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OPTION : Gas Engineering

THEME

**STUDY OF HYDRAULIC FRACTURING OPERATION
IN THE HTFN 11 WELL, HASSI MESSAOUD FIELD**

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Finally, we cannot but extend our heartfelt thanks to all those who, directly or indirectly, contributed to the accomplishment of this work, and to everyone who supported and encouraged us during this academic endeavor.

Dedication

I dedicate this humble work first and foremost to my dear parents, in recognition of their great sacrifices and constant support. I also dedicate it to my beloved sister and to all the members of my cherished family.

I further dedicate this work to my dear friends, each one of them individually, as well as to my colleagues, Mohamed Sebgag and Mohamed Selmane, and to all my classmates in the department, in gratitude for their support and encouragement.

SAHLI Ibrahim

Dedication

I dedicate this humble work first and foremost to my dear parents, in recognition of their sacrifices and constant support. I also dedicate it to my beloved sister, my nephew, all my brothers, and every member of my cherished family.

I further dedicate this work to my dear friends, each one by name.

I also dedicate it to my colleagues, Ibrahim Sahli and Mohamed Selmane, as well as to all my classmates in the department, in gratitude for their support and encouragement.

SEBGAG Mohamed Islam

عنوان المذكرة: دراسة عملية التكسير الهيدروليكي في البئر 11 HTFN بحقل حاسي مسعود
أسماء الطلبة : سباق محمد اسلام - سهلي إبراهيم

ملخص:

تركز هذه الدراسة على تطبيق تقنية التكسير الهيدروليكي المدعومة بالأنابيب الملفوفة في البئر 11 HTFN بحقل حاسي مسعود. في البداية، كان البئر يعاني من إنتاج ضعيف وغير مستقر لا يتجاوز 0.8 م³/س، مع إنتاج غازي يقدر بحوالي 89.91. بعد تصميم وتنفيذ العملية، والتي شملت التحضيرات المسبقة، المعالجة الحمضية، والمرحلة الرئيسية للتكسير باستعمال 66,812 رطل من مادة HSP 20/40 الداعمة، أظهرت القياسات بعد العملية تحسناً ملحوظاً: إذ ارتفع معدل التدفق بحوالي 1.65 م³/س ليصل إلى 2.45 م³/س، وقفز إنتاج الغاز إلى نحو 356.23. من الناحية الاقتصادية، بلغت التكلفة الإجمالية للعملية حوالي 192,429 دولاراً، مع فترة استرجاع لا تتجاوز 17 يوماً عند سعر نفط يقدر بـ 45 دولار/برميل. تؤكد هذه النتائج فعالية تقنية التكسير الهيدروليكي في تحسين مردودية الآبار النفطية، كما تبرز الدور التكميلي للأنابيب الملفوفة في ضمان نجاح العمليات الميدانية.

الكلمات المفتاحية: التكسير الهيدروليكي – الأنابيب الملفوفة – إنتاجية البئر – نفاذية الصخور – حاسي مسعود – بئر 11 HTFN
Memory title : STUDY OF HYDRAULIC FRACTURING OPERATION IN THE HTFN 11 WELL, HASSI MESSAOUD FIELD

The students : SEBGAG Mohamed Islam – SAHLI Ibrahim

Abstract:

This study focuses on the application of hydraulic fracturing supported by coiled tubing in the HTFN 11 well of the Hassi Messaoud field. Initially, the well exhibited a very low and unstable oil flow rate of about 0.8 m³/h, with a gas production of around 89.91. After the design and execution of the operation, including pre-job preparations, acid stimulation, and the main fracturing stage with 66,812 lbs of HSP 20/40 proppant, post-treatment measurements showed significant improvements: the oil flow rate increased by nearly 1.65 m³/h, reaching 2.45 m³/h, while gas production jumped to approximately 356.23. Economically, the total cost of the operation was about \$192,429, with a payback period not exceeding 17 days at an oil price of \$45/bbl. These results confirm the effectiveness of hydraulic fracturing in enhancing well productivity and highlight the complementary role of coiled tubing in ensuring operational success.

Keywords: Hydraulic fracturing – Coiled tubing – Well productivity – Rock permeability – Hassi Messaoud – HTFN 11 well

Titre de mémoire : Étude de opération de fracturation hydraulique dans le puits HTFN 11, champ de Hassi Messaoud

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Résumé:

Cette étude porte sur l'application de la fracturation hydraulique assistée par les tubes enroulés dans le puits HTFN 11 du champ de Hassi Messaoud. Au départ, le puits présentait un débit de pétrole faible et instable d'environ 0,8 m³/h, avec une production de gaz d'environ 89,91. Après la conception et la réalisation de l'opération, comprenant les préparatifs préalables, le traitement acide et la phase principale de fracturation avec 66 812 lbs de proppant HSP 20/40, les mesures post-traitement ont montré une amélioration significative : le débit pétrolier a augmenté d'environ 1,65 m³/h pour atteindre 2,45 m³/h, tandis que la production de gaz a grimpé à près de 356,23. Sur le plan économique, le coût total de l'opération a été estimé à environ 192 429 USD, avec une période d'amortissement ne dépassant pas 17 jours pour un prix du pétrole de 45 USD/baril. Ces résultats confirment l'efficacité de la fracturation hydraulique pour améliorer la productivité des puits et mettent en évidence le rôle complémentaire des tubes enroulés dans la réussite des opérations sur le terrain. **Mots-clés:** Fracturation hydraulique – Coiled tubing – Productivité du puits – Perméabilité des roches – Hassi Messaoud – Puits HTFN 11

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List of symbols and Abbreviations

K_s	Sand permeability,	md
K	Layer permeability,	md
H	Layer thickness (depth),	m
r_e	Reservoir radius,	ft
r_w	Well radius,	ft
μ	Viscosity,	cp
IP	Productivity index,	Without unit
S	Skin	Without unit
σ	Stress	psi
Σ	Deformation	m
L	Length,	m
T	Angle	degré
E	Young's modulus,	psi
ν	Poisson's ratio,	Without unit
G	Shear modulus,	Without unit
R_t	Tensile strength,	bar
P_o	Pore pressure,	psi
P_c	Closure pressure,	psi
P_p	Propagation pressure,	psi
P_f	Fracture pressure,	psi
P_w	Injection head pressure,	psi
P_h	Hydrostatic pressure,	psi
ΔP	Pressure drop,	psi

G_f	Fracture gradient,	psi/ft
L_f	Fracture length,	m
W_f	Fracture width,	m
H_f	Fracture height,	m
K_f	Fracture permeability,	md
X_f	Fracture extension,	m
C	Fluid filtration coefficient,	ft/min
T	Pumping time,	min

General Introduction:

The oil and gas industry remains one of the pillars of modern economies, as hydrocarbons continue to represent the primary source of global energy. However, the increasing complexity of reservoirs, the progressive depletion of easily accessible resources, and the growing need for cost-effective and safe operations have compelled the industry to adopt advanced technologies capable of maximizing recovery while reducing operational risks.

Among these technologies, Coiled Tubing (CT) and Hydraulic Fracturing (HF) have established themselves as essential tools in petroleum engineering. Coiled tubing, introduced as a versatile intervention technique, allows operators to perform a wide range of remedial and maintenance operations without interrupting production or removing completion equipment. Its flexibility, compact design, and ability to operate under live-well conditions make it an invaluable method for well cleanouts, acid stimulation, nitrogen lifting, fishing, and even as a support tool for fracturing and drilling operations.

Hydraulic fracturing, on the other hand, has revolutionized the development of low-permeability and unconventional reservoirs. By creating and propping open artificial fractures within the formation, HF enhances well-to-reservoir connectivity and significantly increases hydrocarbon flow rates. This process has become a cornerstone of modern field development strategies, with studies showing that the majority of new wells rely on fracturing to achieve commercial productivity. Nevertheless, the success of a fracturing operation is not solely dependent on fracture initiation and propagation but also on the careful selection of proppants—solid materials designed to maintain fracture conductivity after pumping has ceased. The choice of proppants involves balancing mechanical performance, density, transport properties, and economic considerations, all of which directly influence well performance and recovery efficiency.

This thesis is structured to address these two key technologies from both theoretical and practical perspectives. Chapter I provides an overview of coiled tubing technology, including its technical specifications, surface and downhole equipment, operational advantages, limitations, and safety considerations. Chapter II focuses on hydraulic fracturing, tracing its historical development, principles, and field applications, with special emphasis on the selection criteria and performance of proppants. Finally, Chapter III presents a field case study of the HTFN 11 well in the Hassi

Messaoud field, which illustrates the practical application of these techniques and evaluates their effectiveness in enhancing production under real reservoir conditions.

Through this integrated approach, the study seeks to highlight the complementary role of coiled tubing and hydraulic fracturing in modern petroleum operations and to demonstrate how their combined application can significantly improve the productivity and economic performance of hydrocarbon reservoirs.

Chapter I

General Overview of coiled tubing

Introduction:

The oil and gas industry is constantly seeking innovative technologies that enhance hydrocarbon recovery while reducing operational costs and risks. Among these technologies, coiled tubing (CT) has emerged as a versatile and efficient solution for performing a wide range of well interventions and remedial operations without interrupting production or removing the completion string.

Coiled tubing consists of a continuous, small-diameter steel pipe stored on a large reel and deployed into the wellbore under pressure. Its design allows for real-time operations such as fluid circulation, tool conveyance, and downhole interventions, even in deviated or horizontal wells. This flexibility makes CT a valuable asset for both routine maintenance and complex downhole procedures.

Over the years, coiled tubing has proven effective in operations such as well cleanouts, acid stimulation, nitrogen lifting, logging, perforation, cement placement, and hydraulic fracturing support. Its compact surface footprint, fast mobilization, and continuous circulation capabilities offer significant time and cost savings compared to conventional methods.

This chapter provides a comprehensive overview of coiled tubing technology, including its technical specifications, surface and downhole equipment, operational advantages and limitations, as well as safety considerations. Real-world case studies will also be presented to illustrate the practical impact and field performance of coiled tubing in various intervention scenarios.

I.1 Definition of Coiled Tubing:

Coiled tubing (CT) refers to a continuous, jointless length of small-diameter steel pipe, typically ranging from 1 to 3.25 inches (25 to 83 mm), stored and transported on a large reel. It is widely utilized in various well intervention and remedial operations without requiring the removal of production tubing or the need to kill the well. Due to its flexibility, CT enables efficient fluid circulation, tool conveyance, and real-time response to downhole conditions. Applications include well cleanouts, acid stimulation, nitrogen lifting, logging, perforation, and support operations in hydraulic fracturing and coiled tubing drilling. [1]

I.2 Technical Specifications and Equipment:

A standard coiled tubing unit (CTU) consists of several interconnected surface and downhole components that work together to enable efficient and safe interventions in oil and gas wells. The main surface equipment includes the control cabin, reel, power pack, injector head, gooseneck, stripper, and blowout preventers (BOPs). Each component plays a crucial role in ensuring the smooth deployment and retrieval of the coiled tubing string. [1]

I.2.1 Control Cabin:

The control cabin is strategically positioned to offer the operator a clear view of the surface equipment, particularly the reel and tubing movement. It is equipped with all necessary controls and monitoring instruments to manage and supervise parameters such as circulation pressure, wellhead pressure, tubing weight, tool depth, movement speed, fluid flow rate, volume pumped, and the operation of the injector head, BOPs, and stripper.

I.2.2 Reel (Drum):

The reel stores and handles the coiled tubing string. It allows controlled spooling and unspooling of the tubing during operations. To minimize bending stress, the reel must have a sufficiently large core diameter. Storage capacities typically range from 5,000 to 22,000 feet, depending on tubing diameter. The reel is also equipped with auxiliary systems like depth counters, purge valves, plug launching systems, isolation valves, and lubrication sprayers to prevent corrosion.

I.2.3 Power Pack:

The power pack provides the hydraulic energy required to operate the CT unit components, such as the reel, injector head, BOPs, and accumulators. Driven by a diesel engine, the power pack supplies multiple circuits at varying pressures (up to 3000 psi) to control different subsystems. It includes safety features such as emergency shutdown systems in case of abnormal temperature or oil pressure variations.

I.2.4 Injector Head:

The injector head is one of the most critical components of the CT unit. It uses twin continuous chains driven by hydraulic motors to push or pull the tubing into or out of the well. Its pulling capacity depends on the injector's size, hydraulic pressure, and speed settings (typically 125–250

ft/min). The injector head is also equipped with gripping systems to maintain tubing integrity and prevent slippage or crushing.

I.2.5 Gooseneck:

The gooseneck is a guiding arch located between the reel and the injector head. It directs the tubing from its coiled state to a straight position for smooth entry into the well. The radius of curvature must be compatible with the tubing diameter to avoid fatigue and premature failure. Typical minimum bend radii range from 13 inches (for 3/4" tubing) to 42 inches (for 2 3/8" tubing).

I.2.6 Stripper:

The stripper, located just below the injector head, ensures a pressure-tight seal around the tubing during well operations. It acts as the primary pressure barrier and prevents tubing buckling. There are three main types: conventional, side-door, and radial strippers. Tandem strippers are often used to enhance safety by providing redundancy in sealing capabilities.

I.2.7 Blowout Preventers (BOPs):

BOPs are critical safety devices mounted above the wellhead. They serve as secondary and tertiary barriers in case of well control events. Common types include:

- ✓ **QUAD BOPs:** Four ram stacks (blind, shear, slip, and pipe rams)
- ✓ **COMBI BOPs:** Compact units with dual-function rams
- ✓ **Annular BOPs:** Provide sealing over varying tubing/tool diameters
- ✓ **Shear/Seal Rams (Safety Head):** Serve as emergency cutoff devices in high-regulation environments

These BOPs are hydraulically controlled from the operator's cabin and typically operate under pressures ranging from 1,500 to 3,000 psi. [1]

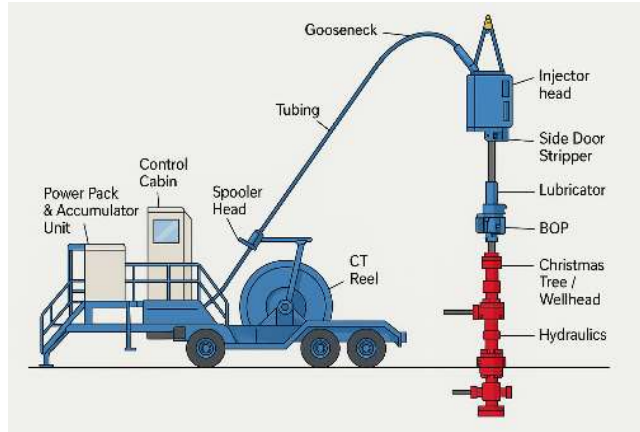


Figure I.1: Schematic Representation of a Coiled Tubing Unit Showing Main Components

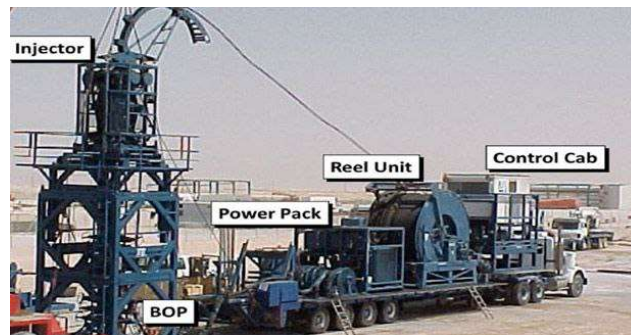


Figure I.2: Field View of a Coiled Tubing Unit with Labeled Equipment

I.3 Applications of Coiled Tubing:

Coiled tubing is a highly versatile technology used in a wide range of oil and gas well operations. Its ability to enter wells under pressure without the need to remove completion equipment makes it an efficient tool for both remedial and routine tasks. The following are the most common applications of coiled tubing in field operations:

I.3.1 Well Cleanouts:

One of the primary uses of coiled tubing is for cleaning operations. It is often employed to remove accumulated sand, scale, paraffin, or other debris that restricts production. The tubing allows for direct circulation of fluids to dislodge and transport unwanted materials to the surface.

I.3.2 Acidizing and Chemical Stimulation:

CT is frequently used for matrix acidizing, where acid is pumped directly into the formation to dissolve scale or improve permeability. Its ability to deliver fluids precisely at targeted zones makes it highly effective for stimulation in both vertical and horizontal wells.

I.3.3 Nitrogen Lifting and Well Kickoff:

In wells with low reservoir pressure, nitrogen can be injected through coiled tubing to reduce hydrostatic pressure and assist in lifting fluids to surface. This technique is often used during well startup or after extended shut-ins.

I.3.4 Logging and Perforation:

Coiled tubing can serve as a conveyance method for running logging tools into the wellbore, especially in deviated or horizontal wells where wireline may not be effective. It can also be used for conveying perforation guns in underbalanced conditions.

I.3.5 Sand Plug and Cement Placement:

CT is ideal for accurate placement of sand plugs or cement slurries in specific intervals of the wellbore. This application is commonly required during zone isolation, water shutoff, or to support mechanical tools.

I.3.6 Milling and Fishing Operations:

CT systems can be used to mill scale, cement, or other restrictions inside the tubing or casing. It is also useful in fishing operations to retrieve stuck tools, wireline, or debris from the well.

I.3.7 Hydraulic Fracturing Support:

In certain cases, coiled tubing is used to convey perforating guns or jetting tools as a preparation stage before fracturing. It can also be used to initiate fractures in small-scale operations or to place diverters.

I.3.8 Coiled Tubing Drilling (CTD):

Although less common, coiled tubing can also be used in directional drilling, especially for re-entry or sidetracking applications in mature wells. CTD offers continuous circulation and reduced trip time compared to conventional drill pipe. [2]

I.4 Advantages and Limitations of Coiled Tubing:

Coiled tubing technology offers numerous operational and economic advantages, making it a preferred solution in many well intervention scenarios. However, it also presents some technical limitations that must be carefully considered when planning operations.

I.4.1 Advantages:

- **Operation under pressure:** One of the most significant advantages of coiled tubing is its ability to operate in live wells without the need to kill the well. This reduces formation damage and downtime.
- **Mobility and rapid deployment:** CT units are compact and easily transportable, allowing for fast mobilization and demobilization, which is particularly beneficial in remote or offshore locations.
- **Continuous circulation:** Fluids can be pumped through the tubing during movement, enabling efficient cleanouts, chemical treatments, and pressure control.
- **High-speed operation:** Coiled tubing allows for faster running and retrieval speeds compared to wireline or snubbing units, increasing operational efficiency.
- **Horizontal and deviated well access:** Due to its flexibility, CT can reach areas that are difficult or impossible to access with rigid tools or conventional pipe.
- **Multifunctional capabilities:** It can be used for a wide range of operations—cleanouts, stimulation, logging, fishing, and even drilling—making it a highly versatile tool.

I.4.2 Limitations:

- **Low tensile strength:** Coiled tubing has limited pulling capacity, which restricts its use in heavy-duty applications or deep wells.
- **Susceptibility to fatigue:** The tubing undergoes repeated bending during spooling and unspooling, leading to fatigue over time and a limited operational life (often around 80 cycles).
- **Pressure and temperature constraints:** CT cannot withstand the same high pressures or extreme temperatures as traditional drill pipe or casing.
- **High friction and pressure losses:** Due to its small diameter, fluid flow inside CT results in greater pressure losses, limiting pumping rates and tool effectiveness.
- **Risk of collapse or crushing:** Differential pressures greater than 1500 psi across the tubing wall may lead to collapse, especially in deep or high-pressure wells.

- **Corrosion sensitivity:** CT is vulnerable to corrosion from acids or hydrogen sulfide (H₂S), requiring careful material selection and monitoring.
- **Complexity in handling and repair:** Any damage to the tubing may require cutting and re-spooling, leading to non-negligible downtime and cost.

I.5 Safety Considerations and Operational Challenges:

Despite its many operational advantages, coiled tubing operations present significant safety and engineering challenges. Understanding and managing these risks is essential to protect personnel, equipment, and the well integrity. [2]

I.5.1 Fatigue and Structural Integrity:

Coiled tubing is subject to repeated mechanical stress due to continuous bending and unbending—particularly during spooling, unspooling, and passage over the gooseneck. These cyclic stresses lead to metal fatigue, which limits the tubing’s service life. Each tubing section is typically monitored for the number of fatigue cycles, and must be removed or trimmed before reaching critical failure thresholds.

I.5.2 Pressure Control and Well Integrity:

Operating under pressure requires robust pressure control systems. The stripper acts as the primary barrier, while a stack of Blowout Preventers (BOPs)—including shear rams and pipe rams—provides secondary and tertiary protection. Failure in any component of the pressure control system can lead to dangerous well control incidents.

I.5.3 Risk of Collapse and Deformation:

Due to its thin wall and high flexibility, coiled tubing is vulnerable to collapse if the external pressure exceeds the internal pressure by more than 1500 psi. It is also susceptible to buckling in deviated wells, especially if excessive compressive forces are applied during pushing operations.

I.5.4 Corrosion and Chemical Exposure:

Exposure to acidic fluids, hydrogen sulfide (H₂S), and other aggressive downhole environments accelerates corrosion. This can lead to pinhole leaks or catastrophic failure if not detected early. Proper material selection (such as corrosion-resistant alloys) and real-time monitoring are essential.

I.5.5 Operational Hazards:

Other operational risks include:

- ✓ Sudden ejection of tubing during retrieval due to trapped well pressure.
- ✓ Tool sticking or equipment failure downhole.
- ✓ Incorrect synchronization between reel and injector head.
- ✓ Human error in control systems or pressure adjustments.

I.6 Coiled Tubing Applications in Hydraulic Fracturing:

Coiled tubing applications in hydraulic fracturing have provided new opportunities to improve well stimulation. The use of CT allows selective fracturing, better proppant placement, and the possibility to treat multiple intervals in a single run. This approach is particularly effective in low-permeability reservoirs and in wells where conventional fracturing methods face technical or mechanical limitations. [3]

1.6.1 Fracturing Through Coiled Tubing:

Recently, as a field-driven, cost-effective application, a hydraulic fracturing technique was introduced by Schlumberger, mainly in western Canada so far. It consists of a coiled tubing (CT) with a bottomhole assembly to isolate sets of perforations (straddle packers). The primary candidates are wellbores that produce gas commingled from multiple low-permeability zones after the fracturing operation. The primary objective is to place proppant effectively within all the producing intervals throughout the wellbore.

This service is called CoilFRAC and can be used both in old wells (which may have a weakened casing that might not withstand fracturing pressures) and new wells with perforated completions. Multiple hydraulic fracture stimulation treatments can be carried out in one single trip. It has been applied in temperatures up to 170°C, in deviated wells up to 75° deviation. CT diameters of 1.75" to 2.375" have been used, with flow rates of 8 to 25 bpm, proppant loadings of 5 to 12 ppg, in well depths up to 10,000 ft. When frictional pressure losses with standard polymer gel fluids become prohibitively high to use CT fracturing technology, a newly developed viscoelastic surfactant base fluid can be used .

Halliburton recently also introduced a similar coiled tubing fracturing service, called Cobra Frac.[3]

Conclusion:

Overall, coiled tubing has become an essential tool in modern well interventions, thanks to its flexibility, speed, and wide range of applications. Whether it's cleaning out a well, performing acid treatments, retrieving stuck tools, or supporting fracturing operations, CT has proven to be a reliable and efficient solution for both simple and complex downhole tasks.

Despite some technical challenges—such as limited pulling strength, bending stress from repeated use, or sensitivity to pressure and corrosion—the benefits it offers, like reducing non-productive time, working while the well remains live, and maintaining better pressure control, make it highly valuable across the oil and gas sector.

The field examples discussed in this chapter show how coiled tubing can help improve well performance and solve operational problems, especially in aging or low-pressure fields. These insights pave the way for the next chapter, where we will take a closer look at how coiled tubing plays a key role in hydraulic fracturing operations.

Chapter II

Hydraulic Fracturing

INTRODUCTION:

In the pursuit of maximizing hydrocarbon recovery from increasingly complex and low-permeability reservoirs, hydraulic fracturing has emerged as a cornerstone technique in modern petroleum engineering. Originally developed as a method to stimulate well productivity, this process has evolved over the decades into a sophisticated, multi-phase operation that integrates geology, fluid mechanics, material science, and advanced engineering practices.

This chapter provides a detailed exploration of hydraulic fracturing, beginning with its historical origins and foundational principles. It delves into the specific objectives of the process, the various types of equipment employed, and the key components of fracturing fluids. Furthermore, it highlights the role of proppants—solid materials critical to maintaining fracture conductivity—and elaborates on their selection criteria, types, and field applications. The chapter concludes by addressing the mechanical behavior of fractured formations, the geometrical characterization of fractures, and the challenges commonly encountered in real-world fracturing operations.

Through this structured analysis, the chapter aims to offer both theoretical grounding and practical insights into one of the most impactful techniques in the oil and gas industry.

II.1. HISTORY:

The first attempts at fracturing formations were not hydraulic in nature, they involved the use of high explosives to break the formation apart and provide “flow channels” from the reservoir to the wellbore. There are records indicating that this took place as early as 1890. Indeed, one of the predecessor companies of BJ Services, the Independent Torpedo Company, was founded in 1905. It used nitroglycerine to explosively stimulate formations in Ohio. This type of reservoir stimulation reached its ultimate conclusion with the experimental use of nuclear devices to fracture relatively shallow, low permeability formations in the late 1950’s and early 1960’s.

In the late 1930’s, acidizing had become an accepted well development technique. Several practitioners observed that above a certain “breakdown” pressure, injectivity would increase dramatically. It is probable that many of these early acid treatments were in fact acid fractures.

In 1940, Torrey recognized the pressure-induced fracturing of formations for what it was. His observations were based on squeeze cementing operations. He presented data to show that the

pressures generated during these operations could part the rocks along bedding planes or other lines of “sedimentary weakness”. Similar observations were made for water injection wells by Yuster and Calhoun in 1945.

The first intentional hydraulic fracturing process for stimulation was performed in the Hugoton gas field in western Kansas, in 1947. The Klepper well was completed with 4 gas producing limestone intervals, one of which had been previously treated with acid. Four separate treatments were pumped, one for each zone, with a primitive packer being employed for isolation. The fluid used for the treatment was war-surplus napalm, surely an extremely hazardous operation. However, 3000 gals of fluid were pumped into each formation. Although post treatment tests showed that the gas Injectivity of some zones had been increased relative to others, the overall deliverability from the well was not increased. It was therefore concluded that fracturing would not replace acidizing for limestone formations. However, by the mid-1960’s, propped hydraulic fracturing had replaced acidizing as the preferred stimulation method. Early treatments were pumped at 1 to 2 bpm with sand concentrations of 1 to 2 ppa.

Today, thousands of these treatments are pumped every year, ranging from small skin bypass fracturing at \$20,000, to massive fracturing treatments that end up costing well over \$1 million. Many fields only produce because of the hydraulic fracturing process. In spite of this, many industry practitioners remain ignorant of the processes involved and of what can be achieved.

II.2. Definition of Hydraulic Fracturing:

Hydraulic fracturing is the process of pumping a fluid into a wellbore at an injection rate that is too great for the formation to accept in a radial flow pattern. As the resistance to flow in the formation increases, the pressure in the wellbore rises to a value that exceeds the breakdown pressure of the formation open to the wellbore. Once the formation "breaks down" a fracture is formed, and the injected fluid begins moving down the fracture. In most formations, a single, vertical fracture is created that propagates in two directions from the wellbore. These fracture "wings" are 180° apart and normally are assumed to be identical in shape and size at any point in time; however, in actual cases, the fracture wing dimensions may not be identical. In naturally fractured or cleated formations, it is possible that multiple fractures can be created and propagated during a hydraulic fracture treatment.[4]

II.3.The Objective of Hydraulic Fracturing:

In general, hydraulic fracture treatments are used to increase the productivity index of a producing well or the injectivity index of an injection well. The productivity index defines the rate at which oil or gas can be produced at a given pressure differential between the reservoir and the wellbore, while the injectivity index refers to the rate at which fluid can be injected into a well at a given pressure differential. Hydraulic fracturing can:

- Increase the flow rate of oil and/or gas from low-permeability reservoirs
- Increase the flow rate of oil and/or gas from wells that have been damaged
- Connect the natural fractures and/or cleats in a formation to the wellbore
- Decrease the pressure drop around the well to minimize sand production
- Enhance gravel-packing sand placement
- Increase the area of drainage or the amount of formation in contact with the wellbore
- Decrease the pressure drop around the well to minimize problems with asphaltene and/or paraffin deposition
- Connect the full vertical extent of a reservoir to a slanted or horizontal well.[4]

II.4. Principle of Hydraulic Fracturing:

Hydraulic fracturing refers to the process of creating conductivity in a rock formation from a well by injecting a fluid carrying a proppant at sufficiently high pressures. Most often, hydraulic fracturing of a reservoir results in the opening of a pre-existing fracture (as in naturally fractured reservoirs), and only rarely in the initiation of a new fracture (as in compact reservoirs).

It is well established that the fracture propagates perpendicular to the minimum in-situ principal stress.

Therefore, it is natural to aim at increasing reservoir productivity by creating a well-formation connection that has significantly higher permeability than the matrix in the first case, or by bypassing damage in the second case.

The success of the treatment largely depends on:

- The selection of the candidate well (completion).
- The amount of remaining recoverable reserves (economic factor).
- The stress profile (favorability).

II.5. Field of Application:

This process is applied when a well's flow rate is insufficient, either due to the low natural permeability of the rock (a few tens of millidarcies in oil reservoirs, even less in gas reservoirs), or due to damage that is difficult to remove through acidizing, in order to achieve sufficient conductivity contrast between the fracture and the formation.

Hydraulic fracturing is only suitable for sufficiently consolidated formations (such as sandstone and limestone), as opposed to plastic formations (such as clay and poorly consolidated sands). Moreover, it is strongly discouraged when it may encourage the flow of an undesirable fluid from a nearby zone (presence of an interface).

In favorable conditions, productivity or injectivity gains can be expected, typically stabilizing around a factor of 3 to 4 (excluding the effect of damage removal).

II.6.Pre-Treatment Measurements:

Several key measurements are conducted before the treatment, including:

- Well logging measurements (diagraphies)
- Core sampling (carottage)
- Well testing

II.6.1 Well Logging Measurements:

Pre-treatment well logs provide information on water/oil and oil/gas contacts, identify permeable zones, and more. These logs serve as a basis for comparison with post-treatment well logs.

II.6.2 Core Sampling:

Laboratory operations on core samples help detect the appearance of fractures during stress variation and predict in-situ stresses.

II.6.3 Well Testing:

Well testing techniques such as build-up, drawdown, and drill-stem testing (DST) are widely used to identify certain parameters related to the well and reservoir, including skin effect and the localization of impermeable barriers.

II.7.Criteria for Selecting Fracture Wells:

The selection of the candidate well is intended to guide it because there is no single rule to follow.

Therefore, before selecting a well, it is necessary to gather and classify the necessary information on the reservoir (reservoir well), without forgetting the economics of the operation.

II.7.1 Reservoir:

II.7.1.1. Nature of the Reservoir:

The success or failure of the hydraulic fracturing operation can be estimated based on the nature of the reservoir rock because reservoir rocks can be fractured more or less easily, but the problem that arises is whether it can be supported by proppants or not? For example, in the case of so-called soft rock (poorly consolidated), the instruction of the proppants is necessary.

II.7.1.2. Interface of the fluids in place:

Carrying out hydraulic fracturing requires perfect knowledge of the interfaces of the fluids in place, because it is essential to avoid extension, for example, gas and/or water for an oil well.

II.7.1.3. Nature of the fluids in place:

The compatibility of the stimulation fluids and those in place is very important, because one can, encounter problems:

- formation of stable emulsions.
- formation of precipitates, and residues of different types, etc

II.7.1.4. Reservoir Permeability:

A more precise understanding of permeability is essential when choosing the well to fracture. For example, permeability values obtained from core measurements and, above all, the interpretation of well tests provide:

- the productivity index (IP)

- formation conductivity (kh)
- Damage to the wellbore (skin effect)

II.7.1.5. Well History:

This section lists all operations undertaken during:

Drilling (logging operation).

Production tests (last pressure buildup, last gauging)

Previous treatments (if applicable).

Neighboring wells.

Production wells.

Injection wells.

Nearby fractured wells: Characteristics of each well, i.e., the production characteristics before and after fracturing

Well Completion: The completion must be adapted to the treatment to be performed. Carrying out the treatment therefore requires good isolation of the levels to be stimulated. An excellent formation/cement sheath/casing connection, as well as the condition of the well equipment, allow for safe injection; therefore, it is necessary to provide a safety coefficient to cope with any possible increase in pressure during treatment.

II.7.1.6. Operation Economics:

The economic interest of hydraulic fracturing lies in estimating the profitability of the treatment, which requires a precise assessment of:

The cost of the treatment itself.

The cost of prior operations.

The profitability of the treatment requires amortization within a reasonable timeframe. It varies depending on:

The geographical location

II.8.Fracturing Equipment :

Fracture treatments require multiple pieces of sophisticated equipment specifically designed for hydraulic fracturing. In many cases, multiple pieces of the same kind of equipment, such as pumps, are necessary. The type, size, and number of pieces of equipment needed are dependent on the size of the fracture treatment, type of treatment, as well as the additives, proppants, and fluids that are used. Table II.1 presents a listing of typical equipment used during a fracturing job, and the purpose of the identified equipment.

- **Fracturing Head** A well head connection that allows fracture equipment to attach to the well
- **Fracturing Pumps** Heavy duty pumps that take the fluid from the blender and pressurize it via a positive displacement pump
- **Blender pumps** Takes fluid from the fracturing tanks and sand from the hopper and combines these with chemical additives before transferring the mixture to the fracturing pumps
- **Transfer pumps** A trailer-mounter pump and manifold system that transfers fluid from one series of Fracturing Tanks to another, or from ponds to the manifold
- **Sand Storage Units** Large Tanks that hold the proppant and feed the proppant to the blender via a large conveyor belt
- **Fracturing Tank-supply** Water containment tanks that store the required volume of water to be used in fracture stimulations
- **Fracturing Tanks-Receiving** Water containment tanks that store produced water from hydraulic fracture stimulations
- **Gel Slurry Tanker Truck** Transports gel slurry to the job site ; the equipment has 2 compartments to allow for the gel to be agitated between the compartments to prevent separation or break down
- **Chemical Storage Trucks** Flatbed trucks used to transport chemicals to the job site, may contain a pump to transfer chemical additives from the on-board storage tanks to the required equipment (i.e. blender)
- **Technical Monitoring Van** The work area for Engineers, Supervisors, pump Operators, Company Representatives, and Regulatory Personnel

- **Acid Transport Trucks** Used to transport acids to job sites ; a truck has separate compartments for the transport of multiple acids or additives
- **Manifold Trailer** Large manifold system that acts as a transfer station for all fluids ; mixed fluids from blender pumps move through the manifold on the way to the pump trucks.

Once onsite, the equipment is “rigged up.” The rig-up process involves making all the necessary iron connections between the fracturing head on the well, the fracturing manifold mounted on the trailer, the fracturing pumps, and the additive equipment that supplies the pumps with fluids. These connections undergo a series of assessments and pre-tests to ensure they can withstand the pressure of the fracturing operation and that all connections have been properly made and sealed.



Figure II.1: Hydraulic Fracturing Equipments.

The figure shows a 3D illustration of some of the main components involved in the hydraulic fracturing process.

II.9. Hydraulic Fracturing Fluids :

Water and sand are the most common constituents of most fracturing fluids, several parameters affect the volume of fracture fluid required for a successful stimulation:

- Propping agent amount and type
- Rock type/stimulation objective
- Designed fracture conductivity

- Rock closure stress/fracture width
- Fluid leak off characteristics
- Proppant transport
- Formation permeability
- Injection rate
- Reservoir thickness.

The main components of a fracturing fluid, besides the base carrier fluid (typically water), are the following additive. Common additive purposes and examples of chemicals used for these purposes are presented in Table

Additive Type	Main Compound	Use in Hydraulic Fracturing Fluids	Common Use of Main Compound
Acid	Hydraulic Acid Or Muriatic Acid	Acids are used to clean cement from casing perforations and drilling mud clogging natural formation porosity, if any, prior to fracturing fluid injection (dilute acids concentrations are typically about 15% acid)	Swimming pool chemical and cleaner
Biocide	Glutaraldehyde	Fracture fluids typically contain gels that are organic and provide a medium for bacterial growth. Bacteria can break down the gelling agent reducing its viscosity an ability to carry proppant. Biocides are added to the mixing tanks with the gelling agents to kill these bacteria.	Cold sterilant in health care industry
Breaker	Sodium Chloride	Breakers are chemicals that are typically introduced toward the later sequences of a fracturing job to “break down” the viscosity of the gelling agent to better release the proppant from the fluid enhance the recovery or “flow back” of the fracturing fluid.	Food Preservative

Corrosion Inhibitor	N, N-Dimethyl Form amide	Corrosion inhibitors are used in fracture fluids that contain acids; they inhibit the corrosion of steel tubing, well casings, tools, and tanks.	Crystallization medium in Pharmaceuticals
Cross linker	Borate Salts	There are two basic types of gels used in fracturing fluids: linear and cross linked. Cross-linked gels have the advantage of higher viscosities that do not break down quickly.	Non-CCA wood preservatives and fungicides
Friction Reducer	Petroleum Distillate Or Mineral Oil	Friction reducers minimize friction, allowing fracture fluids to be injected at optimum rates and pressures.	Cosmetics, nail and skin products
Gel	Guar Gum Or Hydroxyethyl cellulose	Gels are used in fracturing fluids to increase fluid viscosity, allowing them to carry more proppant than straight water solutions. In general, gelling agents are biodegradable.	Food-grade product used to increase viscosity and elasticity of ice cream, sauces and salad dressings.
Iron Control	Citric Acid	Iron controls are sequestering agents that prevent precipitation of metal oxides.	Used to remove lime deposits. Lemon Juice is ~ 7% Citric Acid
Kcl	Potassium Chloride	Kcl is added to water to create a brine carrier fluid.	Table salt substitute
Oxygen Scavenger	Ammonium Bisulfate	Oxygen present in fracturing fluids through dissolution of air causes the premature degradation of the fracturing fluid; oxygen scavengers are commonly used to bind the oxygen.	Used in cosmetics

Proppant	Silica , Quartz Sand	Proppants consist of granular material, such as sand, mixed with the fracture fluid. They are used to hold open the hydraulic fractures, allowing the gas or oil to flow to the production well.	Play box sand, concrete or mortar sand.
Scale Inhibitor	Ethylene Glycol	Scale inhibitors are added to fracturing fluid to prevent precipitation of scale (calcium carbonate precipitate).	Automotive antifreeze and de-icing agent
Surfactant	Naphthalene	Surfactants are used to reduce interfacial tension and promote more efficient clean-up or flow-back of injected fluids.	Household fumigant (found in mothballs)

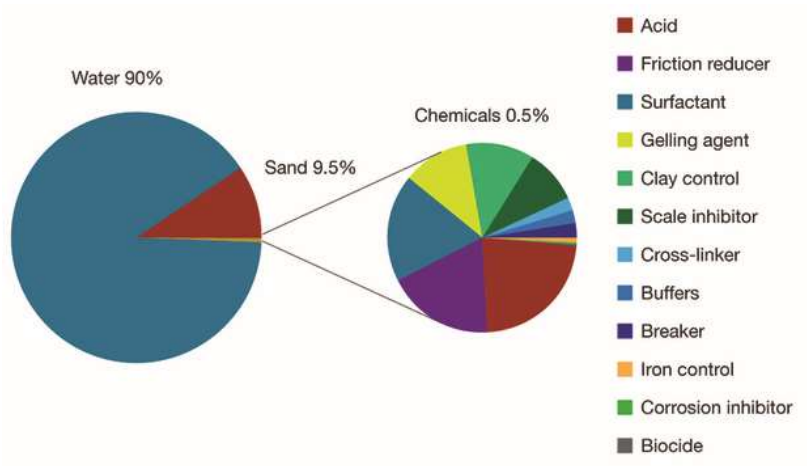


Figure II.2: Typical Fracture Fluid Composition

II.10.Hydraulic Fracturing Proppants:

II.10.1.Definition of Proppants:

Proppants are small solid particles used in hydraulic fracturing to keep the walls of an induced fracture open after the pumping process has ended. Their main function is to maintain a conductive channel that connects the reservoir to the wellbore. The conductivity of the propped fracture must be high enough to reduce the radial flow resistance typically seen around an unfractured well, thereby enabling linear flow into the fracture. Selecting the appropriate proppant is a key aspect of fracturing design. For example, using sand may reduce costs, but if it crushes under stress, it can decrease well productivity. On the other hand, stronger alternatives may improve performance but come at a higher cost, which must be justified by the expected economic return. [5]

II.10.2.Proppants Selection:

The main requirement for an ideal proppant used in hydraulic fracturing is to maintain high permeability under reservoir conditions. This necessitates sufficient strength to resist crushing under increased rock stresses resulting from production and depletion. The proppant should have a uniform, preferably spherical shape, as well-rounded particles are less likely to bridge in perforations or fractures and are less prone to crushing under high closure stress. A narrow particle size distribution is also essential to reduce point loading and minimize breakage within the fracture. Additionally, the proppant should contain minimal amounts of oversized or undersized particles, including dirt and other impurities. It must also be resistant to fracturing fluids, formation fluids, and acids. Availability in a range of suitable sizes is important, as size affects not only permeability but also placement efficiency—larger particles tend to settle faster and are more prone to bridging. A low density, ideally matching that of the fracturing fluid, is preferred to prevent settling during transport within the fracture. Lastly, the proppant must be available in large quantities at an acceptable cost. [6]

II.10.3. Proppant Selection Criteria:

Selecting the appropriate proppant involves balancing several factors:

- **Reservoir Conditions:** Depth, temperature, and closure stress dictate the required strength and durability of the proppant.
- **Economic Considerations:** Cost of the proppant and its impact on overall project economics.
- **Operational Factors:** Compatibility with fracturing fluids, ease of transport and placement, and potential for flowback.

II.10.4 Proppant Types in Hydraulic Fracturing:

In hydraulic fracturing operations, proppants are solid materials introduced into the fracture network to maintain the created fractures open once the pumping pressure is released. The selection of an appropriate proppant is critical, as it directly influences the fracture conductivity and, consequently, the efficiency and productivity of the well.

1. Natural Sand (Frac Sand)

Frac sand is the most commonly used proppant due to its wide availability and cost-effectiveness. It is composed of high-purity quartz sand with durable, round grains that provide resistance to crushing under pressure. The sand undergoes processing steps, including washing to remove fines and screening to achieve the desired grain size distribution.

Advantages:

- ❖ Cost-effective and readily available.
- ❖ Suitable for shallow to moderately deep wells with lower closure stresses.

Disadvantages:

- ❖ Lower strength compared to synthetic proppants, making it susceptible to crushing under high-pressure conditions.
- ❖ Potential for fines generation, which can reduce fracture conductivity.

2. Resin-Coated Sand (RCS)

Resin-coated sand involves applying a resin layer to natural sand grains, enhancing their strength and reducing fines generation. There are two primary types:

- Curable Resin-Coated Sand: The resin cures downhole, bonding the grains together and providing increased resistance to proppant flowback.
- Pre-Cured Resin-Coated Sand: The resin is cured during manufacturing, offering consistent properties and ease of handling.

Advantages:

- ❖ Improved mechanical strength over uncoated sand.
- ❖ Reduces proppant flowback and fines migration.

Disadvantages:

- ❖ Higher cost compared to natural sand.
- ❖ May require specific handling and pumping equipment.

3. Ceramic Proppants:

Ceramic proppants are manufactured from materials like bauxite or kaolin, sintered at high temperatures to achieve high strength and uniformity. They are designed to withstand high closure stresses and maintain conductivity in deep, high-pressure wells.

Advantages:

- ❖ High crush resistance and mechanical strength.
- ❖ Uniform size and shape enhance fracture conductivity.

Disadvantages:

- ❖ Significantly more expensive than sand-based proppants.
- ❖ Higher density may require more energy for pumping and placement.

4. Sintered Bauxite Proppants:

Sintered bauxite proppants are a subset of ceramic proppants known for their exceptional strength and durability. They are suitable for the most demanding applications, such as ultra-deep wells with extremely high closure stresses. [7]

Advantages:

- ❖ Superior mechanical properties, maintaining conductivity under extreme conditions.
- ❖ Minimal fines generation, preserving fracture integrity.

Disadvantages:

- ❖ Highest cost among proppant types.
- ❖ Dense material may pose challenges in transportation and placement.

5. Alternative and Specialized Proppants:

Beyond the conventional proppants, various alternative materials have been explored to address specific reservoir challenges:

- Lightweight Ceramics: Designed to reduce settling rates and improve transport in low-viscosity fluids.
- Resin-Coated Ceramics: Combine the strength of ceramics with the flowback control of resin coatings.
- Natural Materials: Such as walnut shells or glass beads, used in niche applications where specific properties are required. [7]



Figure II.3: Proppant Types Pyramid

II.11. Basic Concepts of Hydraulic Fracturing:

1. Contraintes (Stresses) :

In general, formations are subjected to different stresses that interact to maintain these rocks in a state of compression. Stress (σ) is defined as the force applied per unit area.

$$\sigma = \frac{\text{force}}{\text{surface}} \quad (\text{II.1})$$

2. Local State of Stress in Depth: There are two types of stresses:

- ✓ Total principal stresses ($\sum i$)
- ✓ Effective principal stresses (σi)

These stresses are related to each other by the following relationship:

$$\sigma i = \sum i - \alpha P (i = 1,2,3) \quad (\text{II.2})$$

$$\alpha = 1 - \frac{c_m}{c_b} \quad (\text{II.3})$$

With: PC: Layer pressure.

Cm: Matrix compressibility

Cb: Pore rock compressibility

α : Biot's constant ($0 \leq \alpha \leq 1$), $\alpha \approx 1$.

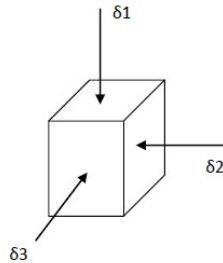


Figure II.4 : Contraintes exercé

3. **Mechanical properties of rocks:** Rocks are characterized by:

- ✓ Young's modulus (E).
- ✓ Poisson's ratio (ν).
- ✓ Shear modulus (G).

4. **Young's Modulus (E):** When a body is subjected to stress, it deforms under the effect of that stress until a certain limit (specific to the material) is reached. This deformation is elastic, meaning that the tested body returns to its initial shape when the stress is removed. For low stresses, the deformation is proportional to the stress. [8]

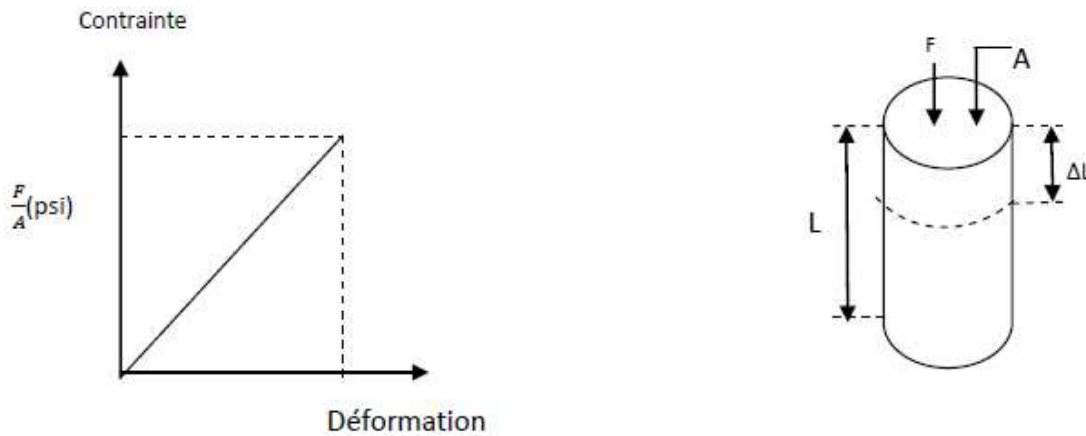


Figure II.5: Elastic Deformation

Deformation is defined as the variation of a dimension relative to the initial length:

$$\Sigma = \frac{\Delta L}{L} = \frac{L1-L2}{L1} \quad (II.4.)$$

The stiffness of a material can be defined as follows: A material will be stiffer than another if, when subjected to the same stress, it undergoes a smaller deformation.

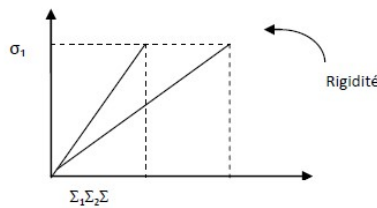


Figure II.6: Material Stiffness

The stiffness of a material can be characterized by the slope of the stress-strain curve. The value of this slope is a material property known as Young's modulus (E)

$$E = \frac{\sigma}{\Sigma} \quad (\text{II.5})$$

The Young's modulus of water or oil-saturated rock is generally lower than the Young's modulus of dry rock.

5. Poisson's Ratio (ν):

The Poisson's ratio (ν) is a dimensionless coefficient defined as the ratio of the lateral dimension change (change in diameter) to the axial or longitudinal dimension change (change in length) when the sample is subjected to compression. It varies for rocks within the range of 0.1 to 0.45. [8]

$$\nu = \frac{\Delta d/d}{\Delta l/l} \quad (\text{II.6}).$$

6. Shear modulus (G):

The shear modulus (G), also known as the modulus of rigidity, is often used in modeling. It represents the material's ability to resist deformation by shear stress. The shear modulus is denoted by (G) and is an important parameter in characterizing the mechanical properties of rocks.

$$G = \frac{E}{2(1+\nu)} \quad (\text{II.7.})$$

E: Young's modulus

ν : Poisson's ratio

II.12. Fracture Geometry:

1.Shape and Orientation of the Fracture: Field experiments have shown that hydraulic fractures develop along horizontal or vertical planes. For depths less than 600 m, it is possible to obtain fractures in horizontal planes. For depths greater than 600 m, the weight of the sediments causes the fracture to develop only in vertical planes, and this is the case in Hassi Messaoud.

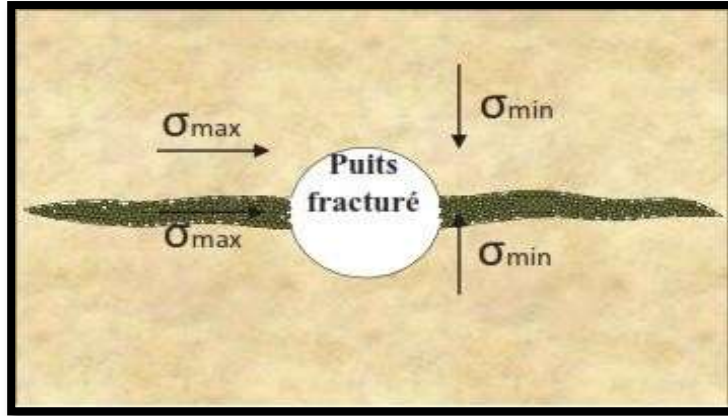


Figure II.7. Shape and orientation of the fracture according to the stress (s)

2. Dimensionless Fracture Conductivity :

The dimensionless fracture conductivity is represented by the ratio:

$$F_{CD} = \frac{K_f W_f}{K X_f} \quad \text{II.8}$$

X_f : Fracture extension (half-length).

W_f : Fracture width.

K : Permeability of the formation.

K_f : Permeability of the fracture

For optimal fracturing, it is sufficient to have $2 < FCD < 10$.

The efficiency of a fracturing operation depends on the following three dimensions:

a) Fracture length (X_f) This is the distance between the well and the point located at the end of the fracture. It can be either the length or the half-length of a fracture, depending on whether the fracture has one or two symmetrical wings.

b) Fracture width (W_f) This is the distance between the two vertical faces of the fracture.

c) Fracture height (H_f) This is the vertical distance between the two points associated with zero width (Figure 8). All of this applies to vertical fractures. In the case of a horizontal fracture, the height replaces the width, and vice versa.

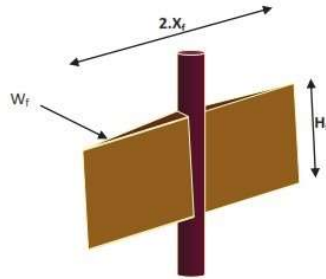


Figure II.8. Evolution of pressure during fracturing.

3. Initiation and Extension

Pressure of the Fracture:

Figure 10 depicts a schematic curve of pressure evolution during fracturing. It is divided into two parts:

- Injection stage.
- Closure stage.

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

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

- Instantaneous Shut-In Pressure (ISIP), which occurs when the pumps are stopped.
- The closure period of the fracture.

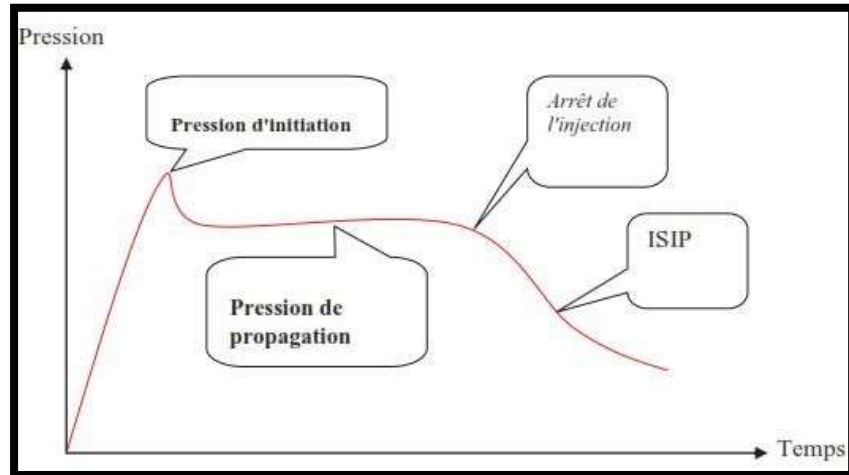


Figure II.9. Evolution of pressure during fracturing

II.13. Classification of parameters involved:

a. Parameters to be known

- Stresses.
- Formation permeability.
- Formation porosity.
- Young's modulus. (Definition: CH II.11.4)
- Poisson's ratio. (Definition: CH II.11.5)

b. Parameters to be chosen

- Injection rate.
- Fracturing fluid (viscosity, filtration).
- Proppant (type, particle size, concentration).

c. Parameters to be obtained

- Fracture width (W_f).
- Fracture extension (X_f).
- Supported height (H_f).
- Conductivity ($K_f * W_f$).

Before starting hydraulic fracturing in any well, it is imperative to know the stress profile (stresses) of the well in order to target and control the fracture effectively. It should be noted that this technique is the most risky and costly. [1]

II.14. Implementation of hydraulic fracturing

II.14.1. Well preparation

- Well testing to estimate current formation permeability (Kh) and depletion state.
- Mechanical cleaning after determining the sediment top.
- Hydrochloric acid cleaning for cleaning the casings, followed by wellbore cleanout.

II.14.2. Pre-job safety procedure:

- Pressure testing of all lines at 10,000 psi.
- Testing of 7" annulus lines at 5,000 psi.
- Testing of 98/5 annulus lines at 5,000 psi. These pressures must be maintained for at least 10 minutes.
- Installing a safety valve for the 7" annulus, set at 3,800 psi, and another one for the 98/5 annulus.
- Opening the master valve of the wellhead and increasing pressure on the 98/5 annulus by 500 psi and maintaining this pressure during the job.
- Increasing pressure on the 7" annulus by 1,000 psi and maintaining this pressure between 2,500 to 3,000 psi during the job.

II.14.3. Injectivity test:

The MD296 well is located in zone 2ex in the central perimeter, with coordinates $X = 804998.75$ and $Y = 123447$. This test immediately precedes the actual treatment. It involves injecting fluid into the formation at a low rate and incrementally increasing the rate. The rate is maintained for a while until the pressure stabilizes, followed by a short pressure drop. ISIP (Instantaneous Shut-In Pressure) for each injection is plotted against the injection rate to obtain the fracture extension pressure. [1]

II.15. Problems of hydraulic fracturing:

Despite the progress made in hydraulic fracturing techniques, there are still challenges encountered during field operations, including the following:

1. Tortuosity phenomenon:

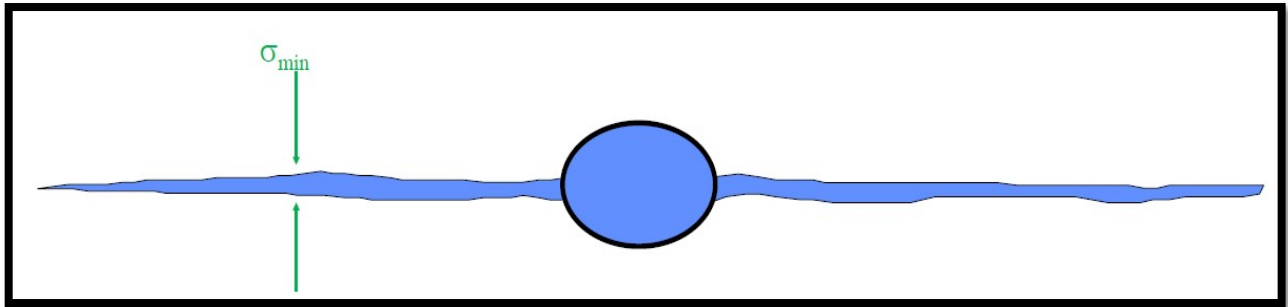


Figure II.10. The phenomenon of tortuosity in a fracture.

The existence of tortuosity near the wellbore is mainly due to the curvature of the initiated path from the wellbore to the tip of the fracture. It can be caused by:

- Poor cementation.
- Stress distribution relative to the perforations. Hydraulic fractures initiate and propagate perpendicular to the principle of least resistance of the rocks, following the plane of maximum stress (Figure 11)

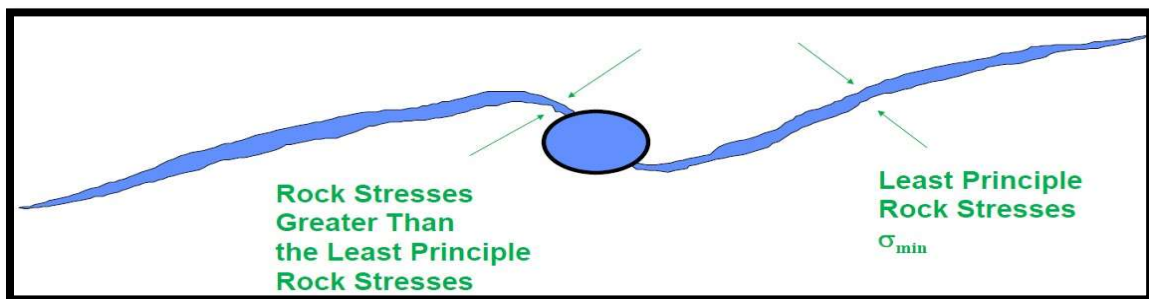


Figure II.11. The ideal shape of a fracture..

In Figure 12, we present the propagation of a fractured well affected by tortuosity. The creation of such a curved path in the well causes an increase in bottomhole pressure during pumping due to the fluid having to follow the curved path. This creates circulation and overload of the proppant-enriched product, leading to premature screen-outs in certain cases.

2. Plugging:

A fracturing treatment designed to enhance reservoir productivity can be a source of formation plugging. This is caused by the fracturing fluid and the proppant.

- The fracturing fluid can cause formation damage and/or reduced fracture conductivity due to: A. Emulsion of the formation with the fracturing fluid. B. High viscosity leading to poor flow. C. Residue left in place after fluid degradation.
- The proppant can significantly impact the created permeability due to: A. Insoluble residues originally present in the fluid or formed during fluid degradation in the fracture and formation pores. B. Proppant crushing in the formation resulting from improper proppant selection.

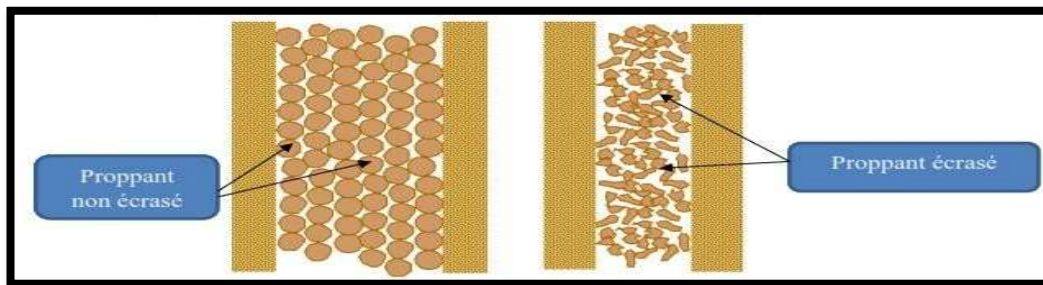


Figure II.12. Crushing strength of the proppant.

3. Screen-Out [9]

A screen-out occurs when the treatment pressure reaches the maximum pressure and the operation needs to be stopped. There are two types of screen-out:

- Tip Screen-Out: Occurs when the proppant has reached the fracture tips and the fracture can no longer propagate in any direction. (Figure 14.)
- Near-Wellbore Screen-Out: Occurs near the wellbore due to various factors such as insufficient pad volume, inadequate fracture width, fluid loss, fluid type, tortuosity, or multiple fractures.

Causes of screen-out can include:

- Insufficient pad volume.

- Inadequate fracture width.
- Fluid loss.
- Type of fluid.
- Tortuosity.
- Multiple fractures
- **Tip Screenout:**

A tip screenout occurs when the proppant has reached the tips of the fracture and the fracture can no longer grow in any direction. (Figure 14.)

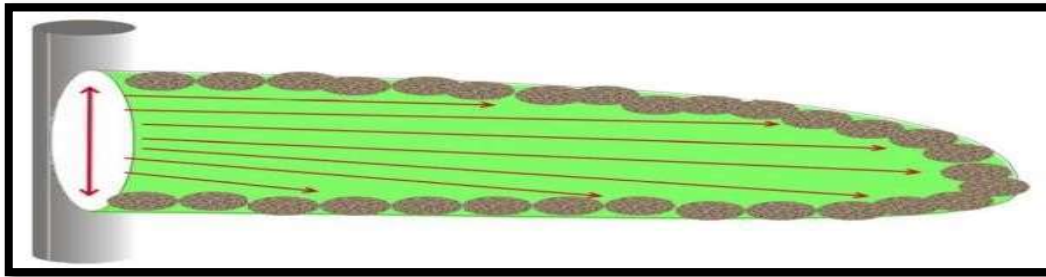


Figure II.13. Proppant-laden tips in the case of Tip Screenout.

- **Near Wellbore Screenout:**

A Near Wellbore Screenout occurs when a proppant pack prevents the hydraulic fluid from reaching the fracture tip.

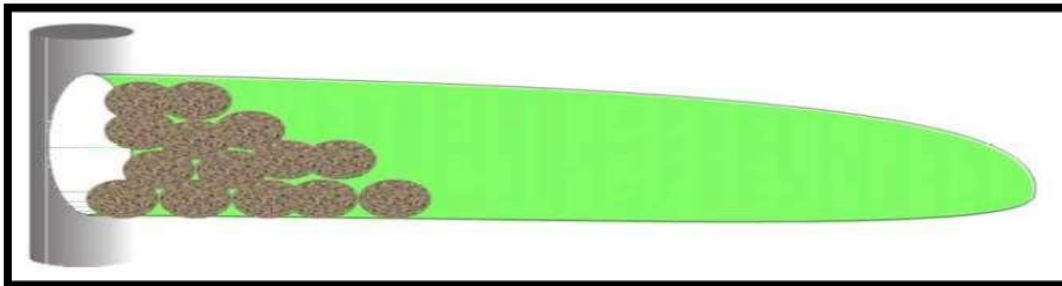


Figure II.14. Proppant Bridging in the Near Wellbore Screenout Case

4. Perforations:

The type of perforations, their density, and distribution play a crucial role in the success of the fracturing process and in avoiding certain problems. To prevent tortuosity issues, the perforations should be oriented in the direction of the maximum horizontal stress. To facilitate the passage of proppant particles, the perforation diameters should be sufficiently large.

5. Wellhead Configuration Typically:

The wellhead series used for production is rated at 5000 psi. However, during the fracturing treatment, pressures easily exceed 5000 psi at the wellhead. To address this issue, a bypass equipment called a "treesaver" is used, which bypasses the wellhead and anchors into the casing.

6. Other Issues:

- Gas and water breakthrough into the fracture propagation towards the areas affected by neighboring injection wells.
- Tubing-annulus communication during the operation. [9]

II.16. Fracture Gradient

1. Fracture Pressure The fracture pressure depends on:

- The state of stress acting on the reservoir.
- Boundary conditions.
- Fluid mobility during injection.

$$PF = Pw + Ph - Pf \quad \text{II.9}$$

With: Pw: injection pressure at the wellhead. Ph: Hydrostatic pressure. Pf: Pressure losses, which can have two components:

- Pressure losses in the tubing.
- Pressure losses at the level of the perforations.

2. Fracture Gradient GF By definition:

The fracture gradient is equal to the ratio of the fracture pressure (B) and the depth of the formation

$$GF = \frac{P_f}{h} \quad \text{II.10}$$

With: PF: fracturing pressure. H: fracturing depth.

CONCLUSION

Hydraulic fracturing has revolutionized the development of hydrocarbon reservoirs by enabling the production of oil and gas from formations that were once considered economically inaccessible. This chapter has provided a comprehensive overview of the technique, from its historical development to its current applications and engineering complexities.

The discussion emphasized the importance of understanding subsurface stress conditions, selecting appropriate fracturing fluids and proppants, and employing precise equipment configurations. It also addressed the influence of fracture geometry and rock mechanical properties on the success of the treatment. Notably, the chapter shed light on field challenges such as screen-outs, tortuosity, and formation damage, all of which must be carefully managed to ensure treatment effectiveness.

In conclusion, mastering the principles and operational parameters of hydraulic fracturing is essential for petroleum engineers aiming to optimize reservoir performance. As technology continues to evolve, so too will the techniques and materials used in fracturing, paving the way for more efficient and sustainable hydrocarbon production.

CHAPTER III

Study of the HTFN 11 well

Study of the HTFN 11 well

III.1 Generalities in the field of Hassi Messaoud

Hassi Messaoud's field is one of the most complex fields in the world.

During geological history, this field underwent on the one hand an intense tectonic evolution characterized by compressive and intensive phases. Other parts, by the diagenetic transformation in the reservoir during its burial during the geological time, until the deposit took shape as represented by the current configuration.

These events can sometimes improve the physical petro parameters (natural hydraulic fracturing, dissolution etc.) as they can reduce them (reduction of porosity due to the phenomena of pressure solution, creation of small grain matrices etc.).

Location (Figure III.1)

The Hassi Messaoud field is located 850 km South – South-east of Algiers and 350 km from the Tunisian border:

- In coordinates Lambert south Algeria is:
- 790,000 to 840,000 East.
- 110,000 to 150,000 North.

The dimensions of the deposit reach 2500 km² with a surface impregnated with oil of about 1600k

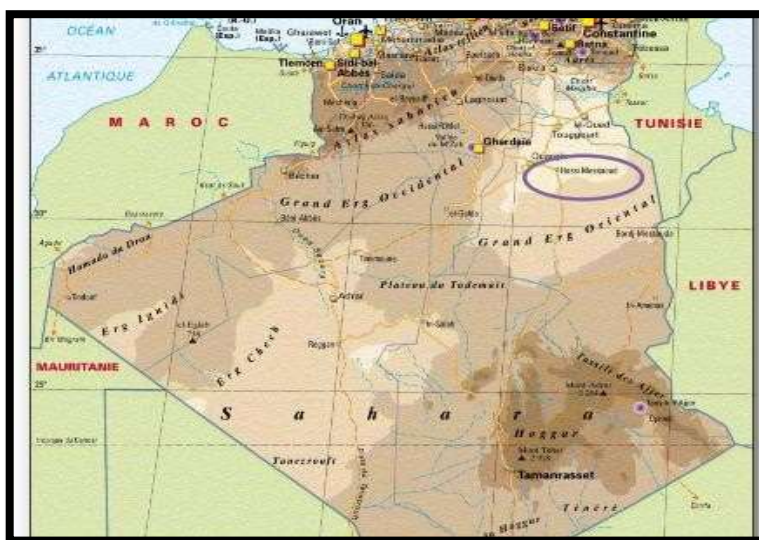


Figure III.1. Fracture shape

III.1.2. Geological situation of the Hassi Messaoud field:

Hassi Messaoud's field occupies the central part of the Triassic province. Due to its size and these reserves, it is the largest oil field in Algeria and covers an area of nearly 2200 km².

Geologically, it is limited:

To the west by the depression of Oued M'ya. To the south by the mole of Amguid El Biod.

In the North by the Djammâa-Touggourt structure.

To the east by the shoals of Dahar, Rhourde El Baguel and the depression of Ghadames.

III.2. Well History and Generality HTFN 11

The HTFN11 is a new well status oil producer realized as part of the development of the Hassi Tarfa deposit. The objective of this well is the exploitation of the Ordovician reservoir (Hamra quartzites).

The HTFN11 well was drilled and completed in 07 February 2018, crosses the hamra quartzite formation. The DST carried out in Open Hole on 24/01/2018 gave 5.74 m³/h oil with an IP of 0.028 m³/h/kg/cm², KHL 70.7 md. m, a Pg of 477.9 kg/cm² and a Skin of 3.86.

The well was drilled in 01/08/2018 between (3453 – 3445) and (3443 – 3440) and (3437 - 3424) and (3418 – 3400).

The Well was put into production on 16/08/2018 with a flow rate of 2.56 m³/h, after, the well did not maintain its flow rate despite three reformat cleanings carried out and a reformat & xylene treatment On 01 September 2019, Additional perms were added targeting the QH2 3455 – 3462m but without results, To this end, it was decided to fracture the well in order to recover the initial potential A production test carried out in 11 February 2020 resulting in 0.8 m³/h of oil with a GOR of 112 stm³/stm³ The well is currently open and produced intermittently. Pt head = 8.5 Kg/cm² 18.3

• objectif

Hydraulic Fracturing in QHE Tank

HTFN Well Positioning 11

The HTFN11 well is located in the northern part of the HassiTarfa perimeter, at a distance of 1.49km southeast of HTFN10, at 1.74km west of HTFN9.

X= 796117.523

Y= 3473994.337

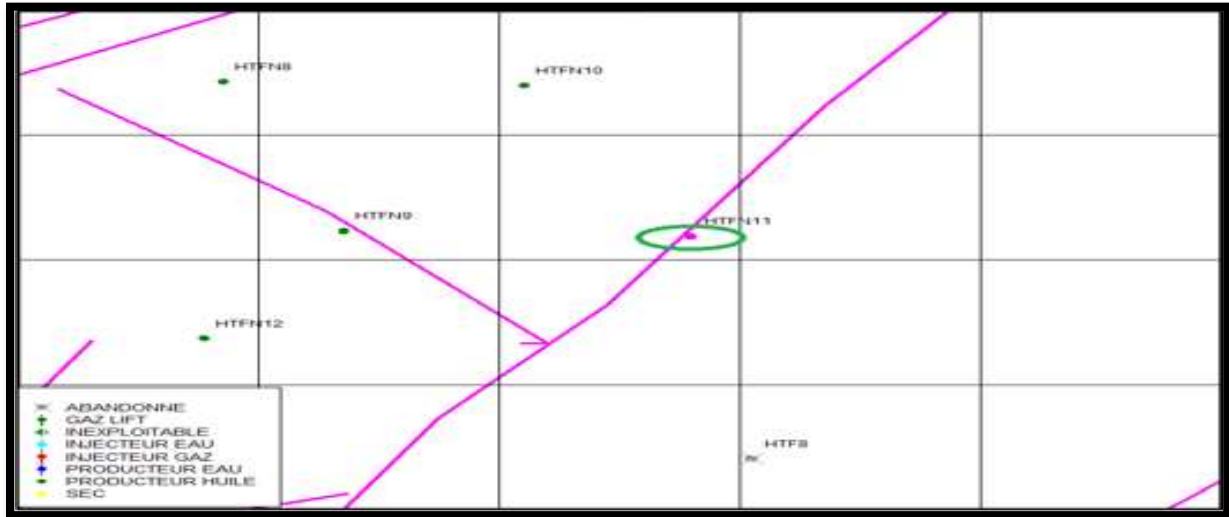


Figure III.2.HTFN 11 Vertical Oil Well Positioning Map

Adjacent Wells:

Neighbouring wells HTFN11 are all open producing wells with stable flow rates +/- 5m3

Table 1.neighbouring wells

Well	State	Distance	Last gauging	Fracturing	Flow m3/h
HTFN9	PPH, open	1083m	26/10/19	No	5.27
HTFN10	PPH, open	1048m	19/11/19	No	4.26
HTFN12	PPH, open	1035m	19/11/19	No	2.2
HTF8	Abandoned				

A single nearby well fractured, HTFN5 whose Data as follows:

Table 2.the adjacent fractured well

well	Condition	Distance	Fracking Date	Proppant	Qav	Qap
HTFN5	PPH, closed	1868m	05/04/2018	28319lbs	0	3.19

III.2.2. HTFN11 Well Operations History:

Well drilled and completed in 07/02/2018, completion 4'' ½. P110 13.5#

25/072018: Cleaning

07/28/2018: Cleaning

07/30/2018: Cleaning at CTU, treated water treatment

01/08/2018: Operation Wire line, perforation

16/08/2018: clean tube cleaning

25/10/2018: Reformat cleaning

17/11/2018: Reformat cleaning + Xylene

24/02/2019: Reformat cleaning

09&10/07/2019: Reformat + Xylene processing

11/07/2019: Start at CTU after processing

10/08/2019: Reformat cleaning + xylene

III.2.3. HTFN 11 well production profile

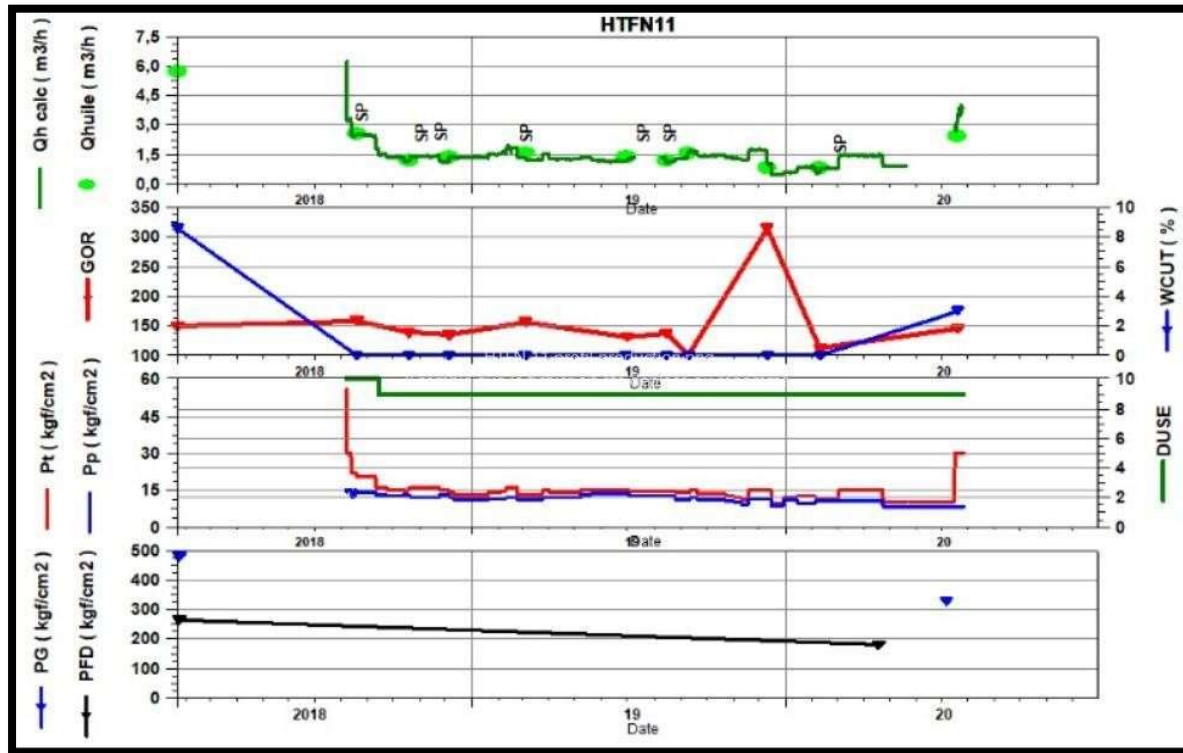


Figure III.3.HTFN 11 Well Production Profile

The current well is open and intermittently produced, according to the profile of last gauging the well flow is about 0.8 m/h.3

III.3. Appropriateness of Fracturing

The selection of HTFN 11 as a candidate for hydraulic fracturing will depend primarily on the permeability and nature of the reservoir and the condition of the well.

The diagraphic interpretation showed that the QH tank has an average porosity throughout its units, on the one hand.

For cementation quality, the RBT liner 4"1/2 has a good cementation except at the 3415m to 3401m and 3390m to 3370m intervals.

The nearby fractured well HTFN 5 gave a good result after the fracturing operation in this area

Under these conditions, the well is a good candidate for hydraulic fracturing. The purpose of hydraulic fracturing treatment is to bypass the skin, creating a fracture that joins the undamaged

area with the bottom of the well, and has sufficient conductivity to have a substantial gain in production.

III.4. Preparation of the Well for Fracturing (Pre Frac Phase)

III.4.1. Pre-well testing

These operations, though optional, are of great interest.

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

III.4.2. Well Control

A monitoring of the well on the wire line is carried out in order to locate the top sediment and any anomalies in the completion (fish, collapse, dislocation, etc.).

III.4.3. Well Cleaning HTFN11 for Frac

Cleaning the tubing with hydrochloric acid (HCl), with a strong tensio-active, is desirable. In the case of well HTFN11, the cleanup was as follows:

- Lowers coiled tubing up to topé bottom of wells using Reformat / Xylen with a high jetting tool
- Pass interval perforation pass 1 with max jetting in reformat / Xylen, pass 2 with hydrochloric acid HCL tube clean concentration 7.5%, pass 3 with water treated for washing the perforations and actual flash coiled tubing.

Note:

In the case of old wells, repairs are usually carried out, because perforations are often blocked.

III.4.4. Thermometry

Before the fracturing operation, a so-called reference thermometry is always performed in order to compare its profile to the one that will be recorded after fracturing. Thermometry is therefore the tool that tells us about the height of the fracture, if it takes place.

III.5.HTFN11 Hydraulic Fracturing Process (Frac Phase) The HTFN11 well fracturing process was completed in three days, and the results provided a design for the main treatment (fracking), which was performed on the third day.

Data: $P_g = 477 \text{ bars}$. $KH = 70.7 \text{ md} \cdot \text{m}$

Perforations: (3400 m - 3462 m) Target: QH WOC: 3467m

1st day: injectivity test

III.5.1. Injection Test

The injection test is performed on July 9, 2020 began with the injection of treated water and acid into the well up to the perforations, 91 bbl of HCL15% acid was directed to the perforations. Acid was moved with treated water then 127.1 bbl of Xylene 40%/

Reformat 60% were injected and moved with treated water.

Below are the measured pumping programs and treatment plots.

Day 2 Data Frac

III.5.2. Data Frac

A. Preparations Required:

07 :00 On site, equipment already installed, pump priming and pressure test:

- Pressure test on lines from 3 "up to 10000 psi, kick-out to 9000 psi.
- 2" Pipe pressure test against Annulus valve at 5000 psi. Set pop offs: A (P4 "1/2 x7" 9 "5/8): 3500 psi / 3550psi.
- B (P9" 5/8 13"3/8): 1200 psi.

08 : 40 Gel Test:

T = 31°, PH = 7, loading 35, viscosity 32 Crosslinking time 2mn30s, PH = 11.5

09:20 Security Meeting: SH = 2, PES Service Company = 19

B. Data Frac:

09:26 Open the well: Whp= 1170 psi.

Live A = 1060 psi, pressurize up to 1500psi then 2000psi. Live B = 236 psi, pressurize up to 500 psi.

09:30 Pumping 11.5 bbl of treated water.

09:31 PrePad pumps with linear gel WF135 (30bpm), linear gel WF135 total pumped is 58.2bbl.

09:34 PAD pumpings with crosslinked gel YF135HTD (30bpm), crosslinked total pumped gel is 357.1 bbl.

09:45 WF135 linear gel pumpings (30bpm). WF135 linear gel total pumped is 177bbl.

09:51 pump stops and analysis pressure decline.

Friction:

Total friction = 1232 psi

Well Friction = 96 psi Tube Friction = 1136 psi

Total volume pumped = 592 bbls Linear gel = 235 bbls

Cross-linked gel = 357 bbls

***Quantities of fluids:**

- Water treated 11.5bbl 1.8 m3
- Linear gel WF135 235.2bbl 37.4m3
- Crosslinked gel YF135HTD 357.1 bbl 56.8 m3
- Corrosive abrasive fluid 00 bbl 00 m3
- Non-corrosive abrasive fluid 603.8 bbl 96 m3

***The injection parameters:**

- Medium Process Pressure 6014 psi
- Maximum process pressure 7161 psi
- Minimum process pressure 891 psi
- Average injection rate 29.1 bbl/min
- Maximum injection rate 30.2 bbl/min

13:36 Close the well Whp=2200 psi and purge the surface cloths at 0 psi.

13:37 Start purging the two rings A and B at 0 psi.

14: 00 Starting the rig for thermolog.

15:20 end of work.

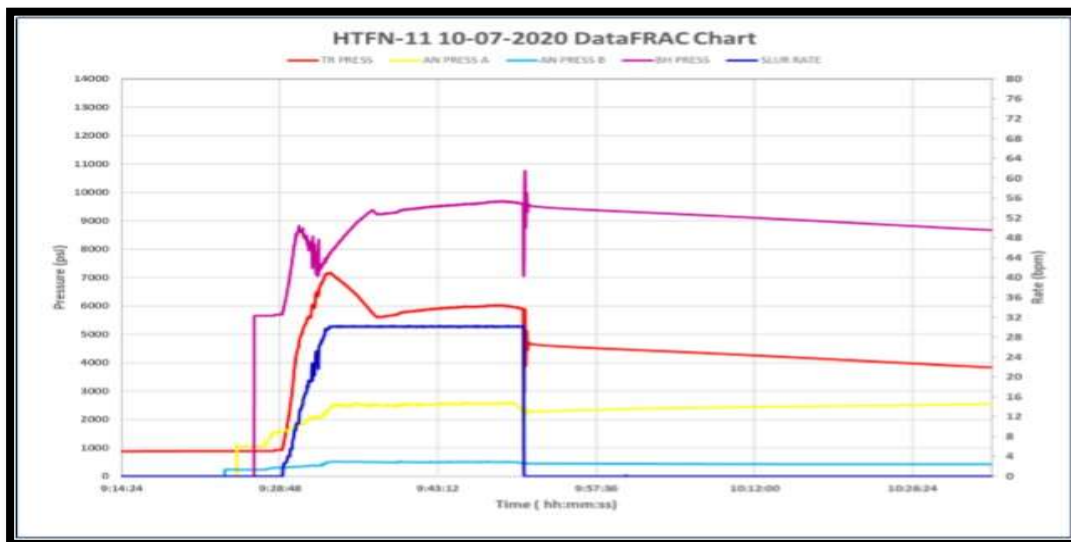


Figure III.4. Evolution of Data Frac pressures

Lpp (SF) = 5877 psi, ISIP (SF) = 4645 psi / ΔP = 1232psi.

Lpp (BH) = 9591 psi, ISIP (BH) = 9495psi / ΔP = 96 psi

Day 3: Fracking

III.5.3. Fracturing

For the reprogramming of frac treatment, newly acquired data frac information and observation such as expected net high pressure and fluid leakage were taken into account to adapt the pumping program to the current situation

In the new design the support agent concentration was maintained the same by pumping only 20/40 HSP from 1 to 8 PPA and the volume of PAD decreased by

15,000 gallons to 1,000.

Employment Procedure:

07:00 - On site, big bags of 22 (20/40) propant HSP, Frac Chemicals had been loaded.

- Prime the pumps and start mixing the gel.

Pressure test:

- Line pressure tests from 3 "to 10,000 psi. / OK, expel @ 9000psi.

- Tests annular line pressure from 2 "to 5000 psi.

- Define Pop Offs:

A (4 "1/2 x 7" 9 "5/8): pop off = 3580psi

- B (9 "5/8 13" 3/8) at 1233psi.

***WF135 Gel Test:**

- Temperature: 31°C

- Viscosity: 32 / Load: 35 / PH = 7

- Crosslinking time: 3min, / PH 12

11:45 - Safety meeting. SH = 4 people, SLB = 16 people.

12:04 - Open the well,

- Live Whp = 41psi,

- Live ring A = 800 psi / load A to 1500psi, 2000psi and 2500psi during work.

- Live ring B = 180 psi / load B at 500 psi.

12:10 Pump pre-ppad with linear gel (0 - 30) bpm, WF135 total pumped is 50.7 bbl.

12:12 Switch to cross-linked gel YF135HTD and PAD pump, total WF135HTD pumped is 238.1bbl.

12:21 (Step 1) pump PPA with crosslinked gel YF135HTD and 20/40 HSP proppant, YF135HTD total 51.6 bbl, total propane 20/40 HSP 1735 lb.

12:22 (step 2) pump PPA with crosslinked gel YF135HTD and 20/40 HSP proppant, YF135HTD total 59.9 bbl, total propane 20/40 HSP 4600 lb.

12:24 (step 3) pump PPA with crosslinked gel YF135HTD and 20/40 HSP proppant, YF135HTD total 54.9 bbl, total propane 20/40 HSP 6194 lb.

12:26 (Step 4) pump PPA with crosslinked gel YF135HTD and 20/40 HSP proppant, YF135HTD total 56.6 bbl, total propane 20/40 HSP 6194 lb.

12:28 (Step 5) pump PPA with crosslinked gel YF135HTD and 20/40 HSF proppant, YF135HTD total 58.2 bbl, total propane 20/40 HSP 10426 lb.

12:29 (step 6) pump PPA, with crosslinked gel YF135HYD and 20/40 HSP proppant, YF135HTD total 42.8 bbl, total propane 20/40 HSP 8848 lb.

12:32 (Step 7) pump PPA with gel cross-linked YF135HTD and 20/40 HSP proppant, YF135HTD total 51.8 bbl, total propane 20/40 HSP 12167 lb.

12:33 (step 8) pump PPA with crosslinked gel YF135HTD and 20/40 HSP proppant, YF135HTD total 54.2, total propane 20/40 HSP 14569 lb.

12:34 Rinse with WF135 165.8bbl.

12:38 Stops pumping after a successful 5 bbl under-rinse and runs pressure decline.

13 :57 Close the wellhead to 3110 Psi and purge the surface line to 0 Psi.

***Quantities of fluids:**

- WF135 216.5 bbl 34.4m linear gel
- Cross linked gel YF135HTD 616.1bbl 98.0m 20/40HSP 66812 lb 30305m
- Corrosive Abrasive Fluid 430.0 bbl 68.4m
- Non-corrosive abrasive fluid 454.6 bbl 72.3m³

13:59 Slowly start bleeding annular pressure A and B at 0 Psi.

14:00 Disassemble all equipment and area cleaning.

15 :45 The end of work.

- The programming procedure

Table 3.the frac processing program executed

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	PrePAD	50.7	20.5	3	WF135	2110		0	0	0
2	Pad	238.1	30.1	7.9	YF135HTD	10000		0	0	0
3	1.0 PPA	51.6	30.1	1.7	YF135HTD	2112	HSP 20/40	1	1	1735
4	2.0 PPA	59.9	30.1	2	YF135HTD	2365	HSP 20/40	2	2	4600
5	3.0 PPA	54.9	30.1	1.8	YF135HTD	2103	HSP 20/40	3	3	6194
6	4.0 PPA	56.6	30.1	1.9	YF135HTD	2104	HSP 20/40	4	4	8273
7	5.0 PPA	58.2	30.1	1.9	YF135HTD	2102	HSP 20/40	5	5	10426
8	6.0 PPA	42.8	30.1	1.4	YF135HTD	1504	HSP 20/40	5	5	8848
9	7.0 PPA	51.8	30.1	1.7	YF135HTD	1776	HSP 20/40	6	6	12167
10	8.0 PPA	54.2	30.1	1.8	YF135HTD	1810	HSP 20/40	7	7	14569
11	Flush	165.8	30.1	5.5	WF135	6994				

The main frac treatment is done as programmed with 66812 lbs of HSP20/40. The graph below shows the main frac parameters that were copied during the operation

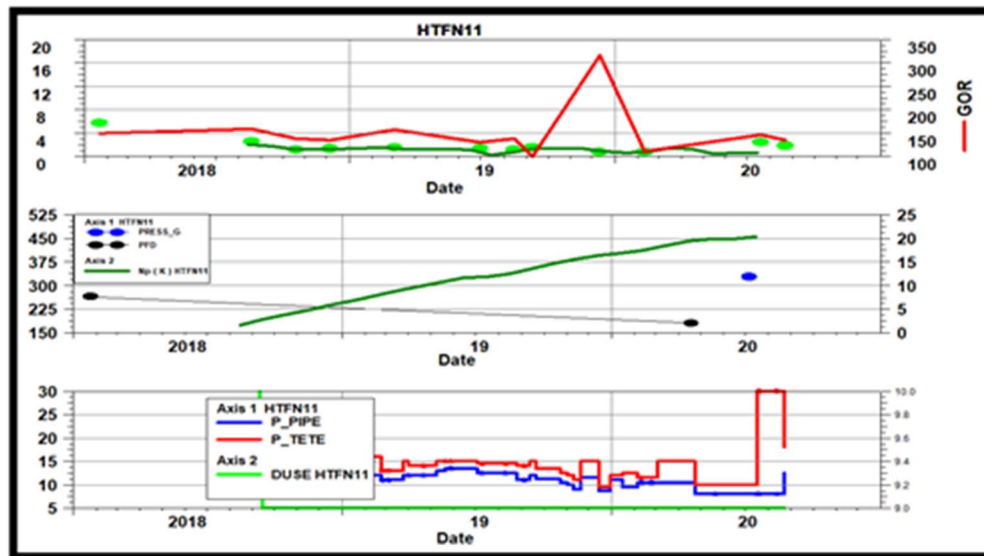


Figure III.5.Pressure evolution during the frac test

III.6. Evolution of the fracturing operation

After the fracturing operation we do a post frac cleaning with Coiled Tubing, up to 2800, with water + N₂. (Pumping of gel and 1m³ of treated water, and displacement with nitrogen) , another cleaning operation was done up to 3455 then we tried to start the well (KICK OFF) after the start and stabilization of the well we observe a flow gain of approximately n1.65 m³/h, then This shows the success of the fracturing operation

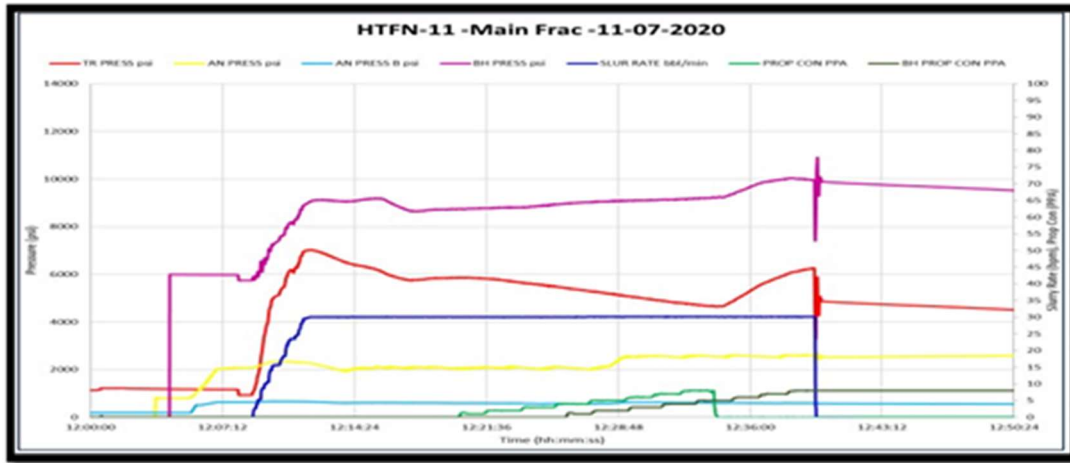


Figure III.6. Last HTFN 11 well gauges after operation

Table 4. Last HTFN 11 well gauges after operation

Date de mesure	Diam Duse (mm)	Unité de sép	Débit (m ³ /h)		GOR	Pression (kg/cm ²)			Temp Huil
			H	G		Press Tête	Press Pipe	Press Sépar	
11/02/2020	9	600	0.8	89.91	112	8.5	6.3	3.16	13
20/07/2020	9	600	2.45	356.23	146	20.6	11.3	3.16	34

III.6.1. Cost of hydraulic fracturing operation

In the evaluation of the costs of this operation, from these data Injection test +Mini Frac + Frac: \$163,773.11

Post Frac clean out: \$9,650 Post Frac Clean out: \$9,675.98 Kick Off after Frac: \$9,330.26

The total amount of the transaction is \$192429.35 2

III.7. Conclusion

In this chapter we study the well HTFN11 and the results obtained confirmed the success of the operation with a flow gain of approximately 1.65 m³/h, in the case where the price of barrel 45\$ the amortization time will be 17 days, So the fracking operation is effective if the fracking operation is successful and we can recover the costs of the operation for days.

General Conclusion

The present study has provided a comprehensive evaluation of two key technologies in modern petroleum engineering: coiled tubing and hydraulic fracturing, and their combined application in the HTFN 11 well at the Hassi Messaoud field. Through a theoretical overview and a practical case study, it has been demonstrated that these techniques play a complementary role in overcoming the challenges of low-permeability reservoirs and in enhancing hydrocarbon recovery.

The analysis of coiled tubing operations highlighted its versatility, operational flexibility, and its critical role in supporting stimulation processes without interrupting production. Likewise, hydraulic fracturing was shown to be a decisive method for improving well productivity by creating artificial fractures and maintaining their conductivity through carefully selected proppants.

The field case study of HTFN 11 confirmed the effectiveness of these techniques under real reservoir conditions. The results underline the importance of accurate reservoir characterization, proper selection of fluids and proppants, and adherence to safety and operational standards in order to ensure successful outcomes.

In conclusion, the integration of coiled tubing and hydraulic fracturing represents a powerful approach to optimizing production in mature and complex fields such as Hassi Messaoud. Looking forward, the continuous improvement of materials, fluids, and operational practices will further enhance the efficiency, safety, and economic performance of such operations, contributing to the sustainable development of Algeria's hydrocarbon resources.

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