

Ministry of Higher Education and Scientific Research

Serial N°:/2026

Kasdi Merbah University Ouargla



Faculty of Hydrocarbons, Renewable Energies and Earth and Universe
Sciences

Hydrocarbon Production Department

To obtain the Master's Degree

Option: Academic Production

Presented by:

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-THEME-

**Effect of Fluid and Production Parameters on Well X21
Performance in the Hassi Messaoud Oil Field**

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Academic Year 2025/2026



ACKNOWLEDGEMENTS

First of all, we would like to thank **Allah – the Almighty** – who granted us the strength and ability to complete this work.

We express our sincere gratitude to all those who contributed to the completion of this thesis on **acid stimulation**. First and foremost, we thank our thesis supervisors, **Mr. BRAHMIA Nabil** and **Mr. ADJOU Zakaria**, for their guidance, support, and valuable advice throughout this research. Their expertise and experience greatly contributed to the success of this work.

Our thanks also go to the entire faculty of the **Department of Hydrocarbon Production** for the quality of teaching and the valuable knowledge they shared with us. Their instruction allowed us to deepen our understanding and develop our skills in the field of production. We also extend our appreciation to the library staff for their assistance and availability in providing the necessary resources for our research.

We sincerely express our gratitude to everyone for their support and dedication to the successful completion of this thesis.

Thank you very much for everything...



Dedication

To my dear parents, my hero, Mr. Rachid, and my queen, my greatest supports and sources of inspiration. Your unconditional love and constant support have allowed me to achieve my goals. I dedicate this thesis to you as a testament of my eternal gratitude.

To my brother HAYTHEM and my sisters.

To my partner: Aimen.

And especially to my friends: Akram Laadouali, Ilies Moussaoui, Med Lamine Nemamsi, Oussama Mebarki, Amir Sakhria, Oussama Khoucha, and Mohammed Ridha Meghaouri.

To all my friends, near and far.

To my family: HAFSAOUI and DJEBBAR, each and every one by name.

Thanks to God, and to all of you, I will continue...

HAFSAOUI Dhiaaeddine



واجز دعاهم ان الحمد لله رب العالمين

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

Alhamdulillah... Today, my heart overflows with gratitude as I stand at this beautiful milestone — graduating and earning my Master's degree.

First and foremost, I thank Allah Almighty for His endless blessings, guidance, and divine success that made this dream a reality.

To my beloved parents, Mr. Djellali Saleh and Mrs. Sari Camilia,

From the bottom of my heart, thank you. Thank you for your endless sacrifices, your unconditional love, your constant prayers, and your unwavering belief in me. You carried my dreams on your shoulders, stayed awake through my sleepless nights, and gave me everything I needed — and more. Every success I achieve is yours. You are my greatest blessing, my safe haven, and my biggest source of strength. I love you beyond words, and I will spend my life trying to make you proud.

To my dear brothers, Moutaz, Zakaria Bellah Djellali, and Abdul Allah Djellali

Thank you for being my pillars of support, my loudest cheerleaders, and my constant motivation. Through every difficulty and every moment of doubt, you stood by me with love, encouragement, and patience.

To my dear colleague and friend, Hafsaoui Daa Eddine,

Thank you for walking this challenging journey with me. I will always value the moments we spent together working toward this goal.

This achievement is not just mine — it belongs to every one of you who loved me, believed in me, and carried me with your prayers and support. My heart is full of love and endless gratitude.

May Allah bless you all, protect you, and grant you the happiness you deserve. I promise to keep striving and making you proud.

With all my love and deepest appreciation, [DJELLALI AIMEN]

Abstract

This work studies the effect of fluid properties on oil well performance using nodal analysis and PIPESIM. The study was applied to Well X21 in the Hassi Messaoud Oil Field using real field and production data.

A simulation model was built to analyze the influence of parameters such as gas-oil ratio, viscosity, density, bubble point pressure, and water cut on well behavior and production stability. The results showed that stimulation operations improved the productivity of the well, while the increase in water cut caused important pressure losses and reduced the natural flowing capacity after stopping the nitrogen lift operation.

Several production solutions were evaluated, including tubing modification and Gas Lift installation. The study showed that Gas Lift is the most suitable solution for maintaining stable production under the current reservoir conditions.

This work confirms the importance of fluid characterization and numerical simulation in understanding production problems and improving well performance.

Keywords: Well Performance, Fluid Properties, PIPESIM, Nodal Analysis, Gas Lift.

Résumé

Ce travail porte sur l'étude de l'influence des propriétés des fluides sur les performances des puits pétroliers à l'aide de l'analyse nodale et du logiciel PIPESIM. L'étude a été appliquée au puits X21 situé dans le gisement pétrolier de Hassi Messaoud à partir de données réelles de production et de réservoir.

Un modèle de simulation a été développé afin d'analyser l'effet du rapport gaz/huile, de la viscosité, de la densité, de la pression de bulle et du taux d'eau sur le comportement du puits et la stabilité de la production. Les résultats obtenus montrent que les opérations de stimulation ont permis d'améliorer la productivité du puits, tandis que l'augmentation du taux d'eau a provoqué des pertes de pression importantes et réduit la capacité d'écoulement naturel après l'arrêt du nitrogen lift.

Plusieurs solutions de production ont été étudiées, notamment la modification du tubing et l'installation du Gas Lift. Les résultats montrent que le Gas Lift représente la solution la plus adaptée pour maintenir une production stable dans les conditions actuelles du réservoir.

Ce travail confirme l'importance de la caractérisation des fluides et de la simulation numérique dans la compréhension des problèmes de production et l'amélioration des performances des puits pétroliers.

Mots-clés : Performance des puits, propriétés des fluides, PIPESIM, analyse nodale, Gas Lift.

الملخص

يتناول هذا العمل دراسة تأثير خصائص الموائع على أداء الآبار النفطية باستعمال التحليل العقدي وبرنامج المحاكاة PIPESIM، حيث تم تطبيق الدراسة على البئر X21 الواقع في حقل حاسي مسعود النفطي اعتمادًا على معطيات حقيقية للإنتاج والمكمن.

تم تطوير نموذج محاكاة لدراسة تأثير نسبة الغاز إلى النفط، اللزوجة، الكثافة، ضغط الفقاعة ونسبة الماء على سلوك البئر واستقرار الإنتاج. أظهرت النتائج أن عمليات التحفيز ساهمت في تحسين إنتاجية البئر، في حين أدى ارتفاع نسبة الماء إلى زيادة خسائر الضغط وتراجع قدرة البئر على الجريان الطبيعي بعد التوقف عن عملية الرفع بالنيتروجين.

كما تمت دراسة عدة حلول لتحسين الإنتاج، من بينها تعديل قطر الأنابيب وتركيب نظام الرفع بالغاز، حيث تبين أن نظام الرفع بالغاز يمثل الحل الأنسب للحفاظ على استقرار الإنتاج في الظروف الحالية للمكمن.

تؤكد هذه الدراسة أهمية توصيف الموائع والمحاكاة العددية في فهم مشاكل الإنتاج وتحسين أداء الآبار النفطية.

الكلمات المفتاحية: أداء الآبار، خصائص الموائع، PIPESIM، التحليل العقدي، الرفع بالغاز.

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NOMENCLATURE AND SYMBOLS

Abbreviations

API — American Petroleum Institute

CPA — Cubic Plus Association Equation of State

ESP — Electrical Submersible Pump

Acid — Acidizing

Frac — Hydraulic Fracturing

GOR — Gas-Oil Ratio

IPR — Inflow Performance Relationship

PI — Productivity Index

PVT — Pressure-Volume-Temperature

SRK — Soave-Redlich-Kwong Equation of State

VLP — Vertical Lift Performance

Symbols and Units

q — Flow rate (bbl/d)

q_o — Oil production rate (bbl/d)

k — Permeability (mD)

h — Reservoir thickness (m)

J — Productivity Index (bbl/d/psi)

P — Pressure (psi)

P_r — Reservoir pressure (psi)

P_{wf} — Flowing bottom-hole pressure (psi)

P_b — Bubble-point pressure (psi)

ΔP — Pressure drop (psi)

T — Temperature ($^{\circ}\text{C}$)

μ_o — Oil viscosity (cp)

μ_g — Gas viscosity (cp)

R_s — Solution gas-oil ratio (scf/STB)

B_o — Oil formation volume factor (bbl/STB)

B_g — Gas formation volume factor (bbl/scf)

γ_o — Oil specific gravity

γ_g — Gas specific gravity

z — Gas compressibility factor

θ — Pipe inclination angle ($^{\circ}$)

WC — Water cut (%)

r_w — wellbore radius (ft)

r_e — damaged zone radius (ft)

General Introduction

General Introduction

General Introduction

The petroleum industry plays a major role in the development of modern economies by supplying the energy required for transportation, electricity generation, petrochemical industries, and many industrial activities. Among the different stages of the petroleum industry, production engineering is considered one of the most important fields because it focuses on the efficient extraction of hydrocarbons from underground reservoirs and their transport to the surface under safe and economical conditions.

As oil fields become mature and reservoir pressure declines with time, maintaining stable production becomes more difficult. Engineers are therefore required to understand not only the characteristics of the reservoir rock, but also the behavior of the produced fluids inside the wellbore. In many cases, production problems are not caused by the reservoir itself, but by the complex interaction between oil, gas, water, pressure losses, and multiphase flow phenomena occurring inside the tubing. For this reason, studying the effect of fluid properties on well performance has become an essential part of petroleum production engineering.

Fluid properties such as viscosity, density, gas-oil ratio (GOR), bubble point pressure, and water cut directly influence the ability of the well to produce hydrocarbons. A small variation in these properties can significantly modify the production rate, pressure profile, and operating conditions of the well. For example, high oil viscosity increases flow resistance both in the reservoir and inside the tubing, which reduces well productivity. Similarly, an increase in water cut leads to a heavier hydrostatic column, making it more difficult for the reservoir to lift fluids naturally to the surface. On the other hand, dissolved gas can improve production by reducing fluid density and creating a natural gas-lift effect.

In petroleum production systems, the performance of a well depends on the balance between two main components: the inflow performance of the reservoir and the vertical lift performance of the tubing system. The inflow performance relationship (IPR) represents the capacity of the reservoir to deliver fluids into the wellbore, while the vertical lift performance (VLP) describes the pressure required to transport these fluids from the bottom of the well to the surface. The intersection between these two curves defines the operating point of the well and determines its actual production rate. Any change in fluid properties affects both the IPR and the VLP, and consequently changes the overall performance of the well.

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With the development of modern simulation technologies, software tools such as PIPESIM have become very important for predicting and analyzing well behavior under different operating conditions. These simulators allow engineers to model multiphase flow, pressure losses, fluid behavior, and artificial lift systems with good accuracy. They also make it possible to perform sensitivity analyses and evaluate the effect of different parameters without carrying out expensive field operations. As a result, production optimization can be achieved more efficiently while reducing technical uncertainty and operational costs.

The present work focuses on studying the influence of fluid properties on well performance using nodal analysis and numerical simulation. Particular attention is given to the impact of parameters such as gas-oil ratio, oil viscosity, density, water cut, and bubble point pressure on production behavior. The study is applied to Well X21 located in the Hassi Messaoud Oil Field, one of the largest and most important oil fields in Algeria. This field has experienced reservoir depletion and increasing production challenges over time, making production optimization an important objective for maintaining economic performance.

The choice of Well X21 as a case study is motivated by the production problems observed after stimulation and nitrogen lift operations. Although the well initially showed a significant improvement in production after hydraulic fracturing and acidizing treatments, production later declined due to increasing water cut and changes in fluid behavior. These conditions make the well an interesting example for analyzing how fluid properties affect well deliverability and stability.

In this study, a PIPESIM model was developed and calibrated using real field data such as reservoir pressure, production rates, tubing configuration, and fluid properties. Different simulation scenarios were then performed in order to evaluate the sensitivity of the well performance to variations in the main fluid parameters. The analysis also investigates possible production solutions, including tubing optimization and gas lift implementation, to improve long-term well productivity.

The importance of this work lies in the fact that understanding fluid behavior is essential for selecting suitable production strategies and artificial lift methods. In mature oil fields, where reservoir pressure is continuously declining, the optimization of fluid flow conditions can significantly extend the productive life of wells and improve hydrocarbon recovery. Moreover,

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simulation studies provide valuable support for engineering decision-making by allowing the prediction of future well behavior under different operating scenarios.

This dissertation is organized into three main chapters. The first chapter presents the fundamental concepts of petroleum production engineering and explains the relationship between fluid properties and well performance. It also introduces the basic equations related to fluid flow in porous media, productivity index, inflow performance, and multiphase flow. The second chapter focuses on the theoretical foundations of multiphase flow and fluid behavior in wellbores, including PVT properties, flow regimes, pressure losses, and nodal analysis concepts. In addition, it provides an overview of the PIPESIM simulator and its application in well performance analysis. The third chapter is dedicated to the practical study of Well X21, including model construction, calibration, sensitivity analysis, and evaluation of different production optimization solutions.

Finally, this work aims to demonstrate that fluid properties play a critical role in determining well performance and production stability. Through the use of nodal analysis and numerical simulation, it becomes possible to better understand production problems, optimize operating conditions, and propose practical engineering solutions adapted to field realities.

One of the major challenges encountered in mature oil wells is the decline in production performance caused by pressure depletion and changes in fluid behavior. In many cases, increasing water cut, viscosity changes, and variations in gas-oil ratio create serious difficulties for natural production and may even lead to the death of the well.

Therefore, the main question addressed in this study is:

How do fluid properties influence well performance and production stability, and how can simulation tools such as PIPESIM help optimize production conditions for Well X21?

To answer this question, this work focuses on analyzing the effect of the main fluid parameters on well productivity through nodal analysis and PIPESIM simulation. Different operating scenarios are studied in order to identify the dominant factors affecting production performance and to propose suitable technical solutions for improving well operation.

Chapter I: Fundamentals of Petroleum Production and Well Performance Analysis

I.1 INTRODUCTION

This chapter presents the basic concepts of petroleum production engineering, focusing on how the reservoir, the well, and surface facilities operate together as one integrated system. It explains the main stages starting from the reservoir characteristics to drilling, well completion, and production equipment.

In addition, the chapter introduces the essential physical properties of reservoir fluids such as solution gas–oil ratio (R_s), oil formation volume factor (B_o), and oil viscosity, which are important for analyzing fluid behavior and predicting well performance. Some commonly used correlations are also mentioned for practical calculations.

Finally, a brief overview of the Hassi Messaoud oil field is provided to give a real field example and link the theoretical concepts to actual petroleum engineering practice. [1]

I.2 Petroleum Production Engineering Fundamentals

I.2.1 The Production System: From Reservoir to Surface Facilities

I.2.1.1 The Reservoir

Usually, a porous rock like sandstone or washed-out limestone serves as the oil and gas-bearing structure. The sand may have been deposited as seafloor or desert sand dunes. When organic material, such as microscopic plants and animals, is deposited during previous geological periods, oil and gas deposits are created.

Hydrocarbons were created 100–200 million years ago under, over, or with the sand or silt due to high pressure and temperature.

A non-porous layer, such as salt, shale, chalk, or mud rock, must cover porous rock in order for an oil reservoir to form and stop hydrocarbons from escaping the structure. Hydrocarbons migrate out of deposits and upward in porous rocks as a result of tectonic motions that fold and elevate rock structures. They gather in crests beneath non-permeable rock, with gas at the top and oil and fossil water at the bottom. [2]

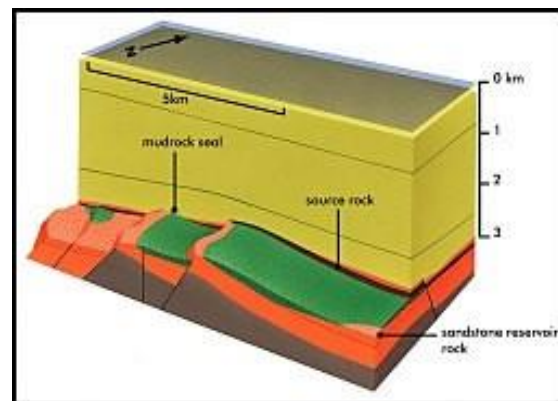


Figure I.1: Hydrocarbon Trap in Sedimentary Basin. [2]

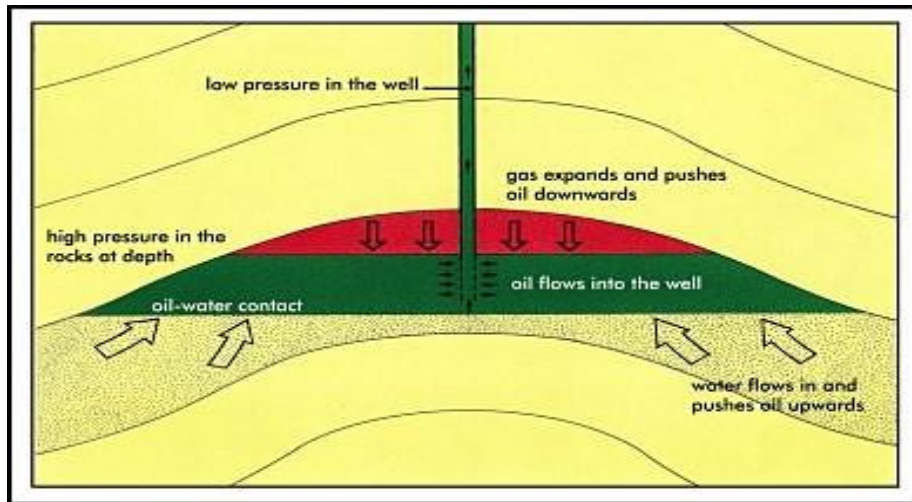


Figure I.2 : Reservoir Drive Mechanism (Gas Cap and Water Drive System) [2]

This process goes on continuously, even today. However, an oil reservoir matures in the sense that a too young formation may not yet have allowed the hydrocarbons to form and collect. A young reservoir (e.g. 60 million years) often has heavy crude, less than 20 API. In certain places, heavy oil reservoirs or tar pools are the result of hydrocarbons leaking out due to significant uplift, erosion, and rock fracture above. Large amounts of bitumen-soaked sands remain after volatile compounds have evaporated from shallow sandy formations, making tar sands among of the world's largest oil resources. These are frequently exposed at the surface and may be strip mined, but in order to increase their fuel production, they must be separated from the sand using hot water, steam, and diluents before being further processed in a refinery using cracking and reforming. [2]

I.2.1.2 The Well

After drilling the well, the next step is completion. Completing a well includes a series of operations: running and cementing the casing, preparing the wellbore, installing the wellhead, and adding production equipment or stimulating the formation when required. [2]

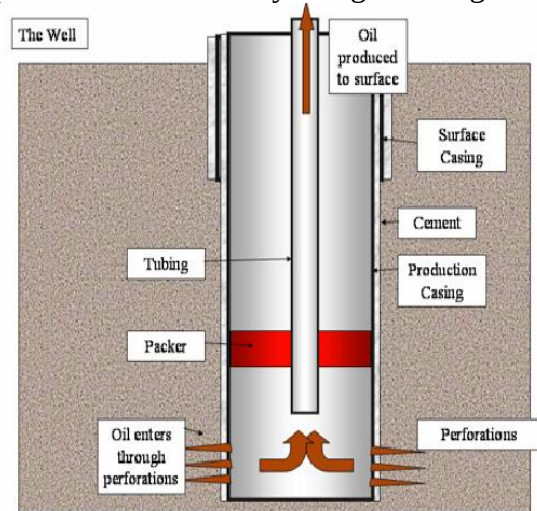


Figure I.3: Typical Oil Well Completion Diagram. [2]

I.2.1.2.1 Well Casing

Chapter I: Fundamentals of Petroleum Production and Well Performance Analysis

Installing well casing is a vital part of the drilling and completion process. Casing consists of steel pipes inserted into the borehole to support the well walls, prevent fluid leakage, and isolate different formations. The casing is usually cemented in place.

The diameter of the well decreases with depth, creating a tapered shape. There are four main types of casing:

- **Conductor Casing:** The shortest section (20–50 feet), installed first to prevent collapse at the surface and help circulate drilling fluid.
- **Surface Casing:** Runs from 100 to 400 meters deep. It protects shallow freshwater aquifers from contamination and provides structural support.
- **Intermediate Casing:** The longest section, used to isolate problematic zones such as high-pressure formations, unstable shales, or saltwater layers. Sometimes replaced by liner strings.
- **Production Casing** (also called oil string): The deepest casing, which provides a conduit for hydrocarbons to reach the surface. Its size depends on lifting equipment, future deepening plans, and well control needs.

Once the casing is installed, **tubing** is placed inside it, and a **packer** is set between the tubing and casing at the bottom to isolate the production zone. Oil and gas flow to the surface through the tubing. [2]

I.2.1.2.2 Well Completion

Well completion is basically the last step after drilling, where the well is made ready to start producing oil or gas. In simple words, it's how we set up the well so fluids can move from the reservoir into the wellbore in a controlled way.

This step really matters because it has a direct effect on how much the well can produce. If the completion is done properly, fluids flow more easily and the well performs better over time. But if it's not well designed, it can restrict the flow and cause issues like sand production or early damage to the well. [2]

I.2.1.3 Wellhead

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Wellheads can be either **dry** or **subsea**.

- **Dry Completion:** The wellhead is located on land (onshore) or on the topside of an offshore platform.
- **Subsea Completion:** The wellhead sits underwater on the seabed, mounted on a special template.

The wellhead is the assembly of equipment installed at the top of the well. Its main jobs are to control and monitor the flow of oil and gas, prevent leaks, and protect the well from blowouts caused by high pressure.

Some formations have very high pressure, so the wellhead must be strong enough to handle it — sometimes up to 140 MPa (1400 bar). [2]

A typical wellhead consists of three main parts:

- The **casing head**
- The **tubing head**
- The **Christmas tree** (the part that looks like a tree with many valves)

The Christmas tree usually includes a master gate valve, wing valve, swab valve, choke, and pressure gauge. It may also have several check valves.

At the very bottom is the **casing head** with casing hangers. The casing pipes are fixed to these hangers by screwing, bolting, or welding. Several valves and plugs are fitted here to allow access to the casing. These let operators open or close the casing, bleed off pressure, check for leaks in the casing, tubing, or packer, and sometimes even produce the well through the casing instead of the tubing. They can also be used to inject lift gas into the casing. [2]

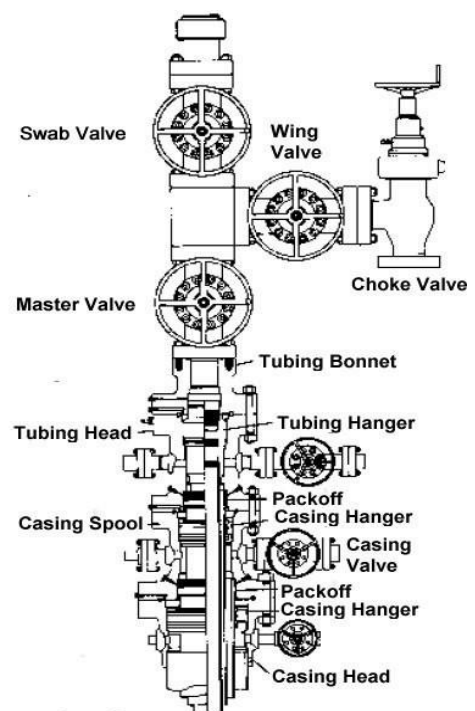


Figure I.4: Schematic Diagram of Wellhead and Christmas Tree System. [2]

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The **tubing hanger** (sometimes called the donut) sits in the wellhead and holds the tubing string in the correct position. It also provides a tight seal, which allows the Christmas tree to be removed safely even when there is pressure in the casing.

- **Master Gate Valve:** This is a strong, high-quality valve located at the very top of the wellhead. It has a full-bore opening (same diameter as the tubing) so that tools can pass through it easily. It is designed to handle the full well pressure safely. Usually, it is kept fully open during normal production and is not used to control the flow.
- **Pressure Gauge:** A basic pressure gauge is installed above the master gate valve (before the wing valve). Other instruments, such as temperature sensors, are often added as well.
- **Wing Valve:** This valve is used to shut in the well. It can be either a gate valve or a ball valve. When the well is closed, operators normally use the wing valve so they can easily read the tubing pressure.
- **Swab Valve:** Located at the top of the Christmas tree, this valve allows access to the well for wireline operations, interventions, and workovers. Above it, there is a tree adapter and cap that can connect to different types of equipment.
- **Choke Valve:** This is usually a large adjustable needle valve (called a variable choke). Its opening can be fine-tuned in small steps of 1/64 inch (known as “beans”). It is made of high-quality steel to resist the high-speed flow of abrasive fluids and sand. On smaller wells, a simpler and cheaper **positive choke** (with a fixed opening) is often used instead.

Christmas trees are usually **vertical**, but they can also be **horizontal**. In a horizontal tree, the master valve, wing valve, and choke are arranged sideways. This makes the tree shorter and can make intervention work easier, especially on subsea wells. [2]

I.2.2 The Role of Petroleum Production Engineering

I.2.2.1 Permeability

Once you have good porosity, the next big question is: *Can the fluids actually flow?* That’s where **permeability** comes in. It’s the property that tells us how easily oil, gas, or water can move through the rock.

The idea goes back to Henry Darcy in 1856. He did a simple but brilliant experiment: he packed sand in a tube, pushed water through it, and measured the pressure drop (or head difference)

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from one end to the other. He discovered that the flow rate is directly proportional to the pressure difference and a characteristic of the porous medium itself. [3]

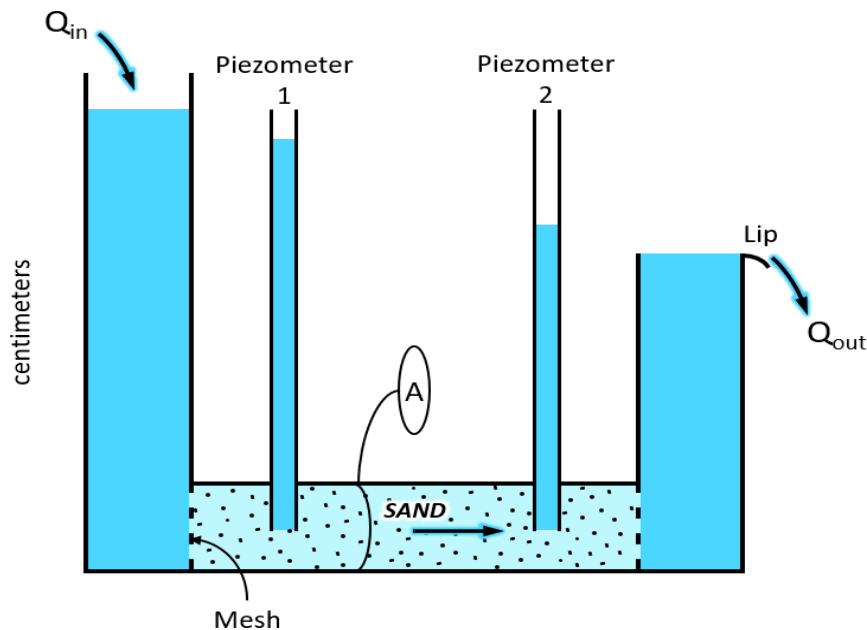


Figure I.5 Darcy's experiment. Water flows through a sand pack and the pressure difference (head) is recorded. [3]

The equation is simple: $u = \frac{k}{\mu} \Delta p$ where k is permeability (the rock's "conductivity"), μ is fluid viscosity, and Δp is the pressure drop. The ratio k/μ is called **mobility**.

Important note: higher porosity doesn't always mean higher permeability. Some rocks (like certain chinks) can have 40% porosity but still low permeability. So never assume one from the other – especially in production engineering, where we care about real flow. [3]

I.2.2.2 The Zone near the Well, the Sandface, and the Well Completion

This is where the real drama happens. Even in a perfect reservoir, fluid has to converge radially toward the wellbore. Because of that geometry, most of the pressure drop occurs in the first few feet around the well – it's logarithmic. One foot of damaged rock near the well can eat up the same pressure drop as 100 feet farther out.

Drilling, cementing, and completion almost always damage this near-well zone (we call it "skin"). That damage can kill 90% of the well's potential if you're not careful.

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That's why **matrix stimulation** (acidizing to clean the pores) or **hydraulic fracturing** (creating a high-permeability highway that bypasses the damage) are so powerful. Fracturing completely changes the flow from radial to linear, and suddenly the near-well damage doesn't matter anymore.

Wells are usually cased and cemented for zonal isolation – you don't want water or gas from another layer ruining your production. Then we perforate, or use slotted liners, gravel packs, etc. Every completion choice affects how the reservoir talks to the well. [3]

I.2.2.3 Classification of Reservoirs

Reservoirs are classified by their phase behavior (see the diagram below). Undersaturated oil, saturated (two-phase), gas, or retrograde condensate – each behaves differently.

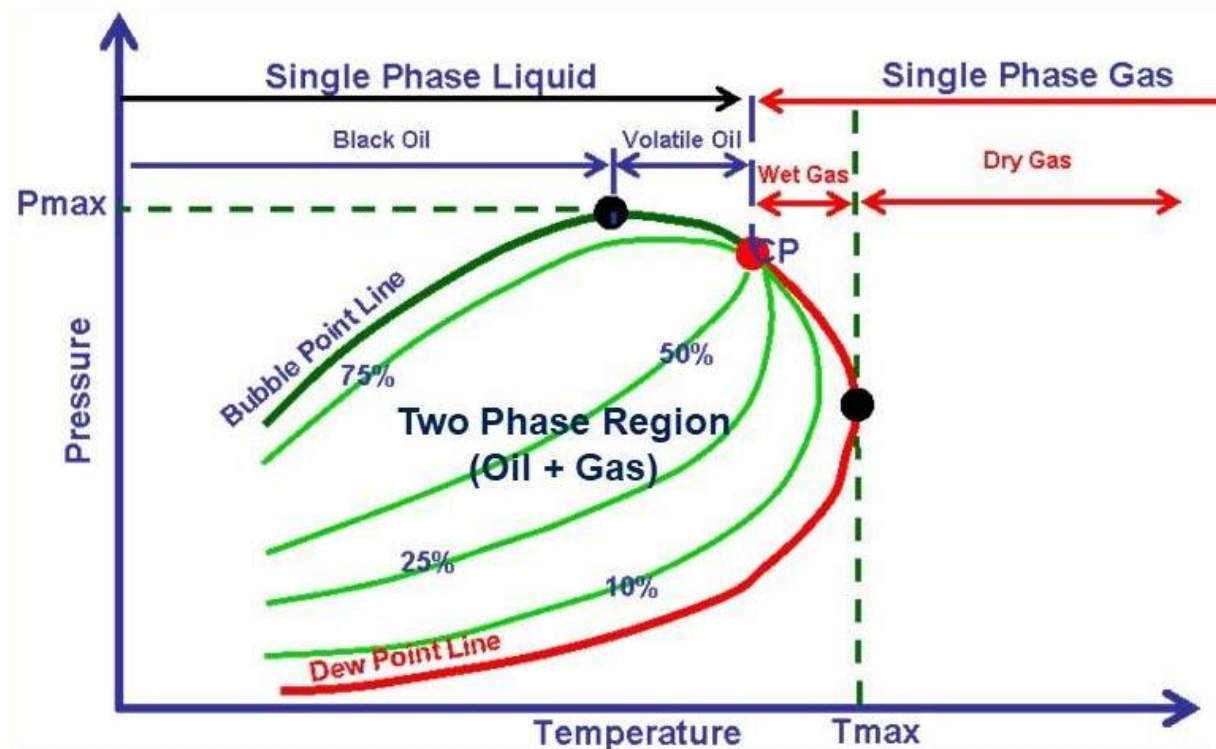


Figure I.6: Hydrocarbon Phase Diagram (bubble-point and dew-point curves, retrograde condensation region, critical point, and cricondentherm). [3]

I.2.2.4 Well Productivity and Production Engineering

Production engineering is all about closing the performance gap. We combine two curves:

- IPR (Inflow Performance Relationship) – what the reservoir can deliver

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- VFP (Vertical Flow Performance) – what the wellbore can lift to surface

Their intersection is the actual producing rate. Your job as a production engineer is to move that point as high as possible – by reducing skin, adding lift, stimulating, or fracturing.

Modern tools (permanent downhole gauges, production logging, pressure-transient analysis) let us diagnose exactly where the problem is. Then we fix it with the right treatment. [3]

I.3 Fluid Flow in Porous Media

I.3.1 Darcy's Law

I.3.1.1 Definition

Darcy's Law is the fundamental equation that describes how fluids flow through porous materials under laminar flow conditions. It was developed by Henry Darcy in 1856 while he was working on water filtration in sand. In the oil industry, we use it to relate the flow rate to the pressure difference, the rock's permeability, and the fluid's viscosity.

The law works best for single-phase, steady-state, incompressible flow. In real reservoirs we often have to apply corrections for gas flow or multiphase conditions, but the basic idea remains the foundation of everything else. [4]

I.3.1.2 The Equation (Linear Form)

For linear flow, Darcy's Law is usually written as:

$$q = -\frac{kA}{\mu} \frac{\Delta p}{L}$$

Where:

- q = flow rate
- k = permeability
- A = cross-sectional area
- μ = fluid viscosity
- Δp = pressure drop
- L = length of the porous medium [5]

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The negative sign just means fluid flows from high pressure to low pressure. [5]

In practical oilfield units for stock tank oil (STB/day), it becomes:

$$q_o = 0.001127 \frac{kA}{\mu_o B_o} \frac{\Delta p}{L}$$

I.3.1.3 Effect of Viscosity and Permeability

Permeability (k) and viscosity (μ) are the two key players here.

- Higher permeability means the rock lets fluid pass more easily — flow rate increases directly with k .
- Higher viscosity (thicker fluid) makes flow harder — flow rate decreases as viscosity increases.

For example, a reservoir with 500 mD permeability will produce much better than one with only 5 mD, even if the oil is the same. On the other hand, heavy oil (high μ) flows very slowly compared to light oil.

That is why we sometimes inject steam

or gas to reduce viscosity in heavy oil fields. [4]

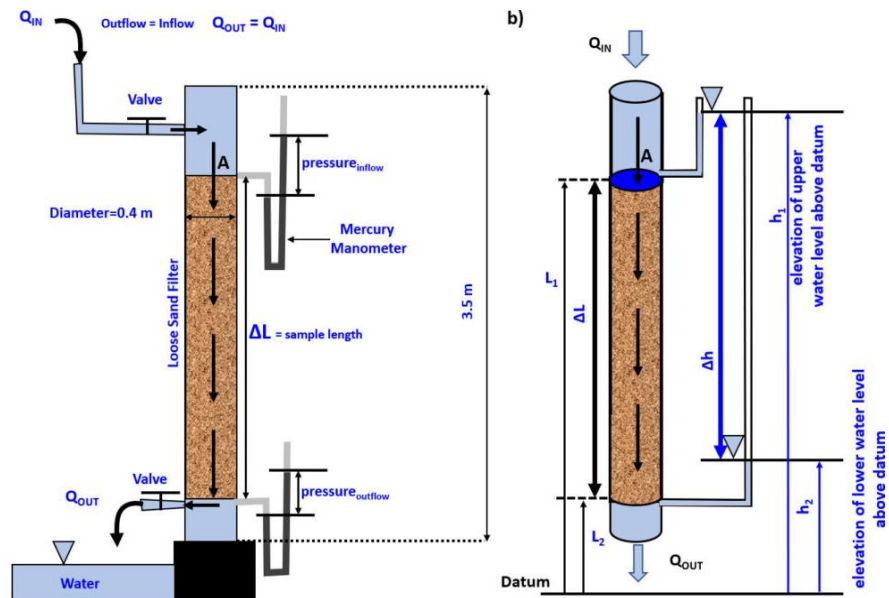


Figure I.7: Darcy's setup showing water flowing through sand, with pressure and flow measured. [4]

I.3.2 Productivity Index (PI or J-index)

Definition The Productivity Index (J or PI) is a simple and very useful number that tells us how productive a well is. It shows how many barrels of oil per day the well can produce for each psi of pressure drawdown (the difference between reservoir pressure and bottom-hole flowing pressure). [4]

$$J = \frac{q_o}{p_r - p_{wf}}$$

Where:

- J = Productivity Index (STB/day/psi)
- q_o = oil production rate
- p_r = average reservoir pressure
- p_{wf} = flowing bottom-hole pressure [5]

A high J value means the well is strong and can produce a lot with relatively small drawdown.

A low J indicates problems such as low permeability, heavy oil, or formation damage. [5]

We can also calculate the theoretical J from Darcy's Law for radial flow (assuming no skin):

$$J = \frac{0.00708 kh}{\mu_o B o \ln\left(\frac{r_e}{r_w}\right)}$$

In the field, engineers usually measure J during well tests by changing the choke size and recording the stabilized rate and pressure. Following how J changes over time helps us see if the well is getting damaged, if the reservoir is depleting, or if a stimulation job was successful. [5]

I.4 Well Performance Fundamentals

After understanding how fluid flows through the reservoir rock (Darcy's Law and radial flow), the next step is to see how the well actually produces. In real life, the production rate is not decided by the reservoir alone or the tubing alone — it is the balance between what the reservoir can deliver and what the tubing can lift to the surface. This balance is what we call **Nodal Analysis**, and it is one of the most useful tools for production optimization. [6]

I.4.1 Inflow Performance Relationship (IPR)

The Inflow Performance Relationship (IPR) curve represents the ability of the reservoir to deliver fluids to the wellbore. It describes the relationship between the flowing bottom-hole pressure (P_{wf}) and the production rate (q). In other words, it shows how the production rate changes when the pressure drawdown increases. The IPR is an essential tool in production

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engineering because it helps evaluate the productivity and performance of oil wells under different operating conditions.

For reservoirs producing above the bubble point pressure, the IPR curve is generally linear because the fluid flow remains single-phase. However, when the bottom-hole pressure drops below the bubble point, gas begins to evolve from the oil near the wellbore, creating a two-phase flow condition. In this case, the IPR curve becomes non-linear and bends downward. To describe this behavior, correlations such as Vogel's equation are commonly used, especially in Black Oil reservoirs like Hassi Messaoud. [6]

The shape and position of the IPR curve provide valuable information about reservoir quality and well productivity. A reservoir with good permeability and sufficient thickness usually exhibits a stronger IPR, meaning it can produce higher flow rates at the same pressure drawdown. Production stimulation treatments such as acidizing or hydraulic fracturing can improve the IPR by reducing formation damage and skin effect, which shifts the curve upward and increases the well production capacity. [6]

I.4.2 Vertical Lift Performance (VLP)

The **VLP** (also called Tubing Performance Relationship or Outflow Curve) describes the pressure required at the bottom of the well (P_{wf}) to lift a certain rate of fluid to the surface through the tubing. It depends on tubing size, well depth, fluid properties, gas-liquid ratio, and surface pressure. [6]

The VLP curve usually starts high at low rates (because of high hydrostatic pressure) and may show a minimum before rising again at very high rates due to friction losses. Smaller tubing increases friction, while larger tubing reduces it but may cause liquid loading at low rates. [7]

Anything that makes lifting easier (larger tubing, lower separator pressure, gas lift, or ESP) shifts the VLP curve downward. [7]

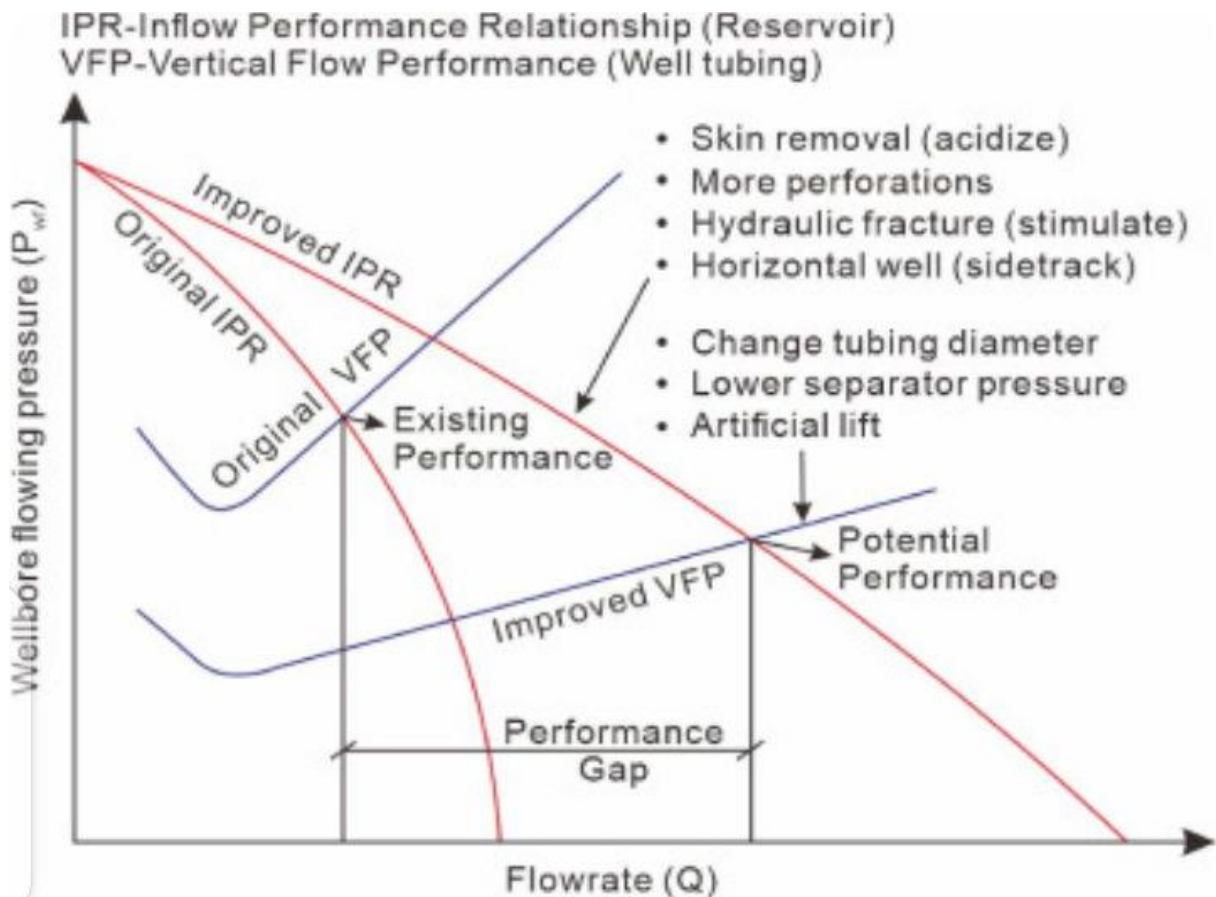


Figure I.8: Example showing how improvements in IPR and VLP affect the well's performance gap. [7]

I.4.3 Operating Point

The operating point is the point where the IPR curve and the VLP curve intersect. At this point, the reservoir inflow is equal to the lifting capacity of the well, which means the well can produce in stable conditions. The intersection gives the actual production rate and the corresponding flowing bottom-hole pressure of the well. [7]

The position of the operating point is very important in production analysis. If the production rate is low, engineers try to improve the well performance either by increasing the reservoir inflow or by reducing pressure losses in the tubing. This can be done through stimulation treatments or by optimizing the production system.

The study of the operating point is one of the main objectives of nodal analysis because it helps determine the best operating conditions for the well and improve production performance. [7]

I.5 Physical Properties of Produced Fluids

After understanding the basic principles of fluid flow in porous media (Darcy's Law, radial flow, and Productivity Index), it is essential to examine the main physical properties of the produced fluids. In this section, the mathematical correlations used to calculate **R_s** (Solution Gas-Oil Ratio), **B_o** (Oil Formation Volume Factor), **μ_o** (Oil Viscosity), **B_g** (Gas Formation Volume Factor), and **μ_g** (Gas Viscosity) are explained.

These are empirical correlations developed from real field data. The most widely used ones for oil properties were proposed by **Standing (1947)** and **Beggs & Robinson (1975)**. They are commonly applied in Black Oil PVT calculations because they are simple and reasonably accurate for light to medium gravity oils such as those found in Hassi Messaoud field. [8]

I.5.1 Oil Properties

I.5.1.1 Solution Gas-Oil Ratio (R_s)

R_s represents the volume of gas (in standard cubic feet) dissolved in one stock tank barrel of oil at standard conditions (scf/STB). [8]

The most popular correlation is **Standing (1947)**, which was developed based on 105 samples from California crude oils:

$$R_s = \gamma_g \left(\frac{P}{18.2} \right)^{1.2048} \times 10^{0.83(0.00091T - 0.125\gamma_{API})}$$

Where:

- γ_g : Specific gravity of the gas (air = 1)
- P : Pressure (psia)
- T : Temperature (°F)
- γ_{API} : API gravity of the oil

Note: Below the bubble point pressure ($P < P_b$), R_s remains constant at its value at P_b . [8]

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I.5.1.2 Oil Formation Volume Factor (B_o)

B_o is the ratio of the volume of oil plus dissolved gas at reservoir conditions to the volume of oil at stock tank conditions (bbl/STB). [8]

Standing correlation (1947):

$$B_o = 0.9759 + 0.00012 \left[R_s \left(\frac{\gamma_g}{\gamma_o} \right)^{0.5} + 1.25T \right]^{1.175}$$

Where:

- $\gamma_o = \frac{141.5}{131.5 + \gamma_{API}}$ (specific gravity of the stock tank oil)
- Other variables are as defined above.

Note: This equation is used for saturated oil. For undersaturated oil ($P > P_b$), oil compressibility (c_o) is applied to account for volume changes with pressure. [8]

I.5.1.3 Oil Viscosity (μ_o)

Oil viscosity (in centipoise, cP) varies with pressure, temperature, and the amount of dissolved gas. It is usually calculated in three steps:

- **Dead Oil Viscosity (μ_{od})** (gas-free oil at atmospheric pressure): One common correlation is **Egbogah (1983)** (modified form):

$$\log_{10}[\log_{10}(\mu_{od} + 1)] = 1.8653 - 0.025086\gamma_{API} - 0.5644 \log_{10}(T)$$

- **Saturated Oil Viscosity (μ_o) at $P \leq P_b$ (live oil): **Beggs & Robinson (1975)** – the most widely used:**

$$A = 10.715(R_s + 100)^{-0.515} \quad , \quad B = 5.44(R_s + 150)^{-0.338}$$
$$\mu_o = A \times \mu_{od}^B$$

Note: As R_s increases, viscosity decreases because dissolved gas lightens the oil. [8]

- **Undersaturated Oil Viscosity (μ_o) at $P > P_b$: **Vasquez & Beggs (1980):****

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$$m = 2.6P^{1.187} \exp(-11.513 - 8.98 \times 10^{-5}P)$$

$$\mu_o = \mu_{ob} \left(\frac{P}{P_b} \right)^m$$

(where μ_{ob} is the viscosity at bubble point pressure).

I.5.2 Gas Properties

I.5.2.1 Gas Formation Volume Factor (Bg)

Bg represents the volume of gas at reservoir conditions relative to standard surface conditions. It is essential for calculating gas volumes and total hydrocarbon in place. [8]

$$Bg = 0.00504 \frac{zT}{P}$$

Where:

- z = gas compressibility factor
- T = temperature (°R)
- P = pressure (psia)

I.5.2.2 Gas Viscosity (μ_g)

Gas viscosity is very low (typically 0.01 – 0.03 cP), allowing gas to flow much more easily than oil. It increases slightly with pressure and temperature.

These oil and gas properties (R_s , B_o , μ_o , B_g , and μ_g) are directly used when building the Inflow Performance Relationship (IPR), calculating Productivity Index, and performing nodal analysis in the next section. They also connect with water properties (density and viscosity) that complete the full picture of produced fluids. [8]

I.6 Multiphase Flow Introduction

I.6.1 Definition of Multiphase Flow

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Multiphase flow is the simultaneous movement of two or more fluid phases (oil, gas, and water) through the same pipe or tubing. In oil wells, it typically involves three phases: liquid oil, free gas, and water.

Unlike single-phase flow, multiphase flow is much more complicated because each phase has different density, viscosity, and velocity. The gas moves faster than the liquids, which creates additional pressure losses and makes production behavior less predictable. [9]

I.6.2 Main Problems in Multiphase Flow

Two key challenges in multiphase flow are **liquid holdup** and **slippage**:

- **Liquid Holdup** Liquid holdup is the fraction of the tubing volume that is occupied by liquid (oil + water) at any given time. Because gas is lighter and rises faster, liquids tend to accumulate in the well. High liquid holdup increases the hydrostatic pressure and makes it harder to lift the fluids to the surface. At low flow rates, this can lead to liquid loading, where the well struggles to produce or even dies. [9]
- **Slippage** Slippage refers to the difference in velocity between the gas phase and the liquid phases. Gas slips past the heavier liquids and moves upward more quickly. This relative movement causes extra friction and pressure drop, and it is one of the main reasons we need special multiphase flow correlations instead of simple single-phase equations. [9]

These two phenomena directly influence the Vertical Lift Performance (VLP) curve used in nodal analysis. Understanding them helps engineers select the proper tubing size, decide when artificial lift is needed, and predict well performance more accurately. [9]

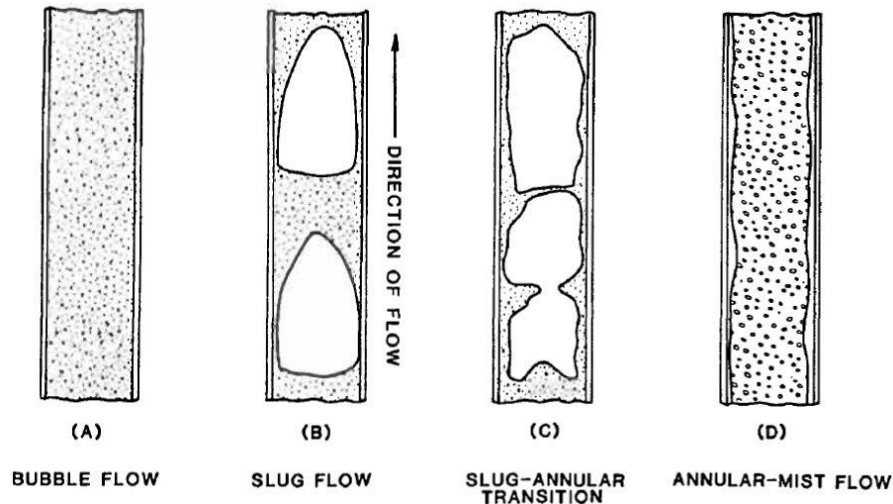


Figure I.9: Typical multiphase flow regimes in vertical wells (Bubble flow, Slug flow, Churn flow, and Annular-Mist flow). The flow pattern changes as gas and liquid velocities increase. [9]

I.7 Link Between Fluid Properties and Well Performance

I.7.1 Viscosity Effect ($\mu \uparrow \rightarrow \text{Production} \downarrow$)

When oil viscosity increases, the oil becomes thicker and flows much more slowly through the reservoir and inside the tubing.

- In the reservoir: High viscosity reduces the Productivity Index (J) because oil moves slowly according to Darcy's Law.
- In the tubing: Higher viscosity increases frictional pressure losses and makes the VLP curve worse.

Result: For the same drawdown, the well produces less oil. This is why heavy oil reservoirs (high μ) usually show low production rates unless we heat the oil or use diluents to reduce viscosity. In Hassi Messaoud, where the oil is relatively light, any increase in viscosity due to pressure drop or temperature change still noticeably affects well deliverability. [10]

I.7.2 Density Effect (Density $\uparrow \rightarrow \text{Pressure Loss} \uparrow$)

Higher fluid density increases the hydrostatic pressure inside the tubing.

- Oil, water, and gas have very different densities (gas is much lighter than oil or water).

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- When liquid holdup is high (more oil and water in the tubing), the average density of the flowing mixture increases, which creates a larger hydrostatic pressure gradient.

This extra pressure loss makes it harder for the reservoir to push the fluids to the surface, shifting the operating point to a lower production rate. That is why liquid loading becomes a serious problem in wells with high water cut or low gas production. [10]

I.7.3 Gas-Oil Ratio (GOR) Effect (GOR $\uparrow \rightarrow$ Lift Effect)

Higher solution gas-oil ratio (R_s) or producing GOR has a positive “gas lift” effect:

- As gas comes out of solution, it mixes with the oil and reduces the average density of the fluid column in the tubing.
- Lower mixture density means less hydrostatic pressure loss, which improves the VLP curve and allows higher production rates for the same bottom-hole pressure.

However, if GOR becomes too high, problems appear: gas breakthrough, excessive free gas, and two-phase flow complications that can reduce oil production. In Black Oil systems like Hassi Messaoud, there is usually an optimum GOR range that helps natural lift without causing too many operational issues. [10]

I.7.4 Overall Link with Well Performance

All the correlations we saw earlier (Standing for R_s and B_o , Beggs & Robinson for μ_o , B_g , and gas viscosity) are not just theoretical numbers. They directly shape both the **Inflow Performance Relationship (IPR)** and the **Vertical Lift Performance (VLP)**. [10]

- PVT properties control the shape of the IPR curve (how much the reservoir can deliver).
- The same properties, together with multiphase flow behavior (liquid holdup and slippage), control the VLP curve (how difficult it is to lift the fluids).
- The intersection point of IPR and VLP — the actual operating point — is therefore strongly influenced by fluid properties. [10]

Understanding these links helps engineers make better decisions: whether to stimulate the well to improve inflow, change tubing size to reduce pressure losses, or install artificial lift when natural flow becomes inefficient.

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In short, fluid properties are not isolated data — they are the bridge between reservoir behavior and surface production performance. This connection is the heart of nodal analysis and the key to optimizing wells in fields like Hassi Messaoud. [10]

I.8 Hassi Messaoud Oil Field Overview

Hassi Messaoud stands as Algeria's largest and most iconic oil field. For more than sixty years, it has been the backbone of the country's hydrocarbon production. Operated entirely by Sonatrach, the national oil company, the field continues to play a vital role in Algeria's economy despite being a mature giant. Its story reflects both the challenges and opportunities of developing a complex reservoir in the heart of the Sahara Desert.

I.8.1 Location

The Hassi Messaoud oil field lies in the Ouargla Province in southeastern Algeria, within the Oued Mya Basin (part of the Triassic Province). It is situated in the Grand Erg Oriental, one of the largest sand dune regions in the Sahara. The field is approximately 650 km southeast of Algiers and about 80 km east of Ouargla city. Its geographic coordinates are roughly 31.6°N and 5.9°E. The structure covers a vast area of around 1,600 to 2,000 km², making it one of the largest oil fields in North Africa. [11]



Figure I.10: Location map of Hassi Messaoud within the Algerian hydrocarbon fields and pipelines network (highlighted in green as an oil field). [11]

I.8.2 History

Exploration teams from the French company SN REPAL discovered the field in 1956 with the MD-1 well. Development started almost immediately, and commercial production began between 1958 and 1960. In the following decades, output rose quickly, reaching a peak of approximately 500,000 barrels per day (bbl/d) in the mid-1970s. After Algeria nationalized its oil industry in 1971, Sonatrach assumed full control.

Over the years, more than 1,200 wells have been drilled. The field has produced several billion barrels of oil and still contributes roughly 15–20% of Algeria's daily oil production, currently

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around 350,000 bbl/d. Most of the associated gas is reinjected to help maintain reservoir pressure. Today, efforts focus on infill drilling, horizontal wells, and enhanced recovery techniques to slow the natural decline and extend the field's life. [11]

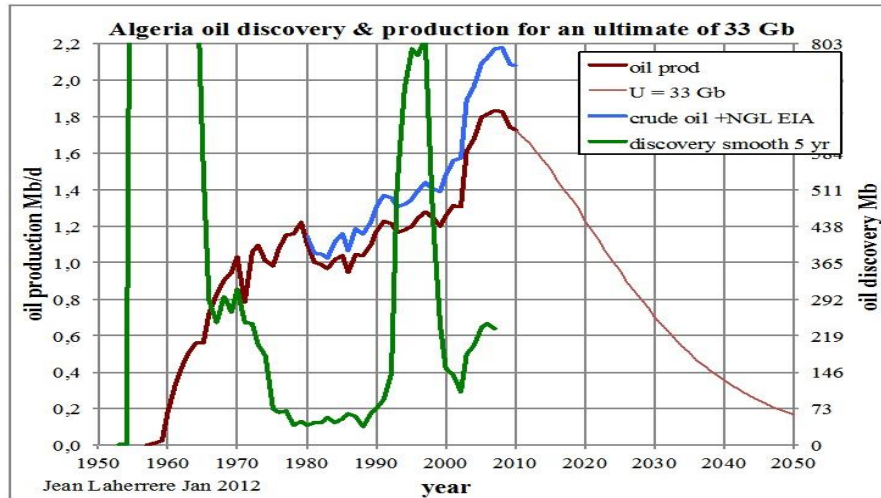


Figure I.11.: Algeria oil production history showing the contribution and peak of major fields including Hassi Messaoud (red curve represents historical and projected oil production). [12]

I.8.3 Geology and Reservoir Characteristics

The main producing reservoir belongs to the **Cambrian age** (Cambro-Ordovician sandstones and quartzites). These rocks lie unconformably on the Precambrian granitic basement and are capped by the Hercynian unconformity and a thick Triassic clay-evaporite sequence that acts as an excellent seal. [11]

The reservoir is divided into several units: R3 (base), R2, Ra, and Ri (top). The **Ra unit** is the highest quality layer, consisting of medium to coarse-grained quartzitic sandstones deposited in fluvial to tidal environments. Gross thickness averages about 300 m, but net pay varies significantly.

Reservoir quality is highly heterogeneous due to:

- Variations in grain size and clay content
- Quartz cementation (diagenesis)
- Natural fracturing

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Average reservoir depth is 3,200–3,400 m. Porosity typically ranges from 5–15% (locally higher in less cemented zones), while matrix permeability is often low (1–10 mD on average, though fractures can increase effective permeability dramatically). The structure is a large elongated anticline trending SSW-NNE, affected by faults. Natural fractures play a key role in productivity, especially in tighter zones. [12]

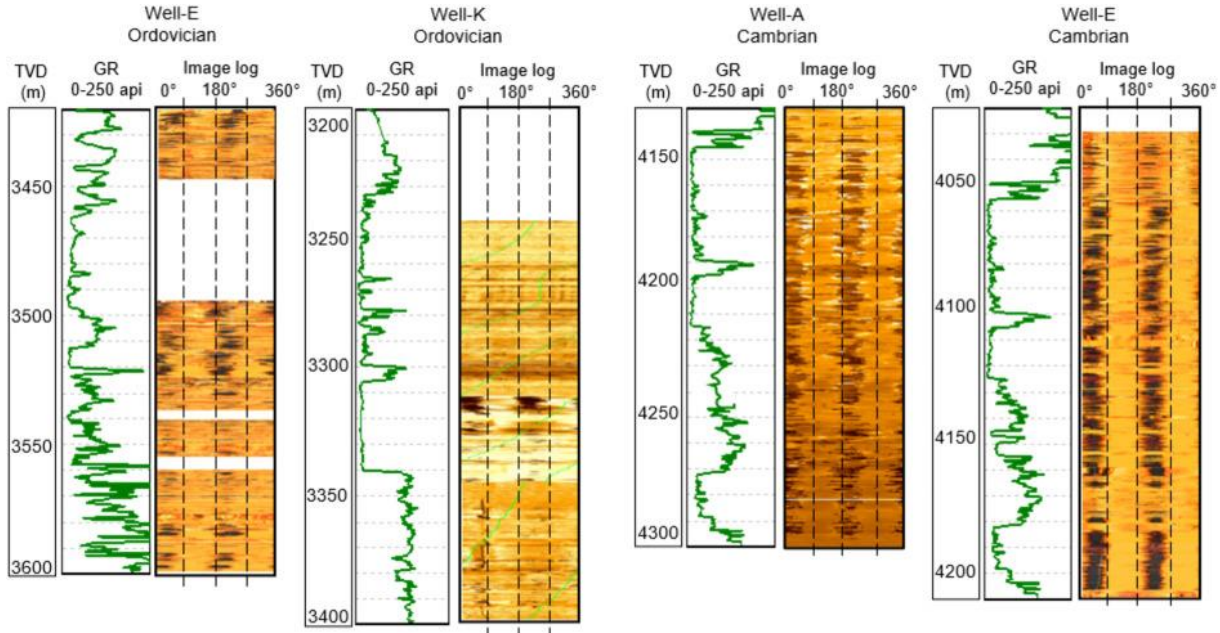


Figure I.12: Example of stratigraphic and image logs from Cambrian reservoir sections in Hassi Messaoud wells, showing layered sandstone/quartzite units and fracture indicators. [12]

I.8.4 Fluid Type

The hydrocarbon fluid in the Hassi Messaoud field is classified as Black Oil. This type of fluid is very common in many giant sandstone reservoirs around the world and behaves in a predictable way under reservoir conditions.

The oil is light to medium gravity, typically ranging between 40–45° API at surface conditions. It has a moderate solution gas-oil ratio (R_s), which means a reasonable amount of gas is dissolved in the oil at reservoir pressure. The reservoir temperature is relatively high, around 118–120°C, while the initial reservoir pressure was quite elevated, reaching approximately 6,800–7,000 psi in many parts of the field. The bubble point pressure varies across the different sectors of the field, generally lying between 2,100 and 2,900 psi, depending on location and depth.

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What makes this fluid a classic Black Oil is that below the bubble point pressure, free gas starts to appear, but the oil still remains as the dominant liquid phase. Above the bubble point, the oil behaves as an undersaturated single-phase liquid. Because of this typical behavior, the standard empirical correlations we discussed earlier — such as Standing’s correlations for R_s and B_o , and Beggs & Robinson’s method for oil viscosity — work very well for Hassi Messaoud. In practice, these correlations have been regularly tuned and matched with actual laboratory PVT data collected from many wells across the field to improve their accuracy.

This Black Oil character has a direct impact on well performance and production strategy. The moderate GOR provides some natural gas lift effect, helping the fluids flow to the surface, but as reservoir pressure declines over time, more gas comes out of solution, oil viscosity increases slightly, and the well’s productivity starts to drop. Understanding the fluid type is therefore essential when building the IPR curve, selecting tubing sizes, and deciding the right time to apply pressure maintenance or artificial lift methods.

In summary, the Black Oil nature of Hassi Messaoud fluid, combined with its good API gravity and moderate gas content, has contributed greatly to the field’s long and successful production history. [12]

CHAPTER II: Theoretical Foundations of Multiphase Flow and Fluid Behavior in Wellbores

II.1 Petroleum Fluid Classification and Phase Behavior

An accurate characterization and understanding of the phase behavior of reservoir fluids is a fundamental step in well performance modeling. In steady-state simulation tools such as PIPESIM, the reliability of the results strongly depends on selecting the correct fluid type, appropriate PVT model, suitable multiphase flow correlations, and a consistent simulation strategy. All of these choices are directly guided by the correct identification and description of the reservoir fluid behavior. [13]

II.1.1 Black Oil vs. Volatile Oil vs. Gas Condensate vs. Dry/Wet Gas

Reservoir fluids are classified according to their hydrocarbon composition, initial reservoir conditions, and production characteristics. The main categories are:

- **Black Oil:** This type is defined by a generally low to moderate initial solution gas-oil ratio ($\text{GOR} < 2000 \text{ scf/STB}$ or $\approx 356 \text{ sm}^3/\text{sm}^3$), and major oil volume contraction beneath the bubble point while stock-tank oil gravity commonly falls within the range of 30° to 45°API . At a lower pressures than the bubble point free gas is released which drives up gas saturation and principally changed relative permeabilities as well as effective viscosities. Hassi Messaoud Zone 4 (Cambrian Ra/Ri sandstone) light black oil is one of the important types, being characterized by oil gravity = 45°API initial $R_s \approx 185.2 \text{ sm}^3/\text{sm}^3$ ($\approx 1040 \text{ scf/STB}$), and bubble point pressure $\approx 153.97 \text{ kg/cm}^2$ ($\approx 2190 \text{ psi}$) at reservoir temperatures of 120°C .
- **Volatile Oil:** Exhibits higher GOR (often $2000\text{--}3000+$ scf/STB), greater liquid shrinkage upon pressure reduction, and behavior close to the critical point. These fluids require more advanced modeling due to significant compositional changes.
- **Gas Condensate:** Displays retrograde condensation, where liquid dropout occurs below the dew point despite decreasing pressure. These systems have very high GOR ($>3000 \text{ scf/STB}$) and rich gas composition.
- **Wet Gas and Dry Gas:** Wet gas produces some surface condensate, while dry gas remains entirely in the single gas phase throughout production and surface separation.

In the Hassi Messaoud field, the main produced fluid is light black oil. However, due to pressure depletion—from an initial pressure of approximately 485 kg/cm^2 down to below 250 kg/cm^2 in

Chapter II: Wellbore Flow Behavior and Fluid Properties Modeling

many areas—and the possible introduction of gas injection, some localized zones may exhibit volatile-like behavior. Accurate fluid classification is essential because misclassification can cause incorrect PVT (Pressure-Volume-Temperature) data input in PIPESIM simulations, leading to faulty predictions of pressure drops and operating points.

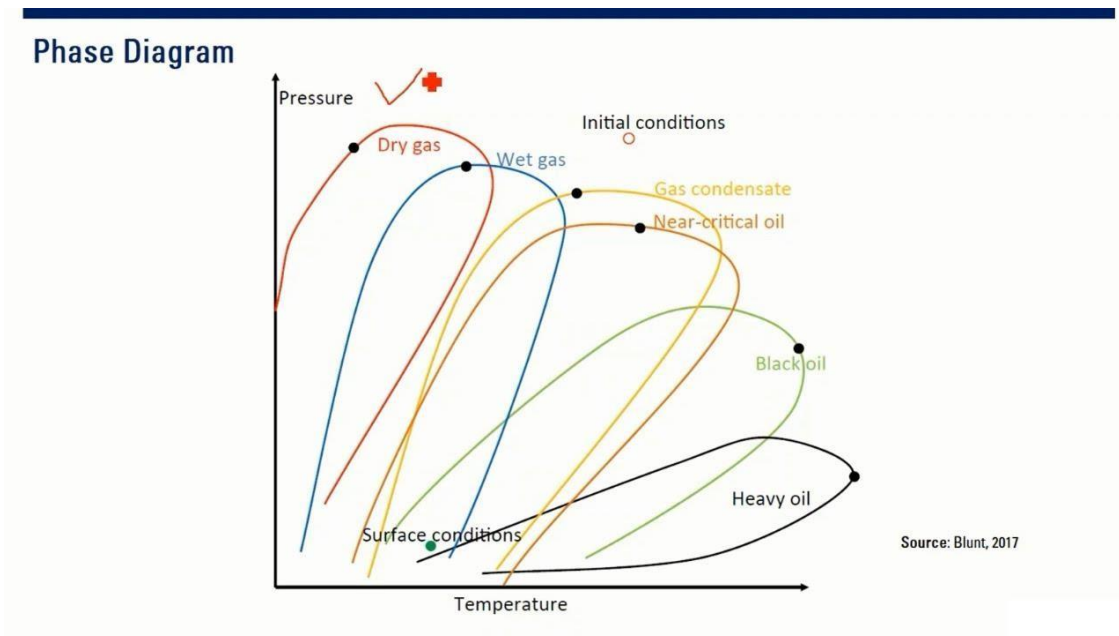
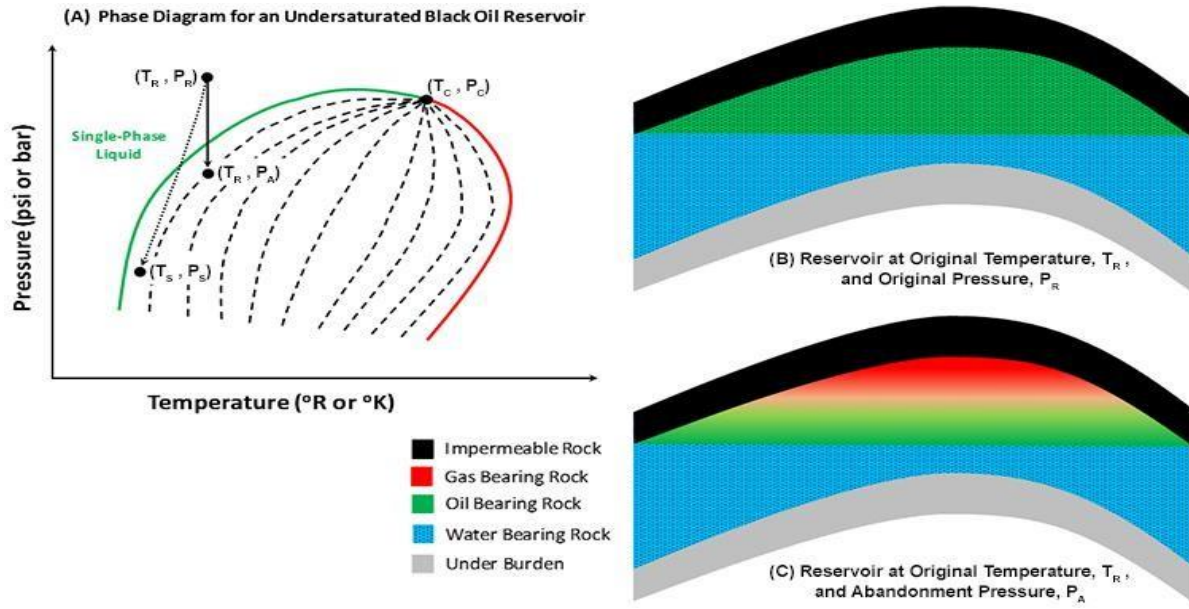


Figure II.1: Typical P-T phase diagram showing envelopes for black oil, volatile oil, gas condensate, wet gas, and dry gas (source: e-education.psu.edu and Whitson wiki).

II.1.2 Phase Envelopes and Critical Properties

The pressure-temperature (P-T) phase envelope defines the boundaries between single-phase and two-phase regions. For undersaturated black oils, as seen initially in Hassi Messaoud, the reservoir conditions lie above the bubble point curve. However, as production continues and reservoir pressure drops, the fluid conditions cross the bubble point line, triggering gas liberation from the oil. Key points on the phase envelope include:

- Bubble point curve: Pressure at which the first gas bubble forms from the oil phase.
- Dew point curve: Pressure at which the first liquid droplet condenses from the gas phase.
- Critical point: Where liquid and vapor phases become indistinguishable (maximum temperature and pressure for two-phase coexistence).

Crossing the bubble point dramatically changes fluid properties: density decreases, viscosity increases (due to loss of light components), and compressibility rises. In Hassi Messaoud Zone 4, the bubble point is approximately 154 kg/cm² at 120°C. Below this pressure, R_s decreases while free gas saturation increases, strongly impacting inflow and outflow performance.

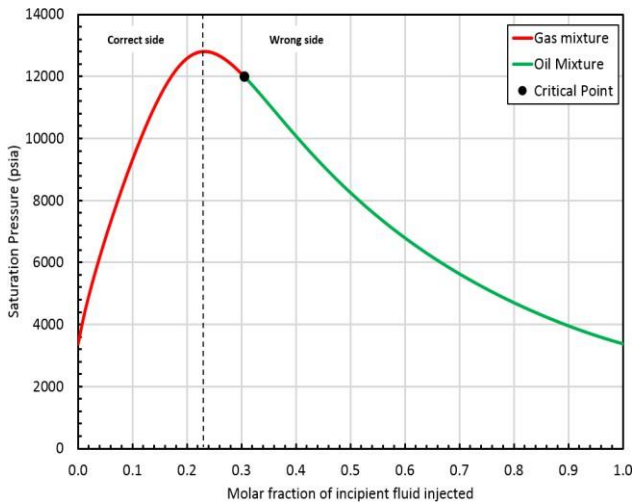


Figure II.2: Saturation pressure versus molar fraction CPA and SRK models with experimental data.

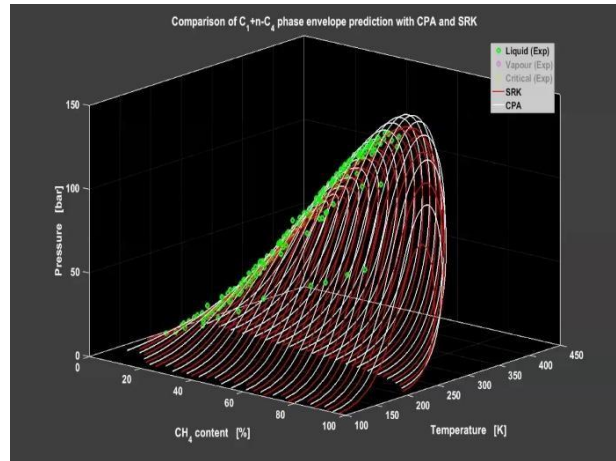


Figure II.3: C₁ + nC₃ phase envelope: Comparison between of injected fluid — Correct vs. Wrong side of the critical point

Chapter II: Wellbore Flow Behavior and Fluid Properties Modeling

The intersection between the IPR and VLP curves represents the operating point of the well, where reservoir inflow equals tubing outflow performance.

The upward displacement of the VLP curve indicates higher pressure losses inside the tubing, while downward displacement reflects improved lifting efficiency and lower flowing bottom-hole pressure requirements.

II.1.3 PVT Properties: Formation Volume Factor (Bo, Bg), Solution Gas-Oil Ratio (Rs), Gas-Oil Ratio (GOR)

Pressure-Volume-Temperature (PVT) properties quantify how fluid volumes change with pressure and temperature and serve as fundamental inputs for well modeling.

- **Oil Formation Volume Factor (Bo):** Ratio of oil volume at reservoir conditions to stock-tank conditions. It reaches a maximum near the bubble point and declines below it due to gas liberation and oil shrinkage. For Hassi Messaoud Zone 4, Bo at bubble point is approximately $1.63 \text{ m}^3/\text{sm}^3$ ($\approx 1.63 \text{ rbbl/STB}$).
- **Solution Gas-Oil Ratio (Rs):** Volume of gas dissolved in oil at given pressure and temperature. Rs remains constant above bubble point and decreases linearly or nonlinearly below it.
- **Gas Formation Volume Factor (Bg):** Essential for calculating free gas volume.
- **Producing GOR:** Total gas produced at surface per unit oil, including both solution and free gas.

These properties are modeled in PIPESIM using laboratory tables (preferred for accuracy) or empirical correlations. Common correlations include Standing, Lasater, Glaso, and Vasquez-Beggs. For Hassi Messaoud fluids, calibration against lab data is necessary because correlations developed for other regions may introduce errors in bubble point and viscosity predictions. [14]

Example of a widely used correlation (Standing):

$$B_o = 0.9759 + 0.00012 \left[R_s \left(\frac{\gamma_g}{\gamma_o} \right)^{0.5} + 1.25T \right]^{1.175}$$

Accurate PVT input is crucial because small errors in Rs or Bo propagate into large discrepancies in predicted production rates and pressure profiles in nodal analysis.

II.2 Key Fluid Properties and Their Definitions

Fluid physical properties directly control pressure gradients, flow regimes, and overall well deliverability.

II.2.1 Density and Specific Gravity

Density is a primary driver of the hydrostatic pressure component. Oil density is often expressed via API gravity: $\gamma_o = \frac{141.5}{131.5 + \text{API}}$ In Hassi Messaoud (45° API), the relatively low density reduces the hydrostatic gradient compared to heavier oils, facilitating natural flow at higher rates. Gas specific gravity (γ_g) is relative to air (typically 0.60–0.80). Mixture density depends on liquid holdup and phase fractions.

II.2.2 Viscosity (Oil, Gas, Water) and Rheological Behavior

Viscosity μ governs frictional pressure drop. Live-oil viscosity decreases sharply with dissolved gas; dead-oil viscosity rises with cooling. Heavy oils or emulsions may exhibit non-Newtonian behavior.

Fluid Properties			
Common Properties	Properties of Water	Properties of Oil	Properties of Gas
• Compressibility • Formation Volume Factor • Density • Specific Gravity • Viscosity • Interfacial Tension	• Salinity • Solution gas-water ratio, • pH	• Solution gas-oil ratio • API gravity • Bubble point pressure	• Critical points • Pseudo pressure • Pseudo temperature • Z factor

Table II.1: Summary of water, oil, and gas properties used in PIPESIM models (source: standard petroleum engineering references).

II.2.3 Surface and Interfacial Tension

Surface tension (gas-liquid) and interfacial tension (oil-water) influence droplet/bubble size, coalescence, liquid holdup, and transition between flow regimes. These properties affect slippage and phase distribution in multiphase flow.

II.2.4 Compressibility and Thermal Expansion

Isothermal compressibility ($c_o = -\frac{1}{V}(\partial V / \partial P)_T$) is low for undersaturated oil but increases significantly below bubble point. Thermal expansion coefficients influence density and viscosity changes along the wellbore temperature gradient, which is important in deep, hot wells such as those in the Sahara (reservoir temperature 120°C in Hassi Messaoud).

II.2.5 PVT Data Matching

The reliability of any nodal analysis study depends heavily on the accuracy of the fluid characterization. Therefore, a significant amount of time was dedicated in this work to properly tuning the PVT model for Well X21.

Using the available field data from Hassi Messaoud field — such as reservoir pressure, separator conditions, production rates, measured GOR, and the limited laboratory PVT reports — the Black Oil model in PIPESIM was carefully adjusted. The matching process mainly targeted the most influential parameters: Solution Gas-Oil Ratio (Rs), Oil Formation Volume Factor (Bo), Bubble Point Pressure (Pb), oil viscosity (μ_o), and the densities of both oil and gas.

Adjustment was performed iteratively by modifying critical properties and applying shift parameters within PIPESIM's PVT matching module until a reasonable match was achieved between simulated and field data. Particular attention was paid to the behavior around the bubble point pressure, as gas liberation in this region causes important changes in viscosity and density, which directly affect hydrostatic pressure losses and multiphase flow in the tubing.

The final tuned model showed acceptable agreement with the well's production history, particularly after the stimulation operations. It provided stable and realistic results throughout the

Chapter II: Wellbore Flow Behavior and Fluid Properties Modeling

sensitivity analysis on fluid properties as well as during the Gas Lift optimization phase.

Although the laboratory PVT data available for this well were relatively limited, the adjusted model proved sufficiently robust and reliable for the purpose of this study. In future work, it is recommended to use more complete laboratory tests such as Differential Liberation and Constant Composition Expansion to further improve the matching and to evaluate the possibility of using a Compositional model.

II.3 Flow Regimes and Pressure Drop

II.3.1 Flow Regimes in Tubing (Bubble, Slug, Churn, Annular, Mist)

Flow regime identification is critical because each regime exhibits different liquid holdup, slippage, and pressure drop behavior. Regimes depend on gas and liquid superficial velocities, fluid properties (density, viscosity), pipe diameter, and inclination:

- **Bubble flow (low gas fraction):** Discrete gas bubbles in continuous liquid phase (low gas rates).
- **Slug flow(intermittent):** Alternating large gas pockets (Taylor bubbles) and liquid slugs (common at moderate GOR).
- **Churn flow(turbulent):** Chaotic, oscillatory transition between slug and annular.
- **Annular flow(high gas velocity):** Gas core with liquid film on the wall (high gas rates).
- **Mist flow(high gas velocity):** Liquid droplets entrained in continuous gas (very high gas velocity).

In vertical Hassi Messaoud wells with moderate GOR ($\approx 185 \text{ sm}^3/\text{sm}^3$), slug and churn regimes predominate at typical production rates. Higher GOR or gas lift shifts the regime toward annular/mist, reducing liquid holdup.

Chapter II: Wellbore Flow Behavior and Fluid Properties Modeling

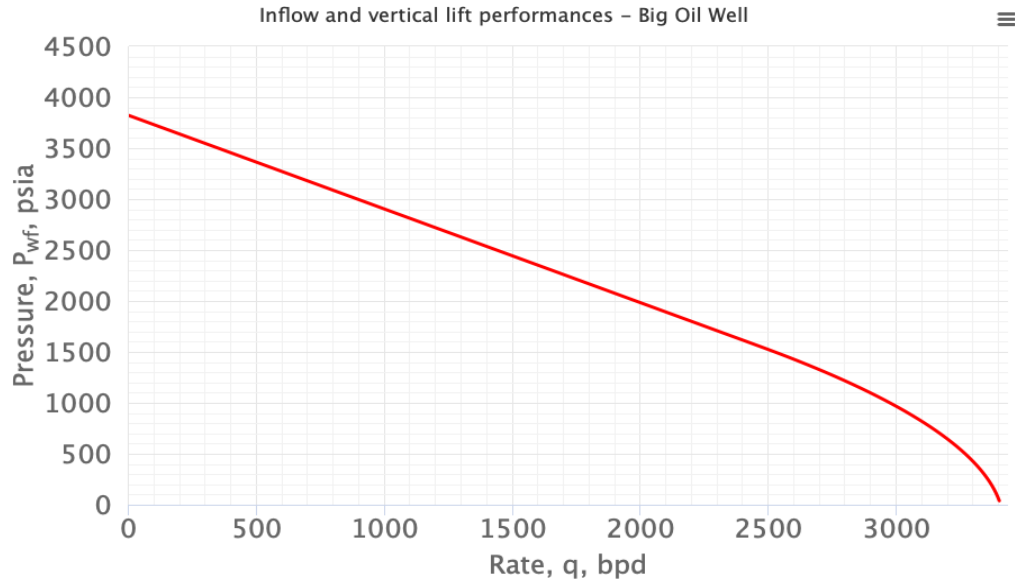


Figure II.4: Typical Inflow Performance Relationship (IPR) curve for a Black Oil well. The curve shows how production rate increases as bottom-hole pressure decreases.

II.3.2 Pressure Drop Components: Hydrostatic, Frictional, and Acceleration

The total pressure drop along the tubing is expressed as: $\frac{dP}{dz_{total}} = \frac{dP}{dz_{hydrostatic}} + \frac{dP}{dz_{frictional}} + \frac{dP}{dz_{acceleration}}$

- **Hydrostatic gradient:** Dominates in vertical wells and is given by $\rho_m g \sin \theta$, where ρ_m is the in-situ mixture density (function of liquid holdup, phase densities, and GOR).
- **Frictional gradient:** Depends on mixture velocity, density, viscosity, and pipe roughness (calculated via Darcy-Weisbach or Fanning friction factor). Viscosity and flow regime strongly influence this term.
- **Acceleration term:** Usually small except at high velocities or restrictions (e.g., chokes).

In Hassi Messaoud depleted wells, hydrostatic losses often constitute 60–80% of total pressure drop, making fluid density and liquid holdup critical.

II.3.3 Effect of Fluid Properties on Flow Regime Transitions

Fluid properties shift regime boundaries:

Chapter II: Wellbore Flow Behavior and Fluid Properties Modeling

- Increasing GOR or decreasing density promotes transition to annular/mist flow (lower holdup, reduced pressure drop).
- Higher viscosity or water cut (emulsions) stabilizes liquid-dominated regimes (bubble/slug), increasing holdup and total pressure drop.
- In mature Hassi Messaoud sectors with rising water cut (up to 60% in some wells), emulsion formation exacerbates liquid loading risks.

Understanding these transitions is essential for selecting appropriate multiphase flow correlations in PIPESIM.

II.4 Inflow Performance Relationship (IPR) Models

The IPR curve represents the reservoir's ability to deliver fluids into the wellbore as a function of bottomhole flowing pressure.

II.4.1 Vogel's IPR for Solution-Gas Drive Reservoirs

Vogel's empirical correlation is widely applied for two-phase flow below the bubble point:

$$q_o = q_{o, \max} \left[1 - 0.2 \left(\frac{p_{wf}}{p_r} \right) - 0.8 \left(\frac{p_{wf}}{p_r} \right)^2 \right]$$

The curve shape depends heavily on bubble point pressure and fluid properties. Below P_b , free gas reduces oil relative permeability, curving the IPR more sharply. [18]

II.4.2 Fetkovich and Other Empirical IPR Correlations

Fetkovich's back-pressure equation is suitable for oil and gas wells:

$$q_o = C(p_r^2 - p_{wf}^2)^n$$

where C and n are determined from well test data. This model accounts for reservoir drive mechanism and turbulence effects. [19]

II.5 Vertical Lift Performance (VLP) and Tubing Performance

VLP (or Tubing Performance Relationship) describes the bottomhole pressure required to lift fluids to the surface for a given production rate.

Chapter II: Wellbore Flow Behavior and Fluid Properties Modeling

II.5.1 Multiphase Flow Correlations (Hagedorn-Brown, Beggs-Brill, OLGAS, etc.)

Several empirical and mechanistic correlations are available:

- **Hagedorn-Brown (1965) [15]:** Developed from vertical well experiments with air and crude oils. It uses a pseudo-holdup concept and performs well for vertical or near-vertical light-oil wells across broad rate ranges. Recommended for Hassi Messaoud-type wells due to its accuracy in slug/churn regimes. Limitations: less reliable for very small or very large tubing diameters and highly deviated wells.
- **Beggs-Brill (1973) [16]:** Handles all inclination angles with explicit flow regime mapping (segregated, intermittent, distributed). Useful when well trajectory includes deviations.
- **Other models:** OLGAS (mechanistic, more physically based), Hasan-Kabir, Gray (gas wells), Duns-Ros.

In PIPESIM, users can select and compare multiple correlations. For Hassi Messaoud vertical producers, Hagedorn-Brown is often the default choice, but validation against field data is recommended.

II.5.2 Role of Fluid Properties in VLP Curves

Fluid properties shift the VLP curve:

- Higher density (lower API) increases hydrostatic gradient, shifting VLP upward (higher required bottomhole pressure).
- Higher GOR provides natural gas lift, shifting VLP downward at higher rates.
- Increased viscosity (due to depletion or emulsions) raises frictional losses, steepening the VLP curve.
- Water cut rise in mature Hassi Messaoud wells often elevates the VLP due to higher mixture density and emulsion viscosity.

Chapter II: Wellbore Flow Behavior and Fluid Properties Modeling

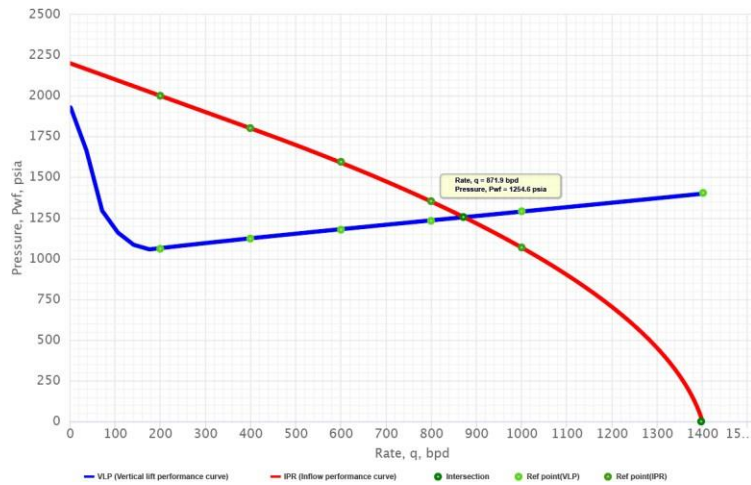


Figure II.5: Example nodal-analysis plot showing IPR and VLP intersection (source: standard petroleum engineering references).

II.6 Nodal Analysis Concept

Nodal analysis is a systems approach that integrates reservoir inflow and wellbore outflow to predict stable operating conditions.

II.6.1 System Analysis: Intersection of IPR and VLP

The well's operating point is the intersection of the IPR and VLP curves. This point gives the stable production rate and flowing bottomhole pressure. Changes in fluid properties (e.g., GOR increase due to depletion or water cut rise) shift both curves, moving the operating point and potentially reducing deliverability or causing liquid loading.

II.6.2 Sensitivity Parameters in Well Performance

Key parameters for sensitivity analysis include fluid density/API gravity, viscosity, solution GOR/bubble point pressure, water cut (and emulsion effects), gas gravity, tubing diameter, and wellhead pressure. In PIPESIM, systematic variation of these parameters generates tornado charts, response surfaces, and families of IPR/VLP curves, helping identify dominant factors affecting well performance in Hassi Messaoud.

II.7 Overview of PIPESIM Simulator

PIPESIM is a steady-state multiphase-flow production-system simulator developed by SLB (formerly Schlumberger). It is one of the most widely adopted tools in the petroleum industry for modelling the complete production chain—from reservoir inflow through the tubing and surface network to the separator. The software integrates rigorous fluid PVT characterization, inflow performance relationship (IPR), vertical lift performance (VLP), and advanced sensitivity/optimization modules, making it ideal for quantifying the effect of fluid properties on well deliverability.

II.7.1 Historical Development and Industry Adoption

Originally introduced in the 1980s, PIPESIM has evolved into a modular, user-friendly platform that supports both black-oil and fully compositional (EOS-based) models. It is routinely used by major operators (including Sonatrach) for well-performance prediction, artificial-lift design, nodal analysis, and production-optimization studies. In the context of Algerian fields such as Hassi Messaoud, PIPESIM has been successfully applied to simulate stimulation effects (acid/frac) and to evaluate how changes in fluid properties (viscosity, GOR, bubble-point pressure) influence stable production rates.

II.7.2 Key Modules Relevant to Fluid Behavior and Well Performance

- **Fluid PVT Module:** Supports black-oil correlations (Standing, Vasquez-Beggs, Glaso), laboratory PVT tables, and equation-of-state (EOS) compositional modelling. Multi-point calibration automatically applies multipliers to match measured bubble-point pressure, solution GOR (R_s), oil formation-volume factor (B_o), density, and viscosity at multiple pressures and temperatures.
- **IPR Module:** Implements Vogel, Fetkovich, and Darcy-based models; incorporates skin, permeability, and reservoir-pressure data from build-up tests.

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- **VLP / Tubing-Hydraulics Module:** Offers a complete library of multiphase-flow correlations (Hagedorn-Brown, Beggs-Brill, OLGA mechanistic, etc.) and calculates pressure-temperature profiles, flow-regime maps, liquid hold-up, and friction factors.
- **Nodal-Analysis and Sensitivity Engine:** Automatically locates the IPR–VLP intersection point and performs parametric sensitivity on fluid properties (density, viscosity, GOR, bubble-point pressure, water cut) while holding reservoir and completion parameters constant.
- **Additional Capabilities:** Gas-lift/ESP design, erosion-velocity limits, liquid-loading prediction, thermal modelling (Joule-Thomson cooling and heat loss), and full surface-network simulation.

II.7.3 Nodal-Analysis Workflow in PIPESIM

The typical workflow used in this thesis is as follows:

1. Import or define fluid PVT data and perform multi-point calibration.
2. Construct the IPR using reservoir parameters (permeability, skin, reservoir pressure) from Saphir build-up interpretation.
3. Build the tubing model with deviation survey, tubing ID/roughness, and selected multiphase correlation.
4. Run nodal analysis to obtain the stable operating point (production rate and flowing bottom-hole pressure).
5. Execute sensitivity cases on fluid properties (e.g., $\pm 20\%$ viscosity, $\pm 15\%$ GOR, $\pm 10\%$ bubble-point pressure) to quantify their impact on VLP curves and deliverability.
6. Generate pressure-depth profiles, flow-regime maps, and optimization tables for gas-lift or tubing-size recommendations.

This workflow ensures that the effect of fluid properties is isolated and rigorously quantified, exactly as required for the present study on Well X21 .

II.7.4 Calibration and Validation Best Practices

Chapter II: Wellbore Flow Behavior and Fluid Properties Modeling

Before any sensitivity run, the fluid model is calibrated against laboratory PVT reports and field pressure surveys. PIPESIM automatically computes calibration multipliers while preserving the shape of the correlation curves. The calibrated model is then validated against measured production data (rate, tubing-head pressure, GOR). In this

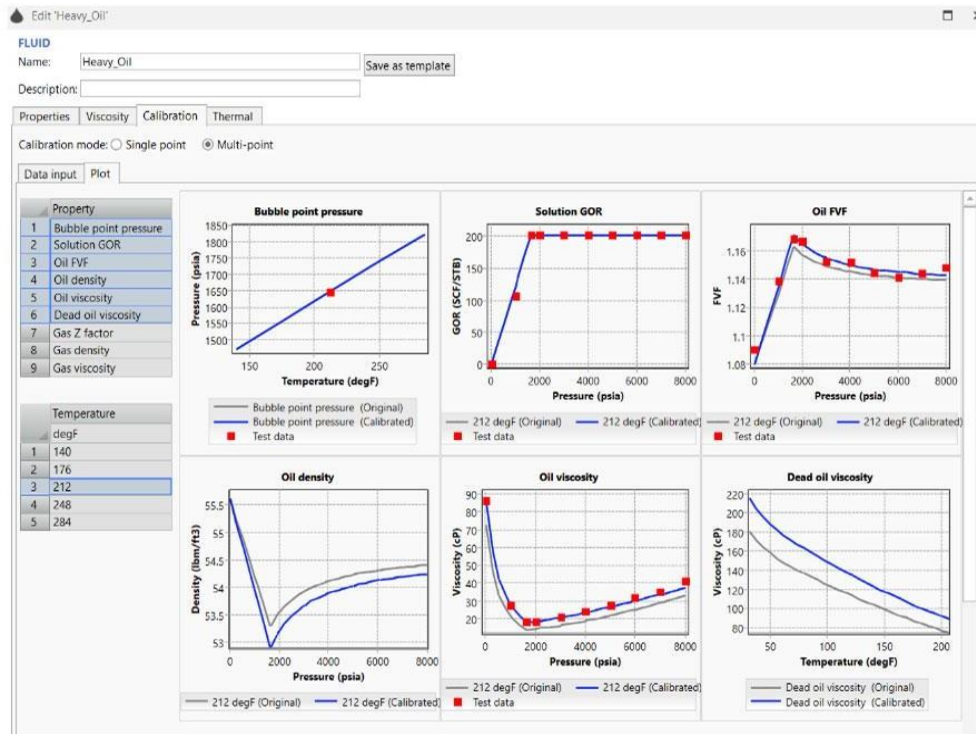


Figure II.6: PIPESIM fluid-editor interface in multi-point calibration mode showing bubble-point pressure, solution GOR, oil FVF, density, and viscosity plots (source: SLB PIPESIM documentation, 2023; analogous workflow applied to Hassi Messaoud light-oil PVT data).

Chapter III: PIPESIM Simulation and Well Performance Analysis – Well X21

Chapter III: PIPESIM Modeling and Performance Evaluation of Well X21 Before and After Stimulation

III.1 Introduction

In the oil and gas industry, well stimulation has always been one of the most effective ways to improve well productivity, especially in mature fields where formation damage is common. Techniques such as matrix acidizing and hydraulic fracturing are routinely used to remove near-wellbore damage or create new high-conductivity paths in the reservoir, allowing hydrocarbons to flow more easily into the wellbore. In the Hassi Messaoud field, many wells have suffered from high skin factor and declining production, making stimulation interventions necessary to restore and even increase output.

To properly evaluate the impact of these stimulation treatments, advanced simulation tools are required. PIPESIM, a widely used steady-state multiphase flow simulator, is an excellent tool for this purpose. It combines Inflow Performance Relationship (IPR) and Vertical Lift Performance (VLP) in a nodal analysis approach, enabling engineers to build realistic well models, match field data, predict well behavior, and test various improvement scenarios.

The main objective of this chapter is to build a calibrated PIPESIM model for Well X21 and to thoroughly analyze its performance before and after the Acid/Frac stimulation campaign. Through this study, the improvement in production rate, skin factor, and productivity index will be quantified and discussed in detail.

This work focuses on vertical oil producer Well X21 located in Zone 23 of the Hassi Messaoud field. The analysis covers well and reservoir description, identification of pre-stimulation problems, model construction and calibration using real field data (DST and Build-Up tests), simulation of stimulation effects, comparison between actual and simulated results, and finally recommendations for further optimization, particularly regarding artificial lift.

III.2 Description of Well X21 and Reservoir Characteristics

III.2.1 Location and Geological Setting of Well X21

The vertical well X21 was drilled as part of the development program of the Hassi Messaoud field. It is located in the northeastern part of Zone 23, southwest of well X22, and targets the Cambrian reservoirs (Ra-R2). The main objective of this well was to investigate the northern

Chapter III: PIPESIM Modeling and Performance Evaluation of Well X21 Before and After Stimulation

extension of the structure previously explored by well X29, where eruptive and intrusive rocks with a thickness of about 248 m were encountered.

According to the interpretation of the 3D seismic data during the development phase, X21 is positioned on the flank of a relatively elevated structural zone. However, at the top of the R2 reservoir, it appears to be situated on the same structural level as well X22. The area around the well is well covered by nearby wells, which made geological correlation more reliable, especially with wells X16, X22, and X20.

From a structural point of view, the well lies within a compartment limited by two major NE-SW oriented faults. In addition, there is a strong possibility of volcanic rocks being present above the Hercynian Unconformity. [21]

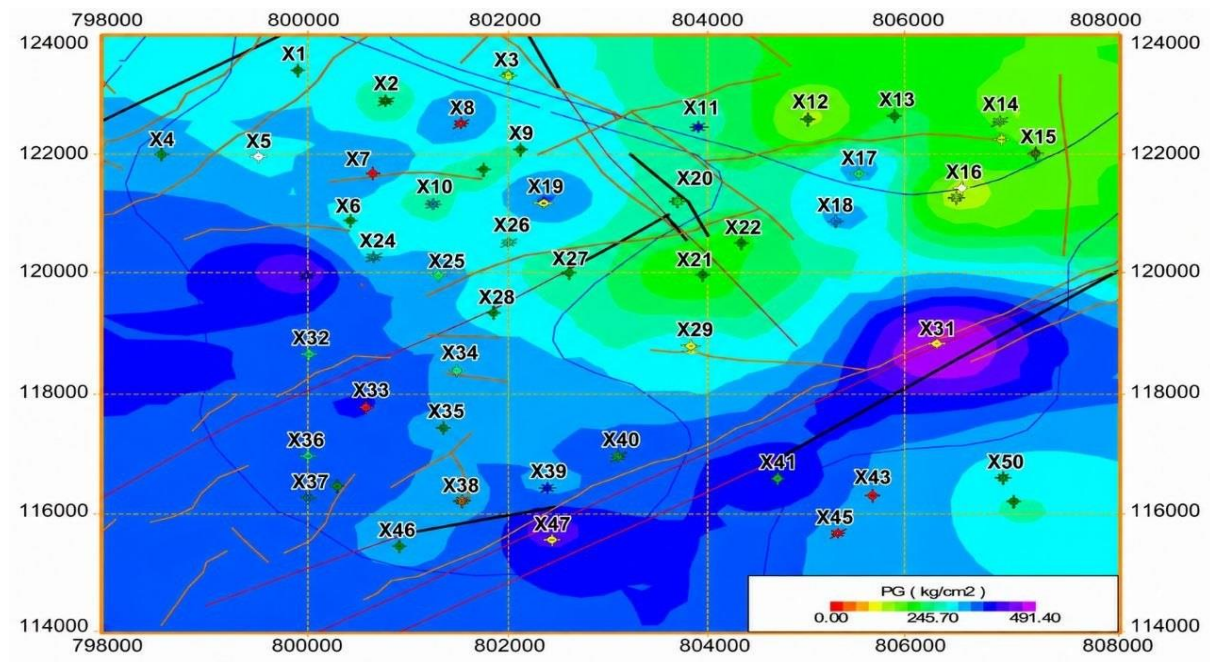


Figure III.1 : Location of Well X21 in Zone 23 [21]

Figure III.2 shows the cross-sectional view of Well X21, giving an overall idea of the well completion and the subsurface configuration. It provides a simplified representation of the production tubing, casing strings, packer placement, and the reservoir interval that is being produced.

The well is completed with a 4½-inch anchored tubing that extends down to the packer depth at around 3317 m. This configuration was chosen to ensure stable production conditions and to allow an efficient flow of fluids from the reservoir to the surface. The packer is set just

Chapter III: PIPESIM Modeling and Performance Evaluation of Well X21 Before and After Stimulation

above the top of the liner to isolate the production zone and maintain proper pressure control inside the wellbore.

The figure also highlights the producing interval, which corresponds to the Cambrian Ra reservoir. This reservoir represents the main hydrocarbon-bearing formation targeted by Well X21. It is generally characterized by low porosity and relatively complex geological conditions, including the presence of faults and volcanic influences in the area.

From an operational perspective, this cross-sectional view helps in understanding the path taken by the fluids from the reservoir toward the surface during production. It also shows how the completion design plays an important role in controlling flow behavior, pressure losses, and overall production stability.

In addition, it helps to better visualize the different well interventions carried out on this well, such as acidizing, hydraulic fracturing, and nitrogen lift, which were all aimed at improving the connectivity between the reservoir and the wellbore and enhancing fluid flow.

Overall, the cross-section confirms that Well X21 is a vertical production well completed in the Cambrian reservoir, designed in a way that allows stimulation operations and future artificial lift solutions such as Gas Lift when needed.

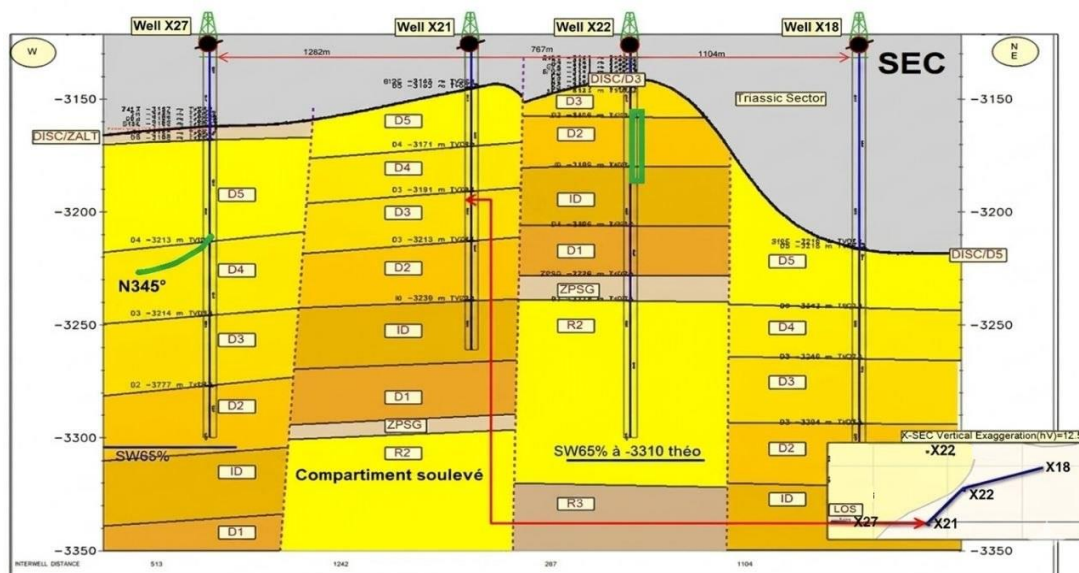


Figure III.2 Crosse Section X21. [21]

Chapter III: PIPESIM Modeling and Performance Evaluation of Well X21 Before and After Stimulation

III.2.2 Wellbore and Completion Data

Well X21 is a vertical oil producer completed with 4½" anchored tubing. The packer is set at the top of the liner at 3317 m, specifically 0.5 m above the liner top. The well is located in Zone 23 of the Hassi Messaoud field, an area known for salt deposits. Its surface coordinates are $X = 803,761.86$ m and $Y = 119,934.65$ m, with a table elevation of 184 m and ground elevation of 174.93 m.

The completion design is relatively standard for vertical wells in this field, using anchored tubing to ensure stability during production. This configuration was taken into consideration during the PIPESIM model construction.

Table III.1 : Well Data [21]

Well Name	X21
Well Type	Vertical oil producer
Tubing	4"1/2 anchored
Packer	Top Liner 3317 m

III.2.3 Reservoir Properties

Well X21 targets the Anisometric Cambrian Ra reservoir. The reservoir is characterized by relatively low porosity, typical of the Cambrian formations in the Hassi Messaoud field. Key reservoir parameters are as follows:

The reservoir temperature is 118 °C, which indicates a high-temperature environment that influences fluid properties and completion material selection. The average porosity is 4.9%, and the tested interval height is 105 m. Initial reservoir pressure was recorded at 219 kg/cm², while the bubble point pressure is 159 kg/cm². Since the well is producing below the bubble point pressure, two-phase flow (oil and gas) is expected in the reservoir.

These parameters were directly used as input data for building the Black Oil model in PIPESIM.

Chapter III: PIPESIM Modeling and Performance Evaluation of Well X21 Before and After Stimulation

Table III.2: Reservoir Data [21]

Reservoir	Anisometric Cambrian Ra
Temperature	118 °C
Average Porosity	4.9 %
Height (Tested Interval)	105 m
Reservoir Pressure (Pg)	219 Kg / cm ²
Bubble Point Pressure (Pbulle)	159 Kg / cm ²

III.2.4 Production History

The production history of Well X21 provides an overall understanding of the well behavior before and after the stimulation operations. By analyzing the evolution of production rate, pressure behavior, Productivity Index (PI), Skin factor, and Gas-Oil Ratio (GOR), it becomes possible to evaluate the effectiveness of the Acid/Frac treatment and identify the main factors controlling the well performance over time.

The following figures summarize the different production phases of Well X21 and illustrate the impact of stimulation and nitrogen lift operations on reservoir deliverability and production stability.

Figure III.3 illustrates the evolution of the oil production rate and wellhead pressure during the period between 2013 and 2014. Before the stimulation treatment, the well produced at a relatively low oil rate, ranging between 2.7 and 3.0 m³/h, while the wellhead pressure varied from 17 to 22 kg/cm². These results indicate weak reservoir performance, mainly due to formation damage around the wellbore and significant pressure losses that limited fluid flow toward the well.

Following the Acid/Frac treatment combined with nitrogen lift, a clear improvement in well performance was observed. The oil production rate increased considerably, reaching about 4.82 m³/h, whereas the wellhead pressure rose to nearly 48.6 kg/cm². This positive change suggests that the stimulation operation effectively improved the connection between the reservoir and the wellbore by reducing near-wellbore damage and enhancing permeability in the treated zone.

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In addition, the higher wellhead pressure reflects better flowing conditions inside the production tubing and a more stable production behavior. Overall, the figure highlights the significant positive effect of the stimulation operation on the productivity and performance of Well X21.

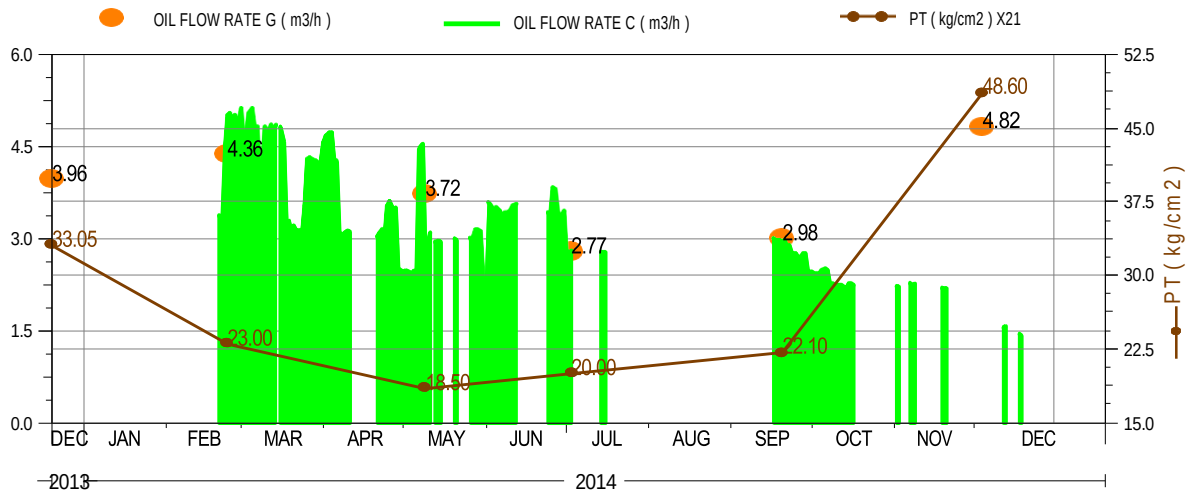


Figure III.3 : PRODUCTION HISTORY [21]

Figure III.4 presents the variation of the Productivity Index (PI) and Skin factor during the different production stages of Well X21. Before the stimulation treatment, the skin factor was highly positive, with a value of about +4.22, which indicates important formation damage near the wellbore. This damage created additional pressure losses and reduced the ability of reservoir fluids to flow easily toward the well. Consequently, the Productivity Index was very low, around 0.041, showing weak well performance and limited productivity.

After the acidizing operation, the skin factor decreased gradually to nearly +2. This reduction suggests that part of the formation damage was removed, allowing better communication between the reservoir and the wellbore. As a result, the oil production rate increased slightly and reached approximately 2.98 m³/h.

A more significant improvement was observed after the hydraulic fracturing and nitrogen lift operations. The skin factor became negative and reached about -3.93, which reflects very favorable flow conditions around the wellbore after stimulation. At the same time, the Productivity Index increased considerably from 0.041 to 0.167, confirming a strong enhancement in reservoir inflow capacity and overall well productivity.

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Overall, the figure clearly shows that the reduction of the skin factor had a direct impact on improving the production performance of Well X21 and increasing its oil productivity.

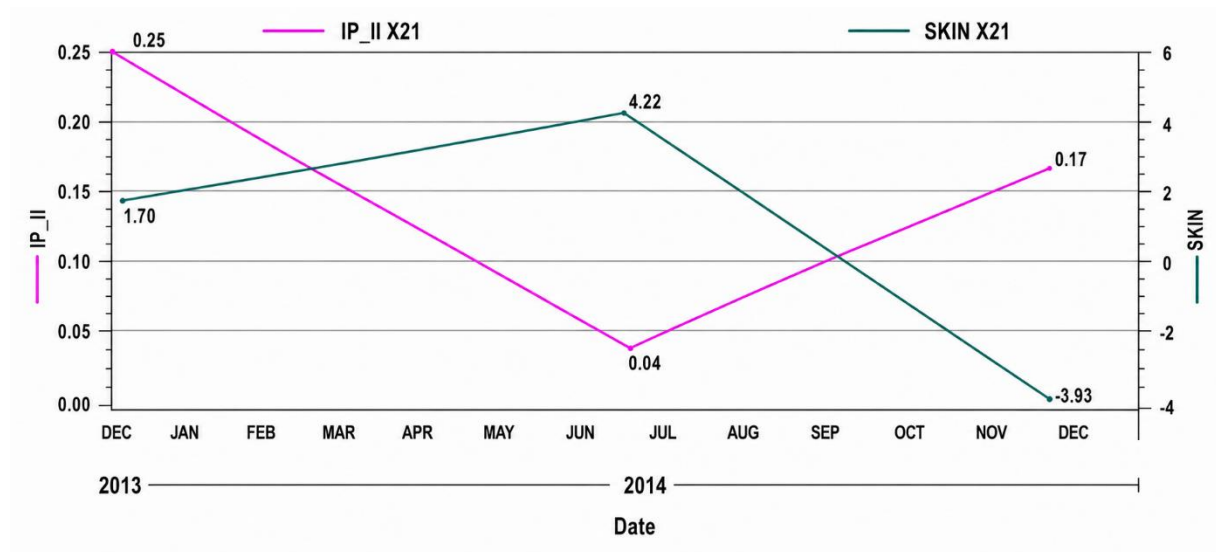


Figure III.4 : Production Index (IP) and Skin History of Well X21 [21]

Figure III.5 shows the variation of reservoir pressure (PG), flowing bottom-hole pressure (PWF), and Gas-Oil Ratio (GOR) during the production period of Well X21. During production, the reservoir pressure gradually decreased from about 219 kg/cm² to nearly 188 kg/cm² as a result of normal reservoir depletion.

Before the stimulation treatment, the flowing bottom-hole pressure was relatively low, around 143 kg/cm², which reflected difficult flowing conditions and weak production performance. After the Acid/Frac treatment and nitrogen lift operations, the flowing bottom-hole pressure increased to nearly 155 kg/cm². This improvement helped stabilize the well and allowed higher production rates to be maintained.

In addition, the Gas-Oil Ratio increased considerably after the stimulation operations, rising from nearly 271 scm/m³ to more than 1520 scm/m³. The increase in gas production reduced the density of the fluid column inside the tubing, which improved lifting conditions and decreased hydrostatic pressure losses. As a result, the well production rate increased significantly and reached approximately 4.82 m³/h.

Despite this improvement, the reservoir pressure continued to decline over time, while the Water Cut increased progressively during production. These conditions gradually made the

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fluid column heavier inside the tubing, leading to unstable flow behavior and eventually causing the well to stop natural production after the nitrogen lift operation ended.

Overall, the production history confirms that the Acid/Frac treatment combined with nitrogen lift had a positive effect on the performance of Well X21. At the same time, the results highlight the need for a permanent Gas Lift system to ensure stable and sustainable production in the long term.

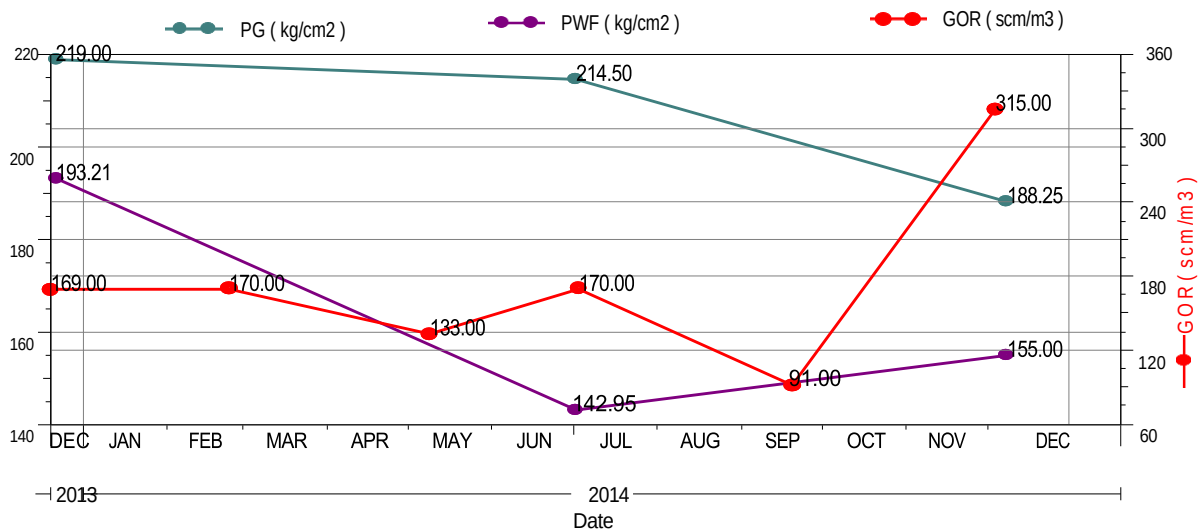


Figure III.5 : Reservoir Pressure (PG), Bottom Hole Pressure (PWF) and GOR History of Well X21 [21]

III.2.5 Operational History and Existing Production Problems

During its production life, Well X21 underwent several operational interventions such as acidizing, hydraulic fracturing, nitrogen lift, clean-out operations, pressure surveys, and tubing modifications. These operations were mainly conducted to improve the well productivity and restore stable production after the gradual decline in its performance.

Although the stimulation operations gave positive results and temporarily improved production, the well continued to face several technical and production problems that affected its long-term stability and natural flowing capacity.

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• Formation Damage

One of the major problems identified in Well X21 was the presence of near-wellbore formation damage before stimulation. The Build-Up test carried out on 02/07/2014 showed weak reservoir communication and poor inflow performance. This damage created additional resistance to fluid flow near the wellbore, which reduced the ability of the reservoir fluids to reach the well efficiently and limited oil production.

To overcome this problem, acidizing and hydraulic fracturing operations were performed in order to reduce formation damage and improve permeability around the wellbore area.

• High Skin Factor

Before stimulation, the well showed a high positive skin factor of about +4.22, which indicates significant pressure losses around the wellbore. Under these conditions, the Productivity Index remained low ($PI \approx 0.041$), while the oil production rate did not exceed nearly 2.78 m³/h.

After the Acid/Frac treatment, the skin factor decreased progressively and later became negative ($S = -3.93$) following the fracturing and nitrogen lift operations. This improvement confirms that the stimulation treatment was effective in enhancing reservoir inflow performance and increasing well productivity.

• Reservoir Pressure Decline

Another important issue observed during production was the continuous decline in reservoir pressure. Over time, the reservoir pressure dropped from approximately 219 kg/cm² to nearly 188 kg/cm² because of reservoir depletion.

This pressure reduction gradually weakened the natural energy of the reservoir, making it more difficult for the produced fluids to flow naturally to the surface. As production continued, the well became increasingly dependent on artificial lift assistance to maintain acceptable production conditions.

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• Water Cut and Gas-Liquid Flow Constraints

The increase in Water Cut represented one of the most serious production challenges for Well X21. As water production increased, the fluid column inside the tubing became heavier, leading to higher hydrostatic pressure losses.

The sensitivity analysis indicated that when the Water Cut exceeded nearly 35%, the well could no longer sustain stable natural flow. After the nitrogen lift operation was stopped, the well eventually became non-eruptive because the reservoir pressure was no longer sufficient to lift the heavy fluid column inside the tubing.

In addition, the multiphase gas-liquid flow inside the tubing created further production constraints. Moderate Gas-Oil Ratio values helped reduce fluid density and improve lifting conditions. However, very high gas rates generated additional friction losses and unstable flow behavior inside the tubing.

Overall, these production difficulties show that although the stimulation operations significantly improved the productivity of Well X21, maintaining long-term and stable production still requires an efficient artificial lift system, especially Gas Lift, to compensate for reservoir pressure decline and increasing Water Cut.

III.2.6 Neighboring Oil Producer Wells :

Table III.3 presents the neighboring oil-producing wells surrounding Well X21 in Zone 23 of the Hassi Messaoud field. The table summarizes the distance and relative direction of each nearby well with respect to Well X21.

According to the available data, Well X22 is the closest neighboring producer, located approximately 767 m northeast of X21. Wells X27 and X20 are situated at distances of nearly 1262 m to the west and 1319 m to the north, respectively. The relatively short distances between these wells indicate that the area surrounding Well X21 is well developed and densely covered by production wells.

The presence of nearby producing wells is important for reservoir evaluation and geological correlation. These wells provide useful information regarding reservoir continuity, pressure behavior, and structural interpretation. They also help improve the understanding of fluid movement and reservoir depletion within the studied zone.

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From a production point of view, the surrounding wells may influence the pressure support and long-term behavior of Well X21 due to cumulative reservoir production effects. Therefore, the production decline observed in Well X21 may partially be associated with the depletion of the shared reservoir compartment.

Overall, the neighboring wells presented in Table III.3 confirm that Well X21 is located in an active production area with good geological and reservoir control, which increases the reliability of reservoir interpretation and production analysis.

Tableau III.3 :Neighboring Oil Producer Wells. [21]

Wells	Zone	Distance(m)	Direction
X20	23	1319	North
X27	23	1262	West
X22	23	767	Northeast

III.2.7 History of Operations

Table III.4 summarizes the main operations carried out on Well X21 throughout its production life. These interventions were mainly performed to enhance well productivity and maintain more stable production conditions over time.

The well history includes several types of operations such as clean-out jobs, acidizing treatments, hydraulic fracturing, nitrogen lift support, pressure surveys, and tubing installation activities. In particular, the acidizing and fracturing operations performed in 2014 were aimed at reducing near-wellbore damage and improving the communication between the reservoir and the wellbore.

Following the stimulation campaign, pressure measurements and Build-Up tests were conducted in order to assess the improvement in well performance and to better understand the reservoir behavior after treatment. Nitrogen lift was also used to assist the flow and help maintain production when natural energy became insufficient.

In addition, a 2 $\frac{7}{8}$ -inch tubing was installed as a temporary solution to improve flow conditions and stabilize production before implementing a permanent Gas Lift system.

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Overall, the operational history clearly shows that Well X21 required multiple interventions to overcome production challenges and sustain its performance over time.

Table III.4: History of operations carried out on well X21. [21]

Start Date	End Date	Operations	Sub-operations
11/01/2015	07/02/2015	SNUBBING	Running 2" 7/8 tubing
08/12/2014	08/12/2014	WIRELIN	SBU pressure measurement
03/12/2014	03/12/2014	WIRELIN	SBU pressure measurement
20/10/2014	20/10/2014	SPECIAL OPERATION	Post-frac clean out
18/10/2014	18/10/2014	SPECIAL OPERATION	Fracturing
17/10/2014	17/10/2014	SPECIAL OPERATION	Shadow frac
17/09/2014	17/09/2014	SPECIAL OPERATION	Kick-off
16/09/2014	16/09/2014	SPECIAL OPERATION	Matrix acidizing – 2nd day
13/07/2014	13/07/2014	WIRELIN	LBU pressure measurement
02/07/2014	02/07/2014	WIRELIN	LBU pressure measurement
30/06/2014	30/06/2014	WIRELIN	Scraping control
22/04/2014	22/04/2014	SPECIAL OPERATION	SPECIAL OPERATION
22/04/2014	22/04/2014	SPECIAL OPERATION	Acid treatment – 2nd phase
21/04/2014	21/04/2014	SPECIAL OPERATION	Acid treatment – 1st phase
17/03/2014	17/03/2014	SPECIAL OPERATION	Clean out
21/02/2014	21/02/2014	SPECIAL OPERATION	Well put on production

III.2.8 Present Condition of Well X21

Table III.5 summarizes the main production and operating data recorded for Well X21 during several gauging tests carried out between 2013 and 2014. The table includes key parameters such as oil production rate, gas production rate, Gas-Oil Ratio (GOR), wellhead pressure, separator pressure, choke size, and oil temperature.

The recorded results clearly show a noticeable change in the production behavior of the well after the stimulation operations. Before treatment, the well was operating under relatively limited conditions, with low to moderate production rates and lower wellhead pressures. After the Acid/Frac treatment combined with nitrogen lift, the oil production rate increased significantly and reached about 4.82 m³/h, while the GOR also increased to nearly 315 scm/m³.

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An important increase in wellhead pressure is also observed after stimulation, reaching approximately 48.6 kg/cm². This reflects improved lifting conditions and better overall well performance. At the same time, the data show some variations in GOR and production stability, which is expected given the complex multiphase flow behavior inside the tubing system.

Overall, the data presented in Table III.5 confirm the positive impact of the stimulation operations on Well X21, while also highlighting the influence of reservoir pressure decline and fluid flow behavior on the long-term stability of production.

Table III.5: Present Condition of Well X21. [21]

Measurement Date	Choke Diameter (mm)	Oil Rate (m ³ /h)	Gas Rate	GOR	Pressure (kg/cm ²)		Separator Pressure	Oil Temp. (°C)	K Psi
					Wellhead	Flowline			
20/12/2013	9.53	3.96	667.69	169	33.05	10	4.18	14	0.483
24/02/2014	12.7	4.36	739.62	170	23	15.2	4.28	25	0.512
09/05/2014	12.7	3.72	495.78	133	18.5	15.4	15.81	25	0.4376
03/07/2014	11	2.77	470.27	170	20	14.6	5	28	0.5416
20/09/2014	11	2.98	271.02	91	22.1	16.5	3.87	23	0.5561
04/12/2014	11	4.82	1520.06	315	48.6	10.1	2.86	21	0.7549

III.2.9 Tests Performed on Well X21

Table III.6 presents the main well tests performed on Well X21 before and after the stimulation campaign. The table highlights key parameters such as reservoir pressure, flowing bottom-hole pressure, Productivity Index (PI), and skin factor, which are used to evaluate well performance and inflow conditions.

Before stimulation, the Build-Up test carried out on 02/07/2014 indicated poor well performance. The results showed a high positive skin factor of about +4.22, which reflects significant near-wellbore damage and additional pressure losses around the wellbore. At the

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same time, the Productivity Index was very low, around 0.041, confirming that the well had limited ability to produce fluids efficiently under these conditions.

After the Acid/Frac treatment combined with nitrogen lift, a clear improvement in well behavior was observed. The Build-Up test performed on 08/12/2014 showed that the skin factor dropped to a negative value of approximately -3.93 , indicating improved flow conditions and enhanced connectivity between the reservoir and the wellbore. In parallel, the Productivity Index increased to about 0.167, which confirms a significant improvement in inflow performance and overall well productivity.

Overall, the test results clearly demonstrate the positive impact of the stimulation operations on Well X21 and highlight the improvement in reservoir communication and production capacity.

Table III.6: Tests Performed on the Well. [21]

Test Type	Date	Reservoir Pressure (kg/cm ²)	Dynamic Bottomhole Pressure (kg/cm ²)	Wellhead Pressure (kg/cm ²)	Fluid Type	Production Index	Injectivity Index	H K	Skin	Choke Size	Remarks
DST	22/12/2013	219	193.21	33.05	Oil	3.97	0.25	1260	1.7	9.53	PFD at 3047.22 m, damaged formation with Skin = 0.75
BUILD UP	02/07/2014	214.5	142.95	17.72	Oil	2.78	0.041	79.4	4.22	11	The well test model was complicated by wellbore storage, which masked the first radial flow

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Test Type	Date	Reservoir Pressure (kg/cm ²)	Dynamic Bottomhole Pressure (kg/cm ²)	Wellhead Pressure (kg/cm ²)	Fluid Type	Production Index	Injectivity Index	H K	Skin	Choke Size	Remarks
											obtained during the DST
BUILD UP	08/12/2014	188.25	155	48.6	Oil	4.82	0.167	85.5	-3.93	11	PFD at 3126.65 m with nitrogen lifting

Test Before Stimulation (Acidizing/Fracturing): A Build-Up Test

A Build-Up test was conducted on Well X21 before the stimulation operations in order to evaluate the reservoir behavior and identify the main factors limiting the well productivity. The recorded pressure variation (ΔP) and pressure derivative ($\Delta P'$) versus time were plotted on a log-log scale, as shown in Figure III.6.

The Build-Up interpretation revealed that the well was strongly affected by near-wellbore damage before stimulation. During the test, the reservoir pressure (P_g) was approximately 214.5 kg/cm², while the flowing bottom-hole pressure (P_{wf}) reached nearly 142.95 kg/cm².

The well was producing at a relatively low oil rate of about 2.78 m³/h with a very low Productivity Index ($PI \approx 0.041$), indicating weak reservoir deliverability and poor inflow performance.

The analysis also showed a high positive skin factor of approximately +4.22, which reflects significant additional pressure losses around the wellbore caused by formation damage and restricted fluid flow near the production zone.

In addition, the pressure derivative curve showed the presence of wellbore storage effects during the early production period, which partially masked the radial flow regime. This behavior confirms unstable pressure response and poor communication between the reservoir and the wellbore before stimulation.

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Overall, the Build-Up test clearly demonstrated that the production performance of Well X21 before stimulation was limited by severe near-wellbore damage and low reservoir inflow efficiency. These results justified the need for acidizing and hydraulic fracturing operations in order to reduce the skin factor and improve well productivity.

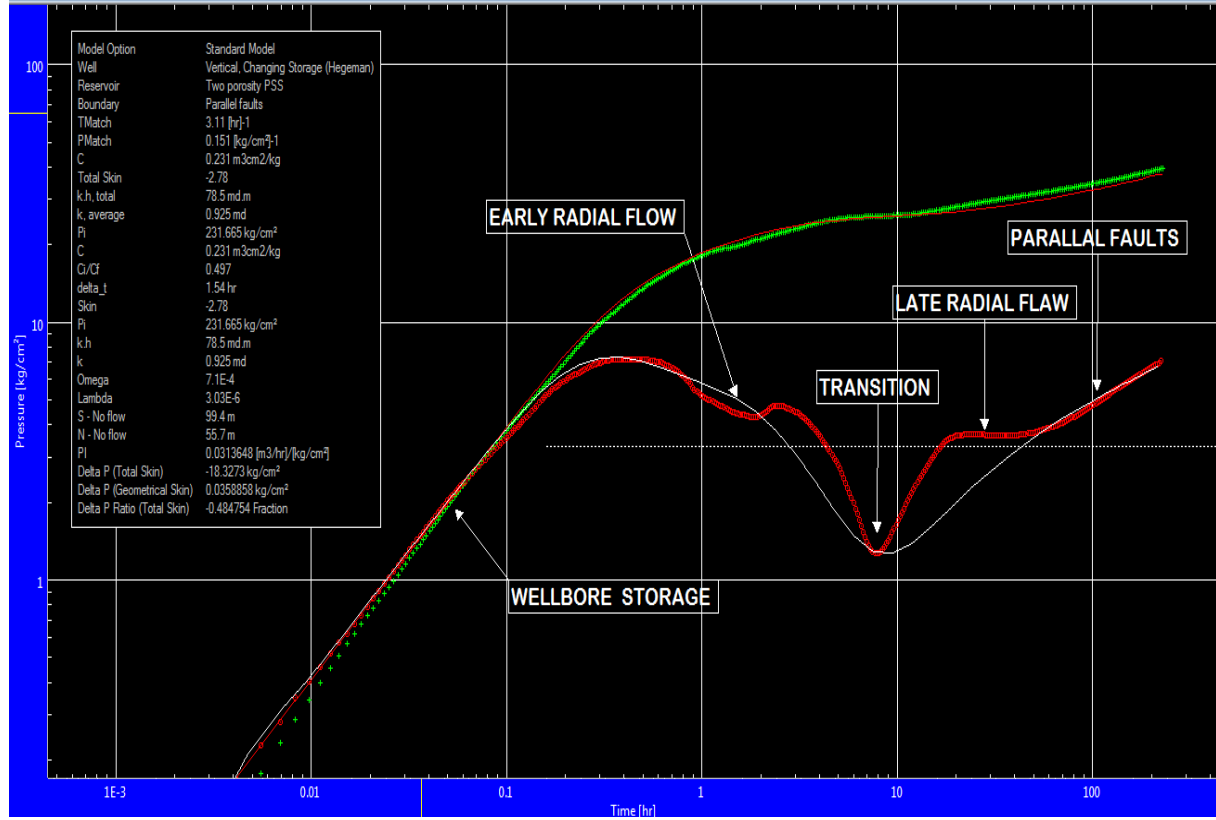


Figure III.6: Pressure Variation (ΔP) and Pressure Derivative ($\Delta P'$) Before the Acidizing Operation as a Function of Time (Δt). [21]

III.3 Pre-Stimulation Well Performance Analysis

Before the stimulation operations, a detailed evaluation of Well X21 was carried out in order to analyze its initial production behavior and identify the main factors limiting its productivity. This evaluation was based on production data, Build-Up test interpretation, and nodal analysis using IPR and VLP curves.

III.3.1 Current Production Status of the Well

Before stimulation, Well X21 was producing under relatively poor operating conditions. The oil production rate ranged between approximately 2.7 and 3.0 m³/h, while the reservoir pressure remained relatively high, varying between nearly 214 and 219 kg/cm². Despite the available reservoir energy, the well showed weak production performance due to important pressure losses and poor inflow conditions.

The flowing bottom-hole pressure (P_{wf}) was approximately 142–143 kg/cm², indicating significant pressure losses between the reservoir and the wellbore. These conditions limited the production efficiency of the well and reduced its ability to maintain stable natural flow.

Figure III.3 illustrates the production history of Well X21 before and after the stimulation operations. The figure clearly shows the low production performance before stimulation and the improvement obtained after the Acid/Frac treatment.

III.3.2 Identification of Performance Limitations

• Productivity Decline

The production data showed that the productivity of Well X21 progressively declined before stimulation. Although the reservoir pressure remained acceptable, the oil production rate stayed relatively low, confirming poor reservoir deliverability and unstable production behavior.

• Near-Wellbore Damage

The Build-Up test interpretation revealed severe near-wellbore damage before stimulation. The calculated skin factor reached approximately +4.22, indicating important additional

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pressure losses around the production interval. This damage considerably restricted fluid flow from the reservoir toward the wellbore.

• Flow Restrictions

The production system was also affected by significant flow restrictions inside the tubing. Hydrostatic and frictional pressure losses reduced the efficiency of fluid transport toward the surface, leading to poor lifting conditions and unstable flow behavior.

Table III.7: Main Performance Limitations Before Stimulation

Parameter	Value	Interpretation
Oil Production Rate (Qo)	2.7 – 3.0 m ³ /h	Low production performance before stimulation
Reservoir Pressure (Pg)	214 – 219 kg/cm ²	Reservoir pressure still relatively acceptable
Flowing Bottom-Hole Pressure (Pwf)	142 – 143 kg/cm ²	Important pressure losses between reservoir and wellbore
Productivity Index (PI)	≈ 0.041	Weak reservoir inflow performance
Skin Factor (S)	≈ +4.22	Severe near-wellbore formation damage
Flow Conditions	Unstable	Presence of hydrostatic and frictional flow restrictions
Well Status	Naturally flowing with difficulty	Artificial lift likely required for long-term production

III.3.3 Nodal Analysis Before Stimulation

• IPR Analysis

Before stimulation, the IPR curve showed weak reservoir deliverability and a relatively flat behavior. The reservoir pressure was about **214.5 kg/cm²**, while the oil production rate was limited to around **2.78 m³/h**.

This poor inflow performance is mainly due to the high positive skin factor ($S \approx +4.22$), which caused additional pressure losses near the wellbore. As a result, the Productivity Index remained very low ($PI \approx 0.041$), confirming limited reservoir–well communication.

• VLP Analysis

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The VLP curve was located at higher pressure levels because of hydrostatic and frictional losses inside the tubing. The flowing bottom-hole pressure was approximately **142.95 kg/cm²**, indicating difficult lifting conditions.

• Operating Point

The intersection of the IPR and VLP curves gave a low operating point of about **2.78 m³/h**. This reflects the combined effect of poor inflow performance and high lift losses.

Overall, the nodal analysis shows that the main limitation before stimulation was near-wellbore damage rather than reservoir pressure.

Table III.8: Nodal Analysis Results Before Stimulation

Parameter	Value	Interpretation
Reservoir Pressure (Pg)	≈ 214.5 kg/cm ²	Reservoir pressure remained relatively acceptable before stimulation
Flowing Bottom-Hole Pressure (Pwf)	≈ 142.95 kg/cm ²	Significant pressure losses between reservoir and wellbore
Oil Production Rate (Qo)	≈ 2.78 m ³ /h	Low production performance before stimulation
Productivity Index (PI)	≈ 0.041	Weak reservoir inflow performance
Skin Factor (S)	≈ +4.22	Severe near-wellbore formation damage
IPR Behavior	Flat curve	Low reservoir deliverability
VLP Behavior	High pressure levels	Important hydrostatic and frictional pressure losses
Operating Point	Low production region	Unstable and limited production conditions

Table III.9 summarizes the main Build-Up test data recorded on Well X21 before the stimulation operations on 02/07/2014. It highlights the key reservoir and production parameters used to evaluate the initial condition of the well prior to acidizing and hydraulic fracturing.

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The results show a reservoir pressure (P_g) of about **214.5 kg/cm²**, while the flowing bottom-hole pressure (P_{wf}) was around **142.95 kg/cm²**. Under these conditions, the well was producing at a relatively low rate of approximately **2.78 m³/h**.

The interpretation of the test also indicates a very low Productivity Index ($PI \approx 0.041$), which confirms weak inflow performance and limited well deliverability. In addition, the skin factor was high and positive, reaching about **+4.22**, clearly showing the presence of significant near-wellbore damage and additional pressure losses around the production zone.

Overall, the results in Table III.9 confirm that Well X21 was in a poor production state before stimulation, mainly due to formation damage and restricted flow conditions, which justified the need for acidizing and hydraulic fracturing operations.

Table III.9: Build-Up Data Before Stimulation (02/07/2014). [1]

Test	Date	P_g	P_{wf}	P_t	Flow rate	I	Skin
BUILD UP	02/07/2014	214.5	142.95	17.72	2.78	0.041	4.22

III.4 PIPESIM Model Development and Calibration

In this section, I will describe how the well model for X21 was developed and calibrated using PIPESIM software. The main objective was to build a realistic numerical representation of the well that reflects its actual behavior in the field as closely as possible. This step is important because a good model allows us to understand how the well is really performing and to predict its response under different operating conditions without needing to test everything directly in the field.

To achieve this, field data such as production rates, pressures, and fluid properties were carefully introduced into the model. Then, the model was adjusted and calibrated until the simulated results matched the real measurements with acceptable accuracy. This process helps reduce uncertainty and increases confidence in the results obtained.

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Once the model was validated, it became a reliable tool to analyze different production scenarios, evaluate the impact of operating changes, and better understand the behavior of well X21 under various conditions.

III.4.1 Model Objectives and Methodology

The PIPESIM model of Well X21 was developed to reproduce the actual production behavior of the well and to assess the impact of stimulation and artificial lift operations on its performance.

The modeling approach was based on nodal analysis using the Inflow Performance Relationship (IPR) and Vertical Lift Performance (VLP) methodology. The model was built using real field data, including production history, Build-Up test results, reservoir properties, PVT data, and well completion information.

Objectives

The main objectives of this study were:

- To reproduce the production behavior of Well X21 before and after Acid/Frac stimulation.
- To investigate the causes of the well becoming non-eruptive after stopping the nitrogen lift.
- To evaluate the potential of Gas Lift as a permanent artificial lift solution.
- To optimize Gas Lift operating parameters for improved production and stability.
- To perform nodal analysis and determine the operating point under different scenarios.
- To study the effect of Water Cut, tubing size, pressure losses, and gas injection rate on well performance.

Methodology

The simulation work was carried out by integrating reservoir inflow, tubing performance, and surface conditions within the PIPESIM environment.

The main steps of the workflow included:

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- Collection and preparation of field and reservoir data.
- Definition of PVT fluid properties and well completion details.
- Construction of the PIPESIM well model.
- Generation of IPR and VLP curves.
- Model calibration using actual field measurements.
- Sensitivity analysis and Gas Lift optimization.

Finally, the calibrated model was used to evaluate the performance of Well X21 under different operating conditions and artificial lift scenarios.

III.4.2 Input Data Preparation

The preparation of input data is considered a key step in building a reliable PIPESIM model. It involves collecting, checking, and organizing all field, reservoir, and fluid data required to correctly represent the real operating conditions of Well X21 before running the simulation.

• Well Data

The well dataset used in this study includes measured depth, production rate, wellhead pressure, flowing bottom-hole pressure, tubing dimensions, and operating temperature conditions.

Before stimulation, Well X21 was producing at an oil rate of about 2.78 m³/h, with a flowing bottom-hole pressure (P_{wf}) of approximately 142.95 kg/cm² and a reservoir pressure (P_r) close to 214.5 kg/cm². During production, the wellhead pressure ranged between roughly 17 and 22 kg/cm².

After the Acid/Frac treatment combined with nitrogen lift operations, the production rate increased significantly to around 4.82 m³/h, while the wellhead pressure reached about 48.6 kg/cm², indicating an overall improvement in well performance.

The well is completed with 4½-inch tubing set down to a packer depth of approximately 3317 m. These parameters were used to accurately reproduce the actual downhole and surface operating conditions of Well X21 in the PIPESIM model.

• Reservoir Data

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The reservoir dataset includes key parameters such as reservoir pressure, reservoir temperature, Productivity Index (PI), permeability-thickness (Kh), and skin factor, all obtained from Build-Up test interpretation.

Before stimulation, the well showed a low Productivity Index of about 0.041, associated with a high positive skin value of approximately +4.22. This clearly indicates near-wellbore damage and restricted reservoir inflow.

After stimulation, the Productivity Index improved to around 0.167, while the skin factor decreased to approximately -3.93, confirming a strong enhancement in inflow performance and reservoir connectivity.

The reservoir pressure remained relatively stable, ranging between 214 and 219 kg/cm² prior to and after the intervention.

• PVT Data

The PVT dataset includes oil density, gas density, oil viscosity, Gas-Oil Ratio (GOR), bubble point pressure, and other fluid properties under reservoir conditions.

These properties are essential for defining multiphase flow behavior and for estimating hydrostatic and frictional pressure losses along the tubing.

After stimulation and nitrogen lift operations, the GOR increased to approximately 315 scm/m³, which had a direct impact on fluid flow behavior and pressure drop inside the wellbore.

• Completion Data

The completion data covers tubing size, casing configuration, perforation interval, packer depth, and overall well architecture.

Well X21 is a vertical oil producer completed in the Cambrian reservoir with 4½-inch anchored tubing installed to a depth of about 3317 m. The completion design was selected to ensure stable flow conditions and efficient hydrocarbon transport to the surface.

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These completion parameters were implemented in the PIPESIM model to accurately reproduce the well geometry and support reliable nodal analysis results.

III.4.3 Selection of Flow Correlations

Several multiphase flow correlations were tested and compared in order to determine the most suitable model for representing the actual production behavior of Well X21 under field operating conditions.

The selection was mainly based on the ability of each correlation to accurately predict flowing bottom-hole pressure, pressure losses along the tubing, and overall production performance during nodal analysis.

After comparison with the available field measurements, one correlation showed a better agreement between simulated and observed data, particularly in terms of bottom-hole pressure and production rate behavior. This close match indicated that the selected model can reasonably represent the real flow conditions in the well.

Accordingly, the chosen flow correlation was retained for the rest of the study. It was considered reliable for modeling the vertical lift performance of Well X21 and for conducting further production optimization using the PIPESIM simulation model.

III.4.4 Model Construction in PIPESIM

Once all field, reservoir, and fluid data were prepared, the Well X21 model was built in PIPESIM by defining the main components of the system, including the reservoir inflow performance, well completion geometry, fluid properties, and surface operating conditions.

The model was structured to represent the full production system of the well, including the inflow performance relationship (IPR), tubing and casing configuration, as well as the wellhead pressure constraints. After that, pressure–temperature profiles were generated along the wellbore, and nodal analysis was performed by combining the IPR and vertical lift performance (VLP) curves to identify the operating point under different scenarios.

Before stimulation, the results of the nodal analysis indicated that the operating point corresponded to a relatively low production rate of around 2.78 m³/h. This limitation was

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mainly attributed to high near-wellbore damage and significant pressure losses within the tubing system, which restricted the well's productivity.

After stimulation operations, the operating point shifted toward higher production rates, reflecting the reduction in skin factor and the improvement in reservoir inflow performance. This change clearly demonstrates the positive impact of the Acid/Frac treatment on well productivity.

The calibrated model was subsequently used for further sensitivity analyses, including tubing diameter effects, water cut variation, gas lift optimization, and overall production behavior evaluation after stimulation.

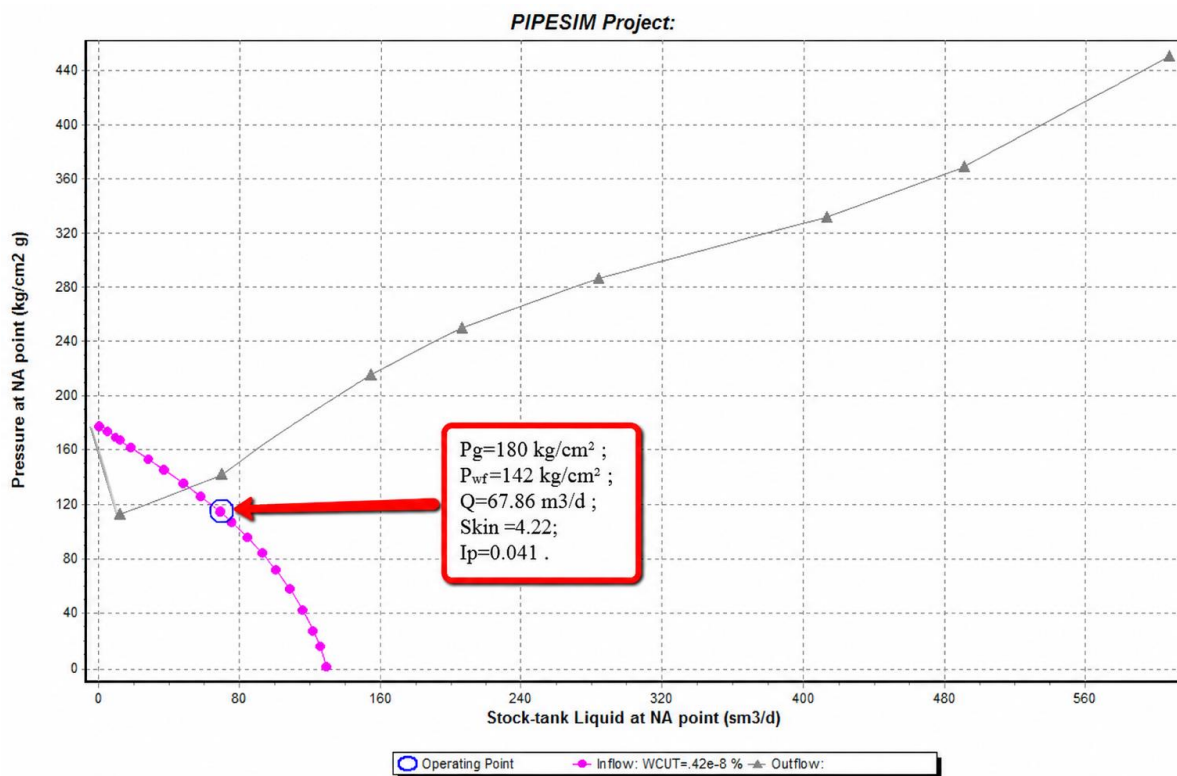


Figure III.7: Simulated Results of the Current State of Well X21. [2]

III.4.5 Model Calibration and Validation with Field Data

The calibration of the PIPESIM model was carried out using available field measurements recorded before and after the stimulation operations.

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The simulated outputs were systematically compared with Build-Up test interpretation results, production rate data, flowing bottom-hole pressure, wellhead pressure, and Productivity Index values to assess the accuracy and reliability of the model.

Before stimulation, the calibrated model successfully reproduced the main production parameters, including an oil rate of approximately 2.78 m³/h, a flowing bottom-hole pressure of around 142.95 kg/cm², and a reservoir pressure close to 214.5 kg/cm². The model also reflected a high positive skin factor of about +4.22 and a low Productivity Index of nearly 0.041, confirming the damaged state of the near-wellbore region.

After stimulation and nitrogen lift operations, the model captured the improved well performance, with an oil production rate increasing to about 4.82 m³/h. The skin factor decreased to approximately -3.93, while the Productivity Index increased to around 0.167. In addition, the wellhead pressure reached nearly 48.6 kg/cm², in agreement with field observations.

Overall, the comparison between simulated and measured data showed a good level of agreement, with engineering deviations generally within an acceptable range of approximately ± 8 –15%.

Based on these results, the model was considered sufficiently calibrated and validated, and therefore reliable for further use in production optimization studies and Gas Lift performance evaluation for Well X21.

III.5 Simulation of Well Stimulation Treatment

In this section, the stimulation treatments performed on Well X21 were modeled and analyzed using PIPESIM software. The main objective was to simulate both the matrix acidizing and hydraulic fracturing operations, evaluate their individual contributions, and understand how each stage improved well performance. The simulation work helped validate the actual field results and provided deeper insight into the effectiveness of the treatments.

III.5.1 Stimulation Treatment Design

Candidate selection criteria Well X21 was considered a good stimulation candidate for several reasons. It showed low initial productivity with a Productivity Index of only 0.041

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bbl/d/psi and a high positive skin factor of +4.22, indicating significant near-wellbore damage. The reservoir is a tight Anisometric Cambrian Ra formation with average porosity of 4.9%. Geological correlation with nearby wells (X20, X22, and X27) suggested that the formation had potential, but near-wellbore restrictions were limiting production.

Expected mechanism of improvement The stimulation aimed to reduce near-wellbore pressure losses by lowering the skin factor and increasing the effective drainage radius. Acidizing was expected to dissolve damage and clean the perforations, while hydraulic fracturing was intended to create highly conductive fractures that bypass the damaged zone and enhance reservoir contact.

Treatment assumptions used in the model In PIPESIM, the effects of stimulation were primarily modeled by adjusting the skin factor and the Productivity Index (PI). A Black Oil fluid model was used, with reservoir temperature set at 118°C, initial reservoir pressure at 219 kg/cm², and bubble point pressure at 159 kg/cm². Vogel's IPR correlation was selected because the well operates below bubble point pressure. Tubing roughness was kept at 0.0006 inch.

III.5.2 Acidizing Scenario

Objective of acidizing The main purpose of the matrix acidizing treatment was to remove formation damage around the wellbore caused by drilling mud, completion fluids, and possible mineral precipitation. This treatment was designed to restore the original permeability in the near-wellbore region.

Expected reduction in skin Prior to acidizing, the skin factor was +4.22. After the acid treatment (conducted in two phases), the skin factor was reduced to approximately +2.0. This improvement led to a moderate increase in production rate from 2.78 m³/h to 2.98 m³/h under an 11 mm choke.

Modeling assumptions in PIPESIM Acidizing was simulated by reducing the skin factor from +4.22 to +2.0 while keeping reservoir pressure and other parameters constant. After calibration, the model predicted an oil rate of 3.31 m³/h compared to the actual field rate of 2.98 m³/h on 20/09/2014. The 10% deviation is considered reasonable, taking into account uncertainties in acid penetration depth and exact fluid composition.

III.5.3 Hydraulic Fracturing Scenario

Objective of fracturing Hydraulic fracturing was performed to create long, high-conductivity fractures that extend beyond the damaged zone. This technique aimed to significantly increase the effective wellbore radius and improve reservoir drainage in this low-permeability formation.

Expected increase in conductivity/productivity The fracturing treatment delivered outstanding results. The skin factor dropped sharply from +2.0 to **-3.93**, indicating excellent fracture conductivity and successful stimulation. The Productivity Index increased more than four times, from 0.041 to 0.167 bbl/d/psi. When combined with nitrogen lift, the well achieved a peak production rate of 4.82 m³/h in the field (4.96 m³/h in simulation).

Modeling assumptions in PIPESIM In the model, the fracturing effect was represented by applying a negative skin value of -3.93 and updating the Productivity Index to 0.167. The simulation was calibrated using the post-frac Build-Up test data from 08/12/2014. Nitrogen lift was modeled by adjusting the flowing bottom-hole pressure to match lift-assisted conditions. The model showed excellent matching with field data, with only a 2.9% deviation.

III.5.4 Simulation Cases and Sensitivity Scenarios

To better understand the impact of the stimulation, several sensitivity cases were performed:

- **Skin variation** Different skin values (+4.22, +3.0, +2.0, and -3.93) were tested. The results clearly demonstrated that reducing the skin factor, especially moving into negative values, produced the largest improvement in production rate (see Figure III.8).
- **Fracture effectiveness** The simulation confirmed that the hydraulic fractures were highly effective. The negative skin value significantly shifted the IPR curve upward, allowing much higher production rates at the same drawdown.
- **Fluid property sensitivity** Sensitivity analysis was carried out on water cut, GOR, oil viscosity, and density. Water cut proved to be the most dominant parameter after stimulation. Even with the excellent skin improvement, increasing water cut caused a rapid decline in natural flow performance.

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- **Tubing sensitivity** Post-stimulation runs showed that switching to 2⅞" tubing would provide better flow stability compared to the existing 4½" tubing under current reservoir conditions.

III.6 Post-Stimulation Well Performance Analysis

III.6.1. Skin Sensitivity Scenarios

The simulation results clearly demonstrate the strong influence of skin factor on the inflow performance and productivity of Well X21.

Before stimulation, the well was characterized by a positive skin factor close to +4.22, indicating severe near-wellbore damage and significant additional pressure losses around the wellbore. Under these conditions, the production rate remained limited to nearly 2.78 m³/h, while the IPR curve shifted downward due to reduced reservoir deliverability.

Following the acidizing treatment, the skin factor decreased to approximately +2, reflecting partial removal of formation damage and improved fluid communication between the reservoir and the wellbore. Consequently, the production rate increased to nearly 2.98 m³/h and the operating point shifted toward more stable production conditions.

After hydraulic fracturing and nitrogen lift operations, the near-wellbore conditions improved considerably and the productivity index increased from approximately 0.041 to 0.167. Under these optimized conditions, the simulated production potential reached nearly 4.96 m³/h, confirming the significant improvement in reservoir inflow performance and well productivity.

These results demonstrate that reducing skin factor plays a critical role in minimizing near-wellbore pressure losses, improving reservoir deliverability, and enhancing long-term production stability.

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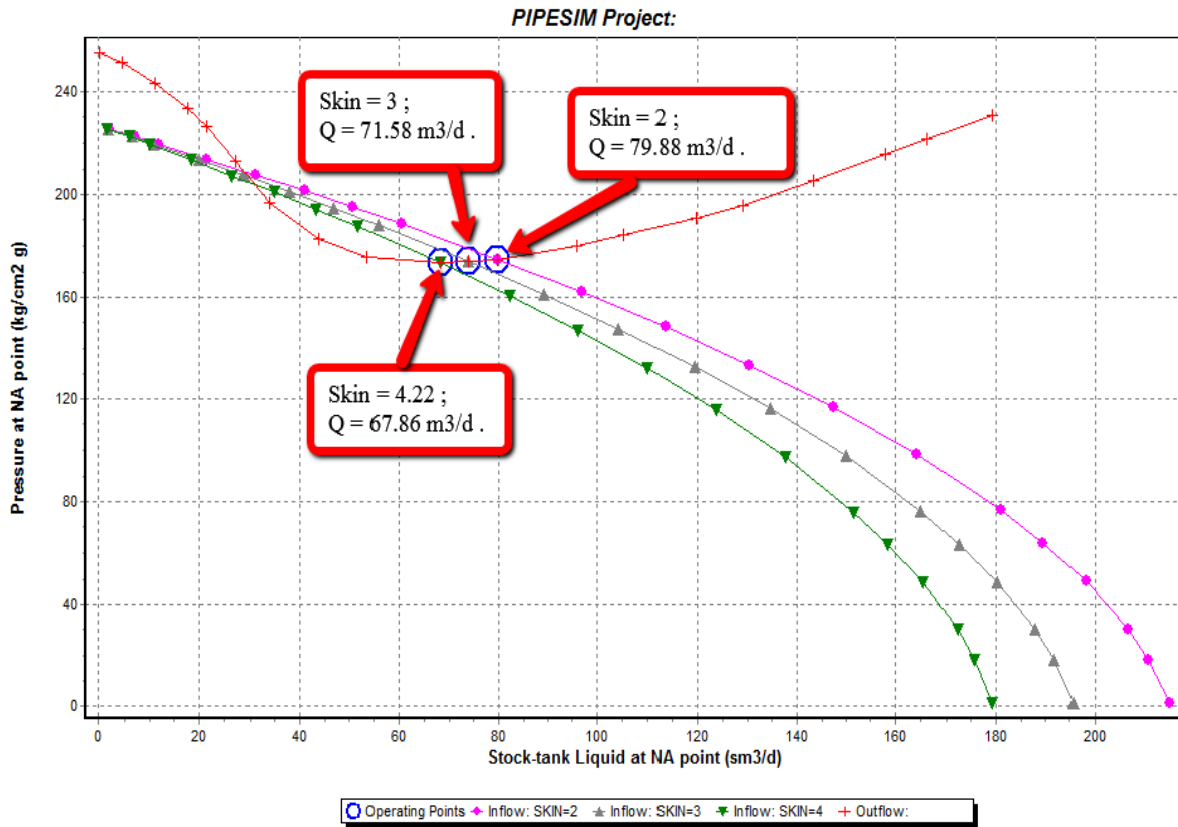


Figure III.8: Different Skin Value Scenarios. [22]

After performing a sensitivity analysis on the skin factor, I reduced it from +4.22 to +2 to simulate the effect of the acidizing job. The PIPESIM model then predicted an oil production rate of 3.31 m³/h.

This simulated value shows very good agreement with the actual field measurement of 2.98 m³/h recorded during the gauging test on 20 September 2014. The small difference (about 10%) between the simulated and measured rates is considered acceptable in well modeling, especially given the uncertainties in reservoir parameters and fluid properties.

This close match confirms two important points: first, the reliability of the PIPESIM model, and second, that the acidizing operation successfully reduced part of the wellbore damage, leading to a noticeable improvement in well productivity.

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Table III.10: Gauging Data After Acidizing. [21]

Measurement DATE	Choke Size (mm)	Flow (m ³ /h) Rate		GOR	Pressure (kg/cm ²)			Oil Temp. (°C)	K PSI	Water Flow Rate (l/h) Recovered
		Huile	Gaz		Wellhead	Pipe	Separ			
20/09/2014	11	2.98	271.02	91	22.1	16.5	3.87	23	.5561	0

III.6.2 State of the Well After Stimulation by Hydraulic Fracturing with Lift

The simulated results obtained from PIPESIM confirm the effectiveness of the hydraulic fracturing treatment applied to Well X21. As illustrated in Figure III.9, the oil production rate increased from approximately $Q_h = 2.98 \text{ m}^3/\text{h}$ to around $4.96 \text{ m}^3/\text{h}$, while the Productivity Index (PI) improved to 0.167. This significant change clearly demonstrates a marked improvement in the well's deliverability after stimulation.

This enhancement is mainly attributed to the creation of high-conductivity fracture channels within the reservoir. These fractures improve the connection between the reservoir and the wellbore by bypassing the damaged near-wellbore zone, thereby reducing pressure drop and minimizing flow restrictions. As a result, reservoir fluids can flow more efficiently toward the production tubing.

In addition to the fracturing effect, the observed improvement is also supported by the reduction in skin factor, which reflects the partial or complete mitigation of formation damage around the wellbore. The combined effect of increased fracture conductivity and reduced skin leads to a higher inflow performance and a more efficient production system.

It is also important to highlight that these results were obtained under Nitrogen Lift conditions using Coiled Tubing (CT). The injected nitrogen plays a crucial role in decreasing the hydrostatic head inside the wellbore, which reduces bottom-hole pressure and enhances the driving force for fluid flow. This artificial lift assistance improves the lifting capacity of the well, particularly in unloading heavier fluids and maintaining stable production.

Overall, the synergy between hydraulic fracturing and nitrogen lift operations resulted in a substantial improvement in well performance, confirming the success of the stimulation strategy implemented for Well X21.

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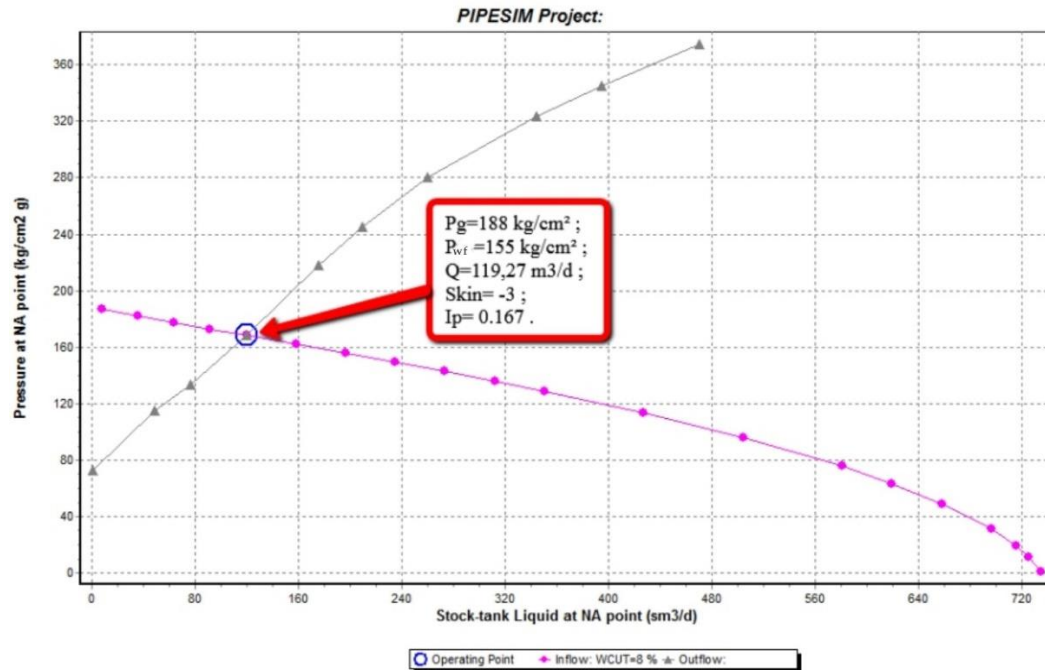


Figure III.9: The Curve Represents the State of the Well after Stimulation by Hydraulic Fracturing with Lift . [22]

The Build-Up test after stimulation shows the new performance of Well X21 following the Acid/Frac treatment and nitrogen lift.

The reservoir pressure (P_g) is about **188.25 kg/cm²**, which is lower than before, as the well is now producing more fluid from the reservoir. The flowing bottom-hole pressure (P_{wf}) is around **155 kg/cm²**, showing that the reservoir is still able to support the higher production rate.

The tubing head pressure (P_t) is approximately **48.6 kg/cm²**, which is consistent with nitrogen lift helping to reduce the pressure inside the well and improve fluid flow to the surface.

The oil production rate increased to about **4.82 m³/h**, confirming the positive effect of the stimulation.

The Productivity Index (I_p) improved to **0.167**, which means the well is now producing more easily for the same pressure drawdown.

The Kh value is around **85.5**, indicating better flow capacity after stimulation.

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Finally, the skin factor dropped to -3.93 , which clearly shows that the near-wellbore damage has been removed and the well is now in a much better production condition.

Overall, these results confirm that the stimulation and nitrogen lift significantly improved the performance of Well X21.

Table III.11: Build Up Data After Stimulation. [21]

	Date	PG	Pwf	Pt	Flow rate	Ip	Kh	Skin
BUILD UP	08/12/2014	188.25	155	48.6	4.82	.167	85.5	-3.93

According to the gauging data, the simulated results are very close to the real field measurements, which indicates that the developed model represents the actual behavior of the well with good accuracy. This close agreement confirms the reliability of the simulation process and demonstrates that the operation was successfully achieved.

The simulation predicted an oil flow rate of $Q_h=4.96$ m³/h while the real flow rate measured during gauging was $Q_h=4.82$ m³/h. The difference between these two values is very small, showing that the model calibration was properly performed and that the selected reservoir and well parameters are consistent with field conditions.

In addition, the calculated skin factor is negative ($S=-3.93$) which reflects an improvement in near-wellbore conditions. A negative skin generally indicates that the formation around the well has been effectively stimulated, allowing fluids to flow more easily toward the wellbore. This reduction in flow resistance contributes directly to better well productivity and confirms the positive impact of the operation on production performance.

Overall, the obtained results show that the simulation model can be considered reliable for predicting well behavior and evaluating future production performance under similar operating conditions.

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Table III.12: Gauging Data After Fracturing. [21]

Measurement DATE	Choke Size (mm)	Flow (m ³ /h) Rate		GOR	Pressure (kg/cm ²)			Oil Temp. (°C)	K PSI	Water Flow Rate (l/h)
		Huile	Gaz		Wellhead	Pipe	Separ			Recovered
04/12/2014	11	4.82	1520.1	315	48.6	10.1	2.86	21	.7549	300

III.6.3 Sensitivity Analysis on Reservoir Fluid and Production Parameters

I discovered throughout the modeling work that fluid properties are more significant than I had anticipated, particularly once the well began producing with higher GOR and increased water cut. Because of this, I made the decision to undertake a special sensitivity analysis on the primary fluid parameters in order to verify the robustness of the PIPESIM model and gain a deeper understanding of how they affect well performance.

III.6.3.1 Effect of Gas-Oil Ratio (GOR)

The GOR dramatically increased from about 271 scm/m³ to over 1520 scm/m³ following the Acid/Frac job and nitrogen lift. I conducted multiple sensitivity tests, changing the GOR from 300 to 2000 scm/m³, to assess the effect of this modification.

The findings demonstrated that the natural gas lift effect inside the tubing makes it easier for the well to flow at lower rates when the GOR is increased. However, because of increased frictional losses, the gain begins to diminish when the GOR rises too high. A greater reservoir GOR marginally lowers the amount of gas that must be injected in the Gas Lift scenario.

Overall, an oil rate variation of roughly $\pm 8-12$ was obtained by varying the GOR by $\pm 30\%$ around the observed value.

III.6.3.2 GOR Sensitivity Interpretation

The GOR sensitivity analysis confirmed the beneficial effect of moderate gas production on vertical lifting efficiency and production stability.

The simulation results showed that increasing Gas-Oil Ratio improved well performance by reducing the average density of the fluid column inside the tubing. Under these conditions, the natural gas-lift effect reduced hydrostatic pressure losses and improved the operating point of the well.

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However, the results also demonstrated that excessive gas production does not necessarily produce continuous productivity improvement. At very high GOR values, frictional losses and unstable multiphase flow behavior increased progressively, limiting the production gain.

The obtained results therefore indicate the existence of an optimum GOR operating range where production performance and flow stability are simultaneously maximized.

III.6.3.3 Effect of Water Cut

This parameter turned out to be one of the most critical factors. The rise in water cut is the main reason why the well died after stopping the nitrogen lift.

Key observations:

- Above 30–40% water cut, the hydrostatic pressure in the tubing increases sharply, making natural flow very difficult.
- With the current reservoir pressure, the well becomes non-eruptive when water cut exceeds approximately 35%.
- Even with the smaller 2 $\frac{7}{8}$ " tubing, stable production is only possible if water cut remains below 25%.

This analysis clearly confirms that water cut has a stronger negative effect on well performance than reservoir pressure decline alone.

Table III.13: Summary of Water Cut Sensitivity. [21]

Water Cut (%)	Oil Rate (m ³ /h) - Natural Flow	Oil Rate (m ³ /h) - Gas Lift	Well Status
0%	2.85	4.12	Flowing
20%	2.15	3.85	Flowing
35%	0.95	3.45	Marginal
50%	0.00	2.95	Non-eruptive

III.6.3.4 Water Cut Sensitivity Interpretation

The sensitivity analysis demonstrated that Water Cut represents one of the dominant parameters affecting the production stability of Well X21.

Under natural flow conditions, increasing Water Cut from 0% to nearly 50% progressively reduced oil production until unstable production behavior was reached. This reduction is mainly associated with the increase in hydrostatic pressure losses caused by the heavier liquid column inside the tubing.

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As the water fraction increases, the average density of the flowing mixture becomes significantly higher, causing the Vertical Lift Performance curve to shift upward and moving the operating point toward lower production rates.

The results also showed that gas lift operations remained capable of maintaining stable production even under high Water Cut conditions. Production rates between approximately 3 and 4.1 m³/h remained achievable after gas lift injection due to the reduction in average fluid density and improvement in lifting efficiency.

These results confirm the strong influence of produced water on well productivity and demonstrate the importance of artificial lift systems under severe multiphase flow conditions.

III.6.3.5 Effect of Oil Viscosity and Density

I also investigated the impact of oil density and viscosity. The oil production rate decreased by 10–18% when viscosity was increased by 50%. This was particularly evident when utilizing smaller tubing because of increased friction.

Density has a definite effect as well. The hydrostatic column became heavier and the output rate dropped by up to 15% as the oil density increased by 5%. In low-pressure situations, these impacts become more pronounced.

III.6.3.6 Black Oil vs. Compositional Model

I quickly compared a simple Compositional model with the Black Oil model, which served as the basic case. Less than 7% separated the expected rates. I came to the conclusion that the Black Oil model is sufficiently accurate for this investigation given the data at hand and the Compositional model's significantly longer calculation time.

III.6.3.7 Effect of Bubble Point Pressure

Changing the bubble point pressure (P_b) from 140 to 180 kg/cm² had a noticeable but moderate effect on the simulation results, with variations ranging between ± 5 and 8%. As the bubble point pressure increases, gas starts to separate from the oil at a higher pressure, leading to earlier gas liberation inside the tubing. This behavior influences the vertical lift performance and slightly changes the well production response.

The sensitivity analysis showed that Water Cut is the main factor responsible for the well's inability to flow naturally after stopping the nitrogen lift. Although the stimulation operation gave very good results, with a negative skin factor (-3.93) and a relatively high productivity index ($PI = 0.167$), the increasing amount of produced water significantly increases the

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hydrostatic pressure inside the tubing. As a result, the well can no longer sustain natural production conditions.

The analysis also highlighted the influence of GOR on well performance. At moderate values, gas presence helps improve production by reducing fluid density. However, when GOR becomes too high, the flow becomes unstable and negatively affects production performance.

Overall, the simulation model showed stable and reliable behavior, since the variation in the results remained within acceptable engineering limits (around $\pm 8\text{--}15\%$). This indicates that the previous simulation results can be considered reasonably reliable for evaluating future production scenarios.

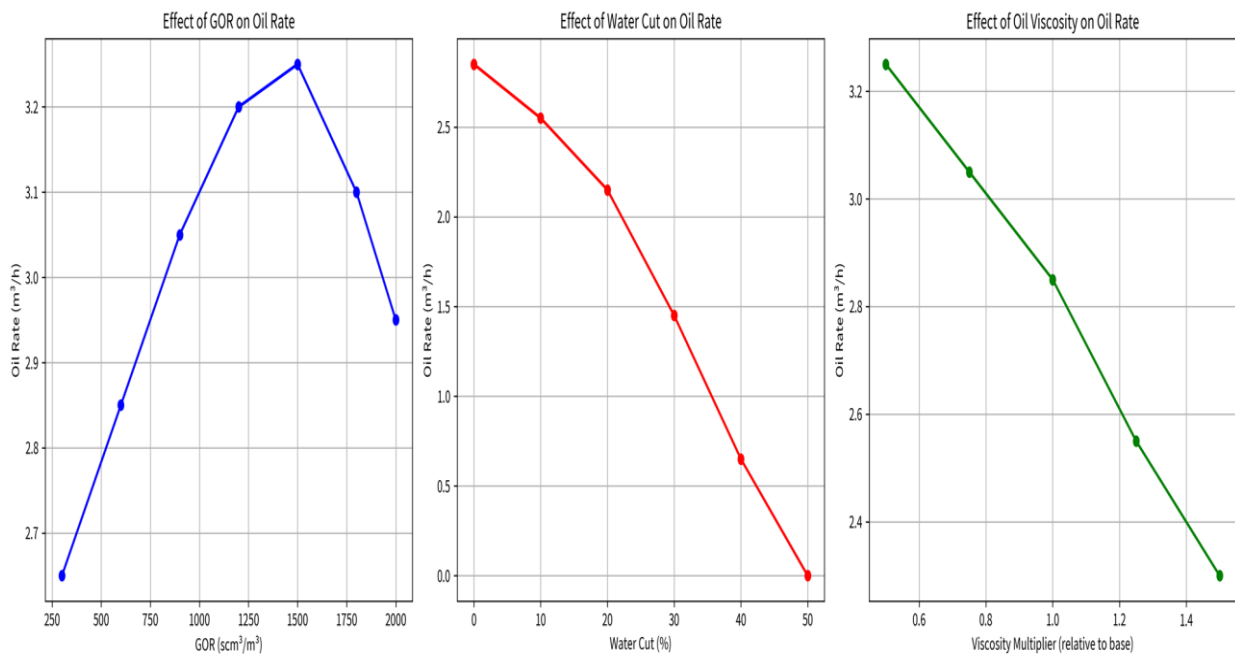


Figure III.10: Sensitivity of Oil Rate to Main Fluid Parameters. [22]

III.6.3.8 Thermal Effects on Multiphase Flow Behavior

Temperature variations along the wellbore play an important role in determining fluid behavior and multiphase flow stability during production operations.

As the produced fluids flow from reservoir conditions toward the surface, pressure and temperature progressively decrease. These thermal variations directly affect fluid viscosity, gas liberation, density, and pressure losses inside the production tubing.

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Under lower temperature conditions, oil viscosity increases considerably, which may increase frictional pressure losses and reduce production efficiency. In addition, temperature reduction may accelerate gas liberation below the bubble point pressure, increasing free gas volume and modifying flow regime behavior inside the tubing.

Thermal effects become more significant under high Water Cut conditions because temperature reduction may also increase liquid holdup and hydrostatic pressure losses during multiphase flow.

Although the present PIPESIM simulations assumed quasi-steady thermal conditions, the obtained results demonstrate that temperature variations may influence Vertical Lift Performance behavior and operating point stability under real production conditions.

Consequently, future studies may incorporate detailed thermal modeling in order to improve pressure profile prediction accuracy and long-term production forecasting.

III.6.4 State of the Well at the Stop of Lift

Figure III.11 presents the performance curve of Well X21, showing that the well is no longer capable of flowing under natural lift conditions.

It is observed that the well cannot lift the produced fluids to the surface due to a high hydrostatic pressure in the tubing. This situation is mainly associated with the increase in water cut, which makes the fluid column heavier and increases the pressure losses inside the wellbore. As a result, the well has become non-eruptive and can no longer sustain natural flow.

In this case, the most appropriate long-term solution is the installation of a Gas Lift system. However, since the Gas Lift facilities are located at a considerable distance from Well X21, an immediate and more practical temporary solution is required to avoid production downtime from a well that still has a relatively good productivity index.

Therefore, a temporary well activation method is recommended to restore production in the short term until the full Gas Lift system becomes available.

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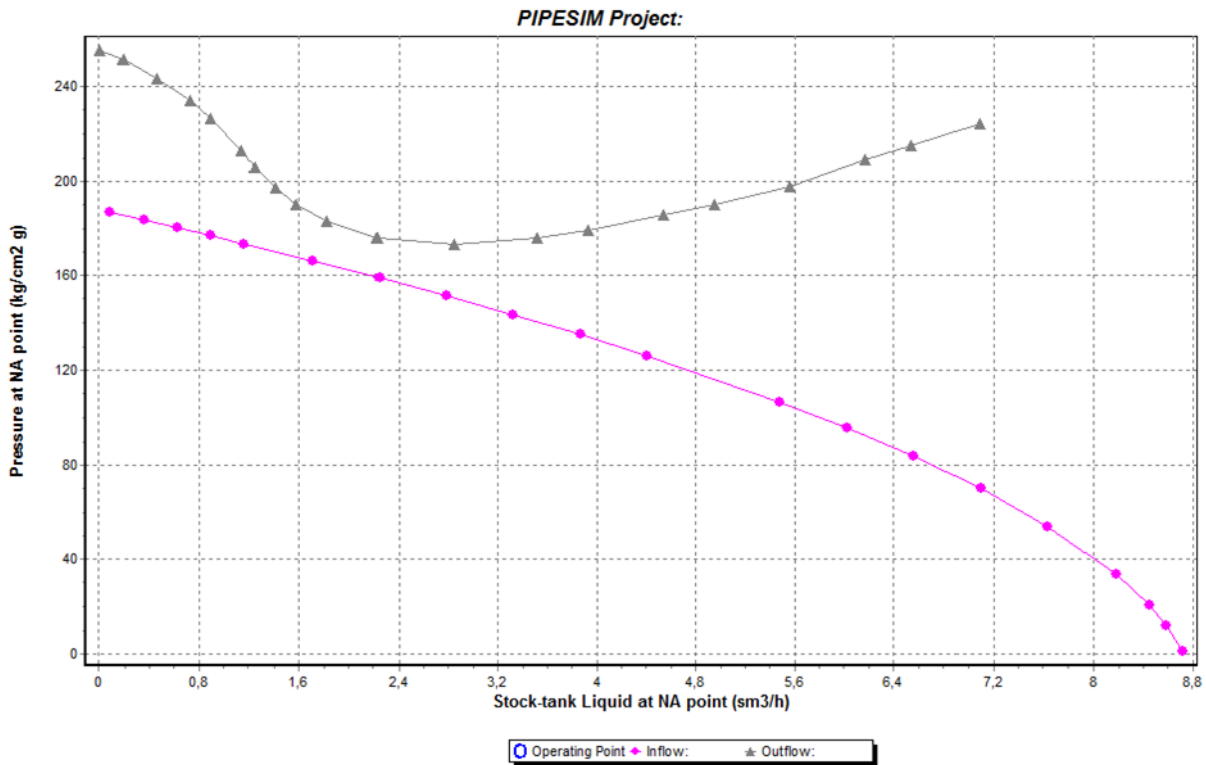


Figure III.11: shows the performance curve of well X21 where it gives no production. [22]

III.6.5 Comparison of Pre- and Post-Stimulation Results

The comparison between the well performance before and after the stimulation operations (Acidizing and Hydraulic Fracturing) shows clear and significant improvements in Well X21.

- **Production rate improvement** Before stimulation, the well was producing at approximately 2.78 m³/h (Build-Up test of 02/07/2014). After acidizing, the production rate increased to 2.98 m³/h (gauging on 20/09/2014). Following hydraulic fracturing combined with nitrogen lift, the rate jumped to 4.82 m³/h (gauging on 04/12/2014). The PIPESIM model predicted 2.82 m³/h, 3.31 m³/h, and 4.96 m³/h respectively, showing very good agreement with field data.
- **Change in productivity index** The Productivity Index (PI) showed remarkable enhancement. It increased from 0.041 bbl/d/psi before stimulation to 0.167 bbl/d/psi after fracturing and nitrogen lift. This represents more than a fourfold improvement in the well's inflow capacity.
- **Reduction in skin factor** One of the most important indicators of stimulation success is the skin factor. It decreased dramatically from +4.22 (damaged wellbore) before stimulation to

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around +2 after acidizing, and reached a negative value of **-3.93** after hydraulic fracturing. This negative skin confirms excellent enhancement of the near-wellbore permeability.

- **Pressure behavior comparison** Reservoir pressure (P_g) declined from 219 kg/cm² to 188.25 kg/cm² due to natural depletion. However, the flowing bottom-hole pressure (P_{wf}) and wellhead pressure improved significantly after stimulation, especially during the nitrogen lift period. The well was able to flow with higher rates under lower drawdown after the treatment.

Table III.14: Comparison Between Field and Simulated Results [21]

Operating Condition	Field Production Rate (m ³ /h)	Simulated Production Rate (m ³ /h)	Deviation
Before Stimulation	2.78	2.82	1.4%
After Acidizing	2.98	3.31	10%
After Fracturing and Nitrogen Lift	4.82	4.96	2.9%

III.7 Discussion of Results

III.7.1 Technical Evaluation of Stimulation Efficiency

The Acid/Frac campaign performed on Well X21 proved to be technically successful. The combination of matrix acidizing followed by hydraulic fracturing significantly improved the connection between the reservoir and the wellbore. The reduction in skin factor to a negative value and the substantial increase in Productivity Index confirm that both near-wellbore damage was removed and a conductive fracture was created. The production history (Figure III.1) clearly shows the jump in oil rate and wellhead pressure after the treatment.

III.7.2 Comparison Between Acidizing and Hydraulic Fracturing

Acidizing alone provided moderate improvement by partially dissolving the damage (skin reduced from +4.22 to +2). However, hydraulic fracturing delivered much greater results by creating new flow paths in the low-permeability Cambrian sandstone. The fracturing job, combined with nitrogen lift, allowed the well to reach nearly double the pre-stimulation rate. This confirms that fracturing was the dominant contributor to the productivity enhancement in this tight reservoir.

III.7.3 Operational and Production Implications

Despite the excellent post-stimulation performance, the well died after stopping the nitrogen lift. This highlights that stimulation improved the **inflow performance** but could not overcome the increasing hydrostatic pressure caused by rising water cut and reservoir pressure decline. The well became non-eruptive due to the heavy fluid column. This situation emphasizes the need for artificial lift to sustain the gains achieved by stimulation.

III.7.4 Limitations of the Model and Simulation Assumptions

The PIPESIM model showed good matching with field data (deviation < 10% in most cases). However, some limitations exist:

- The model assumes steady-state conditions and does not fully account for dynamic changes in water cut over time.
- Compositional modeling was not used due to long computation time; Black Oil model was sufficient but less accurate at very high GOR.
- Thermal effects along the wellbore were simplified.

III.8 Optimization and Recommendations

III.8.1 Well Sensitivity on 2"7/8 Tubing

The results of the tubing sensitivity analysis show that replacing the existing 4"½ tubing with a 2"7/8 tubing has a noticeable impact on well performance and flow behavior.

The simulation indicates that the well can still produce at a rate of approximately $Q_h = 49.81 \text{ m}^3/\text{d}$ (about $2.07 \text{ m}^3/\text{h}$), even when the reservoir pressure decreases from $219.4 \text{ kg}/\text{cm}^2$ to around $188 \text{ kg}/\text{cm}^2$.

Although this configuration does not fully maximize the production potential of the well, it still provides a stable and workable operating condition under the current reservoir limitations. The smaller tubing diameter increases the fluid velocity inside the wellbore, which helps maintain flow stability and reduces the risk of liquid loading and production decline.

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Overall, the 2"7/8 tubing can be considered as a practical interim solution to limit production losses until the gas lift system is installed and fully operational.

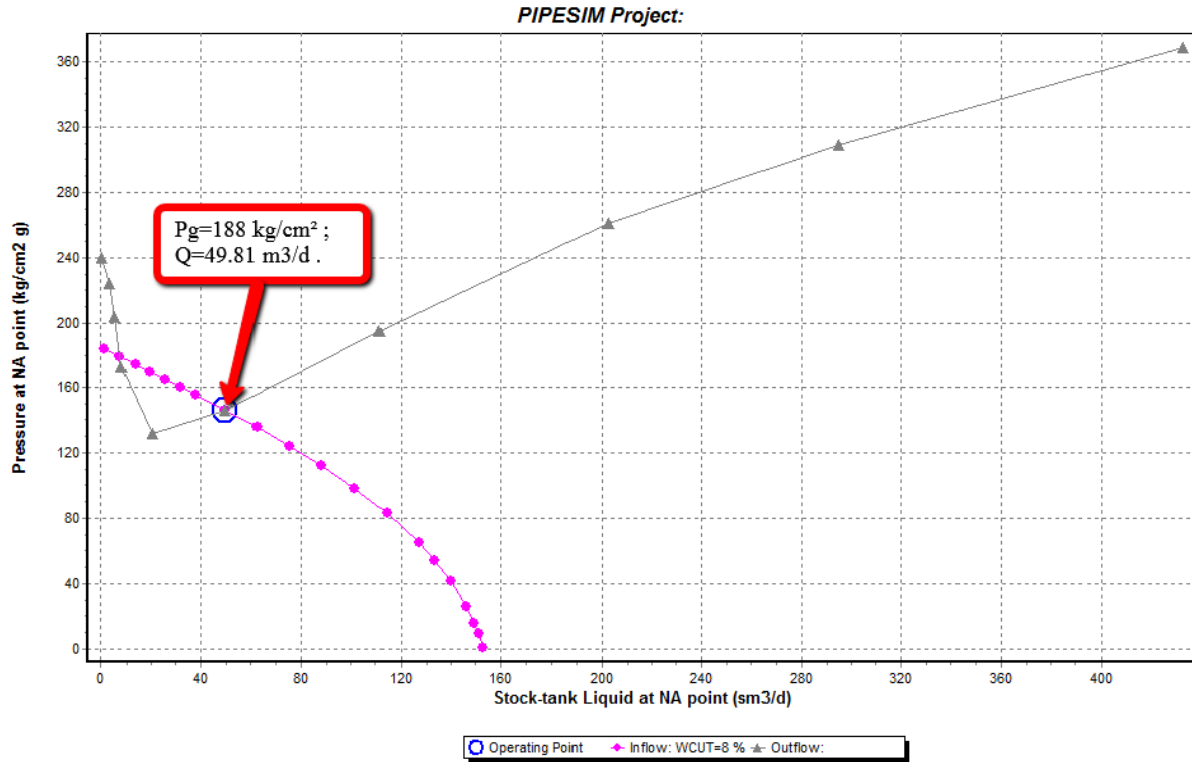


Figure III.12: Sensitivity of Well on Tubing 2"7/8. [22]

III.8.2 Tubing Sensitivity Analysis

The influence of tubing diameter on well performance was investigated using nodal analysis simulations in PIPESIM by comparing several tubing configurations commonly used in production operations.

Three tubing diameters were evaluated during the sensitivity analysis: 2.375 in, 2.875 in, and 3.5 in.

The simulation results showed that the smallest tubing diameter (2.375 in) generated the highest frictional pressure losses despite maintaining relatively high fluid velocity inside the tubing. Under these conditions, the flowing bottom-hole pressure increased considerably, which negatively affected production performance and reduced the operating flow rate.

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Conversely, the largest tubing diameter (3.5 in) significantly reduced frictional pressure losses and improved fluid transport capacity. However, under moderate and low production conditions, fluid velocity decreased progressively, increasing the risk of liquid loading and unstable multiphase flow behavior inside the tubing system.

The intermediate tubing size (2.875 in) provided the most stable operating conditions and represented the best compromise between pressure loss reduction and flow stability. Under this configuration, the operating point remained relatively stable while maintaining acceptable production rates throughout the sensitivity analysis.

The obtained results therefore demonstrate that tubing diameter selection strongly influences production efficiency, pressure losses, and multiphase flow stability during well operation. Consequently, selecting an optimum tubing configuration represents a critical stage in production system optimization studies.

III.8.3 Tubing Sensitivity Interpretation

The comparison between different tubing diameters clearly demonstrates the balance required between minimizing frictional pressure losses and maintaining sufficient fluid velocity for stable transport conditions.

Smaller tubing diameters increase frictional losses, while excessively large tubing sizes may promote liquid accumulation and unstable flow regimes under declining production conditions.

Therefore, the selected tubing diameter must satisfy both pressure loss optimization and long-term flow stability requirements during production operations.

III.8.4 Choice of Choke and Optimum Gas Lift Injection Rate

The next step consists of determining the optimum gas injection rate that minimizes both gravitational and frictional pressure losses. The evolution of the production rate as a function of gas injection rate is presented in the graph below.

According to the obtained results, increasing the injected gas rate initially improves oil production. This is mainly because the gas reduces the density of the fluid column inside the

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tubing, which lowers hydrostatic pressure losses and enhances the lifting efficiency to the surface.

The simulation shows that the production rate increases progressively up to around **20,000 m³/d** of gas injection. In this range, gas lift has a clear positive effect on well performance, shifting the operating point toward higher production.

Beyond this optimum value, the improvement in production becomes less significant and may even slightly decrease. This is mainly due to higher frictional pressure losses and flow instability caused by excessive gas injection inside the tubing.

In addition, very high gas injection rates are less practical in field operations, as they require larger gas volumes and lead to increased operating costs.

Based on these results, a **14 mm choke size** was selected as the optimal configuration, as it provides stable operating conditions and ensures the best compromise between production increase and flow stability for Well X21.

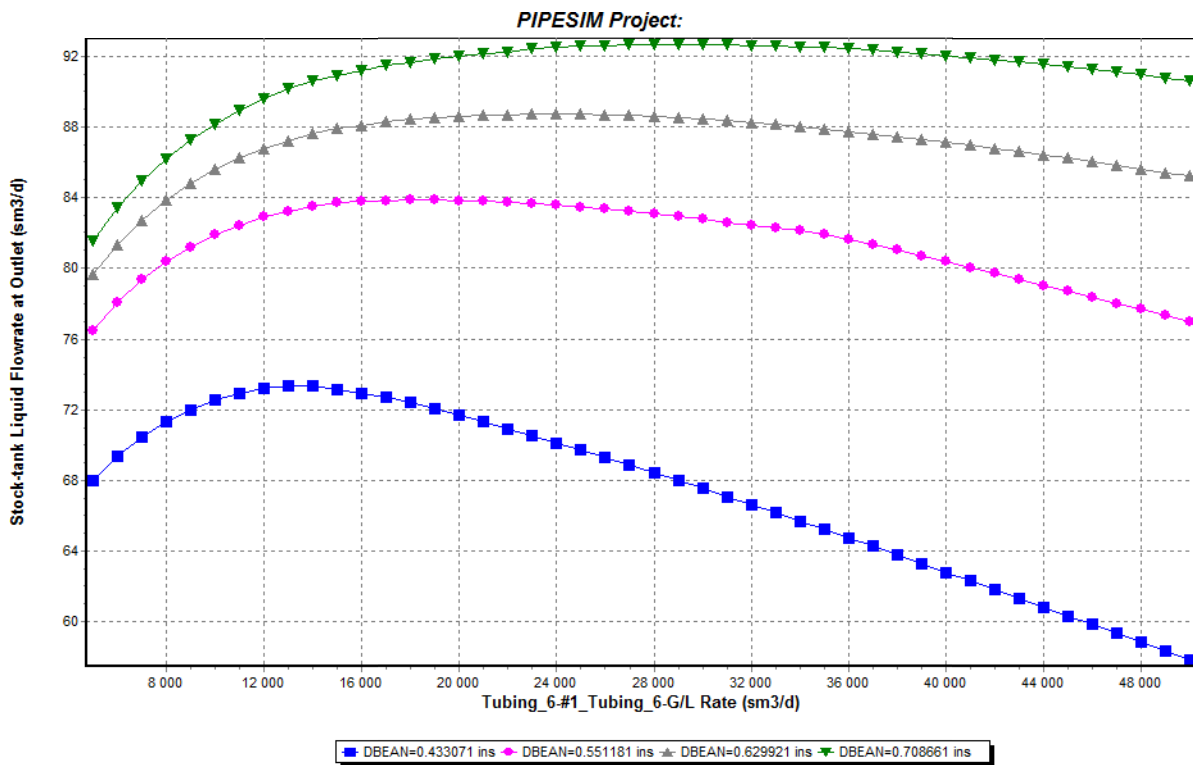


Figure III.13: Choice of Choke and Optimum Flow Rate for Gas Lift Injection. [22]

III.8.5 Sensitivity on Gas Lift Optimization

To achieve maximum recovery, the gas injection rate was optimized using PIPESIM software. The resulting performance curve is presented in Figure III.14, which shows the intersection between the IPR curve (reservoir inflow performance) and the TPC curve (tubing performance curve). This intersection defines the operating point of Well X21 under gas lift conditions.

The simulation results indicate that an injected gas rate of $Q_g = 20,000 \text{ m}^3/\text{d}$ provides the most stable operating conditions and the best balance between production improvement and flow stability. At this optimal rate, the injected gas reduces the average density of the fluid column inside the tubing, which leads to lower hydrostatic pressure losses and improved lifting efficiency.

As a result, the operating point shifts toward higher production levels, allowing the well to reach a liquid production rate of approximately $Q_h = 88.86 \text{ m}^3/\text{d}$ ($\approx 4 \text{ m}^3/\text{h}$). These results confirm that gas lift has a strong positive impact on the production performance of Well X21 and represents the most effective artificial lift method under the studied conditions.

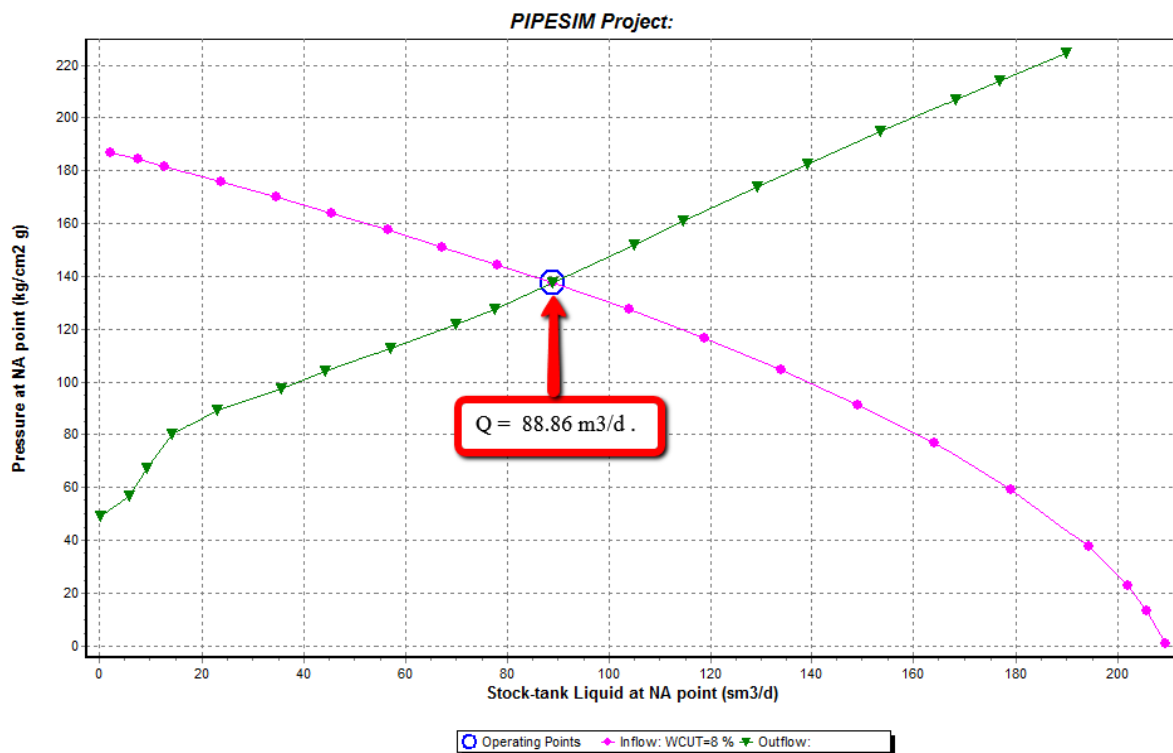


Figure III.14: Sensitivity on Gas Lift Optimization. [22]

III.8.6 Gas Lift Optimization Discussion

Gas lift injection was selected as the preferred artificial lift method because of its operational flexibility and compatibility with the production conditions of Well X21.

The optimization study performed using PIPESIM demonstrated that increasing gas injection rate initially produced a significant improvement in oil production due to the reduction in hydrostatic pressure losses inside the tubing.

The simulation results indicated that the optimum gas injection rate was close to 20,000 m³/d. Below this value, increasing injected gas volume improved production performance considerably. However, above the optimum operating range, the production improvement became progressively smaller because excessive gas injection increased frictional pressure losses and flow instability.

The selected 14 mm choke provided the most stable operating conditions during the optimization process and allowed the well to achieve production rates approaching 4 m³/h under gas lift conditions.

Overall, the obtained results confirm that gas lift represents an efficient solution for restoring and stabilizing production under declining reservoir energy and increasing Water Cut conditions.

III.8.7 Engineering Interpretation of Simulation Results

The simulation results obtained from nodal analysis clearly illustrate the strong interaction between reservoir inflow performance and vertical lifting behavior inside the production system.

The upward displacement of the VLP curve observed during several sensitivity cases indicates an increase in total pressure losses inside the tubing. This behavior is mainly associated with higher hydrostatic pressure gradients caused by increased liquid density and liquid holdup.

Conversely, the improvement observed after gas lift injection demonstrates the beneficial effect of reducing average fluid density. Under these conditions, the required flowing bottom-

Chapter III: PIPESIM Modeling and Performance Evaluation of Well X21 Before and After Stimulation

hole pressure decreases considerably, allowing the operating point to shift toward higher production rates.

Similarly, stimulation operations such as acidizing and hydraulic fracturing improved the inflow performance relationship by reducing near-wellbore damage and increasing the productivity index of the reservoir.

III.8.8 Comparison of Scenarios

After running all the simulations, I thought it would be useful to put everything together in one table to clearly see how the well's performance changed from one case to another.

Looking at these results, the Acid/Frac job clearly did a great job in removing most of the damage, turning the skin from positive to strongly negative and almost doubling the production rate. However, once the nitrogen lift was stopped, the well could no longer flow on its own due to pressure depletion and higher water cut.

The 2 $\frac{7}{8}$ " tubing gives us a simple and inexpensive way to keep the well producing for a while, but the rate is quite low. In my opinion, installing Gas Lift is by far the best permanent solution, as it should allow us to maintain a good production rate over the long term.

Table III.15: Summary of PIPESIM Results for Different Scenarios [21]

Scenario	Oil Rate (m ³ /h)	Skin Factor	PI	Well Status	Comments
Before Stimulation	2.82	+4.22	0.041	Damaged	Heavy wellbore damage
After Acidizing	2.98	+2.0	-	Slightly Improved	Partial improvement
After Acid/Frac + Nitrogen Lift	4.82	-3.93	0.167	Best Performance	Very successful stimulation
After Stopping Nitrogen Lift	0	-	-	Non-eruptive / Dead	Well killed by hydrostatic column
2 $\frac{7}{8}$ " Tubing (Temporary)	2.07	-	-	Flowing (low rate)	Cheap but not optimal
Optimized Gas Lift	≈ 4.0	-	-	Stable Production	Recommended long-term solution

III.9 Conclusion

This chapter presented a complete simulation and performance evaluation of Well X21 using PIPESIM, considering both pre-stimulation and post-stimulation conditions. The main objective was to assess the impact of Acid/Frac treatment and artificial lift on well productivity and to validate the reliability of the developed numerical model using real field data.

The results clearly show that the stimulation operations had a significant positive impact on well performance. Before treatment, the well was operating under poor conditions, with a skin factor of +4.22, a very low productivity index of 0.041, and an oil production rate of only 2.78 m³/h. These values confirmed severe near-wellbore damage and limited reservoir connectivity. After the Acid/Frac treatment combined with nitrogen lift, the well performance improved considerably, with the skin factor decreasing to -3.93, the productivity index increasing to 0.167, and the oil rate reaching 4.82 m³/h. This clearly demonstrates that the stimulation successfully restored and enhanced the flow capacity of the reservoir.

The analysis also showed that hydraulic fracturing played the most important role in improving production by creating high-conductivity flow paths and bypassing the damaged zone, while acidizing provided a moderate contribution by partially cleaning the near-wellbore region. However, the long-term production behavior remains strongly dependent on reservoir pressure decline and increasing water cut, which eventually led to the well becoming non-eruptive after the removal of nitrogen lift support.

From an operational point of view, gas lift optimization proved to be essential for sustaining production, with an optimal injection rate of around 20,000 m³/d, which allowed the well to achieve stable production close to 4 m³/h under artificial lift conditions. In addition, sensitivity analyses confirmed that tubing size, choke configuration, and fluid properties all have a significant influence on well performance and should be carefully optimized in similar field conditions.

Finally, the comparison between simulated and field data showed a good agreement, with deviations generally within acceptable engineering limits, confirming the reliability of the PIPESIM model for this study. This validates the use of nodal analysis as a powerful tool for evaluating stimulation effectiveness and optimizing production strategies.

Chapter III: PIPESIM Modeling and Performance Evaluation of Well X21 Before and After Stimulation

In conclusion, the study demonstrates that proper reservoir stimulation combined with appropriate artificial lift design can significantly restore and improve the productivity of damaged wells. Well X21 is a clear example of how integrated engineering analysis and simulation can guide effective decision-making and maximize production performance in mature reservoirs.

General Conclusion

General Conclusion

General Conclusion

At the end of this work, it can be concluded that fluid properties have a direct and very important influence on well performance and production stability. Throughout this study, the relationship between reservoir behavior, fluid flow, and production system performance was analyzed using both theoretical concepts and practical simulation work. The obtained results clearly show that even small variations in fluid characteristics can significantly affect production rates, pressure losses, and the ability of the well to flow naturally.

The study first highlighted the importance of petroleum production engineering and nodal analysis in understanding the interaction between the reservoir inflow and the tubing outflow system. The concepts of Inflow Performance Relationship (IPR) and Vertical Lift Performance (VLP) were essential for explaining how the operating point of a well is established and how production can be optimized. It was also shown that multiphase flow behavior inside the tubing represents one of the main challenges in oil production, especially in mature reservoirs where water production and pressure depletion become more significant.

Particular attention was given to the physical properties of the produced fluids such as viscosity, density, gas-oil ratio, bubble point pressure, and water cut. The analysis demonstrated that oil viscosity strongly affects fluid mobility and pressure losses. Higher viscosity reduces the productivity of the reservoir and increases friction inside the tubing, leading to lower production rates. In the same way, fluid density and water cut were found to have a major impact on the hydrostatic pressure gradient. As water cut increases, the fluid column becomes heavier, making it more difficult for the well to lift the produced fluids naturally to the surface.

On the other hand, the gas-oil ratio showed a positive effect on well performance within certain limits. The presence of dissolved gas helps reduce the average density of the fluid mixture and improves the natural lifting process. However, excessive gas production may also create unstable flow conditions and increase frictional losses. This confirms that well performance depends on a delicate balance between several fluid parameters acting together rather than on a single factor alone.

The practical part of this work focused on Well X21 from the Hassi Messaoud Oil Field using PIPESIM simulation software. The developed model was calibrated using real production and reservoir data, and the simulated results showed very good agreement with field measurements.

General Conclusion

This confirms the reliability of the model and demonstrates the usefulness of numerical simulation tools for analyzing and predicting well behavior.

The simulation results also confirmed the positive effect of stimulation treatments such as acidizing and hydraulic fracturing. After stimulation, the skin factor became negative and the productivity index increased significantly, which improved the well production rate. However, despite these improvements, the well later became non-eruptive after the nitrogen lift stopped. The sensitivity analysis revealed that the main reason behind this problem was the increasing water cut, which caused a large increase in hydrostatic pressure inside the tubing.

Different sensitivity scenarios were performed to evaluate the influence of the main fluid properties on production performance. Among all the studied parameters, water cut appeared to be the most critical factor affecting the well behavior. The results showed that once the water cut exceeded certain limits, natural flow conditions could no longer be maintained. Oil viscosity and density also showed noticeable negative effects on production, while moderate increases in GOR slightly improved the lifting conditions.

Based on these results, several production optimization solutions were proposed. The use of smaller tubing was identified as a temporary and economical solution to maintain limited production under declining reservoir pressure. However, the study demonstrated that the installation of a Gas Lift system remains the best long-term solution for ensuring stable production and reducing the impact of high water cut. The optimization of gas injection rates and continuous monitoring of well conditions were also recommended to improve future production performance.

In general, this work confirms that understanding fluid behavior is essential for successful well management and production optimization. Modern simulation tools such as PIPESIM provide engineers with an efficient way to analyze production systems, predict future well behavior, and test different operating scenarios without expensive field interventions. This approach helps reduce technical uncertainty and supports better engineering decisions.

Finally, the results obtained in this dissertation show that production problems in mature oil fields are often closely linked to changes in fluid properties and multiphase flow behavior. Therefore, accurate fluid characterization, continuous production monitoring, and proper

General Conclusion

artificial lift selection are necessary to maintain well productivity and extend the economic life of oil fields.

In response to the main question raised at the beginning of this study, the results obtained confirm that fluid properties have a decisive influence on well performance and production stability. Among all the studied parameters, water cut was identified as the most critical factor responsible for the loss of natural flow conditions in Well X21. The study also showed that PIPESIM simulation is an effective tool for understanding well behavior, predicting production performance, and evaluating optimization solutions such as tubing modification and Gas Lift installation.

Study Limitations and Recommendations

Study Limitations and Recommendations

Study Limitations and Recommendations

Although the developed PIPESIM model showed acceptable agreement with actual field production measurements, several technical limitations should nevertheless be acknowledged.

The calibration procedure could be improved further by including detailed History Matching plots comparing measured and simulated pressure and production data before and after calibration operations. Such comparisons would improve the validation process and increase confidence in the reliability of the developed model.

Additional laboratory PVT measurements would also improve the accuracy of the fluid characterization process and reduce uncertainty associated with multiphase flow behavior prediction under varying reservoir and operating conditions.

The sensitivity analysis successfully demonstrated the influence of Water Cut, Gas-Oil Ratio (GOR), tubing size, and gas lift injection on well productivity. For example, increasing Water Cut significantly reduced production stability due to the increase in hydrostatic pressure losses, while gas lift operations maintained production rates between approximately 3 and 4.1 m³/h under high Water Cut conditions. Similarly, the optimized gas lift injection rate reached nearly 20,000 m³/d, which provided the best compromise between production improvement and flow stability.

However, future studies could include additional quantitative analysis involving pressure losses, flowing bottom-hole pressure variation, productivity improvement percentages, and liquid loading evaluation under different operating conditions.

Furthermore, the present study did not include detailed uncertainty analysis related to reservoir pressure depletion, future Water Cut increase, and GOR fluctuations, despite their important influence on long-term production forecasting and operating point stability.

The Gas Lift optimization section may also be expanded in future work by including detailed injection depth analysis, gas lift valve configuration, gas availability constraints, and operational limitations associated with field production systems.

Study Limitations and Recommendations

Thermal effects were not explicitly considered during the simulation process, although temperature variations may significantly influence oil viscosity, gas liberation, fluid density, and multiphase flow behavior inside the tubing system.

Under real production conditions, temperature decreases along the wellbore may increase liquid viscosity and modify pressure losses, particularly under high Water Cut conditions. In addition, thermal variations may affect gas expansion behavior, flow regime transitions, and the stability of multiphase flow during production operations.

The present work assumed quasi-steady thermal conditions along the production tubing. Consequently, future studies may incorporate detailed thermal modeling in order to improve the accuracy of pressure profile prediction, fluid property estimation, and long-term production forecasting.

Despite these limitations, the developed PIPESIM model provided realistic production behavior and acceptable agreement with actual field data obtained from Well X21 in the Hassi Messaoud Oil Field. The study successfully demonstrated the strong influence of fluid properties on well performance and confirmed the effectiveness of nodal analysis and gas lift optimization techniques for improving production stability under complex multiphase flow conditions.

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APPENDIX

APPENDIX

APPENDIX A: Stratigraphic Column and Drilling Phases of the Hassi Messaoud Field

Ere/Sy	ETAGES	LITHO	Ep	TUBAGES & BOUE	DESCRIPTION	
CZ	MIO PLIOCENE		239	Boue douce bentonitique D: 1,1-1,2 V: 45-50	SABLE, CALCAIRE	→ Complexe aquifère eau potable. → Zone d'écoulement
	EOCENE		122		CALCAIRE	
MESOZOIQUE	SENONIEN	CARBONATE	107	Boue KEN X D: 1,26-1,32 V: 50 - 70 F: 2,4	CALCAIRE, DOLOMIE, ANHYDRITE	→ Complexe d'eau à odeur d'H ₂ S. → Utilisée pour l'injection. PG: 87 Kg/cm ² à (-700m).
		ANHYDRITIQUE	209		ANHYDRITE, MARNE, DOLOMIE	
		SALIFERE	149		SEL MASSIF	
		TURONIEN	112		CALCAIRE	
	CENOMANIEN		147		MARNE, CALCAIRE, DOLOMIE	→ Aquifère eau douce. → Utilisée pour la l'injection et besoins généraux. D: 1 PG: 1040 Kg/cm ² à (-1650m).
	ALBIEN		362		GRES, ARGILE	
	APTIEN		24		DOLOMIE	
	BARREMIEN		276		ARGILE, SABLE	
	NEOCOMIEN		182		DOLOMIE, MARNE, ARGILE	→ Eaux chlorurées calciques D: 1.28 → PG: 575 Kg/cm ² à (-2500m).
	MALM		226		ARGILE, MARNE, CALCAIRE	
	DOGG	ARGILEUX	107		ARGILE, MARNE	
		LAGUNAIRE	211		ANHYDRITE, DOLOMIE	
	LIAS	LD1	66		DOLOMIE, ANHYDRITE, ARGILE	
		LS1	90		SEL, ANHYDRITE	
		LD2	55		DOLOMIE, MARNE	
		LS2	58		SEL MASSIF	
	SALIF	LD3	31		DOLOMIE, MARNE	→ Manifestation des argiles fluides
		TS1	46		ANHYDRITE, ARGILE	
		TS2	189		SEL, ARGILE, ANHYDRITE	
		TS3	202		SEL MASSIF	
PALEOZOIQUE	ARGILEUX		113	Boue à sable D: 0,81 V: 50 - 70 F: 2	ARGILE	→ Zones de pertes de boue.
	GRESEUX		0 à 35		GRES, ARGILE	
	ERUPTIF		0 à 92		ANDESITE	
	Quartzites de Hamra		75		Grès très fins	
	Grès d'El-Atchane		25		Grès fins glauconieux	
	Argiles d'El-Gassi		50		Argile verte ou noire	
	Zones des Alternances		18		Alternances grès et argiles	
	R Isométriques		42		GRES Isométriques, Silts	
	R Anisométriques		125		GRES Anisométriques, Silts	
	R 2		100		GRES Grossiers, Argile	
	R 3		370		GRES Grossiers, Argiles	
	Infra Cambrien		45		GRES Argileux rouge	
	SOCLE				Granite porphyroïde rose	

APPENDIX

APPENDIX B: General Information on X21 Well

- Position :**

X	803,761.86
Y	119,934.65
Ztable	184 m
Zsol	174,93 m

- Petrophysical data:**

Mud type: OBM (Oil-Based Mud); density = 0.88 g/cc; viscosity = 40 s/qt (seconds per quart)

- Logging:**

Phase	Date	Company	Job Description	Observations
16"	21-Nov-2013	HESP	GR / Sonic / Caliper	**
12¼"	02 – 03 Dec 2013	HESP	1st Run: GR/Sonic/Caliper 2nd Run: GR 3rd Run: VSP	**
8¾"	10-Dec-2013	HESP	1st Run: GR/Sonic/Caliper/CBL/VDL of 9⅝" casing 2nd Run: GR/Density	**
6"	16-Dec-2013 / 26-Dec-2013	HESP	1st Run: GR-CAL-SONIC 2nd Run: GR-RESIST-DENSITY-NEUTRON 3rd Run: VSP	CBL/VDL performed before deepening

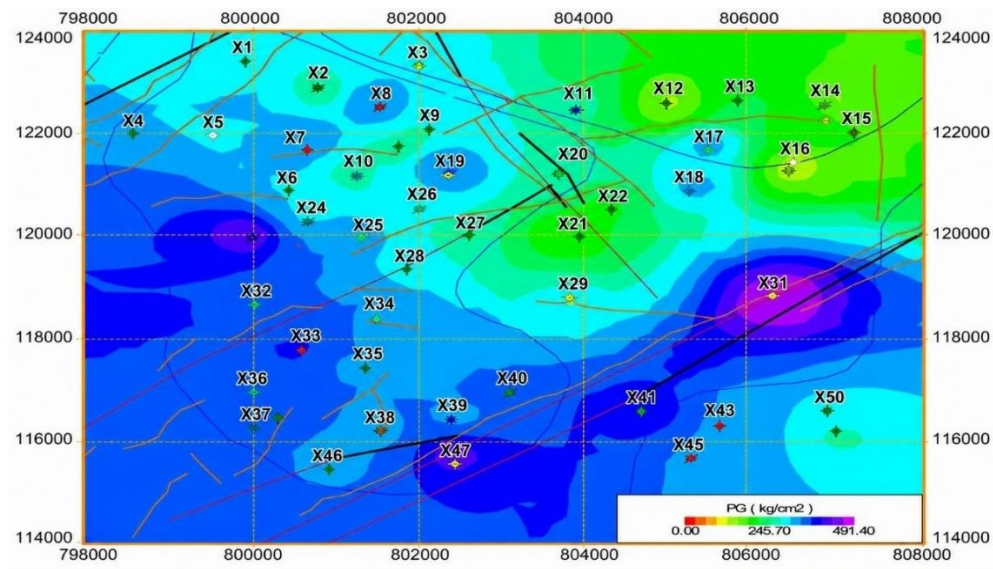
- Casing Depths (Cotes des Tubages)**

Casing Size	Planned Shoe Depth (m)	Actual Shoe Depth (m)	Cement Top (C.E)
18⅝"	506	504	502
13¾"	2,436	2,426	2,395
9⅝"	3,318	3,304	3,305
7"	3,348	3,337	3,337
4½"	-	-	-

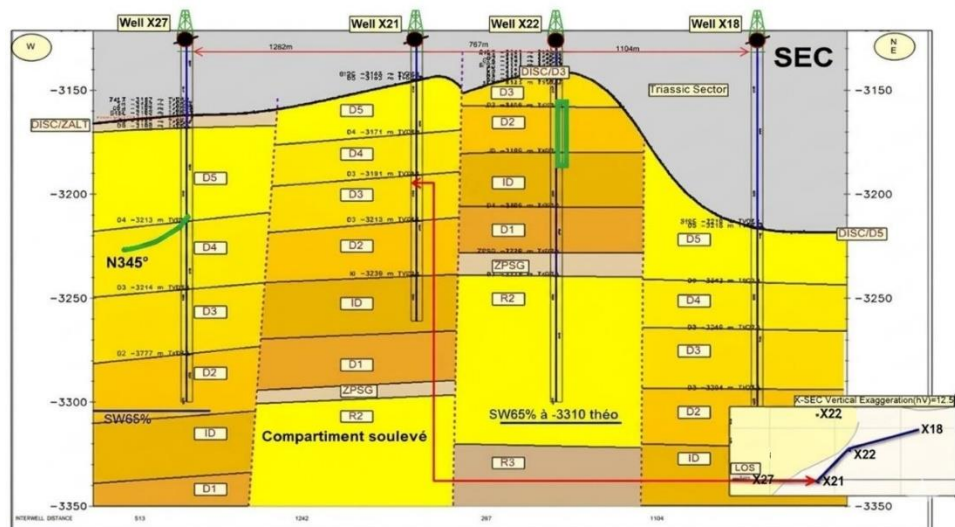
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- Completion Program

Depth (m)	Casing 7"	Cambrian	Well Bottom
Electric	3337	3327	3448.5
Sonde	3337.00	3325	3449



Iso-Pressure Map (Carte Iso-Pression) – Well X21



APPENDIX

Cross Section MD659

APPENDIX C: Results of Well Tests

Parameter	Value	Unit
Reservoir Pressure (Pg)	209.35	kg/cm ²
Flowing Bottomhole Pressure (Pwf)	193.21	kg/cm ²
Wellhead Pressure (Pw)	33.05	kg/cm ²
Flow Rate (Q)	3.96	m ³ /h
Productivity Index (I.P)	0.25	m ³ /h/kg/cm ²
Skin Factor	1.46	-
Gas-Oil Ratio (GOR)	169.0	m ³ /m ³
Hk L (m.md)	1,190.0	m.md
Hk Lointain (m.md)	*	m.md
Hk Proche (m.md)	*	m.md
Choke Size (Duse)	9.53	mm

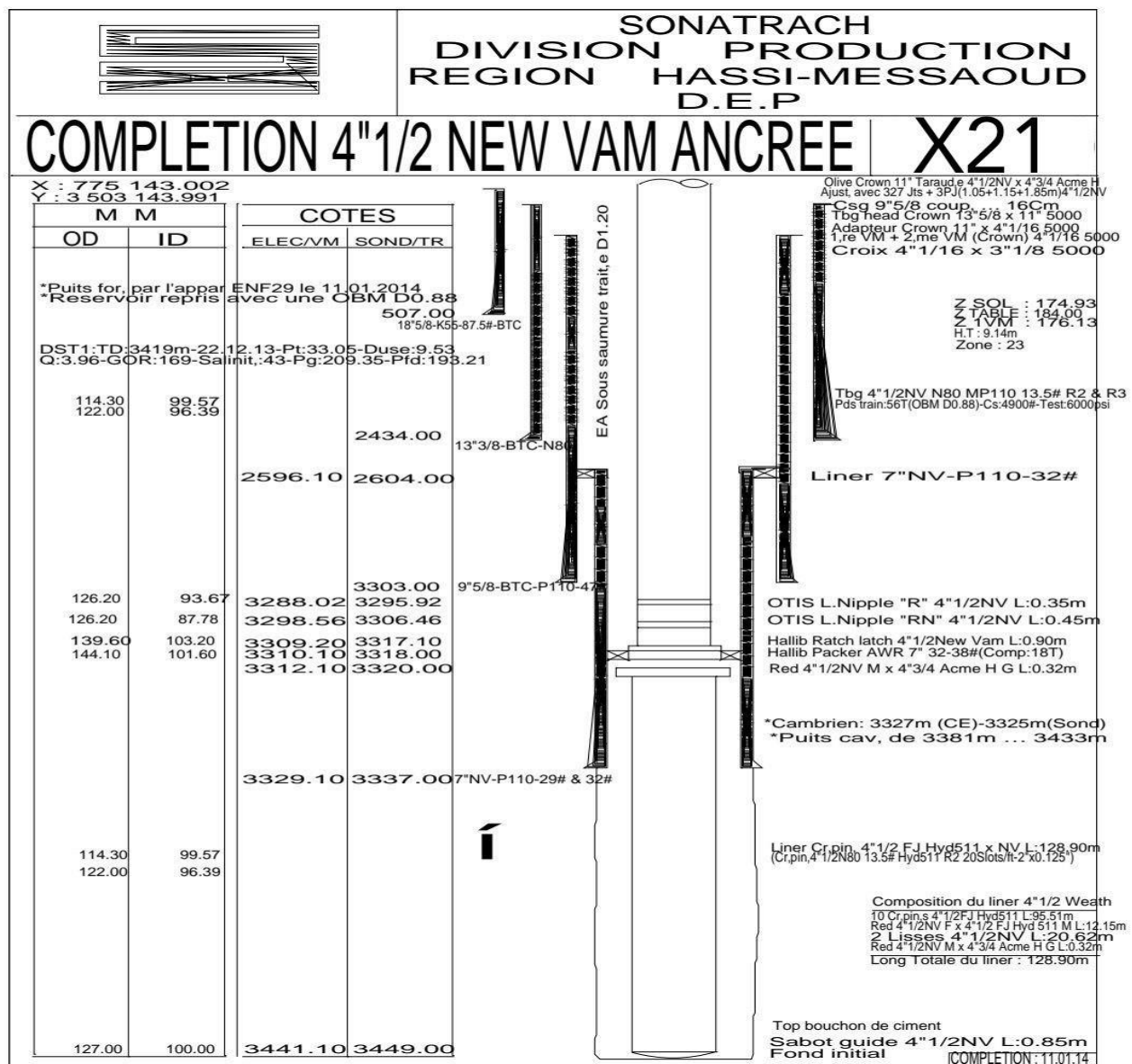
APPENDIX D: Operations performed on X21

Operations performed on X21			
Date Début	Date Fin	Opérations	Sous/opérations
11/01/2015	07/02/2015	SNUBBING	-----
08/12/2014	08/12/2014	WIRELINE	Mesure de pression SBU
04/12/2014	04/12/2014	OPERATION SPECIALE	Kick Off
03/12/2014	03/12/2014	WIRELINE	Mesure de pression SBU
24/11/2014	24/11/2014	WIRELINE	Instrumentation
18/11/2014	18/11/2014	OPERATION SPECIALE	KICK OFF
17/11/2014	17/11/2014	WIRELINE	Grattage Controle
05/11/2014	05/11/2014	OPERATION SPECIALE	Kick Off
28/10/2014	28/10/2014	OPERATION SPECIALE	Kick off
25/10/2014	25/10/2014	OPERATION SPECIALE	Kick Off
22/10/2014	22/10/2014	OPERATION SPECIALE	Kick Off
20/10/2014	20/10/2014	OPERATION SPECIALE	Post frac Clean out
18/10/2014	18/10/2014	OPERATION SPECIALE	Frac
17/10/2014	17/10/2014	OPERATION SPECIALE	Shadow frac
17/09/2014	17/09/2014	OPERATION SPECIALE	Kick Off
16/09/2014	16/09/2014	OPERATION SPECIALE	Matrix 2nd day
15/09/2014	15/09/2014	OPERATION SPECIALE	clean out with Tube clean
13/07/2014	13/07/2014	WIRELINE	Mesure de pression LBU
02/07/2014	02/07/2014	WIRELINE	Mesure de pression LBU
30/06/2014	30/06/2014	WIRELINE	Grattage Controle
26/05/2014	26/05/2014	OPERATION SPECIALE	Clean out
22/04/2014	22/04/2014	OPERATION SPECIALE	OPERATION SPECIALE

APPENDIX

22/04/2014	22/04/2014	OPERATION SPECIALE	Acide 2 eme phase
21/04/2014	21/04/2014	OPERATION SPECIALE	Acide 1 ere phase
15/04/2014	15/04/2014	WIRELINE	Grattage Controle
11/04/2014	11/04/2014	WIRELINE	Grattage Controle
17/03/2014	17/03/2014	OPERATION SPECIALE	clean Out
21/02/2014	21/02/2014	OPERATION SPECIALE	mise en production
01/01/2014	01/01/2014	DIAGRAPHIE	-----
16/12/2013	16/12/2013	DIAGRAPHIE	-----
10/12/2013	10/12/2013	DIAGRAPHIE	-----
02/12/2013	02/12/2013	DIAGRAPHIE	-----

APPENDIX E: Technical Data Sheet of X21



COMPLETION : 11.01.14

APPENDIX

APPENDIX F: Technical Data Sheet of X21 after SNB

