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Option : Production Professionnelle

Présenté Par :

ABBACI Ilies, DJAFRI Aimen, KAOUACHE Alaeddine

-THÈME-

HYDRAULIC FRACTURING TREATMENT IN UNDER-PRESSURIZED RESERVOIRS – CASE STUDY (OMP-742-HMD)

Soutenue le : 08/06/2023 devant la commission d'examen

Jury :

Président :	Dr. Abdelghafour DADEN	Maitre de conférences	Univ. Ouargla
Rapporteur :	Dr. Hamid LEBTAHI	Maitre de conférences	Univ. Ouargla
Examinatrice :	Dr. Fatima Zohra BELMILOUD	Maitre de conférences	Univ. Ouargla
Co-encadrant :	Dr. Ali Seyfeddine GUENAOUI	Maitre-Assistant	Univ. Ouargla

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We would also like to say a big thanks to all the teachers, the administrative staff of the department of hydrocarbon production who participated directly or indirectly in our academic path.

Finally, we want to pay tribute to all those who have encouraged us from close and far.

Dedication

As I approach the end of my studies, it gives me great pleasure to dedicate this modest work to:

My beloved mother, without her I would be nothing, who always gives me hope and never ceases to sacrifice herself for me so that I can succeed in life.

Also, to my dearest Dad, ALLAH YAREHMOU.

Iliès Abbaci

Dedication

As I approach the end of my studies, it gives me great pleasure to dedicate this modest work to:

My beloved mother, without her I would be nothing, who always gives me hope and never ceases to sacrifice herself for me so that I can succeed in life.

To my dearest Dad.

Alaeddine Kaouache

Dedication

As I approach the end of my studies, it gives me great pleasure to dedicate this modest work to:

My beloved mother, without her I would be nothing, who always gives me hope and never ceases to sacrifice herself for me so that I can succeed in life.

To my dearest Dad.

Aimen Djafri

Abstract :

Hydraulic fracturing is a well stimulation technique used to enhance the production of oil and gas from reservoirs, but in under-pressured reservoirs the natural pressure of the rock is insufficient to push hydrocarbons towards the wellbore. This work aims to study the performance of methanol hydraulic fracturing treatment in Hassi Messaoud field. A drop in the fracturing fluid viscosity was observed. The results show that the production index (IP) has improved after the operation, Although only 2% of the required amount of methanol is used (Q=3.52 m^3/h).

Keywords: Hydraulic fracturing, Stimulation, Viscosity, Under-pressured reservoirs.

Résumé :

La fracturation hydraulique est une technique de stimulation des puits utilisée pour améliorer la production de pétrole et de gaz à partir des réservoirs, mais dans les réservoirs à faible pression ou la pression naturelle de la roche est insuffisante pour pousser les hydrocarbures vers le puits de forage. Ce travail vise à étudier les performances du traitement de fracturation hydraulique au méthanol dans le champ de Hassi Messaoud. Une baisse de la viscosité du fluide de fracturation a été observée. Les résultats montrent que l'indice de productivité (IP) s'est amélioré après l'opération, même si seulement 2 % de la quantité de méthanol nécessaire est utilisée (Q=3.52 m^3/h).

Mots-clés : La fracturation hydraulique, Stimulation, Viscosité, Réservoirs à faible pression.

ملخص:

التكسير الهيدروليكي هو تقنية لتحفيز الآبار تستخدم لتعزيز إنتاج النفط والغاز من الخزانات، ولكن في الخزانات ذات الضغط المنخفض، يكون الضغط الطبيعي للصخور غير كافٍ لدفع البترول و الغاز نحو حفرة البئر. يهدف هذا العمل إلى دراسة أداء معالجة التكسير الهيدروليكي بالميثانول في حقل حاسي مسعود. لوحظ انخفاض في لزوجة مائع التكسير، وأظهرت النتائج أن مؤشر الإنتاج قد تحسن بعد العملية، على الرغم من استخدام 2٪ فقط من الكمية المطلوبة من الميثانول (التدفق = 3.52 م^3/ ساعة).

كلمات مفتاحية: التكسير الهيدروليكي، تحفيز الآبار، اللزوجة، الخزانات ذات الضغط المنخفض.

VII. List of Abbreviations

$CaCO_3$: Calcium carbonate

$CaSO_4$: Calcium sulfate

$BaSO_4$: Barium sulfate

pH : Potential Hydrogen

S : Skin

Sp : Perforations skin

Sc : Pseudo skin

SRT : Step-up rate test

Cl : Chlorine

PIFB : Pump-in and flow-back

ISIP : Instantaneous Shut-In Pressure

HPG : Hydroxy Propyl Guar

HEC : Hydroxyethyl cellulose

CMHPG : Carboxy Methyl Hydroxy Propyl Guar

CMHEC : Carboxy Methyl Hydroxy Ethyl Cellulose

N_2 : Nitrogen

CO_2 : Carbon dioxide

KCl : Potassium Chloride

SEM: Scanning electron microscopy

LWC: Lightweight ceramic

VES: Viscoelastic Surfactant

NaAc: Sodium acetate

Hac: Acetic acid

Na S O: Sodium thiosulfate

Kv: Vertical permeability

LCP: Longest Casing Point

D2, ID, D1, R2: Reservoir strata

Pg: Gauge pressure

Lb: Pound

NWB: Near well bore

HPHT: High pressure high temperature

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Introduction

Optimal exploitation of underground oil and gas reserves requires maintaining high rates of oil production. The original structure of certain hydrocarbon reservoirs does not allow the exploitation of deposits. This is the case of shale reservoirs, compact reservoirs and reservoirs damaged by mineral and organic deposits during oil production. This leads to a significant reduction in the permeability and productivity of the well. This is why reservoir stimulation is necessary, particularly by hydraulic fracturing, with the aim of improving productivity or restoring the initial state of the rocks reservoirs, by creating a permeable drain extending as far as possible into the formation so as to facilitate the flow of fluid towards the bottom of the well.

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 fluid characteristics of Methanol are in some ways quite different from ge1led liquids. Methanol 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. These features were very helpful when completing wells in low-pressure zones (depleted reservoir) which is the case of our well study OMP-742.

The main purpose of hydraulic fracturing is to create a conductive path inside the reservoir

After a fracturing treatment a coiled tubing clean up is performed by injection of N2 to help the oil to push the fracturing gel outside the well

However, in the case of underpressurized reservoirs the fracturing treatment risks to be not efficient because of the absence of the high pressure for the flow back.

In addition to that the borate crosslinked gels which are known to be very damaging to the fracture and the reservoir are mostly used especially in HMD field

So how can the fracturing treatment be successful in such cases?

What will be the best fracturing fluid to avoid more damage and help in the flow back?

The aim of this work is to study the importance of using the conventional fluid adding Methanol. A field application consisting of a well was presented. This final brief consists of two parts:

- The theoretical part contains two chapters:

The first chapter provides general hydraulic fracturing fundamentals.

The second chapter provides the hydraulic fracturing in underpressuerized reservoir.

- The practical part is dedicated to the realization the hydraulic fracturing in underpressuerized reservoir using the Methanol.

Chapter I: Hydraulic Fracturing Fundamentals

I.1. Introduction

Formation damage is a challenging issue in oil and gas industry that may seriously affect the productivity of a reservoir during various phases of fluid recovery from the subsurface or causes a reduction in the injectivity of injection wells. where the pore space of formation is blocked near the wellbore.

However, there is no unified system that accurately quantifies the type of damage, its location and extent in the reservoir beyond the wellbore. This means that the design of appropriate stimulation treatments method for each well typically must be tailored to the conditions encountered and observed in a specific reservoir.

Its diagnosis require integration from the drilling time to the end point of the well, therefore controlling, prevention and effective treatments of the formation damage phenomena are the keys for optimum production strategies in oil and gas fields.

Hydraulic fracturing is one of the methods used to stimulate or improve fluid flow from rocks in the subsurface to the well. In brief, the technique involves pumping a water-rich fluid into a borehole at high pressure to create a conductivity path and increase the productivity of reservoirs.

I.2. Reservoir damage

Reservoir or formation damage is an undesirable operational problem that can occur during gas and oil recovery from reservoirs in different stages, including drilling, completion, production, hydraulic fracturing, and workover operations. Formation damage is a hot topic nowadays as more operating companies move to the exploitation of more challenging gas and oil reservoirs in tighter, deeper, and more depleted conditions.

The formation damage is categorized by the mechanism of its creation as either natural or induced. **[1]**

I.3. Types of damage

Production impairments can develop in the reservoir (in the near-wellbore area or at the perforations). Natural damage occurs as produced reservoir fluids move through the reservoir, while induced damage is the result of external operations and fluids in the well, such as drilling, well completion, workover operations or stimulation treatments. Some induced damage triggers natural damage mechanisms.

Natural damage includes phenomena such as fines migration, clay swelling, scale formation, organic deposition, including paraffins or asphaltenes, and mixed organic and inorganic deposition. Induced damage includes plugging caused by foreign particles in the injected fluid, wettability changes, emulsions, bacterial activity, and water blocks. Wellbore cleanup or matrix stimulation treatments are two different operations that can remove natural or induced damage. Selecting the proper operation depends on the location and nature of the damage. **[2]**

I.3.1. Natural damage

I.3.1.1. Fines Migration

Perhaps the most common mechanism, which refers to the movement of naturally existing, fine grained quartz or clay particles in the pore system because of high fluid shear rates. [3]

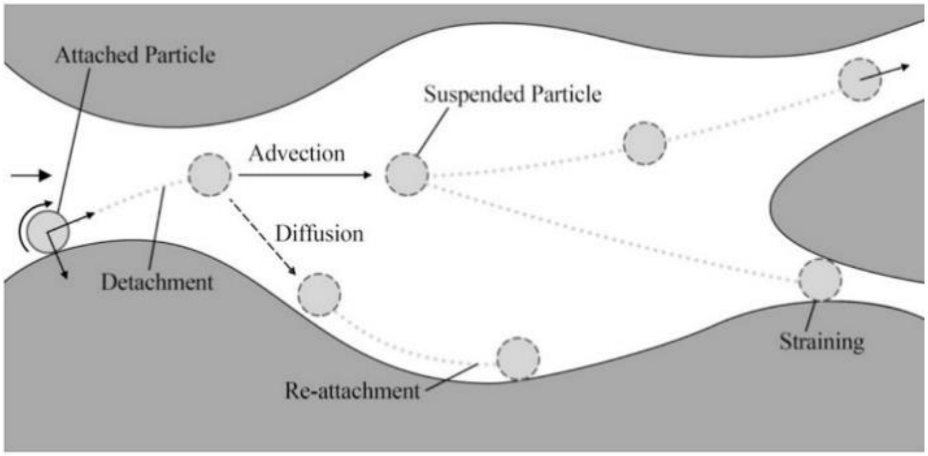


Figure I. 1: Migration of natural fine particles in the reservoir [3]

I.3.1.2. Clay Swelling

A type of damage in which formation permeability is reduced because of the alteration of clay equilibrium. Clay swelling occurs when water-base filtrates from drilling, completion, workover, or stimulation fluids enter the formation. Clay swelling can be caused by ion exchange or changes in salinity. However, only clays that are directly contacted by the fluid moving in the rock will react. **[4]**

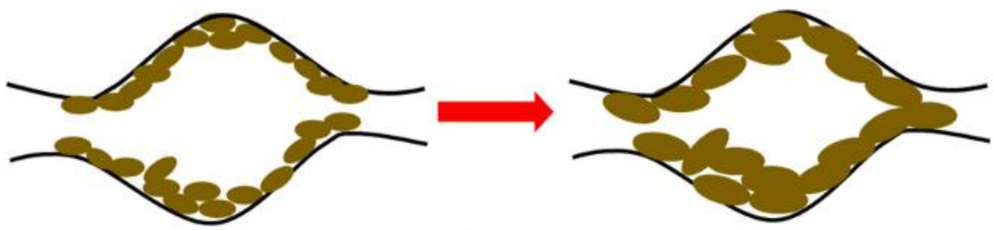


Figure I. 2: Formation damage mechanism caused by clay swelling [4]

I.3.1.3. Scale Formation

Mineral deposition in formation flow channels, on tubing, casing, and producing equipment has continuously plagued the oil industry. Compounds such as $CaCO_3$, $CaSO_4$ and $BaSO_4$ carried in the produced water may crystallize or precipitate because of a pressure drop, a temperature change or exceeding the solubility product. This scaling reduces and sometimes even stops oil production by plugging the formation, perforations or producing equipment. **[5]**

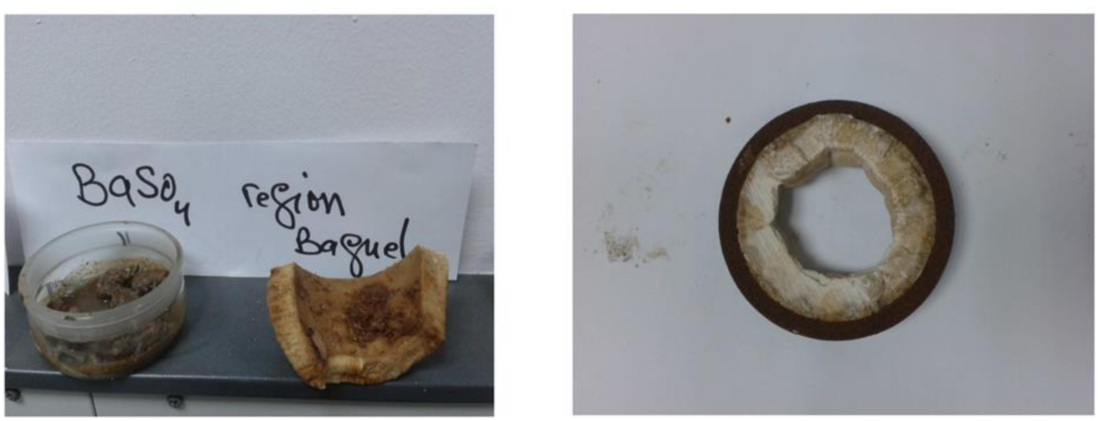


Figure I. 3: An example of barium sulfate scale [5]

I.3.1.4. Organic Deposits

a. Asphaltenes

Organic constituents of crude oils and bitumen, they are polycyclic aromatic compounds (composed of fused benzene rings) with aliphatic side chains containing nitrogen, Sulphur and oxygen compounds. Precipitation can occur anywhere in the reservoir due to changes in pressure, temperature or disturbances in chemical equilibrium, e.g. injection of extreme pH fluids. **[6]**

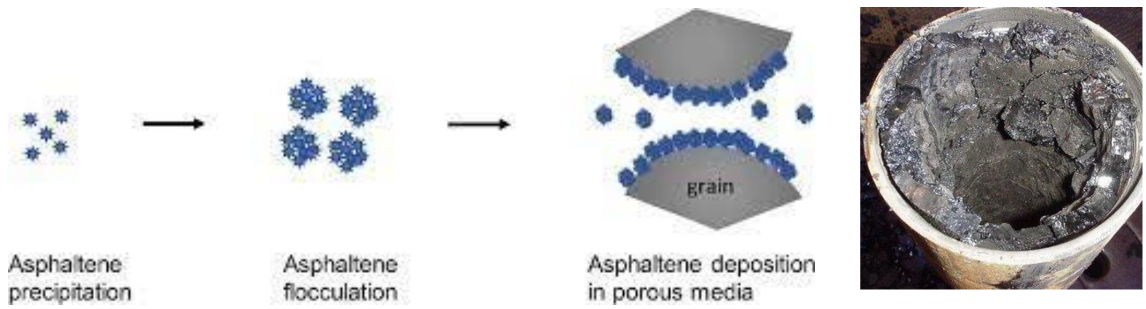


Figure I. 4: Formation damage mechanism caused by asphaltenes [6]

b. Paraffins

Paraffins consists primarily of long chain, saturated hydrocarbons (linear alkanes/ n-paraffins) with a minimum carbon chain lengths of 16 atoms. Paraffin can precipitate as a solid phase when fluid temperature drops below cloud point. **[7]**

Figure I. 5: An example of a paraffin [7]

I.3.2. Induced damage

I.3.2.1. Wettability Changes

A type of damage in which the formation wettability is modified, generating a change in relative permeability that eventually affects well productivity. Surfactants or other additives in drilling fluids, especially oil-base mud, or other injected fluids can change formation wettability. **[8]**

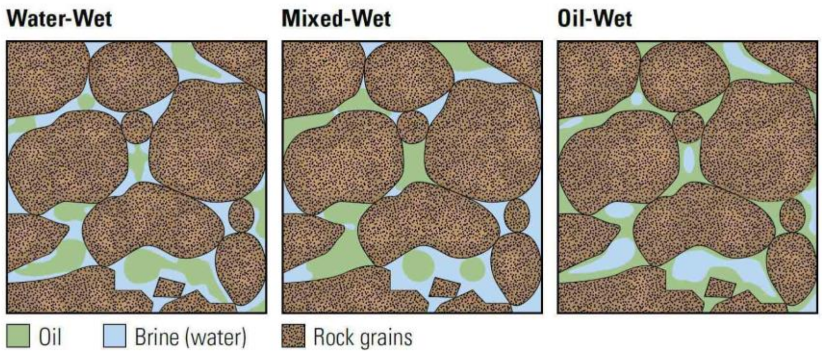


Figure I. 6: Illustration of wettability in rock pores [8]

I.3.2.2. Emulsions

A type of damage in which there is a combination of two or more immiscible fluids, including gas, that will not separate into individual components. Emulsions can form when fluid filtrates or injected fluids and reservoir fluids mix, or when the pH of the producing fluid changes, such as after an acidizing treatment. Emulsions are normally found in gravel packs and perforations, or inside the formation. **[9]**

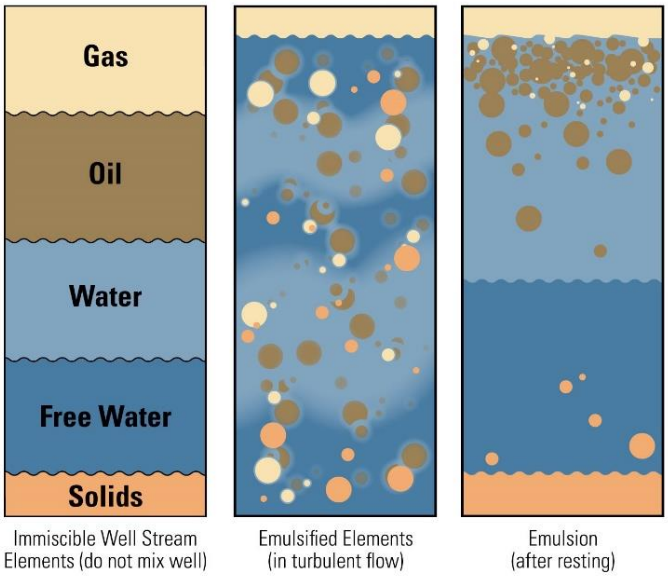


Figure I. 7: Illustration of oil emulsion [9]

I.3.2.3. Biological formation damage

Biological formation damage can occur when bacteria and nutrients are introduced into the formation. Bacterial contamination is most associated with water injection operations, such as fracture stimulation, also occur when drilling with water-base fluids. Biological mechanisms can be divided into three main categories: plugging, corrosion and toxicity. **[10]**

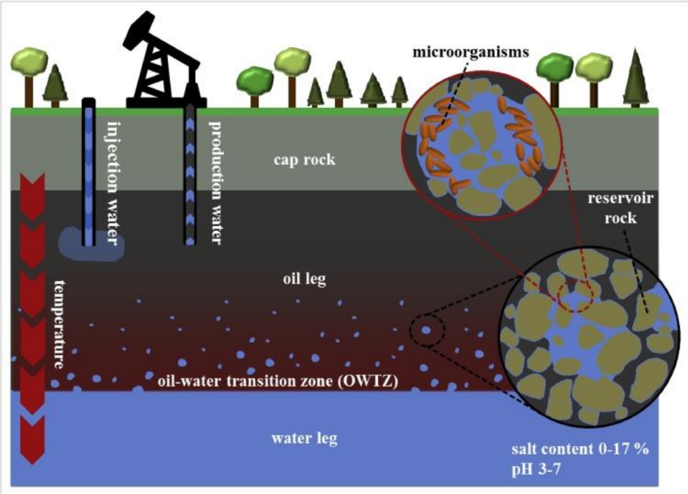


Figure I. 8: Schematic of a deep subsurface oil reservoir with underlying brine water [10]

I.3.2.4. Water Blocks

A production impairment that can occur when the formation matrix in the near-wellbore area becomes water-saturated, thereby decreasing the relative permeability to hydrocarbons. **[11]**

I.4. Skin

The skin is one of the damages that have in the hydrocarbon reservoir during its life. The "S" skin represents the degree of total damage to a well without differentiating matrix damage (which acidification can be a solution) from the secondary damage caused by the configuration of the well: the Pseudo-Skin.

It describes the changes in the area near the well. These changes are due to several problems that can be caused by virtually any oil activity, such as drilling, perforation and stimulation. The skin is a dimensionless factor that can be obtained from a well test, which reflects the bond between, the reservoir and the well.

The skin represents an additional pressure drop (ΔP_{skin}) located in the vicinity of the well.

The skin has several origins, the most important of which are:

Perforations: The model of the ideal well assumes that its contact with the formation extends over 360º, but with perforations it is conceivable that production is forced through the openings only. This results in a pressure drop which is translated into the skin S_p called the parietal effect coefficient and which is a function of the number of perforations, their distribution, and their penetration power.

Partial Penetration: Partial penetration is characterized by the fact that a well produces over a formation thickness less than the total exploitable height. This will be the case when one wants to protect against premature water or gas inflows, or when one is in the presence of a clay barrier. It contributes to the existence of a positive skin (pseudo skin Sc) which varies according to the thickness of the formation, the diameter of the well and the perforated height. Overall damage: In all cases, the additional pressure losses, located in the vicinity of the well (matrix), can be treated as a skin. So, the skin that will be measured during a test is a result of all these skins. **[12]**

The calculation of the skin gives three possibilities are:

$S > 0$: damaged reservoir

$S = 0$: normal productivity (or restored reservoir)

$S < 0$: stimulated well

I.5. Hydraulic fracturing treatment

Hydraulic fracturing is a well-stimulation technique used commonly in low-permeability rocks like tight sandstone, shale, and some coal beds to increase oil and/or gas flow to a well from petroleum-bearing rock formations. A similar technique is used to create improved permeability in underground geothermal reservoirs. **[13]**

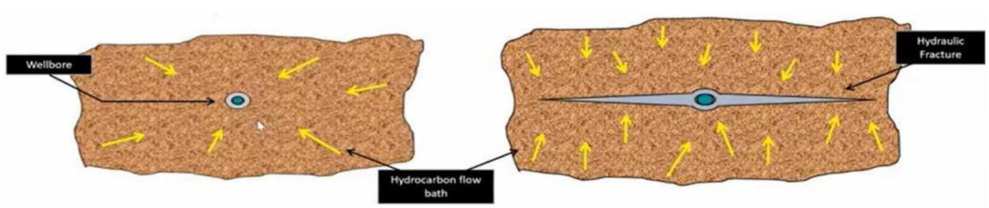


Figure I. 9: A schematic of a hydraulic fracture [13]

I.5.1. Process

Before initiating fracturing, the following points are aspects of well fracturing to consider:

-Type and volume of fluids used.

-Additives and propping agents.

- Technique and successive stages.
- Limits and variations of pressure and flow.
- Closing of the well then disgorging.
- Previous experience.
- Safety and environment standards.

After choosing the type of treatment and the well to be fractured, the operation takes place according to the following five steps:

- **Initiation of the fracture:**

We start with the injection of fracturing fluid at a fracturing rate. We increase the pressure exerting on the fluid to generate tensile stresses likely to initiate the fracture perpendicular to the plane of minimum horizontal stress.

- **Extension of the fracture:**

During this stage, the fracture extends more and more with the pumping of fluid under a flow greater than the filtration rate through the faces of the fracture. Above a critical depth (about 600 meters), the fracture develops generally in a horizontal plane according to a more or less circular radial geometry. In deep wells (beyond 1000 meters), the fracture develops in a plane vertical.

In the intermediate zones, the anisotropy of the formation plays a predominant role. for orientation of fracture development.

- **Proppants:**

They are often used in sandstone formations. They are mixed with the fluid of fracturing to keep the fracture open after stopping pumping at the end of treatment. Proppants should only be injected if the fracture reaches one dimension.

- **Closure of the well:**

This allows the excess pressure to filter out the fracturing fluid at through the walls of the fracture. It is necessary for treatments with agents of support, to allow the latter to be blocked in place before the well discharging.

- **Disgorging and production of the well:**

In this phase, the evacuation of treatment fluid, which remains in the fracture and which filters through its walls, is necessary.

I.5.1.1. Mini frac test

The various fracturing tests allow us to estimate a certain number of very important parameters concerning hydraulic fracturing such as the closing pressure, the filtration coefficient of the fracturing fluid, the efficiency of the operation.

The accurate estimation of these parameters leads us towards a reasonable estimate of the geometry of the fracture thus having a high chance of success and optimization of well treatment.

I.5.1.1.1. Micro fracture test

This test allows us to estimate the minimum horizontal stress in situ, a volume of fluid must be injected into the formation through a limited area (4 to 15ft) with a low flow rate (1 to 25 gal/min). The minimum stress is obtained from the analysis of the fracturing before and after the pumping.

The closing and opening pressure are the best approximation of the minimum stress.

I.5.1.1.2. Mini frac test process

The most important test currently before final processing is the mini frac test, there are three types of mini frac test which can give us very important information regarding the fracturing operation, the actual use of these tests remains a challenge because of the limited knowledge of validating the application techniques of each method.

a. Step-up rate test (SRT)

This test allows us to establish a profile of the extension of the fracturing pressure. An incompressible fluid (water at 2% Cl) is injected into the formation with a low flow rate similar to that of filtration, each flow rate is maintained for a few minutes until stabilization is obtained. (Figure I. 10) presents, the result of SRT giving the expansion pressure at an appropriate rate.

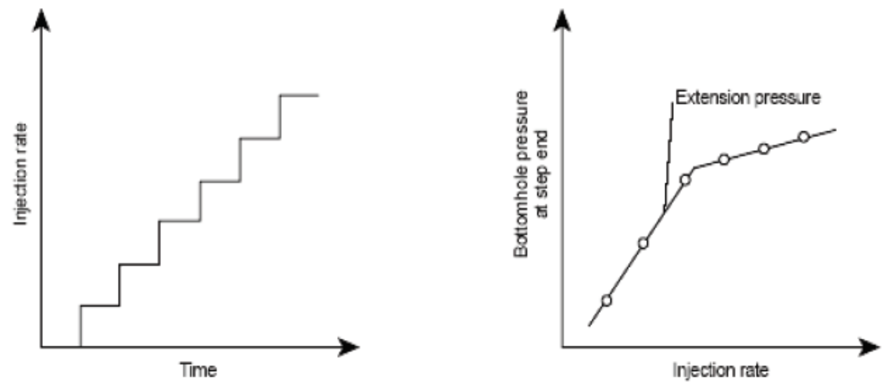


Figure I. 10: A Step-up rate test [14]

The SRT can give us an admissible injection rate for the final treatment with a comparable fluid or it allows us to estimate the hydraulic power required.

b. Pump in and Flow back test

This is a test that is used to determine the fracture closing pressure, it comes directly after the step rate test, requiring the use of the same fluid as the previous test.

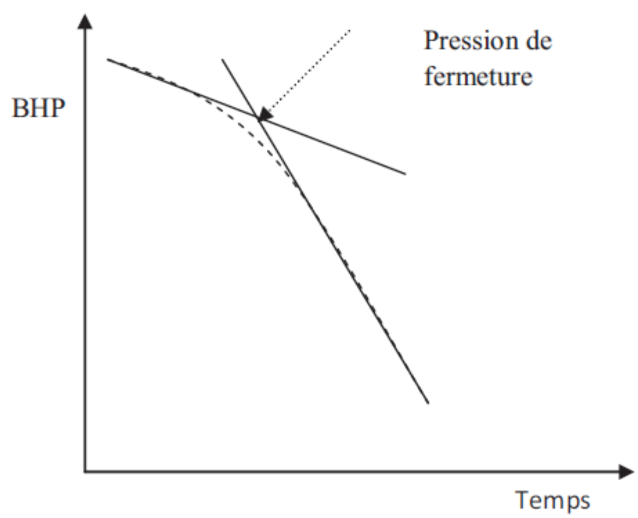


Figure I. 11: Estimation of the closing pressure from the flowback test [14]

c. Hut in test

This test is probably the most productive mini-frac test, during the test, a very large volume of fracturing fluid is injected at a desired flow rate for a specific time (2 to 20 min), after the injection the well will be closed for control the evolution on the surface, the primary information obtained using this test are:

• Fluid filtration: this parameter is obtained from the falloff part of the pressure curve for a desired geometry, the fluid used must be similar to that of the final treatment.

• The height obtained must be taken as the minimum height.

• Any significant deviation of frictional pressure in the ring finger and/or through the perforations indicates a possibility of fluid blockage at the perforations.

• Closing pressure is obtained from a plot of closing pressure as a function of square root of time. the inflection point of the pressure decay curve indicates the closure of the fracture, (see Figure I. 12)

The PIFB test is used to confirm ISIP results.

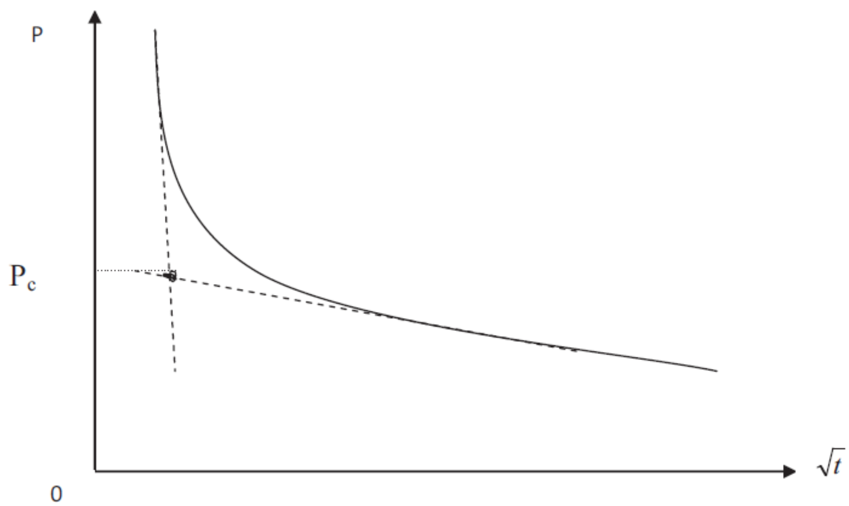


Figure I. 12: Closing pressure as a function of $t^{0.5}$ ***[14]***

I.5.1.1.3. Analysis of pressures during treatment

(Figure I. 13) represents a schematic curve of the pressure evolution during fracturing. It is divided into two parts:

• Injection part.

• Closing part.

The first part presents a peak followed by a plateau, which corresponds to the initiation point of the fracture and its propagation.

The second part begins with a sudden drop in pressure followed by stability. These correspond respectively to:

• Instantaneous Shut in Pressure (ISIP), due to stopping the pumps.

• Period of closure of the fracture. **[14]**

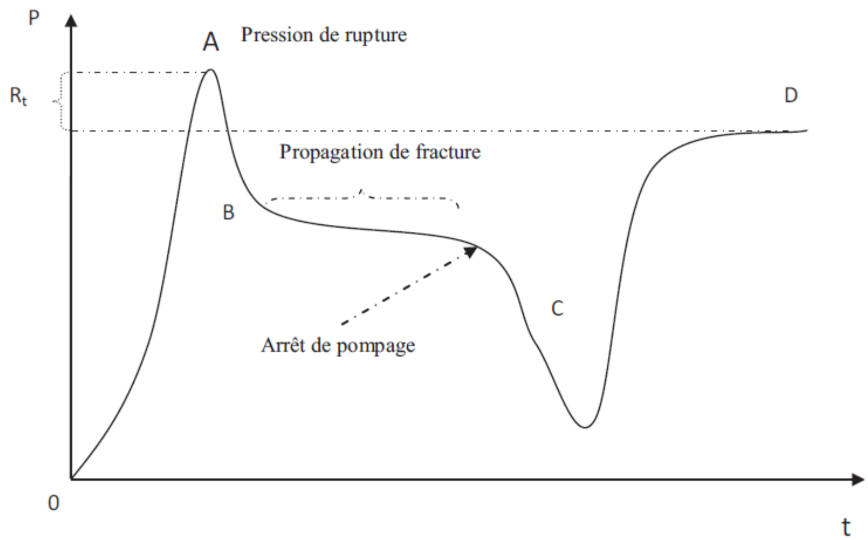


Figure I. 13: Spread of pressure [14]

I.5.2. Fracturing Fluid

Frac fluid is an essential component of hydraulic fracturing treatment. Its main functions are to open the fracture and transport the proppant along the entire length of the fracture. Therefore, the viscous properties of the fluid are generally considered to be the most important.

However, successful hydraulic fracturing treatments require the fluids to have other special properties. Besides exhibiting the proper viscosity in the fracture, it should break down and clean up quickly after processing is completed, provide good fluid loss control, exhibit low friction pressure during pumping, and be as eco-friendly as both economical and practical.

These fluids typically include gels, friction reducers, crosslinkers, breakers and surfactants; these additives are selected for their capability to improve the results of the stimulation operation and the productivity of the well. **[15]**

- Hydraulic fluid consists of **99.5% base stock with about 0.5% additives.**

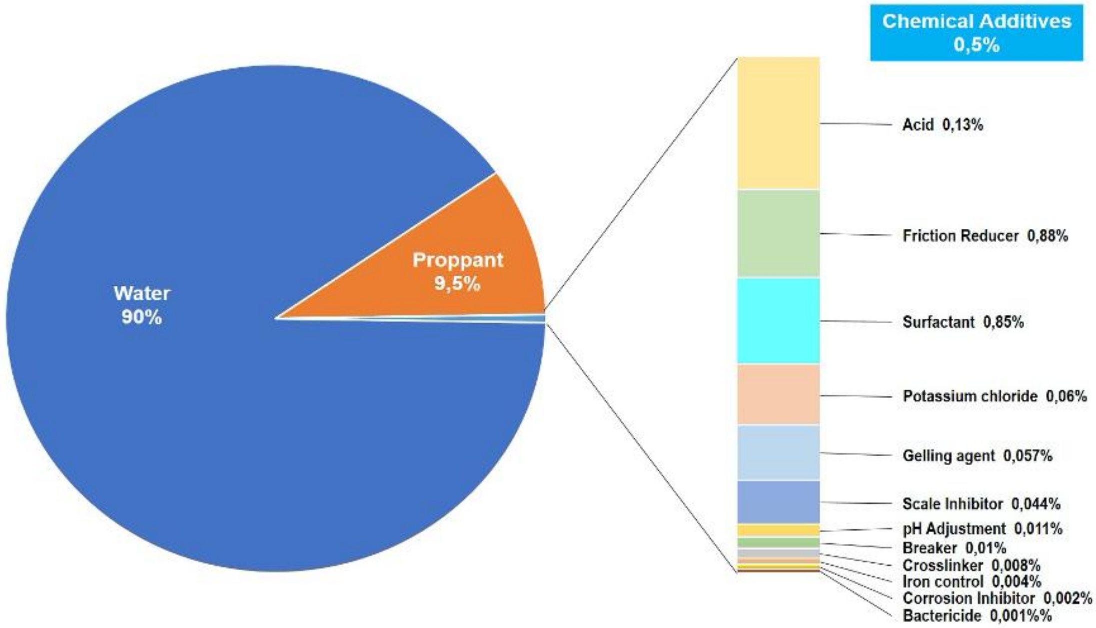


Figure I. 14: Volumetric composition of a fracturing fluids [16]

I.5.2.1. Properties of a fracturing fluid

The ideal fracturing fluid should:

- Be able to transport the propping agent in the fracture
- Be compatible with the formation rock and fluid
- Generate enough pressure drop along the fracture to create a wide fracture
- Minimize friction pressure losses during injection
- Be formulated using chemical additives that are approved by the local environmental regulations.
- Exhibit controlled-break to a low-viscosity fluid for cleanup after the treatment
- Be cost-effective. **[17]**

I.5.2.2. Types of fracturing fluid

The types of fracturing fluids available consist of:

Table I. 1: Fracturing fluids and conditions for their use [17]

Base fluid	Fluid type	Main composition	Used for
Water	Linear	Guar, HPG, HEC, CMHPG	Short fracture, low temperature
	Crosslinked	Crosslinker + Guar, HPG, CMHPG or CMHEC	Long fracture, high temperature
	Micellar	Electrolyte, Surfactant	Moderate length fractures, moderate temperature
Foam	Water based	Foamer + N_2 or CO_2	Low pressure formations
	Acid based	Foamer + N_2	Low pressure, carbonate formations
	Alcohol based	Methanol + Foamer + N_2	Low pressure, water sensitive formations
Oil	Linear	Gelling agent	Short fracture, water sensitive formations
	Crosslinked	Gelling agent + Crosslinker	Long fracture, water sensitive formations
	Water emulsion	Water + Oil + Emulsifier	Moderate length fractures, good fluid loss control
Acid	Linear	Guar or HPG	Short fractures, carbonate formations
	Crosslinked	Crosslinker + Guar or HPG	Longer, wider fractures, carbonate formations
	Oil emulsion	Acid + Oil + Emulsifier	Moderate length fractures, good carbonate formations

I.5.2.3. Proppant

Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore. **[18]**

I.5.2.3.1. Types of proppants

The most common types of proppants in Oil and Gas industry are **Sand, Ceramic and Resin Coated sand**. **[19]**

I.5.2.3.2. Proppant properties

Proppants have various physical properties. Some of the properties that commonly tested in laboratory and have impacts on proppant performance include grain size and grain size distribution, sphericity and roundness, crush resistance, density, turbidity, and acid solubility.**[17]**

I.5.2.3.3. Proppant size

Proppant particle (or grain) size is an important parameter for proppant evaluation and treatment designs, as it affects fracture conductivity and proppant transport. Grain size is measured in mesh size ranges. The mesh size is defined by the number of openings across one linear inch of screen. **[20]**

Commonly used proppant sizes include:

- 12/20
- 16/30
- 20/40
- 30/50
- 40/70

Figure I. 15: Different fracturing proppant size [20]

I.5.2.4. Additives

A wide variety of chemical additives are used in hydraulic fracturing fluids have been described in detail in the below table:

Table I. 2: Additives functions [21]

Additive	Function
Crosslinker	Used to link polymers or gelling agent to improve cohesion, adhesion, thermal stability and maintain fluid viscosity
Gelling Agent	Used to create a gel to suspend the proppant in the water and transport the proppant through the fracture
Scale inhibitor	Prevents scale deposits in the pipe
Corrosion inhibitor	Prevents the corrosion of the pipe
Acid	Help dissolve minerals and initiate cracks in the rock
Biocide	Eliminates bacteria in the water that produce corrosive byproducts
Gel Breaker	Allows a delayed break down of the gel polymer chains
pH Adjusting Agent	Maintains the effectiveness of other components, such as crosslinkers
Friction reducer	Minimizes friction between the fluid and the pipe
Iron controller	Prevents precipitation of metal oxides
Surfactant	Used to increase the viscosity of the fracture fluid
Clay stabilizer (KCl…)	Creates a brine carrier fluid

I.5.3. Fracturing Equipment

Hydraulic fracturing requires a number of expensive equipment such as high-pressure and high-volume fracking pumps, blenders for making the fracking fluids, and storage tanks. We look at the necessary machinery in detail below. **[22]**

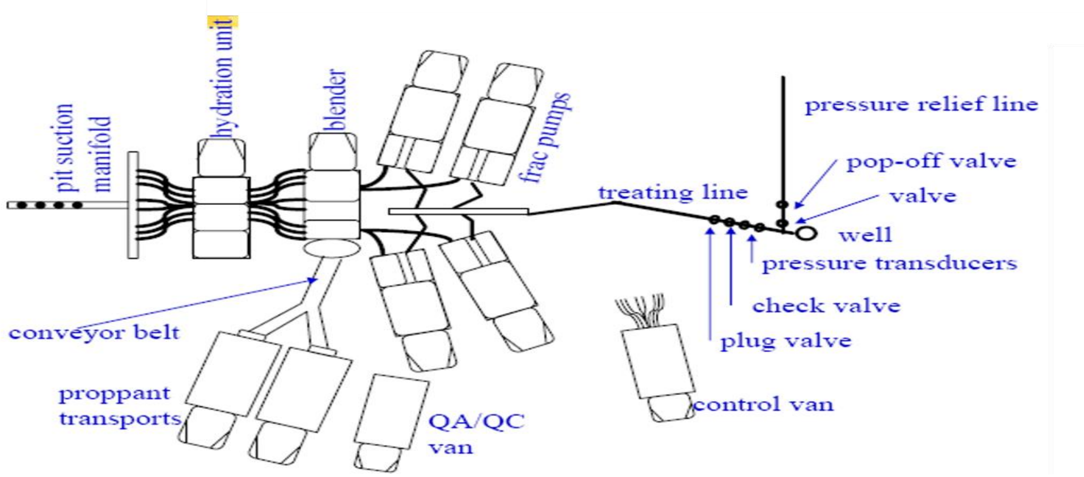


Figure I. 16: Fracturing equipment placement [22]

I.5.3.1. Hydration unit

Hydration units help prepare frac and other frac base fluids (gels) before transferring to the blender for cross-linking. These can operate as a standalone unit without a data van and control systems.

Figure I. 17: Hydration unit [22]

I.5.3.2. Blender

A diesel-engine-powered, truck-mounted machine helps in well acidizing and proppant blending. It can handle highly viscous fracturing fluids with high concentration proppants or low viscous fluids with low concentration proppants.

Figure I. 18: Blender [22]

I.5.3.3. Chemical Additive Unit

The chemical units help in continuously injecting the chemical additives that support the fracturing operations. They have multiple remote-controlled units and, if required, heated chemical tanks.

Figure I. 19: Chemical additive unit [22]

I.5.3.4. Proppant transport

The proppant transport is a track to store the different proppant size at the well site

Figure I. 20: Proppant transport [22]

I.5.3.5. Frac pumps

Mounted on a truck, trailer, or skid, hydraulic fracturing pumps are diesel-powered heavy-duty, high-pressure pumps. The pumping equipment helps in hydraulic and acid fracturing and solvent and liquid carbon dioxide pumping. They work well in different environments, be it desert, arctic, or tropic.

Figure I. 21: Frac pumps [22]

I.5.3.6. Hi/Lo Pressure manifold

A frac manifold is an arrangement of flow fittings and valves installed downstream of the fracturing pump output header and upstream of each frac tree being served.

Figure I. 22: Hi/Lo Pressure manifold [22]

I.5.3.7. Monitoring and control van

The mobile data acquisition system and control center with a high-performance computer system and control system helps monitor, display, record, and analyze pumping and well parameters. It is helpful during fracking, foamed cementing, acidizing, and other pumping operations.

Figure I. 23: Monitoring and control van [22]

I.5.3.8. Other Fracturing Machinery

Other machines include:

- Booster pump skids.
- Frac water tanks.

- Mono pump skids for chemical injection.
- Hydraulic power packs.
- Workshop containers.

I.5.4. Conclusion

Hydraulic fracturing is an important method used to overcome permeability restriction problems in oil and gas reservoirs, stimulating low permeability or damaged formations.

Chapter II: Hydraulic Fracturing in the Under-Pressurized Reservoirs

II.1. Introduction

Reservoir depletion is a complex issue with many contributing factors. By understanding these causes, the industry can work to develop more effective strategies for managing reservoirs and reducing the risk of depletion.

Ultimately, responsible management practices and a focus on sustainability will be crucial in ensuring the long-term viability of the oil and gas industry.

Hydraulic fracturing treatment is a method used to extract oil and gas from under pressured reservoirs in the oilfield. It involves injecting high-pressure water, sand, and chemicals into the wellbore to create fractures in the rock and release the trapped hydrocarbons.

In under pressured reservoirs, the natural pressure of the rock formation is not sufficient to push the oil and gas to the surface. As a result, hydraulic fracturing treatment is necessary to increase the flow of hydrocarbons and improve the overall production of the well. **[24]**

II.2. Challenges of Underpressurized Reservoirs

Underpressurized reservoirs present several challenges for hydraulic fracturing. The lower fluid pressure means that it is harder to create fractures in the rock, and the fractures that are created may not be as extensive as those in higher-pressure reservoirs.

In addition, the lower fluid pressure can make it more difficult to control the direction of the fractures. This can result in fractures that extend beyond the target area, potentially causing damage to nearby wells or even the environment. **[24]**

II.3. Techniques for Hydraulic Fracturing in Underpressurized Reservoirs

To overcome the challenges of underpressurized reservoirs, hydraulic fracturing companies have developed a range of techniques and technologies. One approach is to use specially designed drilling equipment that can handle lower fluid pressures and create more precise fractures. **[24]**

II.4. Hydraulic fracturing in under-pressurized reservoirs

Under pressured reservoirs are becoming increasingly important sources of oil and gas due to the depletion of traditional high-pressure reservoirs

However, these low-pressure reservoirs require additional stimulation to release the trapped hydrocarbons, which is where hydraulic fracturing comes in.

Hydraulic fracturing treatment is necessary in these types of reservoirs to increase the flow of hydrocarbons and improve the overall production of the well. By creating fractures in the rock and increasing the permeability of the reservoir, more oil and gas can be extracted than would be possible with conventional drilling methods. **[24]**

II.5. Causes of reservoir depletion

Reservoir depletion is a major concern in the oil and gas industry. It occurs when the amount of oil or gas extracted from a reservoir exceeds the rate at which it can be replenished. This can lead to reduced production, increased costs, and even permanent damage to the reservoir. We will explore some of the main causes of reservoir depletion and their impact on the industry.

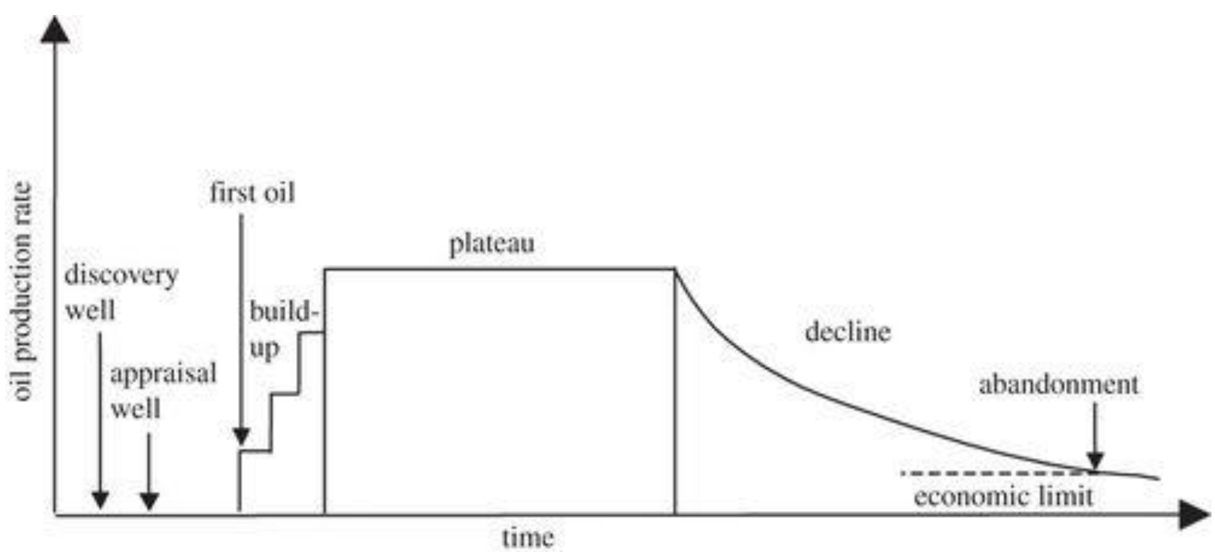


Figure II. 1: Idealized production behavior of an oilfield [25]

II.5.1. Natural depletion

One of the primary causes of reservoir depletion is natural depletion. Over time, the pressure within the reservoir decreases as oil and gas are extracted. As the pressure drops, the amount of oil and gas that can be produced decreases as well.

This natural depletion can be exacerbated by factors such as the permeability of the rock surrounding the reservoir, the viscosity of the oil, and the temperature of the reservoir. These factors can all contribute to a faster rate of depletion. **[25]**

II.5.2. Overproduction

Another cause of reservoir depletion is overproduction. When oil and gas prices are high, there is often pressured to extract as much as possible from a reservoir in a short amount of time. This can lead to overproduction and a faster rate of depletion than would occur naturally.

Overproduction can also lead to other problems, such as water or gas breakthrough. This occurs when water or gas from surrounding areas begins to flow into the reservoir, reducing the amount of oil and gas that can be produced. **[25]**

II.5.3. Poor reservoir management

Poor reservoir management is another cause of depletion. This can include factors such as inadequate monitoring of production rates, improper well spacing, and failure to implement secondary recovery methods such as water flooding.

In some cases, poor reservoir management can even lead to permanent damage to the reservoir, making it impossible to extract any more oil or gas. This can have serious financial and environmental consequences. **[25]**

II.5.4. Geological Factors

Geological factors can also contribute to reservoir depletion. For example, faults or fractures in the rock surrounding the reservoir can allow oil and gas to escape more quickly than anticipated.

Additionally, geological factors such as the presence of natural gas or high levels of sulfur can make it more difficult to extract oil from the reservoir, leading to a slower rate of production and increased risk of depletion. **[25]**

II.6. Gel Damage

Numerous studies have been conducted on the impact of the gel filter cake and residue on conductivity. For example, (Figure II. 2) shows an SEM of a proppant pack that was tested under simulated treatment conditions with a fracturing fluid. The left side of the figure shows gel damage concentrated at the interface with the sandstone platens. The right side of the figure shows gel residue within the proppant pack. **[26]**

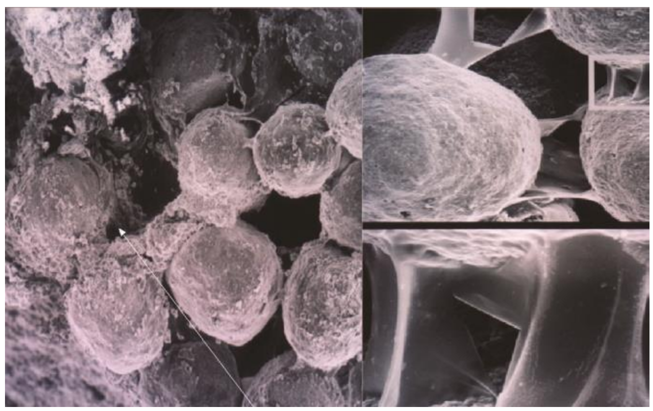


Figure II. 2: Fracture fluid damage in the proppant pack [26]

It is important to also realize the impact of different proppant types on the cleanup of fracturing fluids. Figure 8-51 shows the cleanup effects of the same borate crosslinked guar fluid with three mesh distributions of proppant: 20/40 mesh lightweight ceramic (LWC) and 20/40 and 40/60 mesh Ottawa Sand. There is a 250% difference in pressure required to initiate cleanup of the broken gel between the narrowly sieved LWC proppant compared to the more broadly sieved, angular 20/40 mesh sand. As average proppant diameter and pore throat size are reduced in going to a 40/60 mesh proppant there is a similar increase in required differential pressure.

The consequence of this, is that although the retained permeability of the LWC is close to 70% of the undamaged value, it is reduced to around 50% for the sand proppants. **[26]**

II.7. Fracturing Fluid Selection

Fracturing fluid selection based on laboratory generated data has been detailed. A flowchart is used to illustrate the overall procedure. The procedure utilizes mineralogical evaluation using x-ray diffraction analysis and scanning electron microscopy of the formation core to understand potential sensitivities of the formation material to fracturing fluids. The mineralogical evaluation is designed to identify the appropriate fluid system to be tested under flow conditions with the core. These tests require some time and may follow immersion testing and/or capillary suction time testing. Immersion testing of rock chips and capillary suction time testing are used to screen fluids.

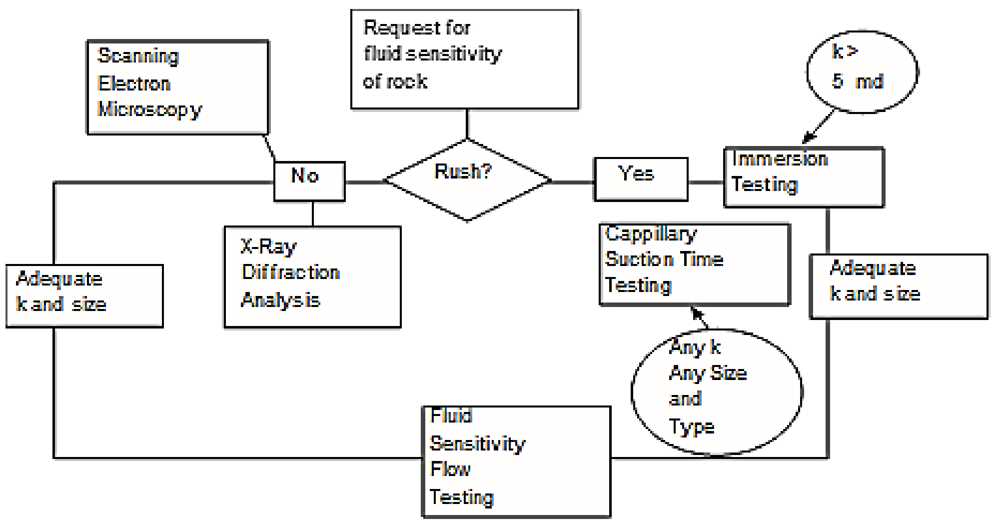


Figure II.3: General procedures for determining sensitivity of formation rock to fracturing fluids

If sensitivity evaluation is required rapidly, immersion testing and/or capillary suction time testing provide valuable results. Flow testing of core plugs is the final step in determining if systems cause minimal damage to the formation. Plugs must be of adequate size and adequate permeability for meaningful flow testing.

II.8. Type of fracturing fluids

II.8.1. Water-based fluids

Because of their low cost, high performance, and ease of handling, water-based fluids are the most widely used fracturing fluids. Many water-soluble polymers can be used to make a viscosified solution capable of suspending proppants at room temperature. **[26]**

a. Guar gum

Guar gum was one of the first polymers used to viscosity water for fracking. Guar is a long- chain, high molecular weight polymer composed of the sugar's mannose and galactose. Polymers composed of sugar units are called polysaccharides. **[26]**

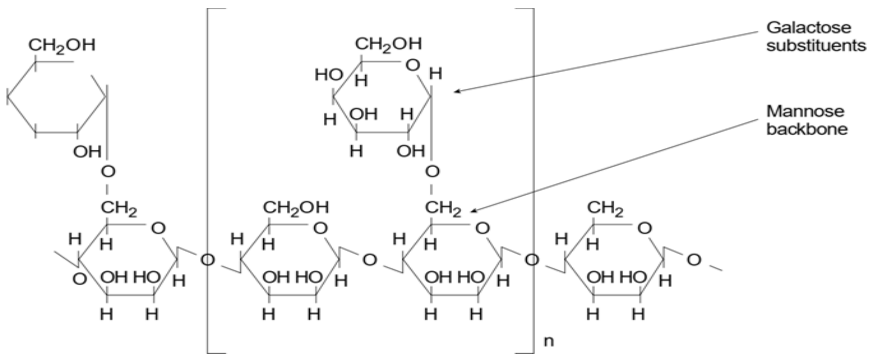


Figure II. 4: Structure of Guar [26]

Recent studies on Guar indicate that the arrangement of galactose units may be more random, with galactose appearing on two or three consecutive mannose units. In addition, the ratio of mannose to galactose can vary from 1.6:1 to 1.8:1. Up to 6-10% insoluble residues may be present in guar fluids.

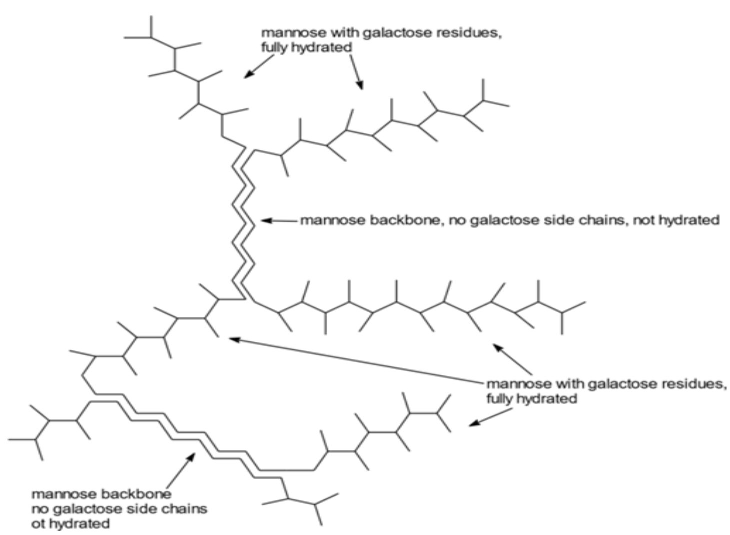


Figure II. 5: Proposed structure of a galactomannan gel in aqueous solution

Once the particles come into contact with the aqueous phase, they absorb water and swell. In the case where the individual particles are not well separated, only the outside of the cluster begins to hydrate, preventing the inner particles from contacting the water.

b. Hydroxypropylguar (HPG)

The derivatization of guar to form hydroxypropyl guar (HPG) is done by reacting the sugar hydroxyls with caustic and propylene oxide. This reaction converts some of the OH sites to -O-CH2- CHOH-CH3, thereby eliminating some of the crosslinking sites.

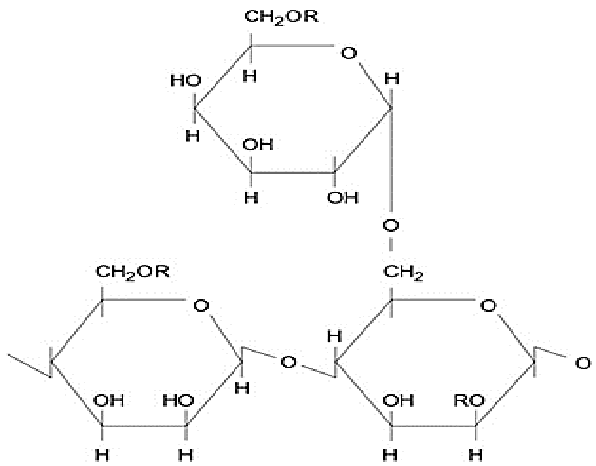


Figure II. 6: Repeated unit structure of hydroxypropylguar (R-CH2-CHOH- CH3) [26]

Further processing and washing removes much of the plant material from the polymer, so HPG typically contains only about 2-4% insoluble residue.

HPG was once considered less damaging to the formation front and proppant pack than guar.

c. Carboxymethylhydroxypropylguar (CMHPG)

Another guar derivative used in recent years is carboxymethylhydroxypropylguar (CMHPG). Treatment of guar with propylene oxide followed by chloroacetic acid yields CMHPG, which is more soluble than HPG and contains fewer insoluble contaminants (about 1% by weight).

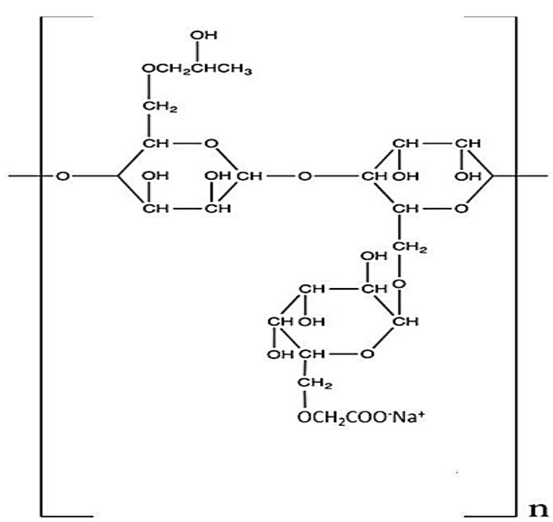


Figure II. 7: Carboxymethylhydroxypropyl Guar (CMHPG) [26]

More recently, CMHPG has been cross-linked with a Zr cross-linker to produce fluids with higher viscosity at high temperatures than those made with comparable amounts of HPG.

d. Cellulose derivatives

Cellulose derivatives have been used occasionally in fracturing fluids. Hydroxyethyl cellulose (HEC) or hydroxypropyl cellulose (HPC) are used when a very clean fluid is desired. These polymers have a backbone composed of glucose sugar units.

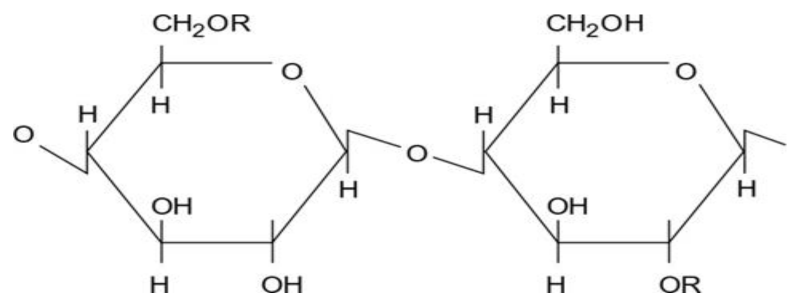


Figure II. 8: Structure of the hydroxyethyl cellulose repeat units [26]

Guar contains hydroxyl pairs that are positioned on the same side of the sugar molecule (cis orientation). In HEC, the OH groups are on adjacent carbons, but they are on opposite sides of the ring (trans orientation).

e. Xanthan gum

Another type of polymer is xanthan gum. Xanthan is a biopolymer, produced metabolically by the microorganism Xanthomonas campestris. Xanthan solutions behave as power law fluids even at low shear rates whereas HPG solutions become Newtonian.

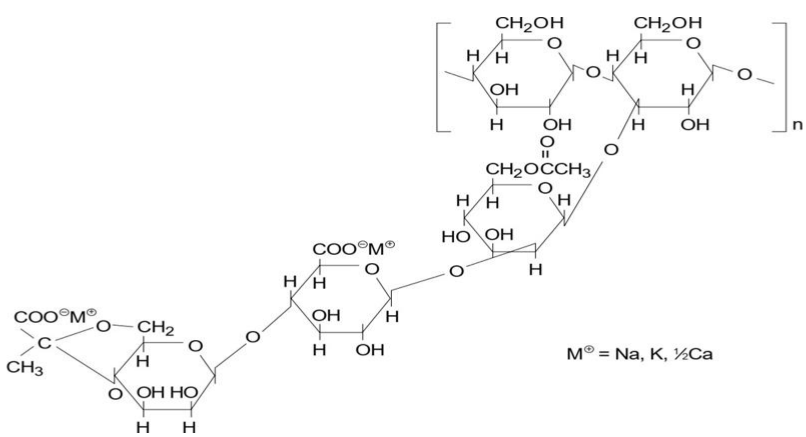


Figure II. 9: Structure of xanthan gum repeat units

f. Water-based, polymer-free fracturing fluids

Water-based, polymer-free fracturing fluids can be prepared using viscoelastic surfactants (VES).

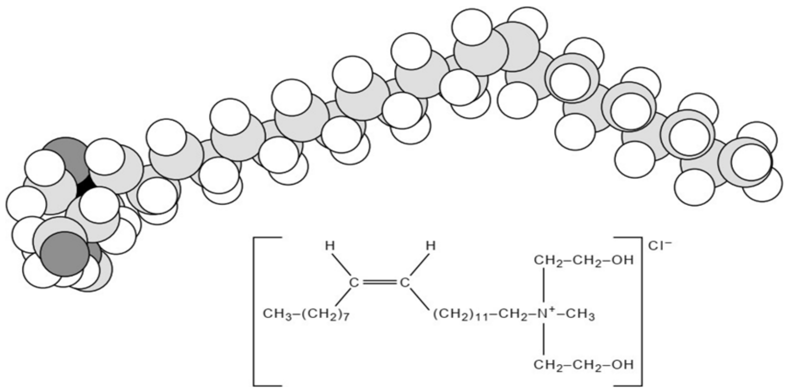


Figure II. 10: Molecular and structural formulas of a viscoelastic surfactant thickener

These surfactants consist of two regions: the head group is the quaternary ammonium portion of the molecule, and the tail group is the long chain hydrocarbon portion of the molecule. The head group is hydrophilic. The tail group is hydrophobic. When the surfactant is added to water, the molecules associate in structures called micelles.

The typical retained permeability of proppant packs treated with VES fluid systems is >95%. VES systems can also be foamed with nitrogen. No additional foaming agent is required.

II.8.2. Oil-based fluids

Oil-based fluids are expensive to use and operationally difficult to handle. As a result, they are now only used in formations known to be extremely water sensitive.

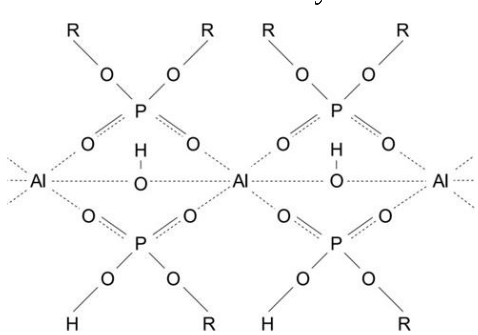


Figure II. 11: Proposed polymer chain structure of aluminum phosphate ester [26]

The R groups shown in (Figure II. 11**)** are hydrocarbon chains that must be soluble in the oil to be gelled. The soluble R groups keep the aluminum phosphate ester polymer in solution.

Some high molecular weight compounds, including kerosene and asphaltenes, are not compatible with the aluminum phosphate gelling system.

II.8.3. Acid-based fluids

Acid fracturing is a well stimulation process in which acid, usually hydrochloric acid (HCl), is injected into a carbonate formation at sufficient pressure to fracture the formation or open existing natural fractures. As the acid flows down the fracture, portions of the fracture face are dissolved.

Because the flowing acid tends to attack non-uniformly, conductive channels are created that typically remain in place as the fracture closes.

II.8.4. Multi-phase fluids

Foams are created by adding gas to the fluid. Emulsions are created by mixing oil and water. The different systems are described in this section:

a. Foams

A foam is a stable mixture of liquid and gas. To make this mixture stable, a surface-active agent (surfactant) is used. The surfactant stabilizes the thin liquid films and prevents the cells from coalescing.

The pressurized gas (nitrogen or carbon dioxide) in a foam expands when the well is forced back and forces the liquid out of the fracture. In addition, the liquid phase is minimal because foams contain up to 95% gas by volume. In the case of a water-based fluid, foaming the fluid significantly reduces the amount of liquid in contact with the formation. Therefore, foams work well in water sensitive formations.

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

Foams are described by their quality:

$$Quality\ of\ m = \frac{Volume\ of\ gas}{Volume\ of\ foam} \times 100 \qquad II.1$$

Below 52%, a stable foam does not exist because there are no bubble/bubble interactions to provide resistance to flow or separation by gravity. Above 52% gas, the gas concentration is high enough that the surfaces of the bubbles touch.

b. Emulsions

An emulsion is a dispersion of two immiscible phases. Emulsion-based fracturing fluids are highly viscous solutions with good transport properties. The higher the percentage of the internal phase, the greater the resistance to droplet movement, resulting in higher viscosity.

II.9. Fracturing fluid additives

II.9.1. Cross-linking agent

Several metal ions can be used to crosslink water-soluble polymers Borate compounds, Ti , Zr, and Al are frequently used crosslinkers. Borate compounds and transition metal complexes react with guar and HPG via cis-OH pairs on the galactose side chains to form a complex. **[26]**

a. Borate crosslinker

One of the simplest crosslinkers, borate ion, is used to produce highly viscous gels with guar and HPG that can be stable above 300°F. At a higher pH

The borate ion $B(OH)_4^-$ is considered as the cross-linking species.

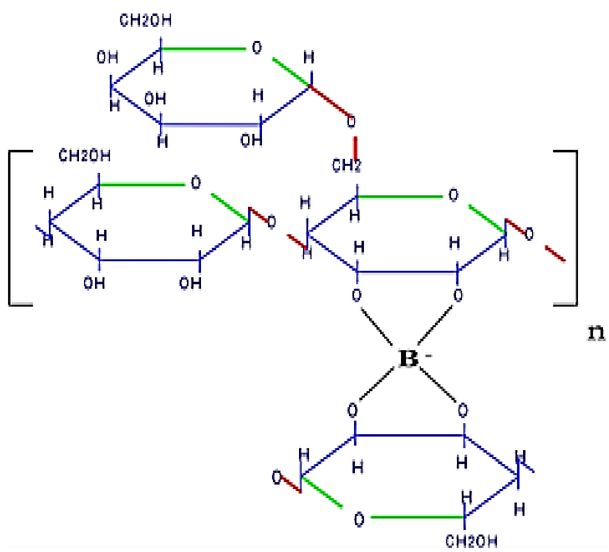


Figure II. 12: Proposed cross-linking mechanism [26]

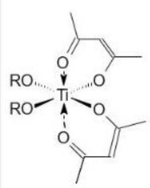
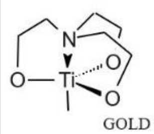
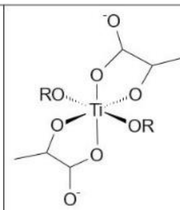
Borate cross-linking is reversible; cross-links form and then break, only to reform again. If the polymer is not thermally degraded, this reversible behavior continues to adapt to changes in shear rate or temperature.

b. Transition metal crosslinkers

Transition metal crosslinkers have been developed for high temperature applications and/or low pH environments. Titanium and zirconium complexes have been used most frequently because of their affinity to react with oxygen functionalities (cis-OH and carboxyl groups), their stable +4 oxidation states, and their low toxicity.

The transition metal-polymer bond is sensitive to shear. High shear irreversibly degrades transition metal-crosslinked fluids. The (Figure II. 14) shows three of the most commonly used titanium complexes; the respective zirconium complexes may have similar structures.

Table II.1: Examples of complexed titanate cross-linking agents [26]

		
Tyzor AA = acetylacetonate titanate	Tyzor TE = triethanolamine titanate chelate	Tyzor LA = lactic acid titanate chelate, usually available with ammonium NH4+ or sodium Na+ or potassium K+ as counterion

II.9.2. Frost Breakers

Gel breakers are used to reduce the viscosity of the fluid mixed with the proppant. The breakers reduce the viscosity by splitting the polymer into low molecular weight fragments. Increasing the concentration of polymer results in a significant increase in viscosity. For example, the viscosity of an unbroken guar fluid containing polymer at 200 lb/1000 gal (20 lb/1000 gal) concentrated 10 times due to fluid loss.

Ideally, a gel breaker introduced into the fluid at the surface should have minimal effect on the gel until pumping ceases (and the fracture closes) and should then react quickly with the gel. **[26]**

a. Oxidizer

Oxidizing breakers are widely used in fracturing applications. The process by which the oxidant acts is the release of free radicals that act on sensitive bonds or oxidizable sites.

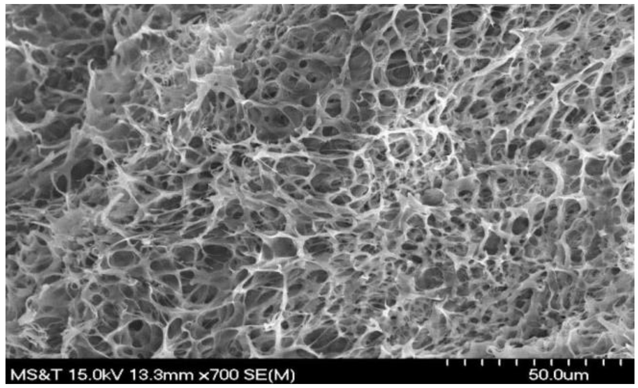


Figure II. 13: Structure of RPPG before degradation [26]

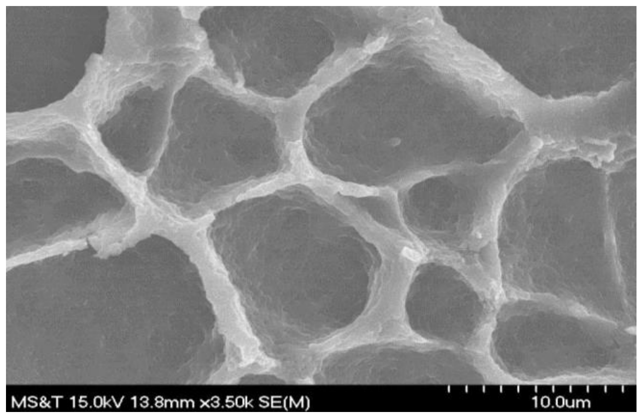


Figure II. 14: Structure of RPPG after degradation [26]

The most common oxidizing breakers are the ammonium, potassium, and sodium salts of peroxydisulfate. Thermal decomposition of peroxydisulfate produces highly reactive sulfate radicals that attack the polymer, reducing its molecular weight and viscosity capacity:

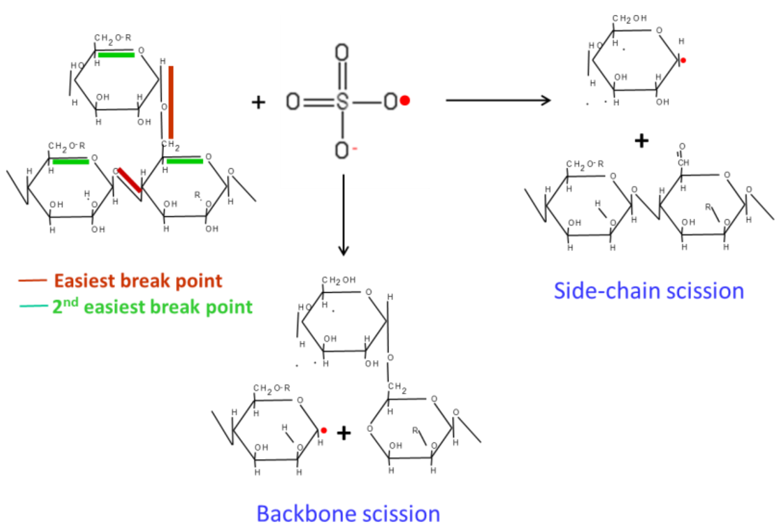


Figure II. 15: Chemistry of polymer cleavage [26]

b. Enzyme breakers

Enzymes are large, highly specialized proteins produced by organisms and consisting of long- chain amino acids linked by peptide bonds. Enzymes can be considered environmentally friendly because they are non-toxic and can be easily broken down and reabsorbed into the environment.

II.9.3. Buffer

For proper polymer dispersion and hydration, the pH of the mixing water must be carefully controlled. The final pH of the fluid also influences the cross-linking reactions as specified in the following sections.

Buffers maintain the pH value within a defined region, which depends on the system used. A buffer consists of a salt of a weak acid with its corresponding acid, for example sodium acetate (NaAc) and acetic acid (HAc), or alternatively a salt of a weak base and its corresponding base. Buffers can be used at any pH on the pH scale. **[26]**

II.9.4. Bactericides

Biocides are used to kill bacteria. Bacteria like to feed on natural polymers present in fracturing fluids. They can therefore reduce the viscosity of the fracturing fluid and cause it to lose its ability to carry proppants.

In addition, bacteria can also cause reservoir fluids to produce hydrogen sulfide and become acidic, which can be a huge problem. For this reason, biocides are added to fracking fluid mixing tanks. **[26]**

II.9.5. Stabilizers

Stabilizers are used to prevent degradation of polysaccharide gels at temperatures above 200°F. Common stabilizers are methanol and sodium thiosulfate (Na S O). 223 Sodium thiosulfate is typically used at 10 to 20 lbm/1000 gal. Sodium thiosulfate is the more effective of the two, increasing viscosity at elevated temperatures by a factor of 2 to 10. **[26]**

II.9.6. Clay stabilizers

Clay stabilizers are salts such as ammonium chloride or potassium chloride, added to water- based fracturing fluids to prevent swelling of water-sensitive, i.e., formations that contain clays that can be mobilized by water. **[26]**

II.9.7. Surfactants

Surfactants are used to reduce surface and interfacial tensions and modify the wettability of fluids to facilitate their recovery in the formation.

Reducing the interfacial tension between reservoir fluids and water prevents the formation of emulsions and reduces permeability. Changing the wettability of the fracturing fluid, by changing its filtration contact angle in the formation, facilitates flowback. **[26]**

II.10. Rheology of the fracturing fluid

The requirements for fracturing fluids are to develop sufficient viscosity at the time and temperature of exposure to create a fracture geometry and carry the proppant along the fracture, have a controllable viscosity during and after working (fracture profile), low friction in the tubulars during pumping, good fluid filtration property, be compatible with formation and completion fluids, less expensive and environmentally friendly. **[27]**

II.10.1. Viscosity of the fracturing fluid

Viscosity is a measure of a fluid's resistance to deformation under an applied force or pressure. Most fracturing fluids are non-Newtonian fluids, which means that their viscosity depends on the shear rate. The rheology of fracturing fluids is defined by the power law model, illustrated in the equation: $\boldsymbol{\tau = K\gamma^n}$

Where τ is the shear stress in units of lbf/ft^2, γ is the shear rate in sec-1, K is the consistency index in units of lbf-sec $/ft^{n2}$ and n is the dimensionless flow behavior index.

The values of n and K are calculated by plotting a log-log graph (Figure II. 18) of shear stress versus shear rate. **[27]**

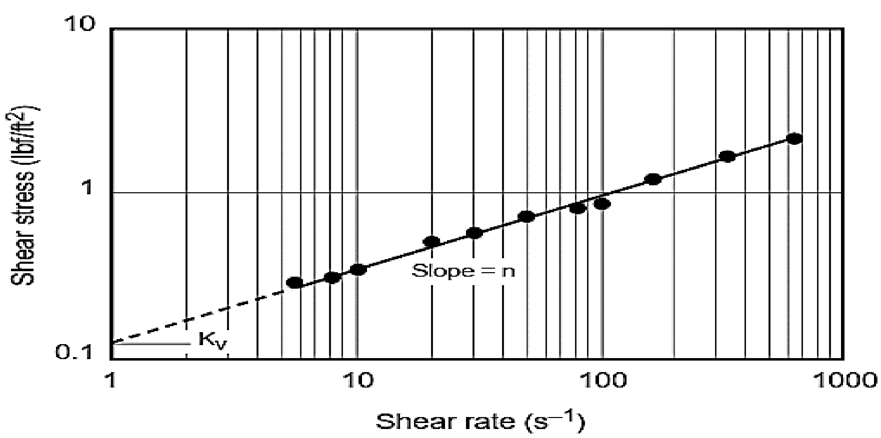


Figure II. 16: Determination of power law coefficients from capillary viscometer data [27]

Fluid properties are usually measured using rotary viscometers with cylindrical geometry. Thus, the parameters obtained depend on the geometry and are represented by n' and Kv. These parameters were calculated for all viscosity tests performed in this study.

$$\mu_a = \frac{K}{\gamma^{1-n}} \qquad II.2$$

The slope of the straight-line part is equal to the behavior index n, and the value of τ at $\gamma = 1.0$ s-1 is equal to the coherence index K. A log-log plot of μ_a as a function of γ has a straight-line slope of n - 1 when the power-law model is applicable according to the Eq.

II.10.2. Shear rate (γ)

In fluid mechanics, shear rate is a measure of the rate at which a fluid flows past a fixed surface. Shear rate can be thought of as a measure of the agitation of a fluid.

II.10.3. Shear stress (τ)

Shear stress is the resistance the fluid offers to an applied shear rate. For example, it takes more force (or pressure) to pump water at 20 bpm than at 10 bpm.

II.10.4. Behavior index (n')

It describes the degree of deflection of Newtonian fluids, n' is equal to the slope of the straight line on the log-log plot and is dimensionless. Most fracturing fluids are pseudoplastic when n'<1 and it influences the flow profile inside a pipe.

II.10.5. Consistency index (K')

K' can be found at the intersection between the straight line and the Y-axis on the log-log graph. This value gives an indication of the viscosity of the fluid and its unit of measurement is $lbf/sec/ft^{n2}$.

II.10.6. API RP 39 Viscosity test

Rheological tests such as API RP 39 are designed to characterize fracturing fluids under downhole conditions within the fracture (time, temperature, and shear rate) to determine engineering parameters (known as the [n',k'] power law).

The shear rate on typical fracturing jobs varies from a few tens of s-1 to a few hundred s-1 as:

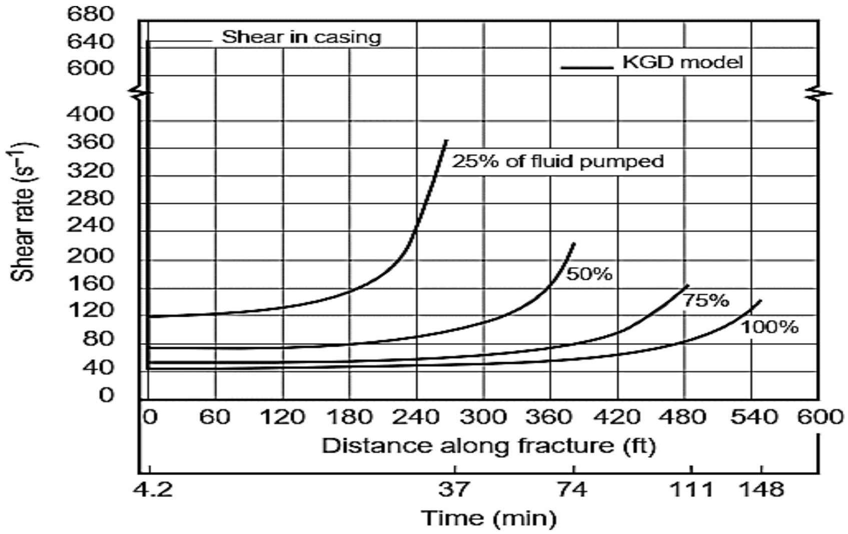


Figure II. 17: Shear rate profile during a fracture operation

The API assumes that:

- The sample temperature must reach the target (+/- 5 deg F) within 20 minutes of the test.

- Shear ramps should begin when the sample temperature reaches 90% of target or after the first 20 minutes.

- Shear ramps (nominal shear rate of 100s-1, 75s-1, 50s-1, 25s-1, 75s-1, 100s-1 blue dots) should be evenly spaced every 30 minutes with a constant shear rate of 100s-1 in between for the entire test.

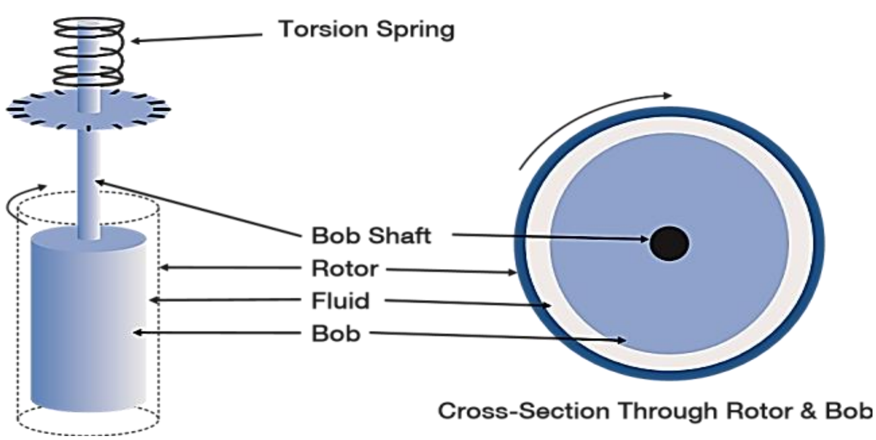


Figure II. 18: Schematic illustration of the rotor and coil configuration used to measure viscosity

Sometimes lower shear rates are used between shear ramps (40s-1 instead of 100s-1) with the argument that this is closer to reality, but this is to provide lower shear exposure to the fluid and achieve a higher viscosity.

The viscosity determined from the comforter geometry is called "apparent" because the shear regime is not uniform throughout the deformation geometry. It approaches a uniform deformation regime when the gap between the coil and the cup is on the edge of zero. In the geometries normally used in Fann 50 R1-B2, R1-B5.

II.11. Damage due to fracturing fluid

Unbroken gel or polymer can cause a significant reduction in the permeability of the proppant pack and have a negative effect on fracture conductivity. Fracturing fluid filtrations in the formation can cause fracture front damage. This decreases the permeability of the formation outside the fracture.

Several properties can be used to evaluate degradation performance, including gel viscosity and concentration, and the weight of gel residue. However, degradation of the gels does not mean the return of the fluid, because after degradation, a lot of residue remains which damages the permeability of the cores.

II.11.1. Type of gel and its concentration

Different types of gels have been developed for different conditions, and the same breaker degrading different gels can lead to completely different results. Although different types of gels have a different amount of residue after degradation, the amount of residue depends mainly on the insoluble materials in the gels.

II.11.2. Types of breakers and concentration

Because each type of breaker operates on a different mechanism to degrade the polymer, each breaker produces a different set of factors that affect the amount of residue.

Ammonium peroxydisulfate (APS) is one of the most commonly used oxidants. And the most commonly used enzyme is the specific binding enzyme (LSE). Enzymatic crushers have been observed to provide more effective molecular weight reduction than oxidative crushers. Studies have shown that enzymatic breakers continue to catalyze molecular weight reduction of polymers for at least eight weeks.

Increasing the breaker concentration shortens the degradation time and increases the degree of degradation. However, a high concentration of breaker is necessary to reduce package damage.

II.11.3. Temperature

Although different types of breakers have different application temperature ranges, when the temperature exceeds the highest application temperature, the breakers can decompose, which reduces the degradation effect. With higher temperature, even without the addition of breakers, the viscosity of the gel will decrease, which is similar to the degradation of the gel.

Temperature can also shorten the time required for gels to degrade to the expected degradation performance, and the use of polymeric aggregate dispersants can reduce pore blockage at high temperatures, maintaining up to 150% higher permeability than separate breakers.

However, this does not mean that the higher the temperature, the better the degree of degradation. Different mills have different temperature application ranges, if the temperature is higher than the range, the degree of degradation will decrease. Especially for enzymes, when the temperature is 75ºF.

In addition, for the application of oxidants, there are still temperature limitations. If the temperature is too high, the brittle can decompose and lose the ability to degrade the gels.

II.11.4. Quantity of ions and pH of solutions

For the influence of ions, the degradation performance of gels is significantly affected by the type of ions in the produced water and decreases in the order of Al_3^+ >Mg_2^+ >Ca +>Na_2^+ with the same ion concentration.

Regarding the effect of pH values, pH can affect the degradation process, especially for enzymes. Enzyme application environments are generally recommended as slightly acidic. **[26]**

When the pH value is between 3 and 5, the enzymes are most active and have the highest reaction rate, when the value is 8, the reaction rate decreases, when the pH value increases to 10, the enzymes are inactive but can still degrade the gels when the pH decreases, while when the pH increases to 12, the enzymes become denatured and cannot degrade the gels anymore.

II.12. Methanol in fracturing fluid

Methanol is a colorless liquid alcohol that is used in a variety of industrial applications, including as a solvent, fuel, and antifreeze. In recent years, it has also been used as an additive in hydraulic fracturing fluid to improve the efficiency of the process. **[27]**

Methanol from Schlumberger lowers the surface tension of water and reduces capillary pressure which results in lower energy required to move the water across boundaries and through.

II.12.1. Field Methanol mixing

- fire-fighting equipment
- Stop all engines and other ignition sources that are not necessary
- Install signs around all combustible and flammable storage tanks
- PPE
- Determine the Schlumberger Fluid Flammability Rating (FFR)
- Bonding and grounding **[27]**

Table II. 2: Operation approvement [27]

Does this Management of Change result in the need for a further Exemption or Management of Change?Yes

Approver Details						
#	Approver Name	Approver Type	Approval Date	Comments	Status	Update Date
1	Guerziz Badreddine	Intermediate Approver	3/14/2020 11:26:08 PM	Meeting is help with the engineer in charge, Rig-up to be done as per Std 30, brief the involved crew about it. If you feel unsafe to proceed, stop the job, evaluate, consult. Be safe	Approved	3/14/2020 11:26:08 PM
2	Abderahim Noh	Final Approver	3/14/2020 11:28:36 PM	approved	Approved	3/14/2020 11:28:36 PM

Attachments				
Description	File Name	File Size	Upload Date	Uploaded By
SDS Methanol	SDS_Methanol K46.pdf	103,029	Mar 14, 2020	Mohammedi Sabrina
WIS-013-20-Methanol VP FP for well OMP-742	WIS-013-20-Methanol VP FP for well OMP-742.pdf	933,344	Mar 14, 2020	Mohammedi Sabrina
Meteo_Hassi Messaoud_15.03.2020	Meteo_Hassi Messaoud_15.03.2020.PNG	51,456	Mar 14, 2020	Mohammedi Sabrina

Links from this report			
Link	Link Type	Link Target / URL	Report Description
HARC	HARC	HARC - 20200314201148	Pumping Flammable Fluids

II.12.2. Methanol Application

Nethanol pumping in h f can be used in:

- Water blocks
- Stabilizer
- Foam Fracturing, containing methanol

Methanol can be used as an additive in the fracking fluid nowadays to improve its properties and enhance the efficiency of the fracking process.

Example composition of a fracking fluid used by the operator “Chesapeake Appalachia LLC” in Bradford, PA (Marcellus Shale).

The maximum methanol concentration in the fluid was 0.00239% (% by mass). **[27]**

Table II. 3: Hydraulic fracturing fluid component information [27]

Hydraulic Fracturing Fluid Product Component Information Disclosure - ATGAS 2H
CHESAPEAKE APPALACHIA LLC

API #	3701521237	County	BRADFORD	Fracture Date	4/18/2011
Surface Casing Depth (ft)	455	State	PENNSYLVANIA	Proppant Mass Pumped (lbs)	1,651,580
True Vertical Depth of Well (ft)	6,740.7	Longitude	-76.710095	Water Volume Pumped (gals)	1,565,298
Play	MARCELLUS SHALE	Latitude	41.666349	Frac Fluid Volume Total (gals)	1,647,714
Well Type	HORIZONTAL	Lat/Long Projection	NAD27	Total Fluid Mass Pumped (lbs)	14,876,546

Supplier	Product Type	Product Name	Total Product Pumped (gals)	Total Product Mass (lbs)	Component Listed on MSDS	Chemical Abstract Service Number (CAS #)	MAXIMUM Component Concentration of Product (% by Mass)	MAXIMUM Component Mass Pumped (lbs)	MAXIMUM Component Concentration Pumped (% by Mass)	MAXIMUM Parts per Million (PPM) by Mass
X CHEM OILFIELD CHEMICALS	Anti-Bacterial Agent	B84	650	5,970	Glutaraldehyde (Pentanediol)	000111-30-8	27.00%	1,612	0.01084%	108
					Didecyl Dimethyl Ammonium Chloride	007173-51-5	8.00%	478	0.00321%	32
					Quaternary Ammonium Compound	068424-85-1	5.50%	328	0.00221%	22
					Ethanol	000064-17-5	4.00%	239	0.00161%	16
	Scale Inhibitor	SC30W	201	1,829	Sodium polyacrylate	N/A	30.00%	549	0.00369%	37
					Methanol (Methyl Alcohol)	000067-56-1	15.00%	274	0.00184%	18
PUMPCO SERVICES	Friction Reducer	Plexslick 921	2,285	20,225	Water	007732-18-5	40.00%	8,090	0.05438%	544
					Petroleum Distillate Hydrotreated Light	064742-47-8	35.00%	7,079	0.04758%	476
					POLY(ACRYLAMIDE-co-ACRYLIC ACID	009003-06-9	28.00%	5,663	0.03807%	381
					Polyethoxylated Alcohol Surfactants	N/A	7.00%	1,416	0.00952%	95
	Acid	Acid HCL	4,500	43,587	Hydrochloric Acid	007647-01-0	15.00%	6,538	0.04395%	439
	Non-Emulsifier	Plexbreak 145	15	120	Water	007732-18-5	65.00%	78	0.00053%	5
					2-Butoxyethanol (Ethylene Glycol Monobutyl Ether)	000111-76-2	15.00%	18	0.00012%	1
					Methanol (Methyl Alcohol)	000067-56-1	15.00%	18	0.00012%	1
					Coconut oil, Diethanolamide	068603-42-9	7.00%	8	0.00006%	1
					Diethanolamine	000111-42-2	3.00%	4	0.00002%	0

II.13. Conclusion

This chapter gives us an overview on hydraulic fracturing with the conventional fluid and the several parameters to know and to choose the successful operation, in addition fracturing treatment using methanol as an energized fluid especially in depleted reservoir which is our OMP-742 well case.

Chapter III: Hydraulic Fracturing Treatment using Methanol Pumping in HMD Field

III.1. Introduction

This chapter is for the study and evaluation of hydraulic fracturing with the uses of the methanol. Methanol hydraulic fracturing is a relatively new technique used in the oil and gas industry to extract hydrocarbons from shale rock formations. This process involves injecting a mixture of water, sand, and methanol into the ground at high pressure, which creates small fractures in the rock. These fractures allow the hydrocarbons to flow more freely to the surface.

One of the advantages of using methanol in hydraulic fracturing is that it can help to reduce the amount of water needed for the process. Methanol is also less expensive than other chemicals commonly used in hydraulic fracturing, such as guar gum.

III.2. Well data and problematic

OMP-742 is a deviated well with low pressure

III.2.1. Well Location

OMP-742 is situated in the North-Est of Hassi Messaoud field.

These are the geological coordinates of the well: X :82106.13 Y:135590.84**.**

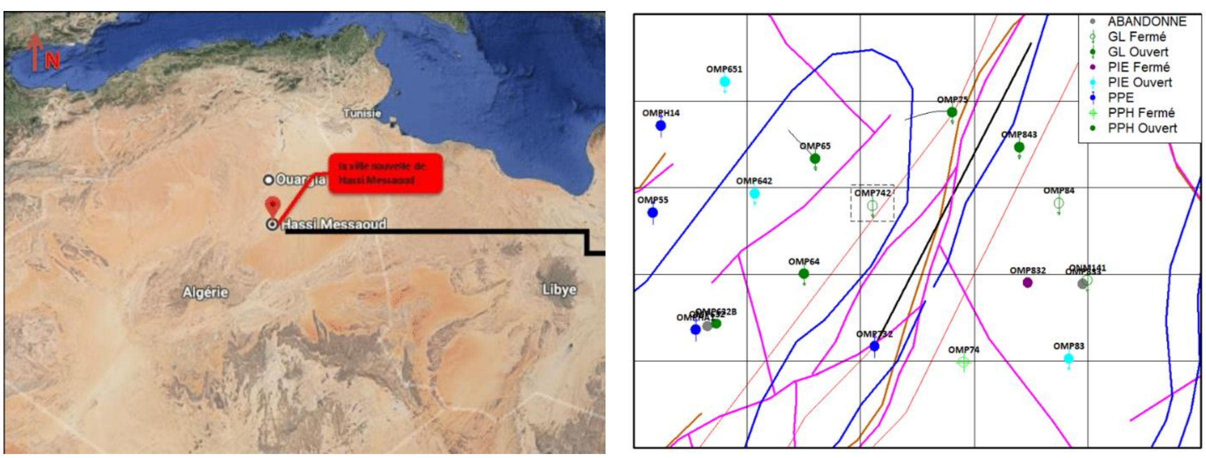


Figure III. 1: OMP-742 Well location [28]

III.2.2. Well completion

OMP-742 completed with LCP: covering D2, ID, D1, Salt and R2, the LCP is perforated in D2, ID and D1 that have a good potential.

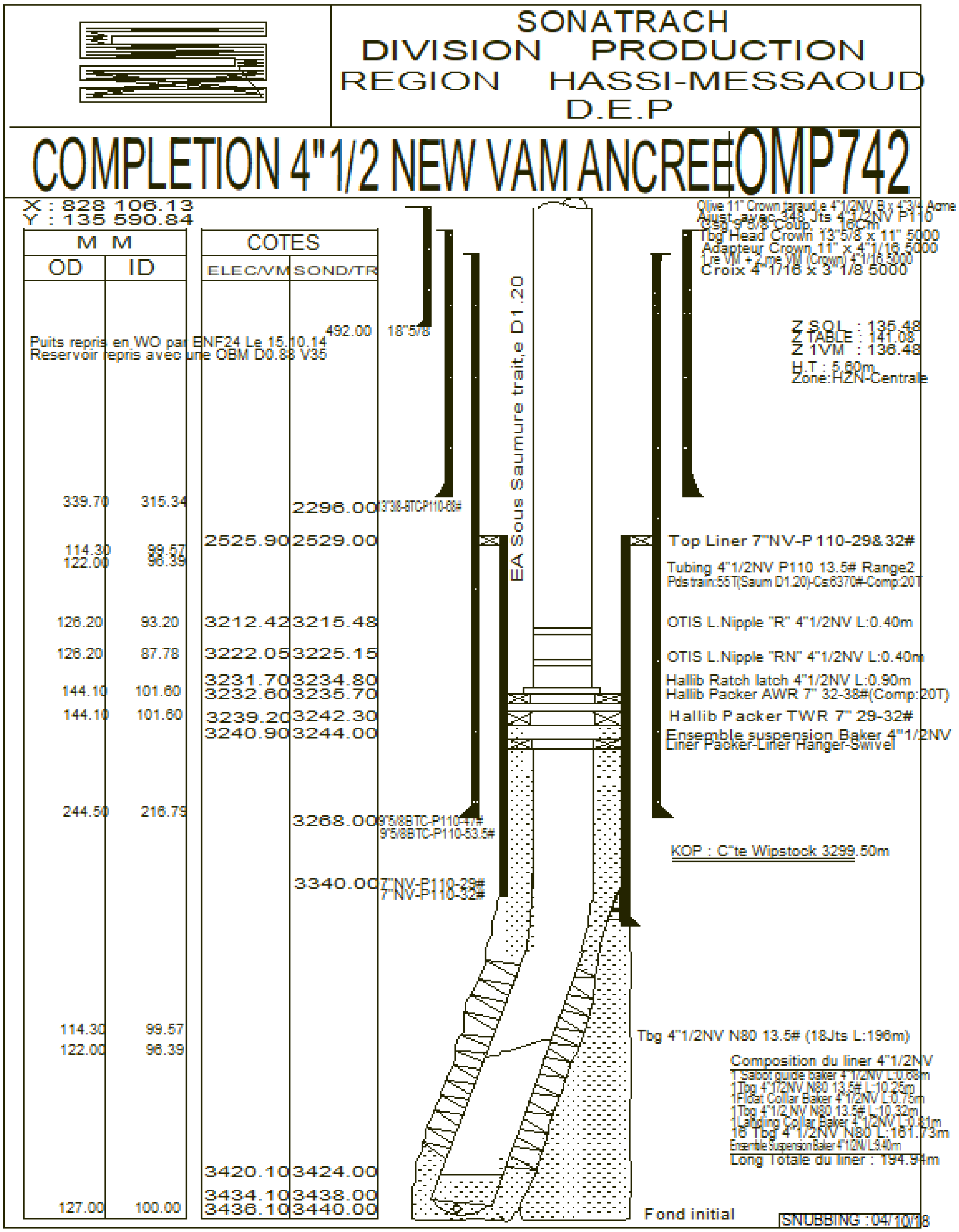


Figure III. 2: OMP-742 Completion [28]

Table III. 1: OMP-742 Completion data [28]

End of drilling and completed	05 January 2016
Initial Well Depth MD (m)	3440m
Deviation	Side track @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

III.2.3. Petro-physical Data

OMP-742 is crossing different reservoir especially with a good potential in the ID and D1 intervals. The intervals are characterized by a permeability of 2.83md and 6-7% porosity with a weak water saturation. The latest reservoir pressure measured was 157.67 KG/cm2 (2223 Psi) – VERY LOW.

Table III. 2: Petro-physical Data [28]

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	120ºC

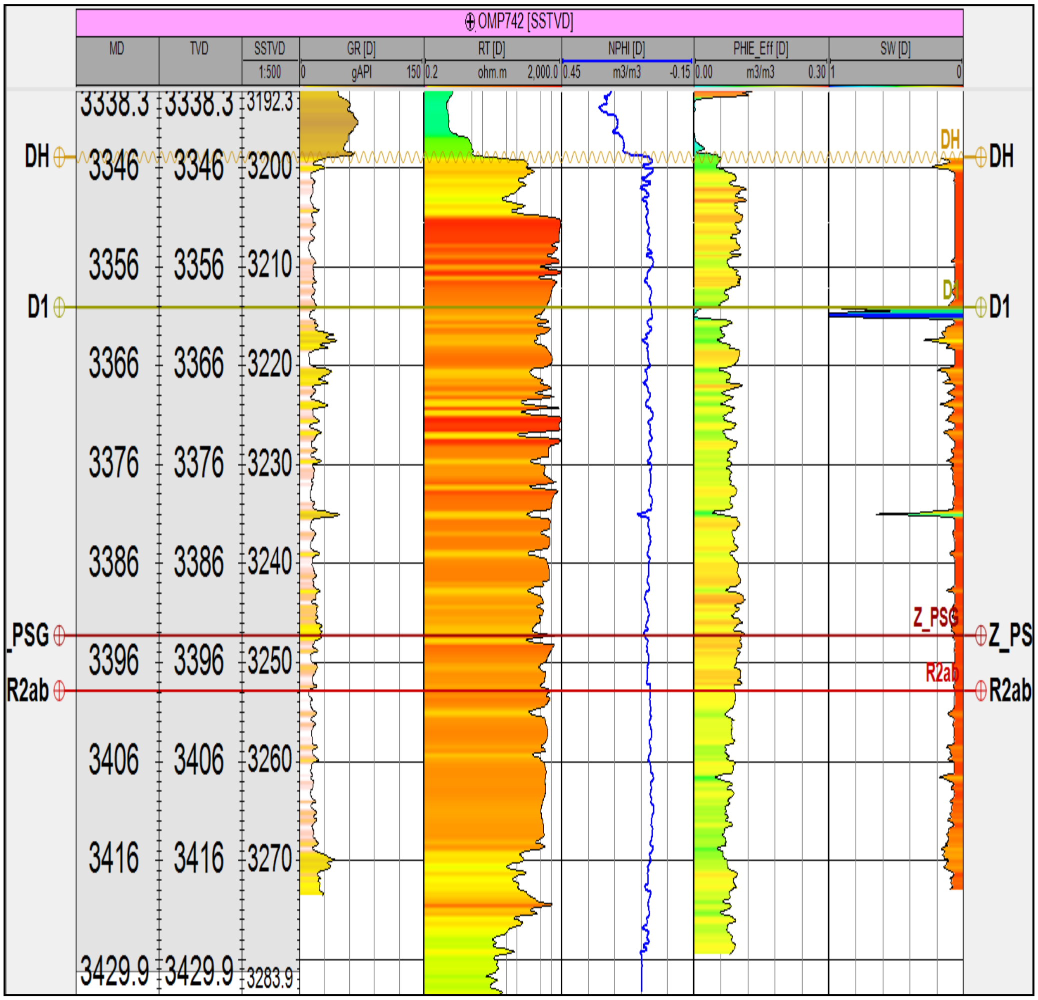


Figure III. 3: OMP-742 Well log [28]

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.

Even with the strong damage caused by the drilling fluid, the well gave a flow rate of $3.2 m^3$ /h during DST. After completion, the well did not start although the start-up attempts made. The gas lift supply installed 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.

III.2.4. Candidate selection for Methanol Hydraulic Fracturing

According to the core, the reservoir has good Petro-physical characteristics, and from Elan interpretation the D1 and ID carry the best reservoir properties.

OM-P742 is 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 62 m from the bottom perforations, and the stress profile shows barriers at the bottom of D1 and Z_{psg} 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 drops and a very high skin in wellbore

- From the previous discussion and the analysis of the well data, the **OMP742 is a candidate for a Methanol Hydraulic Fracturing.**

III.2.5. Wellsite rig up

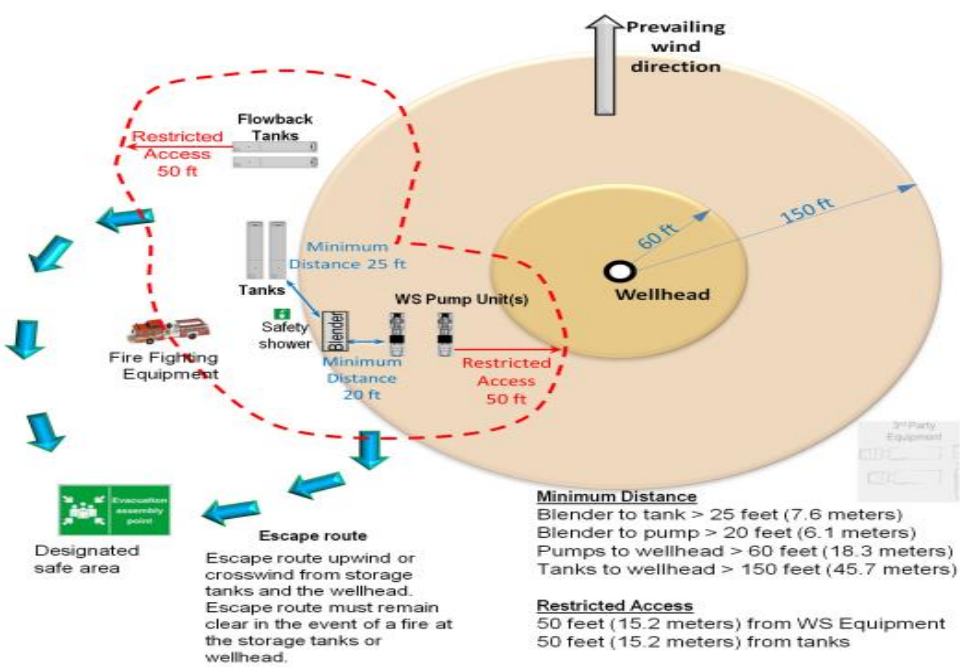


Figure III. 4: Wellsite rig up [28]

The above figure represents the rig up map of a fracturing field and the position of each equipment respecting the distances between the equipment and the wellhead.

III.3. Methodology

III.3.1. Design

- To reach effective X_f of 50-60 m we need design a job size around 100k lb.
- High PPA concentrations are recommended to ensure higher conductivity NWB.
- Methanol, is strongly recommended to be added to frac fluid to facilitate clean out.**[30]**

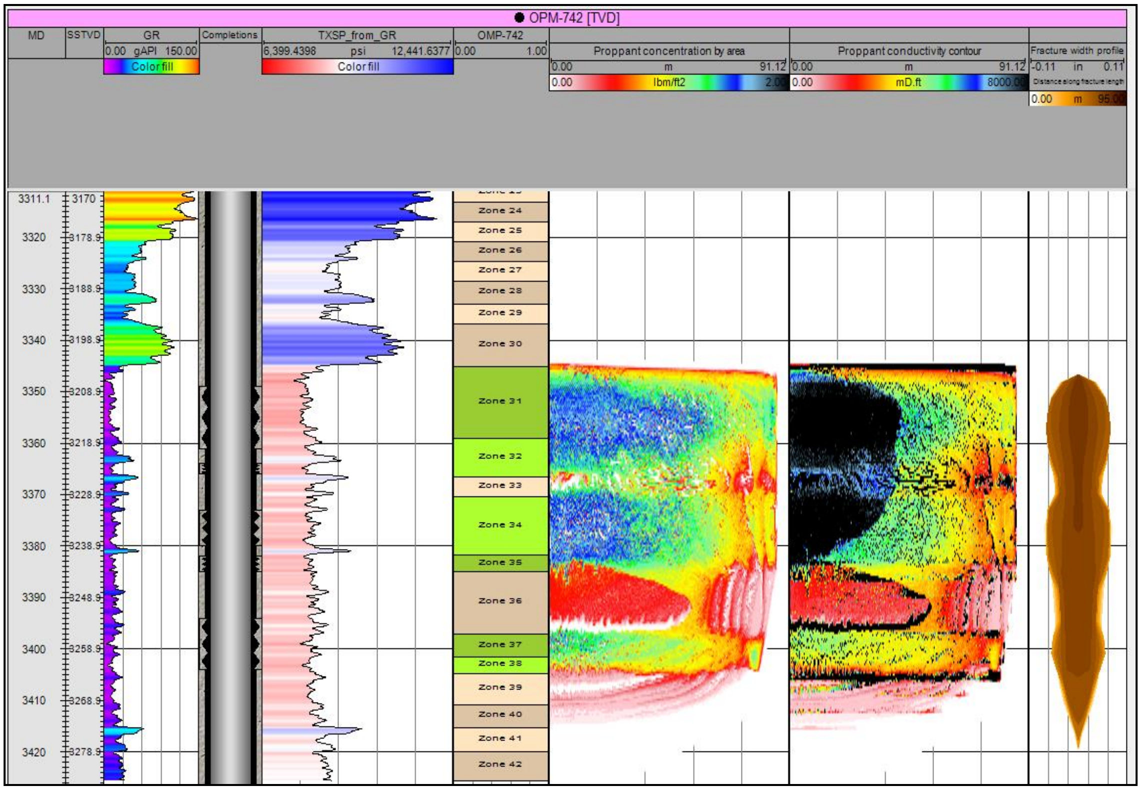


Figure III. 5: OMP-742 Design [28]

The design was done using Petrel software developed by SLB company to reach the required results as represented in (Figure III. 5).

III.3.2. Materials

III.3.2.1. Proppant

Bauxite-based proppants was selected to measure his conductivities under bottom conditions:

- Bauxite-based proppants, size 20/40. (Figure III. 6)

Figure III. 6: Bauxite proppant of size 20/40 used in the experiments [26]

III.3.2.2. Guar gum

Due to their low cost, high performance and ease of handling, water-based fluids are the most widely used fracturing fluids.

Figure III. 7: Guar sample used in tests [26]

Guar Polysaccharide gel powder (Figure III. 7) was used to prepare the linear gel in the laboratory tests. It was estimated that fluid loss during fracturing operations and during closure increases the concentration of polymers in the fracture after closure.

III.3.2.3. Cross-linking agent

Boric acid B(OH)3 (Figure III. 8) was used as the cross-linking agent as it is one of the types most used in Hassi Messaoud region. A concentration of between 5 and 6 lbs/1000 gal was considered to prepare the cross-linked fluid for the proppant permeability tests.

Figure III. 8: Sample of borate crosslinker used [26]

III.3.3. Equipment used to measure the permeability of the proppant

To measure the permeability of the proppant sample, the containment cell proposed by was used (Figure III. 9). A stainless-steel piston was constructed to be filled with proppant and fracturing fluid and subjected to a calculated stress at a constant temperature using different gel concentrations.

Figure III.9: Fabricated piston components

The cell (Figure III. 22) can contain a sample with a diameter of 4 cm, a maximum length of 10 cm and a minimum length of 5 cm. Two small filters have been used in the inlet and outlet channels of the injected fluid to prevent the transport of proppant outside the containment chamber. The cell consists of three main parts:

III.3.3.1. Cylinder

It is 16 cm long, 6 cm in diameter with a thickness of 1 cm. The cylinder (Figure III. 11) is threaded at the base to enable it to be closed by the plug.

On the other side, the cylinder has a 2 cm thick extension with 4 holes for the nuts to fix the pressure applied by the piston on the proppant.

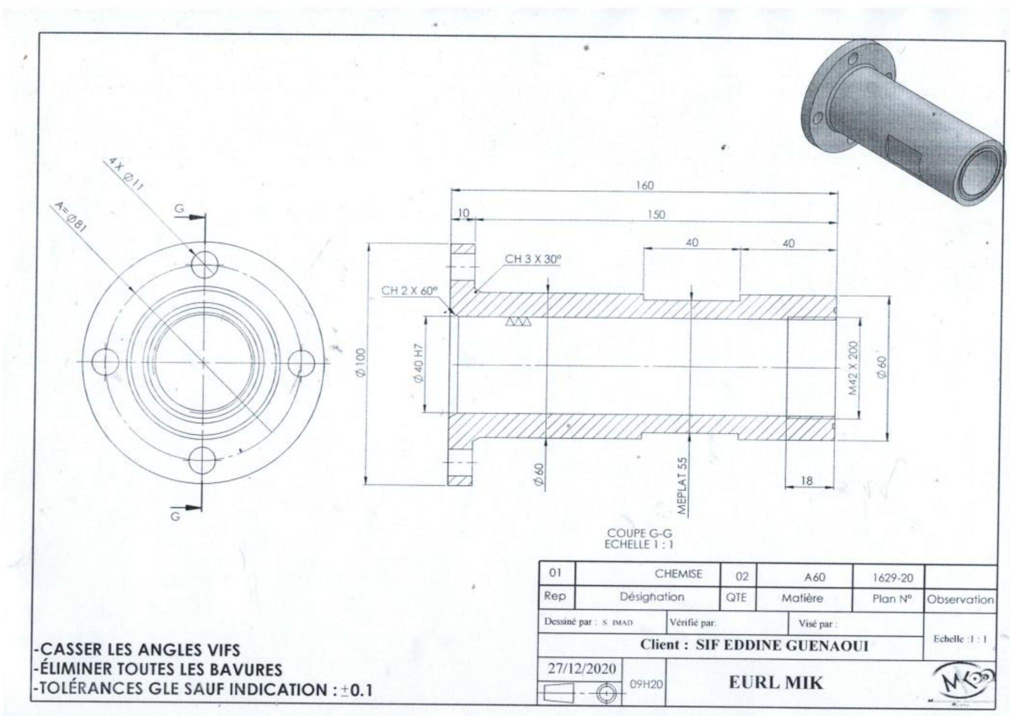


Figure III. 10: Piston cylinder body for measuring proppant permeability

III.3.3.2. Piston

It is 4 cm wide and 11.5 cm long. The piton is fitted with 3 O-rings to prevent leakage of fluid outside the cell during permeability measurement. The piston (Figure III. 12) has a small 2 mm channel at the fluid inlet to the containment chamber.

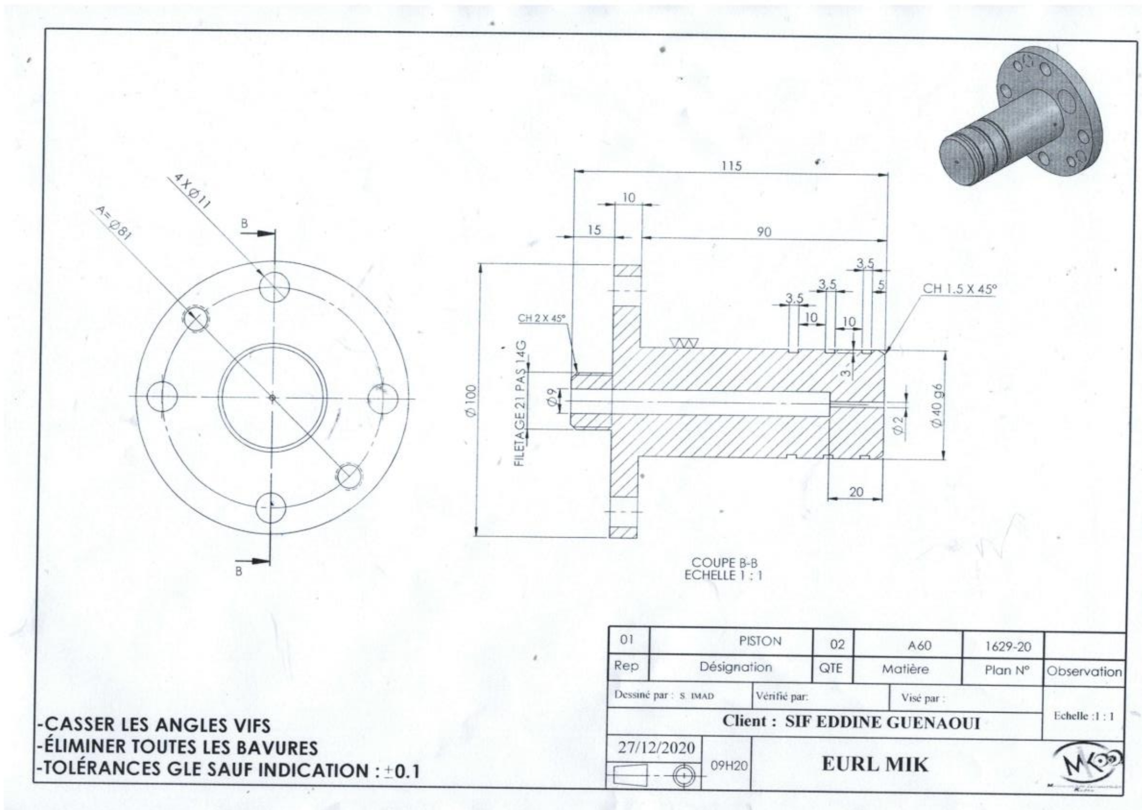


Figure III. 11: Fabricated piston for measuring proppant permeability

For connection to the permeability measurement system, the piston has a threaded extension on the other side. Four holes are provided for nuts to fix the pressure applied during experiments.

III.3.3.3. Plug

To enable the cell to be filled with proppant, a plug (Figure III. 13) with a radius of 6.9 cm and a thickness of 4 cm was built to close the containment chamber. The plug is threaded on both sides, the first to close the cell at its base and the second to be connected to the permeability measurement system.

The plug is hexagonal in shape so that it can be tightened, and an O-ring seal has also been used to prevent leakage outside the cell.

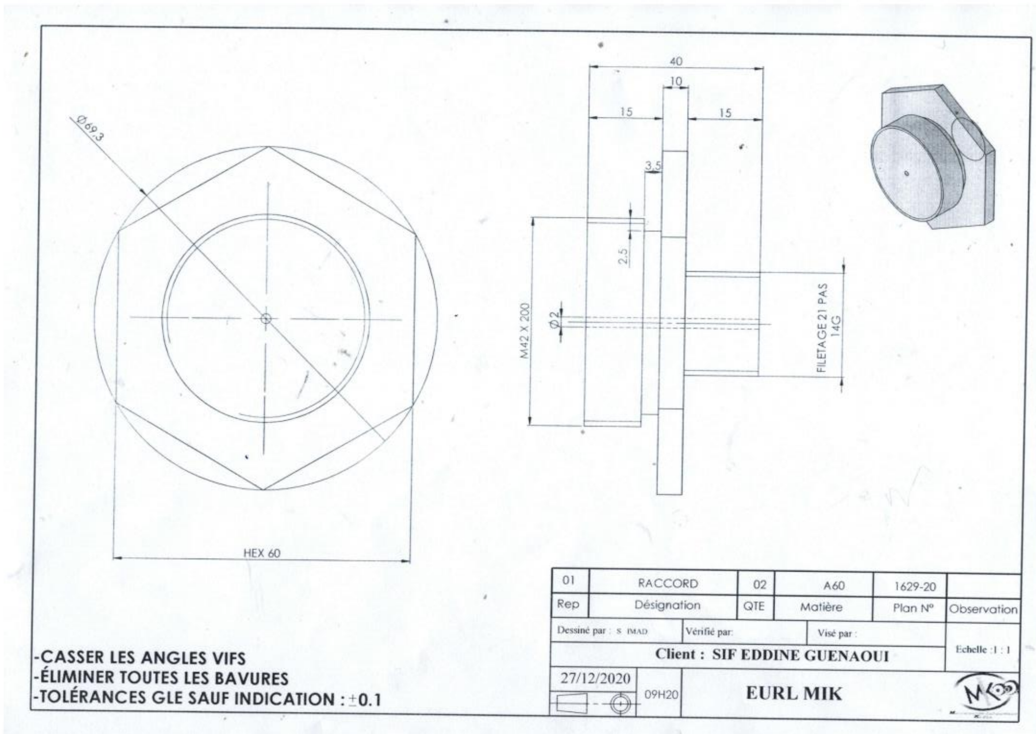


Figure III. 12: Piston plug for proppant permeability measurement

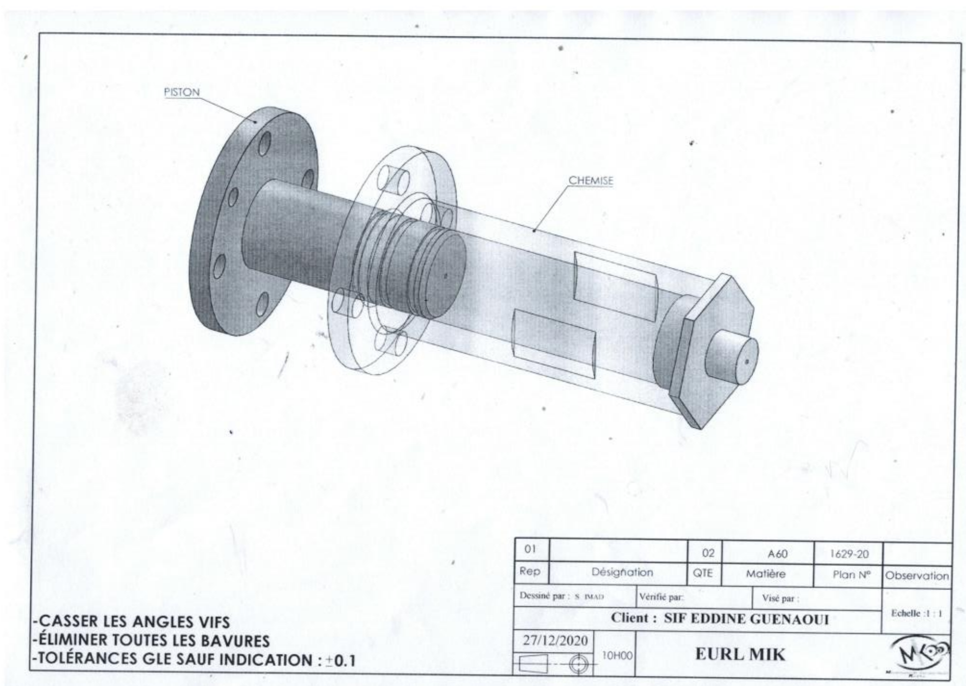


Figure III. 13: Complete piston with its three main parts

III.3.4. Permeability measurement system

To measure proppant permeability, an installation (Figure III. 14) was set up, consisting of:

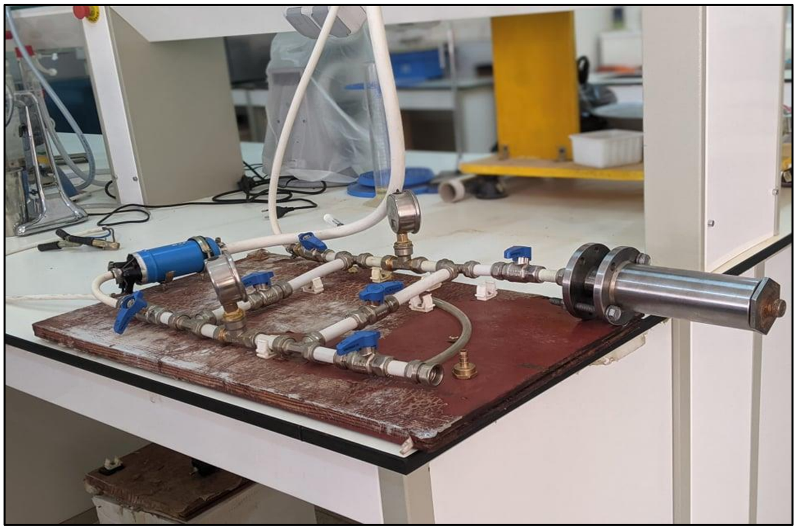


Figure III. 14: Schematic diagram of proppant permeability measurement system

III.3.4.1. Diesel oil tank

A diesel oil tank is used to maintain hydrostatic pressure for the injection pump.

III.3.4.2. Pipes and valves

The plant contains several valves to control the flow path and a return valve to control flow. The plant is equipped with a threaded cross-over to connect the containment cell for permeability measurement.

III.3.4.3. Diesel pump

For diesel injection, a high-pressure electric fuel pump (Figure III. 16) was used to maintain a constant rate during proppant permeability injection.

Figure III. 15: High-pressure electric fuel pump [26]

III.3.4.4. Manometers

Several manometers (0 to 10 bar) (Figure III. 17) are installed in the plant to measure the pressure difference during permeability measurement.

Figure III. 16: Manometer used

III.3.5. Equipment used to prepare the fracturing fluid

III.3.5.1. Rheometer Fann 35

To check the viscosity of the linear gel, Fann Model 35 viscometers were used which are direct reading instruments available in six operating speeds.

Fann Model 35 viscometers are used in research and production. These viscometers are recommended to evaluate the rheological properties of fluids, Newtonian, and non-Newtonian.

Figure III. 17: Viscometer model 35SA

The model includes an R1 rotor shroud, B1 coil, F1 torsion spring, and stainless-steel sample cup for testing in accordance with the American Petroleum Institute's recommended practice for field testing of water-based drilling fluids, API RP 13B-1/ISO 10414-1 specification.

III.3.5.2. Viscosimeter CHANDLER 5550 HPHT

The HPHT Model 5550 Viscometer is a concentric cylinder viscometer that utilizes the rotor and coil geometry accepted by the power industry. Its design meets the requirements defined in ISO and API standards for measuring the viscosity of high pressure and high temperature completion fluids.

Figure III. 18: Viscometer CHANDLER 5550 HPHT

The Chandler Engineering Model 5550 Viscometer has been used to test the rheology of fracturing fluid. It is a high pressure, high temperature viscometer designed to test a variety of petroleum fluids.

III.3.5.3. Hydraulic press

To simulate the pressure applied on the proppant inside the fracture, a Big Red hydraulic press (Figure III. 20) was used with a maximum force of 10 tons. To simulate the stress applied to the proppant inside the fracture, a hydraulic press with a gauge to read the applied force was used.

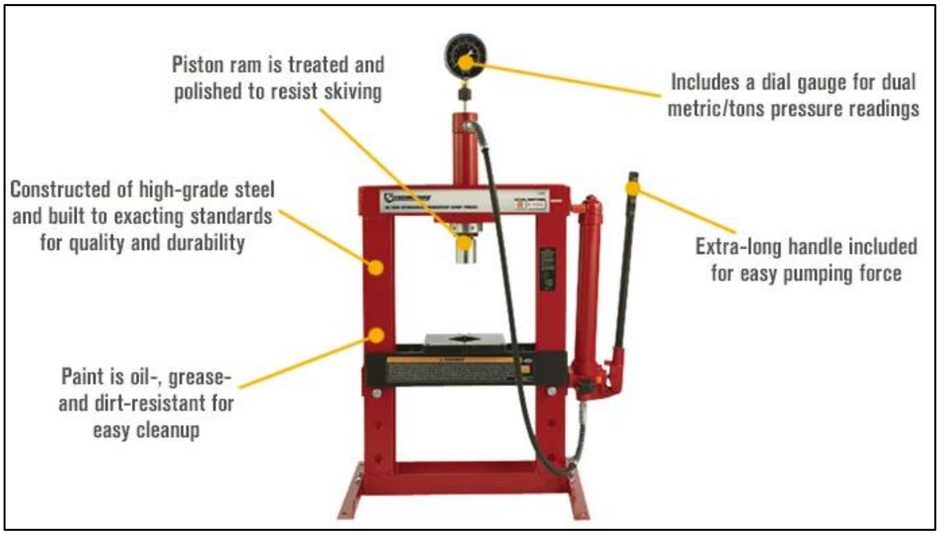


Figure III. 19: Big Red 10-ton hydraulic bench press

III.3.5.4. UN30 universal oven

Temperature is a very important parameter in hydraulic fracturing and to ensure this, the UN30 universal oven (Figure III. 20) was used for temperature control in proppant conductivity tests. Typically, the temperature of the Hassi Messaoud reservoir is 120°C, so this oven was used to simulate background conditions by selecting the desired time and temperature for the tests.

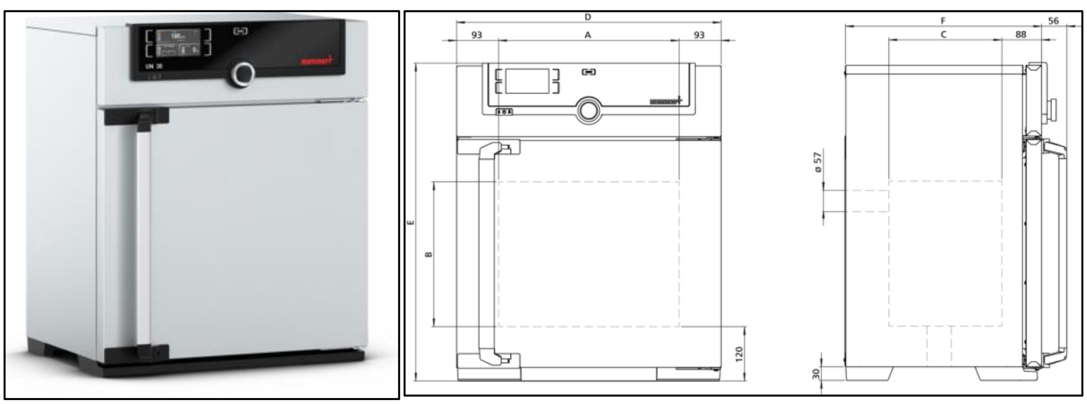


Figure III. 20: Universal oven UN30

III.3.5.5. Mixer

To prepare the linear gel an AM120Z-H mixer which is a digital laboratory mixer was used to ensure proper hydration of the guar gel powder in water.

Figure III. 21: Overhead Stirrer AM120Z-H

It is a digital overhead with variable speed function, simple operation in a wider speed range, apply to stable liquid stirring, especially for mixing a small volume of samples, oil, chemical and medical products. It is designed for the laboratory high viscosity liquid stirring and mixing.

III.3.6. Operating method

III.3.6.1. Viscosity of linear fluids

To determine the viscosity of linear fluids, the Fann Model 35 rheometer (Fann 35) is mainly used. The following items are required:

- Viscosimeter Fann 35 with the appropriate parameters (velocity factor, R-B factor and spring factor).
- Rotor and bob
- Fann 35 sample section
- Fracturing fluid
- A thermometer

To measure the viscosity of the linear gel, the following steps were followed:

1. Install the rotor and coil if they are not already there.
2. Fill the sample cup to the mark with fracturing fluid.

3. Place the sample cup on the stage. The three pins at the bottom of the cup fit into three holes in the stage.
4. Raise the stage until the sample cup is level with the mark on the rotor.
5. Set the Fann 35 to the desired shear rate (300 rpm).
6. Let the dial come to a steady reading and record the reading.
7. Measure and record the temperature of the fluid.

III.3.6.2. Viscosity of cross-linked fluids

The following items were used to perform this test:

- High pressure high temperature viscosimeter (HPHT), Fann 5550 with appropriate parameters (velocity factor, R-B factor and spring factor),
- Rotor and bob 5 or bob 5X; different bobs will have different shear rate ramps.
- Sample of fracturing fluid.

To perform HPHT gel rheology tests:

1. Turn on the viscometer and its computer.
2. Provide water and nitrogen (N2)
3. Prepare the cross-linked fracturing fluid as described in the cross-linked fluid preparation section.
4. Activate the viscometer computer program a then Heat Bath.
5. Place approximately 26 ml (for a bob 5) of the cross-linked gel into the rotor cup, followed by the required amount of fracturing agent.
6. Place approximately 26 ml of additional cross-linked gel into the rotor cup.
7. Remove the oil bath cover and close the glass door. 10.
8. Select bob 5, interval stirring rate (118 rpm) and final temperature setpoint.

III.3.6.3. Long-term proppant conductivity

The long-term conductivity of proppant was measured under multiple conditions to study the effect of closure pressure, gel residue, time, temperature, breaker, and gel concentration following the test program and steps mentioned in the following section.

a. Cell preparation

Figure III. 22: Placing the proppant sample and fracturing fluid in the containment cell

1. The mixture was then placed in the containment cell and pressurized at various stresses between (2,000 psi - 8,000 psi) using the hydraulic press.
2. Two metal filters are used to prevent transport of the proppant out of the cell during sample compression and during fluid flow for permeability measurement.
3. Nuts were used to maintain the pressure applied to the proppant.

Figure III. 23: Containment cell compression

4. The containment cell was placed in the oven at 120°C, which is the temperature of the Hassi Messaoud Field reservoir.

5. The cell is maintained at various times between 12 h and 72 h.

Figure III. 24: Placing the sample in the oven

6. Finally, the containment cell was removed from the oven and connected to the installation.

b. Permeability measurement

7. Permeability was calculated by injecting Diesel.

8. Initially, the gel and Diesel start to flow out of the containment cell, the stable rate of Diesel is maintained until the Diesel is clear.

During proppant permeability measurement, a steady-state flow method was applied. To maintain a constant flow rate, a needle valve was installed behind the containment cell to maintain a constant pressure. The pressure in the cylinder is monitored by pressure gauges, so flow can be calculated by measuring the volume discharged from the containment cell and time.

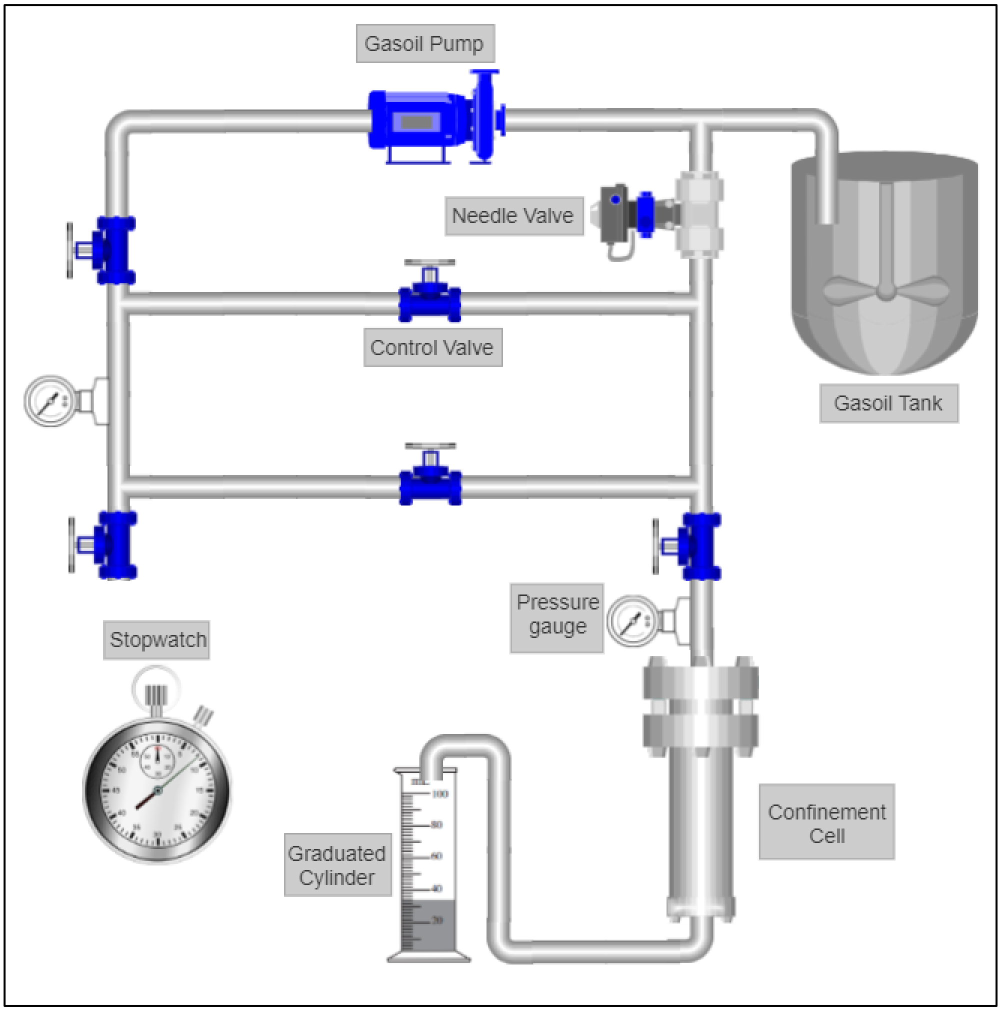


Figure III. 25: Permeability measurement installation diagram

Permeability was measured using Darcy's law:

$$K = \frac{Q.\mu.L}{A.(P_1 - P_2)} \qquad \textit{III-1}$$

K is the permeability of the proppant pack (Darcy).

μ is the viscosity of the test fluid at test temperature (cP).

Q is the flow rate (cm3/s).

L is the length between pressure ports (cm).

A is the cross-sectional area of the test unit perpendicular to the flow (cm2).

ΔP is the pressure drop (upstream pressure minus downstream pressure) (atm).

III.4. Results and analysis

III.4.1. Design results analysis

The operation performed in March 2020. It started by filling up the well with 11470 gal of treated water where the breakdown was observed around 5,800 psi (Surface), then a STR was performed using 334704 gal of treated water, followed by pumping 15% HCl Acid treatment, where 3831 gal was pumped & displaced by 7618.8 gal of treated water followed by a sharp shut down and a pressure decline monitoring.

Table III. 3: Injection and DataFRAC measured Pumping Schedule

As Measured Pump Schedule										
Step #	Step Name	Slurry Volume (bbl)	Slurry Rate (bbl/min)	Pump Time (min)	Fluid Name	Fluid Volume (gal)	Proppant Name	Max Prop Conc (PPA)	Prop Conc (PPA)	Prop Mass (lb)
1	Well Fill Up	271.6	16.3	20.7	Treated Water	11407	-	0	0	0
2	Acid	91.2	6.4	15.6	Acid 15% HCl	3831	-	0	0	0
3	Overflush	181.4	16.3	11.1	Treated Water	7618.8	-	0	0	0
4	Step Rate Test	79.7	16.3	4.9	Treated Water	3347.4	-	0	0	0
5	Pre-PAD	82	22.1	4.7	WF135 + 2% Methanol	3445	-	0	0	0
6	PAD	428.6	35	12.2	YF135HTD + 2%Methanol	17951	-	0	0	0
7	Flush	177.4	35.1	5.1	WF135 + 2%Methanol	7449	-	0	0	0

The DataFRAC was carried right after in the same day, it started by pumping 3445 gal of PrePAD stage with linear gel WF135 slowly ramping the rate up to 35 bpm, followed by the PAD stage with the crosslinked gel YF135HTD where 17951 gal were pumped. Finally, the well was flushed by pumping 7449 of linear gel WF135 than the pumps were shut down and the pressure decline was monitored and recorded.

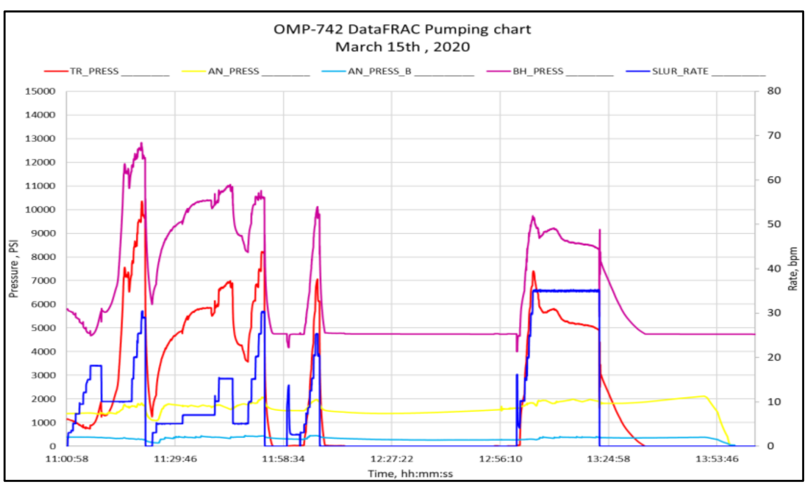


Figure III. 26: OMP-742 Data FRAC Pumping chart [28]

The surface ISIP was recorded at 3254psi and the bottom-hole ISIP at 8005 psi. The LPP (Last Pumping Pressure) was 4921 psi at surface and 8336 psi at bottom-hole pressure with total friction of 1667 psi at 25 bpm (Linear Gel). The closure pressure of calibration decline was picked up from the G-Function method at 6,450 psi corresponding to a frac gradient of 0.58 psi/ft and net pressure of 1423 psi.

The fluid efficiency was estimated to be 7%. Thermolog was carried out in the day after the DataFRAC stages to estimate the fracture height and calibrate the fracture model.

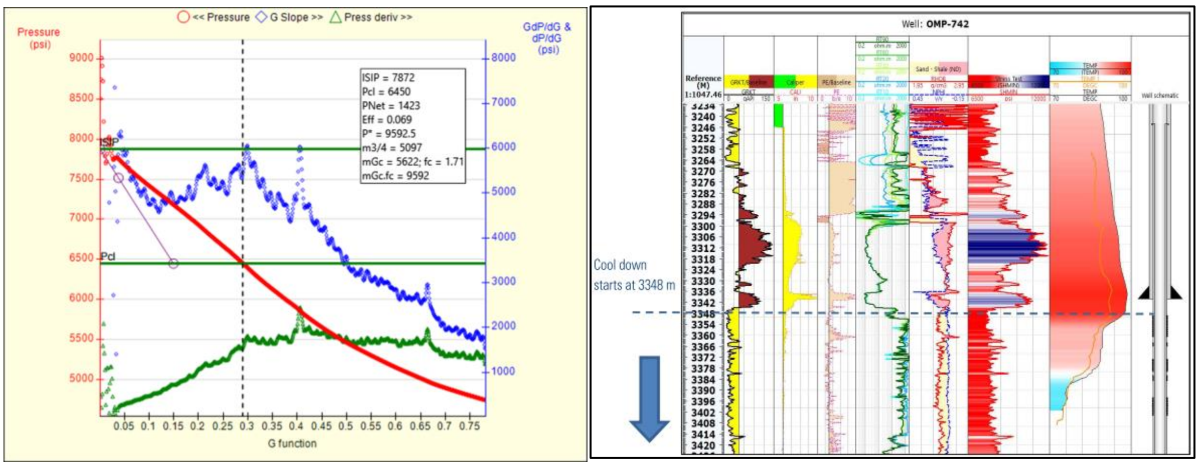


Figure III. 27: OMP-742 G function & Thermolog [28]

The main fracturing treatment performed on April, 2020 started with a Pre-PAD stage ramping the rate up to 35 bpm achieving a pumped volume of 99.8 bbls with linear gel WF135, followed by the PAD stage consisting of 379.4 bbls of crosslinked gel YF135HTD. The proppant stages were stepped from 1 to 2 PPA with 30/50 HSP proppant followed by 20/40 HSP from 3 to 7 PPA. The treatment was flushed with 166.9 bbls of Linear gel WF135 including an under flush of 10 bbls.

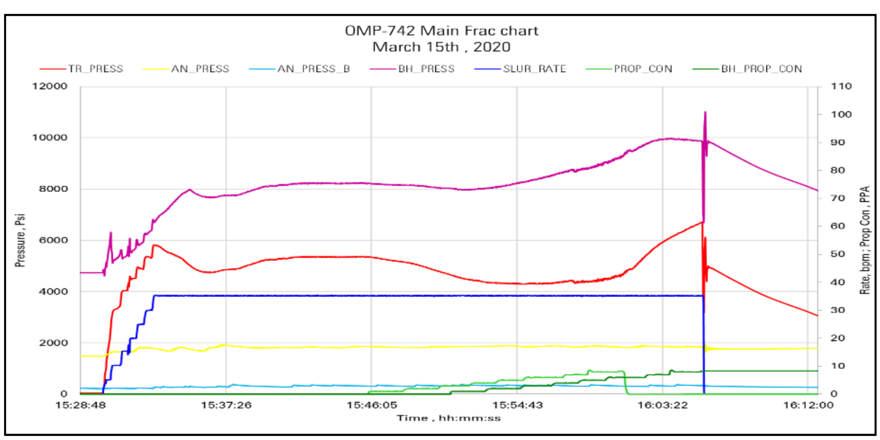


Figure III. 28: OMP-742 Main frac chart [28]

The total amount of proppant pumped during this treatment was 113,051 lbs, the total proppant placed into the formation is 110,660 lbs is at a maximum bottom hole proppant concentration of 7 PPA.

Table III. 4: Injection and DataFRAC measured Pumping Schedule [28]

As Measured Pump Schedule									
Step #	Step Name	Slurry Volume (bbl)	Slurry Rate (bbl/min)	Pump Time (min)	Fluid Name	Fluid Volume (gal)	Proppant Name	Prop Conc (PPA)	Prop Mass (lb)
1	pre-pad	105.1	20	7.3	WF135 +2% Methanol	4389	-	0	0
2	Pad	441.2	35.2	12.5	YF135HTD +2% Methanol	18533	-	0	0
3	1.0 PPA	73.8	35.2	2.1	YF135HTD +0.5% Methanol	3001	20/40 HSP	1	2958
4	2.0 PPA	76.1	35.2	2.2	YF135HTD +0.5% Methanol	3000	20/40 HSP	2	5959
5	3.0 PPA	65.4	35.2	1.9	YF135HTD +0.5% Methanol	2498	20/40 HSP	3	7531
6	4.0 PPA	53.9	35.2	1.5	YF135HTD +0.5% Methanol	1999	20/40 HSP	4	8000
7	5.0 PPA	55.5	35.2	1.6	YF135HTD +0.5% Methanol	2001	20/40 HSP	5	9953
8	6.0 PPA	55.8	35.2	1.6	YF135HTD +0.5% Methanol	1732	20/40 HSP	6	11542
9	7.0 PPA	45.0	35.2	1.3	YF135HTD +0.5% Methanol	1790	20/40 HSP	7	10475
10	8.0 PPA	111.5	35.2	3.2	YF135HTD +0.5% Methanol	3733	16/30 HSP	8	28778
11	Flush	163.7	35.2	4.7	WF135+0.5% Methanol	6906	-	0	0

As Measured Totals			
Slurry (bbl)	Pump Time (min)	Clean Fluid (gal)	Proppant (lb)
1247.0	39.8	49584	85197

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 and the 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.

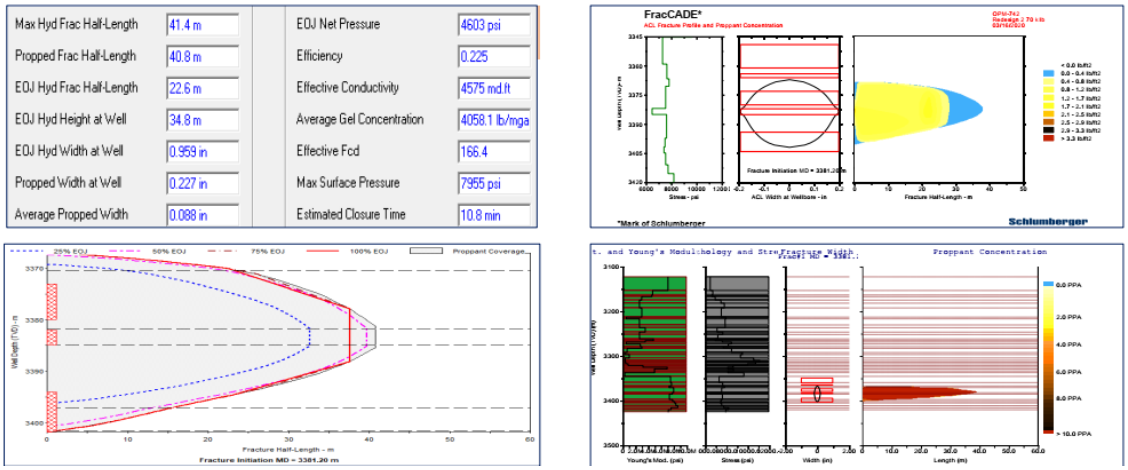


Figure III. 29: frac geometry after main treatment [28]

The Temperature Log Results shows that the perforations are taking fluid. The fracture shows a Height growth. A fiber Pad of 18,000 gals was used to mitigate the low fluid efficiency and Methanol was 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 60.5 lbs with 20/40 and 16/30 HSP. The design will be adjusted during pumping. A high risk of screen out was encountered due to the very low fluid efficiency.

III.4.2. Fracturing fluids rheology results analysis

Before testing the breaker's performance on the fracturing fluid, the sample's rheology was tested to ensure that the fluid is stable at high temperature and the rheological parameters are stable.

The graph shows sample viscosity as a function of time and temperature. In this stability test, a borate-crosslinked fluid was used at a concentration of 35 lb/1000 gal guar and 6 ppt borate as mentioned in the procedures section. The test was carried out at 120°C.

At the start of the test, the fluid viscosity was very high, exceeding 1000 cP, then stabilized between 700 and 800 cP. By applying high shear, the fracturing fluid showed good reversibility and viscosity recovery.

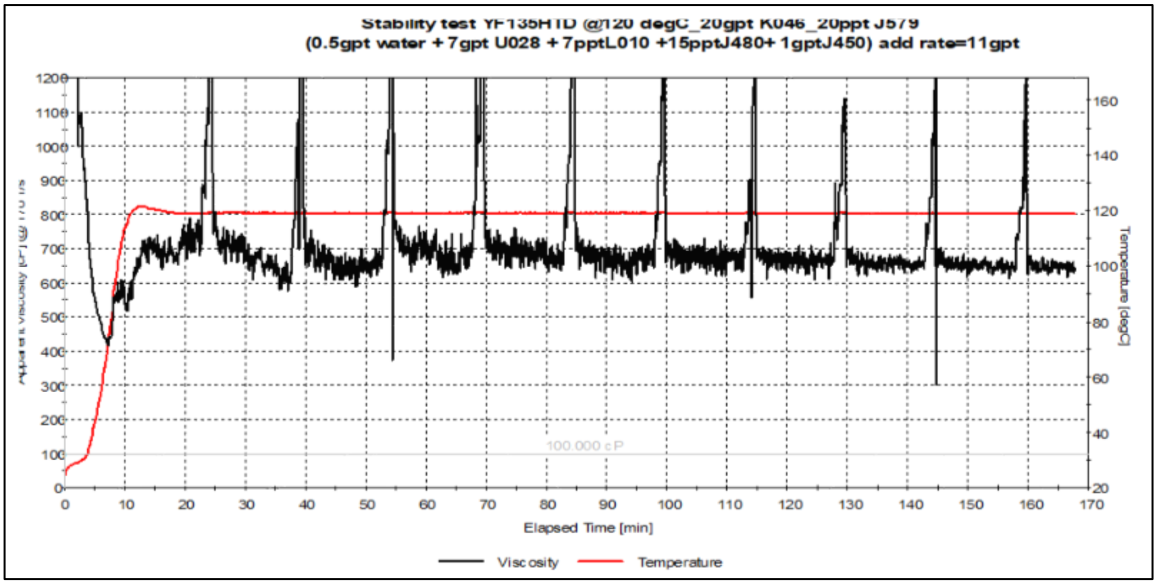


Figure III. 30: Stability test YF135 HTD

The below charts represent the breakers tests using methanol with frac fluid which shows a good crosslinking and breaking time.

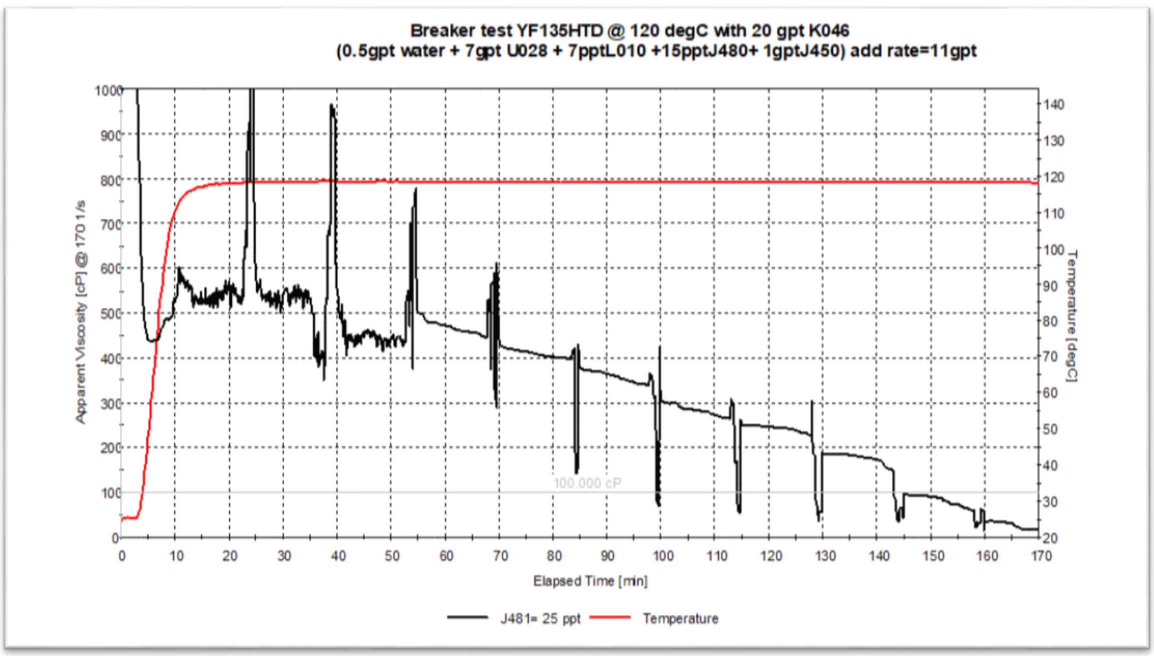


Figure III. 31: Breaker test YF135HTD @ 120 deg C with 20 gpt K046

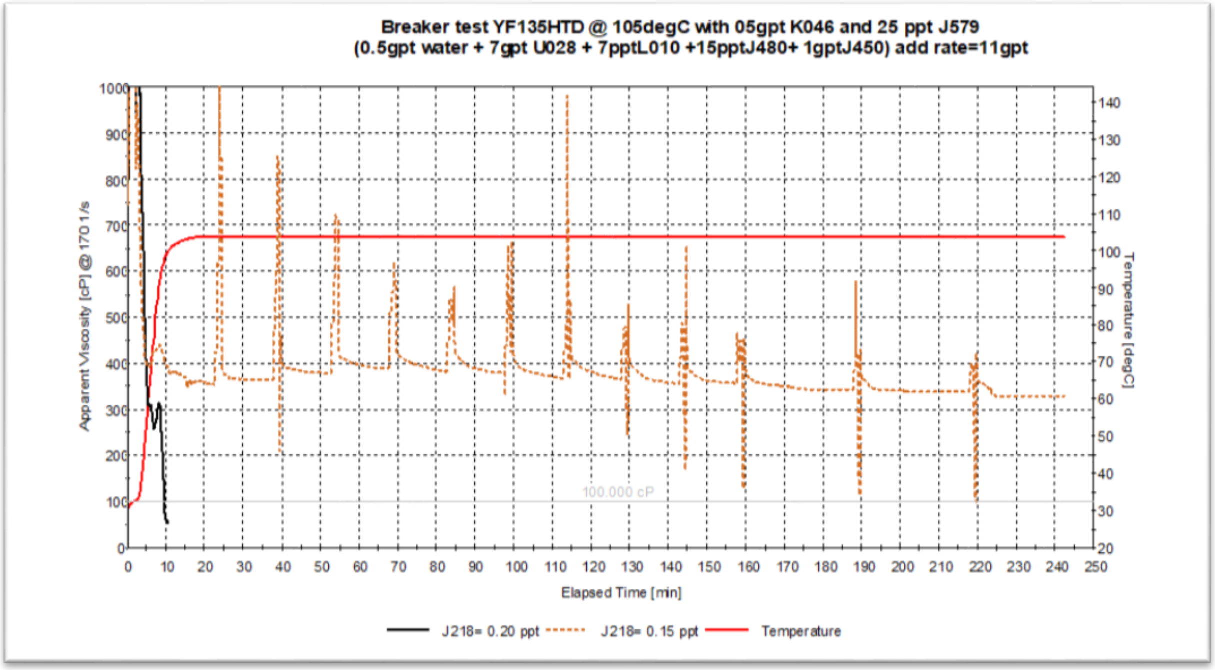


Figure III. 32: Breaker test YF135HTD @ 105 deg C with 05 gpt K046

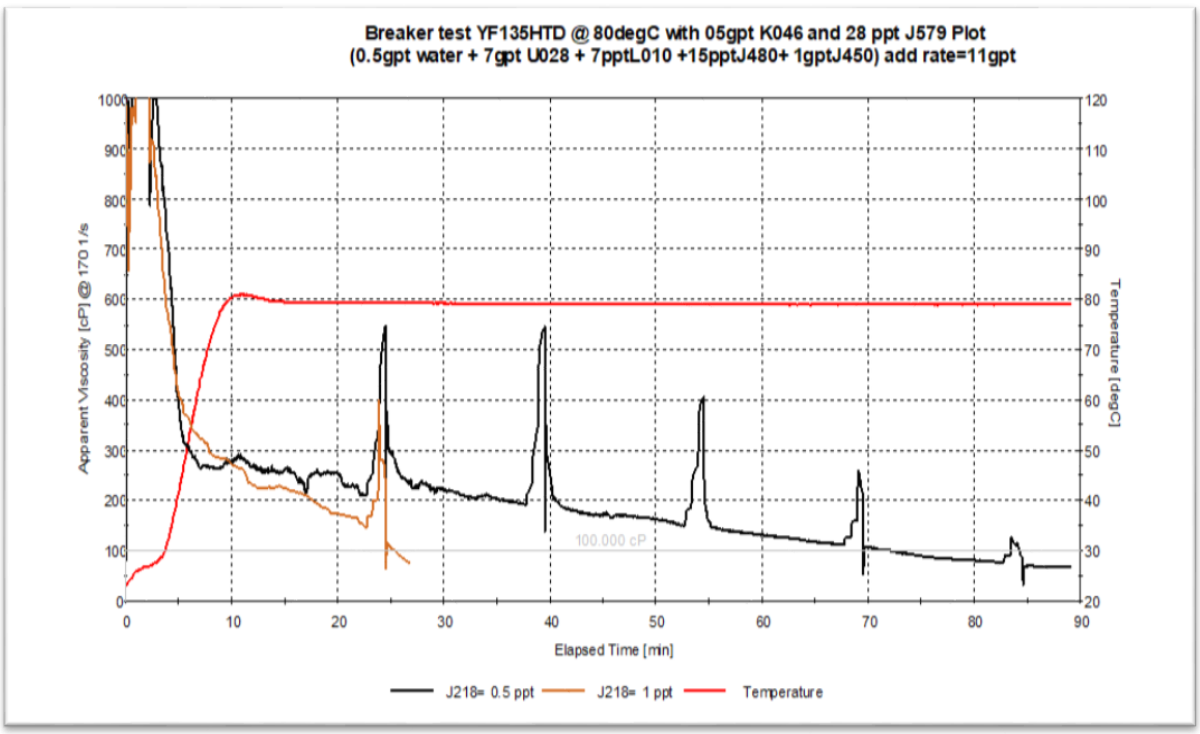


Figure III. 33: Breaker test YF135HTD @ 80 deg C with 05 gpt K046

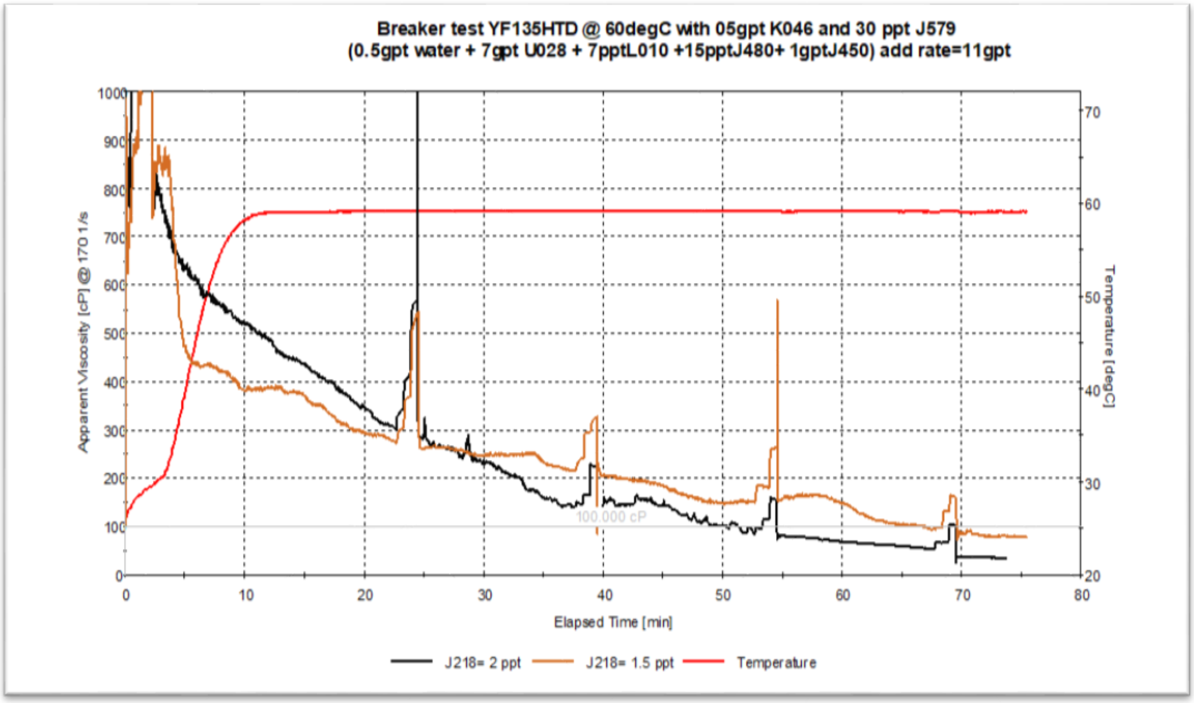


Figure III. 34: Breaker test YF135HTD @ 60 deg C with 05 gpt K046

III.4.3. Proppant permeability results analysis

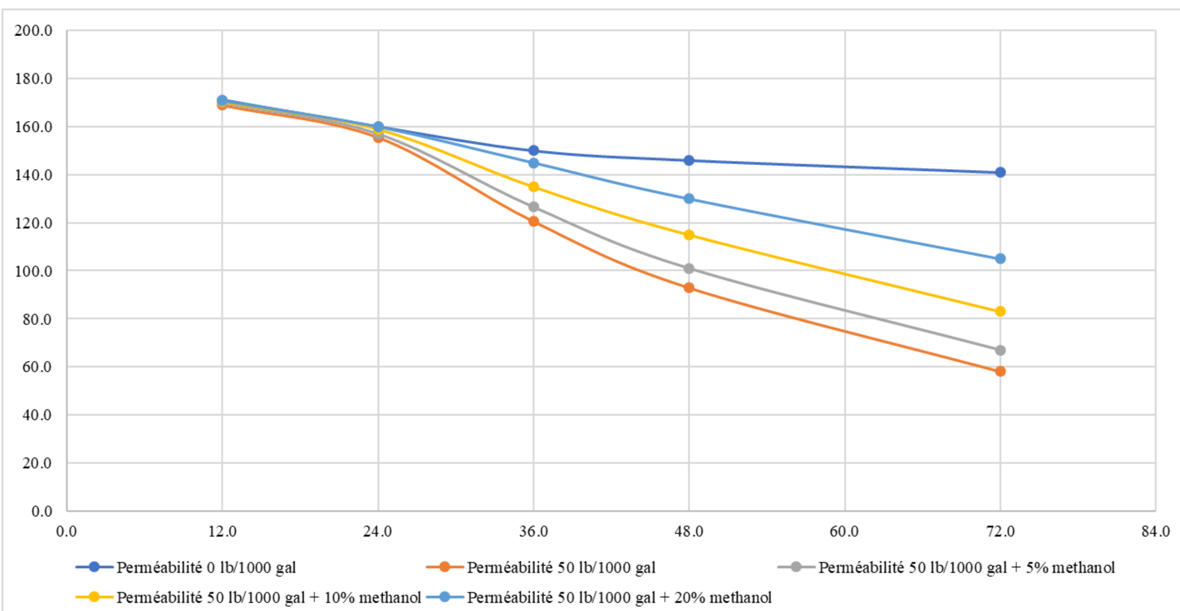


Figure III. 35: Permeability of 20/40 HSP proppant under 6000 psi at 120 C with 50 lb/1000 gal of borate crosslinked fluid and different concentration of methanol.

The effect of fracturing fluid on proppant permeability was investigated using one type of proppant 20/40 HSP and Guar gel type with borate crosslinker, sodium bromate breaker and different concentration of Methanol as mentioned in materials section.

The confinement cell was filled by the proppant and fracturing fluid with different concentrations and subjected to a stress of 6,000 psi. The proppant was then kept under stress and temperature of 120 °C at extended time. The permeability was measured by injecting the Gasoil at room temperature to examine the effect of time between closure and cleanup operations and gel concentration on the retained permeability.

(Figure III. 34) represents the permeability of 20/40 HSP proppant as function of extended time, all plots show that more the time is extended more the permeability impairment is severe.

As plotted in (Fig. 34) when using no gel concentration, the permeability impairment was low, and the decrease of proppant permeability was due to the pressure applied for long time. When using 50 lb/1000 gal of crosslinked guar gel, the permeability was around 170 mD after 12 hours. A drop of 25% was reported after 24 hours, this permeability drop will continue to reach 75% after 72 hours due to gel damage.

- When using 50 lb/1000 gal **+5% of Methanol**, the permeability was around **170 mD** after 12 hours, after 24 hours this permeability drop will continue to reach **158 mD**, after 72 hours it was **68 mD.**
- When using 50 lb/1000 gal **+10% of Methanol**, the permeability was around **170 mD** after 12 hours, after 24 hours this permeability drop will continue to reach **159 mD**, after 72 hours it was **82 mD.**
- When using 50 lb/1000 gal **+20% of Methanol**, the permeability was around **170 mD** after 12 hours, after 24 hours this permeability drop will continue to reach **145 mD**, after 72 hours it was **105 mD.**

This can be explained by the low viscosity of methanol compared to water, methanol reduces the pumping pressure required to deliver the fracturing fluids to the formation. [Lower piping friction requires less hydraulic power, which has significant impact on reducing cost (Antoci et al. 2001).]

Because methanol is miscible in water and has much lower surface tension (22.6 dynes/cm) than water (75 dynes/cm).

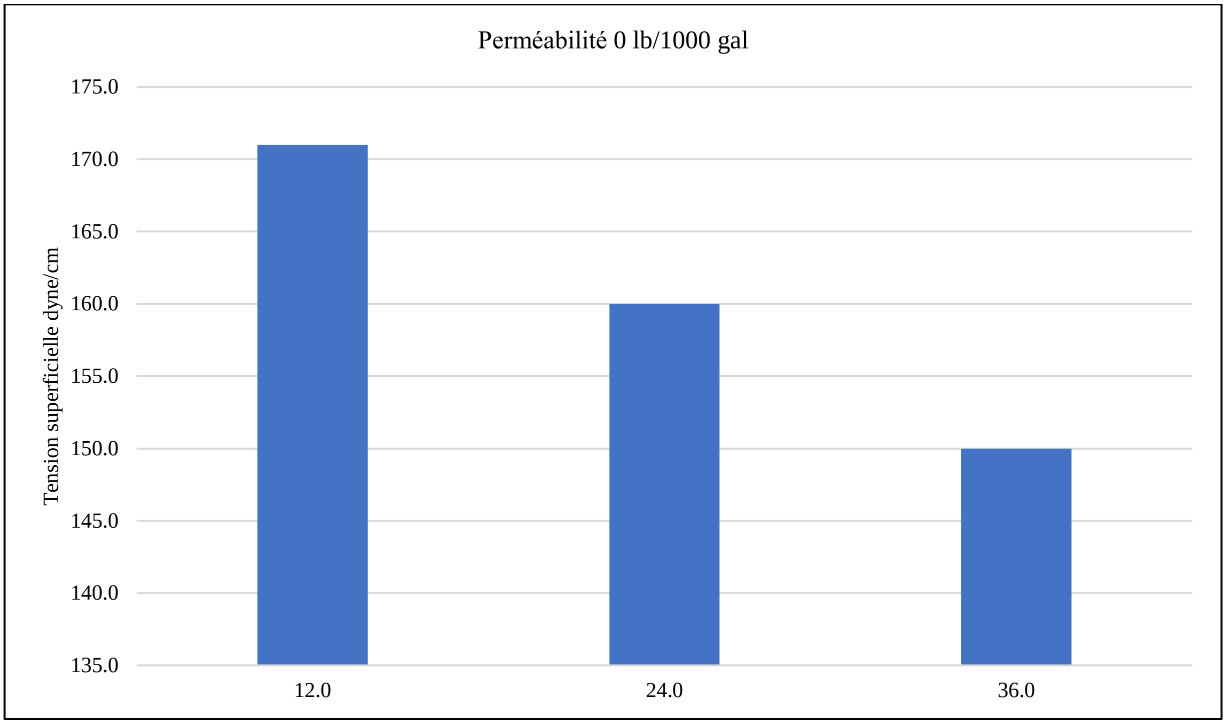


Figure III. 36: Surface tension of the gel without and with the addition of Methanol [27]

As the heated methanol starts to approach the wellbore, methanol is converted into **vapor**. This vaporization results in a significant increase of the upward **driving force** and enhancement of the fluids **flowback**. **[27]**

- After fracturing treatment using methanol at OMP-742.

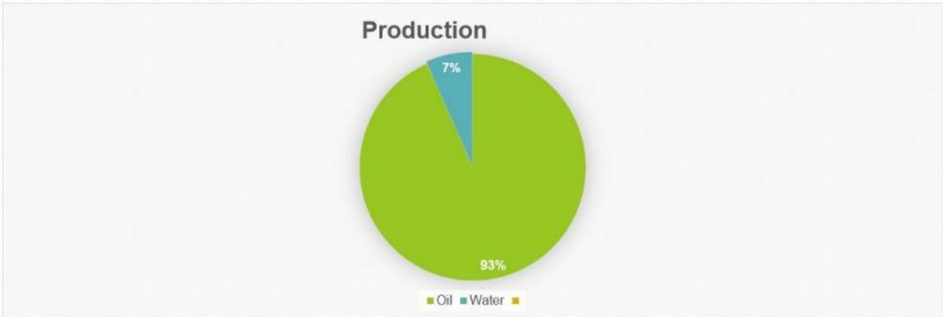


Figure III. 37: Water-Oil ratio

It is noted that the methanol treatment improved the productivity rates.

- Due to the positive results, we have had from this well, we can recommend the use of methanol in hydraulic fracturing at HMD field.

Conclusion

This study has allowed us to show the importance and efficiency using hydraulic fracturing technique in the exploitation of reservoirs with poor physical characteristics, including permeability of the rock. This technique increase the well productivity, which gives a considerable economic gain.

In our study, we analyze the results of Methanol Hydraulic Fracturing done in the well OMP-742 Hassi Messaoud. We can conclude:

The important gain in the flow rate and conductivity shows the necessity of using this technique of stimulation in this type of reservoir.

According to the new research and application of the modern fracturing treatment with Methanol in whole world, Methanol has demonstrated larger more benefits compared to conventional method of Hydraulic Fracturing, 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 Methanol.

Indeed, both Methanol and conventional fracturing is a profitable operation, but it is very precious and expensive, the reason why we recommend making 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.

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