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Presented by:

**LAMARAT Abdelmounaim , MEGHAOURI Mohammed Rida**

**THEME**

|                                                                                                          |
|----------------------------------------------------------------------------------------------------------|
| Modeling and optimization of performance (production, pressure) by gas-lift injection. RHOUD NOUSS field |
|----------------------------------------------------------------------------------------------------------|

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Jury :

President : KORAICHI ASMA

Supervisor : DOUAK MOHAMED

Examiner : MILOUDI MUSTAPHA

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## إهداء

طريقٌ طويل طويناه، وعقبات ظنناها جبلاً فجعلها الله بتوفيقه وتيسيره سراباً. لم يكن الوصول سهلاً، ولم تكن ليالي السهر هينة، لكن لذة البلوغ أنستني مشقة البدايات، ولأن الأحلام العظيمة تستحق عناء الرحلة.. سهرت، وتعبت، وحصدت.

إلى من غرس في روحي بذور الطموح، وسقى دربي بجهدهِ وتضحيتهِ ليصنع مني طالباً للعلا. إلى من كان ظهري حين تميل بي الأيام، وأول من آمن بي وبعثرتي قبل نجاحي.. إلى قدوتي، وعزي، وتاج رأسي...

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# إهداء

من قال أنا لها "نالها"  
وأنا لها إن أبت رغما عنها اتيتُ بها.  
لم تكن الرحلة قصيرة ولا ينبغي لها ان تكون لم يكن الحلم قريبا ولا الطريق كان محفوفًا بالتسهيلات  
لكنني فعلتها و نلتها.  
إلى الذي زين اسمي بأجمل الألقاب، من دعمني بلا حدود واعطاني بلا مقابل...  
من علمني أن الدنيا كفاح وسلاحه العلم والمعرفة داعمي الأول في مسيرتي و سندي وقوتي وملاذي  
عند الله ...  
إلى فخري واعتزازي  
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إلى من جعل الله الجنة تحت أقدامها واحتضنتني قلبا قبل يدها وسهلت لي الشدائد بدعائها إلى القلب  
الحنون  
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أصدقائي الذين بمثابة إخوتي  
...مانو، ضياء، طارق، شمس الدين، حسام وأحمد...  
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## Abstract:

This thesis optimizes the Gas Lift performance of three wells equipped with a Concentric Tubing completion. Using PIPESIM simulation, the economic optimum gas injection rate was determined for each well, while keeping the injection depth fixed due to practical field constraints. Results showed that a strategic reallocation of the available lift gas—reducing over-injection in one well to kick-off a dead well and boost an under-performing one—increased total field production by 52.4 m<sup>3</sup>/d. This significant gain was achieved without increasing total gas consumption or compression requirements, proving the high technical and economic efficiency of the optimization strategy.

**Keywords:** Gas Lift, Activation, Optimization, Nodal Analysis, PIPESIM, Concentric Tubing, Gas Lift Performance Curve (GLPC), Optimum Injection Rate.

## Résumé :

Ce mémoire optimise les performances du système d'extraction au gaz (Gas Lift) pour trois puits équipés de tubes concentriques. À l'aide de la simulation PIPESIM, le taux d'injection de gaz économique optimal a été déterminé pour chaque puits, la profondeur d'injection restant fixe en raison des contraintes opérationnelles. Les résultats montrent qu'une redistribution stratégique du gaz disponible — réduisant la sur-injection d'un puits pour réactiver un puits mort et stimuler un puits faible — a augmenté la production totale de 52,4 m<sup>3</sup>/j. Ce gain important a été réalisé sans augmenter la consommation globale de gaz ni l'énergie de compression, prouvant la grande efficacité de l'optimisation.

**Mots-clés :** Gas Lift, Activation, Optimisation, Analyse Nodale, PIPESIM, Tubes Concentriques, Courbe de Performance (GLPC), Taux d'Injection Optimum.

## ملخص :

تهدف هذه المذكرة إلى تحسين أداء نظام الرفع بالغاز لثلاثة آبار مجهزة بتقنية الأنابيب متحدة المركز (Concentric Tubing) باستخدام محاكاة PIPESIM. نظراً للقيود الميدانية لتغيير الأنابيب، تم تثبيت عمق الحقن والتركيز على استخراج معدل الغاز الاقتصادي الأمثل لكل بئر. أثبتت الدراسة أن إعادة التوزيع الاستراتيجي للغاز المتاح — بتقليل الحقن المفرط في بئر واستغلال الفائض لإحياء بئر ميت ودعم بئر ضعيف — أدت إلى رفع إجمالي إنتاج الحقل بمقدار 52.4 متر مكعب/يوم. تحقق هذا الإنجاز الكبير بنفس كمية الغاز الإجمالية ودون طاقة ضغط إضافية، مما يؤكد الكفاءة الاقتصادية لعملية الأمثلة.

**الكلمات المفتاحية:** الرفع بالغاز، التحسين، تنشيط، التحليل العقدي، برنامج PIPESIM، الأنابيب متحدة المركز، منحى أداء الرفع بالغاز، معدل الحقن الأمثل.

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## **List of Abbreviations**

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API: American Petroleum Institute

BHP: Bottom Hole Pressure (bar / psi)

FBHP: Flowing Bottom Hole Pressure (bar / psi)

GLPC: Gas Lift Performance Curve

GLV: Gas Lift Valve

IPR: Inflow Performance Relationship

MD: Measured Depth (m)

OPEX: Operational Expenditure (\$)

PVT: Pressure Volume Temperature

SPM: Side Pocket Mandrel

VLP: Vertical Lift Performance

WHP: Wellhead Pressure (bar / psi)

## List of Symbols

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Bo: Oil Formation Volume Factor ( $\text{m}^3/\text{m}^3$ )

d: Density

GOR: Gas Oil Ratio ( $\text{sm}^3/\text{sm}^3$  / scf/STB)

Pb: Bubble Point Pressure (bar)

PI: Productivity Index (bbl/d/psi)

Pr: Reservoir Pressure (bar)

Qg: Gas Injection Rate ( $\text{m}^3/\text{d}$  / STB/d)

Ql: Liquid Production Rate ( $\text{m}^3/\text{d}$  / STB/d)

uo: Oil Viscosity (cp)

WC: Water Cut (%)

$\Delta p$ : Pressure Drop (bar / psi)

**List of Annexes**

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Annexe : WELL COMPLETIONS

# **Introduction**

## **INTRODUCTION :**

Oil and gas currently serve as humanity's primary energy sources and are indispensable raw materials for numerous industries. The demand for these fossil fuels continues to rise, a trend that is unlikely to reverse, particularly with the emergence of new economic powers. Consequently, producing countries are compelled to increase their output to meet this growing demand.

Achieving this requires either the discovery of new reservoirs—which is becoming increasingly difficult and costly—or the production optimization of already discovered fields. Ultimately, a reservoir's production depends not only on its natural potential but also on the performance of the production system implemented to exploit it.

In many wells, the natural energy driving the oil cannot generate a sufficient pressure differential between the reservoir and the wellbore to lift the fluids to the surface facilities. In other instances, this natural energy simply cannot sustain an adequate flow rate. Under such conditions, the well is classified as non-flowing or incapable of natural flow.

Among the most widely used artificial lift methods is Gas Lift. This technique is applied to non-flowing or underperforming wells by injecting compressed gas as deep as possible into the production tubing to stimulate fluid production.

In this thesis, we will investigate the impact of gas injection to optimize reservoir production in RHOUD NOUSS field.

The objectives of our study are as follows:

- Model the production system using PIPESIM software.
- Conduct a sensitivity analysis of well performance against various parameters.
- Forecast the evolution of production over time.
- Evaluate the effect of an artificial lift technique, specifically gas lift, on overall production.

To achieve these outlined objectives, this thesis is structured into four main chapters. Chapter One provides a comprehensive overview of the Rhourde Nouss field, detailing its exploration and development phases, structural divisions, and stratigraphic profile. Chapter Two delves

into the Gas Lift artificial lift method, exploring its fundamental principles, techniques, applications, types, and key operational parameters. Chapter Three focuses on well performance and introduces the PIPESIM software, breaking down Nodal Analysis, IPR, and VLP concepts, alongside the specific correlations used to model their curves. Finally, Chapter Four presents a practical case study of three non-flowing (dead) wells. Through detailed simulation, we conduct a sensitivity analysis on the impact of gas injection and determine the optimum gas injection rate to maximize the production of each individual well.

**CHAPTER I**

**OVERVIEW OF THE**

**RHOUD NOUSS FIELD**

## **CHAPTER I : OVERVIEW OF THE RHOUD NOUSS FIELD**

### **I.1 Introduction :**

The Rhourde Nouss Region is an operational unit of the National Company for the Exploration, Production, Transportation, Processing, and Marketing of Hydrocarbons (SONATRACH). The Rhourde Nouss field was part of the Hassi Messaoud region until January 1984. Its operations were then transferred to the Gassi-Touil region. In 1987, this field became an independent region and was ranked as the second-largest gas-producing region in the country. Production at Rhourde Nouss did not begin until 1988, following the installation of a processing facility . The hydrocarbon accumulations are located in reservoirs from the Triassic, Silurian, and Ordovician periods. The fluids encountered include natural gas, gas with condensate, and crude oil.

### **I.2 Geographical location :**

The Rhourde Nouss region is located 1200 km southeast of Algiers (Figure I.1) . Furthermore, it is situated 280 km southeast of Hassi Messaoud and 350 km northwest of Ain-Amenas . Geographically, it is positioned between :

- Parallels  $29^{\circ}16'$  and  $30^{\circ}$
- Meridians  $06^{\circ}24'$  and  $07^{\circ}$

The region covers an area of approximately 10,000 km<sup>2</sup>. It is bounded to the north by the Gassi-Touil region, and to the south by the Hamra and Tin-Fouyé Tabenkourt regions [3].

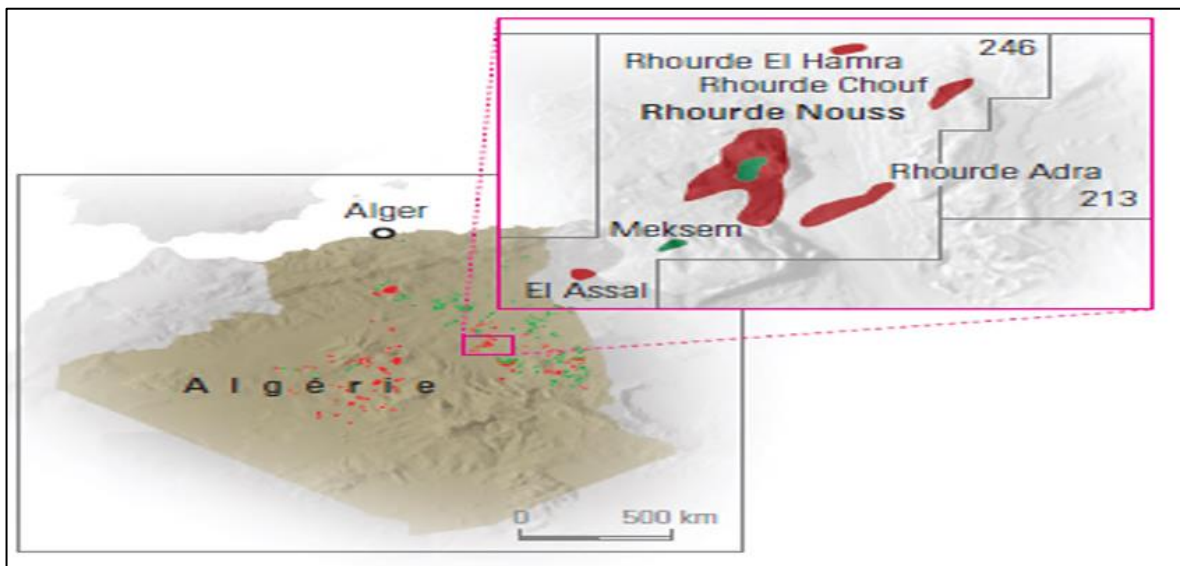


**Figure I.1 : Location of Champs de Rhourde Nouss**

### **I.3 History of Exploration and Development :**

Numerous gravimetric, magnetometric, and seismic surveys conducted across the entire Triassic province have led to the identification of several potential hydrocarbon-bearing structures (Fig I.2). The chronological sequence of studies in this area is as follows:

#### **I.3.1. Major phases of exploration in the region :**

- 1946: First seismic exploration surveys were carried out by the oil companies SN-REPAL and CPA.
- 1948: A vast gravimetric survey campaign was deployed in the northern part of the Sahara.
- 1954: Following encouraging results, reconnaissance operations focused on the Triassic basin. Subsequent detailed reflection seismic surveys were concentrated on the structural highs of Hassi Messaoud, Hassi R'Mel, Rhourde El Baguel, and Rhourde Nouss.
- 1956: Exploration began in the Rhourde Nouss region, conducted by the EL PASO company (France-Africa). The drilling of the HR-1 well at the crest of the Hamra structure allowed the first testing of the Barremian-Neocomian age reservoirs.
- 1958: The drilling of the HR-2 well on the same structure revealed the presence of gas in the Triassic reservoirs.

- 1959: Exploration efforts shifted to the west, where the Ramade structure yielded negative results.
- 1961: Siting and drilling of the RN-1 exploration well. This well discovered gas in the Upper Clayey-Sandstone Triassic with a flow rate of 480,000 m<sup>3</sup>/day. Comprehensive testing conducted in the Argillaceous-Sandstone Silurian demonstrated that it was gas-saturated.
- August 1963: The RN-4 well, drilled on the flank of the structure, revealed the existence of an oil rim in the Upper Clayey-Sandstone Triassic, with a flow rate of 120 m<sup>3</sup>/day. The discovery of this oil rim significantly encouraged further hydrocarbon exploration in the region.
- February 1970: Another oil rim in the Silurian was discovered by the RN-101 well. Meanwhile, a well drilled in June revealed the presence of gas condensate in the Hamra Quartzites.
- 1972: The drilling of the RNSE-1 well in the South-East structure proved the presence of gas condensate and oil in both the Upper Clayey-Sandstone Triassic and the Argillaceous-Sandstone Silurian.
- In 1974: The drilling of the RNSW-1 well on the South-West structure revealed the presence of gas condensate and oil within the Upper Clayey-Sandstone Triassic unit. However, the other reservoirs were found to be entirely water-bearing [5].

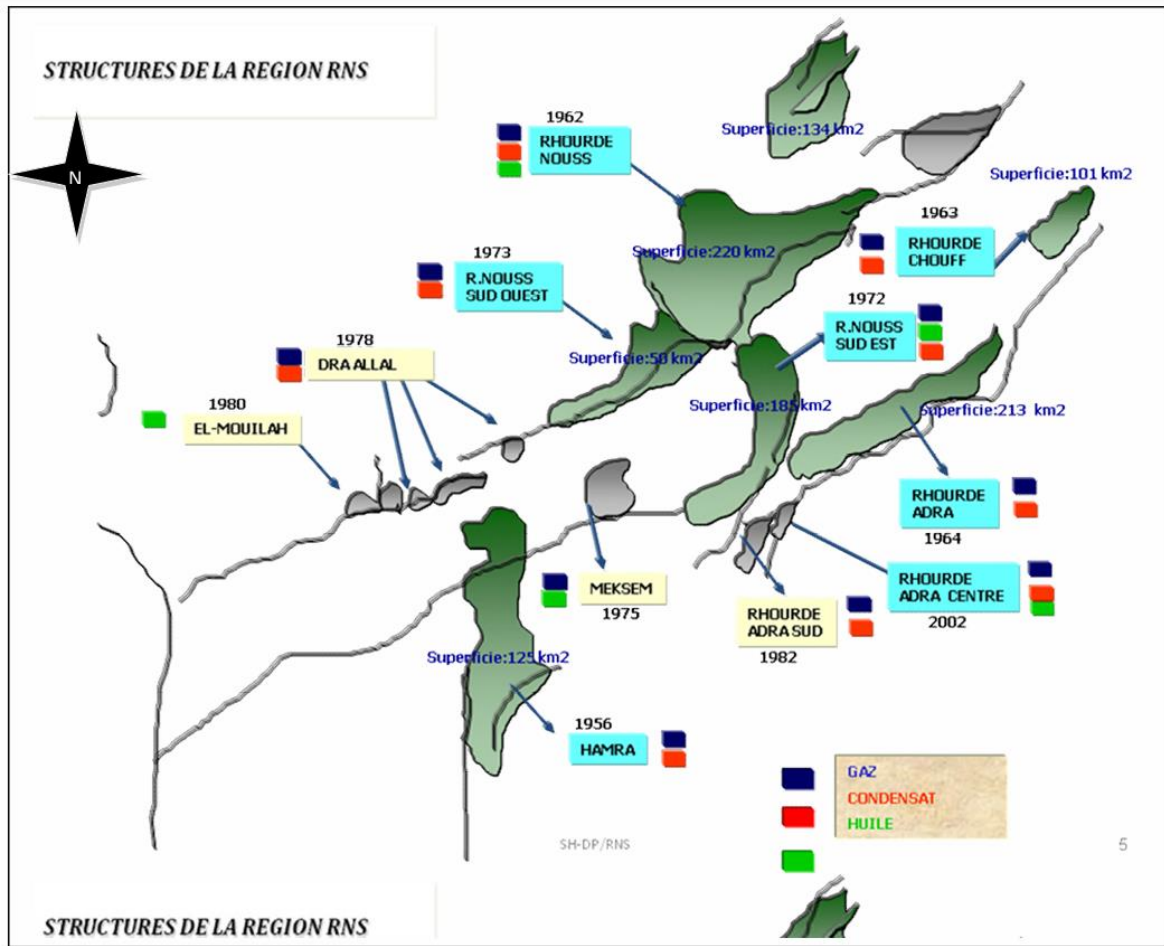


**Fig I.2 Main reservoirs of the Rhourde Nouss field discovered during the exploration phase**

### I.3.2. Main development phases :

- In 1983: Over 80 wells were drilled across the entire region. Dozens of these reached the Hercynian unconformity, and ten successfully reached the Hamra Quartzites (including RN-11, RN-42, and RN-101).
- In 1987: The bringing into production (commissioning) of the Hamra field positioned the region as the second-largest gas field in the country, following Hassi R'Mel.
- In 1990: Start of gas condensate production from the Upper Clayey-Sandstone Triassic (Phase A).
- In 2000: Commissioning of the LPG (Liquefied Petroleum Gas) unit (Phase B).

- In 1998: The effective start of the development of the Hamra Quartzite tight reservoir.
- 2008 to 2013: Intensive development of the Hamra Quartzites reservoir, which included the drilling of over 40 new wells.
- In 2014: Commissioning of the Hamra Quartzite gas condensate Central Processing Facility (CPF).
- In 2017: Start of development for the satellite fields (the periphery of Rhourde Nouss). Operations are ongoing to bring the Silurian Clayey-Sandstone (SAG) reservoirs of the GTL periphery into production via the RNS processing units [5].

### **I.4 Geological context :**

The Rhourde Nouss region is located in the extreme south of the North-Eastern Sahara province (Figure I.2). It behaves as a positive structural zone extending in a meridional (north-south) direction, bounded by major structural elements:

- To the West: By the Amguid-El Biod mole. This mole represents a vast sub-meridional structural unit spanning 600 km, from Amguid in the south to Rhourde El Baguel in the north.
- To the North-East: By the Berkine Basin, towards which the southwest-northeast axes of the Rhourde Hamra and Rhourde Chouff structures plunge.
- To the South-East: By the western part of the Ahara mole. The area is further bordered by the Tin Fouyé Tabenkourt depression to the southeast, and the Maouar structural high to the east [3].

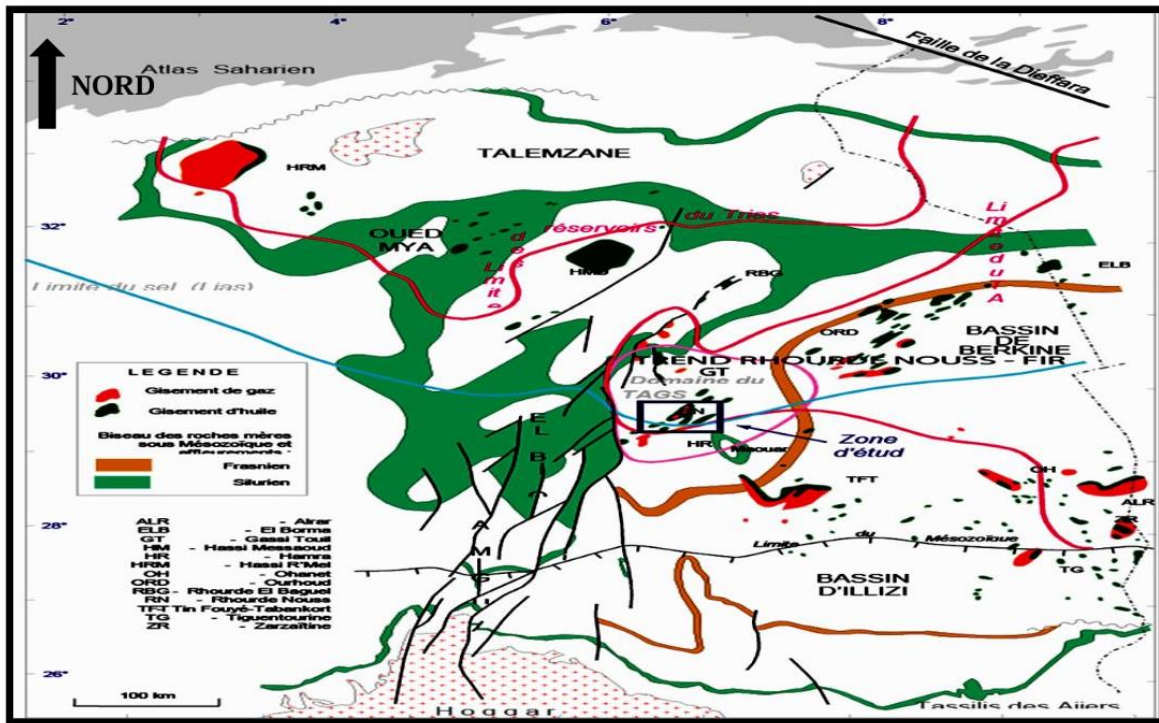


Figure I.3: Geological map of the Rhourde Nouss region

## I.5 Stratigraphic Overview :

The stratigraphic sequence of the Rhourde Nouss region is composed of the following units:

### I.5.1. Ordovician :

Subdivided from bottom to top into:

- ❖ El-Gassi Clays (42 m): A layer of dark gray, silty clay.
- ❖ El-Atchane Sandstones (45 m): Interbedded layers of siliceous sandstone and silty clay.
- ❖ Hamra Quartzites (140 m): A complex of hard, fractured quartzites and compact quartzitic sandstones.
- ❖ Ouargla Sandstones (90 m): This unit primarily consists of siliceous sandstones, containing a few thin layers of silty clay.
- ❖ Azzel Clays (78 m): A layer of dark gray to black, silty clay.
- ❖ Oued Saret Sandstones (80 to 190 m): Alternating layers of sandstone and silty clay.

- ❖ Micro-conglomeratic Clays (36 m): A layer of dark gray to black, silty clay.
- ❖ M'kratta Bed (5 to 30 m): Consists of a quartzitic sandstone layer.

### **I.5.2. Silurian :**

- ❖ Argillaceous Silurian (250 to 320 m): Consists of dark gray to black clay.
- ❖ Triassic: It rests unconformably on the clayey-sandstone Silurian. From base to top, it is divided into:
  - Lower Clayey-Sandstone Triassic (50 m): Composed of fine-grained sandstone with siliceous to silico-argillaceous cement, becoming micro-conglomeratic at the base.
  - Upper Clayey-Sandstone Triassic (100 to 165 m): Represented by metric-thick layers of medium-grained, grayish-white sandstone with siliceous to silico-argillaceous cement, interbedded with siliceous clays[3] .

### **I.6. Oil-related aspects :**

From the exploration phase through to the development of the Rhourde Nouss region, several discoveries have been made.

The identified hydrocarbons are:

- Oil and gas condensate in the TAGS and infra-TAGS of Rhourde Nouss.
- Gas condensate in the TAGS and infra-TAGS of Rhourde Adra.
- Oil and gas condensate in the TAGS of South-East Rhourde Nouss and South-West Rhourde Nouss.
- Oil in the infra-TAGS of South-East Rhourde Nouss (Triassic and Silurian A).
- Gas condensate in the Hamra Quartzites of Central Rhourde Nouss, South-East Rhourde Nouss, and Rhourde Adra.
- Minor amounts of oil in the Hamra Quartzites of South-West Rhourde Nouss and Meksem[3].

## **I.7. Conclusion :**

This chapter presents an overview of the Rhourde Nouss field, Algeria's second-largest gas region. Structurally divided into four main areas, the field's production relies on several complex reservoirs, most notably the naturally fractured Hamra Quartzites (Ordovician) and the TAGS formation (Triassic). Developed continuously since the 1980s, these reservoirs primarily contain gas condensate along with oil accumulations. Understanding these distinct geological characteristics—such as natural fractures and tight formations—is a crucial first step for building accurate well models and optimizing the field's future production performance.

# **CHAPTER II**

## **Gas lift activation method**

## **CHAPTER II : Gas lift activation method**

### **II.1 Introduction :**

At the very beginning of petroleum exploitation, the flow of hydrocarbons, which are most often light, is ensured by sufficient reservoir energy that allows fluid movement from the reservoir to the surface facilities. This is commonly the case in most reservoirs worldwide.

Each hydrocarbon-producing reservoir has a so-called reservoir pressure, which represents the energy (potential) that enables liquids and/or gas to flow from the bottom of the well to the surface, due to the pressure drawdown thus created.

As production proceeds, reservoirs gradually become depleted, experiencing a continuous decline in both pressure and natural flowing energy.

The possible breakthrough of water, which is a relatively heavy fluid, further accelerates this depletion.

At a certain stage, this pressure may become insufficient to sustain natural production.

At this point, the well, which was previously flowing, is said to have become non-flowing and therefore requires the use of artificial lift methods.

Gas lift increases well production by reducing pressure losses through the injection of gas into the tubing at the deepest possible point.

### **II.2 Oil recovery :**

Production from wells in oil fields characterized by strong natural drive mechanisms continues as long as the reservoir pressure remains higher than the pressure exerted at the fluid entry point from the reservoir into the wellbore. However, this condition does not persist indefinitely due to the natural pressure decline resulting from continuous reservoir production. Consequently, the flow of oil from the bottomhole to the surface gradually loses efficiency, making it necessary to support the hydrostatic column within the well to lift the fluids to the surface.

At this stage, oil recovery methods become essential. Oil recovery is generally classified into three main stages:

- **Primary Recovery:** The recovery factor is typically less than 30%.
- **Secondary Recovery:** The recovery factor generally ranges from 30% to 50%.
- **Tertiary Recovery (Enhanced Oil Recovery, EOR):** The recovery factor typically ranges from 50% to 80% .

The focus of this chapter is on artificial lift methods within the scope of primary recovery. Artificial lift is implemented when the reservoir pressure is insufficient to allow the fluid to reach the surface, when the well production rate is too low to be economically viable, or when the well is producing at high water cut. Other factors may also justify the application of artificial lift techniques .

The Figure II.1 below illustrates the well's inability to produce under natural flow conditions due to low reservoir pressure .

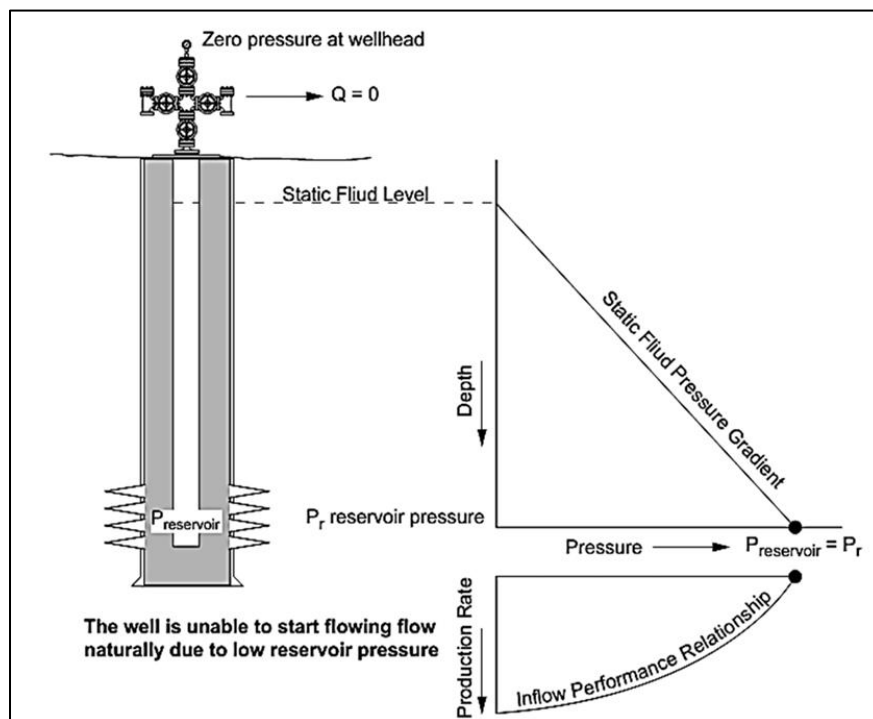


**Figure II.1 : Inability of the well to produce under natural flow conditions due to low reservoir pressure.**

### II.3 Artificial lift techniques :

Various artificial lift methods have been developed for wells where the reservoir energy is insufficient to drive oil to the surface and into the gas-oil separation units (GOSPs) against

their operating pressures. Numerous downhole techniques have been engineered for this purpose, the most significant of which are summarized below (Figure II.2) :

- Sucker Rod Pumps (SRP)
- Electrical Submersible Pumping (ESP)
- Hydraulic Pumping Systems
- Gas Lift (GL)
- Progressing Cavity Pumping (PCP)

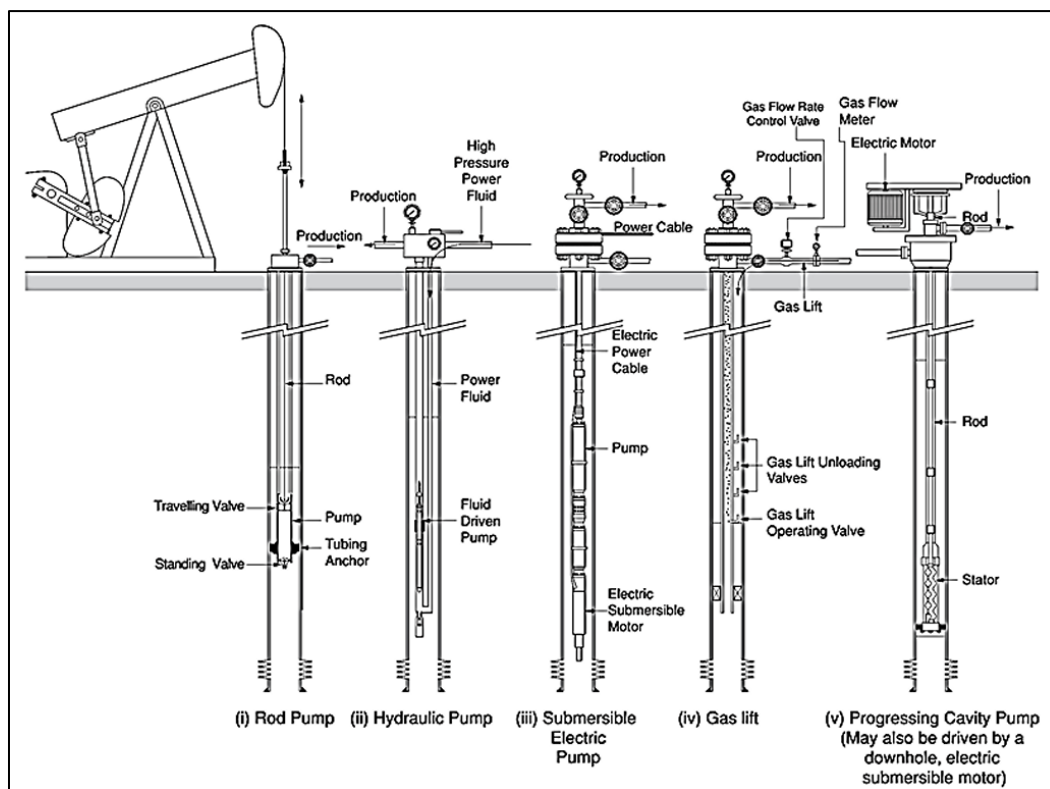


**Figure II.2 : Artificial lift techniques**

### II.4 Gas lift :

This method is used for wells where oil stops flowing to the surface or cannot reach high-pressure separation units. In this process, gas is injected into the well to lift the oil by lowering its density and reducing the weight (hydrostatic pressure) of the oil column. This creates a pressure difference between the reservoir and the bottom of the well, which helps the oil flow

from the ground into the well and then to the surface. Also, as gas bubbles rise and expand inside the production tubing, they push and move the oil upward [6].

### **II.4.1 Gas lift application :**

Gas lift has many applications, and approximately 20% of the world's producing wells use this activation method.

#### **1. Increasing Flow Rate :**

For wells that have a drop in pressure but can still produce without artificial lift, and have a naturally low GOR (Gas-Oil Ratio) or GLR (Gas-Liquid Ratio), gas-lift can be used to increase their production compared to their natural flow.

#### **2. Starting Production in Non-Eruptive Wells :**

In cases where a well cannot flow using its own energy (depleted well), gas-lift is used. By injecting gas to lighten the hydrostatic column, the bottom-hole pressure is reduced. This makes it easier for the fluids to circulate and rise through the tubing.

#### **3. Well Kick-off :**

Sometimes, even a naturally flowing (eruptive) well cannot restart after being shut down or "killed" (neutralization). In this case, it must be activated to regain its flow. If the well is already equipped with gas-lift mandrels, it can be restarted using high-pressure gas.

#### **4. Gas Well Unloading :**

Gas lift is a highly effective application for addressing 'Liquid Loading' in gas wells. By injecting high-pressure gas, it facilitates the removal of accumulated liquids from the wellbore that obstruct the natural flow of gas, thereby reducing hydrostatic back-pressure and restoring the well's optimal production capacity [6].

### **II.4. 2 The Principles of Gas-lift :**

Gas is injected into the annulus (the space between the casing and tubing) to the maximum depth possible. The gas then enters the tubing through Gas-Lift Valves, which are installed within the tubing string inside special holders called Side Pocket Mandrels. Once the gas enters the tubing, the flow starts and production begins based on the following :

1. **Gas Expansion:** The expansion energy of the gas inside the tubing lifts the liquid to the surface.
2. **Gas Solubility:** The gas dissolves in the oil within the tubing, reducing the specific gravity of the liquid. This decreases the hydrostatic pressure of the fluid column and its resulting pressure gradient. Consequently, the flowing bottom-hole pressure (driven by the reservoir pressure) becomes higher than the pressure required for production.

### II.4.3 Gas lift types :

**II.4.3.1 Depending on the injection method :** Gas lift is achieved by either continuous or intermittent gas injection.

#### a) **Continuous Gas Lift (CGL) :**

Continuous gas lift is the most used mode of gas lift injection. In this technique, high-pressure gas is injected continuously into the annulus between the casing and the tubing. The injected gas enters the tubing through one or more gas-lift valves installed at a specific depth. the gas mixes with the produced fluids, forming a gas–liquid mixture with a lower density than the original liquid column. This reduction in hydrostatic pressure decreases the flowing bottomhole pressure, enabling the reservoir pressure to lift the fluids to the surface more efficiently (Figure II.3) .

Continuous gas lift therefore operates in a steady-state flow regime , and it is typically applied in wells with medium to high production rates where the reservoir pressure is still sufficient to sustain continuous flow.

It is commonly used in large oil fields due to its operational reliability and ability to handle challenging conditions such as sand production and deviated wells, since it contains no moving mechanical parts in the downhole . However, the system requires a reliable source of injection gas and surface compression facilities, which increases operational costs, and its efficiency decreases significantly in wells with very low production rates.

**b) Intermittent Gas Lift (IGL) :**

Intermittent gas lift is a type of gas lift used mainly for wells with low productivity or insufficient reservoir energy to sustain continuous production. In this method, gas is injected periodically in cycles rather than continuously. At the beginning of each cycle, gas injection stops, allowing formation fluids to accumulate in the production tubing at the bottom of the well. When the injection valve opens, a high-pressure gas slug enters the tubing and pushes the accumulated liquid column toward the surface.

Fluids are therefore produced in separate batches called “slugs” instead of a continuous flow. After the liquid slug reaches the surface and the tubing is partially emptied, gas injection stops again and the accumulation phase restarts, repeating the cycle (Figure II.3).

This method is characterized by unsteady flow conditions and variable production rates and is suitable for mature wells with declining reservoir pressure or marginal wells with low liquid production. Although it requires less injection gas than continuous gas lift and can extend the productive life of low-rate wells, it generally results in less stable flow behavior and lower production efficiency [6].

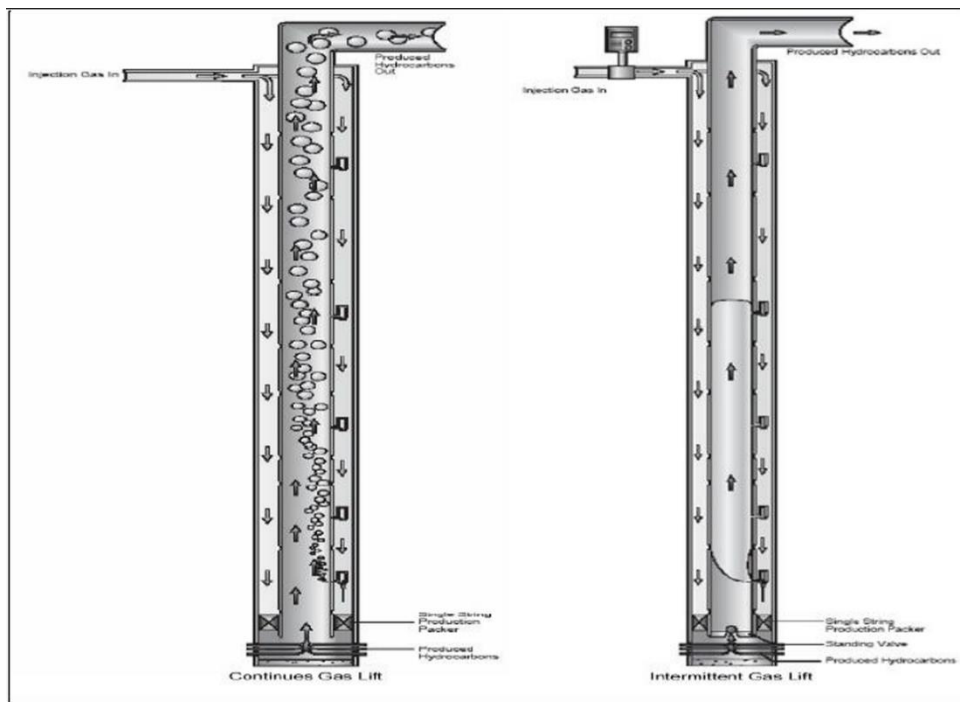


**Figure II.3 : Continuous and Intermittent Gas Lift**

**II.4.3.2 Depending on the type of completion :** Gas lift can be used in both single and multiple completions, and well production can be :

**a) Completions for direct gas lift :**

Gas is injected into the annular space between the tubing and casing and the reservoir produced by the tubing. This is the most common design due to its simplicity and ease of operation.

**b) Reverse gas lift :**

**b.1) Concentric tubing :** a small-diameter string lowered into the existing production tubing (Figure II.4), named for its thin shape, and is used as a simple, cost-effective artificial lift solution for wells not originally equipped with gas lift valves. In this system, gas is injected through the Concentric string rather than the annulus, traveling down to a specific depth where it exits to mix with fluids within the original 7" or 4.5" tubing to reduce their density and lift them to the surface. This concentric setup is typically installed using a snubbing unit, which allows the pipe to be run even under pressure without killing the well, ensuring that production continues through the initial tubing rather than the casing.

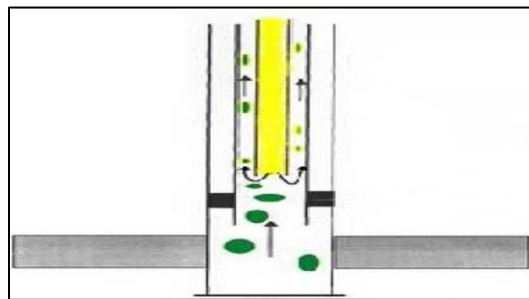


**Figure II.4 : Concentric tubing**

**b.2) Gas-Lift with Production through the Casing :** For very high flow rates, wells can be designed so that reservoir production flows directly through the casing, while gas is injected through the tubing. However, this method has several disadvantages such as Measurement Limitations it is impossible to take measurements (such as pressure or temperature) on the fluid side between the tubing and the casing , High Gas Volumes large volumes of gas are required, and the design and equipment used must be specialized.

**b.3) Dual Gas-Lift :** For multiple completions where two different levels (zones) are produced separately, the main challenge with this type of gas-lift is the space constraint (bulkiness), especially regarding the valves (Figure II.5) [6].

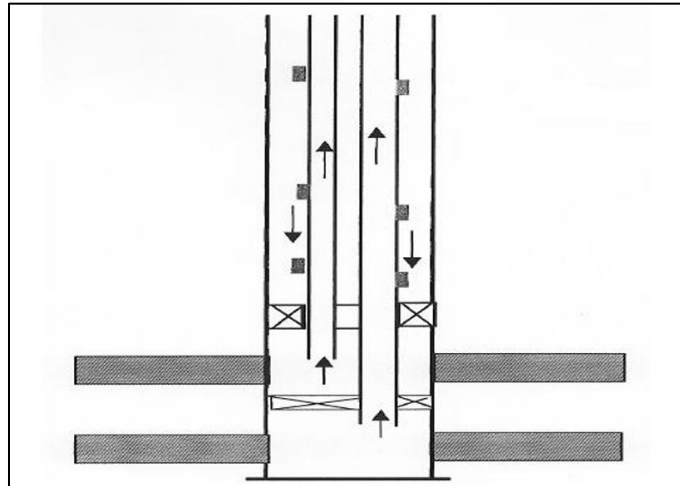


**Figure II.5 : Dual Gas-Lift completion**

#### **II.4.3.3 Based on the Surface Injection Circuit :**

- a) **Closed-Loop Gas-Lift :** The gas used for the gas-lift is recovered from the separators' outlet. After undergoing several treatment phases (such as natural gasoline removal and dehydration), the gas is re-compressed by a compressor battery and re-injected into the well (Figure II.7) .
- b) **Open-Loop Gas-Lift :** Treated gas from a gas reservoir (gas field) is used for the gas-lift. After use, this gas is either burned at the flare or sold in the market (commercialized) (Figure II.6) .

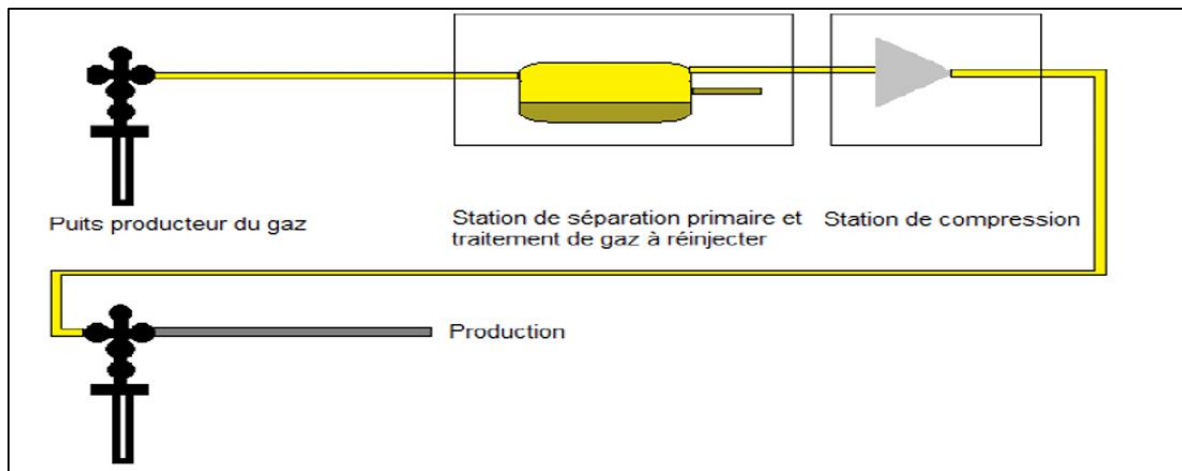


Figure II.6 : Open-Loop Gas-Lift

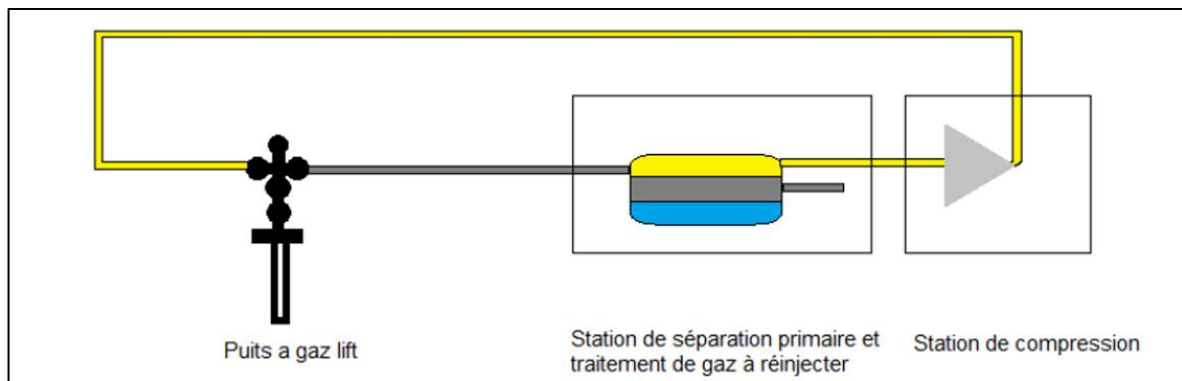


Figure II.7 : Closed-Loop Gas-Lift

- c) **Auto Gas-Lift** : This type of gas-lift is a very special case, as it depends on the completion design and the nature of the reservoir (the presence of a Gas Cap). In this scenario, the source of the injection gas is underground. Perforations made in the liner directly across the gas cap zone allow gas to flow into the annulus. Consequently, this gas performs the same role as gas injected from the surface [1].

#### II.4.4 The Main Parameters of Gas-Lift :

- a) - **Injected Gas Pressure** :

is the pressure at which gas is injected from the surface into the well in order to enter the production tubing through the Gas Lift Valves. This pressure must be high enough to

overcome the pressure in the annulus, open the gas lift valve, and allow the injected gas to flow into the tubing. Once the gas enters the production tubing, it mixes with the produced fluids and reduces the density of the fluid column, which decreases the hydrostatic pressure and facilitates the lifting of fluids to the surface.

The available injection gas pressure also affects the number of **unloading valves** installed in the well. Unloading valves are placed at different depths and are used during well start-up to gradually remove the liquid column, reduce tubing pressure, and allow gas to reach deeper valves; this process is known as **the Gas Lift Unloading Process**.

When the available gas injection pressure is sufficiently high, the well can operate using a **Single-Point Gas Lift system**, where only one injection valve is installed and no unloading valves are required. In this case, the high gas pressure allows the injected gas to reach the deep operating valve directly and overcome the hydrostatic pressure of the fluid column. This configuration significantly simplifies the design, operation, and maintenance of the well because fewer valves are required and the unloading procedure becomes unnecessary. However, when the available gas pressure is relatively low, it may not be sufficient to start the well. In such cases, the injection pressure is temporarily increased by about 10 to 15 bar for a few hours to initiate the well start-up process and allow the unloading of the liquid column until the gas reaches the operating valve. After the well begins producing normally, the pressure can be reduced to its regular operating value.

The surface injection pressure is commonly estimated using the R. V. Smith equation, which is widely applied in gas lift design. This method is based on calculating the pressure losses in the vertical gas column, taking into account several parameters such as the injected gas rate, the injection pressure at the bottom of the well, and the pressure losses occurring along the gas path due to friction, gas weight, and pressure variation with depth.

**R.V. SMITH Formula :**

$$e^s P_1^2 - P_2^2 = \frac{Q_g^2 \gamma_g T X f Z (e^s - 1)}{d^5 S} * 0.925 * 10^{-2} \quad (\text{II. 1})$$

**P<sub>1</sub>:** Surface injection pressure, in bar.

**P<sub>2</sub>:** Bottom-hole injection pressure, in bar.

**Q<sub>g</sub>**: Gas injection rate, in cubic meters per day (m<sup>3</sup>/day).

**γ<sub>g</sub>**: Gas specific gravity (relative density).

**T̄**: Average temperature in the well, in Kelvin (K).

**X**: Injection depth, in meters (m).

**f**: Friction factor, depends on Reynolds number and pipe roughness.

**Z**: Gas compressibility factor, accounts for non-ideal gas behavior.

**d**: Diameter of the tubing, in meters or specified units.

**S**: A coefficient defined as  $0.0685 \times (\gamma_g \times X) / (T \times Z)$ , representing the effect of the gas column weight.

**Re**: Reynolds number for the gas flow, calculated as  $18 \times \gamma_g \times Q_g / (\mu_g \times d)$ , used to determine the flow regime.

**μ<sub>g</sub>**: Gas viscosity, used in Reynolds number calculation.

- This equation is used to calculate the relationship between P1 and P2 taking into account pressure losses that occur when gas moves inside the injection column in the well.
- In other words, the equation helps us determine : how much gas pressure should be at the surface P1 in order to reach the injection depth with the required pressure P2 [1] .

### **b) - Injection depth :**

Injection depth is defined as the depth at which the injected gas enters the production tubing through the operating gas lift valve. It is one of the most important parameters in the design and optimization of gas lift systems because it directly affects the pressure distribution in the well and the overall lifting efficiency.

From a theoretical point of view, the efficiency of the gas lift system increases when the injection point is located deeper in the well. Injecting gas at a greater depth allows a larger portion of the fluid column to be aerated, which significantly reduces the average density of

the mixture inside the tubing. This reduction in density leads to a lower pressure gradient in the tubing and therefore improves the production rate of the well.

However, the injection depth cannot be chosen arbitrarily. It is mainly limited by the available gas injection pressure at the surface. The injected gas must have sufficient pressure to travel down the annulus and overcome the pressure of the fluid column in the tubing at the injection point. If the available gas pressure is insufficient, the gas will not be able to reach deeper valves and the injection depth must be placed at a shallower level.

From a practical and operational perspective, the injection depth is usually established through the installation of several gas lift valves at different depths during the completion stage. These valves include unloading valves and one operating valve. During the well start-up process, the unloading valves allow the gradual removal of the liquid column from the tubing. As the pressure conditions change, the gas injection point progressively moves deeper until the deepest valve, known as the operating valve, becomes active. Under stable production conditions, gas injection occurs only through this deepest valve, which defines the effective injection depth of the gas lift system.

In engineering practice, the determination of the optimal injection depth requires the analysis of several parameters such as reservoir pressure, bottom-hole flowing pressure, tubing pressure gradient, available surface injection pressure, gas injection rate, and well geometry. These parameters are usually evaluated using well performance analysis and production simulation tools such as PIPESIM, which allow engineers to model the well behavior and determine the most efficient injection depth for maximizing production .

Therefore, the correct selection of the injection depth is essential for ensuring efficient gas lift performance, stable well operation, optimal gas utilization, and improved hydrocarbon production [1].

### **c) - Gas injection rate :**

Gas injection rate is the volume of gas injected into the well per unit time to assist the lifting of reservoir fluids to the surface, usually expressed in  $\text{Sm}^3/\text{day}$  or  $\text{SCF/D}$ . It is a key operational parameter in gas lift systems because it affects the pressure gradient in the

production tubing and the overall well performance. The injected gas mixes with the produced liquids through the gas lift valve, forming a gas–liquid mixture with lower density than the original fluid column. This reduces the hydrostatic pressure and lowers the bottom-hole flowing pressure, allowing reservoir fluids to flow more easily to the surface. However, the gas injection rate must be carefully optimized, since both insufficient and excessive injection can reduce production efficiency. A low injection rate provides limited density reduction, while excessive gas may cause unstable flow and inefficient lifting, a condition known as over-injection. In practice, the relationship between gas injection rate and liquid production rate is represented by the gas lift performance curve, which shows an optimum gas injection rate beyond which additional gas does not improve production. Determining this optimal rate requires analyzing parameters such as reservoir pressure, injection depth, tubing pressure gradient, fluid properties, and gas availability, often using simulation tools like PIPESIM to maximize production while minimizing gas consumption.

### **II.4.5 Advantages and disadvantages of the gas lift :**

#### **a) - Advantages :**

- The initial equipment cost for Simple Gas-Lift (SGL) is generally low.
- Gas-lift is suitable for all well profiles, including highly deviated or S-shaped (helical) wells. The only requirement is the ability to lower a wireline tool string to install the valves when necessary.
- Large volumes of fluid can be produced using gas-lift; the only limiting factor is the pressure drop
- Gas-lift is compatible with producing solids (sand) or large volumes of water.
- The ability to use gas produced locally from the field.

#### **b) – disadvantages :**

- Injection gas may not be available for the operation .
- Not suitable for lifting high-viscosity crude oil or emulsions .
- Susceptible to gas freezing and hydrate formation at low temperatures.

- Pressure Limitations: High minimum Flowing Bottom-Hole Pressure (FBHP); consequently, the abandonment pressure may not be reached.

## **II.5 Why use Gas-Lift in RHOUD NOUSS ?**

- Abundance of Injection Gas: Since RNS is primarily a gas field, the required injection gas is readily available in large quantities. This eliminates the need for external gas sources and significantly reduces the overall operational costs.
- Sand Handling: The RNS field faces significant sand production challenges. Gas-Lift is considered the most effective well activation method in such environments. Unlike other methods, such as Electrical Submersible Pumps (ESP), Gas-Lift has no moving parts downhole, which prevents mechanical wear and erosion caused by sand particles.
- Efficient Solids Transport: Gas-Lift facilitates the lifting of produced sand from the reservoir formation to the surface. By maintaining sufficient flow velocity, it prevents sand from settling at the bottom-hole, which could otherwise lead to the blockage or "burying" of the production perforations, once the sand reaches the surface, it can be efficiently separated and managed using surface facilities such as sand filters, ensuring the safety and integrity of the production equipment.
- Gas-lift is highly effective in RNS for handling high flow rates and managing large volumes of associated fluids.

## **II.6 conclusion :**

The principle of gas-lift is to use the gas produced from the field to increase the daily amount of oil extracted when the reservoir begins to "lose its energy" or decline.

# **CHAPTER III**

## **Well performance and Pipesim Overview**

## CHAPTER III : Well performance and Pipesim Overview

### III.1 Introduction :

The nodal system involves segmenting the various components of a well completion to forecast flow rates and optimize the production system. Figure (Fig.III.1) presents a simplified schematic of the produced fluid flow during operations. This flow path can be subdivided as follows :

1. Flow through the porous medium .
2. Flow in vertical or inclined tubing .
3. Flow in a horizontal or inclined pipe at the surface .

The figure (Fig. III.1) illustrates the various pressure drops that can occur throughout the production system, from the reservoir to the separator. To simplify this system, nodes are placed to connect the various segments, so that they can be defined by equations or correlations. The most commonly used node is point  $P_{wf}$  (well bottom), where the selection of the system allows us to subdivide it into :

- Reservoir system
- Well equipment system ( tubing , Pipelines )

Based on the principle of the nodal system, we can plot the evolution of reservoir pressure as a function of flow rate, known as “ inflow ” and bottomhole pressure as a function of wellhead pressure, known as “ outflow ” .

Inflow equation :

$$P_r - \Delta P_{res} = P_{wf} \quad (III. 1)$$

Outflow equation :

$$P_{sep} + \Delta P_{pipe} + \Delta P_{tubing} = P_{wf} \quad (III. 2)$$

The bottom-hole flowing pressure  $P_{wf}$  is the equilibrium point where the energy delivered by the reservoir (inflow) perfectly matches the energy required by the production system to lift the fluids to the surface (outflow) [1].

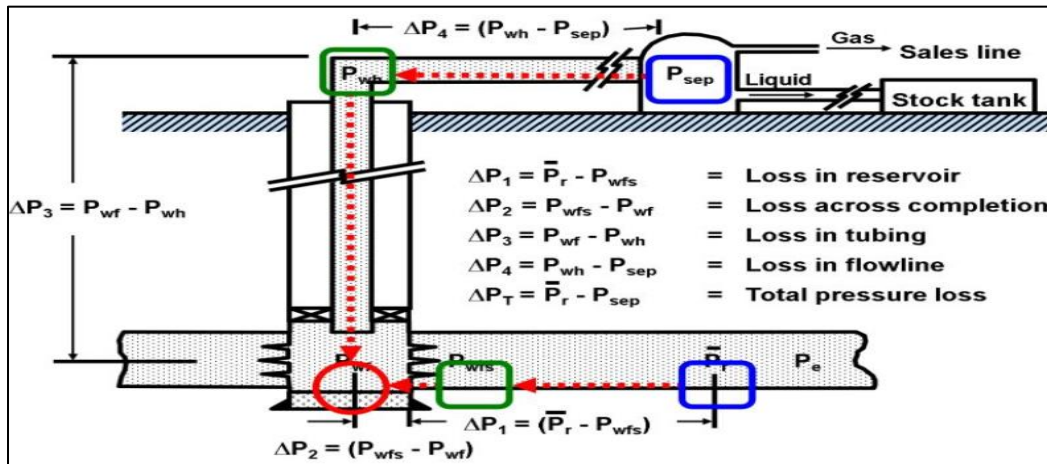


Figure III.1 : Pressure drops in a production system

### III.2 Pressure Drops :

When a well is producing, the fluid (effluent) enters the wellbore at its bottom-hole flowing pressure ( $P_{wf}$ ) and reaches the surface at its wellhead flowing pressure ( $P_{whf}$ ). During this upward journey, which typically covers several kilometers, energy is lost in the form of pressure drops . These pressure drops are the sum of two factors :

- **Friction losses:** Caused by the fluid flowing against the tubing walls.
- **Hydrostatic weight:** The weight of the fluid column (gas, water, and oil) inside the tubing.

Gas-lift helps increase a well's production by reducing the total pressure drops. This is achieved by injecting gas into the tubing at the deepest possible point . This process creates two opposing effects :

- An increase in friction losses (negative effect) .
- A decrease in the weight of the fluid column (positive effect) .

### III.3 Fundamentals of Nodal Analysis :

**Nodal Analysis**, invented by Gilbert, is considered the most important and widely used tool in production engineering for evaluating, designing, and optimizing the performance of oil and gas wells. This method relies on fundamental laws of physics, specifically the principles of **Mass Conservation** and **Momentum Conservation**.

The core idea of this analysis is very simple: we divide the entire production journey (from inside the reservoir at the bottom up to the surface facilities) into two main sections :

1. **Inflow Section:** Represents the fluid movement from the reservoir.
2. **Outflow Section:** Represents the fluid movement inside the pipe towards the surface.

These two sections are separated by an imaginary intersection point that we choose, called the "**Node**".

Mathematically and physically, for the well to produce stably, the two sections (inflow and outflow) must satisfy two basic conditions at this "Node":

- **The First Condition (Flow Continuity):** The amount of fluids reaching the node from the reservoir must exactly equal the amount leaving it and traveling to the surface.

$$Q_{in} = Q_{out}$$

- **The Second Condition (Pressure Match):** The pressure calculated at this node coming from the reservoir direction must perfectly match the pressure calculated at the same node but working backwards from the surface direction.

$$P_{node\ inflow} = P_{node\ outflow}$$

In this study , the Bottomhole was selected as the node. This allows the separation of reservoir performance (IPR) from production tubing performance (VLP) to facilitate the evaluation of the gas lift effect [9].

**III.3.1 Inflow Performance Relationship (IPR) :**

The Inflow Performance Relationship (IPR) curve represents the mathematical and physical relationship between the fluid production rate  $Q$  and the flowing bottomhole pressure  $P_{wf}$ . In other words, it reflects the "reservoir's ability" to drive fluids towards the bottomhole. The primary driving force here is the pressure drop, commonly known as the **Drawdown**, which represents the difference between the static reservoir pressure  $P_r$  and the flowing bottomhole pressure  $P_{wf}$ . This phenomenon is governed by Darcy's Law of flow in porous media.

**A. Single-Phase Flow - PI Model :**

Darcy's experiments result in what is known as "**Darcy's law**". For general flow through a porous media:

$$Q = \frac{K A (P_0 - P_1)}{\mu L} \quad (\text{III. 3})$$

The Darcy's law can be written for any geometry, but radial flow geometry is the one of most interest to the production engineer dealing with single well issues. Considering radial flow geometry, Darcy's law looks like:

$$q_o = \frac{7.08 \times 10^{-3} \times k_o \times h \times (P_r - P_{wf})}{\mu_o \times B_o \times \left[ \ln \left( \frac{r_e}{r_w} \right) - s \right]} \quad (\text{III. 4})$$

- $q_o$ = Flow rate
- $h$ = Effective feet of pay
- $P_r$ = Reservoir pressure
- $P_{wf}$ = Wellbore pressure
- $r_e$ = Drainage radius
- $r_w$ = Wellbore radius
- $B_o$ = Formation volume factor
- $k_o$ = Effective permeability
- $\mu_o$ =Average viscosity

For a particular well, we can assume that  $h$ ,  $P_r$ ,  $P_{wf}$ ,  $r_e$ ,  $r_w$ ,  $B_0$ ,  $k_0$  and  $\mu_0$  are constant. Thus replaced by  $K$ :

$$q_0 = K (P_r - P_{wf}) \quad (III.5)$$

The constant  $K$  is known as Productivity index or simply “PI”. PI is often called  $J$  in some textbooks. When the wellbore pressure  $P_{wf}$  is higher than the bubble pressure  $P_b$ , oil flows as a single liquid phase. In this case, the relationship between the production rate and drawdown is linear and is expressed by the productivity index PI, The productivity index (PI) is equal to the liquid flow rate divided by the well drawdown ( $P_r - P_{wf}$ ) [9].

$$q_0 = PI (P_r - P_{wf}) \quad (III.6)$$

Graphically, it looks like this:

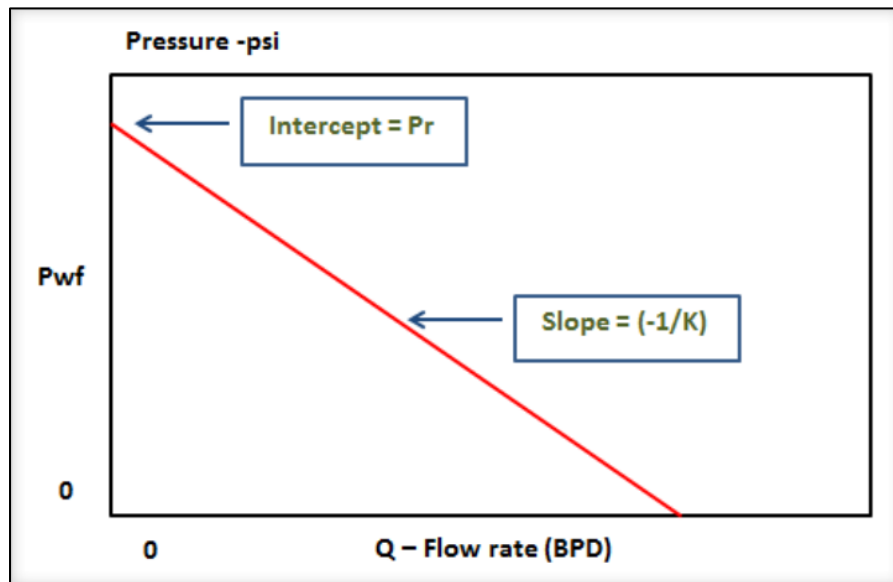


Figure III.2 : Single-Phase IPR

### B. Two-Phase Flow - Vogel's Model :

The PI model is ideal for single-phase liquid flow (oil, water, or both). However, when pressure drops below the bubble point, dissolved gas becomes free gas. Because gas has significantly higher permeability and much lower viscosity (~50 times less) than oil, it flows much faster ( $Q_g \gg Q_l$ ) and is produced in disproportionate amounts. This free gas occupies pore spaces, which decreases oil relative permeability. Simultaneously, oil viscosity

increases as it loses dissolved gas. Together, these two effects reduce the overall oil production rate at any given bottom-hole pressure.

Graphically, it would look like this :

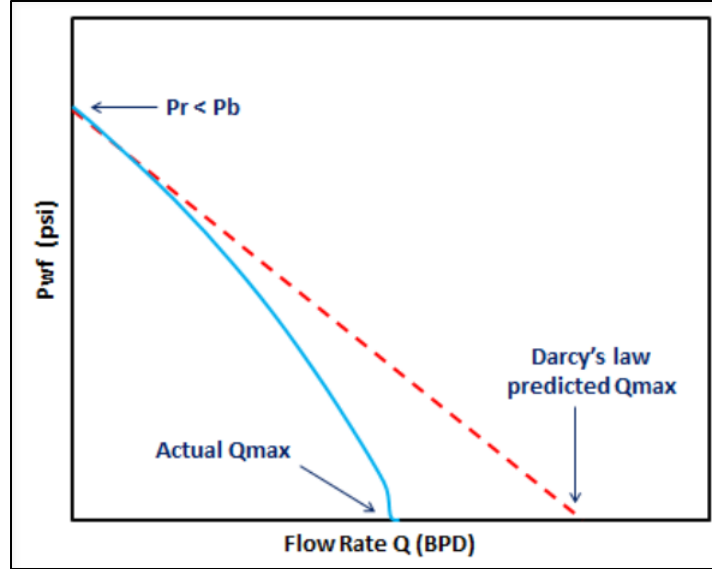


**Figure III.3 : Two-Phase Flow IPR**

Productivity of an oil well draining a solution-gas drive reservoir was investigated by Vogel using numerical simulation. A total of 21 simulations covering a wide range of oil, PVT properties, and relative permeabilities were made . By using dimensionless pressures and rates, Vogel found well productivity could be described by:

$$\frac{Q}{Q_{\max}} = 1 - 0.2 \left( \frac{P_{wf}}{P_r} \right) - 0.8 \left( \frac{P_{wf}}{P_r} \right)^2 \quad (\text{III. 7})$$

where Q is oil production rate in BPD , Qmax is maximum oil production rate in BPD, Pwf is bottomhole flowing pressure in psia, and Pr is average reservoir pressure in psia .

In the numerical simulation, the two models (Linear and Vogel) are combined to create a composite performance curve (**Composite IPR**) that accurately reflects the behavior of the reservoir under all pressure conditions.

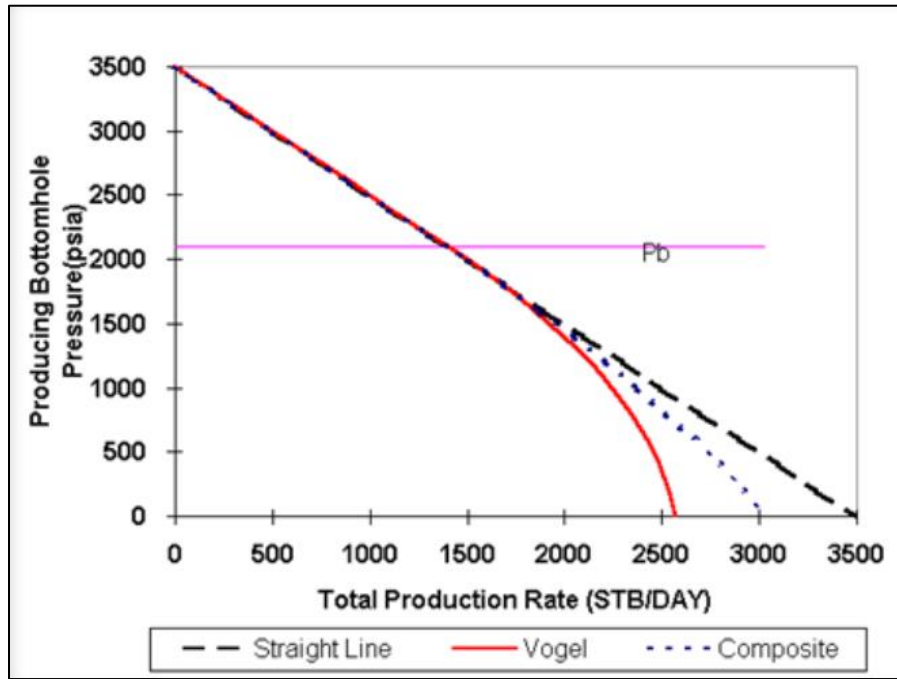


**Figure III.4 : Composite IPR**

Although Vogel's equation was originally developed for solution gas drive mechanism reservoirs, it is generally accepted for other drive mechanisms as well [9].

### III.3.2 Vertical Lift Performance (VLP) :

The Vertical Lift Performance (VLP), also known as outflow performance, describes the dynamic behavior of fluids as they travel upward from the bottomhole (the node) to the surface wellhead. It represents the pressure required to lift a specific volume of fluid through the production tubing.

To successfully push the fluid to the surface, the flowing bottomhole pressure  $P_{wf}$  must be high enough to overcome the surface wellhead pressure  $P_{wh}$  plus the total pressure losses ( $\Delta P_t$ ) occurring inside the tubing. The fundamental mechanical energy balance equation for this flowing fluid is expressed as :

$$P_{wf} = P_{wh} + \Delta P_{\text{elevation}} + \Delta P_{\text{friction}} + \Delta P_{\text{acceleration}} \quad (\text{III. 8})$$

The total pressure drop consists of three main physical components :

1. **Hydrostatic Pressure Drop (Elevation Drop)** : The energy required to support the actual weight of the fluid column. This is the primary objective of gas lift optimization; since gas injection reduces the density of the mixture, significantly lowering the hydrostatic weight.
2. **Frictional pressure loss**: The resistance resulting from the fluid's friction against the inner walls of the pipe as it rises.
3. **Acceleration pressure loss**: The pressure loss resulting from changes in the fluid's velocity (usually very small and negligible in oil wells).

Calculating these pressure losses is extremely complex because oil, gas, and water do not move at the same speed. Since gas is lighter, it moves faster and tends to slip past the heavier liquids, a phenomenon known as “liquid slippage.” This causes liquid to accumulate inside the pipe, increasing the actual volume of trapped liquid (liquid holdup) relative to its original inflow. To account for this phenomenon, the oil industry relies on sophisticated empirical correlations for multiphase flow [9].

### **The Hagedorn-Brown Equation (Correlation Equation) :**

Developed in 1965 using data from a 1,500-foot experimental well, the Hagedorn and Brown correlation is an industry-standard empirical model for vertical multiphase flow. It is particularly highly regarded for modeling **Continuous Gas Lift** systems. The model's primary strength lies in its ability to accurately predict pressure drops across various tubing diameters, especially in high Gas-Liquid Ratio (GLR) environments. It effectively models the severe liquid slippage and holdup phenomena that occur when large volumes of gas are injected into the tubing.

### **III.3.3 The Operating Point and Gas Lift Optimization Mechanism :**

The well's operating point is determined by plotting the IPR and VLP curves on a single coordinate axis (pressure versus production rate). The point of intersection represents the only hydraulic equilibrium that physically ensures the system's sustainability.

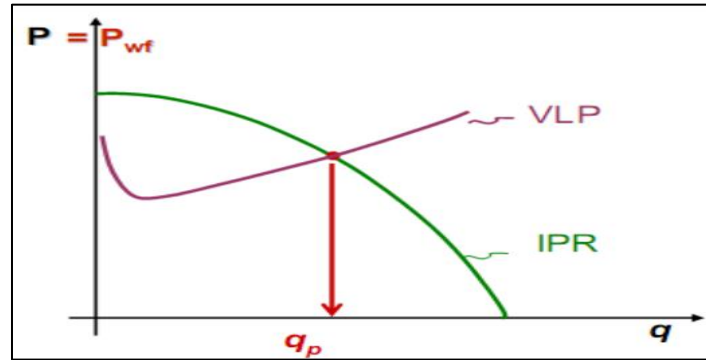


**Figure III.5 : Intersection of IPR and VLP Curves**

In optimization studies using continuous gas lift, the engineering approach focuses on adjusting the VLP curve without altering the reservoir properties (IPR).

When gas is injected, the hydrostatic head decreases, causing the VLP curve to shift downward and to the right, creating a new intersection point at a higher production rate and lower bottomhole pressure. However, if the optimum gas injection rate is exceeded, the very high velocity of the mixture inside the tube leads to an increase in the friction component ( frictional drop ) .

The benefit gained from hydrostatic weight reduction is exceeded. At this point, the VLP curve begins to rise again, and production starts to decline, which explains the distinctive convex shape of the gas lift performance curve [9].

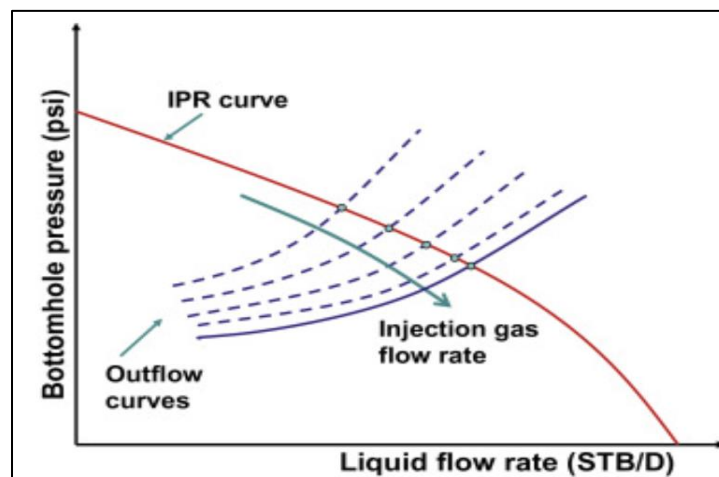


**Figure III.6 : Effect of Gas Injection Rate on VLP Curves**

### III.4 Pipesim Overview :

PIPESIM, developed by Schlumberger (SLB), is widely recognized as the industry standard for steady-state multiphase flow simulation. The software relies on rigorous mathematical solutions of mass, momentum, and energy (heat transfer) conservation equations, enabling engineers to design, diagnose, and optimize entire production systems—from the reservoir pore space to the surface gathering centers.

To achieve the specific objectives of this study, which focus on evaluating the performance of the wells and optimizing their gas lift consumption within a production network, a sequential processing approach was adopted utilizing three primary modules within the simulator:

#### III.4.1 Well Modeling & Nodal Analysis Module :

This module is not merely a drawing tool but a comprehensive engineering environment for constructing a complete "Digital Twin" for each individual well. This phase encompasses the following precise steps:

- **Fluid and PVT Modeling:** Accurate characterization of fluid properties (using the Black Oil Model) based on field data, such as oil gravity (API), Gas-Oil Ratio (GOR), and Water Cut. These parameters are critical for calculating the mixture density during the lifting process.
- **Wellbore Architecture:** Defining the physical and thermal parameters of the well, including the geothermal gradient, wellbore deviation survey, and the internal diameters of the production tubulars.
- **Calibration and History Matching:** This feature is utilized to diagnose the well and match the model with actual field conditions. Through Nodal Analysis, reservoir properties (e.g., Skin Factor) and flow correlation coefficients (e.g., Holdup Multipliers for the Hagedorn & Brown correlation) are iteratively adjusted to ensure that the generated IPR and VLP curves intersect precisely at the actual well test data point [10].

### III.4.2 Artificial Lift & Sensitivity Analysis Module :

Once the validity of the baseline model (Base Case) is established, this module is introduced to simulate the dynamics of Continuous Gas Lift. This tool facilitates the following:

- **Injection System Setup:** Specifying the depths of gas injection ports (valves) and the available lift gas pressure from the surface infrastructure.
- **Sensitivity Analysis:** Rather than evaluating a single operating point, the simulator performs dozens of computational iterations to test the response of the flowing bottomhole pressure and liquid production rate across a wide spectrum of gas injection rates.
- **Performance Curve Generation:** This process culminates in the creation of the "Gas Lift Performance Curve." From this curve, two critical operating points are extracted: the technical maximum production limit, and the **Optimum Gas Injection Rate**, which represents the highest lifting efficiency with the minimum excess gas consumption [10].

### III.4.3 Network Simulation & Gas Allocation Optimization Module :

This module represents the most advanced application in production engineering and serves as the strategic tool to achieve the overarching goal of this thesis.

- **Backpressure Effect Modeling:** When a group of wells is tied to a single production gathering manifold, they interact hydraulically and exert backpressure on one another. This module accurately simulates this complex interference to reflect true field conditions.
- **Optimum Gas Lift Allocation:** In real-world operations, gas compressor capacity is strictly limited. This module employs sophisticated mathematical algorithms based on the "Equal Marginal Gradient" principle to manage this operational constraint. The algorithm evaluates the relative lifting efficiency of each well in the network and dynamically redistributes the limited available lift gas (Gas Allocation). It diverts gas away from poorly responding wells and reallocates it to highly responsive wells,

ultimately guaranteeing the achievement of the maximum total liquid production from the entire network [10].

# **CHAPTER IV**

## **CASE STUDY**

## CHAPTER IV : Case study

### IV-1 Introduction :

The objective of this chapter is to model and optimize gas-lift wells that are connected to the same manifold.

Gas-lift optimization based on the injected gas volume involves determining the optimal amount of gas to inject in order to recover the maximum possible volume of oil. To accomplish this, we utilized the PIPESIM software.

The three wells in this study are equipped with a **Concentric Tubing Gas Lift** system. In this design, the lift gas is injected down through an inner tubing string, and the reservoir fluid flows up to the surface through the annulus (the space between the inner and main tubing).

Because of this physical setup, changing the injection depth is not a practical option. It would require a costly well intervention operation to pull out and change the length of the inner tubing. Therefore, the injection depth was kept fixed in all PIPESIM simulations. The **Gas Injection Rate** was the only practical variable modified and optimized in this study.

Well (RN1) was selected as a case study to illustrate this process.

### IV-2 Well testing data :

**Table IV-1 : Well testing data**

| <b>Well name</b> | <b>Reservoir temperature (C)</b> | <b>Reservoir Pressure (bar)</b> | <b>Liquide Rate (m3/d)</b> | <b>FBHP (bar)</b> | <b>GOR (sm3/sm3)</b> | <b>Water Cut (%)</b> |
|------------------|----------------------------------|---------------------------------|----------------------------|-------------------|----------------------|----------------------|
| <b>RN1</b>       | <b>111.5</b>                     | <b>180</b>                      | <b>42</b>                  | <b>140</b>        | <b>93</b>            | <b>20</b>            |
| <b>RN2</b>       | <b>90</b>                        | <b>150.7</b>                    | <b>118.7</b>               | <b>120</b>        | <b>90</b>            | <b>51</b>            |
| <b>RN3</b>       | <b>95</b>                        | <b>125</b>                      | <b>31.8</b>                | <b>86</b>         | <b>90</b>            | <b>20</b>            |

**IV-3 PVT data :**

- Gas specific gravity : 0.65
- Bubble point pressure :  $P_b = 145$  bar
- Average Oil viscosity :  $\mu_o = 0.575$  cP
- Oil formation volume factor :  $B_o = 1.402$  m<sup>3</sup>/sm<sup>3</sup>
- Average surface oil density :

**Table IV-2 : API density data**

| Well        | RN1   | RN2   | RN3  |
|-------------|-------|-------|------|
| API density | 35.56 | 39.15 | 38.9 |

**IV-4 Application of Nodal Analysis using PIPESIM :**

To determine the system's operating point and optimize production, the physical and thermodynamic data of the well must be introduced into the PIPESIM software. The modeling procedure follows a sequential approach :

**IV-4 -1 Fluid Definition (PVT Data) :**

Before configuring the physical wellbore, the thermodynamic properties of the reservoir fluid must be defined in the software's Fluid Manager. This crucial step involves inputting:

- **PVT Parameters:** Bubble point pressure ( $P_b$ ), oil formation volume factor ( $B_o$ ), oil density (API gravity), gas specific gravity, fluid viscosity, and reservoir temperature.

**IV-4 -2 Wellbore Modeling :**

Once the fluid is defined, the physical architecture of the well is built using the dedicated tabs in the Well interface :

- **General:** Defines the basic configuration, including the well name active status, and well type (Production).

- **Deviation survey:** Inputs the directional survey data (Measured Depth vs. True Vertical Depth) to accurately map the well's trajectory from surface to bottom hole.
- **Heat transfer:** Specifies the geothermal gradient and ambient temperature profile to simulate heat exchange and fluid temperature variations along the wellbore.
- **Tubulars:** Details the mechanical dimensions (Outer/Inner Diameters) and pipe roughness for the casing and tubing strings.
- **Downhole equipment:** Identifies the type and setting depth of downhole accessories, such as the isolation packer (Pk).
- **Artificial lift:** Defines the gas lift system parameters, specifically the injection depth of the Gas Lift tube.
- **Completions:** Inputs the reservoir inflow data to generate the Inflow Performance Relationship (IPR). This includes reservoir static pressure, temperature, well testing data (Ql , FBHP ), middle perforation depth and the selected inflow model (Vogel).

#### **IV-4 -3 Inflow Performance Relationship (IPR) :**

We used Vogel's model to determine the inflow curve (the flow in the reservoir) (Figure IV-1 / IV-2 / IV-3) .

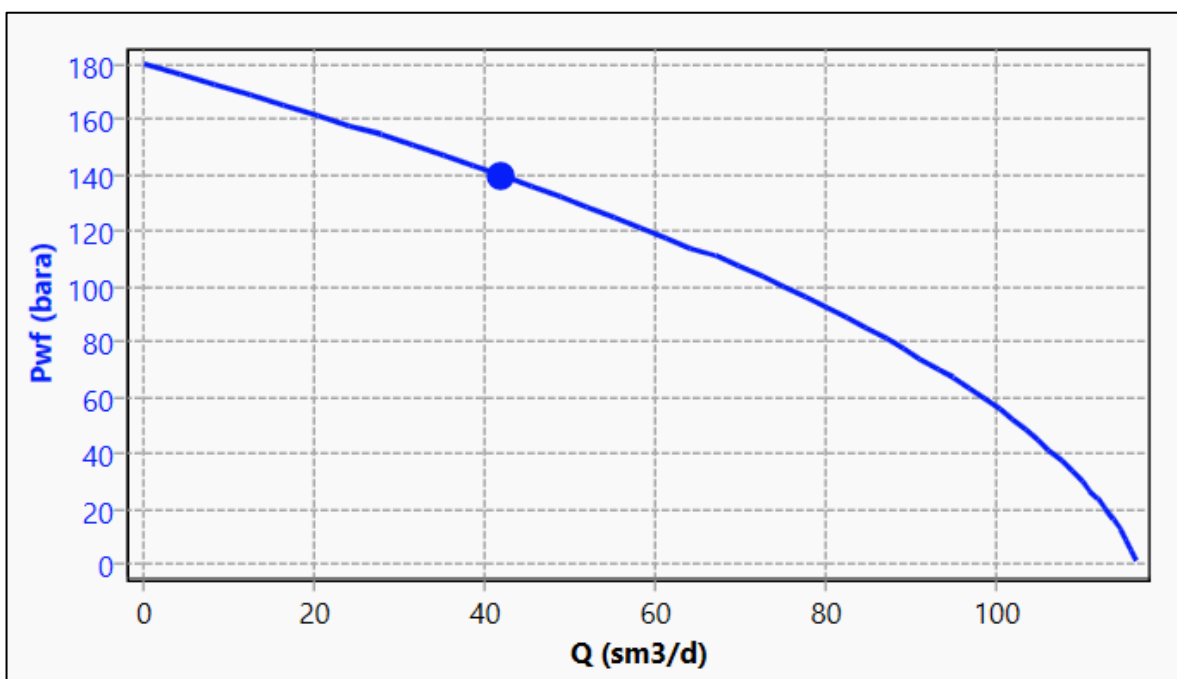


Figure IV-1 : IPR curve of RN1

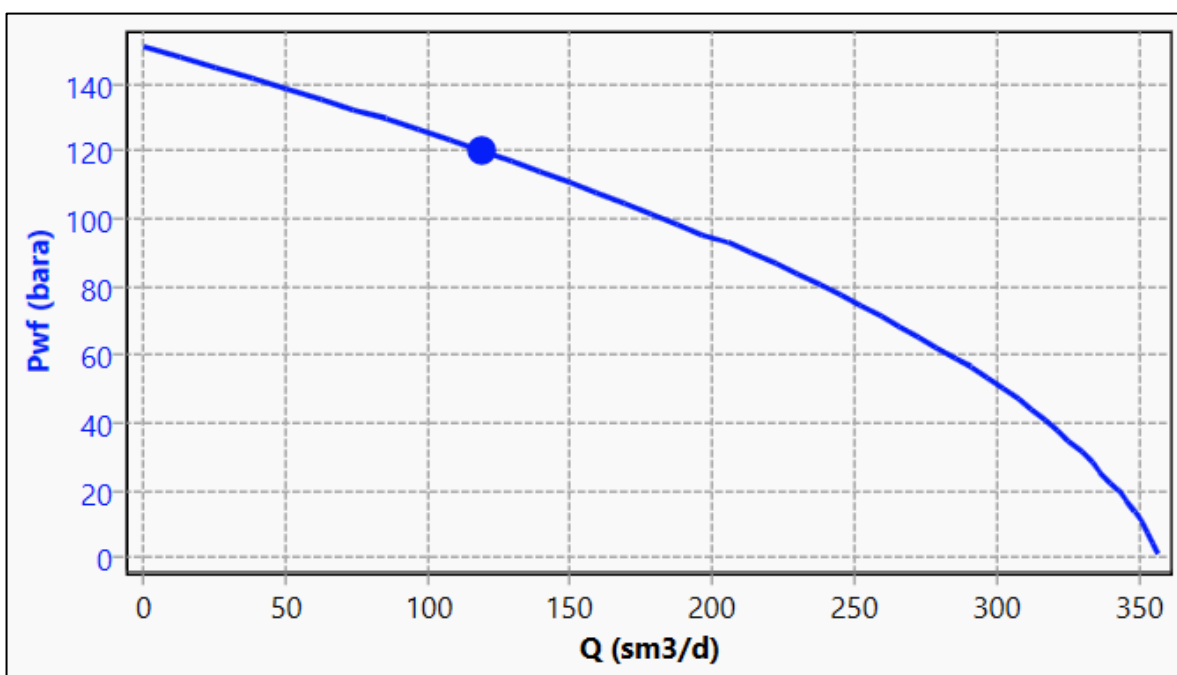


Figure IV-2 : IPR curve of RN2

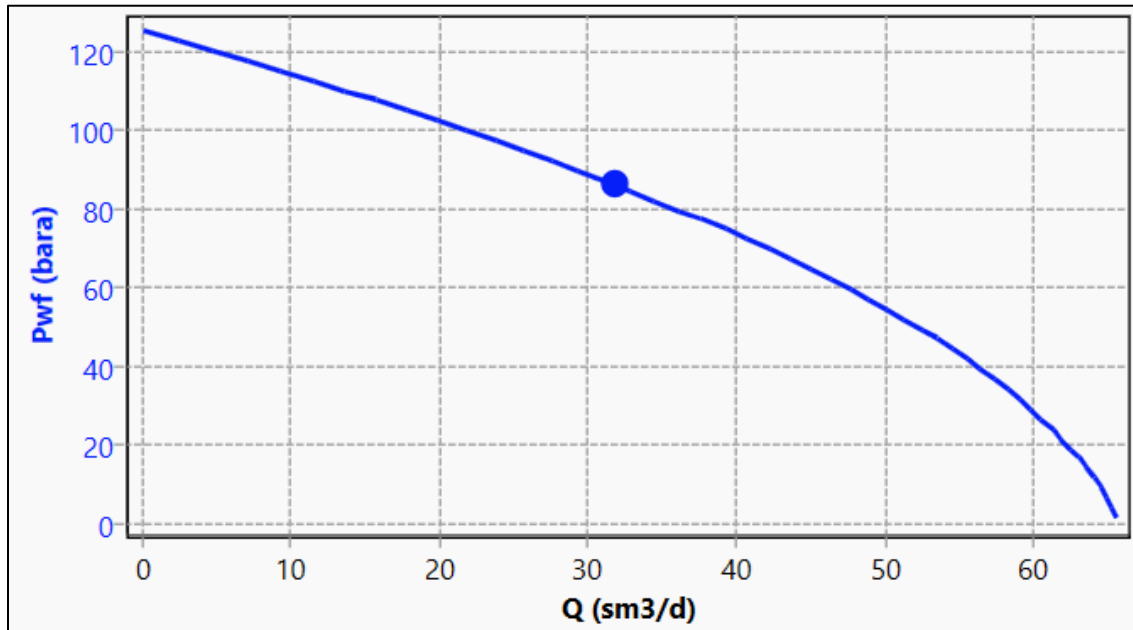


**Figure IV-3 : IPR curve of RN3**

#### **IV-4 -4 Vertical Lift Performance Relationship (VLP) :**

The Hagedorn & Brown correlation was selected to generate the Vertical Lift Performance (VLP) curve due to its high accuracy and reliability in simulating multiphase flow within vertical and near-vertical wells. This empirical correlation is particularly robust in calculating liquid holdup and the slip effect between the faster-moving gas phase and the slower liquid phase, which is a critical physical factor for accurate simulation in gas-lifted wells. Consequently, it ensures a precise estimation of the total pressure drop along the production tubing—governed by both the mixture's hydrostatic head and friction—yielding a highly reliable operating point in the nodal analysis.

#### **IV-4 -5 Operating point IPR/VLP Without Gas Lift injection :**

Without gas-lift injection, it is clear that the IPR and VLP curves do not intersect, since the well is not producing (Figure IV-4 / IV-5 / IV-6).

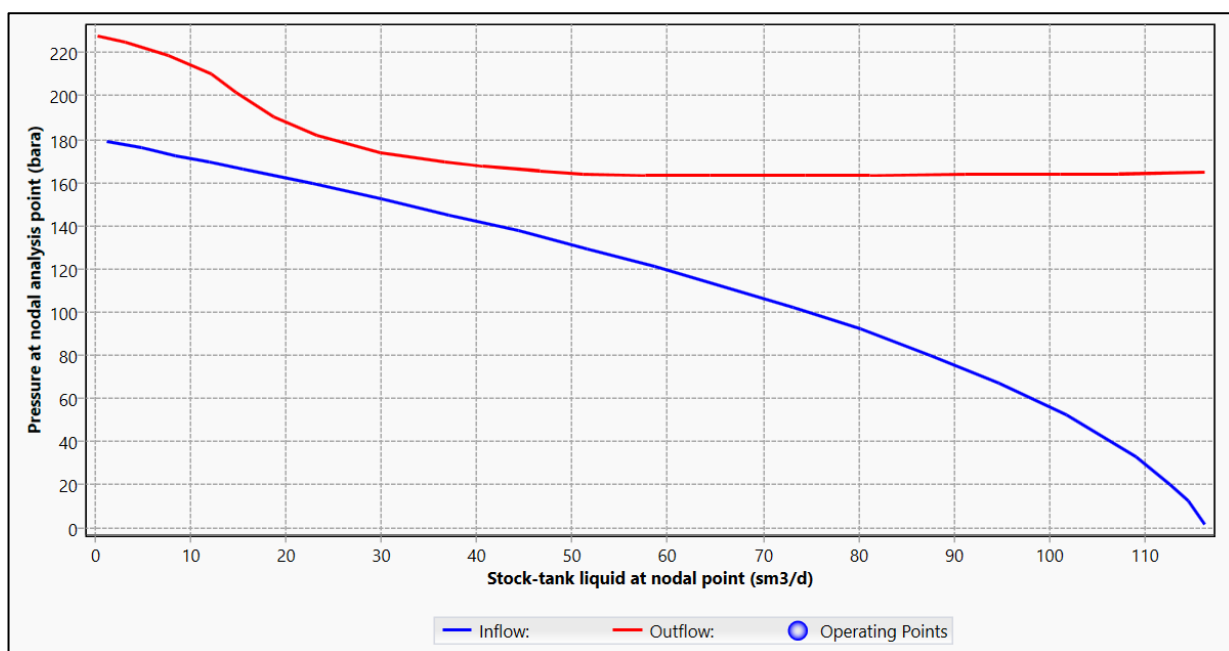


**Figure IV-4 : IPR/VLP curve without gas lift injection of RN1**

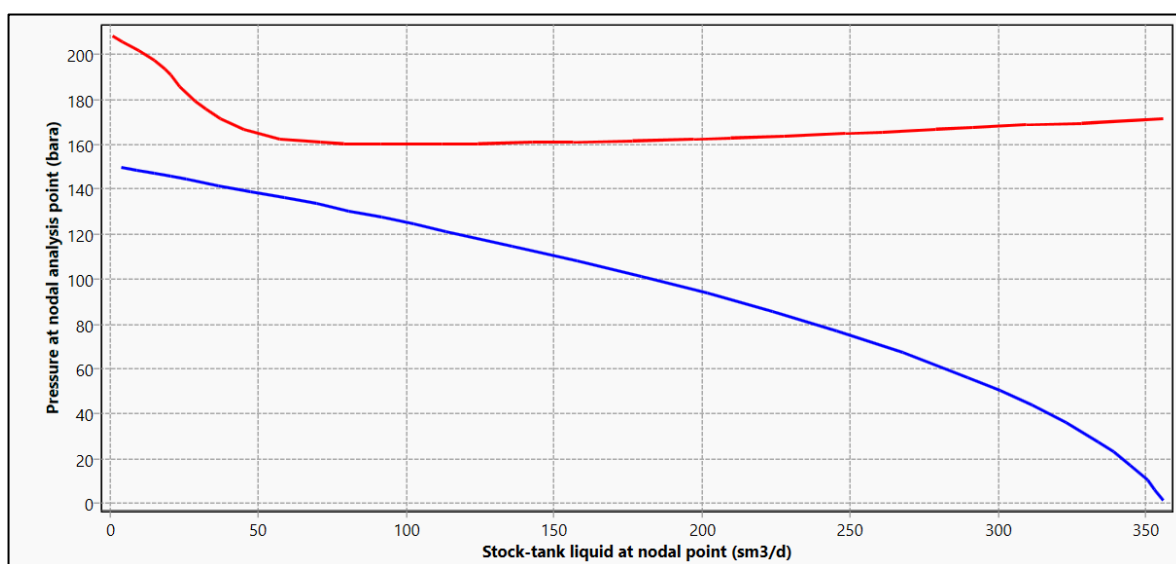


**Figure IV-5 : IPR/VLP curve without gas lift injection of RN2**

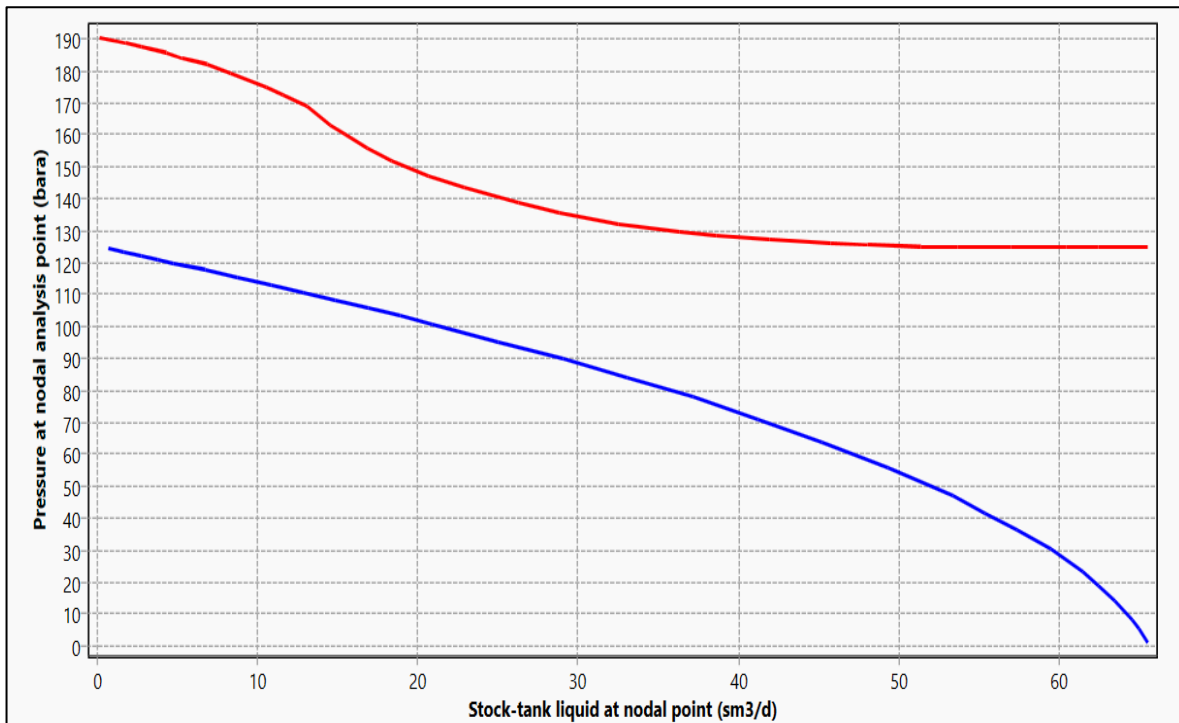


**Figure IV-6 : IPR/VLP curve without gas lift injection of RN3**

#### **IV-4 -6 Gas lift injection sensitivity analysis (GL performance curve) :**

As part of the Gas Lift Sensitivity Analysis, the Gas Lift Performance Curve (GLPC) was generated (Figure IV-7 / IV-8 / IV-9) , as illustrated in the figure below. This curve plots the total liquid production rate against the injected gas rate. The primary objective of this analysis is to evaluate the well's dynamic response to varying gas injection volumes. The curve initially demonstrates a rapid increase in liquid production due to the significant reduction in the hydrostatic head of the fluid column. As injection increases, production reaches a peak. Beyond this point, excessive gas injection significantly increases the mixture velocity, causing frictional pressure losses to dominate over the benefits of density reduction, which consequently leads to a decline in production. Based on this physical behavior, the curve serves as the fundamental tool to determine the 'Optimum Gas Injection Rate,' ensuring maximum well deliverability combined with optimal operational efficiency.

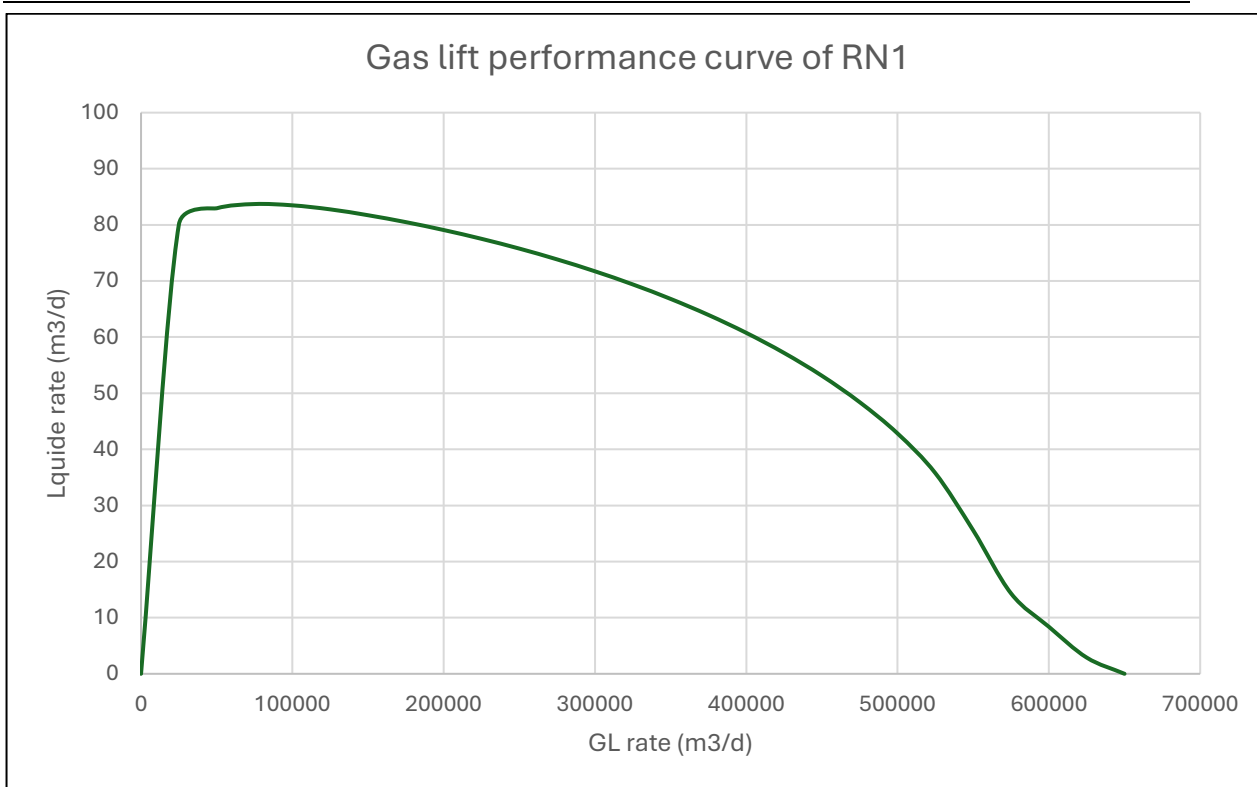


**Figure IV-7 : Gas lift performance curve of RN1**

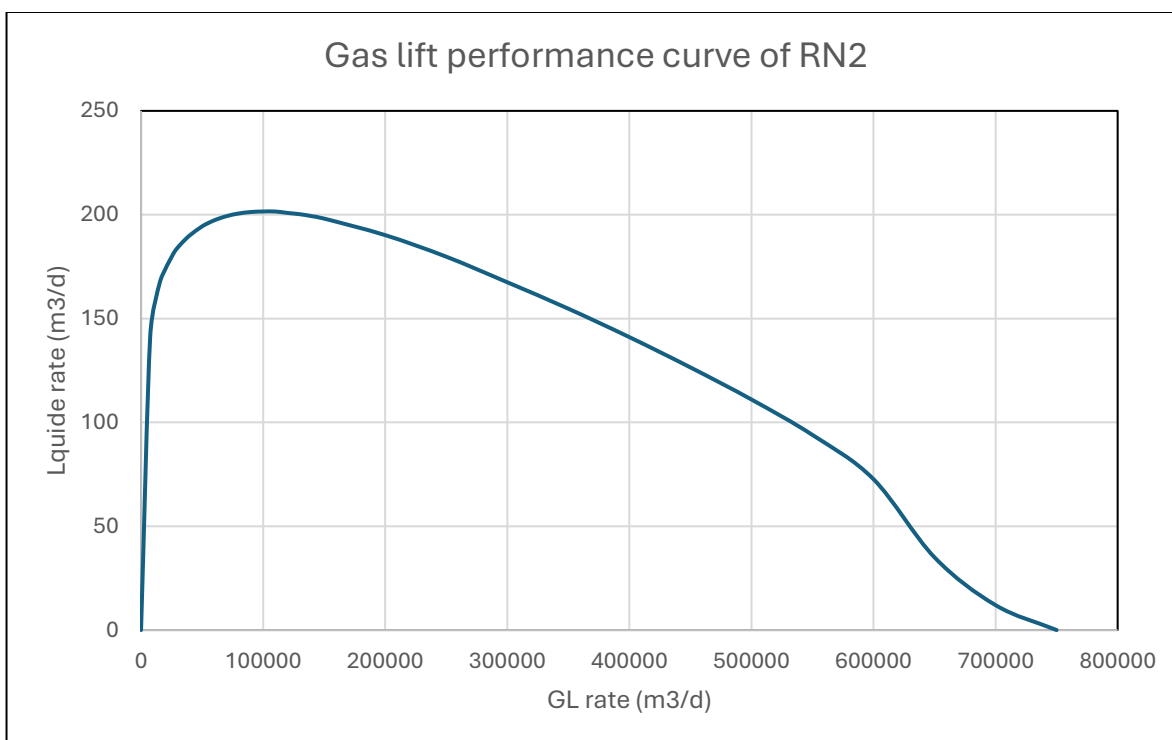


**Figure IV-8 : Gas lift performance curve of RN2**

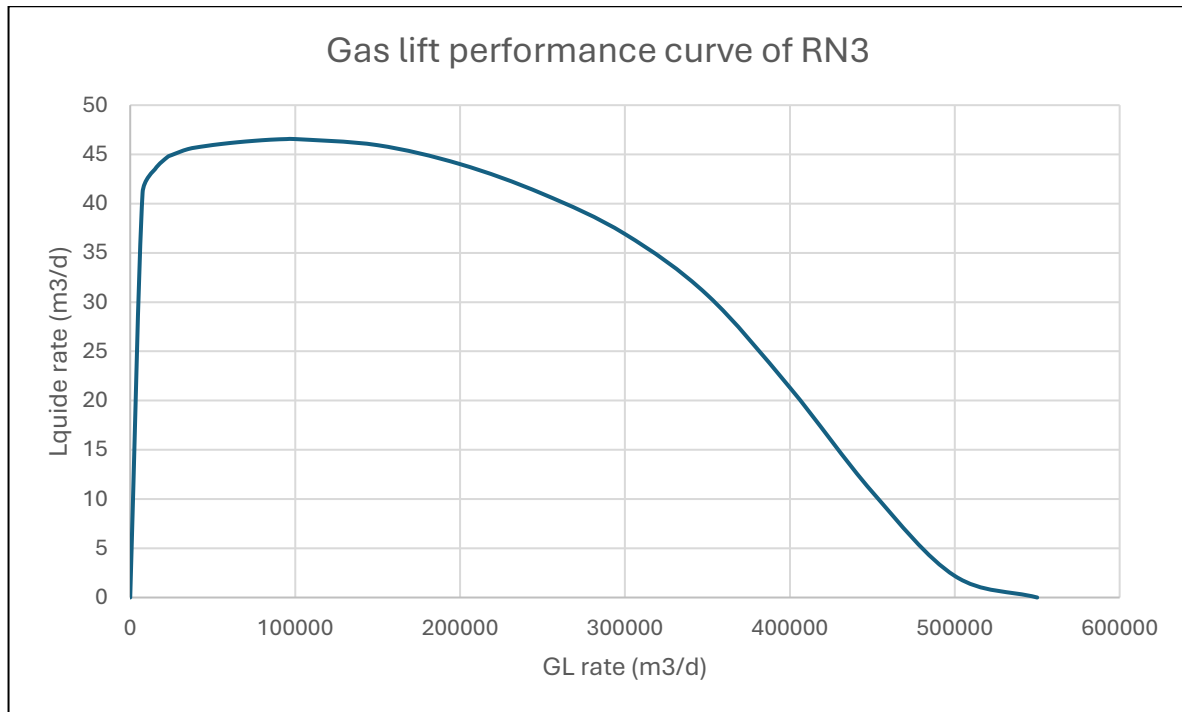


**Figure IV-9 : Gas lift performance curve of RN3**

#### **IV-4 -7 Gas Lift Optimum Rate Selection :**

The selection of the optimal gas injection rate is a critical phase in gas lift design, as it directly governs both well deliverability and the overall energy efficiency of the artificial lift system. This selection process relies on analyzing the physical behavior demonstrated by the Gas Lift Performance Curve (GLPC).

##### **IV-4 -7 -1 Operational Zones of the Performance Curve :**

The relationship between the injected gas rate and the total liquid production rate can be physically divided into three distinct operational regions (Figure IV-3) :

- Zone 1: Gravity Dominated Region:** This is the initial, steeply rising section of the curve. In this phase, the injected gas efficiently lightens the fluid column, significantly reducing the hydrostatic pressure head. The well exhibits a highly favorable marginal response, where a relatively small volume of injected gas yields a substantial, rapid increase in liquid production.

- **Zone 2: Plateau Region:** As gas injection continues, the curve begins to flatten into a plateau. In this transitional zone, the positive effect of reducing the fluid mixture density is gradually counterbalanced by the increasing frictional pressure losses caused by higher fluid velocities inside the production tubing.
- **Zone 3: Friction Dominated Region:** Beyond the plateau, excessive gas injection forces the curve to decline. In this region, the extremely high velocity of the multiphase mixture generates severe frictional resistance (a choking effect) against the pipe walls. This friction dominates the flow dynamics, surpassing any remaining benefits of density reduction and ultimately reducing the liquid production rate.

#### IV-4 -7- 2 Determination of the Optimum Rates :

To establish the most logical operating conditions, two specific reference points are extracted from the aforementioned zones:

- **The Technical Optimum (Peak of Zone 2):** Located at the absolute crest of the curve within the plateau region (Zone 2), this point represents the theoretical maximum liquid production the well can physically deliver. At this exact point, the mathematical slope of the curve is zero. While it indicates the absolute production ceiling, operating at the Technical Optimum is rarely recommended, as the massive volume of gas required to reach this peak offers an extremely poor return on compression energy.
- **The Economic/Practical Optimum (Upper Boundary of Zone 1):** This point is strategically identified at the "knee" or the inflection point of the curve, representing the transition exactly at the end of Zone 1 and before entering the flat plateau of Zone 2. Selecting the injection rate at this point is the most efficient operational strategy. At this Economic Optimum, the well achieves the vast majority of its maximum production potential while consuming significantly less lift gas. Beyond this point, the principle of diminishing returns applies; the marginal increase in liquid becomes negligible compared to the substantial increase in gas requirements, making further injection practically and economically unjustified.

**Note :** we will take RN1 as an example to show how to determine the technical & economic optimums from gas lift performance curve

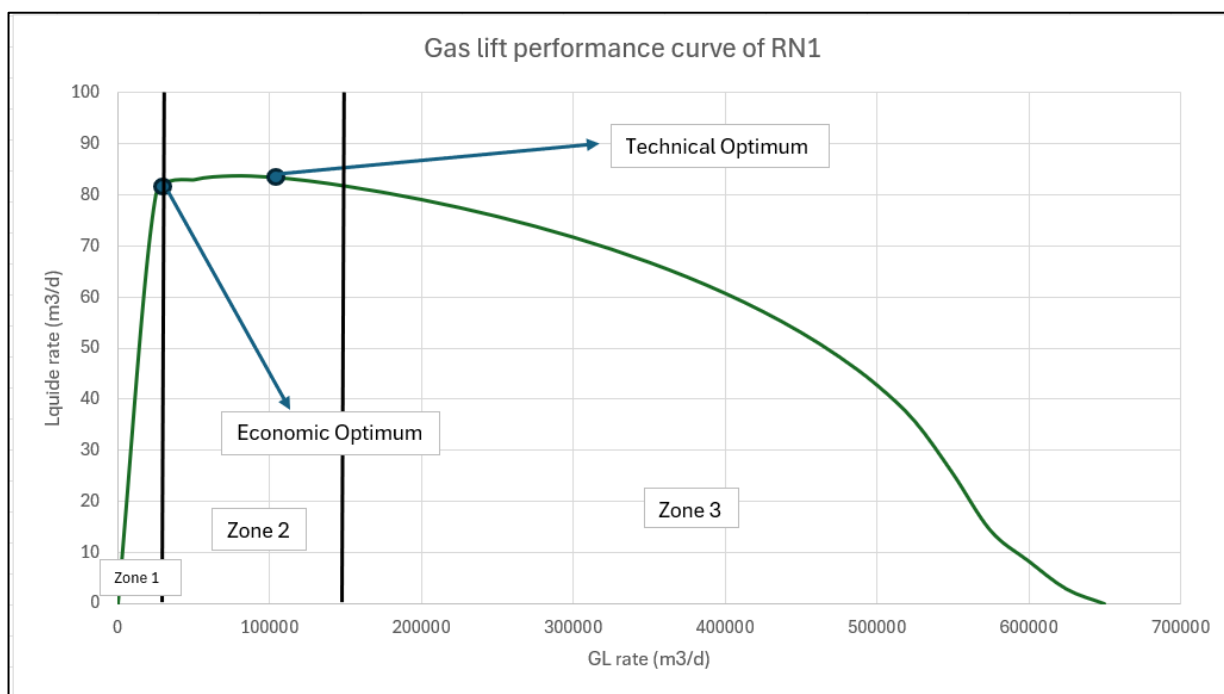


**Figure IV-10 : GLPC for Well RN1 showing operational zones and optimum points**

From GLPC of RN1 :

**Table IV-3 : Technical and Economic Optimum of RN1**

| /                     | Gas lift rate (m3/d) | Liquide rate (m3/d) |
|-----------------------|----------------------|---------------------|
| The Technical Optimum | 72 000               | 83.61               |
| The Economic Optimum  | 25 000               | 80.11               |

IV-4 -8 Operating point IPR/VLP With Gas Lift injection :

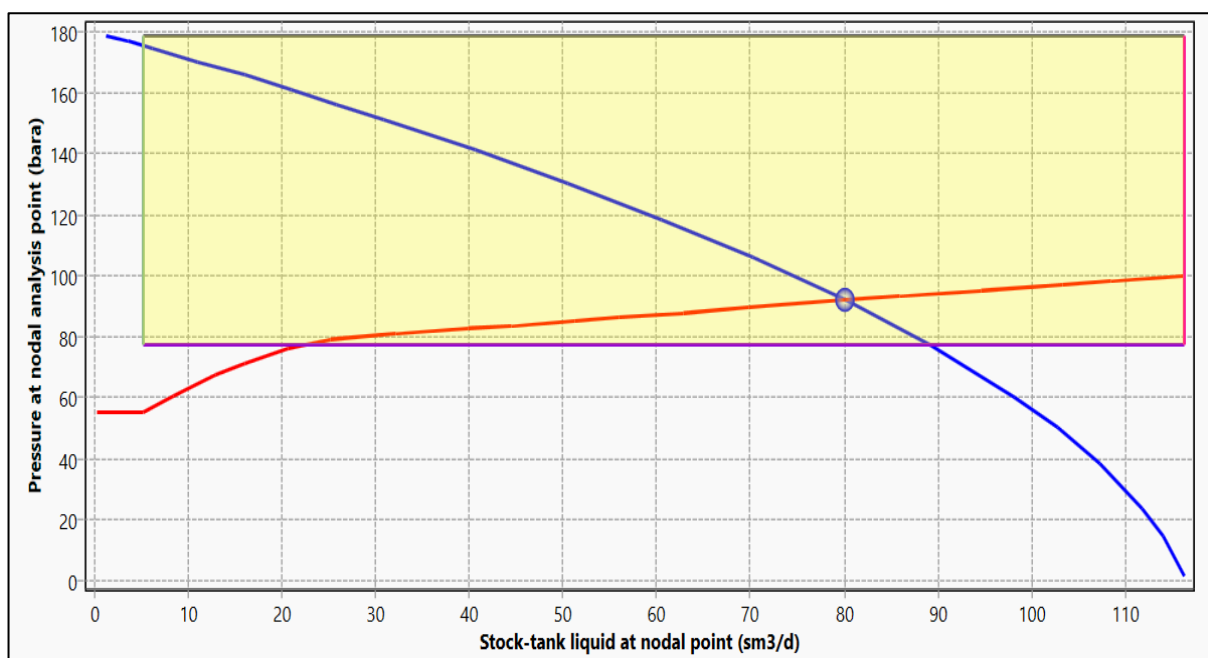


Figure IV-11 : Operating point of RN1 with gas lift injection

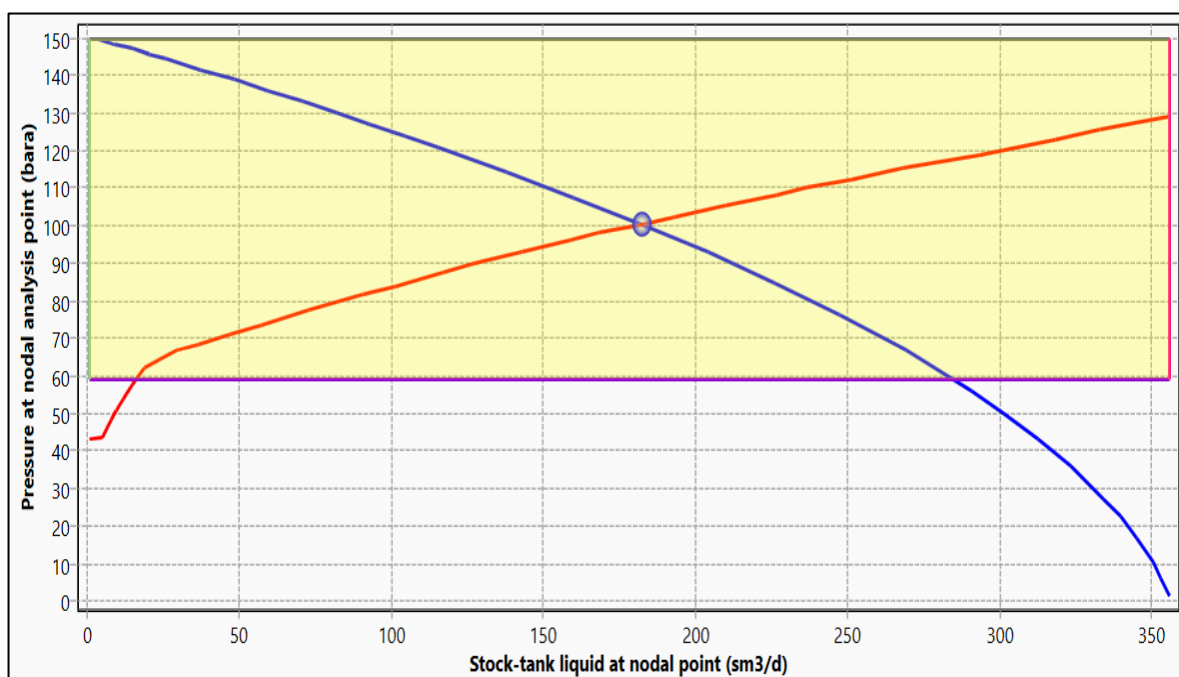


Figure IV-12 : Operating point of RN2 with gas lift injection

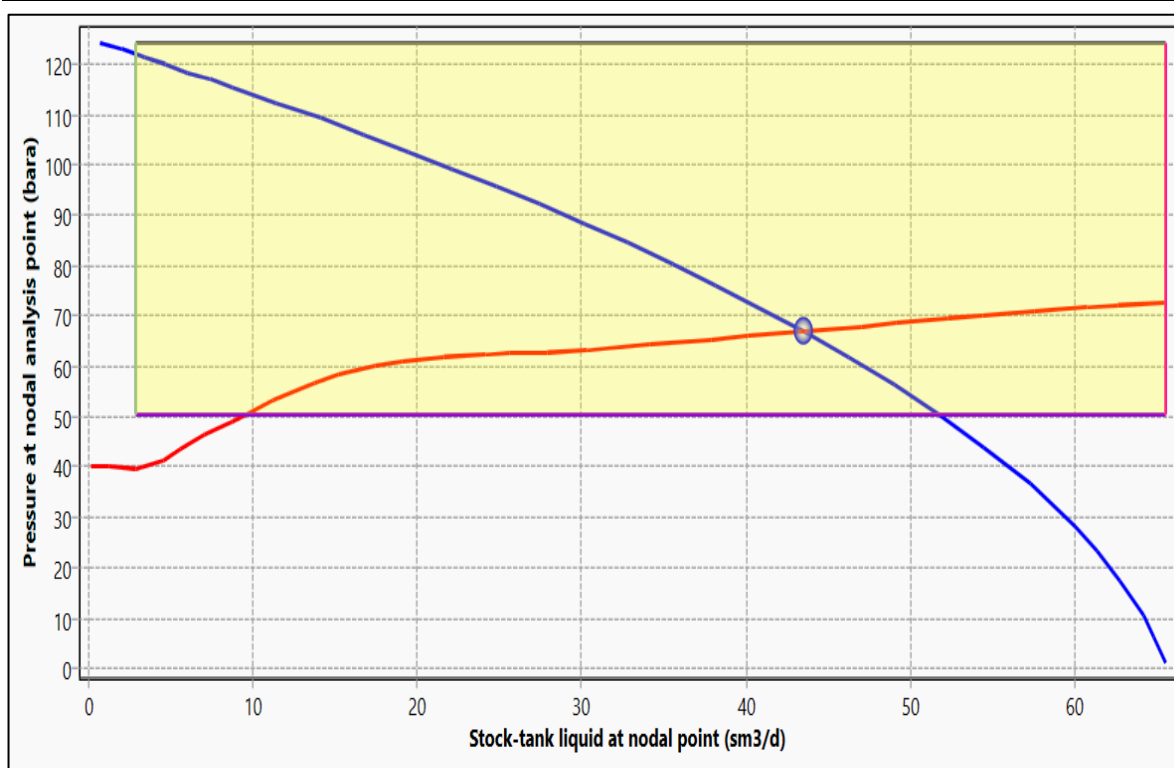


**Figure IV-13 : Operating point of RN3 with gas lift injection**

#### **IV-5 Final Results :**

Following the detailed analysis of the primary well, the identical simulation workflow was executed for the other two wells. The optimized results are presented in the following table.

**Table IV-4 : Technical and Economic Optimum of RN1/RN2/RN3**

|                          | <b>RN1</b>                           | <b>RN2</b>                            | <b>RN3</b>                           |
|--------------------------|--------------------------------------|---------------------------------------|--------------------------------------|
| <b>Technical Optimum</b> | GL rate = 72 000<br>Liq rate = 83.61 | GL rate = 90 000<br>Liq rate = 201.2  | GL rate = 75 000<br>Liq rate = 46.4  |
| <b>Economic Optimum</b>  | GL rate = 25 000<br>Liq rate = 80.11 | GL rate = 27 500<br>Liq rate = 182.15 | GL rate = 15 000<br>Liq rate = 43.49 |

Table IV-5 : Final Results

| Well | GL rate before<br>(m <sup>3</sup> /d) | Liquide rate<br>before (m <sup>3</sup> /d) | GL rate after<br>(m <sup>3</sup> /d) | Liquide rate<br>after (m <sup>3</sup> /d) |
|------|---------------------------------------|--------------------------------------------|--------------------------------------|-------------------------------------------|
| RN1  | 2000                                  | 55.05                                      | 25 000                               | 80.11                                     |
| RN2  | 65 000                                | 198.3                                      | 27 500                               | 182.15                                    |
| RN3  | 0                                     | 0                                          | 15 000                               | 43.49                                     |

#### IV-6 Interpretation of Results :

The comparative results summarized in the table above demonstrate the profound impact of applying Nodal Analysis for Gas Lift optimization. The data reveals that true optimization is not achieved by indiscriminately increasing gas injection, but rather by implementing a smart allocation strategy based on the specific performance curve of each well. The interpretation of these results can be divided into a well-by-well analysis and a global system evaluation:

##### IV-6-1 Well-by-Well Analysis (Micro Level):

- **Well RN1 (Correcting Under-Injection):** Prior to optimization, this well was severely starved of gas (receiving only 2,000 m<sup>3</sup>/d), resulting in a sub-optimal liquid rate of 55.05 m<sup>3</sup>/d. By increasing the injection to its economic optimum (25,000 m<sup>3</sup>/d), the well exhibited a strong marginal response, boosting liquid production to 80.11 m<sup>3</sup>/d. This confirms the well was previously operating deep within the gravity-dominated zone.
- **Well RN2 (Eliminating Over-Injection):** This well presents a classic case of inefficient gas utilization. Initially, a massive volume of 65,000 m<sup>3</sup>/d was injected to produce 198.3 m<sup>3</sup>/d. The optimization process revealed that the well was operating in the friction-dominated plateau. By drastically cutting the injected gas by more than half (down to 27,500 m<sup>3</sup>/d), the liquid production experienced only a minor,

acceptable decline (to 182.15 m<sup>3</sup>/d). This massive gas saving is the key driver of the field's improved efficiency.

- **Well RN3 (Kicking-off a Dead Well):** The most dramatic improvement is observed in RN3. Initially, the well was completely dead (0 m<sup>3</sup>/d) due to excessive hydrostatic backpressure. By redirecting a portion of the gas saved from RN2, an optimum rate of 15,000 m<sup>3</sup>/d was injected, successfully unloading the well (kick-off) and establishing a solid production rate of 43.49 m<sup>3</sup>/d.

**IV-6-2 Overall System Performance (Macro Level):** The most significant engineering achievement of this study is observed at the macro level. Before optimization, the total field injection was 67,000 m<sup>3</sup>/d, yielding a total liquid production of 253.35 m<sup>3</sup>/d. After the reallocation, utilizing a nearly identical total gas volume (67,500 m<sup>3</sup>/d), the overall liquid production surged to 305.75 m<sup>3</sup>/d.

### IV-7 Conclusion:

By simply redistributing the available lift gas based on the Economic Optimum principles, the total asset production was increased by ~52.4 m<sup>3</sup>/d without adding any new compression capacity or incurring additional operational expenditures (OPEX). This perfectly validates the effectiveness of the implemented Gas Lift optimization workflow.

## **Conclusion and Recommendations**

### **Conclusion :**

In conclusion, this study highlights the critical role of production optimization in the Rhourde Nouss (RNS) field. Using Nodal Analysis and PIPESIM software, we identified Gas-Lift as the most efficient artificial lift method for this specific reservoir.

Simulations conducted on wells RN1, RN2, and RN3 validated this approach, achieving a total production increase of 52.4 m<sup>3</sup>/day (a 20.7% growth). This demonstrates the system's strong capability to sustain high production rates. Furthermore, lacking downhole moving parts, Gas-Lift effectively mitigates the field's severe sand production challenges by preventing mechanical wear. Utilizing the field's abundant natural gas for injection also eliminates the need for external sources, making the method highly cost-effective.

Ultimately, the optimized Gas-Lift framework developed herein—supported by sensitivity analyses and Gas Lift Performance Curves (GLPC)—is essential for extending the field's productive life and maximizing economic returns. Future work could build upon this foundation by integrating real-time monitoring to continuously adapt injection rates to the reservoir's dynamic behavior.

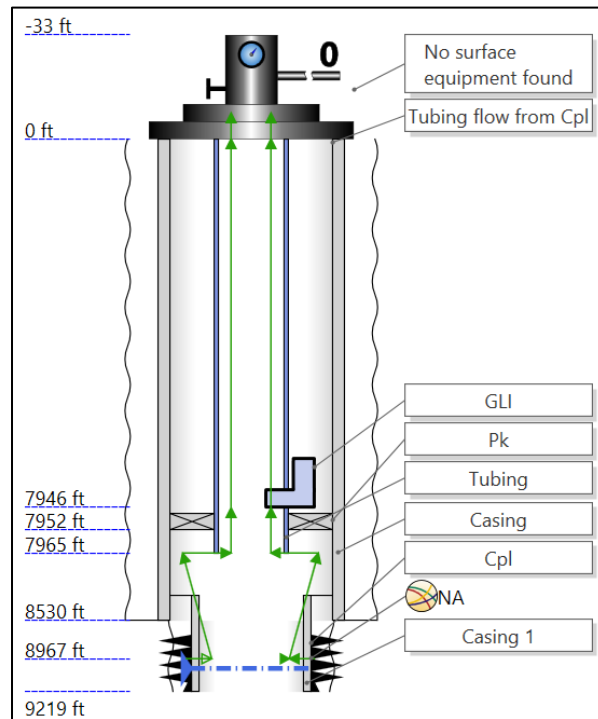
### **Recommendations :**

- ✓ **Field-Wide Simulation:** Expand PIPESIM analysis to the entire RNS field network to evaluate well interference and optimize gas allocation field-wide.
- ✓ **Surface Sand Management:** Upgrade or install advanced surface desanders to safely handle the lifted sand and protect surface facilities from erosion.
- ✓ **Real-Time Monitoring:** Integrate smart monitoring to continuously track well pressures and flow rates, enabling dynamic adjustments to gas injection.
- ✓ **Economic Evaluation:** Conduct a detailed CAPEX/OPEX study to compare Gas-Lift operational costs against the financial returns gained from the 20.7% production increase.
- ✓ **Continuous Data Updating:** Perform regular well testing to update PVT data and IPR curves, ensuring future simulation accuracy as reservoir pressure naturally depletes.

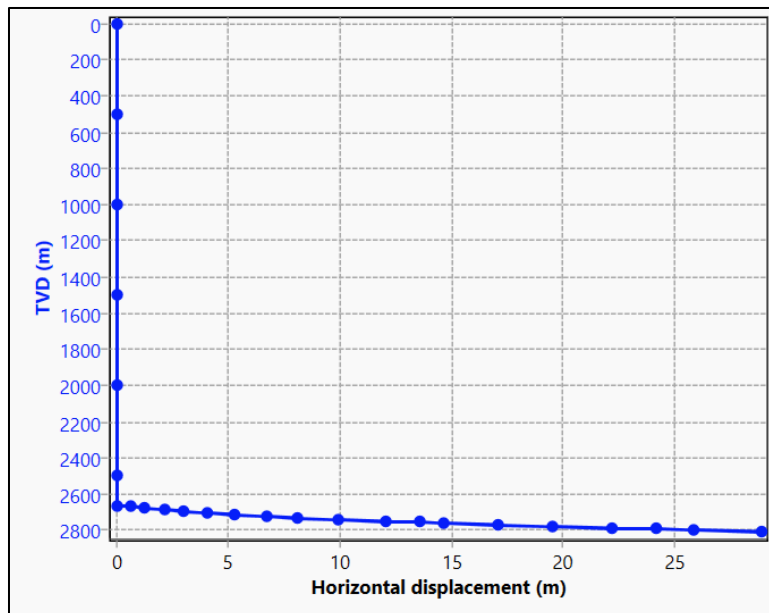
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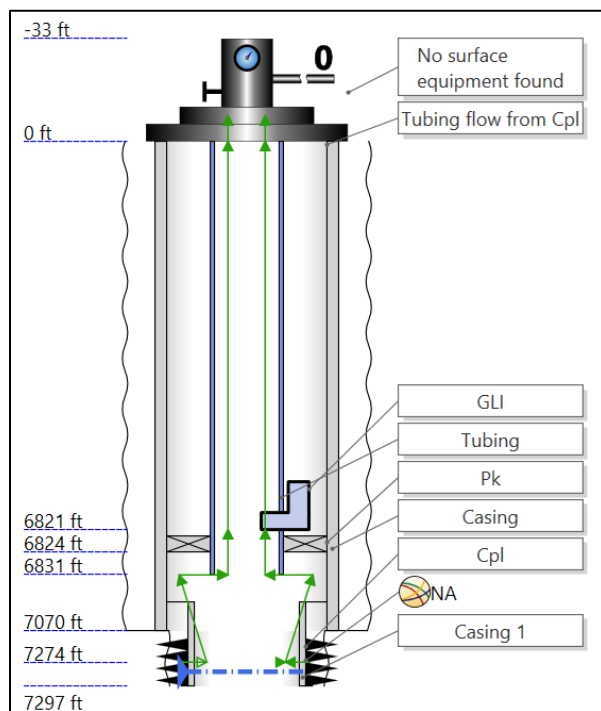
## Annexe : WELL COMPLETIONS



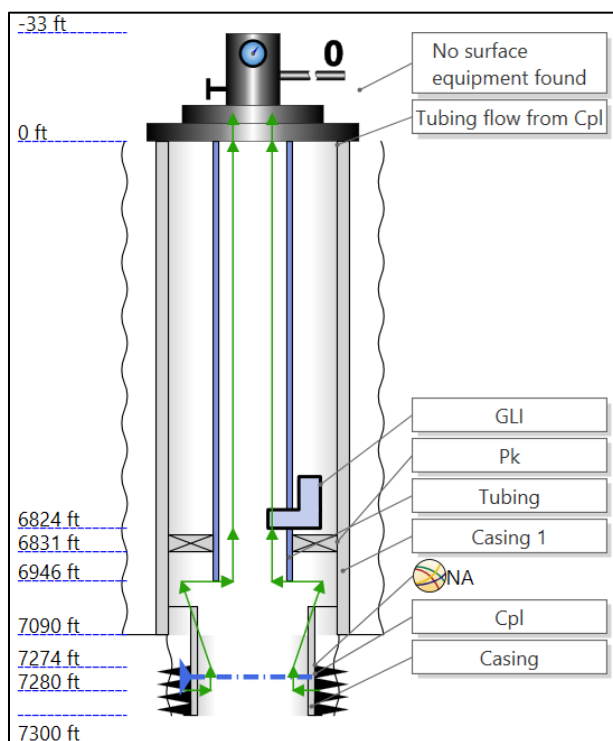
RN1 completion



Deviation survey of RN1



RN2 completion



RN3 completion

