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-THEME-

Comparative Study and Optimization of Multi-Stage Hydraulic Fracturing: Frac Point System Versus Plug-and-Perf with Cemented Liner Completions: MDZ-548 & OMGZ-60

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بسم الله الرحمن الرحيم

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In the name of Allah, the Most Gracious, the Most Merciful.

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We ask Allah to make this work beneficial, and to guide us in future endeavors toward knowledge, sincerity, and excellence.

Dedication

"يَرْفَعِ اللَّهُ الَّذِينَ آمَنُوا مِنكُمْ وَالَّذِينَ أُوتُوا الْعِلْمَ دَرَجَاتٍ"

First and foremost, I give thanks to Allah, the Highest, the Wise, and the Merciful, for granting me the strength, patience, faith, and intelligence necessary to complete this work. Without His guidance, nothing would have been possible.

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May this modest achievement be accepted by Allah.

And may He make it one step closer to excellence and piety.

BELATTAR HAMZA

Dedication

"وَمَا تَوْفِيقِي إِلَّا بِاللَّهِ عَلَيْهِ تَوَكَّلْتُ وَإِلَيْهِ أُنِيبُ"

*First, to my mom, **Sameh Mesbah**, thank you for being my biggest supporter, my shoulder to cry on, and my reason to keep going. No matter how tough things got, your love never wavered. I hope I've made you proud.*

*To my dad, **Abdelouahab "Fouzi"**, you worked so hard to give me every opportunity, always believing in me even when I didn't believe in myself. Your sacrifices mean more to me than words can say.*

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الملخص

تُعدّ عملية التكسير الهيدروليكي من أهم تقنيات التحفيز المستخدمة على نطاق واسع لتعزيز إنتاجية المكامن الضيقة. وقد أصبحت تقنية التكسير الهيدروليكي متعدد المراحل (**MSHF**) عنصرًا أساسيًا في نجاح تطوير الآبار الأفقية والمنحرفة.

تُقدّم هذه الدراسة تحليلًا مقارنًا بين نظامي إتمام مختلفين لتقنية :**MSHF** نظام **FracPoint** (الذي يعتمد على تفعيل المراحل باستخدام الكرات في بيئة مفتوحة البئر)، ونظام **Plug-and-Perf** (الذي يستخدم بطانة أسمنتية مع عزل ميكانيكي لكل مرحلة). تم استخدام برنامج **MSUITE** لمحاكاة هندسة الكسور، وتحليل استجابة الضغط، وتقييم أداء المراحل والنتائج الاقتصادية.

أظهرت النتائج أن البئر **MDZ-548** باستخدام (**FracPoint**) شهدت زيادة في معدل إنتاج النفط من 1.5 **م³/س إلى 3.8 م³/س**، بينما البئر **OMGZ-60** باستخدام (**Plug-and-Perf**) تحسّن الإنتاج فيها من **1.2 م³/س إلى 4.2 م³/س**. من الناحية الاقتصادية، بلغت تكلفة عملية الإتمام بنظام FracPoint حوالي 1.82 مليون دولار، مع عائد صافي للوحدة (NUR) يقدّر بـ **40 دولارًا** للبرميل. في المقابل، تراوحت تكلفة تقنية **Plug-and-Perf** بين 2.1 و2.3 مليون دولار، مع تحقيق عائد صافي أعلى يتراوح بين 55 و60 دولارًا للبرميل. كما كشفت تحاليل الضغط عن وصول قيمة الضغط الفوري بعد الإغلاق (ISIP) إلى psi 11,000 فيMDZ-548 ، و16,285 psi فيOMGZ-60 ، مع ملاحظة احتواء أفضل للكسور في الحالة الثانية.

تُساهم هذه الدراسة في تعميق الفهم المتعلق بتصميم عمليات التحفيز في التكوينات الضيقة، وتقدّم رؤى عملية لتحسين الأداء، وتطوير استراتيجيات الإتمام، وتقليل عدم اليقين في تطوير المكامن غير التقليدية.

الكلمات المفتاحية: المكامن الضيقة، الآبار المنحرفة، التكسير الهيدروليكي متعدد المراحل، FracPoint، Plug-and-Perf، MSUITE

Résumé

La fracturation hydraulique est une technique de stimulation clé largement utilisée pour améliorer la productivité des réservoirs tight (à faible perméabilité). La fracturation hydraulique multi-étagée (MSHF) est devenue un pilier fondamental dans le développement réussi des forages horizontaux et déviés.

Cette étude présente une analyse comparative entre deux systèmes de complétion MSHF : le système FracPoint (activation par billes dans des complétions en trou ouvert) et le système Plug-and-Perf (avec chemisage cimenté et isolation mécanique des étapes). Le logiciel

MSUITE a été utilisé pour simuler la géométrie des fractures, analyser la réponse en pression, et évaluer la performance des étapes ainsi que les résultats économiques.

Les résultats montrent que pour le puits MDZ-548 (**FracPoint**), le débit de production de pétrole est passé de 1,5 m³/h à 3,8 m³/h, tandis que pour le puits **OMGZ-60** (Plug-and-Perf), il a augmenté de 1,2 m³/h à 4,2 m³/h. Sur le plan économique, l'opération de complétion avec FracPoint a coûté environ 1,82 million USD, avec un revenu net unitaire estimé (NUR) d'environ 40 USD par baril. En comparaison, la méthode Plug-and-Perf a coûté entre 2,1 et 2,3 millions USD, avec un NUR supérieur compris entre 55 et 60 USD par baril. L'analyse des pressions a révélé des valeurs ISIP allant jusqu'à 11 000 psis pour **MDZ-548** et 16 285 psis pour **OMGZ-60**, avec un meilleur confinement des fractures dans ce dernier.

Ce projet contribue à une meilleure compréhension de la conception des stimulations dans les formations tight, et propose des recommandations pratiques pour améliorer les performances, optimiser les choix de complétion, et réduire les incertitudes dans le développement des réservoirs non conventionnels.

Mots-clés : Réservoir tight, Puits dévié, Fracturation hydraulique multi-étagée, FracPoint, Plug-and-Perf, MSUITE.

Abstract

Hydraulic fracturing is a key stimulation technique widely applied to enhance the productivity of tight reservoirs. Multi-stage hydraulic fracturing (**MSHF**) has become a cornerstone in the successful development of horizontal and deviated wells.

This study presents a comparative analysis between two **MSHF** completion systems: the FracPoint system (ball-drop activation in open-hole completions) and the Plug-and-Perf system (cemented liner with mechanical stage isolation). The **MSUITE** software was used to simulate fracture geometry, analyze pressure response, and evaluate stage performance and economic outcomes.

The results showed that for Well MDZ-548 (**FracPoint**), the oil production rate increased from 1.5 m³/h to 3.8 m³/h, while for Well **OMGZ-60** (Plug-and-Perf), it improved from 1.2 m³/h to 4.2 m³/h. Economically, the **FracPoint** completion cost approximately $1.82 million with an estimated Net Unit Revenue (**NUR**) of $40 per barrel, whereas the Plug-and-Perf method cost between $2.1 and $2.3 million, delivering a higher NUR of $55–$60 per barrel. Additionally,

pressure analysis revealed **ISIP** values up to 11,000 psi for MDZ-548 and 16,285 psi for **OMGZ-60**, with better fracture containment observed in the latter.
This project contributes to a deeper understanding of stimulation design in tight formations and offers practical insights to improve performance, optimize completion strategy, and reduce uncertainty in tight reservoir development.
Keywords: Tight reservoir, Deviated well, Multi-stage hydraulic fracturing, FracPoint, Plug-and-Perf, MSUITE.

Table of Contents

Chapter III: Hydraulic Fracturing Concepts and Fundamentals

CHAPTER IV: The application of multistage fracturation in Hassi Messaoud oil field :MDZ-548 & OMGZ-60

List of figures

List of tables

Nomenclature

FVF	**Formation Volume Factor**
Fcd	**Dimensionless Conductivity**
Kf / Wf	**Fracture Permeability / Fracture Width**
Xf / Lxf	**Fracture Length / Half Fracture**
Ke / K	**Formation Permeability**
H / Hhp	**Net Pay Height / Hydraulic Horsepower**
σ / ε	**Stress / Strain**
E	**Young's Modulus (Psi).**
ν / G	**Poisson's Ratio / Shear Modulus**
σv	**Vertical Stress**
σ'	**Effective Stress**
α	**Biot's Constant**
ppa	**Pounds of Proppant Additive per Gallon**
εTect	**Tectonic Strain**
BHLPP	**Bottom Hole Last Pumping Pressure (Psi).**
BHISIP	**Bottom Hole Instantaneous Shut-In Pressure (Psi).**
SISIP	**Surface Instantaneous Shut-In Pressure (Psi).**
SLPP	**Surface Last Pumping Pressure (Psi).**
Δp	**The Pressure Differential (Or Drawdown).**
ΔPpipe friction	**Pipe Friction Pressure Loss (Psi).**
ΔPnwb	**Near-Wellbore Friction (Psi).**
ΔPTotal	**Total Friction Pressure Loss (Psi).**
PBH	**Bottom Hole Pressure (Psi)**
Pp	**Pore Pressure (Psi).**
Re	**Drainage Radius**
Rw	**Wellbore Radius**
μ	
η	

CL	Viscosity
n’	Efficiency
Bs	Leak-Off Coefficient
E’	Fluid Rheology Coefficient
VPad	Closure effect factor
Vi	Deformation Modulus
Tc / tinj	Volume of Gel Pad (Gallon).
Q	Injected Volume
QGas	Closure Time (Min) / Injection Time (Min).
QOil	Flow Rate (m3/H)
GOR	Gas Flow Rate (m3/H).
AAPG	Oil Flow Rate (m3/H).
API	Gas-Oil Ratio
BHFP	American Association of Petroleum Geologists
BPM	American Petroleum Institute
ESP	Bottomhole Flowing Pressure
OWC	Barrels Per Minute
PLT	Electric Submersible Pump
SRV	Oil-Water Contact
TOC	Production Logging Tool
FracPoint™	Stimulated Reservoir Volume
HSP	Top of Cement
ISP	Ball-activated sleeve system
Nolte G	High-Strength Proppant
Pad	Intermediate-Strength Proppant
Slurry	Pressure decline analysis method
THT	Pad fluid
OMGZ / MDZ	Proppant-laden fluid
FMI	Tubing Head Temperature
XRD	Well naming convention

	Formation MicroImager **X-Ray Diffraction**

General Introduction

GENERAL INTRODUCTION

The oil and gas industry remains a fundamental pillar of Algeria's national economy, with a significant share of public revenue dependent on the efficient and sustainable exploitation of hydrocarbon resources. As conventional reservoirs continue to mature and natural productivity declines, attention is increasingly turning toward more challenging and lower-quality reserves—particularly tight reservoirs, characterized by extremely low matrix permeability, often below 0.1 millidarcy. Unlocking the potential of these unconventional formations requires the application of advanced stimulation techniques to ensure technically and economically viable hydrocarbon recovery.

Among these techniques, Multi-Stage Hydraulic Fracturing (MSHF) has become a key strategy, particularly in horizontal and deviated wells. This method involves injecting fluids at high pressure to create a network of artificial fractures, thereby improving reservoir connectivity and enhancing hydrocarbon flow. Two major MSHF completion systems are commonly used in industry: the FracPoint system, which relies on open-hole completions with ball-activated sliding sleeves, and the Plug-and-Perf system, which uses cemented liners, selective perforations, and mechanical stage isolation.

This thesis is structured into five chapters.

Chapter I introduces the fundamentals of petroleum reservoirs and provides a detailed classification based on geological and physical criteria relevant to stimulation design.

Chapter II focuses on the geological and petrophysical characteristics of tight reservoirs, highlighting their heterogeneity, low porosity and permeability, and the flow constraints that justify the need for hydraulic stimulation.

Chapter III covers the theoretical background of hydraulic fracturing, including fracture mechanics, in-situ stress regimes, types of fracturing fluids, additives, and the engineering design principles of multi-stage operations.

Chapter IV presents the practical application of the study conducted during our internship at Alscif Company, where we carried out a field-based evaluation in the Hassi Messaoud oil field a tight sandstone reservoir known for its geological complexity. In this context, we selected two horizontal wells, MDZ-548 and OMGZ-60, based on key technical factors including well integrity, well trajectory, and the geomechanical behavior of the reservoir rock. Using MSUITE software, we designed and estimated the parameters of multi-stage fracturing operations for both wells, allowing for a comparative analysis of stimulation geometry and operational performance under real conditions.

Finally, Chapter V presents and discusses the results, conclusions, and recommendations derived from this study.

The core problem addressed in this work revolves around how Algeria can optimize completion design in tight reservoirs to overcome low flow rates and high stimulation costs. This thesis aims to compare the technical and operational performance of the FracPoint and Plug-and-Perf systems, identify the key factors influencing stimulation success in tight formations, and provide practical recommendations for optimizing hydraulic fracturing in Algeria's unconventional reservoirs. Furthermore, the study explores the potential integration of digital technologies, particularly Artificial Intelligence (AI), to enable real-time optimization, enhance decision-making, reduce operational costs, and support more efficient and sustainable resource development.

CHAPTER I

Petroleum reservoirs and their production mechanism.

Introduction

Characterization of petroleum reservoirs and their effective exploitation are key elements of reservoir engineering. A petroleum reservoir can be described as an underground geological formation that exhibits porosity and permeability and has preserved hydrocarbons under conditions favorable to their entrapment and ultimate recovery. Typically located within sedimentary rock formations like sandstones and carbonates, these reservoirs play a dual role of acting both as channels and storage facilities for hydrocarbons, which are controlled by factors such as capillary forces, gravity segregation, and different structural or stratigraphic trapping mechanisms.

The classification of reservoirs is discussed methodically within this chapter based upon differ ent criteria, such as the type of fluid, lithological attributes of the rock, drive mechanisms, trap geometry, and reservoir conditions such as pressure and temperature. Such classification systems are important for choosing appropriate recovery methods and anticipating production behavior in projects. For instance, determining whether a reservoir is under a water-drive system, solution-gas drive system, or gas-cap drive system can significantly affect field-development plans and recovery efficiency.

The scheme given is an inclusive categorization and examination of reservoirs, thus making a platform for conventional and nonconventional system comparisons. A foundation has been la id for sophisticated reservoir management and stimulation methods, which are to be discussed later.[1]

I.1. Overview of petroleum reservoir

I.1.1. Definition

A petroleum reservoir, in its most comprehensive geological sense, is a porous and permeable rock formation capable of storing and transmitting fluids, notably hydrocarbons. These formations typically consist of sedimentary rocks, such as sandstones or limestones, whose pore spaces are interconnected sufficiently to allow fluid migration.

When immiscible fluids of different densities and viscosities such as oil, gas, and water coexist within such porous media, their distribution and movement are governed by gravity and capillary forces. Over geological time, if fluid migration is halted by overlying or laterally sealing low-permeability barriers (such as shales or tight carbonates), hydrocarbons can accumulate. This leads to the formation of a petroleum trap a geologic configuration that prevents the further escape of these fluids.

Thus, a petroleum reservoir is defined as a subsurface volume of permeable rock, structurally or stratigraphically confined, where hydrocarbons have accumulated and are retained under favorable pressure and fluid conditions.

Most reservoirs are capped by impermeable rocks, which act as seals, and are commonly underlain by formation water. In many cases, these reservoirs are interbedded with less permeable layers, yet fluid communication between zones over geological timescales can result in equilibrium across the reservoir, evidenced by a common oil-water contact. However, this is not a guaranteed condition and must be verified during reservoir characterization.

While exceptions exist, the vast majority of petroleum reservoirs occur in sedimentary rocks, primarily within porous sandstones and carbonate formations, which provide the necessary porosity and permeability to support commercial hydrocarbon production. Understanding the nature of this porosity is essential to the classification, evaluation, and development of petroleum reservoirs[2] (**Figure I.1**).

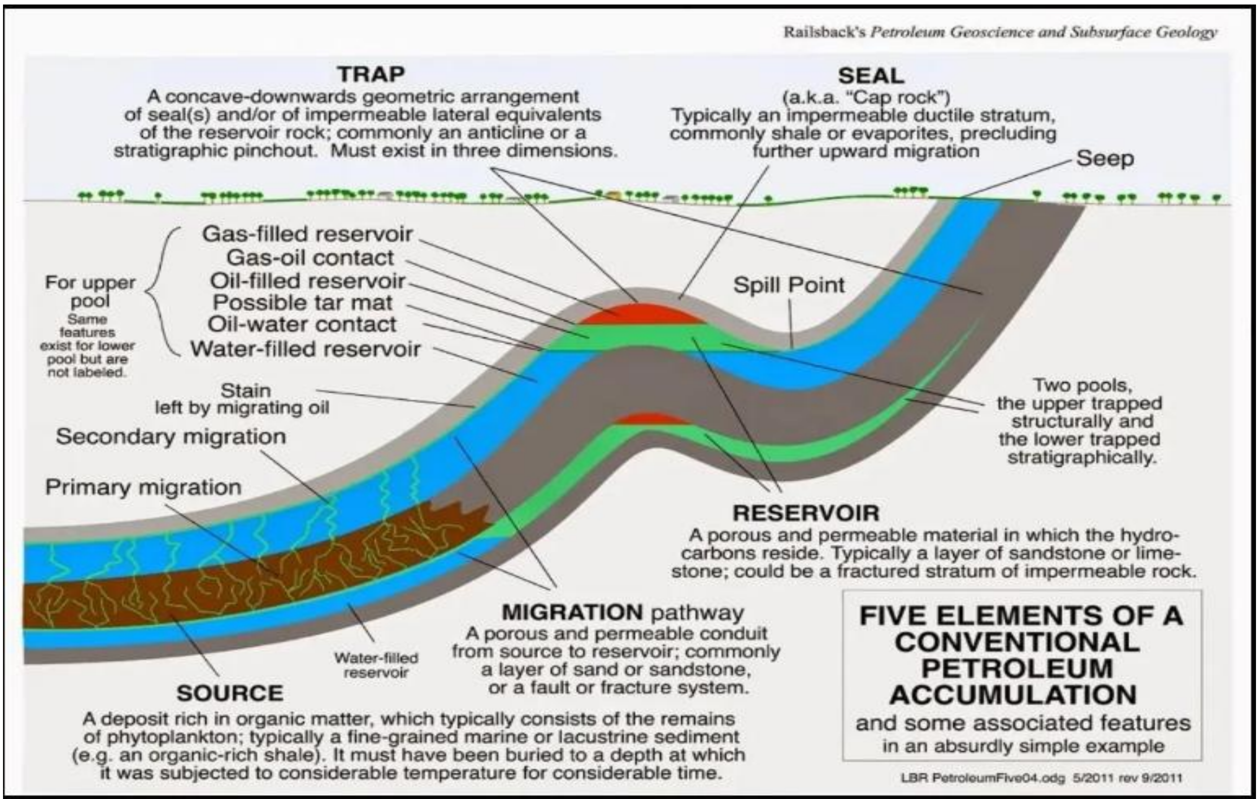


Figure I.1 Petroleum System elements[3]

I.1.2. Classification of petroleum reservoirs

I.1.2.1. Classification Based on Fluid Phase

Petroleum reservoirs are primarily classified based on the dominant hydrocarbon phase present under reservoir conditions. This classification is crucial as it influences the selection of production strategies and recovery methods.

a. Oil Reservoirs

- **Undersaturated Oil Reservoirs**: These reservoirs have pressures above the bubble

point, meaning no free gas is present initially. As production proceeds and pressure drops below the bubble point, gas begins to come out of solution, forming a gas cap.

- **Saturated Oil Reservoirs**: These reservoirs are at or near the bubble point pressure,

and a gas cap may form over time as gas comes out of solution.

In both cases, the primary recovery mechanism is the expansion of the oil and dissolved gas. However, the presence of a gas cap can enhance recovery by providing additional drive energy.

b. Gas Reservoirs

- **Dry Gas Reservoirs**: Contain primarily methane with little to no heavier hydrocarbons.
- **Wet Gas Reservoirs**: Contain heavier hydrocarbons that can condense into liquids

under surface conditions.

- **Gas-Condensate Reservoirs**: These reservoirs contain hydrocarbons that exist as gas

in the reservoir but condense into liquid as pressure drops during production. This retrograde condensation can complicate recovery efforts.

I.1.2.2. Classification Based on Reservoir Rock Type

The type of reservoir rock significantly influences porosity, permeability, and recovery methods:

a. Clastic Reservoir

Composed primarily of sandstones and siltstones, clastic reservoirs have porosity that is primarily intergranular. These rocks are deposited by mechanical processes such as water or wind transport.

b. Carbonate Reservoirs

Composed of limestones and dolomites, carbonate reservoirs often have more complex porosity systems, including vuggy, intercrystalline, and fracture-dominated porosity. These rocks are formed by chemical and biological processes, such as the accumulation of shell fragments or coral reefs.

I.1.2.3. Classification Based on Drive Mechanism

Reservoirs can be classified by the natural energy mechanisms that enable production:

a. Solution-Gas Drive

This mechanism relies on the expansion of dissolved gas coming out of solution as pressure drops, providing the energy to drive oil toward the wellbore.

b. Gas Cap Drive

In reservoirs with a gas cap, the expansion of the gas provides additional drive energy, pushing oil toward the production wells.

c. Water Drive

An active aquifer underlying the reservoir provides pressure support by pushing water into the reservoir as oil is produced, maintaining pressure and enhancing recovery.

d. Combination Drive

Some reservoirs exhibit a combination of the above mechanisms, with varying contributions from gas expansion, water influx, and solution gas.

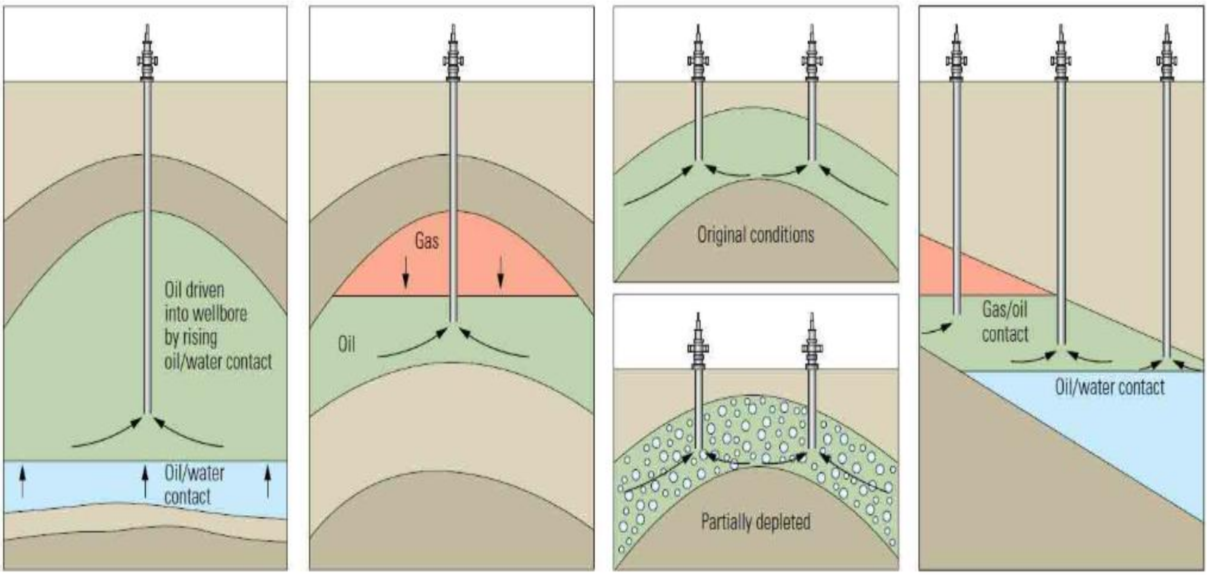


Figure I.2 Formation drive mechanisms[4]

I.12.4. **Classification Based on Trap Type**

Trapping mechanisms are crucial in the formation and accumulation of hydrocarbons:

a. Structural Traps

Formed by tectonic activity such as folding and faulting, leading to the formation of domes, anticlines, and fault traps. These are the most common and productive types of traps.

b. Stratigraphic Traps

Result from variations in rock properties, such as changes in porosity or permeability, leading to pinch-outs, unconformities, or reef buildups that trap hydrocarbons.

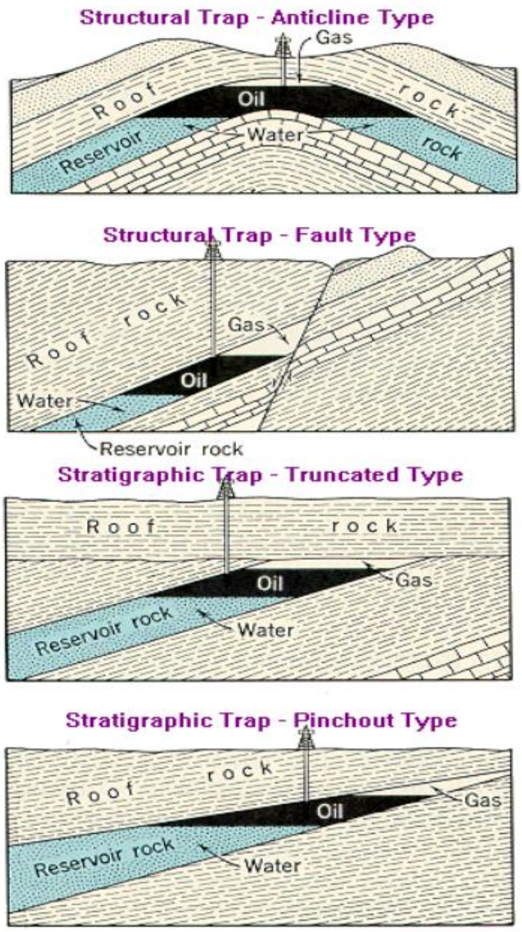


Figure I.3: Trap types[5]

c. Combination Traps

Involve elements of both structural and stratigraphic traps, such as a faulted anticline with a pinch-out. [5]

I.1.2.5. Classification Based on Reservoir Conditions

Conditions like temperature and pressure influence fluid behavior:

a. Conventional Reservoirs

These have sufficient porosity (>10%) and permeability (>10 mD) to allow hydrocarbons to flow naturally to the wellbore.

b. Unconventional Reservoirs

These include tight gas, shale oil/gas, and coalbed methane reservoirs, which have low porosity and permeability, requiring stimulation techniques like hydraulic fracturing to produce hydrocarbons.

I.1.2.6. Classification Based on Pressure-Temperature (P-T) Regimes

Reservoir fluids can also be classified based on their pressure-temperature relationships:

a. Undersaturated Oil Reservoirs

Pressure is above the bubble point, and oil exists as a single phase.

b. Saturated Oil Reservoirs

Pressure is at the bubble point, and gas begins to come out of solution, forming a gas cap.

c. Retrograde Gas-Condensate Reservoirs

These reservoirs contain gas that condenses into liquid as pressure drops during production, complicating recovery efforts. [6]

I.1.2.7. Integrated Classification Systems

In practice, multi-criteria classifications are used, incorporating lithology, trap type, fluid type, and production mechanism to accurately describe a reservoir and define development strategies. This holistic approach allows for more effective exploration and production planning.

Conclusion

Here, we have presented a comprehensive examination of the inherent attributes that define petroleum reservoirs and varied criteria that are used for their categorization. From a technical viewpoint, it is important to determine if a reservoir can be categorized as clastic or carbonate, conventional or non-conventional, or be water, gas, or solution- drive type, since such information has significant implications for methods of exploration and production. The classification systems discussed herein have dual purposes, namely to categorize reservoirs and facilitate better scheme formulation for developments and to provide appropriate recovery methods. This critical insight becomes more important as petroleum engineering advances through ever more complicated and varied formations, such as tight and shale reservoirs. This chapter hence provides a theoretical and applied basis for dealing with production issues and for developing economical, productive, and technically feasible reservoir management tactics throughout the rest of this thesis. [1]

CHAPTER II

Generality about tight reservoir

Introduction

In the face of the progressive depletion of easily exploitable conventional petroleum resources and an ever-increasing global energy demand, the oil industry is being compelled to shift its efforts toward the exploration and development of so-called unconventional reservoirs. Long regarded as uneconomical or technically inaccessible, these reservoirs now represent a strategic alternative that is essential to ensuring medium- and long-term energy security.

Among these resources, tight reservoirs are becoming increasingly significant in the exploration and development strategies of major oil companies. These geological formations, often composed of sandstones, carbonates, or occasionally shales are characterized by extremely low permeability (typically less than 0.1 millidarcy) and reduced porosity. These petrophysical properties severely limit the natural flow of hydrocarbons, making their exploitation unfeasible using conventional methods.

Unlike traditional reservoirs, tight reservoirs require advanced stimulation techniques to enable economically viable production. Among these techniques, multi-stage hydraulic fracturing, often combined with horizontal drilling, stands out as the most effective technological solution. Its purpose is to artificially create a network of fractures in the reservoir rock, thereby increasing the effective permeability and facilitating the drainage of hydrocarbons toward the wellbore.

In the current context of energy transition marked by the need to optimize existing resources while reducing the environmental footprint of the oil industry tight reservoirs represent a major technical and economic challenge. Their development demands a deep understanding of their geological, petrophysical, and mechanical properties, as well as rigorous expertise in stimulation techniques.

This thesis falls within this framework. Its objective is to highlight the specific characteristics of tight reservoirs by comparing them with conventional reservoirs and to present the principles, mechanisms, and performance of multi-stage hydraulic fracturing as a stimulation method suited to these complex environments. Through this study, we aim to identify the key parameters influencing the success of this technique while discussing its technical, economic, and environmental implications.[7]

II.1. Characteristics of Tight Reservoirs

II.1.1 Geological structure

Tight reservoirs are a class of low-permeability petroleum systems encountered across a variety of sedimentary lithologies, including sandstones, siltstones, dolomites, argillaceous limestones, shales, and sandy carbonates. Although they may be genetically linked to conventional systems, tight reservoirs are fundamentally different in that they exhibit extremely limited porosity and fluid transmissivity, often requiring detailed geological and petrophysical evaluation for effective development planning.

These formations are commonly **continuous and laterally extensive**, deposited in **stacked sedimentary sequences**, with limited vertical communication and high heterogeneity. In certain cases, especially in organic-rich intervals, these rocks may **act both as source and reservoir**, forming **self-sourced petroleum systems**, a hallmark of unconventional plays.

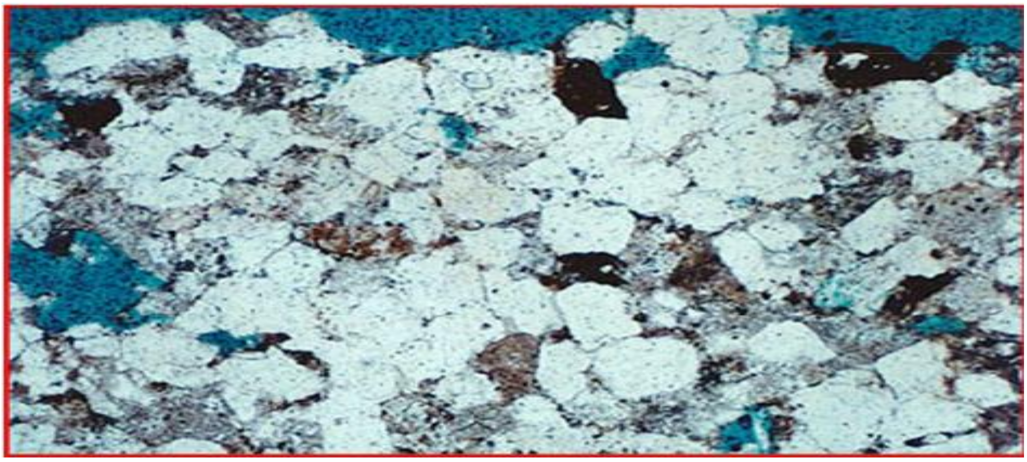


Figure II.1: Thin section of tight gas sandstone.[8]

II.1.2 Mechanisms of Tightness Development

The origin of tightness in these formations is governed by both primary depositional characteristics and secondary geological processes**:**

➢ **Primary controls**

- Mineralogical composition and grain texture, inherited from the sediment source.
- Grain size and sorting, which dictate initial pore space configuration.

- Depositional regime (e.g., fluvial, deltaic, lacustrine), controlling sediment layering and compaction trends.
- Early lithification, influencing mechanical rigidity and compaction response.

➢ **Secondary controls**

Diagenesis**, including**

- Mechanical compaction under overburden stress.
- Cementation by silica, calcite, or clay minerals, significantly reducing pore volume.
- Selective dissolution generating secondary porosity, albeit often isolated.
- Tectonic activity, which may result in natural fracturing**,** stress anisotropy, and structural compartmentalization, directly influencing reservoir connectivity and performance.

In tight reservoirs, **porosity is typically <10%**, with permeability often **below 0.1 millidarcy**, especially in zones affected by authigenic mineral overgrowths (such as quartz or dolomite cement). The remaining pore space is usually secondary in nature formed post-deposition and often poorly connected leading to capillary trapping and low effective permeability.[8]

II.1.3 Petrophysical Characteristics

Tight formations present unique petrophysical challenges, including:

- Low effective porosity and permeability**.**
- Small pore throat sizes, resulting in high capillary pressure and water saturation.
- Non-Darcian flow behavior, particularly in nanoporous domains.

To characterize these reservoirs properly, a multi-scale approach is needed:

- Core analysis: Provides direct information on facies, depositional texture, and pore architecture.
- Thin section petrography: Identifies grain-to-grain contacts, matrix composition, and cement types.

- **XRD** and **SEM**: Deliver mineralogical and microstructural details, especially in the nanometer scale.
- **Wireline logging** (e.g., NMR, resistivity imaging): Assesses porosity, saturation, and formation heterogeneity.

Facies distribution, sedimentary structures, and diagenetic overprint all impact reservoir quality and continuity. These must be carefully evaluated to build reliable reservoir models, especially in heterogeneous tight formations.

II.1.4 Examples from Algerian Sedimentary Basins

Algeria hosts several prolific sedimentary basins with confirmed or potential **tight reservoir systems**:

➤ **Timimoun Basin**

- Located in the central-western Sahara region.
- Composed primarily of tight Triassic sandstones and Permo-Carboniferous sequences.
- Reservoirs exhibit low porosity (3_8%) and permeability often below 0.1 mD.
- Notable for dry gas accumulations with challenging production profiles.

➤ **Ahnet and Mouydir Basins**

- Characterized by deep, underexplored Paleozoic formations, with potential for tight gas and shale gas systems.
- Reservoir rocks include tight quartzites and dolomites with minimal natural porosity.
- These basins are subject to ongoing geological and geophysical assessments for

unconventional resource potential.

➢ **Reggane Basin**

- Located in the southwest of Algeria.
- Known for low-permeability sandstones with good gas content.
- Reservoirs typically require detailed core evaluation due to complex diagenetic histories.

➢ **Illizi and Berkine Basins (eastern Algeria)**

- Though largely known for conventional plays, both basins also contain tight intervals, especially within the Devonian and Silurian sequences.
- Sandstones here often show extensive cementation and compaction, leading to degraded permeability.
- Structural features and depositional variability impact reservoir performance significantly.

➢ **Hassi R'mel Region**

- While Hassi R'mel is Algeria's largest conventional gas field, adjacent formations have been identified with tight gas potential, particularly within deeper stratigraphic intervals.

➢ **Hassi Messaoud Basin**

- Situé dans le bassin d'Oued Mya, dans le sud-est de l'Algérie.
- Principalement connu pour ses gisements pétroliers conventionnels exploités depuis les années 1950.
- Les réservoirs principaux sont des grès arkosiques du Crétacé inférieur, piégés dans

des structures anticlinales bien définies.

- Toutefois, des niveaux plus profonds ou latéralement diagenés montrent des

caractéristiques de réservoirs compacts à très faible perméabilité, notamment dans des zones non fracturées ou fortement cimentées.

- Ces niveaux, peu exploités à ce jour, présentent un potentiel en ressources tight oil

encore sous-évalué, nécessitant une caractérisation pétrophysique détaillée et une réévaluation géologique intégrée. [9]

II.1.5 Porosity and Permeability in Tight Reservoirs

➢ **Definition and Importance of Porosity and Permeability**

Porosity refers to the percentage of rock volume occupied by voids or pores that can store fluids, whereas permeability quantifies the ability of those fluids to move through the interconnected pore network. In tight reservoirs, both properties are significantly diminished due to post-depositional geological processes.

In conventional reservoirs, porosity typically ranges from **15% to 30%**, and permeability can reach several hundreds of millidarcies (mD). In contrast, tight reservoirs are characterized by:

- **Effective porosity**: generally, **below 10%**, often around **3–8%**.
- **Permeability**: extremely low, in the range of **0.001 to 0.1 mD**, and may even fall

into the **nanodarcy (nD)** domain.[10]

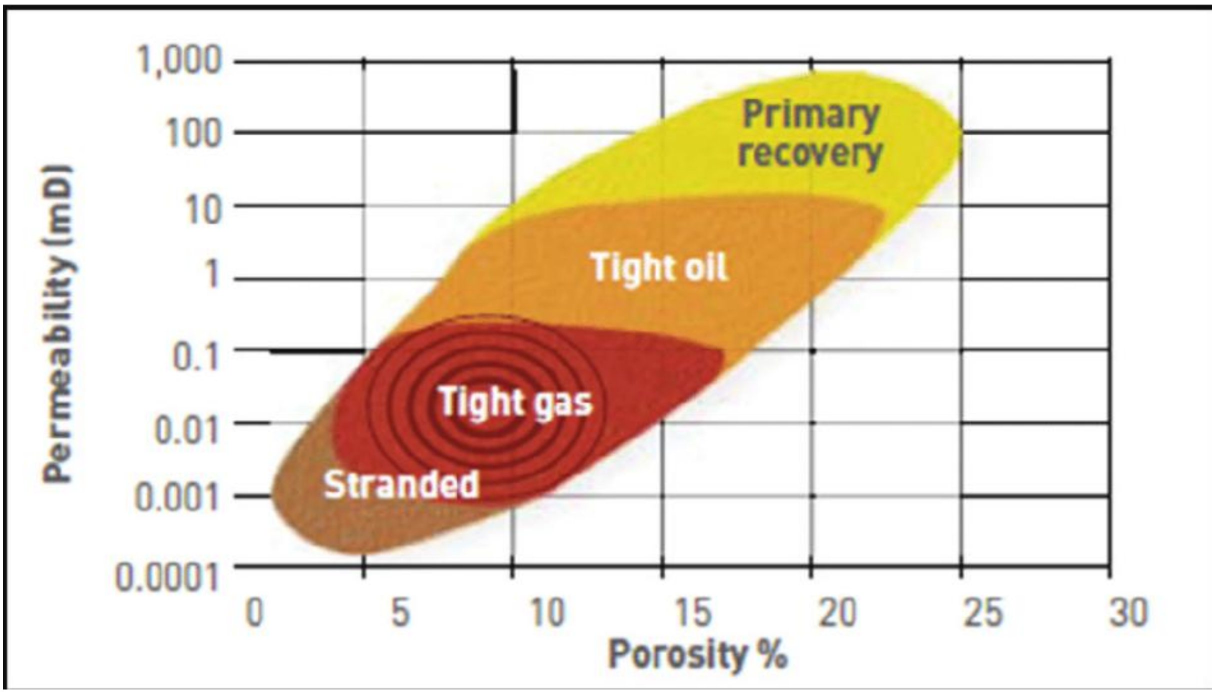


Figure II.2 Porosity vs. Permeability Diagram[11]

- **Porosité primaire vs secondaire**

- **Primary porosity** is inherited from the initial sedimentary deposition (e.g., intergranular porosity in sandstones, intercrystalline in carbonates).

- **Secondary porosity** is formed post-depositionally through processes such as dissolution, fracturing, or chemical alteration often in overpressured zones or deeply cemented carbonate intervals.

In Algerian basins such as **Timimoun** and **Reggane**, Scanning Electron Microscope (SEM) studies have shown that residual porosity is predominantly secondary, poorly connected, and typically confined to microfractures or underdeveloped intercrystalline voids.

- **Factors Influencing Porosity and Permeability**

- **Cementation** (by quartz, calcite, dolomite, or clay minerals).
- **Authigenic growth**: progressive pore blockage by secondary minerals.
- **Mechanical compaction**: grain rearrangement under lithostatic stress.

- **Thermal alteration**: especially at depths exceeding 3500 meters, where clay mineral stability is compromised.
- **Natural fracturing**: often the only conduit for flow within tight, matrix-dominated formations.

In the **Lower Devonian units of the Illizi Basin**, porosities of **6–9%** have been measured, but poor pore connectivity significantly limits natural well deliverability in the absence of artificial stimulation.[12]

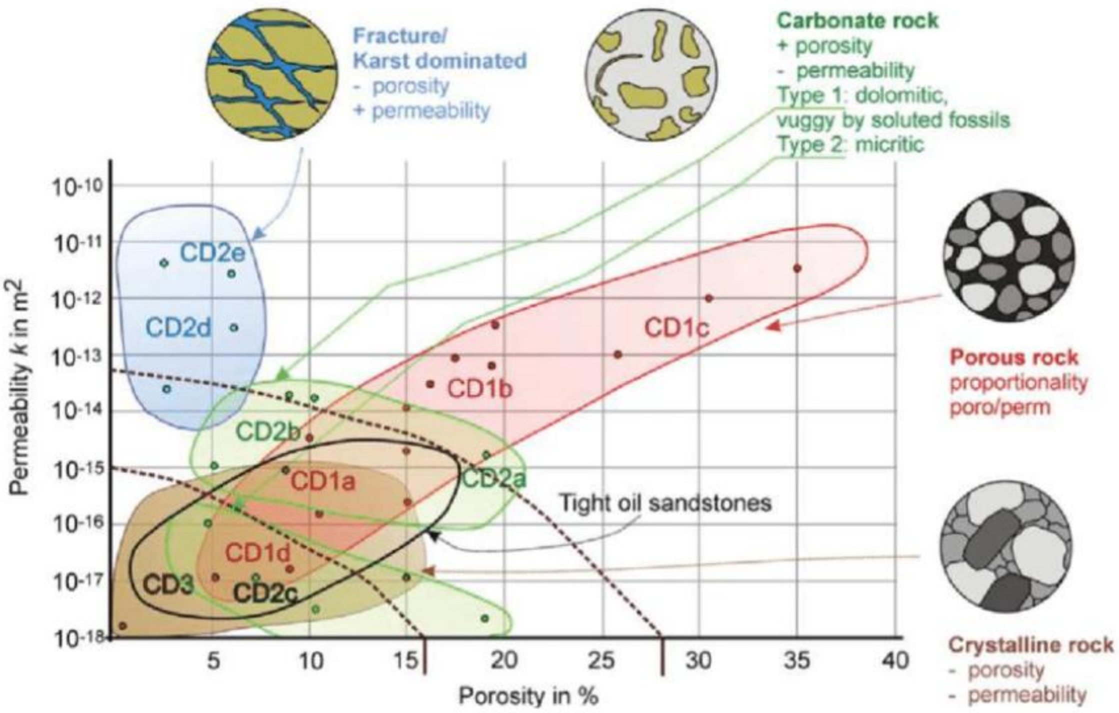


Figure II.3 Ranges of Porosity and Permeability by Lithology[11]

II.1.6 Fluid Flow Behavior in Tight Reservoirs

➢ **Non-Darcy Flow Regime**

In conventional systems, fluid flow typically obeys **Darcy's Law**, which assumes linear, laminar flow driven by pressure gradients. However, in tight formations:

- The **pore and throat sizes** are so small that flow behavior becomes **nonlinear**.
- **Capillary forces and surface tension effects** dominate, making flow highly sensitive

to **water saturation**, **interfacial tension**, and **rock wettability**.[14]

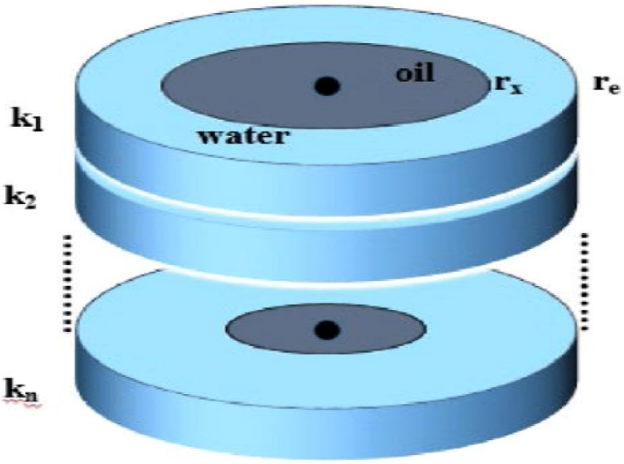


Figure 7 Production Schematic in a Low-Permeability Heterogeneous Reservoir[13]

- **Capillary trapping & saturation effects**

- **High capillary pressure** in narrow pores traps fluids especially water making oil or gas mobilization difficult.
- This results in **high irreducible water saturation**, often exceeding 50%, thereby reducing recoverable hydrocarbon volumes.
- Gas may exist either in solution or as trapped phases within disconnected nanopores.

- **Role of Natural Fractures**

Natural fractures, frequently observed in **Reggane**, **Ahnet**, and **Berkine**, play a pivotal role in enhancing productivity in tight reservoirs. Often, they are the primary flow pathways**:**

- They function as fluid superhighways, bypassing the low-permeability matrix.
- Their orientation and interconnectivity determine the effective drainage area.

FMI (Formation MicroImager) logs have confirmed the presence of well-developed vertical and sub-horizontal fracture networks in compact Triassic layers of the **Timimoun Basin**.

- **Pressure Sensitivity and Flow Initiation**

Flow in tight reservoirs is highly pressure-dependent:

- Below a critical threshold pressure, no measurable flow occurs.
- A high-pressure differential is required to initiate and sustain flow.

This behavior necessitates the use of non-linear flow models, which incorporate:

- Threshold pressure effects,
- Non-Darcy flow curves (nonlinear rate vs. pressure response),
- Fluid phase behavior shifts (e.g., condensate dropout, volatile oil expansion) at

depths exceeding 4000 meters, as seen in certain zones of the **Hassi Messaoud Basin**.[9]

Tight reservoirs in Algeria represent a technically demanding yet high-potential frontier in oil and gas development particularly in gas-rich basins such as **Timimoun**, **Ahnet**, and **Reggane**. Their complex nature is governed by an interplay of depositional history, diagenetic processes, and tectonic evolution, all of which contribute to low conventional reservoir quality.

A successful exploration and development strategy must be based on a deep understanding of reservoir rock properties, including sedimentology, petrophysics, and structural geology. Advanced reservoir description tools such as core-based analysis, thin-section petrography, and mineralogical characterization **(XRD, SEM)** are critical for evaluating reservoir potential, identifying sweet spots, and supporting the design of efficient and cost-effective production programs. [13]

II.2. Comparison Between Tight and Conventional Reservoirs

II.2.1 Geological Characteristics

- **Conventional Reservoirs**

Conventional reservoirs are typically found in porous and permeable rock formations, such as sandstone or limestone. These formations allow hydrocarbons to migrate from the source rock and accumulate in traps beneath impermeable cap rocks. The natural pressure within these reservoirs enables oil and gas to flow freely to the wellbore upon drilling.

- **Unconventional Reservoirs**

Unconventional reservoirs consist of low-permeability formations like shale, tight sandstone, or coal beds. In these reservoirs, hydrocarbons are often retained within the source rock itself and do not migrate to form concentrated accumulations. Due to the tight nature of these rocks, hydrocarbons cannot flow freely and require stimulation techniques to enhance permeability. [15]

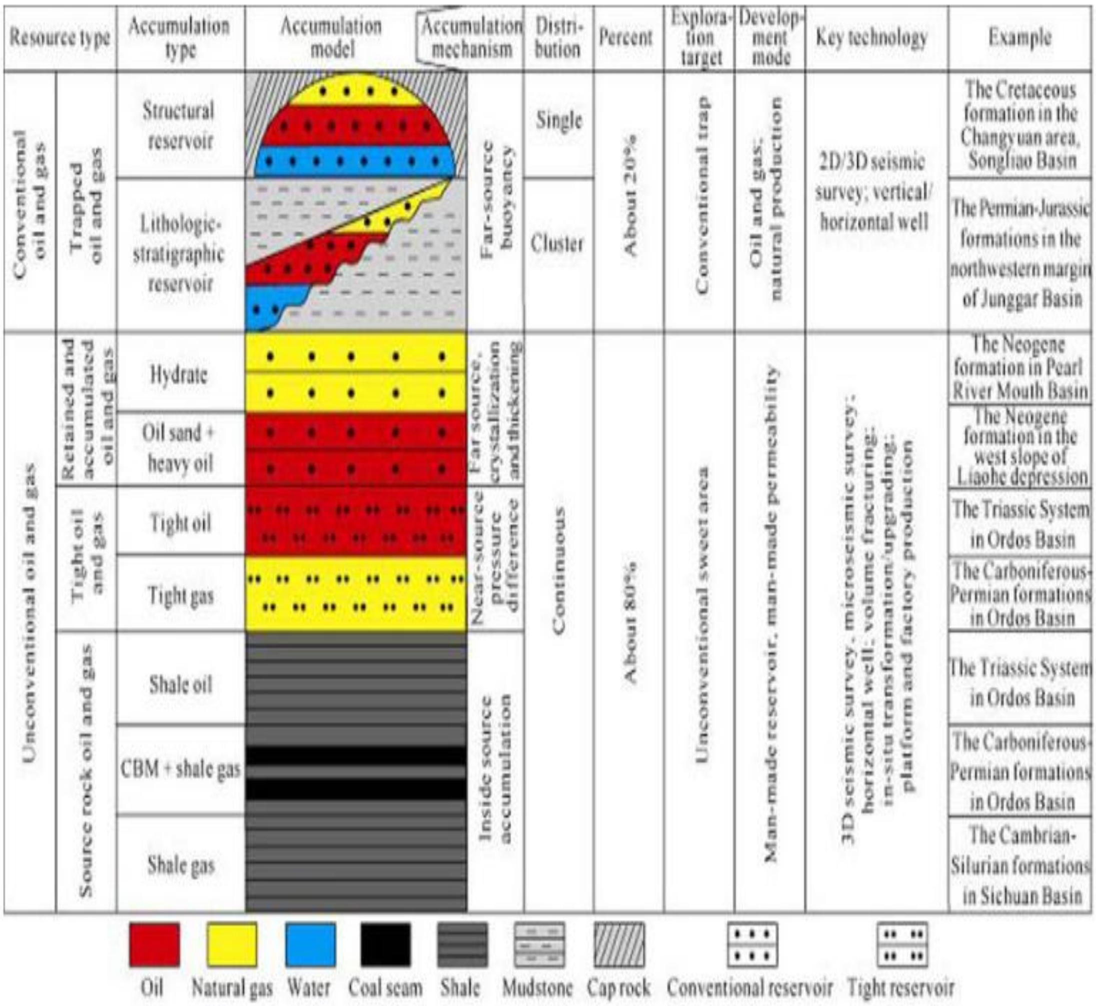
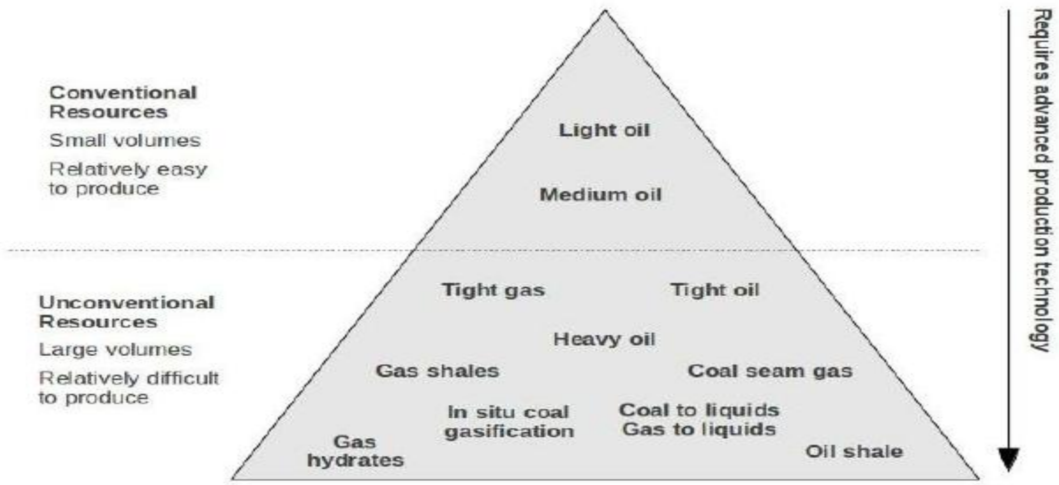


Figure 8: Classification and comparison of conventional and unconventional oil and gas reservoirs.[15]

II.2.2 Extraction Techniques

➢ Conventional Reservoirs

Extraction from conventional reservoirs typically involves vertical drilling methods. The natural pressure of the reservoir drives the hydrocarbons to the surface. In cases where pressure declines, secondary recovery methods like water or gas injection are employed to maintain



production levels.

Figure 9: Graphical comparison of conventional and unconventional resources, highlighting extraction methods.[16]

➢ Unconventional Reservoirs

Unconventional reservoirs require advanced extraction techniques due to their low permeability. Methods such as horizontal drilling and hydraulic fracturing (fracking) are employed to create pathways that allow hydrocarbons to flow to the wellbore. These techniques are more complex and costly compared to conventional methods. [16]

II.2.3 Economic Considerations

- **Conventional Reservoirs**

Developing conventional reservoirs is generally more cost-effective due to simpler extraction methods and higher recovery factors, often around 30%. The predictability of reservoir behavior and established technologies contribute to lower operational risks and costs.

- **Unconventional Reservoirs**

Unconventional reservoirs involve higher capital expenditures due to the need for specialized drilling and stimulation techniques. Recovery factors are typically lower, averaging below 10%, which can impact the economic viability of projects. However, advancements in technology and higher oil prices can improve the feasibility of developing these resources.

II.2.4 Environmental Impact

- **Conventional Reservoirs**

Conventional oil and gas extraction has a relatively lower environmental footprint. The processes involved are well-understood, and the infrastructure required is less extensive, leading to reduced land disturbance and water usage.

- **Unconventional Reservoirs**

The development of unconventional reservoirs poses greater environmental challenges. Hydraulic fracturing requires significant water volumes and can lead to concerns about groundwater contamination and induced seismicity. Additionally, the extensive surface infrastructure needed can result in habitat disruption and increased greenhouse gas emissions.

Table II.1: Key Differences between Conventional and Unconventional Reservoirs

Aspect	Conventional Reservoirs	Unconventional Reservoirs
Rock Type	Porous and permeable (e.g., sandstone, limestone)	Low-permeability (e.g., shale, tight sandstone, coal beds)

Hydrocarbon Flow	Flows naturally due to reservoir pressure	Requires stimulation to enhance flow
Extraction Method	Vertical drilling, secondary recovery techniques	Horizontal drilling, hydraulic fracturing
Recovery Factor	Approximately 30%	Typically below 10%
Economic Risk	Lower, with established technologies	Higher, due to complex extraction methods
Environmental Impact	Lower, with less land and water usage	Higher, with concerns about water use and seismicity

Conclusion

Tight reservoirs show significant differences from conventional systems due to their complex geological history, limited pore interconnection, and nonlinear behavior of fluids. The formation of these reservoirs is caused by synergy between depositional conditions and intense diagenetic processes such as compaction, cementation, and mineral transformation, which significantly reduce porosity and permeability. Furthermore, natural fractures often play critical roles by acting primarily as avenues for hydrocarbon migration and production,
particularly for formations that occur in areas like Reggane and Ahnet. Algeria's sedimentary basins exhibit significant tight gas and tight oil potential, though these resources remain underdeveloped. Detailed reservoir characterization using advanced tools—such as SEM, XRD, core analysis, and wireline imaging is essential for identifying productive zones and guiding the design of efficient stimulation programs.

The difference between traditional reservoirs and those that are. tight has thrown into relief important technological challenges, lower recovery efficiencies, and added financial risks of tight systems. Still, through applying new technologies and using combined reservoir modeling throughout their life cycle, Algeria has a strategic opportunity available to diversify its resource base and deliver future energy requirements sustainably

Chapter III
Hydraulic Fracturing Concepts and Fundamentals

Introduction

In petroleumengineering, the optimization of well productivity is a critical objective, achieved primarily through strategic stimulation treatments. Theseinterventions are designed to either remediate near-wellbore formation damage – an impairment of permeability in the immediate vicinity of thewellbore – or to engineer a highly conductive conduit within the reservoir rock, commonly known as a propped fracture.

Among the variousstimulation methodologies, hydraulic fracturing stands as a cornerstone technique. Its fundamental purpose is to restore, or indeed enhance, thehydraulic communication between the wellbore and the hydrocarbon-bearing reservoir.

This process intrinsically increases formation permeability, therebydirectly augmenting the well's productivity index and ultimately its hydrocarbon flow rate in both conventional vertical and challenging horizontal wellgeometries.

A prerequisite to anysuccessful stimulation campaign is a rigorous diagnostic evaluation to precisely characterize the nature and spatial extent of any existing formationdamage. This critical step enables the selection and tailored design of the most efficacious treatment strategy, ensuring maximum remedial impact andsustained production enhancement.

III.1 Definition

Hydraulicfracturing is anoperation that involves intentionally fracturing the reservoir rock to create ahighly permeable drainage pathway. This created pathway extends as far aspossible into the formation, thereby facilitating the flow of hydrocarbons towards the wellbore. This process is particularly applicable when a well'sproduction rate is insufficient, not due to wellbore plugging or damage, but rather because the natural permeability of the reservoir matrix isinherently low. This is often the case in tight oil reservoirs with permeabilities of only a few tens of milli-darcys, and even lower for gasreservoirs

III.2 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
- 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.

III.3 Hystorical of Hydraulic Fracturing

Hydraulic fracturing is not a new technology, and the use of this technology can be traced to the early 1900s. Fracturing was first developed in the United States in the 1950's. In Canada much of the fracture treatments were applied to conventional reservoirs. In the mid of 1990, over the past 50 years, there have been significant advances in hydraulic fracturing technology.[19]

Table III.1 Highlights in the Development of Hydraulic Fracturing.

Date	Comment
Early	Fracturing with cement pumpers Vertical wells fractured with foam
1950s	Klepper gas unit no.1: first well to be fractured to increase productivity
1947	Stephens County, Oklahoma: first commercial fracturing treatment
1949	Fracturing with cement pumpers
1950	Evolution of fracture geometry, Increasing well productivity
1950s	Fracturing pumpers and blenders
1960s	Massive hydraulic fracturing, Increase recoverable reserves, Hydraulic
1970s	fracturing in Europe
	First gas well drilled in Barnett shale in Texas.
1983	Evolution of proppant transport, Fracture conductivity testing, Cross linked
1980s	gel fracturing fluids developed; used in vertical wells.
	First horizontal well drilled in Barnett shale Orientation of induced fractures
1990s	identified Foam fracturing.
	Slickwater fracturing fluids introduced
1996	Microseismic postfracturing mapping developed
1996	Slickwater refracturing of originally gel-fractured wells
1997	Multistage slickwater fracturing of horizontal wells

2002	First hydraulic fracturing of Marcellus shale
2003	Horizontal wells become dominant
2004	Increased emphasis on improving the recovery factor
2005	Use of multi well pads and cluster drilling
2007	

III.4 Hydraulic Fracturing Fluid

A hydraulic fracturing fluid for geothermal applications needs to combine a number of, sometimes conflicting, properties. While traveling down the well the viscosity should be relatively low to avoid an excess of friction. During the time it creates the fracture the viscosity should be high to increase the efficiency and to carry the proppant into the fracture. Upon terminating the treatment, the fluid should lose its viscosity to allow easy flow back (in a producer) or easy (re-) start of injection. Furthermore, a fluid should be compatible with the formation rock and should not pose a threat to the environment. [21]

III.4.1 Types of Fracturing Fluid

To combine all these requirements in a single fluid formulation is not easy but the oil and gas industry has succeeded in formulating fluids that come very close. following fluid types are the mostly used:

Table III.2. Fracturing Fluids and Conditions for Their Use.[21]

Base Fluid	Fluid type	Main composition	Used for
	Linear	Guar, HPG, HEC, CMHPG	Short fractures, low temperature
	Crosslinked	Crosslinker + Guar, HPG, CMHPG or CMHEC	Long fractures, high temperature
	Micellar	Electrolite + 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

Oil	Alcohol based Linear Crosslinked Water emulsion	Methanol + Foamer + N_2 Gelling agent Gelling agent + Crosslinker Water + Oil + Emulsifier	Low pressure, Water-sensitive formations Short fractures, Water-sensitive formations Long fractures, Water-sensitive formations Moderate length fractures, good fluid loss control
Acid	Linear Crosslinked Oil emulsion	Guar + HPG Crosslinker + Guar or HPG Acid + Oil + Emulsifier	Short fractures, carbonate formations Longer, wider fractures, carbonate formations Moderate length fractures, carbonate formations

III.4.2 Fracturing Fluid Additives

Fracturing fluids are complex mixtures containing as many as six or seven different components. Many low concentrations of various additives are used to control specific behavioral characteristics of the frac-fluids at several distinct phases of the fracture treatment. The relative compatibility of the mixed additives must be determined for each formulation to avoid reactions that will lead to loss of the reacting additives through precipitation and/or deactivation. Gelling agents and crosslinkers define the specific fluid type, and they are not considered to be additives.Fluid additives are materials used to produce a specific effect, independent of fluid type. When using additives, however, their relative compatibility needs to be carefully verified. And in general, the question should be asked whether the additive, mostly advocated by the service companies, is really required. The basic principle of using additives in fracturing fluids should be to keep it as simple as possible. [21]

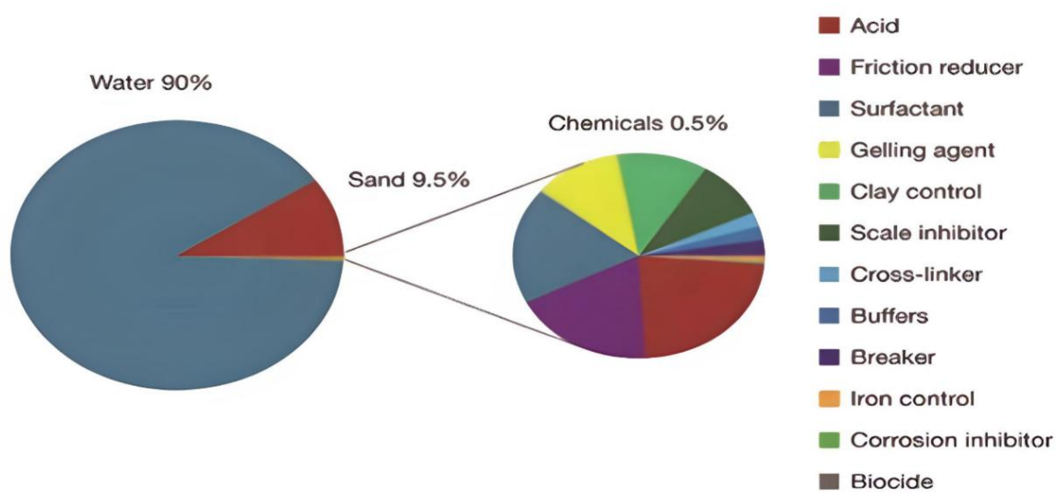


Figure III.1: Typical Fracture Fluid Composition. [22]

Fracturing fluids contain various additives, each serving a specific function to optimize the treatment:

- **Crosslinkers:** Chemicals that react with polymers to create a high-viscosity, gel-like

structure for proppant transport.

- **Breakers:** Enzymes or chemicals that reduce the fluid's viscosity after proppant

placement, allowing for easy flowback.

- **Fluid Loss Additives:** Particles or polymers that temporarily plug pores on the fracture

face to minimize fluid leakage into the formation.

- **Friction Reducers:** Polymers that reduce friction pressure losses in the tubing and

fracture.

- **Biocides:** Prevent bacterial growth that can degrade polymers or plug the formation.
- **Surfactants:** Improve fluid flowback and reduce surface tension.
- **Clay Stabilizers:** Prevent clay swelling and migration that can damage permeability.
- **Gelling agent:** A chemical additive used to increase the viscosity of the fluids.

The choice of proppant is highly dependent on the anticipated reservoir closure stress and temperature conditions to ensure long-term fracture conductivity.

Table III.3 Proppant Selection Based on Closure Pressure[22]

Contrainte de fermeture	Temperature	Agent de soutènement
≤6000 psi	--	Sable
≥ 6000. 1200 ≤	≥250 ºF	RCS (Resin-coated sand)
≥ 6000. 1200 ≤	≥250 ºF	ISP(Intermediat Strength Proppant)
≥1200 psi	--	HSB(heigh Strength Bauxite)

III.4.3 Commonly Used Fracturing Gels in Hassi-Messaoud (HMD), Algeria

In the Hassi-Messaoud field, specific crosslinked polymer gels are frequently employed due to their robust performance in deep and consolidated formations:

- **Spectra Frac G3500 (BJSP):** The Spectra Frac G® system is a premium, high-

performance fracturing fluid for applications from 60° to over 300°F (16° to 149°C). The water-based system is comprised of a refined, natural guar gelling agent crosslinked at high pH by a patented, organo-complexed borate complexor. The fluid is designed for use in either batch-mix or continuous-mix applications. [24]

- **HYBOR #35 (Halliburton):** This gel is known for its controlled crosslinking

capabilities, which allows for precise viscosity management. It effectively reduces friction pressure losses during pumping and exhibits excellent shear stability, minimizing degradation even under high shear rates. HYBOR #35 is particularly recommended for highly consolidated and deep formations due to its high apparent viscosity within the formation, which aids in creating wide fractures and ensuring minimal residue upon flowback.

- **YF 135 HTD (Dowell Schlumberger):** This gel system is characterized by its lower

polymer concentration, offering a more economical fluid design.

III.4.4 Hydraulic Fracturing Process

III.4.4.1 Equipments

Once the well has been drilled and the wellbore has been tested for integrity, the site is prepared for well stimulation through hydraulic fracturing. Various surface facilities and mobile equipment including fracture fluid storage tanks, sand storage units, chemical trucks, blending equipment and pumping equipment surround the wellhead on the lease. The hydraulic fracturing process is monitored from a single truck often referred to as the Data Monitoring Van. The Data Monitoring Van will monitor and record the rate and pressure at which the fracturing fluid is pumped down the wellbore, the rates of the necessary additives present in the fracturing fluid and proppant concentration. Prior to and during the hydraulic fracturing job, you can expect to see an increase in heavy traffic on the roads surrounding the lease, as required equipment and services, such as graders, water trucks, the service rig and other heavy equipment is transported to and from the site. Once the hydraulic fracturing program and related operations are completed the traffic should decrease substantially. [24]

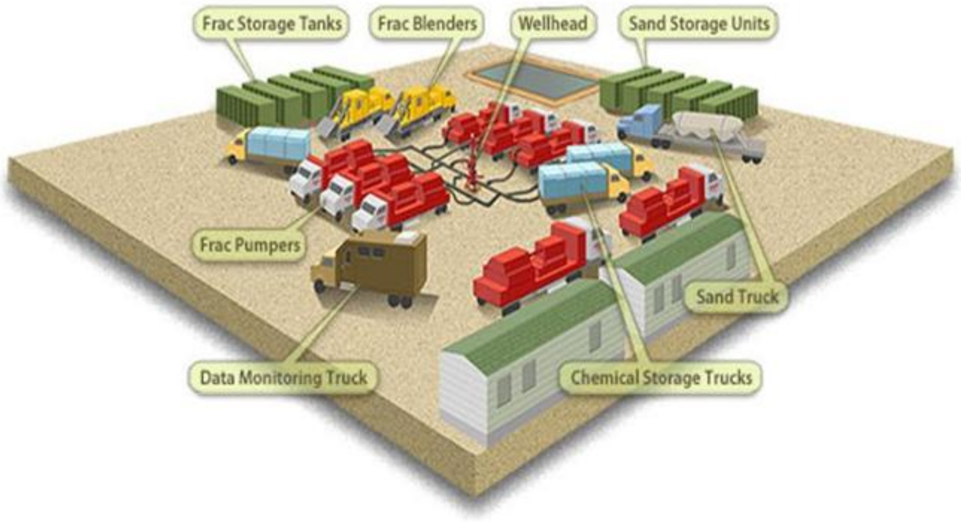


Figure III.2: Hydraulic Fracturing Equipments.[24]

III.4.4.2 Chronological Sequence of Hydraulic Fracturing Process

1- Well Data Analysis: Well Location, Existing Well Diagram, Log / Petrophysics (Sw, Por), MDT (K, Pr), and Geomechanically modelling (Stress Distribution).

2- Fracturing Design: Optimum half length, Design pump Schedule, Treatment pressure, Flow capacity, and Fracture geometry.

3- Injection Tests.

4- Treatment Evaluation: Injection tests analysis, and Calibration injection Test / DATA Frac (Data Frac Analysis & Pressure Match analysis).

5- Treatment Redesign.

6- Main Frac Execution.

7- Main Frac Evaluation & Result: Pressure Match, and Frac Simulation

III.4.5 Multi Stage Hydraulic Fracturing

In recent years, the use of **horizontal drilling** in oil and gas production has increased steadily. This method is becoming more popular because it helps improve production by increasing the contact between the wellbore and the reservoir. By drilling horizontally, a larger section of the reservoir rock is exposed, which allows more oil or gas to flow into the well.

To meet the goal of increasing production, especially from **unconventional reservoirs**, new techniques have been developed to stimulate these formations in a more **efficient and cost-effective** way. One of the most effective approaches is **multi-stage hydraulic fracturing** in horizontal wells.

There are several methods used for completing horizontal wells with multi-stage fracturing, such as **plug & perf**, and Frac point **sliding sleeves**. Each method has its own benefits and challenges, and it is not always easy to choose the one that gives the best results for a specific reservoir.

III.4.5.1 Multi-Stage Hydraulic Fracturing Process

- **Diagnostic Fracture Injection Test (DFIT)**

The **Diagnostic Fracture Injection Test (DFIT)** is the most commonly used technique in unconventional shale reservoirs to determine key completion parameters and reservoir properties for optimal fracture design. The principle involves creating a small fracture by injecting 10–100 barrels of water at a rate of 2–10 BPM, followed by pressure fall-off monitoring over a specified duration.

Typically, DFIT is performed **a few weeks prior** to the main hydraulic fracturing operation, depending on the formation's permeability.

The **closure time** after DFIT injection is influenced by the formation's permeability and the injection duration, which in turn determines the time required to reach pseudo-radial flow. It is critical to allow adequate monitoring time post-injection to observe this flow regime, enabling accurate assessment of reservoir characteristics.

Key **completion and reservoir parameters** determined from DFIT include:

- ✓ Instantaneous Shut-In Pressure (ISIP)

- ✓ Fracture gradient
- ✓ Net pressure (net extension pressure)
- ✓ Fluid leak-off behavior
- ✓ Closure time
- ✓ Closure pressure (minimum horizontal stress)
- ✓ Approximation of maximum horizontal stress
- ✓ Anisotropy
- ✓ Fluid efficiency
- ✓ Effective permeability [27]

➢ **Mini-Fracture Tests (Mini-Frac)**

The **Mini-Frac Test** is designed to gather critical formation data before the main fracturing treatment. It is especially recommended when limited or uncertain data exists regarding rock mechanics and fluid leak-off characteristics—common in most wells, especially in unexplored or low-quality data zones.

Mini-fracs are generally **not performed** only when there is **reliable offset well data** from similar fracturing treatments.

A mini-frac is conducted using the **same fluid type and flow rate** as the planned main treatment but **without any proppant.** The injected fluid volume must also be sufficient to simulate actual treatment conditions.

When well-executed, mini-fracs provide valuable information on:

- Fracture geometry
- Rock mechanical properties
- Fluid leak-off behavior

These insights are critical for the successful design and implementation of the main hydraulic fracturing operation. [28]

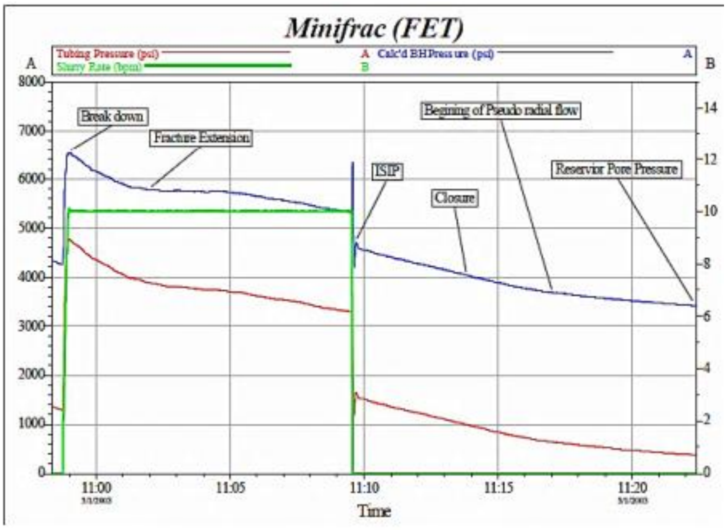


Figure III.3 Example of a mini-frac job plot[28]

➢ Step-Rate Tests

Step-rate tests are typically performed during the fracture design phase, before the actual treatment. Along with the mini-frac, they are considered **calibration tests**, helping engineers align fracture models with the actual formation response.

There are two main objectives:

- **Determine fracture extension pressure**
- **Assess near-wellbore friction** (via Step-Down Test)

Both types of step-rate tests are extremely useful for fine-tuning treatment parameters and validating the expected pressure behavior of the formation. [29]

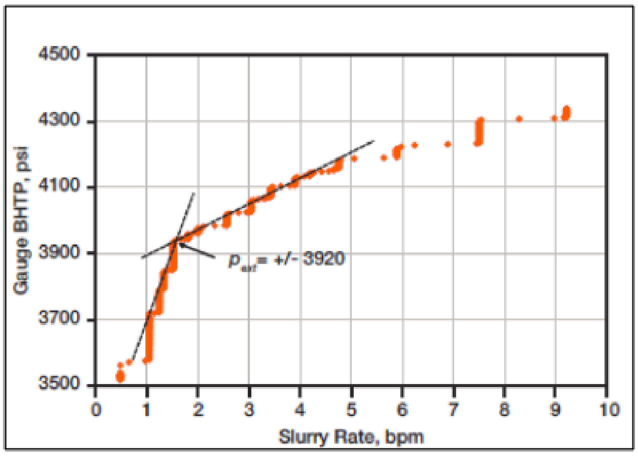


Figure III.4 Typical pressure-rate crossplot of a step-rate test.[29]

➢ **Pump-In and Flowback Test**

This procedure consists of a **short pump-in stage** followed by a **flowback period**. Its purpose is to acquire detailed data for a mini-frac analysis of the well using **the same fluid and flow rate** as the main treatment.

Key parameters obtained from the pump-in/flowback test include:

- Final Closure Pressure (FCP)
- Fluid efficiency
- Net pressure
- Leak-off parameters
- Validation of treatment design

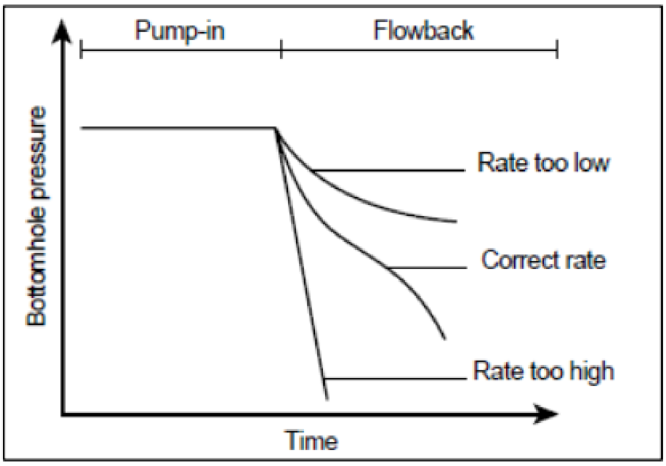


Figure III.5 Pump-in and flowback test. [30]

III.4.6 Main Multi-Stage Hydraulic Fracturing Operation

The main fracturing operation typically proceeds through the following stages:

a. Pad Injection

The **pad fluid** is a highly viscous fluid used to initiate fractures within the target formation. It is injected at a rate that **exceeds the leak-off rate** to open and propagate the initial fracture.

This fluid is typically a **crosslinked gel**, pumped at rates ranging between **10–25 BPM**.

b. Slurry Injection

Immediately following the pad stage, a **slurry** consisting of crosslinked gel mixed with a **proppant** (e.g., sand or ceramic beads) is injected. The slurry sustains and widens the fractures initiated by the pad fluid, allowing deeper propagation into the formation.

c. Slurry Flush (Displacement)

Once the planned slurry schedule has been pumped, the **proppant flow is stopped**, and the well is flushed. This stage involves pumping clean fluid (water and chemicals only) into the wellbore to **clean the production tubing** of any remaining proppant.

The flush volume is calculated based on:

- Tubing depth
- Diameter
- Quality and type of proppant
- Perforation characteristics at the bottom hole

This step ensures that **all remaining proppant** is displaced into the formation and that the tubing is cleared for post-fracturing operations.

III.4.7 Well Candidate Selection Criteria

Basic Requirements

In order to get maximum benefit from the stimulation expenditure, a proper candidate and treatment selection procedure is of paramount importance. In this section, the procedure to arrive at a proper selection of candidates and the most applicable type of treatment is discussed in some detail.

The basic requirements for a successful stimulation treatment are simple:

- The reservoir must contain adequate volumes of moveable hydrocarbons.
- The reservoir pressure should be high enough to initiate and maintain hydrocarbon flow towards the wellbore.
- The production system (tubing, flowlines, separators, etc.) can accommodate the extra production.

- A professional treatment design, execution, and supervision is of paramount importance.

The well and reservoir requirements will be dictated by economical constraints, but the minimum requirements for successful fracturing treatments may be translated into the following rules of thumb:

- **Hydrocarbon saturation**: 30% or more
- **Water cut**: 50% or less
- **Gross reservoir height**: 10 m or more, in horizontal wells, where transverse fractures are expected, this requirement is not applicable.
- **Permeability**: **Gas**: less than 10 mD

  Oil: less than 50 mD

- **Reservoir pressure: Gas**: at least two times the abandonment pressure

  Oil: not more than 80% depletion

- **Production system:** Current production not more than 80% of maximum capacity of facilities

It is stressed, that the above cut-off values are not rigid criteria, but merely guidelines for a first selection of candidate wells. In general, there should be a clear indication of substantial production gains (into the stock tank), provided the treatment is planned and executed in an optimum manner. After this initial screening, a more thorough evaluation of the well performance is required, to further assess its suitability for a stimulation treatment.

III.4.7.1 Frac Point (Sliding Sleeves) Method

The **Frac Point System** is an open-hole multi-stage fracturing method that uses **sliding sleeves** and **isolation packers** to stimulate specific zones along a horizontal well. Each sleeve is opened by dropping a **pressure-activated ball**, allowing continuous hydraulic fracturing without the need for perforation or plugs.

This system speeds up operations, reduces costs, and enables **precise zonal stimulation**. The balls both open the sleeves and seal them to direct the treatment into the target zone. **Dissolvable balls** are often used to avoid the need for well cleanup later. [25]

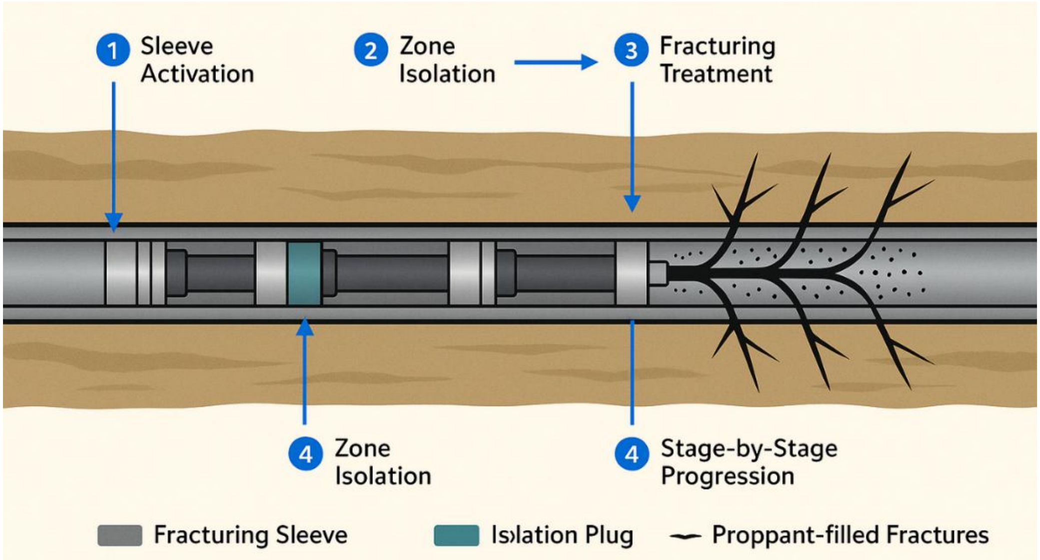


Figure III.6 Frac point System Method[25]

➢ **FracPoint Completion Equipment**

The FracPoint completion system by Baker Hughes is designed for multi-stage fracturing in open hole horizontal wells. The system incorporates a series of ball seats with varying diameters, allowing for sequential fracturing operations without the need to shut down the pumps.

This is accomplished by dropping balls that land on their corresponding seats, which isolates individual intervals and simultaneously opens the Frac sleeves.

The specialized FracPoint completion system includes six main components:

a. Ball Seat Sub
b. Pressure-Activated Frac Sleeve (P-Sleeve)
c. FracPoint Open Hole Short Radius Packer
d. Ball-Activated Frac Sleeve
e. Liner Hanger Packer
f. Wellbore Isolation Valve

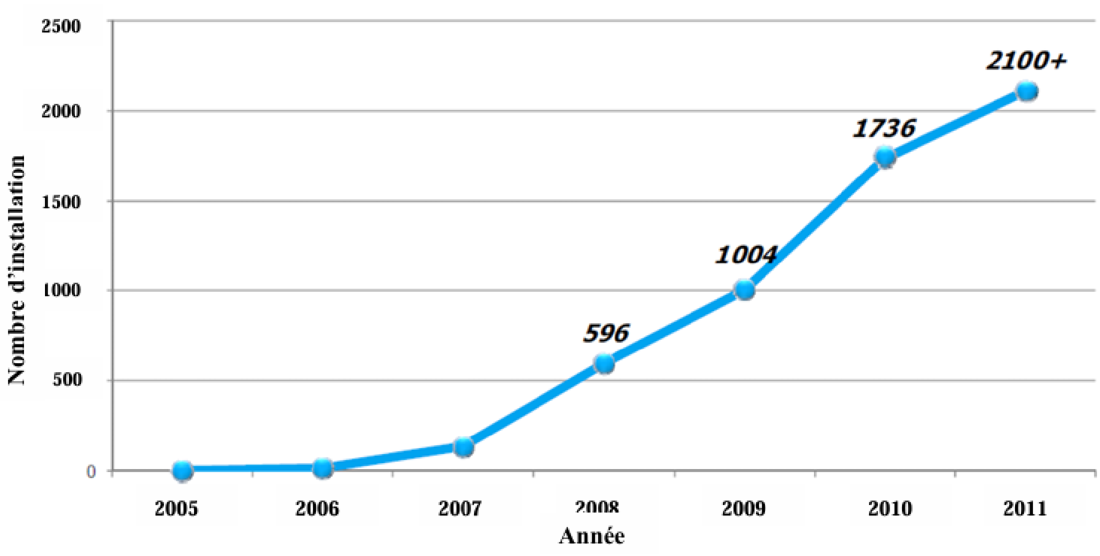


Figure III.7 Number of FracPoint Completion System Installations[25]

III.4.7.2 Cemented Plug-and-Perf Completions Method

Cemented Plug-and-Perf (P&P) completions represent one of the oldest and most widely used multistage stimulation techniques in the oil and gas industry. The method begins with cementing a production casing or liner in place. A bridge plug is then deployed downhole via wireline along with perforating guns to isolate a specific stage. After setting the plug and perforating the target zone, the tools are retrieved, and the stage is stimulated with the plug serving to divert treatment fluids into the formation. This sequence is repeated for each target zone until the entire well is completed. Following stimulation, coiled tubing is employed to mill out the plugs and enable well flowback. [26]

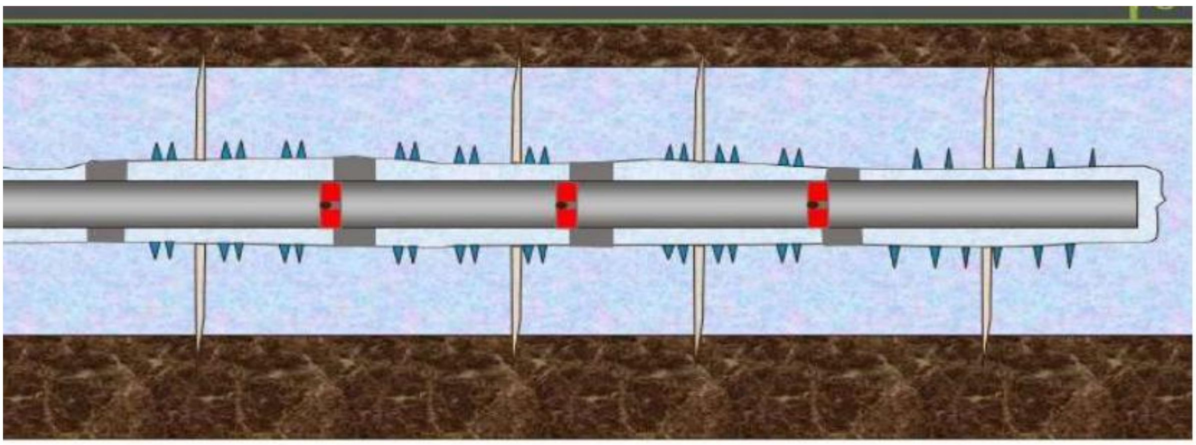


Figure III.8 plug and perf staging[26]

III.4.7.3 Comparison Between Different Multi-Stage Methods

The following table presents the strengths of these two methods:

Table III.4. Comparison Between Different Multi-Stage Methods

Plug & Perf Method	Sliding Sleeve Method
• **Easy well completion.** • **Good casing cementing ensures better isolation between stages.** • **We can place an unlimited number of stages.** • **Good cementing supports the tubing to resist formation stresses.** • **We can perforate the reservoir at any depth.** • **Reduction in equipment costs.**	• No need for CT or Wireline intervention. • Immediate flow back. • Less debris production compared to Plug & Perf methods, as there is no need to mill the plugs. • Recommended for fractured reservoirs. • Much more recommended in less stressed zones. • Sliding sleeves allow faster stage transitions since they can be opened or closed from the surface without multiple trips into the well.

Conclusion

Through this chapter, we have confirmed that hydraulic fracturing is an essential stimulation technique for enhancing hydrocarbon recovery in tight reservoirs, particularly those with very low permeability such as in the Hassi Messaoud field. The effectiveness of the fracturing operation depends heavily on the appropriate selection of fluids and additives, with crosslinked gels proving to be highly suitable for the thermal and mechanical conditions of the region. Furthermore, the application of multi-stage hydraulic fracturing in horizontal wells has been shown to significantly improve reservoir contact and production potential. Two main completion systems—FracPoint and Cemented Plug-and-Perf—were analyzed, each offering operational advantages based on specific reservoir and well characteristics. Lastly, we emphasized the importance of well candidate selection, which must be based on thorough petrophysical, geological, and geomechanical evaluation. These conclusions provide the technical basis for the comparative analysis and field case studies that follow in the next chapter.

CHAPTER IV

The application of multistage fracturation in Hassi Messaoud oil field: MDZ-548 & OMGZ-60

Introduction

This case study chapter applies the theoretical and technical foundations of hydraulic fracturing to two real field applications from the **Hassi Messaoud basin**: **well, MDZ-548** and **well OMGZ-60**. These two wells, although located in the same basin, were completed using different multi-stage fracturing techniques. The purpose of this chapter is to compare, analyze, and interpret the performance of these two completion methods in tight and heterogeneous reservoir environments, and to assess their effectiveness in improving well productivity.

Well MDZ-548 serves as the primary example of a **FracPoint system** implementation. This system uses **ball-drop-activated sliding sleeves**, allowing for continuous fracturing stages without the need for wireline or coiled tubing intervention during the job. The study details all stages of the operation, including geological context, reservoir properties, job design, mini-frac pressure analysis, and post-job interpretation using Horner plots, Nolte G-function, and Square Root Time diagnostic tools. From this, key values such as **closure pressure**, **net pressure**, **leakoff coefficient**, and **fluid efficiency** were determined using software tools like **MinFrac**. The fracture geometry, efficiency of the stimulation, and well response post-fracture was also evaluated to assess the suitability of the FracPoint method in this specific reservoir.

On the other hand, **well OMGZ-60** represents a case where the **Plug-and-Perf technique** was applied using a **cemented liner**. This method involves selective perforation and mechanical stage isolation using bridge plugs. The operational procedure, stage configuration, and treatment parameters are described in detail, followed by a comparative assessment of stimulation performance. Despite using more conventional stimulation equipment, the P&P method offers flexibility in stage placement and easier re-fracturing options. The study also analyzes the operational time, complexity, and production expectations linked to this technique.

By comparing the results from both wells, this case study aims to determine the **technical advantages, limitations, and cost-performance trade-offs** between the two multi-stage hydraulic fracturing systems. The goal is to guide the selection of the most appropriate technique for future stimulation programs in similar tight sandstone reservoirs in Algeria, particularly those with challenging petrophysical and geomechanical properties.

Ultimately, this practical section highlights the importance of integrating field data, diagnostic pressure analysis, and post-job performance evaluation to enhance stimulation design and well productivity in complex tight formations.

IV.1. GEOLOGICAL DESCRIPTION OF THE HASSI MESSAOUD FIELD[31]

The Hassi Messaoud field is considered one of the most geologically complex oil fields in the world. Throughout its geological history, this field has undergone intense tectonic evolution, marked by both compressional and extensional phases. Additionally, it has been subject to diagenetic transformations within the reservoir during its burial over geological time, eventually leading to the formation of the field as it is configured today. These events may sometimes enhance petrophysical properties such as the creation of natural fractures or conversely, degrade them, for example by reducing porosity due to pore plugging. Therefore, understanding the lithology of this field is a crucial step that plays a key role during well interventions throughout the production phase.

IV.2. Historical Overview of the Hassi Messaoud Field

The Hassi Messaoud reservoir was discovered by two separate companies: CFPA in the northern part of the field and SN-REPAL in the southern part.

The field was officially discovered on January 16, 1956, by SN-REPAL, which initiated the first exploration well, MD-1. This well encountered productive oil-bearing Cambrian sandstones at a depth of 3,338 meters.

In May 1957, approximately seven kilometers northwest of MD-1, CFPA confirmed the existence of the reservoir by drilling well OM-1.

Initially, drilling activity was limited to about ten wells per year. However, the pace of development significantly increased starting in 1967 and especially after the nationalization of hydrocarbons on February 24, 1971.

To date, the field has seen the drilling of approximately 1,800 wells.

IV.3. Geographical Location

The Hassi Messaoud field is a major hydrocarbon reservoir, contributing more than 50% of Algeria's total oil production. It is located approximately 850 km south-southeast of Algiers, 350 km from the Tunisian border, and about 80 km east of Ouargla. Its location, in Lambert South Algeria coordinates, is as follows:

- Easting: from 790,000 to 840,000
- Northing: from 110,000 to 150,000

In geographic coordinates:

- Northern boundary: Latitude 32°15′
- Southern boundary: Latitude 31°30′
- Western boundary: Longitude 5°40′
- Eastern boundary: Longitude 6°35′

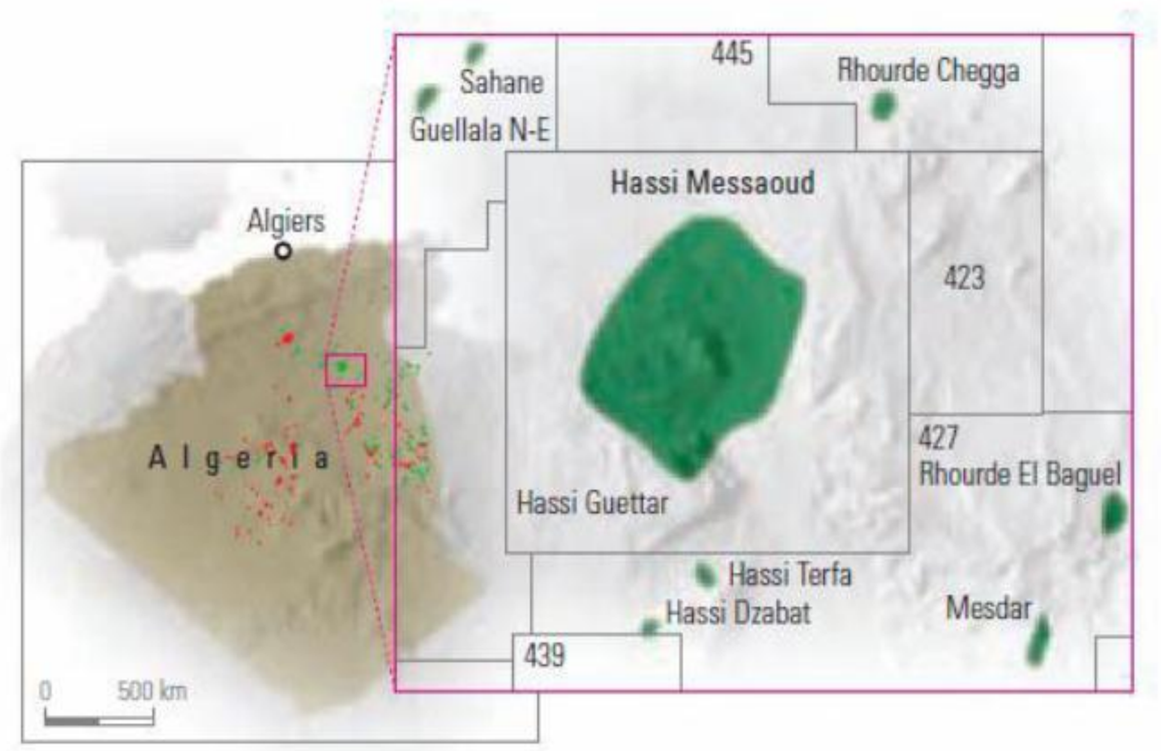


Figure IV.1 : LOCATION OF THE HASSI MESSAOUD FIELD[31]

IV.4. Geological Framework

The structure of the Hassi Messaoud field represents the northern extension of the Amguid-El Biod high and occupies the central part of the Triassic province.

This reservoir is bounded as follows:

- To the north, by the Djemaa-Touggourt structure
- To the south, by the Amguid-El Biod high
- To the east, by the Dahar and Ghadames depressions
- To the west, by the Oued Mya depression

IV.5. Well Zoning and Numbering

The evolution of well pressures as a function of production has made it possible to subdivide the **Hassi Messaoud field into 25 production zones** of varying extent. These zones are relatively independent and correspond to a set of wells that communicate with each other but not with those of neighboring zones. Each zone exhibits a specific behavior in terms of **reservoir pressure**. The wells within the same zone jointly drain a clearly defined volume of oil in place. However, it is important to note that **pressure alone cannot be the only criterion** for defining these zones.

The Hassi Messaoud field is divided into **two distinct areas**: the **North Zone** and the **South Zone**, each having its own well numbering system established by the first companies that discovered the field.

- **North Field**

Uses a geographic and chronological numbering system, e.g., Omn 43

O: Uppercase, referring to the Ouargla permit

m: Lowercase, referring to a 1600 km² block

n: Lowercase, referring to a 100 km² square

4: Abscissa (X-coordinate), **3:** Ordinate (Y-coordinate)

- **South Field**

Mainly follows a chronological system, complemented by geographic coordinates based on intervals of 1.250 km, aligned with Lambert coordinates, e.g., Md10 (33)-(15).

It is important to note that the current subdivision is not fully satisfactory, as a single zone may be further divided into sub-zones (e.g., 1a, 1b, 1c).[37]

IV.6. Reservoir Description and Characteristics

IV.6.1. Drainage and Reservoir Subdivisions

At the early stage of the reservoir delineation, the sandstones of Hassi Messaoud were subdivided into four zones: **R1**, **Ra**, **R2**, and **R3**.

IV.6.2. Reservoir Characteristics

The reservoir lies beneath the Hercynian unconformity and is sealed by a thick Triassic clay-evaporite overburden.

The formation water is highly saline, saturated with various dissolved salts (360–370 g/L), with a density of 1.21 g/cm³ and a viscosity of 0.45 cP.

The original oil-water contact (OWC) was located at a depth of **3,380 m** (Sw = 100%) and has since partially encroached into a significant portion of the **R2** zone. The aquifer is **inactive**.

The sandstones of Hassi Messaoud are mainly composed of **anisometric sandstones**. Only the **Ra zone**, which is approximately 100 meters thick, exhibits the best petrophysical properties and is the **most productive** part of the Cambrian reservoir, located between roughly **3,300 m and 3,500 m** depth.

The reservoir rock properties vary widely depending on the classification, degree of quartz cementation, and clay content. Key characteristics include:

- **High heterogeneity**, both vertically and laterally;
- **Low porosity**, ranging from **5 to 10%**;
- **Very low permeability**, averaging between **1 and 2 millidarcies (mD)**;
- The **crude oil is light**, with an average surface density of **0.8 g/cm³** (equivalent to **45°**

API), which favors enhanced oil recovery through gas injection;

- **Oil viscosity** is approximately **0.2 cP**;

- The **oil formation volume factor (Bo)** is in **m^3/std m^3**, and the **gas formation volume factor (Bg)** is **0.0005 m^3/std m^3**.

- The **average total compressibility** (oil + water + rock) is **3.63×10^{-4} $(kg/cm^2)^{-1}$**
- **Oil saturation** ranges from **80% to a maximum of 90%**
- **Reservoir pressure** varies between **120 and 400 kg/cm^2**
- **Bubble point pressure** ranges from **140 to 200 kg/cm^2**
- **Reservoir temperature** is approximately **118°C**
- **Wells exhibit an average Gas-Oil Ratio (G.O.R)** of **219 m^3/m^3**

(except in breakthrough wells, where the G.O.R can exceed **1,000 m^3/m^3** or more)

- The **productive zone thickness** can reach up to **120 meters**, but in some areas, it can also be **zero**

- The **reference depth** is **3,200 meters**

From a reservoir characterization perspective, the Hassi Messaoud field is defined by a **perfect trilogy**:

- **Heterogeneous**, both vertically and laterally.
- **Anisotropic**, due to the presence of silt.
- **Discontinuous**, in terms of fluid flow.

These factors **heterogeneity**, **discontinuity**, and **anisotropy** lead to a **reduction in recovery** compared to an ideal homogeneous medium, and they also result in **difficulties in interpolating well parameter values**.

IV.7 Case of the well MDZ-548

IV.7. 1 well overview MDZ-548

The **MDZ-548 well**, located in the **Hassi Messaoud field**, was **drilled in May 2003** and completed as a **horizontal well targeting multiple fracture zones** within the **Cambrian**

formations (D5, D3, D2, and ID). It features a **1,117-meter horizontal section** with a **maximum deviation of 88.25°**, and is equipped with **4.5-inch production tubing** above a **6-inch open-hole section** extending from **3428 m to 4545 m MD**.

Historical production data showed an **initial flow rate of 5.5 m³/hr** of oil, with a **reservoir pressure of 205 kg/cm²** and a **skin factor of -1.32**, indicating **favorable reservoir conditions** and a good response to stimulation. However, by **2008**, the production had declined to **2.36 m³/hr**, though the presence of **mobile hydrocarbons** was still confirmed.

Candidate Selection Rationale

MDZ-548 was **selected for hydraulic fracturing** after a comparative evaluation of five wells, due to:

- Its **horizontal configuration** with access to multiple reservoir layers
- **Stable wellbore geometry** and **good structural conditions**
- A history of **declining productivity**, suggesting potential for improvement through stimulation
- The presence of **tight, low-permeability zones** requiring enhanced conductivity pathways

Reservoir Characteristics

- **Permeability:** 4 mD
- **Porosity:** 4.6%
- **Net Pay Thickness:** 75 m
- **Reservoir Pressure:** ~2,845 psi (205 kg/cm²)
- **Reservoir Temperature:** 120°C
- **Water Saturation:** 10%

Fracturing and Treatment Operations

In 2009, a **multi-stage hydraulic fracturing campaign** was executed using the **FracPoint™ system**, coiled tubing, and real-time **micro-seismic monitoring**. Key operations included:

- Formation **breakdown** with treated water
- **Mini-fracs** for calibration (ISIP measurement)
- **Main fracs** using **SpectraFrac G 3500** and **20/40 sinterball proppant**
- **Displacement** with 35# linear gel
- **Shut-in** and **pressure decline monitoring** after each stage

Pressure Decline Analysis

Following each stage, **pressure decline (fall-off)** was carefully monitored to analyze:

- **ISIP** and fracture propagation behavior.
- **Leak-off characteristics** of the formation.
- Flow regime transitions (e.g., **linear**, **bilinear**, **radial**).
- **Fracture conductivity** and reservoir response.

These analyses helped

- Confirm effective fracture initiation.
- Identify the extent and behavior of created fractures.
- **Calibrate fracture models** and **adjust future designs.**

Discussion: MDZ-548 was chosen for fracturing due to its structural suitability, declining production, and the need to unlock potential in tight zones. The **pressure decline analysis** proved crucial in validating the stimulation effectiveness, enhancing understanding of the reservoir, and guiding optimization for productivity improvement**.** [32]

IV.7. 2 FRAC-POINT Completion

The FracPoint completion system implemented in the **MDZ-548** well features a multistage ball-activated hydraulic fracturing setup designed for efficient stimulation of tight reservoir intervals. The system begins with an HRD setting sleeve **(10 ft long, H02632),** followed by a Polished Bore Receptacle (PBR) **(10 ft, H28071)** and an **S-3** liner hanger packer **(H04040)** to anchor the liner within the **4.5” 13.5 lb/ft P-110** New Vam casing, starting from a kick-off point (KOP) at **3040 MD**.

The completion string includes a series of ball-drop actuated frac sleeves and CMB re-closable sleeves designed to isolate and stimulate individual stages. The first stage includes a frac sleeve with an internal diameter (ID) of **0.326 in (Ball 3.5)** and a **23.78 bbls** re-closable sleeve. The second and third stages use sleeves with IDs of **0.2275 in (Ball 2.5, 50.03 bbls)** and **0.225 in (Ball 2, 40.15 bbls),** respectively. The fourth stage, located near the toe, uses a sleeve with an ID of **0.1525 in (Ball 1.75),** completing the multistage system.

Zonal isolation between each fracturing interval is achieved using RE Packer and E Packer water swellable packers **(H30187),** which expand in response to wellbore fluids, ensuring reliable mechanical separation of the stages. Depth markers associated with these stages are recorded at **3525.91 MD**, **3659.82 MD, 4061.6 MD, 4162.13 MD**, and **4371 MD**, where the final sliding sleeve is installed. The system terminates with a double valve float shoe, which facilitates safe cement displacement and provides backflow prevention during completion.

This FracPoint system enables continuous, intervention-free fracturing across multiple stages using a single pumping operation, reducing operational time while improving stimulation efficiency in tight reservoir conditions.

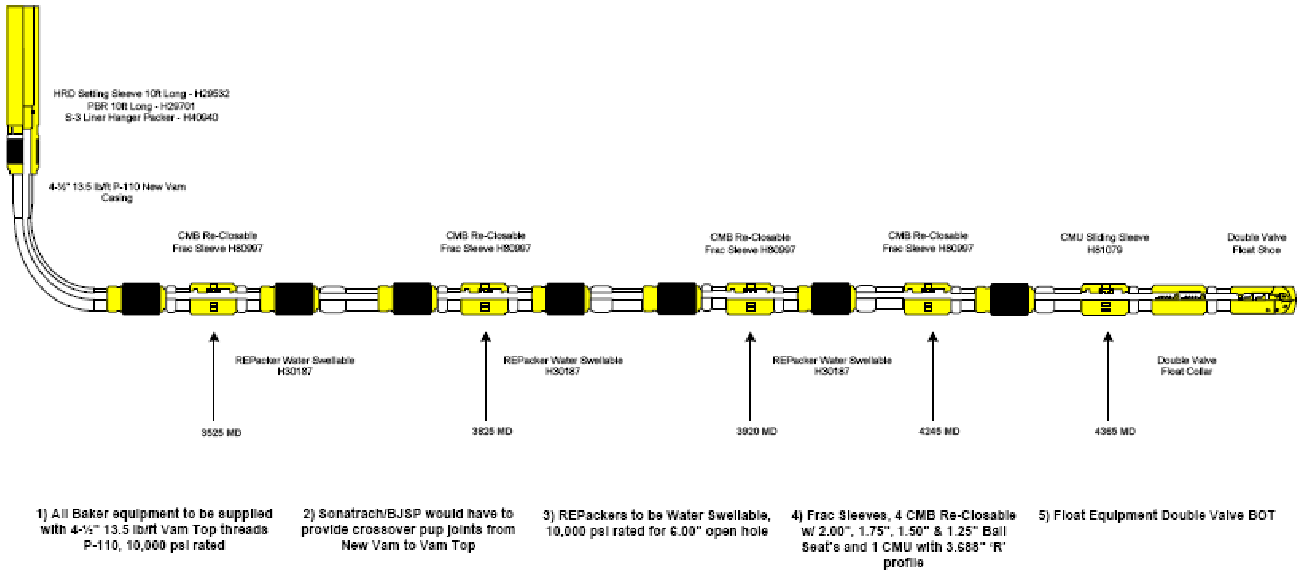


Figure IV.2 : Frac Point Completion – MDZ-548 [32]

IV.7. 3 Pressure Decline Analysis

The pressure decline data from the second mini frac was analyzed to determine closure pressure, fluid efficiency, and the fluid leakoff coefficient. The mini frac analysis software MinFrac was used for this purpose.

Procedure

- **Data Collection:** Pressure data was recorded during the shut-in phase following the second mini frac stage.
- **Software Input:** The shut-in pressure data was imported into MinFrac, which applies multiple analytical techniques to interpret pressure behavior.
- **Plot Generation:** Three diagnostic plots were generated:
  - Horner Time Plot
  - Nolte G Function Plot
  - Square Root of Time Plot
- **Closure Pressure Identification:** Inflection points and deviations from linearity were analyzed to determine fracture closure pressure.
- **Additional Parameters:** Fluid efficiency and net pressure were also calculated from the pressure decline trends.

Horner Time Plot

The Bottomhole Pressure versus Horner Time plot is commonly used to aid in determining the minimum pressure at which the fracture has closed, indicated by a straight line resulting from pseudo-radial flow.

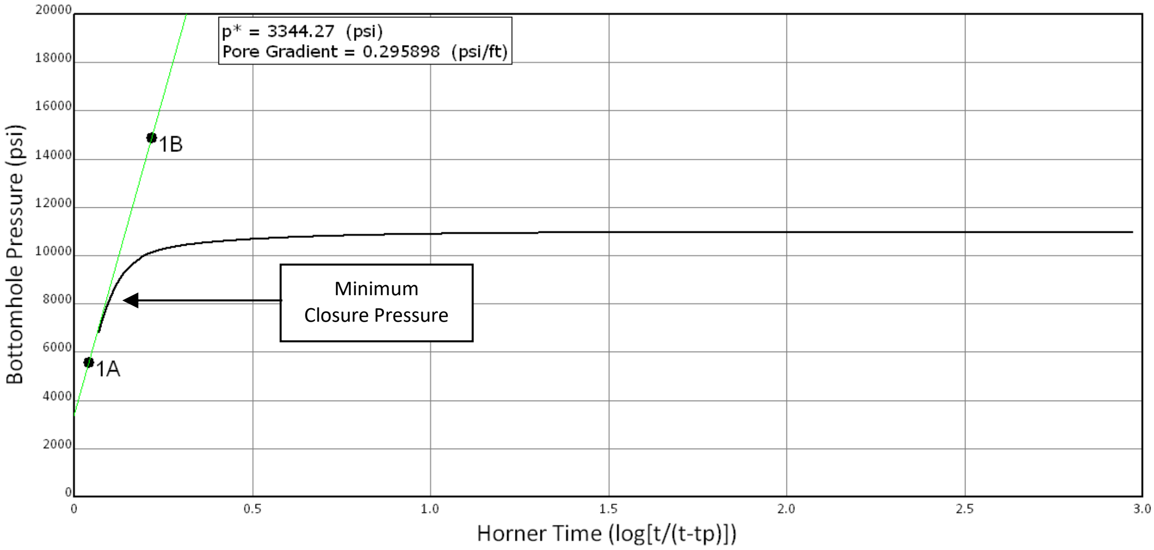


Figure IV.3 : Bottomhole Pressure versus Horner Time [32]

Interpretation

- A linear trend is observed at approximately **8,000 psi**, indicating pseudo-radial flow.
- This suggests that the **fracture has closed at this pressure**, though Horner analysis is

typically used for verification rather than primary closure determination.

- The Horner Time Plot suggests that pseudo-radial flow occurs at +/- 8,000 psi and

therefore the fracture is assumed to be closed.

Nolte G Function Plot

An inflection from straight-line behavior on a plot of the bottomhole pressure versus the Nolte G function indicates a fracture related event and may be considered to be the pressure at which the fracture is closed. As well, the derivative of the Nolte G function is useful in identifying non-ideal fracture behavior such as leakoff from natural fractures or fissures.

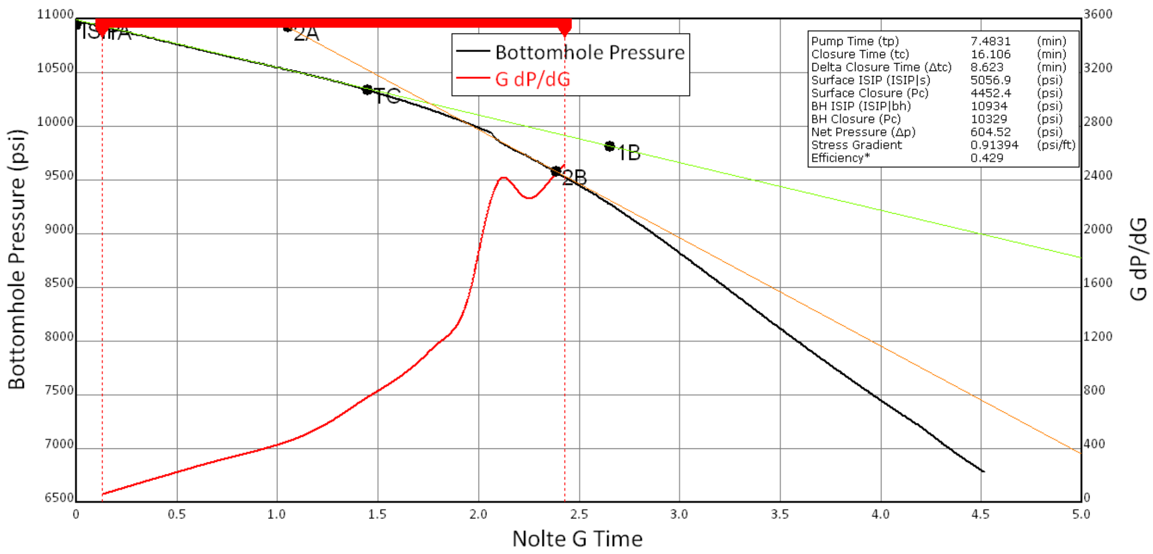


Figure IV.4 : Bottomhole Pressure versus Nolte G Time[32]

Interpretation

- The Nolte G Time function indicates that the bottomhole closure pressure is **10,329 psi**, corresponding to a fracture closure pressure gradient of **0.91 psi/ft**.
- The early time derivative on the Nolte G plot suggests height regression.

Square Root Time Plot

An inflection from straight-line behaviour on a plot of the bottomhole pressure versus the square root of the shut-in time also indicates a fracture related event and may be considered to be the pressure at which the fracture is closed.

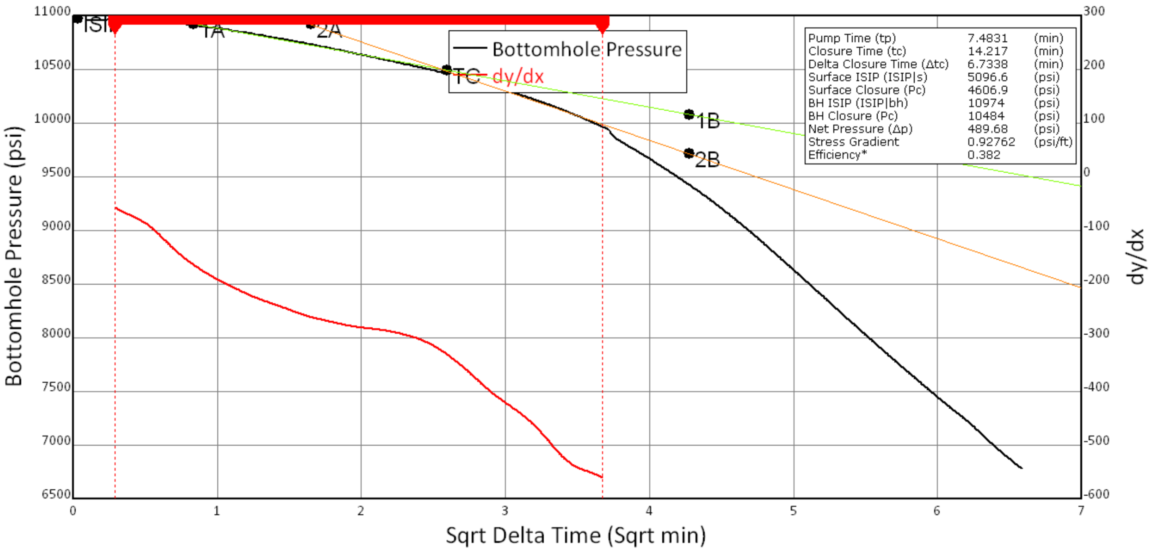


Figure IV.5 : Bottomhole Pressure versus Square Root Time[32]

Interpretation

- The Square Root Time plot suggests a lower fracture closure pressure of **10,484 psi**, corresponding to a closure gradient of **0.92 psi/ft**.
- Note that the data is subjective and a closure point could be picked at a higher pressure as well.

A summary of the pressure decline analysis is presented in the following table.

Table IV.1: Pressure Decline Analysis Summary[32]

Parameter	Nolte G	Square Root Time
Closure Pressure, psi	10,329	10,484
Closure Gradient, psi/ft.	0.91	0.92
Net Pressure, psi	604	489
Time to Closure, minutes	8.62	6.73
Fluid Efficiency, %	42	38

IV.7. 4. Injectivity Test

Objective: Assess well injectivity and formation responsiveness prior to the fracture treatments, establishing baseline data necessary for designing subsequent hydraulic fracturing.

Procedure

The following table is a summary of the treatment volumes.

Table IV.2: Treatment Volumes Summary – Injection Test/Min Frac[32]

Operation	**Fluid Type**	**Volume (gals)**
*Establish Injectivity**	Treated Water	3,956
Injection Test	Treated Water	3,406
pre-pad	35#Gel	2,780
Mini frac	Spectra Frac G® 3500	11,957
Mini frac Displacement	35# Gel	8,694

- The well was prepared with safety measures and initial flow established by filling the well with water.
- An injection test involved pumping 94 barrels of fluid at controlled rates, monitored through pressure gauges.
- The process included flowing with a ball on seat at 13 Bbls, shifting at 5250 psi, followed by a small water injection (7363 gallons) to evaluate injectivity and formation response.

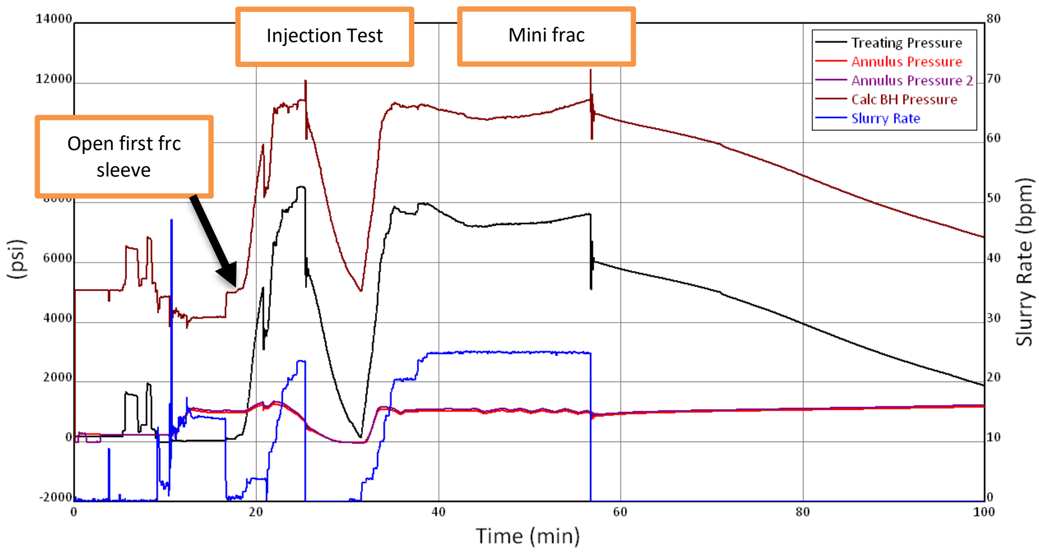


Figure IV.6 : Injection Test/Mini Frac[32]

Results & Interpretation

- The instantaneous shut-in pressure (ISIP) measured was approximately 10,934 psi.
- The estimated total bottomhole friction was around 556 psi, indicating low initial

formation resistance.

- The fracture gradient from this test was approximately 0.94 psi/ft.
- Graphical data (pressure vs. time) showed a stable pressure response, indicating good

perforation connectivity and negligible formation damage.

- A summary of the pressure decline analysis is presented in the following table:

Discussion: The injectivity test confirmed good injectivity and formation responsiveness, supporting the feasibility of aggressive fracture treatments. The low friction and stable pressure response suggested minimal formation impairment, allowing for optimized treatment design in subsequent stages.

IV.7. 5. Mini Hydraulic Fracture (Mini Frac)

Objective: Evaluate formation fracture behavior, calibrate fracture models, and determine leakoff characteristics to inform the design of the main fracturing treatment.

Procedure

- Pumped with Spectra Frac G® 3500 fluid, with 11,957 gallons of pad fluid displaced

with a gel barrier.

- Pumping involved initiating fracture with low rates, reaching a bottomhole

instantaneous shut-in pressure (ISIP).

- During the mini frac, a proppant slug was not used; instead, the focus was on pressure

response and leakoff behavior.

Results & Interpretation

- The ISIP during mini frac was approximately 10,934 psi.
- Estimated total bottomhole friction was 556 psi, indicating low formation resistance.
- The pressure data (pressure vs. volume/volume rate) showed a typical pressure build-up with a relatively stable response, with the fracture extending primarily within the perforated interval.
- Graphs showed a characteristic pressure-rise pattern before a slight decline, indicating controlled fracture propagation.

Modeling & Simulation

- Data input into Meyer's Model provided estimates of fracture dimensions, confirming a contained fracture mainly within the targeted zone.
- The fracture was initiated in the lower stress zones, and the low leakoff during mini frac permitted an aggressive re-design of the main treatment.

Discussion: The mini frac validated the formation's fracture behavior, leakoff characteristics, and fracture propagation, confirming that an intensified main treatment could be designed to enhance well productivity effectively.

IV.7. 6. Mini Frac Pressure Match

Model Inputs

The inputs for the fracturing simulator were derived from various sources. The closure stress in the fracture interval, or horizontal minimum stress, was calibrated to the closure pressure derived from the mini frac analysis and the bounding layers were assigned typical values of stress based on the relative clay content of the lithology.

The principal inputs for the simulator are summarized below.

Table IV.3: *Reservoir Parameters D4*

Parameter	D 4
Permeability, mD	12.6
Gross Pay, m	32
Net Pay, m	13
Reservoir Pressure, psi	2,973
Reservoir Temperature, °C	120
Porosity, %	6.10
Water Saturation, %	3.24

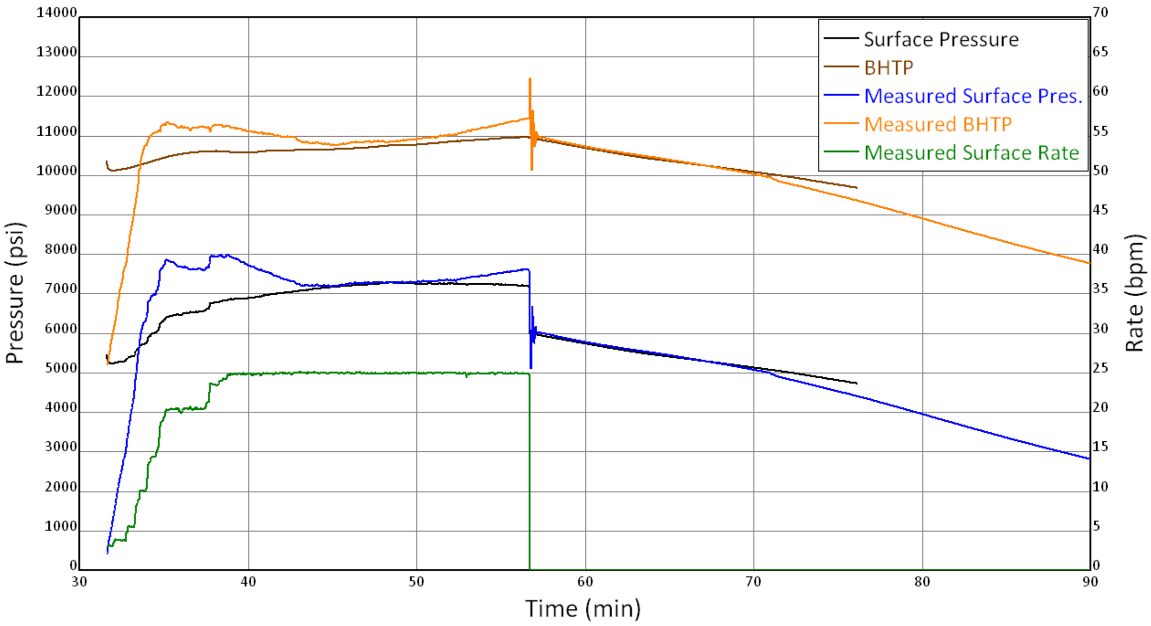


Figure IV.7 : Mini Frac Pressure Match [32]

Results & Interpretation

- The fracture simulator used for the pressure matching was Meyer's Model. The bottom hole pressure derived from the recorded data was matched to that predicted from the simulator as shown in the following plot.

- The data was matched using a total leakoff coefficient of ***0.002 ft/min$^{1/2}$*** throughout the

D4 interval. The magnitude of this leakoff coefficient is indicative of low fluid loss during the mini frac.

IV.7. 7. Main Fracture Treatment

Objective: Increase hydrocarbon flow capacity by creating a long, conductive fracture with optimal proppant placement, utilizing insights gained from the mini frac.

Design & Procedure

- The treatment incorporated 136,300 lbs of Sinterball 20-40 bauxite proppant, with a maximum concentration of 10 lbm/gal.
- Pumping schedules were intensified based on mini frac results, with a decrease in pad volume and proppant schedule (~5,000 lbs more than initially planned).
- In the process, the fracture was initiated predominantly in the lower stress zones, with an aggressive treatment schedule aimed at maximizing fracture conductivity.
- During pumping, a tip screenout was observed at approximately 4 lbm/gal stage, indicating fracture reaching a critical size

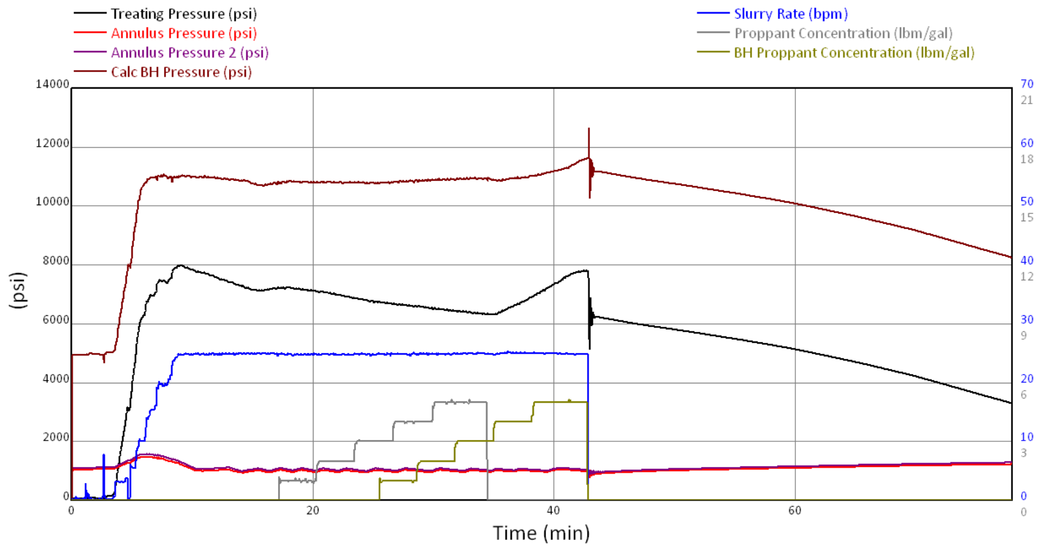


Figure IV.8 : Main Frac Treatment Data Plot[32]

The following table is a summary of the treatment volumes.

Table IV.4: Treatment Volumes Summary – Main Frac[32]

Fluid Summary	**Fluid Type**	**Volume (gals)**
Pre-Pad	35# Gel	1,000
Pad	Spectra Frac G® 3500	10,067
Fluid for Proppant	Spectra Frac G® 3500	16,632
Displacement	35# Gel	8,868
Proppant Summary	Proppant Type	Volume (lbs)
Proppant Volume, Surface	Sinterball 20-40	50,000
Proppant Volume, In Formation	Sinterball 20-40	45,500

Results & Interpretation

- The bottomhole instantaneous shut-in pressure (ISIP) during the main frac was recorded at 11,606 psi, 392 psi higher than during mini frac, reflecting increased fracture volume.
- Pressure monitoring and modeling suggested an additional pressure of approximately 800 psi was generated during proppant packing.
- Fracture modeling indicated a long, highly conductive fracture within the target zone, supported by the pressure data and proppant distribution models.

Graphs & Data

- Pressure vs. time graphs showed typical fracture propagation patterns with a clear tip screenout.

- Model outputs predicted a fracture geometry conducive to enhanced connectivity and flow.

Discussion: The main frac successfully created a long, conductive fracture with optimal proppant confinement. The low entry friction and contained fracture ensured maximum fracture complexity and length, promising significant improvements in production performance.

First Main Frac Pressure Match

The calculated bottomhole pressure was matched to that predicted from the fracture model in order to estimate fracture dimensions and proppant distribution within the fracture

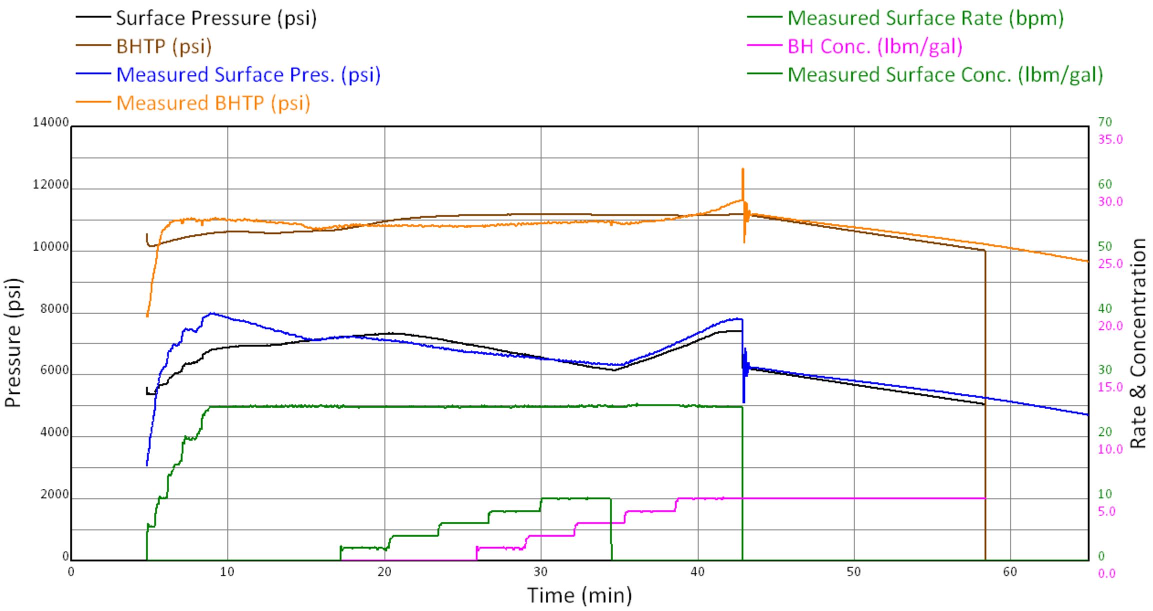


Figure IV.9 : Main Frac Pressure Match[32]

- Based on this pressure match, the simulator predicts that approximately 150 psi of additional pressure was generated while packing the fracture with proppant.
- A plot of the predicted proppant concentration within the fracture and the fracture conductivity across the pay zone are presented on the following page.

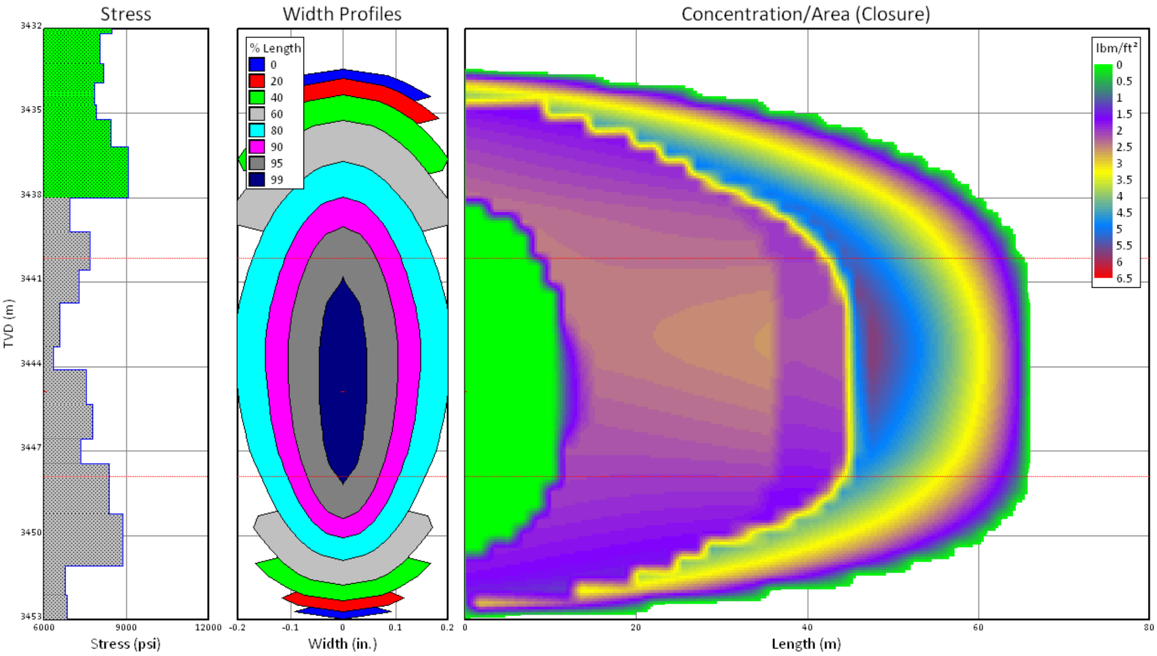


Figure IV.10 : Fracture Concentration Profile[32]

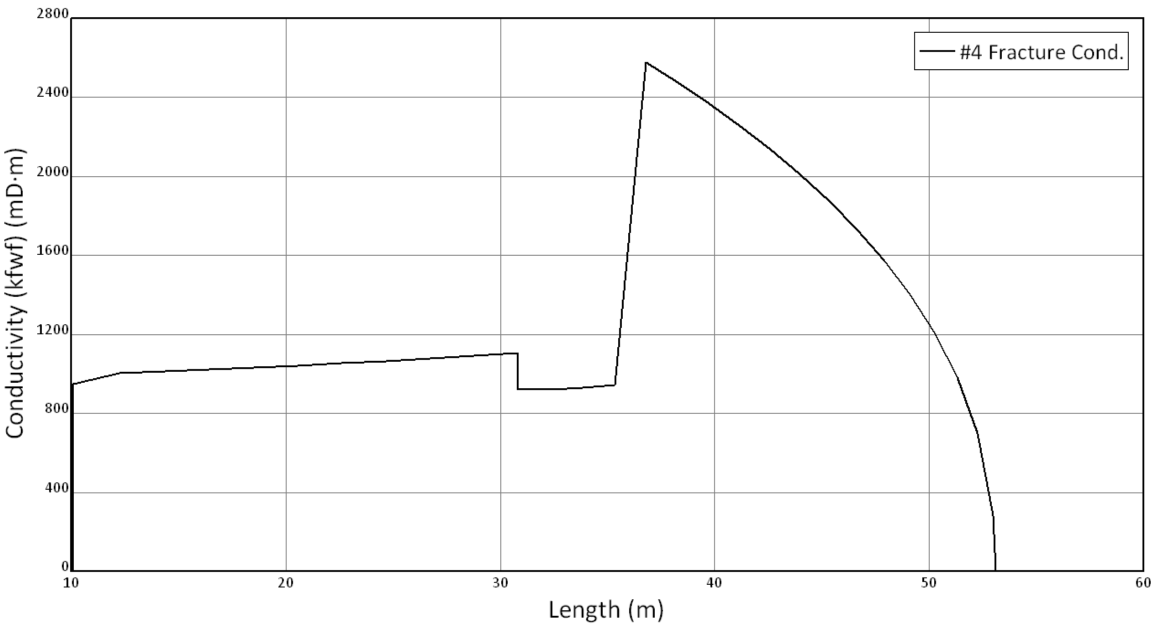


Figure IV.11 : Fracture Conductivity Profile[32]

The main fracture data was matched to the simulator using a total leakoff coefficient of $\mathbf{0.004\ ft/min^{1/2}}$.

Table IV.5: Fracture Dimensional Results[32]

	HQ
Propped Length, m.	66
Total Propped Height, m.	20
Upper Frac Height, mTVD	3,4233
Lower Frac Height, mTVD	3,453
Ave. Propped Width in Pay, inches	0.20
Ave. Proppant Conc. in Pay, lbm/ft2	2.5
Ave. Frac Conductivity, mD-m	1043
Dim. Frac Conductivity	9.1
Reference Formation Permeability, mD	4
Damage Factor Applied	0.5

IV.8. Case of the Well OMGZ-60 (plug and perf)

IV.8.1. well overview OMGZ-60 (plug and perf).

OMGZ60 is a Horizontal well, located in the HZN, drilled as part of the project "Development of zones with weak petrophysical characteristics of the Hassi Messaoud field" This project aims to exploit compact zones through the use of unconventional technology, which consists of drilling horizontal drains parallel to the direction of min stress (Sh min), followed by hydraulic fracturing. The drilling of the well was completed on 03/12/2023 in the Cambrian Ra reservoir with a lateral penetration of 15m in D3, 60m in D2 and 894m in ID up to a final TD of 4375mMD, 3418.8m CS TVD, AZ35°, Inc 88.7 and VS 1060.05m, subsequently The reservoir was covered with a 4"1/2 15.1# cemented liner, and the well was completed with 4 1/2 13.5 tubing #, anchored with a Packer Hal THT 10K, and a Tie Back Seal placed at the top of the liner, and the 4"1/2x7" annular is filled with a 1.5 sg brine. The well is currently being cleaned and put under treated water with a view to subsequently perforating and fracturing.

Petrophysical data

OMGZ60_LUMP_TVD

Zones	Flag Name	Top	Bottom	Gross (m)	Net (m)	Av_Shale Volume (m3/m3)	Av_Porosity (m3/m3)	Av_Water Saturation (m3/m3)
D3	ROCK	3388.000	3397.000	9.000	8.928	0.285	0.037	0.280
	RES	3388.000	3397.000	9.000	8.928	0.285	0.037	0.280
	PAY	3388.000	3397.000	9.000	6.448	0.279	0.041	0.171
D2	ROCK	3397.000	3418.000	21.000	20.972	0.185	0.066	0.042
	RES	3397.000	3418.000	21.000	20.972	0.185	0.066	0.042
	PAY	3397.000	3418.000	21.000	20.421	0.187	0.068	0.042
ID	ROCK	3418.000	3449.000	31.000	30.985	0.243	0.060	0.258
	RES	3418.000	3449.000	31.000	30.425	0.237	0.061	0.251
	PAY	3418.000	3449.000	31.000	24.290	0.225	0.065	0.199
D1	ROCK	3449.000	3474.000	25.000	24.955	0.205	0.065	0.458
	RES	3449.000	3474.000	25.000	24.815	0.203	0.065	0.457
	PAY	3449.000	3474.000	25.000	9.286	0.179	0.071	0.301
ZPS	ROCK	3474.000	3481.000	7.000	6.911	0.279	0.084	0.831
	RES	3474.000	3481.000	7.000	6.628	0.267	0.085	0.825
	PAY	3474.000	3481.000	7.000	0.000			
R2 ab	ROCK	3481.000	3517.000	36.000	35.980	0.311	0.087	0.970
	RES	3481.000	3517.000	36.000	33.981	0.294	0.089	0.969
	PAY	3481.000	3517.000	36.000	0.000			
R2 c	ROCK	3517.000	3530.000	13.000	8.369	622.053	0.099	0.999
	RES	3517.000	3530.000	13.000	3.064	0.370	0.100	0.999
	PAY	3517.000	3530.000	13.000	0.000			

Figure IV.12 : Petrophysical Data of the Well OMGZ-60[33]

Table IV.6: Reservoir Parameters

Parameter	Cambrian ID
Permeability, mD	-
Net Pay	30,42
Reservoir Pressure, kg/cm2	280
Reservoir Temperature, °C	118
Porosity, %	6,1
Water Saturation, %	25,1

The lithology was modeled regarding the open hole logs and the supplied rock mechanics information. The lithology and derived permeability profile was entered into a three-dimensional fracture simulator, MFrac from Meyer's Model, to predict fracture dimensions and proppant distribution to design the treatment. [33]

IV.8.2. Injection Test

- Open the well WHP= **92 psi.**
- Fill the well & injection was established, total volume of Treated water pumped **359 bbl** with rate of **18 bpm**

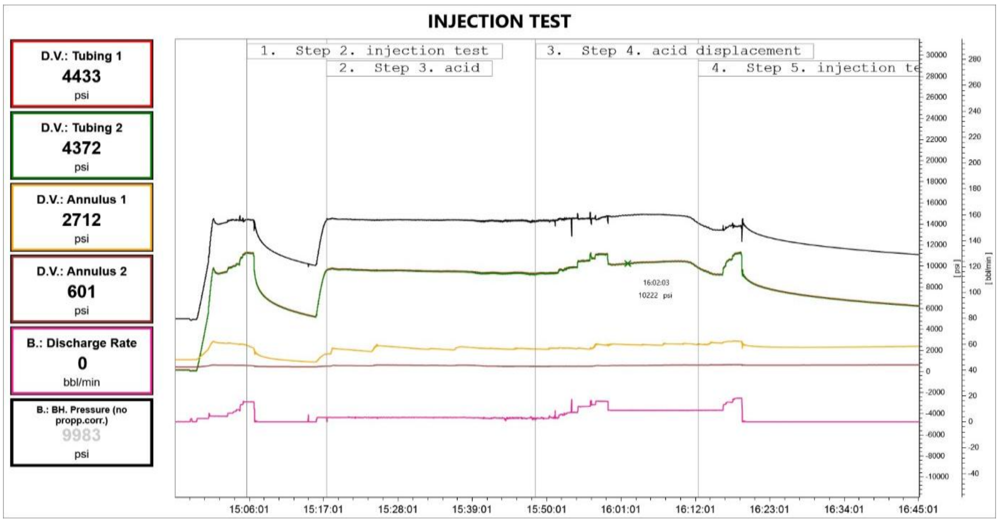


Figure IV.13: Injection test with treated water and Acid displacement[33]

Results & Interpretation

- The bottom hole **instantaneous shut-in pressure** (ISIP) is **13,860 psi**. This corresponds to a **fracture gradient** of **1.03 psi/ft**.

- **The last pumping BH pressure was 14,348 psi**
- The estimated **total bottomhole friction** with treated water at a pump rate of **18 bpm** was **488psi.**
- The surface **instantaneous shut-in pressure** (ISIP) is **9,250 psi**. The last pumping surface pressure **was 11,228 psi**
- The estimated total friction with treated water at a pump rate of **18 bpm** was **1,978** psi.
- Tubing friction: total friction – total bottom hole friction = **1,490** psi

Table IV.7: Treatment Volumes Summary – Injection with acid

Operation	**Fluid Type**	**Volume (gals)**
Fill Well	Treated Water	2,100
Establish Injection	Treated Water	937
Acid Spearhead	15% S3 Acid	4,158
Acid Displacement	Treated Water	8,820
Establish Injection	Treated Water	3305

IV.7.3. Mini Frac

A mini frac was pumped with Spectra Frac G®3500 fluid and displaced with 35# gel.

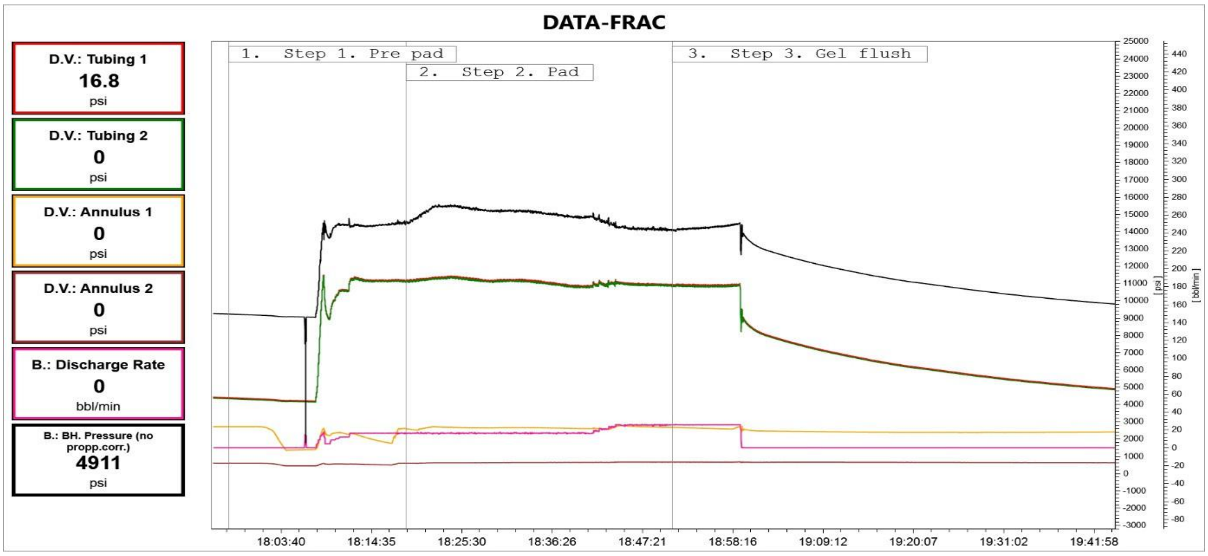


Figure IV.14: Treatment Data: Mini Frac[33]

Results & Interpretation

- The bottom hole instantaneous shut-in pressure (ISIP) is 14,091 psi. This corresponds to a fracture gradient of 1.25 psi/ft.
- The last pumping BH pressure was 14,485 psi
- The estimated total bottomhole friction with treated water at a pump rate of 25 bpm was 394 psi.
- The surface instantaneous shut-in pressure (ISIP) is 9,117.5 psi.
- The last pumping surface pressure was 10,910 psi
- The estimated total friction with 35# linear gel at a pump rate of 25 bpm was 1,795.5psi.
- Tubing friction: total friction – total bottom hole friction = 1,398.5 psi

The following table is a summary of the treatment volumes.

Table IV.8: Treatment Volumes Summary – Mini frac

Operation	Fluid Type	Volume (gals)
Pre-Pad	35# Gel	6,436
Mini Frac Pad	Spectra Frac G	25,242
Mini Frac	3500	8,946
Displacement	35 # Gel	

Pressure Decline Analysis

The pressure decline data from injection test with linear gel was analyzed to determine closure pressure, fluid efficiency, and the fluid leakoff coefficient. The mini frac analysis software MinFrac was used for this purpose.

Horner Time Plot

The Bottomhole Pressure versus Horner Time plot is commonly used to aid in determining the minimum pressure at which the fracture has closed, indicated by a straight line resulting from pseudo-radial flow.

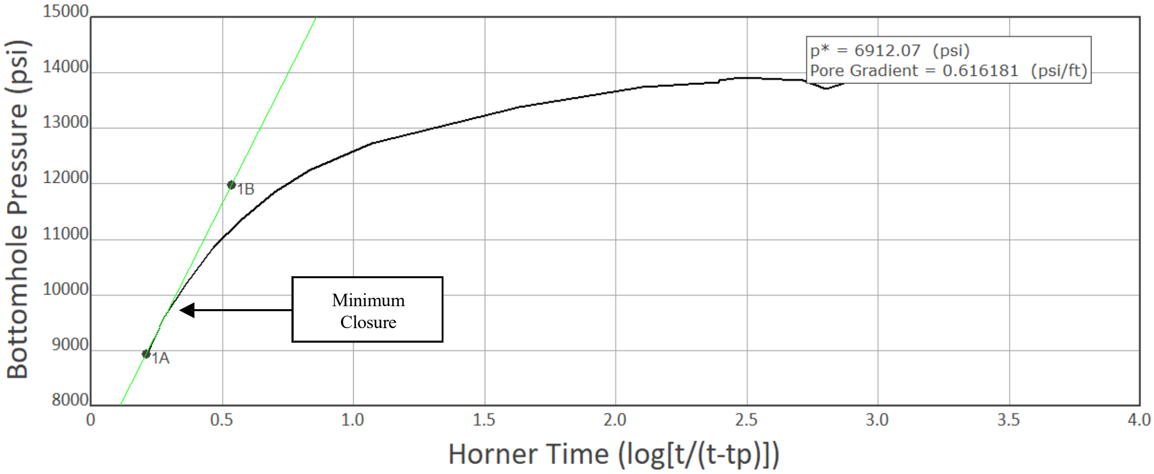


Figure IV.15: Bottomhole Pressure versus Horner Time[33]

Results & Interpretation

- The Horner Time Plot suggests that pseudo-radial flow begins at +/- 9,570 psi and therefore, the fracture is assumed to be closed.

Nolte G Function Plot

An inflection from straight-line behaviour on a plot of the bottomhole pressure versus the Nolte G function indicates a fracture related event and may be considered to be the pressure at which the fracture is closed. As well, the derivative of the Nolte G function is useful in identifying non-ideal fracture behaviour such as leakoff from natural fractures or fissures.

Nolte G Function Plot

An inflection from straight-line behaviour on a plot of the bottomhole pressure versus the Nolte G function indicates a fracture related event and may be considered to be the pressure at which the fracture is closed. As well, the derivative of the Nolte G function is useful in identifying non-ideal fracture behaviour such as leakoff from natural fractures or fissures.

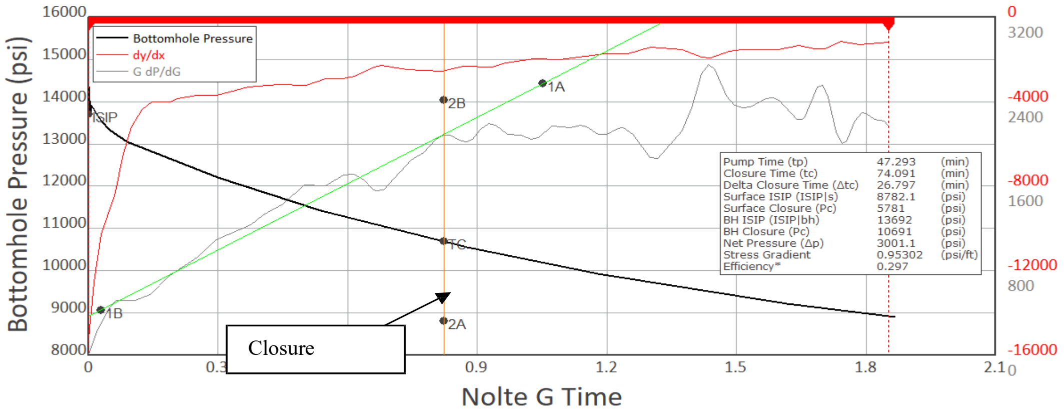


Figure IV.16: Bottomhole Pressure versus Nolte G Time[33]

Results & Interpretation

- The Nolte G Time function indicates that the bottomhole closure pressure is 10,691 psi, corresponding to a fracture closure pressure gradient of 0.95 psi/ft.

Square Root Time Plot

An inflection from straight-line behaviour on a plot of the bottomhole pressure versus the square root of the shut-in time also indicates a fracture related event and may be considered to be the pressure at which the fracture is closed.

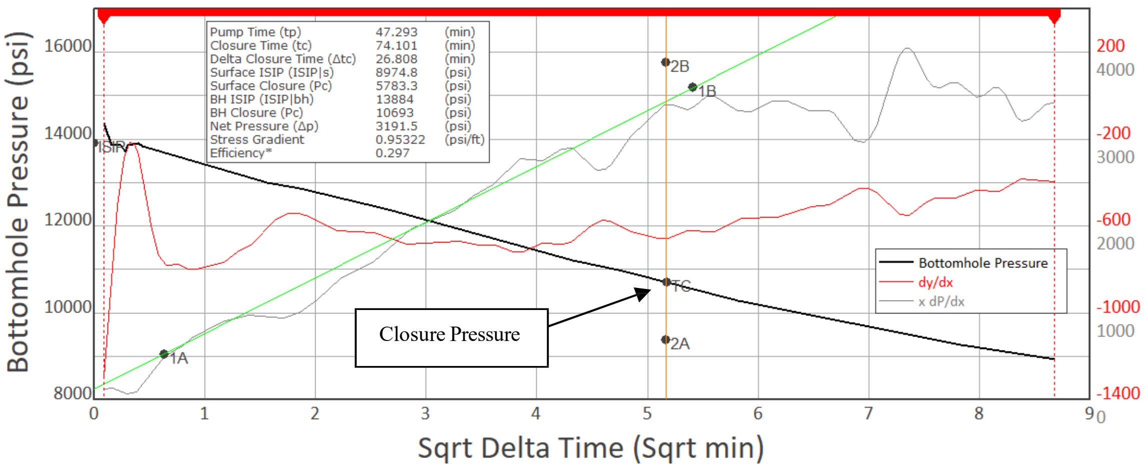


Figure IV.17: Bottomhole Pressure versus Square Root Time[33]

Results & Interpretation

- The Square Root Time plot suggests a higher fracture closure pressure of 10,693 psi, corresponding to a closure gradient of 0.95 psi/ft.

A summary of the pressure decline analysis is presented in the following table.

Table IV.9: Pressure Decline Analysis Summary

Parameter	Nolte G	Square Root Time
Closure Pressure, psi	10,691	10,693
Closure Gradient,	0.95	0.95
psi/ft. Net Pressure,	3,001	3,191
psi	74.09	74.10
Time to Closure,	29.7%	29.7%
minutes Fluid		
Efficiency, %		

IV.8.4. Main Frac

The main fracture treatment was redesigned based on an analysis of the Data Frac

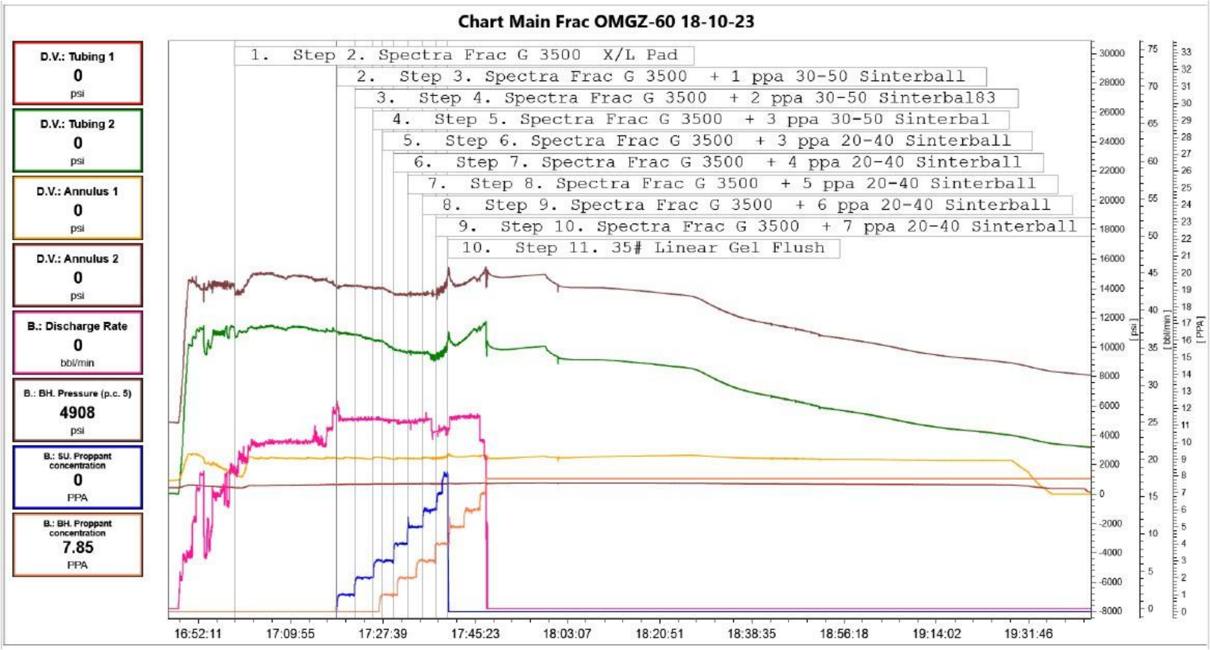


Figure IV.18: Main Frac Treatment Data Plot[33]

Results & Interpretation

- The treatment was pumped as per the design schedule with 15,800 lbs 30/50 and 44,164 lbs 20/40 in formation, the displacement volume pumped is 186 bbls. The following table is a summary of the treatment volumes.

Table IV.10: Volumes Summary – Main Frac

Fluid summary	Fluid Type	Volume (gals)
Prepad **Pad** **Fluid for proppant** **Displacement**	**35# Gel** **Spectra Frac G3500** **Spectra Frac G3500** **35#Gel**	**5,670** **18,354** **23,100** **7,812**
Proppant Summary	Proppant Type	**Volume (lbs)**
Proppant Volume, Surface **Proppant Volume, Surface**	HSP proppant 30-50 HSP proppant 20-40	**15,800** **50,926**
Proppant Volume, in formation **Proppant Volume, in formation**	HSP proppant 30-50 HSP proppant 20-40	**15,800** **44,164**

Summary / Recommendations

The following conclusions and recommendations can be made from this analysis:

- According to bottom Hole pressure behaviour, we adjusted the proppant concentration to 7 ppg in order increase the conductivity near the wellbore.
- A total of 15,800 lbs of HSP 30/50 and 50,926 lbs of HSP 20/40 to a maximum concentration of 7 Ib/gal was pumped and 59,964 lbs was placed in formation

IV.8.5. Comparative Study Between the Two Techniques (Frac-Point and Plug & Perf)

➢ **Technical Specifications**

FracPoint System (Ball-Activated Multistage Fracturing):

- **Design**: Utilizes ball-activated sleeves (single-entry or multiple-entry) installed in a cemented or open hole completion.

- **Activation**: Frac balls of varying sizes are dropped sequentially to open specific sleeves during the fracturing process.

- **Advantages**
  - Continuous fracturing with minimal intervention.
  - Reduced operational time compared to traditional methods.
  - No need for perforation, enhancing wellbore integrity.
- **Limitations**
  - Potential for sleeve malfunction or failure.
  - Limited flexibility in stage placement once installed.
  - Challenges in re-stimulation if required.

Plug-and-Perf with Cemented Liner

- **Design**: Involves a cemented liner with perforated intervals isolated by bridge plugs.
- **Activation**: Perforation guns are used to create openings, followed by the placement of bridge plugs to isolate stages.

- **Advantages**
  - High flexibility in stage placement and re-stimulation.
  - Proven track record in various reservoir conditions.
  - Ability to address issues like stuck tools or non-productive zones.
- **Limitations**
  - Increased operational time due to multiple runs.
  - Higher risk of mechanical failures with plugs.
  - Potential for increased cost and complexity.

➢ Operational Procedures

FracPoint System

- **Well Preparation**: Install ball-activated sleeves at predetermined intervals.

- **Fracturing Process**
    1. Drop the first frac ball to open the initial sleeve.
    2. Pump fracturing fluid and proppant to create the fracture.
    3. Drop subsequent frac balls to open subsequent sleeves.
    4. Repeat until all stages are fractured.
- **Post-Fracturing**: The IN-Tallic™ frac balls disintegrate, leaving a clear flow path.

Plug-and-Perf with Cemented Liner:

- **Well Preparation**: Run a cemented liner with perforated intervals.
- **Fracturing Process**
    1. Use perforation guns to create openings at each stage.
    2. Place bridge plugs to isolate each stage.
    3. Pump fracturing fluid and proppant into the isolated stage.
    4. Repeat for each stage.

Post-Fracturing: Mill out the bridge plugs to restore wellbore integrity.

➢ Contingency Plans

FracPoint System

- **Sleeve Malfunction**: Utilize coiled tubing to mill out the malfunctioning sleeve.
- **Ball Drop Failure**: Deploy a secondary ball-drop system or use coiled tubing to assist

in ball placement.

- **Screen-Out**: Adjust proppant concentration and fluid viscosity; consider re-fracturing

if necessary.

Plug-and-Perf with Cemented Liner

- **Plug Failure**: Replace the faulty plug using coiled tubing or wireline.
- **Perforation Issues**: Re-perf the zone using perforation guns or consider alternative

stimulation methods.

- **Screen-Out**: Modify fracture design or fluid system; perform re-fracturing if required.

➢ Reservoir Impact

FracPoint System

- **Zonal Isolation**: Achieved through mechanical sleeves; potential for incomplete isolation.
- **Fracture Geometry**: Fractures may be less confined, leading to potential proppant flowback.
- **Re-Stimulation**: Challenging due to the lack of intervention points.

Plug-and-Perf with Cemented Liner

- **Zonal Isolation**: Enhanced through cemented liners and bridge plugs.
- **Fracture Geometry**: More controlled fractures with reduced risk of proppant flowback.
- **Re-Stimulation**: Easier access for re-fracturing or additional stimulation treatments.

➢ Cost Analysis

FracPoint System

- **Initial Cost**: Lower due to fewer equipment requirements.
- **Operational Cost**: Reduced due to continuous fracturing and fewer intervention needs.
- **Risk Management**: Potentially higher costs if sleeve malfunctions occur.

Plug-and-Perf with Cemented Liner

- **Initial Cost**: Higher due to additional equipment and materials.
- **Operational Cost**: Increased due to multiple runs and potential plug milling.

- **Risk Management**: Higher flexibility may lead to cost savings in complex reservoirs.

General Conclusion

&

Recommendation

Conclusion

This study presented a comparative technical and operational evaluation of two multistage hydraulic fracturing (MSHF) completion systems applied to tight reservoirs in the Hassi Messaoud field: the FracPoint system (ball-drop) and the Plug-and-Perf system. The analysis was based on two horizontal wells MDZ-548, completed using the FracPoint method, and OMGZ-60, stimulated with the Plug-and-Perf technique.

Both systems demonstrated effectiveness in improving production from tight formations, but with distinct differences in operational behavior, stimulation design, and economic performance. The FracPoint system in MDZ-548 enabled fast, continuous pumping with minimal post-fracturing intervention. It resulted in a notable production increase from 1.5 m^3/h to 3.8 m^3/h, confirming the viability of this method in operational environments where simplicity and speed are critical. In comparison, the Plug-and-Perf system in OMGZ-60 achieved a larger production increase from 1.2 m^3/h to 4.2 m^3/h, demonstrating higher stimulation precision and better zonal isolation.

Economically, the total cost of the FracPoint operation in MDZ-548 was approximately $1.82 million, while the Plug-and-Perf job in OMGZ-60 cost between $2.1 and $2.3 million. Despite the higher cost, OMGZ-60 achieved a Net Unit Revenue (NUR) of $55–$60 per barrel, outperforming MDZ-548, which showed a NUR of around $40 per barrel. These results underline the trade-off between cost efficiency and stimulation effectiveness.

Pressure analysis also reflected this contrast. ISIP values in MDZ-548 reached around 11,000 psi, with efficient fracture initiation across stages. In OMGZ-60, ISIP values were even higher, up to 16,285 psi, with consistent fracture gradients of 1.03 psi/ft, contributing to improved fracture containment and conductivity.

To support the analysis and design of these operations, we used MSUITE software for the simulation, treatment design, real-time monitoring, and economic evaluation. This tool proved essential for modeling fracture geometry, estimating breakdown pressures, optimizing stage configuration, and comparing the economic returns of each completion strategy.

In summary, both completion systems provided valuable outcomes. The FracPoint system offered operational simplicity, faster execution, and lower costs ideal for streamlined developments while the Plug-and-Perf system delivered higher production and better control, making it the preferred solution in complex and high-potential tight reservoirs.

Recommendations

- **Reservoir Matching:** For tight or unconventional reservoirs, prioritize the plug-and-perf method due to its enhanced control, stage isolation, and adaptability to complex reservoir conditions. For simpler or conventional formations, the frac point system, especially shifting tools over ball drop where mechanical intervention is possible, can offer cost-effective and faster stimulation.

- **Optimize Stage Design:** In high-stage-count applications, especially in long horizontal wells, consider using hybrid approaches that combine both methods (e.g., initial stages with frac point, followed by plug-and-perf in the lateral) to balance cost and efficiency.

- **Pressure Management:** Use plug-and-perf where higher breakdown pressures or precise fracture containment is required, especially when pressure communication between stages must be avoided.

- **Operational Planning:** Where intervention logistics are challenging (remote locations, limited coiled tubing access), ball-drop systems may be more suitable, provided the number of stages and pressure profile are within manageable limits.

- **Future Technologies:** Evaluate dissolvable plugs and sleeves or frac sleeves with coiled-tubing-actuated shifting tools to reduce post-frac intervention time and cost in unconventional applications.

- **Economic Assessment:** Conduct detailed cost-benefit analyses before selection, taking into account not only upfront completion costs but also log-term production gains and workover risks.

Long-Term Vision

This project aims to harness the power of Artificial Intelligence to transform the evaluation and optimization of hydraulic fracturing in tight formations. The long-term vision is to develop an intelligent framework capable of understanding the principles and mechanisms of hydraulic fracturing, analyzing the design and execution of multistage fracturing techniques, and accurately evaluating their efficiency and performance. By integrating AI into these processes, the goal is to enable faster decision-making, reduce operational costs by over $20 million annually, and enhance the prediction and prevention of failures. Ultimately, this digital solution aspires to support smarter, more sustainable, and more productive fracturing operations across unconventional reservoirs.

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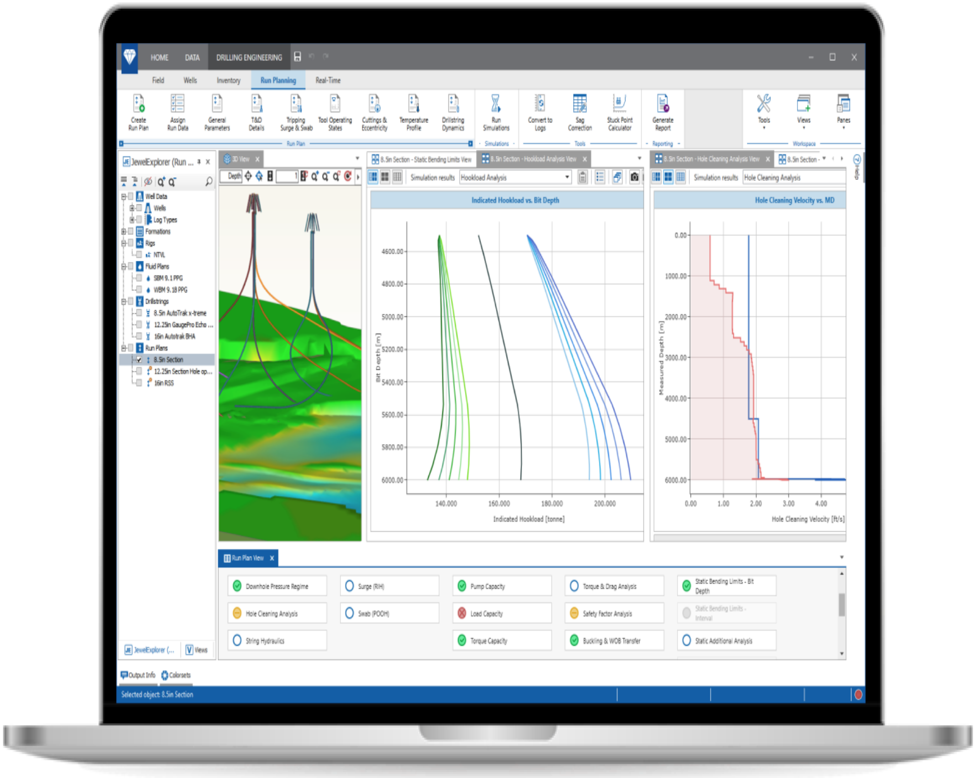
32. Summary of Post-Job Fracture Report for MDZ-548 Well.ALSCIF EX BJSP Company.

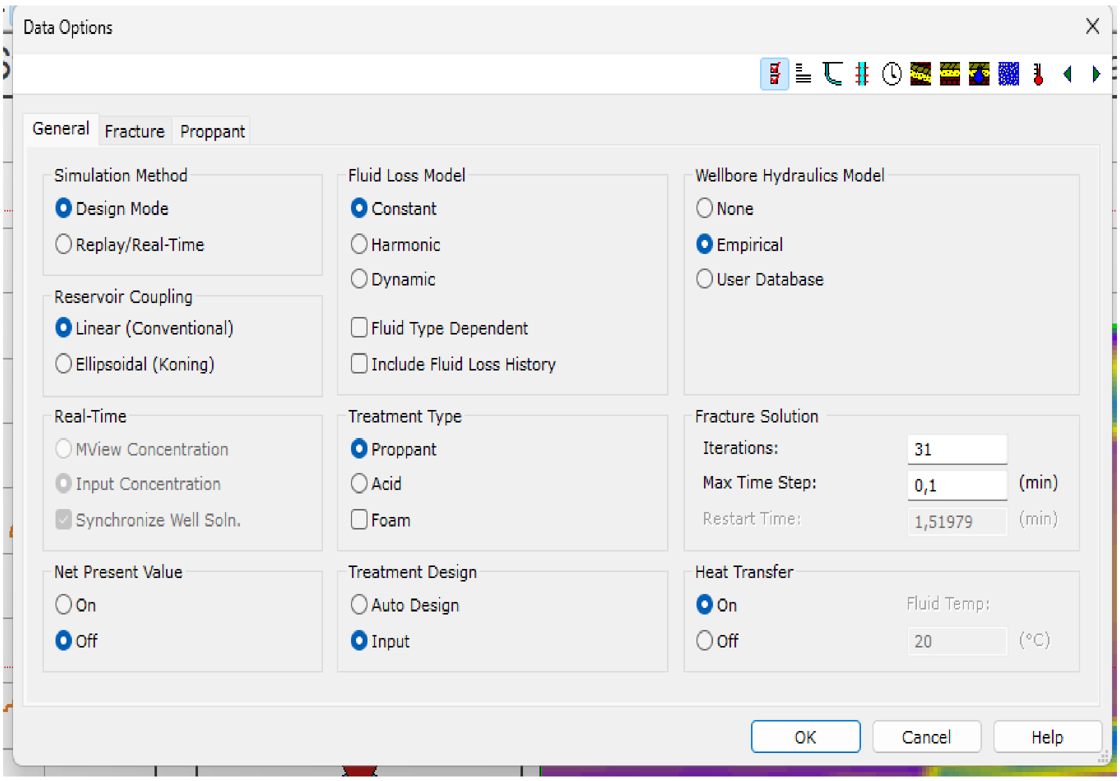
33. Post Job Report OMGZ-60 All Stages.

APPENDICES

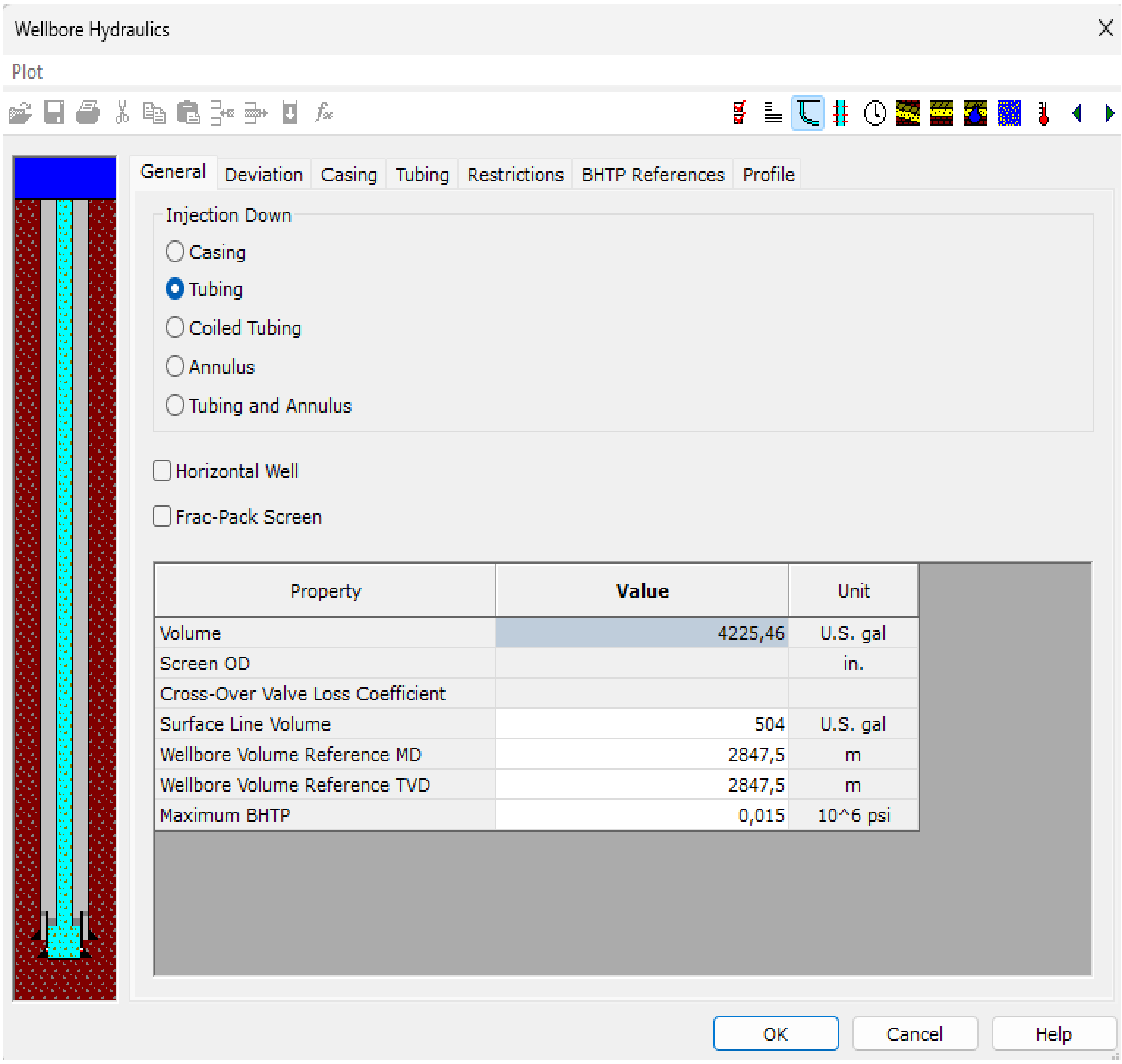
Annexe A: The window of Msuite software of Baker Hughes



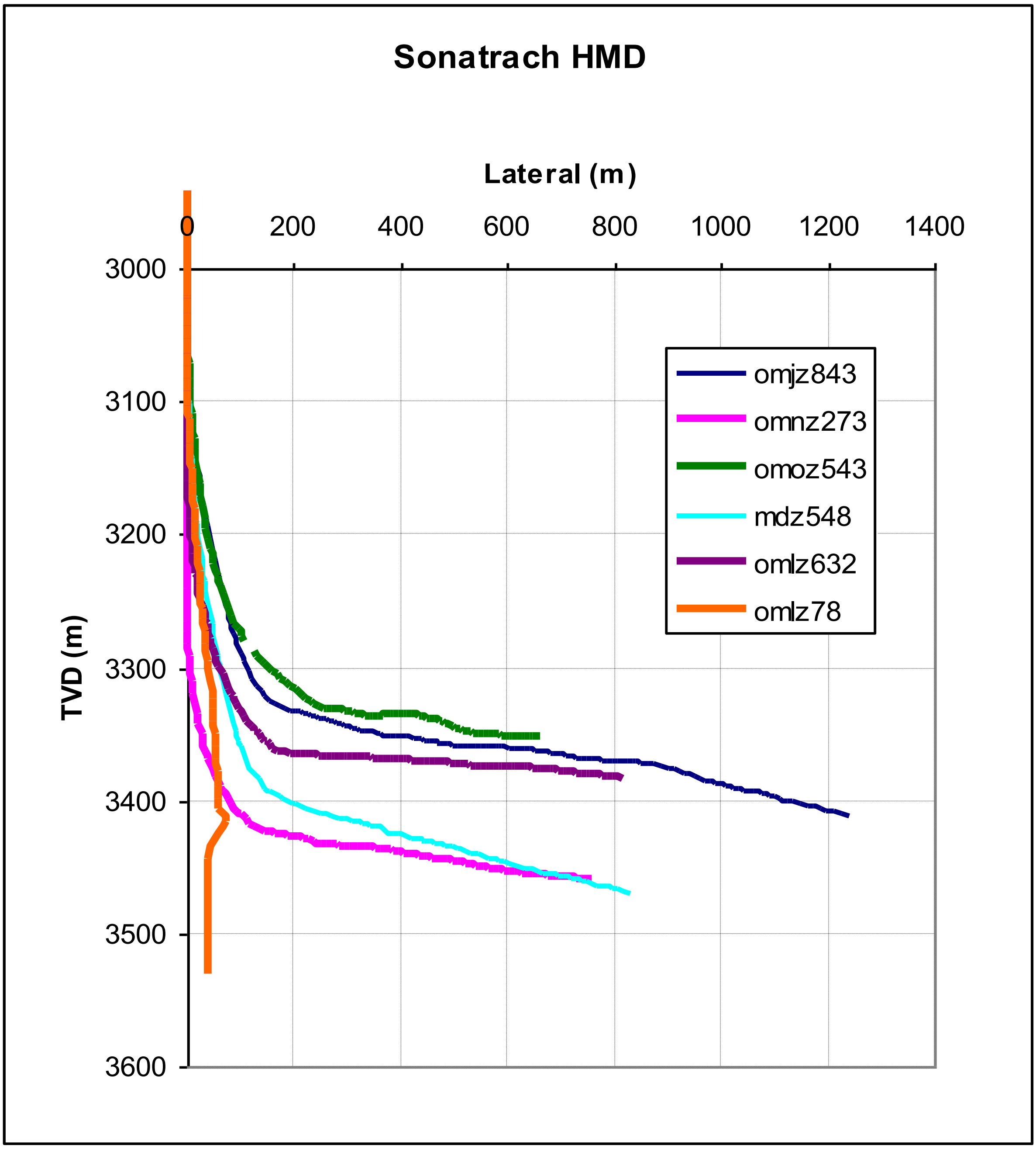
Annexe B: The options data input window of Msuite software



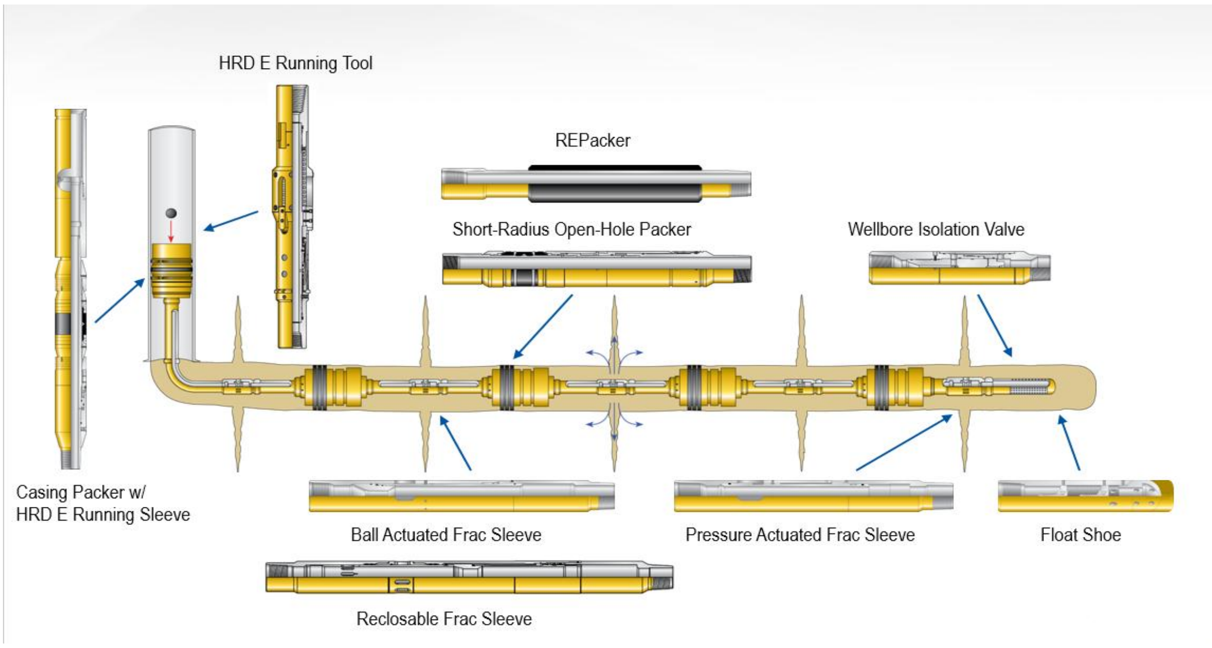
Annexe C : The Wellbore Hydraulics data input window of Msuite software



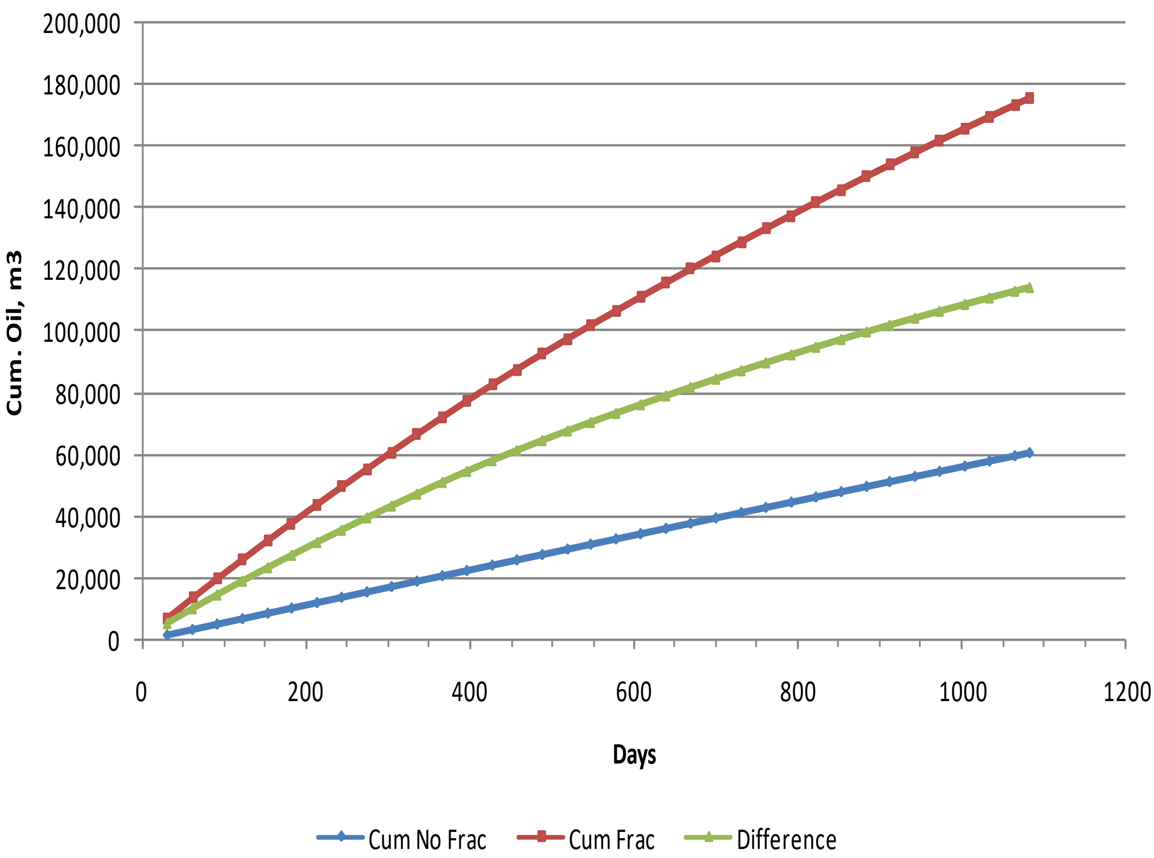
Annexe D: Wells' Trajectory of MDZ-548 and Distance from WC (Orig.)



Annexe E : Frac-point completion of MDZ-548



Annexe F : Cumulative production diagram of MDZ-548



Annexe G : OMGZ-60 Main frac gel samples

Annexe H:

OMGZ-60 Main Frac broken gel samples