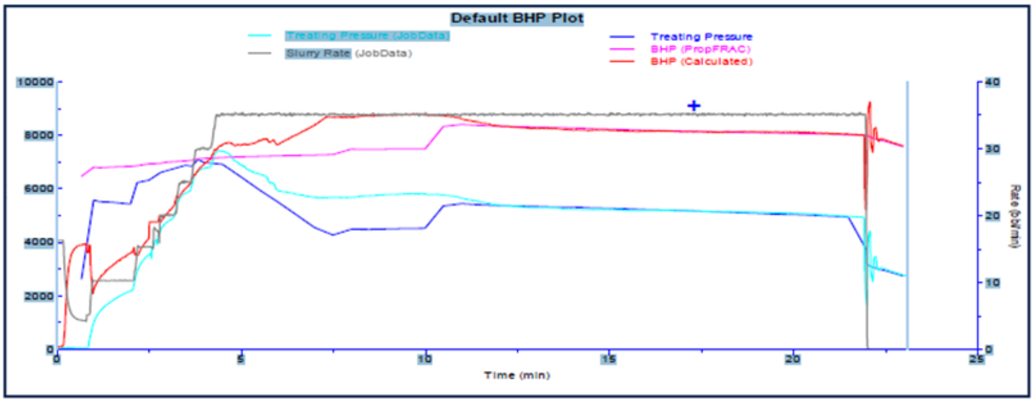


Figure V.21: BHP Pressure plot.

Ct 1.4E-2 ft/min0.5

EOJ Net Pressure 1529 psi
Efficiency 0.075

- **G45RTN Geometry simulated by Fraccad software :**

DATAFRAC Pressure Match Geometry History

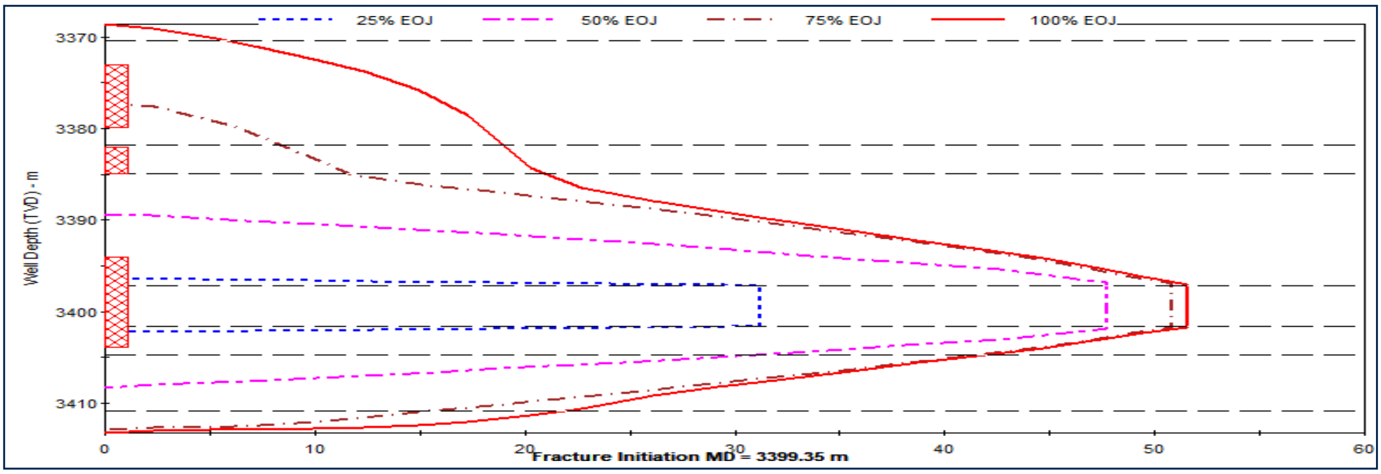


Figure V.22: Pressure Match Geometry History.

V 7.10.1 Comparison of the values of the calculated parameters and those of the simulator:

Parameter	Symbol	Calculat -ed value	Unit software	Unit
Cross-linked gel	PAD	33701	39079	Gal
$ISIP_{BH}$	$ISIP_{NWB}$	7872	8005	Psi
$ISIP_S$	$ISIP_S$	3254	3254	Psi
Pressure drop at the bottom	ΔP_{NWB}	331	331	Psi
Total pressure drop	ΔP_{Total}	1667	1667	Psi
Friction pressure drop	$\Delta P_{Friction\ pipe}$	1336	13336	Psi
Closure pressure	Pc	6450	6600	Psi
Net pressure	P_{net}	1423	1529	Psi
Efficiency	η	8%	7%	%
Fracturing gradient	Gf	0.58	0.59	Psi/ft
Half length	X_f	19.2	18.8	m
Height	H_f	54	34.8	m
Width	W_f	0.2	0.244	In
Dimensionless fracture conductivity	F_{CD}	6.94	-	-

Table V.15: Calculated values comparing to values from simulator.

V 7.10.2 Redesign using Fraccad software:

Fraccad software can provide multiple designs, it is up to the program runner to select the most convincing, the redesign is displayed in the form of tables and graphs. Below we show the redesign made by Fraccad

Pumping schedules:

Step Name	Treatment Type	Pump Rate bbl/min	Fluid #	Fluid Name	Gel Conc. lb/mgal	Fluid Volume gal	Prop. #	Prop. Conc. PPA	Prop. Mass lb	Slurry Volume bbl	Pump Time min
Pad	Propped Fracture	35.0	1	YF135HTD	35.0	18000	0	0.00	0	428.6	12.2
1.0 PPA	Propped Fracture	35.0	1	YF135HTD	35.0	1500	2	1.00	1500	36.9	1.1
2.0 PPA	Propped Fracture	35.0	1	YF135HTD	35.0	1500	2	2.00	3000	38.1	1.1
3.0 PPA	Propped Fracture	35.0	1	YF135HTD	35.0	1500	2	3.00	4500	39.3	1.1
4.0 PPA	Propped Fracture	35.0	1	YF135HTD	35.0	1500	2	4.00	6000	40.4	1.2
5.0 PPA	Propped Fracture	35.0	1	YF135HTD	35.0	2000	2	5.00	10000	55.5	1.6
6.0 PPA	Propped Fracture	35.0	1	YF135HTD	35.0	2000	2	6.00	12000	57.1	1.6
7.0 PPA	Propped Fracture	35.0	1	YF135HTD	35.0	2000	2	7.00	14000	58.7	1.7
8.0 PPA	Propped Fracture	35.0	1	YF135HTD	35.0	2400	3	8.00	19200	72.6	2.1
Flush	Propped Fracture	35.0	4	WF135	30.2	6679	0	0.00	0	159.0	4.5

Table V.16: Pumping schedule (re-design using fraccad).

- 1 PPA to 7 PPA will be pumped with 20/40 HSP (51,000 lb)
- 8 PAA stage will be pumped with 16/30 HSP (19,200 lb)
- Total Proppant is : 70,200 lb

Total Fluid Volume:	39079 gal	Total Proppant Mass:	70200 lb
Total Slurry Volume:	986.1 bbl	Total Pump Time:	28.2 min
% PAD Clean:	55.6	% PAD Dirty:	51.8

V 7.10.3 Main treatment :

The below pumping schedule is conventional with total proppant of 72 .000lbs of 20/40 HPS and 38 .000 lbs 16/20 HPS proppant at a rate of 35 bpm .

	Step Name	Pump Rate	Fluid Name	Fluid Volume	Proppant Name	Proppant Conc.	Proppant Mass	Slurry Volume	Pump Time
		bbl/min		gal		PPA	lb	bbl	min
1	Pad	35.00	YF135HTD +2% Methanol	18000		0.00	0	428.6	12.2
2	1 PPA	35.00	YF135HTD +0.5% Methanol	2000	20/40 HSP	1.00	2000	49.3	1.4
3	2 PPA	35.00	YF135HTD +0.5% Methanol	2000	20/40 HSP	2.00	4000	50.9	1.5
4	3 PPA	35.00	YF135HTD +0.5% Methanol	2000	20/40 HSP	3.00	6000	52.3	1.5
5	4 PPA	35.00	YF135HTD +0.5% Methanol	2000	20/40 HSP	4.00	8000	53.9	1.5
6	5 PPA	35.00	YF135HTD +0.5% Methanol	2000	20/40 HSP	5.00	10000	55.5	1.6
7	6 PPA	35.00	YF135HTD +0.5% Methanol	2000	20/40 HSP	6.00	12000	57.1	1.6
8	7 PPA	35.00	YF135HTD +0.5% Methanol	2000	20/40 HSP	7.00	14000	58.7	1.7
9	8 PPA	35.00	YF135HTD +0.5% Methanol	2000	20/40 HSP	8.00	16000	60.2	1.7
10	9 PPA	35.00	YF135HTD +0.5% Methanol	2000	16/20 HSP	9.00	18000	61.8	1.8
11	10 PPA	35.00	YF135HTD +0.5% Methanol	2000	16/20 HSP	10.00	20000	63.4	1.8
12	Flush	35.00	WF135 +0.5% Methanol	6889		0.00	0	164.0	4.7

Table V.17: Main treatment schedule pumping.

Total Slurry Volume	991.63 bbl
Total Clean Volume	38000 gal
Total Proppant Mass	110000lb
Percent Pad Clean	0.47 %
Percent Pad Dirty	0.43 %
Under Displacement Volume	5.0 bbl

V 7.10.4 Main Processing Records :

The bottom hole pressure derived from the calculated bottom hole pressure was matched to that predicted by the fracture model

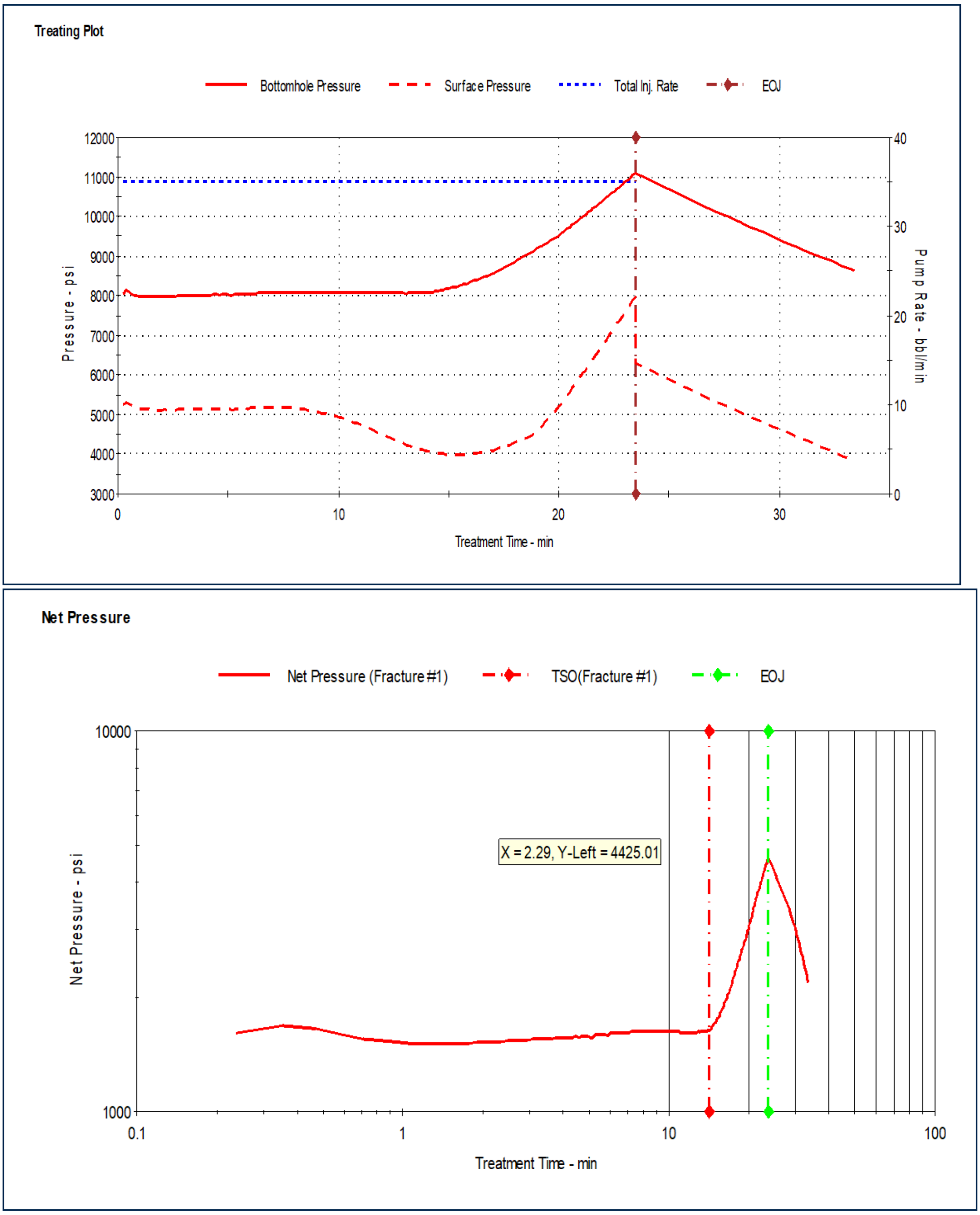


Figure V.23: pressure match.

V 7.10.5 Post-fracturing evaluation by Fraccad:

The Fraccad is able to assess the geometric characteristics of the fracture by drawing on the results of the DataFrac and the Main Frac. It generates the tables below.

Geometry of the fracture after MainFRAC, OMP742 (Fraccad):

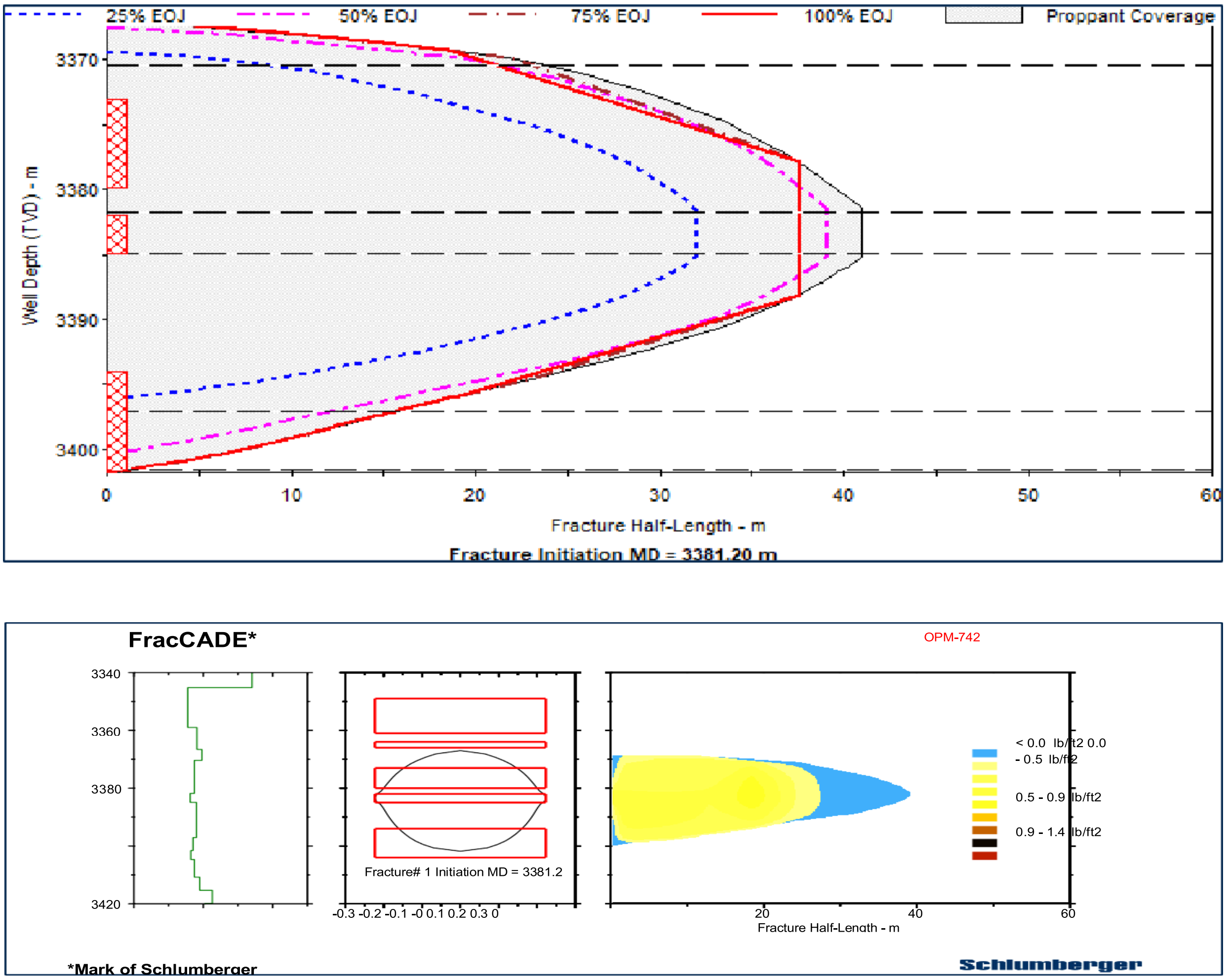


Figure V.24: Geometry of the fracture after Main frac.

V 7.10.6 Fracture conductivity:

The following profile plot shows the geometry of the fracture and the areal proppant distribution predicted by the fracture simulator ;based on this net pressure

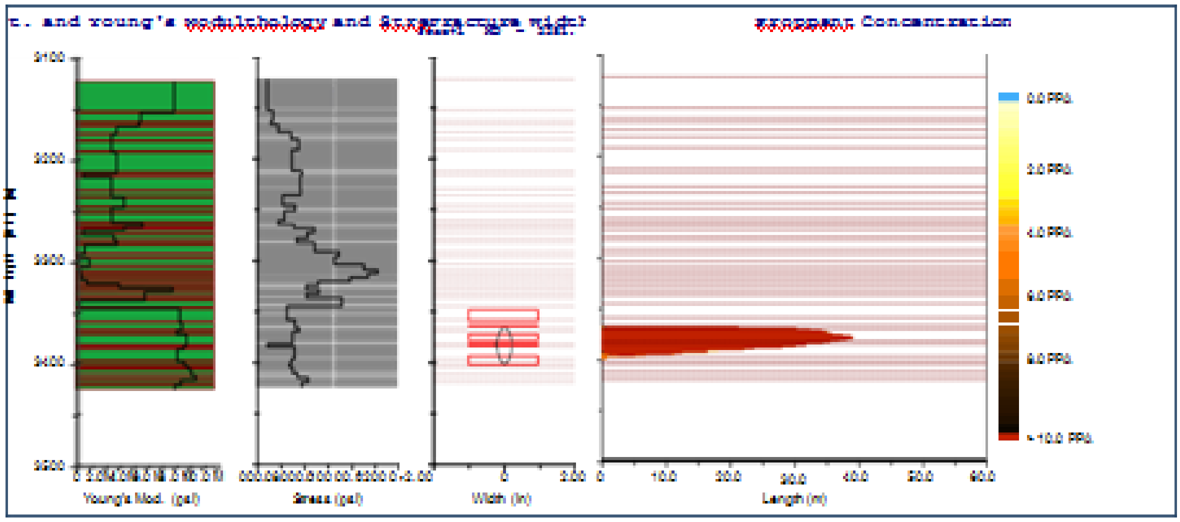


Figure V.25: Geometry of the fracture and the areal proppant distribution.

- **Simulation summary and fracture dimensions:**

The simulator results are tabulated below:

Max Hyd Frac Half-Length	41.4 m	EOJ Net Pressure	4639 psi
Propped Frac Half-Length	41.0 m	Efficiency	0.210
EOJ Hyd Frac Half-Length	18.8 m	Effective Conductivity	5228 md.ft
EOJ Hyd Height at Well	34.8 m	Average Gel Concentration	3810.6 lb/mga
EOJ Hyd Width at Well	0.968 in	Effective Fcd	190.1
Propped Width at Well	0.244 in	Max Surface Pressure	7989 psi
Average Propped Width	0.093 in	Estimated Closure Time	9.9 min

V.8 Production data:

OMP-742 well production diagrams:

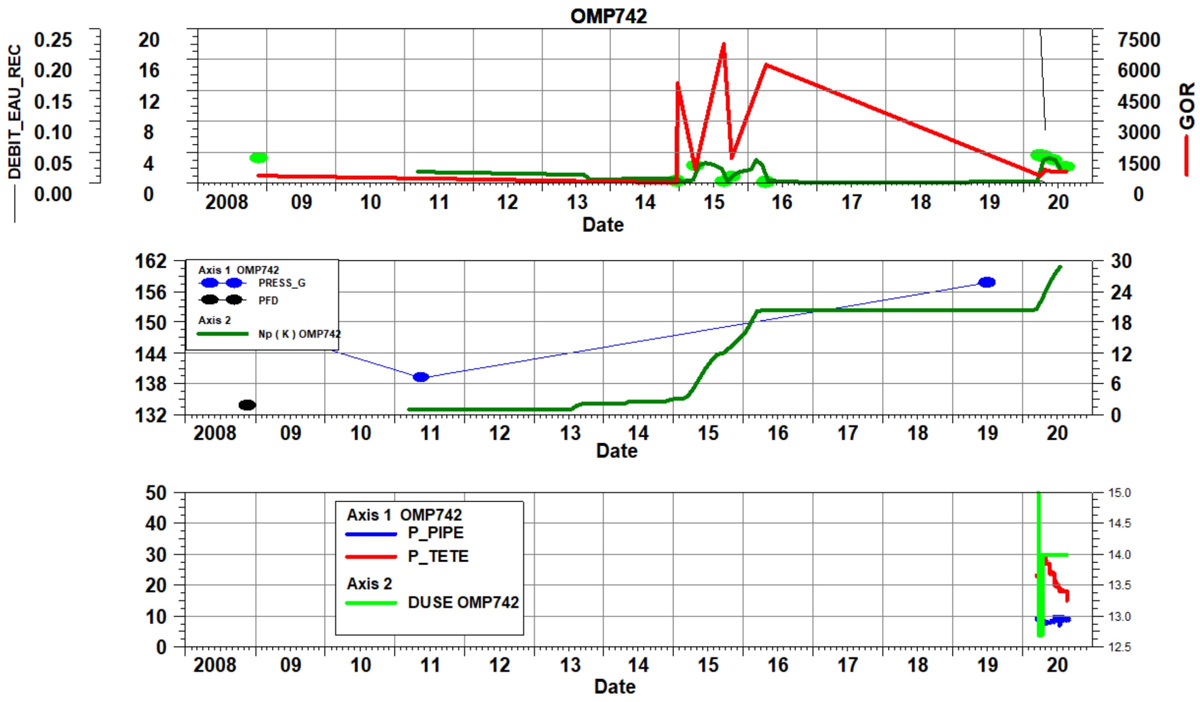


Figure V.26: Production diagrams of OMP-742 well.

Summary of OMP-742 well production :

Date Mesure	Diam. Duse (mm)	Unité Sépar.	Débit (m³/h)		GOR	Pression (kg/cm²)			Densité		Parametres GL			Temp. Huile (°C)	K Psi	Débit Eau (l/h)		Observations
			Huile	Gaz		Press. Tete	Press. Pipe	Press. Separ.	Huile	Gaz	Press. Reseau (Bar)	Press.Inj (Bar)	Débit GL (M3/J)			Récupérée	Injectée	
22/11/2008	9.53	-	3.2	1117.68	350	47.8	10	4.89	.791		-	-	-	16	0.8651	0	0	-
19/12/2014	18	1440	0		0	17	10	9.99	-		-	-	-	--	92695.9341	142	0	-
20/12/2014	18	1440	0.22	1066.85	4840	12.5	10.5	10.61	.804		-	-	-	13	9.2124	0	0	-
28/03/2015	12.7	FastQ	2.2	1471.17	669	23.6	10	--	.797		-	-	-	15	1.0407	0	0	-
26/08/2015	12.7	600	0.2	1312.23	6713	17	11	4.28	.806		-	-	-	40	8.4371	0	0	-
06/10/2015	12.7	Vx29	0.82	1008.10	1228	16	12.2	--	-		-	-	-	--	1.8689	0	0	-
06/04/2016	15	1440	0.1	573.74	5737	20	11.1	11.17	-		-	-	-	--	26.1815	0	0	-
30/03/2020	12.7	-	3.51	1283.38	365	30.5	9.4	9.17	.777		-	-	-	18	0.8406	250	0	-
24/04/2020	14	-	3.46	2135.00	617	29	7.9	--	.807		-	-	-	25	0.9693	85	0	-

Table V.18: Summary of well Test operation on OMP-742 well.

V.9 Economic evaluation:

In order to assess the contribution of hydraulic fracturing, an economic evaluation is necessary to enable us to decide whether or not to continue with the main treatment of the fracturing. In evaluating the costs of this operation, we can consider the cost associated with the hydraulic fracturing operation and well depreciation times.

V.9.1 The total cost of the OMP-742 well operation: 283,230 USD:

V.9.2 Gain of the operation:

- Oil rate before frac Q $_{\text{Before frac}}$ = 0.2 m3/h.
- Oil rate after frac Q $_{\text{After frac}}$= 3.51 m3/h.

- ΔQ = Q After frac – Q Before frac
  - ΔQ = 3.51 – 0.2 = 3.31 m3 / h = 79.44 m3 / j

ΔQ= 79.44 m^3/j = 499.76 bbl/d.

V.9.3 Calculation of the cost in volume:

If we take the average price of a barrel of oil in 2020 is $ 40 (Until 12/31/2020)

- **The cost in equivalent volume (bbl) = The total cost of the operation / The price per barrel.**

With: The total cost = 283,230 $

OMP-742 well	Barrel price 35 $	Barrel price 40$	Barrel price 50$
The cost in equivalent volume (bbl)	8092	7081	5665

Table V.19: Cost in equivalent volume (bbl).

V.9.4 Le délai d'amortissement ou Pay Out Time :

- **Depreciation period = The cost in equivalent volume / ΔQ**

With: ΔQ = 79.44 m3/j = 499.76 bbl/d.

OMP-742 well	Barrel price 35 $	Barrel price 40$	Barrel price 50$
Depreciation period (Pay Out Time) (Days)	**With 8092 bbl We get 16 Days**	**With 7081 bbl We get 14 Days**	**With 5665 bbl We get 11 Days**

Table V.20: Amortization period or Pay Out Time.

V.10 Fracturing with Foam:

In this part we will stimulate different scenarios using an energized fluid as foam fracturing to achieve the same fracture geometry as well as the downhole dimensions (FCD ,XF ,WF,HF, LF) of a conventional job.

V 10.1 Job design procedure:

The procedure in fracturing with foam is almost similar to the conventional fracturing. the difference will be observed in the end type of the fluid used with the e some addition to new parameters like foam quality and nitrogen factor that will affect some surface parameters like rate and volume

To achieve the FCD, the proppant volume and geometry obtained from the conventional fracturing, different simulation will be permed using different pumping schedules scenarios while changing the quality of foam (percent of N2). The goal is to achieve the executed downhole design, which is:

- Maintaining downhole rate at 35 pbm.
- Total propped volume pumped 852000 lb.
- Achieve downhole maximum concentration 8PPA.
- using N2 Foam fluid.

V 10.2 OMP-742 conventional as measured pump schedule:

- 15%~17% N2 Foam Quality Schedule design.
- 27%~31% N2 Foam Quality Schedule design.
- 35%~40% N2 Foam Quality Schedule design.

V 10.2.1 The first Foam Quality schedule design:

- 15%~17% N2 Foam Quality Schedule design:

The surface schedule volume obtains from the simulator:

Surface Schedule Volume Information										
Step Name	Step Liquid Vol. (bbl)	Cum. Liquid Vol.	Step Prop. Mass (lb)	Cum. Prop. Mass (lb)	Step CO2 Vol. (bbl)	Cum. CO2 Vol. (bbl)	Step N2 Vol. (Mscf)	Cum. N2 Vol. (Mscf)	Step Time (min)	Cum. Time (min)
Pad	375.0	375.0	0	0	0	0	102	102	12.5	12.5
1.0 PPA	60.1	435.0	2958	2958	0	0	16	118	2.08	14.58
2.0 PPA	60.3	495.0	5959.4	8917.4	0	0	17	135	2.16	16.74
3.0 PPA	50.5	546.0	7531.5	16448.9	0	0	14	149	1.88	18.62
4.0 PPA	39.8	586.0	8000	24448.9	0	0	12	161	1.54	20.16
5.0 PPA	39.6	625.0	9953.5	34402.4	0	0	12	173	1.58	21.74
6.0 PPA	38.0	663.0	11542.2	45944.6	0	0	12	185	1.57	23.31
7.0 PPA	29.6	693.0	10474.8	56419.4	0	0	9	194	1.25	24.56
7.0 PPA	71.1	764.0	28778.4	85197.8	0	0	22	216	3.09	27.65
Flush	140.0	904.0	0	85197.8	0	0	37	253	4.69	32.34

Table V.21: Pumping Schedule volume for 15%-17% Foam Quality.

The surface Schedule Rate information:

Surface Schedule Rate Information							
Step Name	B.H. Total Rate (bbl/min)	B.H. Prop. Conc. (PPA)	N2 B.H. Quality (%)	Pumper Total Rate (bbl/min)	Blender Prop. Conc. (PPA)	Surface N2 Rate (scf/min)	N2 Vol. Ratio (scf/bbl)
Pad	35	0	15	30	0	8152	1630
1.0 PPA	35	1	15	30	1.2	7701	1391
2.0 PPA	35	2	15	30	2.4	7600	1389
3.0 PPA	35	3	16	30	3.6	7594	1386
4.0 PPA	35	4	17	30	4.8	7802	1384
5.0 PPA	35	5	17	30	6	7582	1382
6.0 PPA	35	6	17	30	7.2	7576	1380
7.0 PPA	35	7	17	30	8.4	7374	1378
8.0 PPA	35	8	17	30	9.6	7177	1378
Flush	35	0	15	30	0	7955	1337

Table V.22: Surface Schedule Rate.

Foam Calculation Totals		
28699 gal	of	Liquid
559.7 Mscf	of	N2
85200 lb	of	Proppant

V 10.2.2 The second Foam Quality Design:

- 27 % to 31% N2 Foam Quality Schedule:

Surface Schedule Volume Information										
Step Name	Step Liquid Vol. (bbl)	Cum. Liquid Vol.	Step Prop. Mass (lb)	Cum. Prop. Mass (lb)	Step CO2 Vol. (bbl)	Cum. CO2 Vol. (bbl)	Step N2 Vol. (Mscf)	Cum. N2 Vol. (Mscf)	Step Time (min)	Cum. Time (min)
Pad	328.0	328.0	0	0	0	0	168	168	12.6	12.6
1.0 PPA	51.8	380.0	2958	2958	0	0	27	195	2.1	14.7
2.0 PPA	51.8	431.0	5959	8917	0	0	28	223	2.2	16.8
3.0 PPA	43.2	475.0	7532	16449	0	0	25	248	1.9	18.7
4.0 PPA	33.8	508.0	8000	24449	0	0	20	268	1.5	20.3
5.0 PPA	33.2	542.0	9954	34402	0	0	21	289	1.6	21.8
6.0 PPA	31.9	573.0	11542	45945	0	0	20	309	1.6	23.4
7.0 PPA	24.5	598.0	10475	56419	0	0	17	326	1.3	24.7
8.0 PPA	58.2	656.0	28778	85198	0	0	40	366	3.1	27.8
Flush	121.0	777.0	0	85198	0	0	63	429	4.7	32.4

Table V.23: Pumping Schedule volume for 27%-31% Foam Quality.

The surface Schedule Rate information:

Surface Schedule Rate Information							
Step Name	B.H. Total Rate (bbl/min)	B.H. Prop. Conc. (PPA)	N2 B.H. Quality (%)	Pumper Total Rate (bbl/min)	Blender Prop. Conc. (PPA)	Surface N2 Rate (scf/min)	N2 Vol. Ratio (scf/bbl)
Pad	35	0	27.0	26.0	0	13300	1478
1.0 PPA	35	1	27.0	26.0	1.36	13300	1391
2.0 PPA	35	2	27.0	26.1	2.74	13100	1389
3.0 PPA	35	3	27.8	26.1	4.16	13000	1386
4.0 PPA	35	4	29.0	26.0	5.63	13200	1384
5.0 PPA	35	5	30.0	26.0	7.14	13200	1382
6.0 PPA	35	6	30.4	26.1	8.62	13000	1380
7.0 PPA	35	7	31.3	26.1	10.2	13000	1378
8.0 PPA	35	8	32.0	26.1	11.8	12900	1378
Flush	35	0	27.0	25.9	0	13400	1337

Table V.24: Surface Schedule Rate.

Foam Calculation Totals		
32654 gal	of	Liquid
428.9 Mscf	of	N2
85200 lb	of	Proppant

V 10.2.3 The Third Foam Quality :

- 35%~40% N2 Foam Quality Schedule:

The schedule Volume information:

Surface Schedule Volume Information										
Step Name	Step Liquid Vol. (bbl)	Cum. Liquid Vol.	Step Prop. Mass (lb)	Cum. Prop. Mass (lb)	Step CO2 Vol. (bbl)	Cum. CO2 Vol. (bbl)	Step N2 Vol. (Mscf)	Cum. N2 Vol. (Mscf)	Step Time (min)	Cum. Time (min)
Pad	291.0	291.0	0	0	0	0	219	219	12.6	12.6
1.0 PPA	45.8	337.0	2958	2958	0	0	35	254	2.1	14.7
2.0 PPA	45.4	382.0	5959	8917	0	0	38	292	2.2	16.8
3.0 PPA	37.4	420.0	7532	16449	0	0	32	324	1.9	18.7
4.0 PPA	29.4	449.0	8000	24449	0	0	26	350	1.5	20.3
5.0 PPA	28.8	478.0	9954	34402	0	0	27	377	1.6	21.8
6.0 PPA	27.3	505.0	11542	45945	0	0	27	404	1.6	23.4
7.0 PPA	20.8	526.0	10475	56419	0	0	22	426	1.3	24.7
8.0 PPA	49.1	575.0	28778	85198	0	0	52	478	3.1	27.8
Flush	108.0	683.0	0	85198	0	0	82	560	4.7	32.4

Table V.25: Pumping Schedule volume for 35%-40% Foam Quality.

Surface Schedule Rate information:

Surface Schedule Rate Information							
Step Name	B.H. Total Rate (bbl/min)	B.H. Prop. Conc. (PPA)	N2 B.H. Quality (%)	Pumper Total Rate (bbl/min)	Blender Prop. Conc. (PPA)	Surface N2 Rate (scf/min)	N2 Vol. Ratio (scf/bbl)
Pad	35	0	34	23	0.0	17300	1454
1.0 PPA	35	1	35	23	1.5	17300	1454
2.0 PPA	35	2	36	23	3.1	17200	1458
3.0 PPA	35	3	38	23	4.8	17300	1454
4.0 PPA	35	4	38	23	6.5	17200	1458
5.0 PPA	35	5	39	23	8.2	17100	1449
6.0 PPA	35	6	41	23	10.1	17100	1449
7.0 PPA	35	7	42	23	12.0	17100	1449
8.0 PPA	35	8	43	23	14.0	17100	1449
Flush	35	0	34	23	0.0	17300	1454

Table V.26: Surface schedule Rate.

Foam Calculation Totals		
28699 gal	of	Liquid
559.7 Mscf	of	N2
85200 lb	of	Proppant

V 10.2.4 Volume Comparison For different design:

	Name	Unit	Average Foam Quality			
			conventional	15% ~17%	21% ~31%	35%~40%
Volumes	Liquid	(gal)	52374.0	37961.0	32654.0	28699.0
	N2	(gal)	0.0	2720.1	4605.9	6010.5
		(Mscf)	0.0	253.3	428.9	559.7
	Proppant	(lb)	85200.0	85200.0	85200.0	85200.0
Av .Rate	Liquid	(bpm)	35.0	30.0	26.0	23.0
	Av N2	(bpm)	0.0	5.0	9.0	12.0
		(scf/min)	0.0	~ 7600	~ 13100	~ 17300

Table V.27: Volume Comparison for different design.

From the Table above we Remarque:

- The more we increase the foam quality factor, the less fluid we will need to achieve the target downhole design.

Which result in having:

- **Low fluid content:** The small amount of liquid phase present in foams, around15 to 45 percent of the total volume is replaced Nitrogen,coupled with the high-energy potential of foams are responsible for the good cleanup characteristic and low formation damage of foam. Lower liquid volumes reduce filter cake buildup, in addition of the bubbles created by the nitrogen will plug the pores that will reduce the leakoff, which will be synonym of increase the fluid efficiency
- Less liquid leakoff also reduces the chances for fluiid incompatibilities that lead to precipitates and/or emulsion.
- **Better Good fluid efficiency**.
- **Less damaging to the fracture conductivity.**
- **Good rheological performance at reduced polymer loading**.

V 10.3 Job Result:

From the study above we conclude that Nitrogen foamed fluid can successfully be used to replace the conventional fracturing fluid, moreover foams are more efficient and practical then the conventional , , , especially in this following point :

- **JOB SAFETY:**

Because foam is basically a combination of inert nitrogen and water ,there is no combustion or explosion hazard during field operation ,also because frictional pressure are low and fracture placement can be achieved at low pump rates injection pressure are usually reduce.

- **DEEP FRACTURE PENETRATION:**

Due to the extremely low fluid leakoff, a better fluid efficiency will greatly increased length of hydraulic fracture penetration and propagation into the formation. Empirical calculations show that fracture lengths up to 10.000 feet are possible with stable foam in low permeability reservoirs. This is important, because improved fracture penetration of the drainage radius of the well, directly related to the successful stimulation of productivity.

- **FLUID SENSITIVE RESERVOIR:**

Formation susceptible to permeability damage due to the contact with the water or oil are excellent candidate. Only 15% to 25% of the foam fluid entering the formation is water. This water may be KCL inhibited, to reduce possible clay swelling. And the foam is essentially confined to the fracture because of the low fluid leak-off, therefore on flowback of the well most of the fluid is recovered with little or no contact with the reservoir

- **RAPID FLOWBACK :**

The energy of the N2 foamed fluid help in assuring immediate flowback of treatment fluid and rapid return of the well to production: the expansion of the N2 gas in the fracture provides a high solution gas energy to flowback the fluid from the reservoir to the surface

Conclusion and recommendation:

The following conclusions can be made from the fracture treatment:

- ✓ From the use of conventional fluid we have:
  - The FG resulted (0.58 psi/ft) from Calibration injection was used to calibrate the stress profile
  - The closure pressure is estimated @6,450 psi (0.58 psi/ft) with a Net pressure of 1,423 psi and a fluid efficiency of 7% Very low fluid efficiency 7% can be mitigated by performing Fiber PAD
  - The frac did close after only 4 min DataFRAC
  - Temperature log results showed a main cool down from 3348 m while the bottom of the fracture was taken at 3,402 (WL tool tagged at this depth), 1 pass was performed,
  - Temperature log results and DataFRAC analysis results were used for stress and leak-off profile calibration.
  - The Temperature Log Results shows that the perforations are taking fluid. The fracture shows a Height growth.
  - A fiber Pad of 18,000 gals will be used to mitigate the low fluid efficiency
  - K046 Methanol will be used with 20 gpt in Pad and 5 gpt in the proppant stages to help in the fracture clean up due to the very low reservoir pressure (157.67 kg/cm2).
  - A conventional Design was agreed on with 70.2 lbs with 20/40 and 16/30 HSP.
  - A high risk of screenout is encountered due to the very low fluid efficiency

Important Remark:

Because of low reservoir characteristics of OMP742 well, Sonatrach has performed 4 well testing operation to monitor flow rate decline with time then has decided to convert the production mode of the well to Gas-Lift mode during first semester of 2021.

Below, are figures of WT Data performed after Frac during the period: March 2020 – Till June 2020.

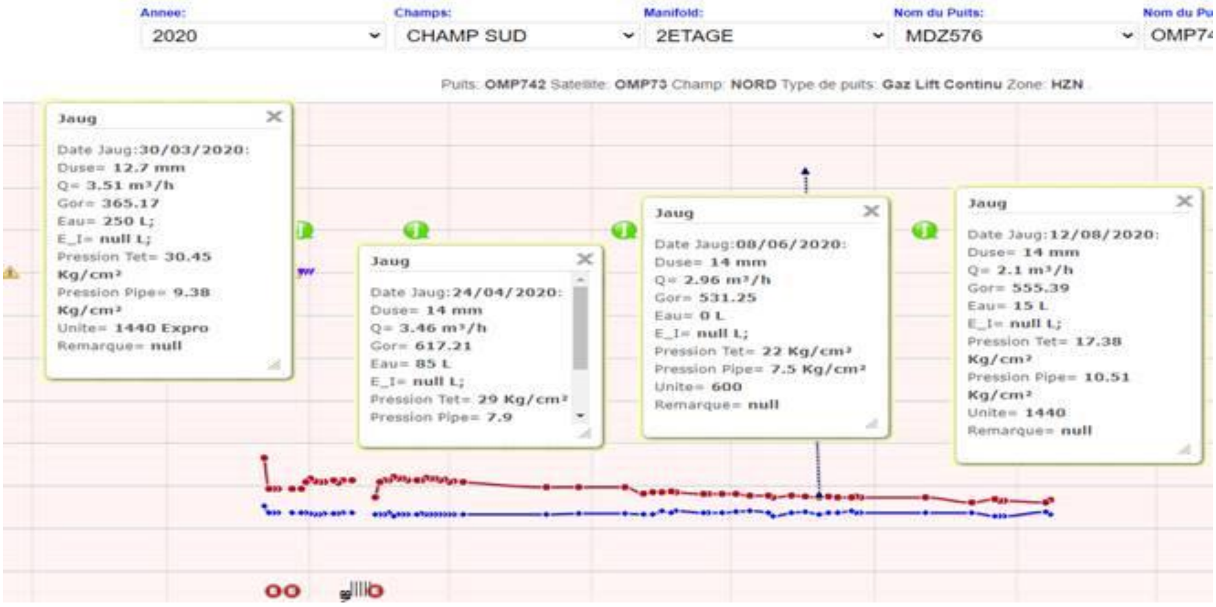


Figure V.27: Well testing Data after frac.

- ✓ From the use of Foam fluid N2 with different quality:

As a benefit of using 35% to 40% foam quality of N2 is to get less fluid, by a liquid volume of 28699 gal, with a volume of N2=559.7Mscf. (Equivalent to 6000 gal).

Since foams contain up to 95% by volume gas, therefor the liquid phase can be minimized, which is important for water sensitive formation although as fracturing fluid foams still provide good fluid loss control. When the well is flowed back, the gas phase in foam provide sufficient energy to flowback the frac fluid followed by hydrocarbons , which accelerate recovery and minimize clean out time.

General Conclusion

The present study shows the necessity and the importance of the use of the hydraulic fracturing technique in the exploitation of reservoirs with mediocre petrophysical characteristics, in particular the permeability of the reservoir rock. This technique allow improving the productivity of the wells by several times, which gives us a considerable gain from an economic point of view. Which is proved in our well study case OMP-742, the well restart producing at considerable rate, Q= $3m^3/h$ approximately, despite the low reservoir pressure (depleted reservoir) and low permeability K.

According to the new research and application of the modern fracturing treatment with foam in whole world, foam has demonstrated larger more benefits compared to conventional method of Hydraulic Fraccturing, which is recognized as being more effective stimulation method but still encounter following problems: significant polymer damage, extended clean up time due to low reservoir pressure (typically over one month) , and undesirable geometry caused by water –based cross linked fluids ,that 's why the step change in improving both the cleanliness of the proppant pack and address the under pressured oil and gas well was provide by switching the proppant caring fluid to foam .

Hydraulic fracturing treatments based on foam as the main proppant carrier fluid effectively reduces the amount of liquid pumped overall, provide better fluid-loss control and aids in post-treatment flow back. Foam fracturing causes less damage to the formation and proppant pack, therefore improving the productivity of the well

Indeed, both foam and conventional fracturing is a profitable operation, but it is very precious and expensive, the reason why we recommend to make the right choice of candidate wells and give the necessary time to establish a design, which are the key parameters in the success of the treatment.

Currently, about 40 percent of all fracturing stimulation treatment performed in USE land and Canada are Foam fracturing jobs. Uses of Foam outside is very limited ,though nevertheless, foam usage is expected to expand overseas as more wells become depleted and typical gases and equipment used for foam fracturing become increasingly available around the globe.

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