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-THEME-

Well Test Interpretation and Reservoir Characterization Using KAPPA Saphir

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Dedication

I dedicate this work, first and foremost, to myself, for the patience, determination, and perseverance that carried me through every challenge and difficult moment. This journey was not always easy, but I remained strong and continued moving forward with hope and ambition.

To my beloved family, whose love, prayers, and constant support have always been my greatest source of strength. Thank you for believing in me, encouraging me, and standing by my side throughout every step of this journey.

To my parents, for all the sacrifices you made to give me a better future. Your guidance, wisdom, and unconditional love inspired me to never give up.

To my sisters and brothers, thank you for your encouragement, laughter, and the beautiful moments that made this path lighter and more meaningful.

To my friends and colleagues, thank you for your support, motivation, and unforgettable memories shared along the way.

This achievement is not mine alone; it is a reflection of everyone who believed in me and helped me become the person I am today.

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Dedication

From the bottom of my heart, I dedicate this work to all those who are dear to me.

To my wonderful mother, Atika,

My source of inspiration and unconditional love. This dedication is a heartfelt tribute to your endless care, support, and sacrifices. You have always been the light that illuminated my path and guided me through every challenge. To you, my loving and exceptional mother, I dedicate these words with deep gratitude and affection as an eternal expression of my love for you.

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KORICHI BASMA

Abstract

This study focused on the interpretation and analysis of well test data of Well-1 in HMD FIELD using both conventional interpretation techniques and KAPPA Saphir software. The different stages of data preparation, diagnostic analysis, model matching, and pressure transient interpretation were performed in order to characterize reservoir behavior and evaluate well performance.

The conventional Horner interpretation provided preliminary reservoir characterization through semi-log analysis, whereas modern KAPPA Saphir offered a more detailed and reliable interpretation using advanced diagnostic and model-matching techniques.

The obtained results indicate that the reservoir is characterized by moderate permeability and satisfactory reservoir pressure, while the positive skin factor reflects the presence of near-wellbore damage affecting fluid flow toward the Well-1.

The comparison between the conventional and modern interpretation approaches highlighted the importance of advanced pressure transient analysis tools in improving the accuracy of reservoir characterization and supporting production optimization and reservoir management decisions.

keywords :

Well testing, Interpretation, Reservoir, Permeability, Skin factor, Pressure, Radial flow, Diffusivity equation, Kappa Saphir

Résumé

Cette étude a porté sur l’interprétation et l’analyse des données de tests de puits du **puits-1 du champ HMD**, en utilisant à la fois les méthodes conventionnelles d’interprétation et le logiciel **KAPPA Saphir**. Les différentes étapes de préparation des données, d’analyse diagnostique, d’ajustement des modèles et d’interprétation des transitoires de pression ont été réalisées afin de caractériser le comportement du réservoir et d’évaluer les performances du puits.

L’interprétation conventionnelle basée sur la méthode de **Horner** a permis d’obtenir une première caractérisation du réservoir à travers l’analyse semi-logarithmique, tandis que l'utilisation du logiciel **KAPPA Saphir** a fourni une interprétation plus détaillée, précise et fiable grâce à ses outils avancés d'analyse diagnostique et de modélisation.

Les résultats obtenus montrent que le réservoir présente une **perméabilité modérée** ainsi qu'une **pression de réservoir satisfaisante**. En revanche, la **valeur positive du facteur de skin** met en évidence l'existence d'un endommagement dans la zone proche du puits, affectant l'écoulement des fluides vers le **puits -1**.

La comparaison entre l'approche conventionnelle et l'approche moderne a démontré l'importance des outils avancés d'analyse des transitoires de pression pour améliorer la précision de la caractérisation des réservoirs, optimiser les performances de production et soutenir efficacement les décisions de gestion et d'exploitation des réservoirs.

Mots-clés :

Tests de puits ; Interprétation ; Réservoir ; Perméabilité ; Facteur de skin ; Pression ; Écoulement radial ; Équation de diffusivité ; KAPPA Saphir.

الملخص :

ركزت هذه الدراسة على تفسير وتحليل بيانات اختبار البئر رقم 1 بحقل حاسي مسعود باستعمال كل من الطرق التقليدية للتفسير وبرنامج KAPPA Saphir. وقد تم تنفيذ مختلف مراحل تحضير البيانات، والتحليل التشخيصي، ومواءمة النماذج، وتحليل الضغط العابر، بهدف توصيف سلوك المكمن وتقييم أداء البئر.

سمح التفسير التقليدي بطريقة Horner بالحصول على توصيف أولي للمكمن اعتمادًا على التحليل شبه اللوغاريتمي، في حين وفر برنامج KAPPA Saphir تفسيرًا أكثر دقة وموثوقية بفضل تقنيات التحليل التشخيصي المتقدمة وعمليات مطابقة النماذج.

أظهرت النتائج المتحصل عليها أن المكمن يتميز بنفاذية متوسطة وضغط مكمني جيد، بينما تعكس قيمة الـ Skin factor الموجبة وجود ضرر بالقرب من البئر يؤثر على حركة الموائع نحو البئر رقم 1.

كما أبرزت المقارنة بين الطريقتين التقليدية والحديثة أهمية أدوات تحليل الضغط العابر المتقدمة في تحسين دقة توصيف المكمن ودعم قرارات تسيير المكامن وتحسين الإنتاج.

الكلمات المفتاحية

اختبار الآبار، التفسير، المكمن، النفاذية، عامل السكين، الضغط، الجريان الشعاعي، معادلة الانتشار، KAPPA Saphir.

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List of symbols and Abreviations

P : Pressure (psi)

Pi : Initial Reservoir Pressure (psi)

Pwf : Flowing Bottom-Hole Pressure (psi)

Pe : External Boundary Pressure (psi)

ΔP : Pressure Drop (psi)

ΔPskin : Pressure Drop Due to Skin Effect (psi)

Q : Flow Rate (STB/day)

J : Productivity Index (STB/day/psi)

k : Reservoir Permeability (md)

ks : Skin Zone Permeability (md)

h : Reservoir Thickness (ft)

S : Skin Factor (dimensionless)

m : Semi-log Straight Line Slope (psi/cycle)

r : Radial Distance from Well Center (ft)

rw : Wellbore Radius (ft)

rs : Radius of Skin Zone (ft)

re : Drainage Radius (ft)

rinv : Radius of Investigation (ft)

t : Time (hr)

tp : Production Time Before Shut-in (hr)

Δt : Shut-in Time (hr)

tD : Dimensionless Time

pD : Dimensionless Pressure

C : Wellbore Storage Coefficient (bbl/psi)

CD : Dimensionless Wellbore Storage Coefficient

Ct : Total Compressibility (psi^{-1})

Cf : Fluid Compressibility (psi^{-1})

Cr : Rock Compressibility (psi^{-1})

μ : Fluid Viscosity (cp)

ρ : Fluid Density (lb/ft^3)

V : Fluid Volume (bbl)

v : Fluid Velocity (ft/day)

Φ : Porosity (%)

α : Diffusivity Coefficient (ft^2/hr)

B : Formation Volume Factor (RB/STB)

Bo : Oil Formation Volume Factor (RB/STB)

η : Hydraulic Diffusivity (ft^2/hr)

rd : Radius of Investigation (ft)

MDH : Miller-Dyes-Hutchinson Method

PBU : Pressure Build-Up Test

PTA : Pressure Transient Analysis

EOR : Enhanced Oil Recovery

HMD : Hassi Messaoud field

General introduction

General introduction

The petroleum industry plays a fundamental role in the global economy, as oil and gas remain the primary sources of energy used in transportation, industry, electricity generation, and petrochemical activities. The continuous increase in energy demand has encouraged petroleum companies to improve reservoir management techniques and optimize hydrocarbon recovery in order to ensure efficient production and long-term reservoir performance.

Reservoir engineering is considered one of the most important disciplines in the petroleum industry because it focuses on understanding reservoir behavior and evaluating production performance. in this context, obtaining reliable information about reservoir properties such as permeability, pressure, porosity, and fluid flow behavior is essential for making appropriate technical and economic decisions.

Several techniques are used to characterize reservoirs and evaluate their performance, including seismic surveys, well logging, core analysis, PVT studies, and well testing. Among these methods, well testing is considered one of the most effective techniques because it provides direct information about the dynamic behavior of the reservoir through pressure response analysis. By creating a pressure disturbance inside the reservoir and analyzing the recorded pressure data, engineers can estimate important reservoir parameters and identify flow regimes and reservoir boundaries [1] .

Well test interpretation has significantly evolved over the years, moving from conventional analytical methods such as the Horner and MDH methods to more advanced interpretation techniques based on pressure derivative analysis and type-curve matching [1]. The development of specialized software such as KAPPA Saphir has greatly improved the accuracy and reliability of pressure transient analysis, making it possible to model complex reservoir systems and obtain more precise interpretation results.

Hassi Messaoud field (HMD) is one of the largest and most strategic oil fields in Algeria. Due to its complex geological characteristics and major economic importance, accurate well test interpretation is essential for understanding reservoir behavior and optimizing production performance. Therefore, this work focuses on the understanding of reservoir behavior via the interpretation of pressure buildup test data from Well-1 located in the HMD using conventional and modern method (KAPPA Saphir software).

The objective of this study is to evaluate, analyze and interpret well test data in order to estimate the optimal reservoir parameters such as permeability, skin factor, reservoir pressure, and wellbore storage effects. In addition, this work aims to compare the results obtained using conventional interpretation methods with those generated using KAPPA Saphir software in order to evaluate the efficiency and reliability of both interpretation approaches.

This study is organized into three main chapters :

Chapter I presents the fundamental concepts of well testing. It introduces the main types of well tests, reservoir flow regimes and flow geometries, as well as important concepts such as skin effect, wellbore storage, radius of investigation, and productivity index. This chapter provides the theoretical background necessary for understanding pressure transient behavior and reservoir performance.

Chapter II focuses on well test interpretation methods. It presents the diffusivity equation and its fundamental principles, followed by conventional interpretation methods, particularly the Horner method. It also introduces modern interpretation techniques, including type-curve matching and pressure derivative analysis, with emphasis on their role in identifying flow regimes and estimating reservoir parameters.

Chapter III presents the practical application of well test interpretation to Well-1 in the Hassi Messaoud field. It first provides a brief description of the field, the reservoir, the well, and the KAPPA Saphir software. The pressure buildup test data are then prepared and interpreted using both the conventional Horner method and KAPPA Saphir. Finally, the obtained results are compared in order to characterize the reservoir behavior and evaluate the well performance.

Overall, the study combines theoretical concepts, interpretation methods, and a practical case study to demonstrate the application of pressure transient analysis in reservoir characterization and well performance evaluation.

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Chapter I :

Fundamentals of Well Testing

I. Chapter I: Fundamentals of Well Testing

I.1. Well Testing Definition :

Well testing is an important reservoir engineering technique used to evaluate reservoir and well performance through pressure transient analysis. By analyzing pressure response over time, engineers can estimate key reservoir parameters such as permeability, reservoir pressure, skin factor, and reservoir boundaries. Pressure transient tests including drawdown, buildup, injectivity, and interference tests provide valuable information about reservoir behavior and fluid flow characteristics [1].

- **Detection of Reservoir and Well Problems**:
  Well testing helps identify problems related to the reservoir or the wellbore, such as formation damage or the production of unwanted fluids including water or gas. This allows engineers to apply corrective actions that improve efficiency and reduce operational costs.
- **Production Optimization:**
  Well testing provides essential information about well performance, enabling engineers to optimize operating conditions and maximize hydrocarbon recovery.
- **Reservoir Evaluation:**
  Pressure transient analysis offers valuable information about reservoir properties such as permeability, reservoir boundaries, and pressure behavior. These parameters are fundamental for reservoir characterization, field development planning, and enhanced oil recovery (EOR) strategies [1].

I.2. Types of Production Well Tests :

I.2.1. Pressure Drawdown Test :

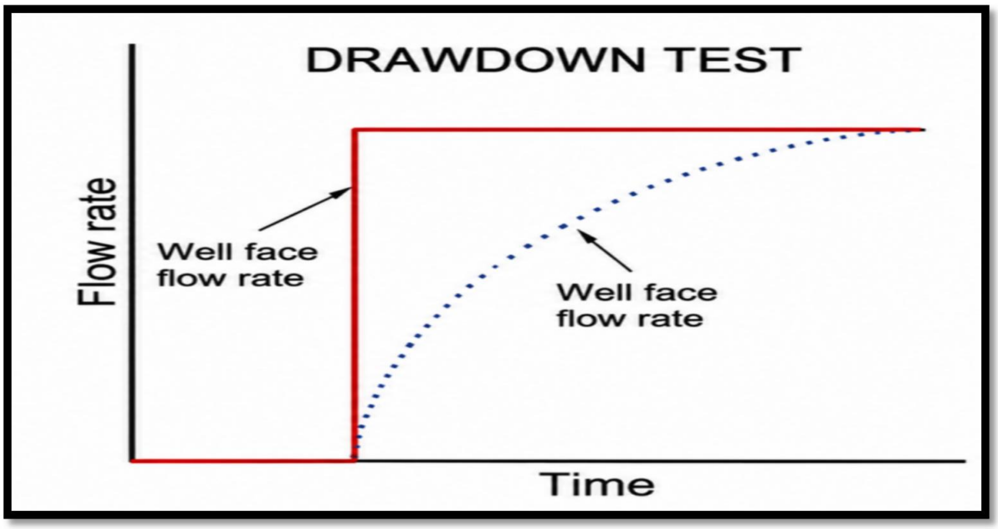

Figure I.1 :Schematic Representation of a Drawdown Test [3].

A drawdown test is performed by opening a well that is initially shut-in, stable, and at static conditions to produce at a nearly constant flow rate. During the test, the pressure response is recorded and analyzed to evaluate reservoir and well characteristics. Most conventional well test interpretation methods are based on drawdown test principles and pressure transient analysis.(Figure I.1)

In practice, achieving ideal testing conditions may be difficult. Maintaining a strictly constant flow rate is challenging, even after the well appears to stabilize, and the well may not initially be in a fully static or stable state, particularly after drilling operations or previous production periods. Despite these limitations, drawdown testing remains an effective method for reservoir boundary detection because boundary effects generally require long observation times, during which the influence of short-term flow-rate fluctuations becomes less significant [2].

I.2.2. Pressure Buildup Test :

In a buildup test, a well that is already producing—ideally at a constant flow rate—is shut in, and the down hole pressure response is recorded as pressure gradually builds up over time. The interpretation of buildup data generally requires only minor modifications to the methods used for constant-rate drawdown analysis. One practical advantage of buildup testing is that the constant flow-rate condition is easier to achieve because the flow rate becomes zero after shut-in.

However, buildup tests also present certain operational limitations. Achieving a stable production rate before shut-in may be difficult, particularly when the well must be temporarily closed to install pressure measurement tools. In addition, production is interrupted during the shut-in period, resulting in temporary production losses. Despite these limitations, buildup testing remains one of the most widely used pressure transient testing techniques for reservoir and well evaluation (Figure I.2) [4].

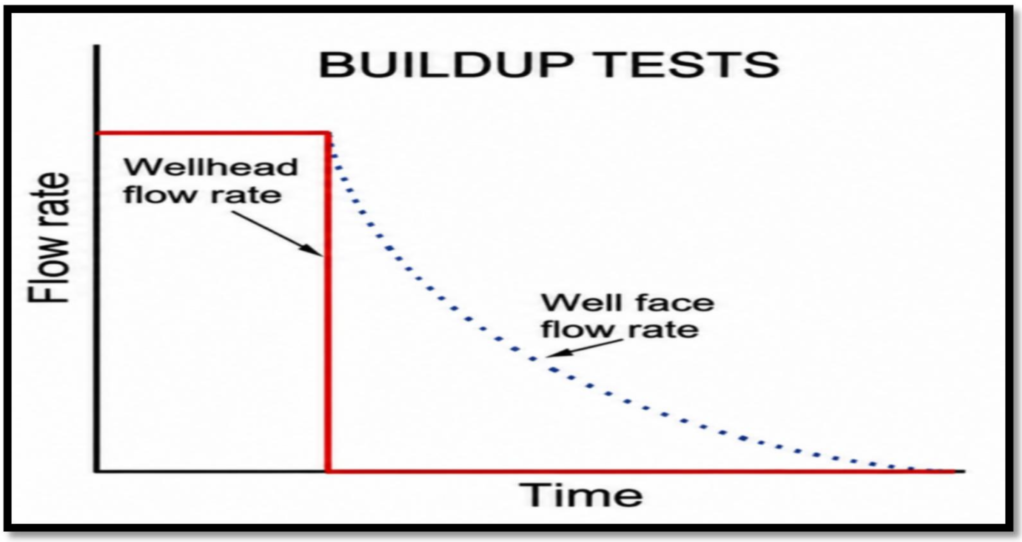

Figure I.2 : Buildup Test [3] .

I.3. Types of Fluids :

The isothermal compressibility coefficient is a key parameter for determining the type of reservoir fluid. Based on this property, reservoir fluids are generally classified into three main categories (Figure I.3) [4] **:**

- **incompressible fluids**
- **slightly compressible fluids**
- **compressible fluids**

The isothermal compressibility coefficient C is described mathematically by the following two equivalent expressions:

- **In term of fluid volume :**

$$C = -\frac{1}{V}\frac{\partial V}{\partial p} \quad (I.1)$$

Where:

C = Compressibility coefficient

V = Volume

P = Pressure

- **In term of fluid density :**

$$C = -\frac{1}{\rho}\frac{\partial \rho}{\partial p} \qquad (I.2)$$

ρ = Fluid density .

where V and ρ are the volume and density of the fluid.

. **Incompressible Fluids:** volume (or density) does not change with pressure:

$$\frac{\partial V}{\partial P} = 0 \;/\; \frac{\partial \rho}{\partial P} = 0 \qquad (I.3)$$

Incompressible fluids do not exist; this behavior, however, may be assumed in some cases to simplify the derivation and the final form of many flow equations

- **Slightly Compressible Fluids:** These fluids exhibit small changes in volume, or density, with changes in pressure. Crude oil and water systems fit into this group
- **Compressible Fluids:** These fluids have large changes in volume as a function of pressure. All gases are considered compressible fluids [5] .

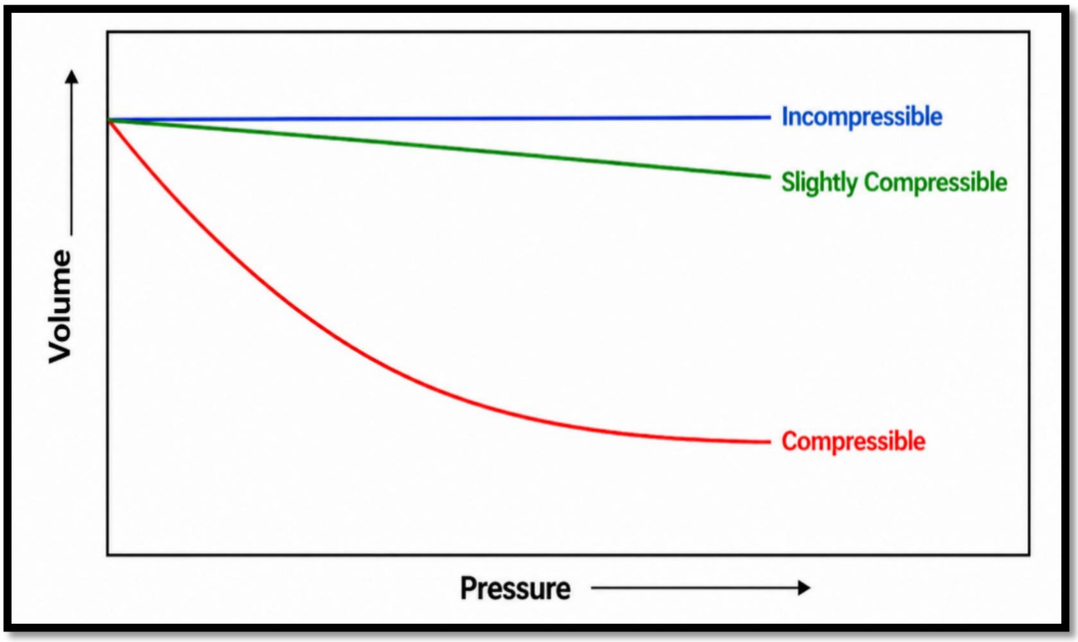

Figure I.3 : Fluids Compressibility Types [5] .

I.4. Reservoir Flow Regimes :

To explain the fluid flow behavior and reservoir pressure distribution as a function of time, it is essentially necessary to identify three types of flow regimes [6]:

The three principal flow regimes are (shown in Figure I.4) :

- steady-state flow
- unsteady-state flow
- pseudosteady-state flow

I.4.1. Steady State Flow :

The pressure at every location in the reservoir remains constant, i.e., does not change with time. Under steady-state conditions, the reservoir pressure remains unchanged with time at any specific location, which means that the pressure variation with respect to time is equal to zero. In petroleum reservoirs, this flow regime is generally observed only when continuous external support is available, such as a strong aquifer drive or efficient pressure maintenance systems that compensate for fluid production.

$$\left(\frac{\partial p}{\partial t}\right)_i = 0 \qquad (I.4)$$

I.4.2. Unsteady-State Flow (Transient Flow) :

The rate of change of pressure with respect to time at any position in the reservoir is not zero or constant.

$$\left(\frac{\partial P}{\partial t}\right)_i = f(i, t) \qquad (I.5)$$

The pressure derivative with respect to time is essentially a function of both position i and time t.

I.4.3. Pseudo-steady-State Flow (semi-steady state or quasi-steady state flow):

During pseudo-steady-state flow, the reservoir pressure decreases uniformly with time throughout the reservoir. Although pressure continues to decline, the decline rate remains constant at all reservoir locations. Therefore, the pressure variation with respect to time is considered constant at every point in the system [7].

$$\left(\frac{\partial p}{\partial t}\right)_i = \text{constant} \qquad (I.6)$$

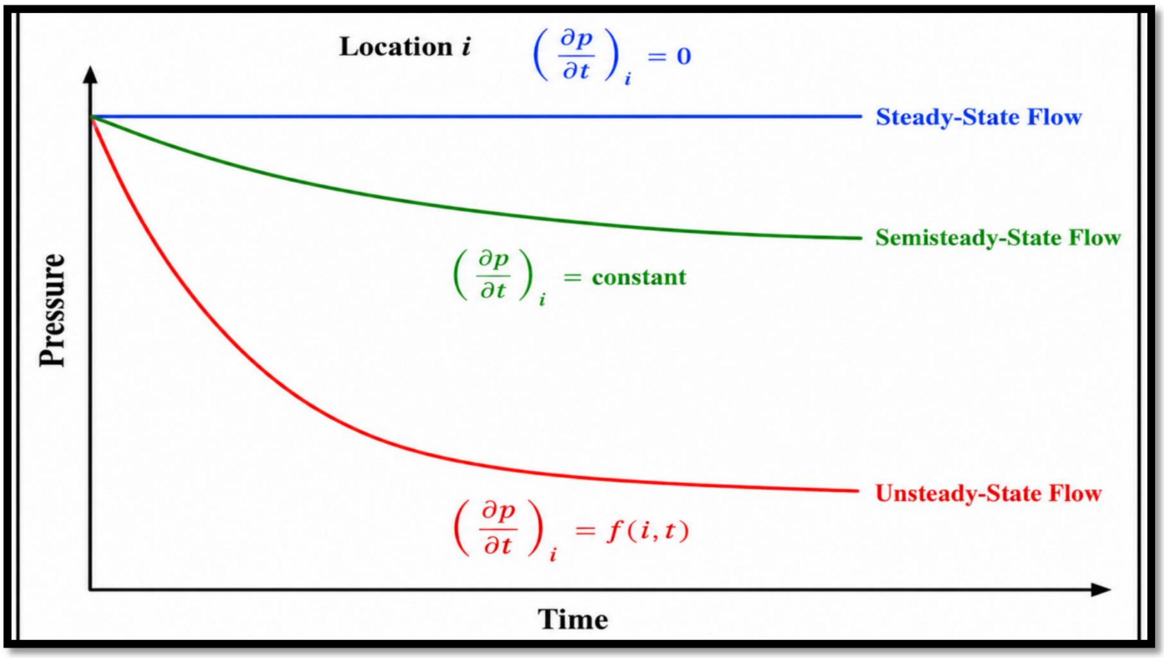

Figure I.4 : Reservoir Flow Behavior [8] .

I.5. Reservoir Flow Geometry:

The geometry of a reservoir plays an important role in determining its flow behavior. Since most reservoirs have irregular boundaries, a precise mathematical description of their geometry often requires the use of numerical simulation tools. However, for many engineering applications, reservoir flow can be idealized using simplified geometries (Figure I.5) , including [8]**:**

- **radial flow**
- **linear flow**
- **spherical and hemispherical flow.**

I.5.1. Radial Flow :

In the absence of significant reservoir heterogeneities, fluid flow toward or away from a wellbore generally follows radial streamlines over a considerable distance from the well.

Since fluids converge toward the well from all directions, this flow pattern is referred to as radial flow.

I.5.2. Linear Flow :

Linear flow occurs when the flow paths are parallel and fluid moves in a single direction. In this case, the cross-sectional area available for flow remains constant. A common application of linear flow equations is the flow of fluids into vertical hydraulic fractures.

I.5.3. Spherical and Hemispherical Flow :

Depending on the wellbore completion configuration, spherical or hemispherical flow may develop in the near-wellbore region. A well with a limited perforated interval can exhibit spherical flow around the perforations. Similarly, a partially penetrating well within the pay zone may lead to hemispherical flow. This condition can also occur in situations where bottom-water coning is significant.

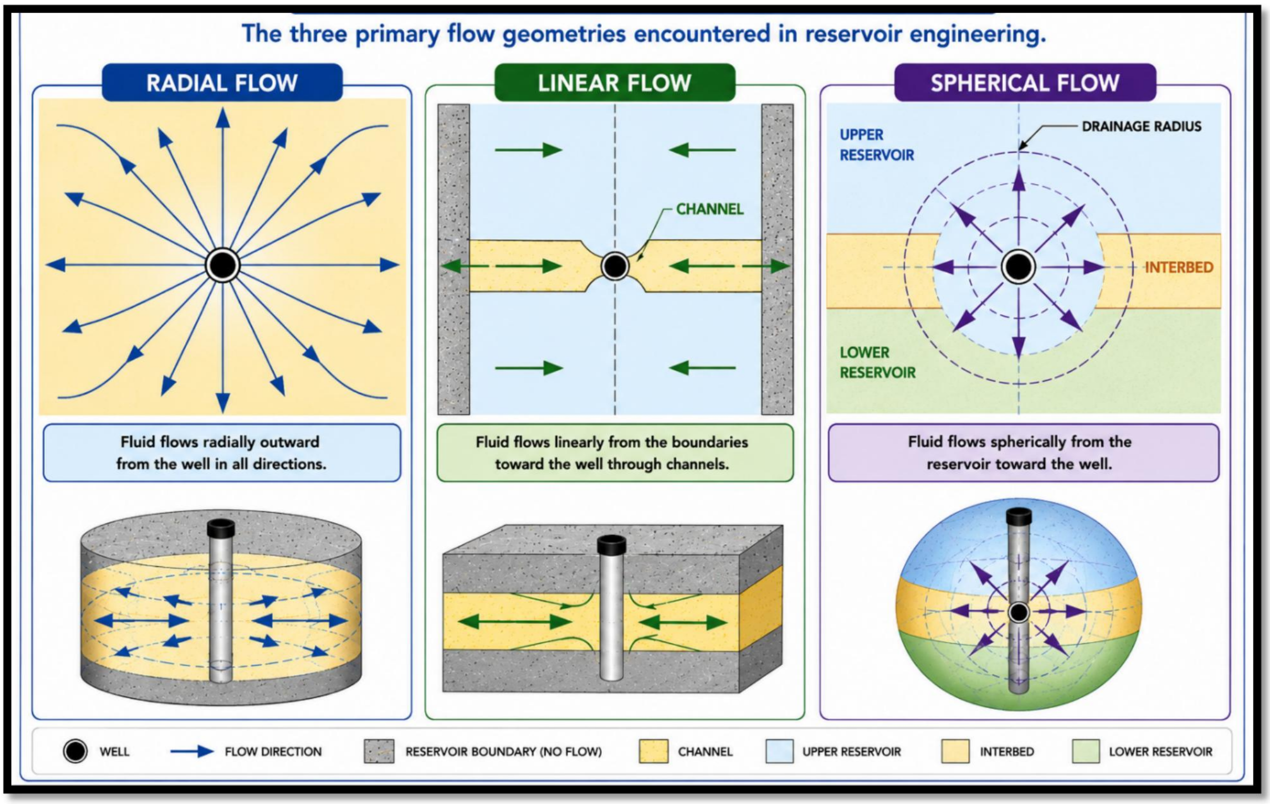

Figure I.5 : Reservoir Flow Geometries

I.6. Number of Flowing Fluids in The Reservoir :

The mathematical expressions that are used to predict the volumetric performance and pressure behavior of a reservoir vary inform and complexity depending upon the number of mobile fluids in the reservoir. There are generally three flow systems:

- single-phase flow (**oil, water, or gas**)
- two-phase flow (**oil–water, oil–gas, or gas–water**)
- three-phase flow (**oil, water, and gas**).

The description of fluid flow and subsequent analysis of pressure data becomes more difficult as the number of mobile fluids increases [7].

I.7. Skin Effect :

During drilling, completion, or workover operations, materials such as mud filtrate, cement slurry, or clay particles may invade the formation and reduce its permeability near the wellbore. This phenomenon is known as formation damage, and the affected region is referred to as the skin zone. The skin zone may extend from a few inches to several feet into the formation.

Conversely, some wells are subjected to stimulation treatments such as acidizing or hydraulic fracturing, which enhance permeability in the near-wellbore region. As a result, the permeability near the wellbore differs from that of the undisturbed formation.

Damage mechanisms create an additional localized pressure drop during fluid flow, commonly expressed as **Δp**_skin.

In contrast, stimulation treatments reduce flow resistance and consequently decrease the pressure drop. The overall effect of these near-wellbore permeability alterations is referred to as the skin effect [9].

The skin factor is expressed as [4] :

$$S = \left(\frac{k}{ks} - 1\right) ln\frac{rs}{rw} \quad (I.7)$$

Where:

- S = Skin factor
- k = Reservoir permeability
- ks = Skin zone permeability (damaged or stimulated zone)
- rs = Skin radius (affected zone radius)
- rw = Wellbore radius

The figure below illustrates the pressure drop behavior in the skin zone for three possible cases:

ΔP skin > 0 : in dicates an additional pressure drop due to wellbore damage**.**

$$K_{skin} < K$$

ΔP skin < 0 : indicates less pressure drop due to wellbore improvement **.**

$$K_{skin} > K$$

Δp skin = 0 : indicates no changes in the wellbore condition. [4]**.**

$$K_{skin} = K$$

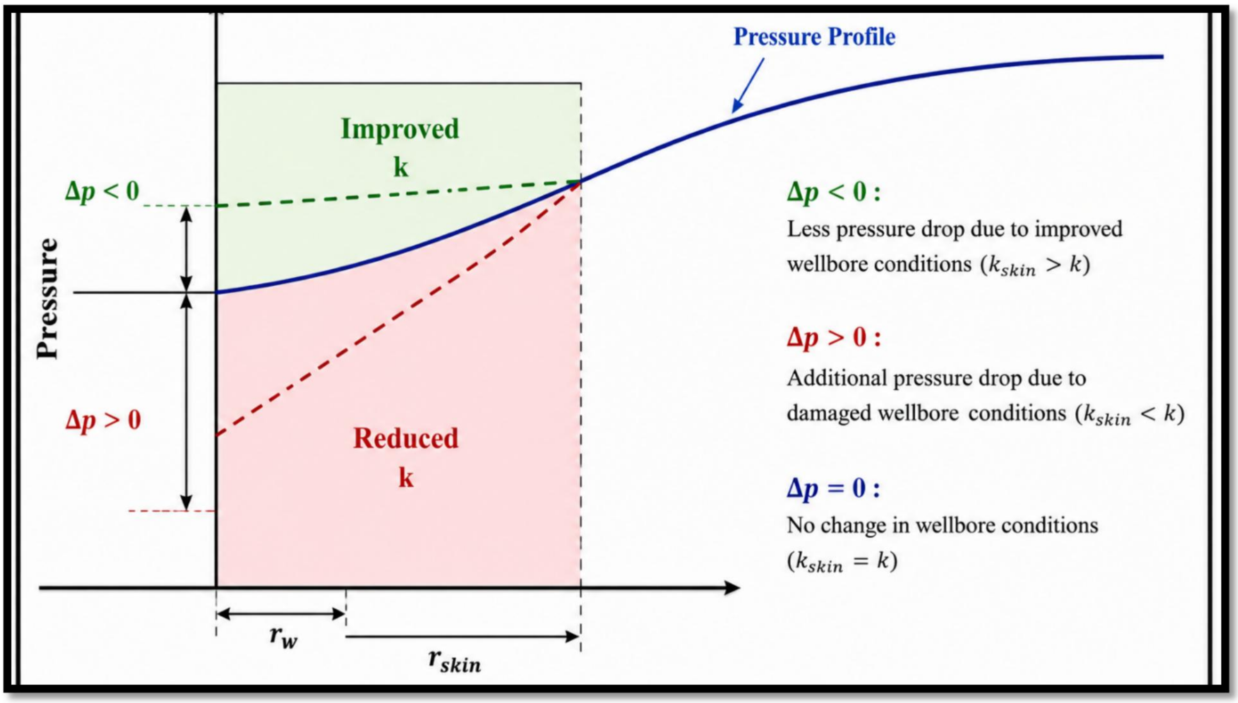

Figure I.6 : Skin Effect Around the Wellbore [17]

Hawkins proposed the following approach :

$$\Delta_{pskin} = [\Delta_p \text{ in skin zone due to } K_{skin}] - [\Delta_p \text{ in skin zone due to k}] . \qquad (I.8)$$

Near wellbore effects (skin factor) The skin factor is a constant used to modify the flow equations derived under ideal conditions (homogeneous and isotropic porous media) so that they can be applied to real reservoir conditions. It is an empirical parameter that accounts for the combined effects of various near-wellbore phenomena not included in the original theoretical development of the flow equations [9]**.**

I.8. Wellbore Storage Effect :

The wellbore storage effect is defined immediately after a production start up or shut-in, when the pressure behaviour at early-times is dominated by the compressibility and volume of the wellbore fluid; as illustrated in Figure I.7 [10] **.**

At the start of a flow period, production at surface is due to the expansion of the fluid in the wellbore, and not the reservoir. There is a time lag when the surface production rate becomes consistent with the sand face rate and this defines the wellbore storage period. At shut-in, the fluid gets compressed in the wellbore and the rate at sand face gradually goes to 0.

Wellbore storage is a function of the wellbore fluid and the completion size. The wellbore storage coefficient is defined as: C = Cf / Vf with Cf the fluid compressibility and Vf the fluid volume. It is measured in units of bbl/psi.

All types of wells, including fractured wells, may experiment wellbore storage at the start of a drawdown period or a Pressure Buildup (PBU) test **.**

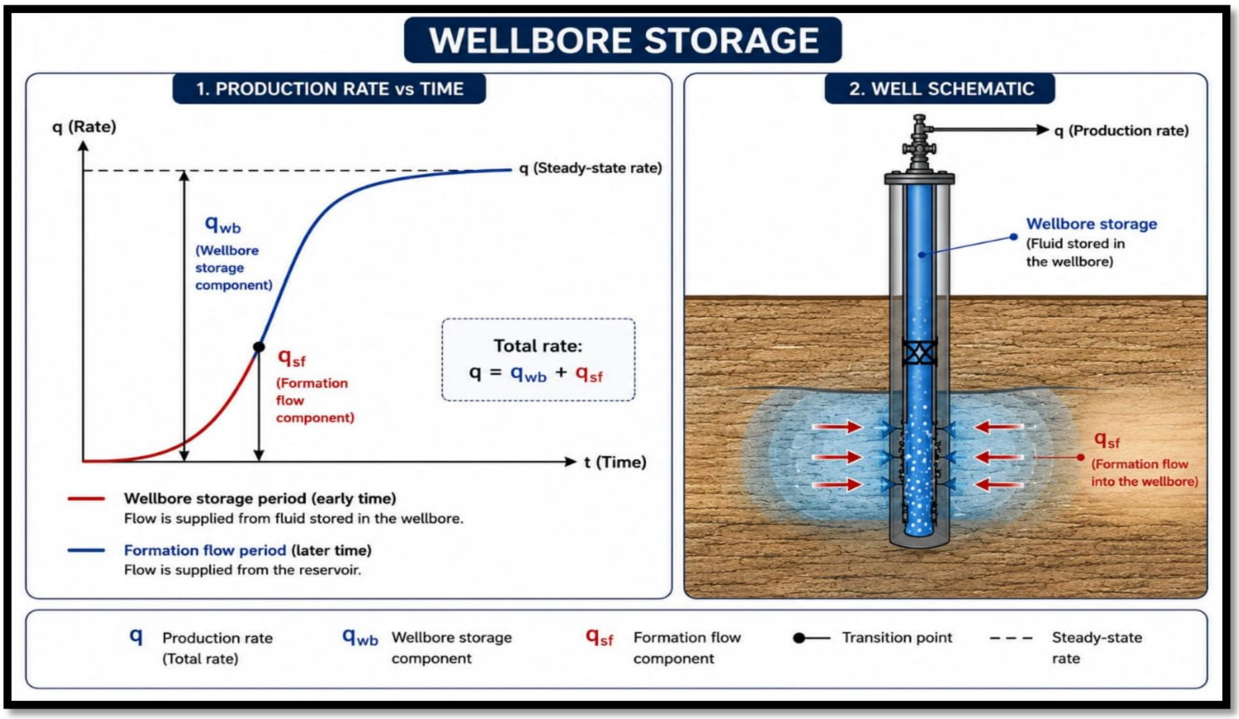

Figure I.7 : Wellbore Storage.

I.9. Radius of Investigation :

The radius of investigation refers to the distance into the reservoir that a pressure transient has reached after a disturbance, such as a change in production or injection rate at a well. As time progresses, the pressure disturbance propagates further into the reservoir as presented in Figure I.8.

Although this concept is not strictly rigorous from a theoretical standpoint, it is sufficiently accurate for practical applications. In theory, any pressure change at the well has an immediate, although extremely small, effect throughout the entire reservoir. However, at a certain distance from the well, the magnitude of this effect becomes negligible and cannot be measured.

The maximum distance at which the pressure response remains detectable is defined as the radius of investigation [8].

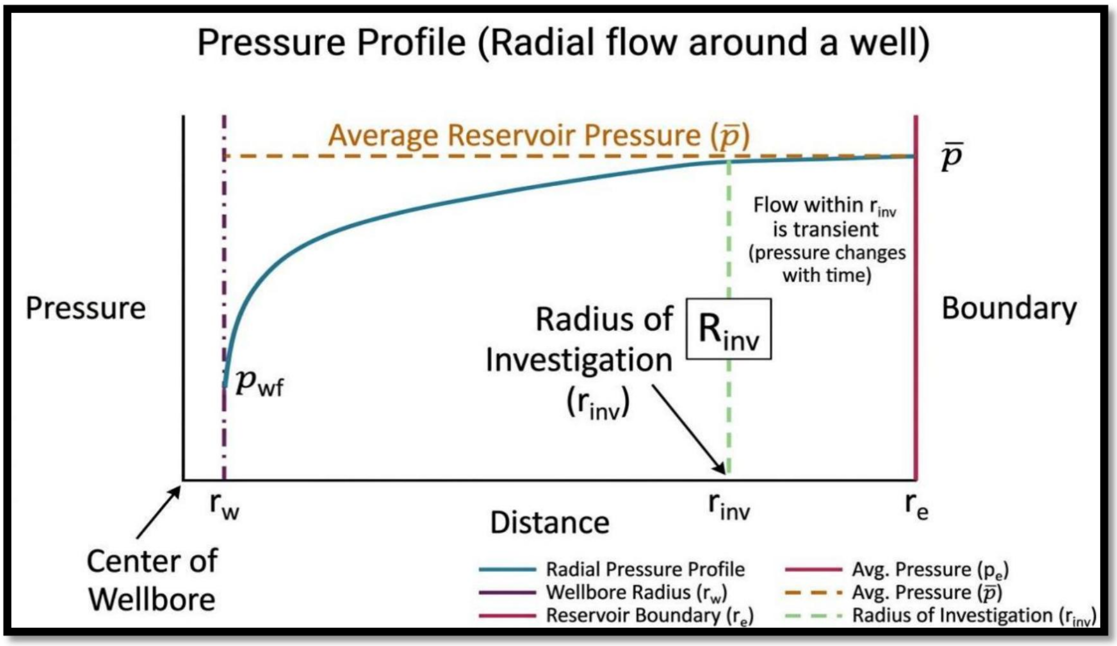

Figure I.8 : Radius of Investigation [5].

The radius of investigation is calculated using the following equation:

$$r_d = 1.5\sqrt{\frac{k}{\mu c t \varnothing}t} \tag{I.9}$$

- rd = Dimensionless radius
- k = Reservoir permeability (md)
- μ = Fluid viscosity (cp)
- ct = Total compressibility (psi^{-1})
- φ = Porosity (%)
- t = Time (h or day)

I.10. Productivity Index (J) :

The productivity index is a measure of the well potential or ability to produce and is a commonly used indicator of well performance. The productivity index can be mathematically expressed as the ratio of volumetric flow produced by a well **(bbl/day)** to the pressure loss between reservoir and bottomhole **(psi).**

Productivity Index: $$J = \frac{Q_o}{p_{\bar{r}} - p_{wf}} = \frac{Q_o}{\Delta p} \qquad \text{(I. 10)}$$

- **J** = Productivity Index, STB/day/psi
- **Q** = Surface flow rate at standard conditions, STB/D
- **Pe** = External boundary radius pressure, psi
- **Pwf** = Well sand-face mid-perf pressure, psi

Over a longer timescale as the oil and gas reservoirs are depleted, the reservoir pressure drops down. Hence flow and pressure loss also change. But this depletion can only be considered over a timescale of a few years. For shorter time scales, the hydrocarbon fluid flow as well as the reservoir pressure can be considered to be constant. This is known as pseudo steady state for the producing well [5] .

Chapter II :
Well Test Interpretation

II. Chapter II: Well Test Interpretation

II.1. Introduction:

Well test interpretation is considered one of the most important studies in reservoir engineering for understanding reservoir behavior and evaluating its dynamic properties. This process is based on analyzing pressure variations with time during production and shut-in periods, allowing engineers to obtain valuable information about both well and reservoir performance.

Well test interpretation helps determine several essential reservoir parameters such as permeability, reservoir pressure, skin factor, and boundary effects, in addition to identifying different flow regimes within the reservoir. It is also used to evaluate the communication between the well and the reservoir and to detect the presence of geological barriers or natural fractures. The interpretation process relies on mathematical and physical principles related to fluid flow through porous media, where the actual pressure response is compared with theoretical reservoir models in order to understand reservoir behavior accurately. Pressure derivative analysis is considered one of the most important tools for identifying flow regimes and characterizing reservoir properties. A proper understanding of well test interpretation plays a major role in improving field development strategies and supporting accurate decisions related to reservoir management and production optimization.

II.2. Diffusivity Equation:

The diffusivity equation governs the evolution of pressure in a reservoir over time. It is derived by combining three fundamental laws **:**

II.2.1. Darcy’s Law

Darcy’s law describes fluid flow through a porous medium. It states that the fluid flow rate through a rock sample is proportional to [11]:

- the pressure gradient (assumed small),
- the cross-sectional area S
- and the fluid mobility.

This law is independent of the medium porosity and does not explicitly account for fluid or rock compressibility.

Vector form:

$$q = -\frac{k}{\mu} S \text{ grade } P \qquad (\text{II.1})$$

Linear steady-state flow:

$$\frac{dP}{dx} = \frac{\mu}{k} \frac{Q}{S} \quad \Rightarrow \quad Q = Q = \frac{k}{u} S \frac{P1 - P2}{x1 - x2} \qquad (\text{II.2})$$

- μ = Fluid viscosity , cp
- k = Reservoir permeability, md
- Q = Flow rate , cm^3/s or bbl/day
- S = Cross-sectional area , ft^2

Radial flow (cylindrical coordinates):

$$Q = \frac{K}{\mu} 2\pi r \text{h} \frac{dP}{dr} \qquad (\text{II.3})$$

Integrated between the wellbore radius r_w and reservoir radius r_e:

$$Q = \frac{K}{\mu} 2\pi r \text{h} \frac{Pw\text{-}Pe}{ln\frac{rw}{re}} \qquad (\text{II.4})$$

Where:

- Q = Flow rate , bbl/day
- k = Reservoir permeability , md
- μ = Fluid viscosit , cp
- r = Radius , ft
- h = Reservoir thickness , ft
- Pw = Wellbore pressur , psi
- Pe = External reservoir pressure , psi
- rw = Wellbore radius , ft
- re = External drainage radius , ft

II.2.2. Fluid Equation of State:

This relation describes how fluid density varies with pressure. This variation is expressed through the fluid compressibility:

$$Ce = \frac{1}{\rho}\left(\frac{d\rho}{dP}\right)_T \qquad \text{(II.5)}$$

a. Mass Conservation Law:

The change in mass within a reservoir volume element equals the difference between inflow and outflow over time [6] :

$$div\, \rho\, V + \varnothing + \frac{\partial\rho}{\partial t} = 0 \qquad \text{(II.6)}$$

- ρ = Fluid density , lb/ft³ or kg/m³
- V = Fluid velocity , ft/s or m/s
- φ = Porosity , %

b. Diffusivity Equation Derivation:

By combining these three laws and applying the following assumptions:

- low and constant fluid compressibility (liquid case),
- small pressure gradients (low-velocity flow in reservoirs),

we obtaint he standard diffusivity equation:

$$\Delta P - \frac{1}{K}\frac{dp}{dt} = 0 \qquad \text{(II.7)}$$

$$K = \frac{k}{\varnothing\ \mu c_t} \qquad \text{(II.8)}$$

K is called the **hydraulic diffusivity** of the medium.

II.2.3. Radial Diffusivity Equation (Vertical Well) :

$$\frac{\partial^2 P}{\partial r^2} + \frac{1}{r}\frac{\partial P}{\partial r} - \frac{1}{K}\frac{\partial P}{\partial t} = 0 \qquad \text{(II.9)}$$

II.3. Assumptions and Limitations of The Diffusivity Equation:

The diffusivity equation is based on several simplifying assumptions, including:

- Homogeneous and isotropic porous medium
- Uniform reservoir thickness
- Single-phase flow
- Constant rock and fluid properties (such as viscosity and compressibility), independent of pressure
- Complete well penetration of the formation, with negligible gravity effects [10].

II.4. Well Test Interpretation:

Figure II.1 illustrates the relationship between flow rate variations (input) and the corresponding pressure response (output) during a well test.

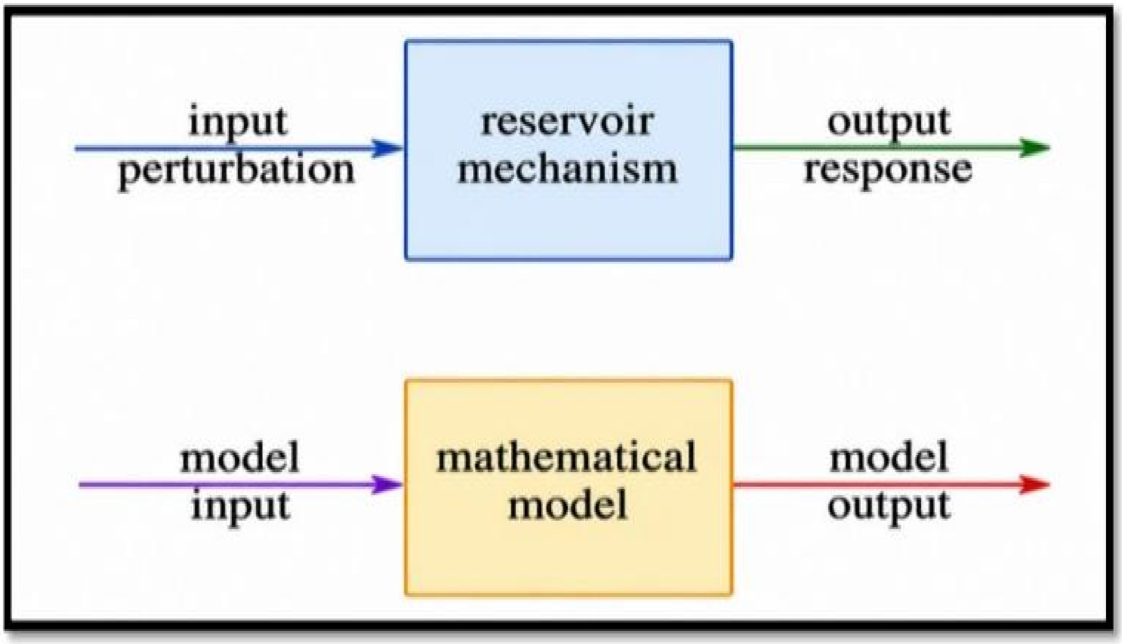

Figure II.1 : Relationship Between Reservoir Response and Mathematical Model Simulation [3].

II.5. Key Points of Well Test Interpretation:

Reservoir interpretation relies on several fundamental concepts, as illustrated below.

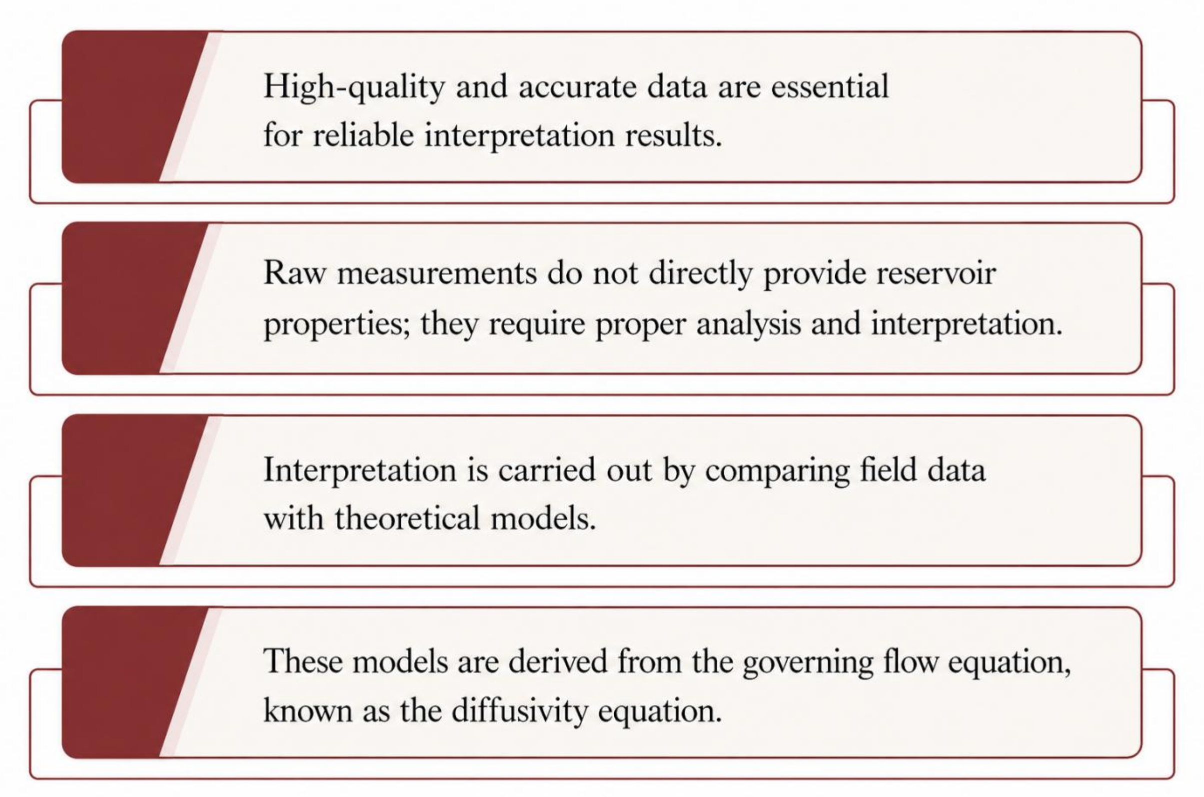

Figure II.2 : Key Points of Well Test Interpretation **.**

II.6. Well Test Interpretation Method :

II.6.1. Conventional Method :

Conventional methods were developed as far back as the **1930s**, and became the only methods available until the **1970s** . These methods consist of drawing the lines and slopes corresponding to each type of flow then using the appropriate equations to calculate the parameters of the well and the reservoir. Diagnosis of the type of flow is therefore necessary . This method is mainly based on the testing technique , the methods are [9]:

- **miller –dyes and hutchingson (Mdh method).**
- **Horner's method.**

a. Miller –Dyes and Hutchingson (MDH Method) :

The most simple semi-log plot, in which the time axis is log(Δt), is called the Miller-Dyes Hutchinson or MDH plot, as shown in Figure II.3. It is strictly valid only for the first ever drawdown on a well, but can in exceptional circumstances be used for analysis of a later drawdown or even a build-up**. In 1998**, with computers that can handle superposition rigorously, it should only be used for Drawdown [8].

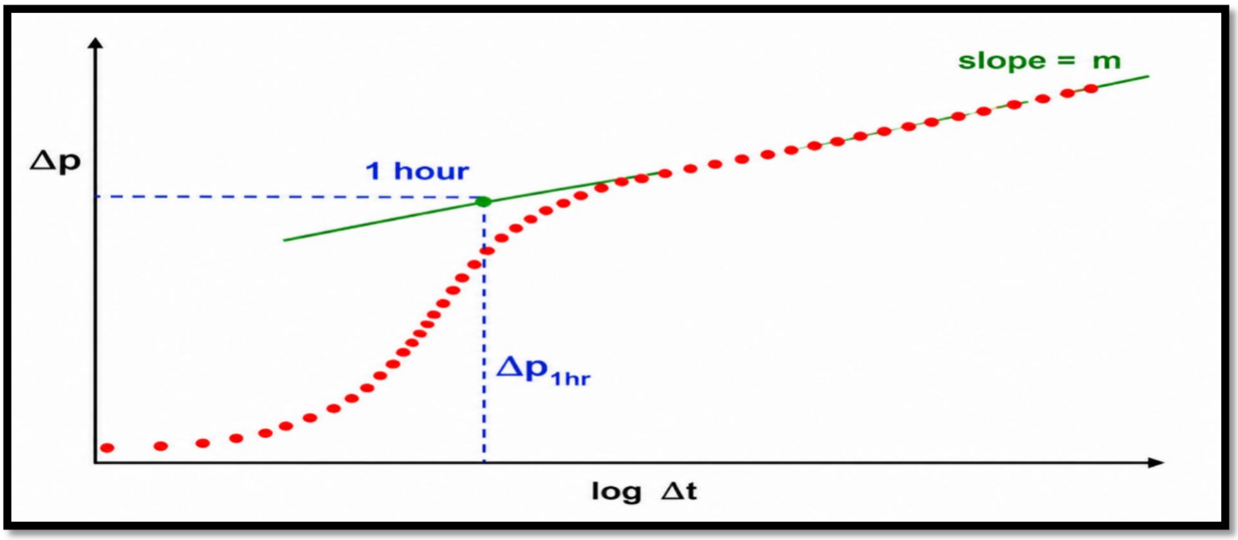

Figure II.3 : MDH Plot For Δt [8]

All of the semi-log plots are more conveniently represented with pressure on the y-axis, since this does not affect the interpretation results. For the MDH method, the corresponding drawdown representation is illustrated in Figure II.4.

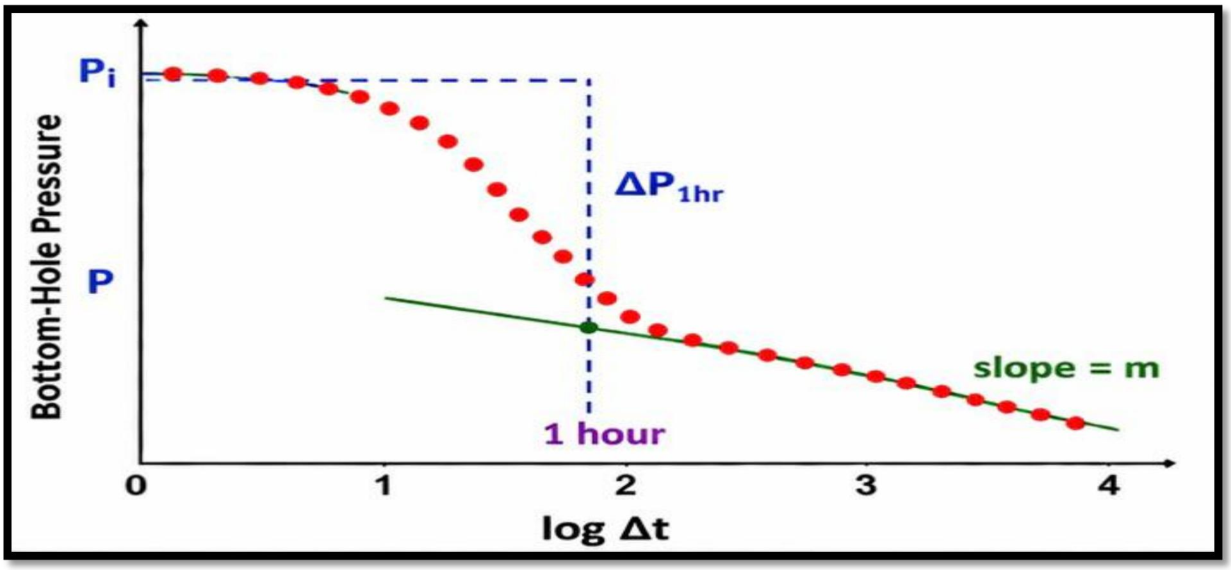

Figure II.4 : MDH Plot For P [8].

As already mentioned the slope of the straight line is :

$$m = 162.6 \frac{q \mu B}{K h} \qquad \text{(II.10)}$$

This gives the permeability-thickness product as :

$$Kh = 162.6 \frac{q \mu B}{m} \qquad \text{(II.11)}$$

- q = Flow rate , STB/day
- B = Formation volume factor , bbl/STB
- m = Slope of the pressure-time plot , psi/cycle
- 162.6 = Conversion constant

The value of the pressure on the line at Δt = 1 hour is used to evaluate the skin:

$$S = 1.151\left[\frac{\Delta p1hr}{m} - \log\left(\frac{k}{\phi \mu C t r w 2}\right) + 3.23)\right] \qquad \text{(II.12)}$$

Where:

- S = Skin factor
- Δp1hr = Pressure change at 1 hour , psi
- m = Slope of pressure-time plot , psi/cycle
- k = Reservoir permeability , md
- φ = Porosity , %
- µ = Fluid viscosity , cp

- ct = Total compressibility , psi^{-1}
- rw = Wellbore radius , ft
- 1.151 and 3.23 = Conversion constants

b. Horner Plot Method:

The Horner plot method is used to analyze pressure buildup data following a drawdown period. In the simplest case, a buildup occurs after a single constant-rate production period, where a shut-in(build-up) follows a drawdown at rate +q, represented conceptually using superposition with an equivalent injection of rate −q. Assuming that both regimes reach infinite-acting radial flow (IARF), the buildup pressure can be approximated by [13] :

$$\mathbf{P = Pi - 162.6\,\frac{q\,\mu\,B}{Kh}\log\left(\frac{tp+\Delta t}{\Delta t}\right)} \qquad (\text{II.13})$$

Pi = Initial reservoir pressure , psi

Δt = Pressure buildup time , hr

Under IARF conditions, a linear relationship exists between pressure and the Horner time function:

$$\mathbf{\log\left(\frac{tp+\Delta t}{\Delta t}\right)} \qquad (\text{II.14})$$

This function depends on tp , the duration of the production period before shut-in. The coefficient of the logarithmic term is the same as in the MDH method, meaning the slope of the straight line is denoted as m, from which permeability-thickness can be determined:

$$\mathbf{Kh = 162.6\,\frac{q\,\mu\,B}{m}} \qquad (\text{II.15})$$

Using the pressure at 1 hour after shut-in, the skin factor equation becomes:

$$\mathbf{S = 1.151\left[\frac{\Delta p1hr}{m} - \log\left(\frac{k}{\varnothing\ \mu Ctrw2}\right) + \log\left(\frac{tp+1}{tp}\right) + 3.23\right]} \qquad (\text{II.16})$$

Where:

- S = Skin factor
- Δp1hr = Pressure change at 1 hour , psi
- m = Slope of pressure-time plot , psi/cycle

- k = Reservoir permeability , md
- φ = Porosity , %
- μ = Fluid viscosity , cp
- ct = Total compressibility , psi^{-1}
- rw = Wellbore radius , ft
- tp = Production time , hr
- 1.151 and 3.23 = Conversion constants

It should be noted that the Horner time function causes the data to be plotted in a reversed manner. At early shut-in times (Δt small), the Horner time becomes large, whereas as Δt approaches infinity, the function approaches 1 and its logarithm tends toward zero. This graphical behavior is illustrated in Figure II.5.

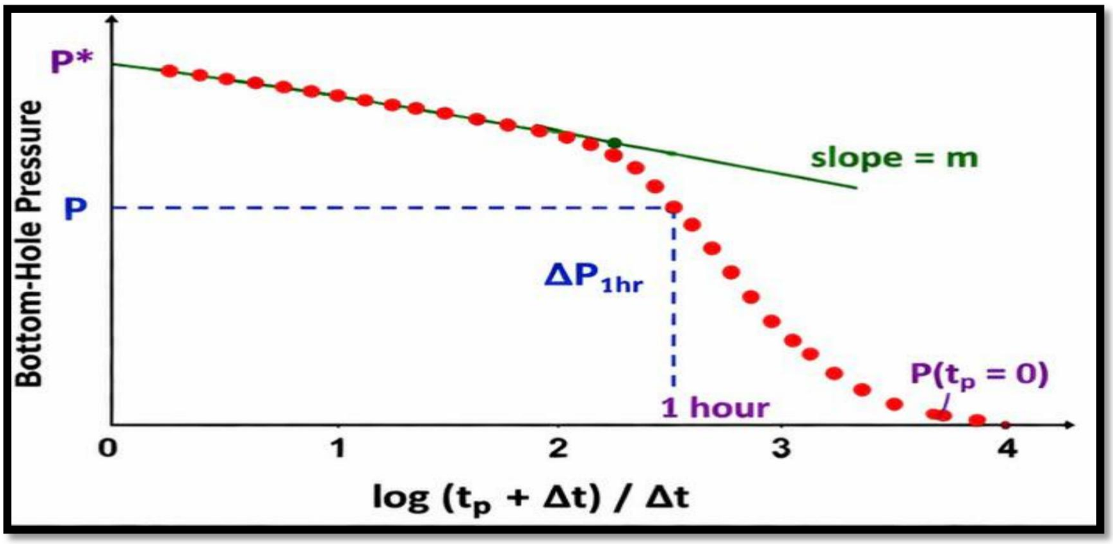

Figure II.5 : Horner Plot Extrapolated Pressure in Horner Analysis [9].

II.7. Extrapolated Pressure in Horner Analysis:

If the reservoir were truly infinite, the pressure during buildup under infinite-acting radial flow would continue to increase and eventually intersect the y-axis at p_i, the initial reservoir pressure.

However, since no reservoir is truly infinite, the straight-line radial flow trend obtained from Horner analysis, when extrapolated to infinite shut-in time, yields a value denoted as p^*. This is an extrapolated pressure rather than a true physical reservoir pressure.

Although p^* may be close to the actual stabilized shut-in pressure, it should not be interpreted as the current reservoir pressure. inreality, the pressure behavior will eventually deviate from the straight-line "m" trend as boundary effects begin to influence the system, which is unavoidable infinite reservoirs

II.8. Regions of The Horner Plot :

- **Early-Time Region (ETR):**
  This portion of the plot provides information related to wellbore storage effects and skin factor.
- **Middle-Time Region (MTR):**
  This region reflects the infinite-acting radial flow (IARF) regime and is used to determine reservoir properties as well as identify the appropriate reservoir model.
- **Late-Time Region (LTR):**
  This part of the plot provides information about reservoir boundaries and their influence on pressure behavior [13] .

The different regions of the Horner plot are presented in Figure II.6.

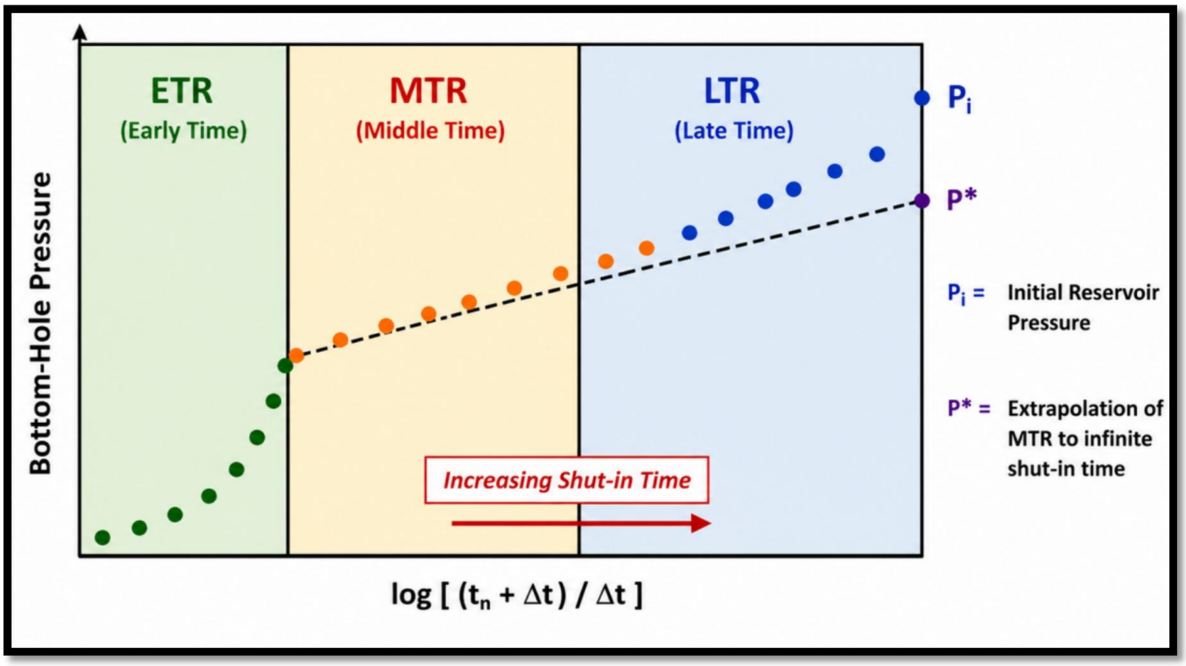

Figure II.6 : Sequences Times in Well Interpretion

II.9. Modern Method :

II.9.1. Type Curve Matching

Although reservoir parameters can be estimated using conventional methods such as semi-log analysis, type curve matching offers several additional advantages. Unlike methods that focus on specific portions of the data, type curve analysis utilizes the entire data set, ensuring consistency over all time ranges and allowing the interpretation of transitional flow regimes between different response periods [14].

The principle of type curve matching is shown in Figure II.7.

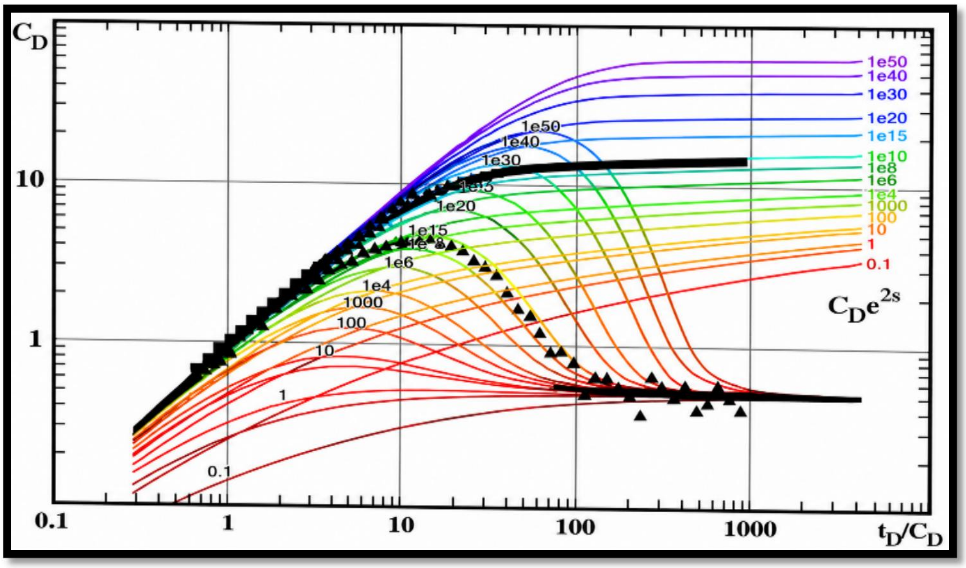

Figure II.7 : Type Curve Matching Method [14] .

In log-log type curve analysis, the theoretical model curves dimensionless pressure and pressure derivative) have the same shape as the measured field data (pressure change and time). To perform the matching, the field data are plotted on log-log paper using the same scale as the standard type curves [15].

The plotted data are then superimposed onto the type curves and shifted both horizontally and vertically—while keeping the axes parallel—until the best possible match is achieved. The inclusion of the pressure derivative in both the data and the type curves significantly improves the accuracy and ease of the matching process .

Once a satisfactory match is obtained, corresponding points between the model and the data are identified. These correspondences allow the calculation of key reservoir parameters such as permeability, wellbore storage, and other properties, as described in type curve analysis methods**.**

The infinite-acting radial flow equation derived in the Sidebar on page 4 can be written in terms of the wellbore storage coefficient C and skin factor s as follows :

$$\mathbf{p_D = 0.5\left[\ln\left(\frac{t_D}{C_D}\right) + 0.80907 + \ln(C_D e^{2s})\right]} \qquad (\text{II.17})$$

where the dimensionless wellbore storage coefficient is [10] :

$$\mathbf{C_D = \frac{0.8937\,C}{\emptyset h C_t r_w^2}} \qquad (\text{II.18})$$

The wellbore storage coefficient, C, is assumed to remain constant and represents the compressibility effects of the fluid contained within the wellbore. The radial flow equation is one of the fundamental mathematical models used in modern well test analysis. It demonstrates that the infinite-acting response of a well, considering constant wellbore storage and skin effects and subjected to a single-step change inflow rate, can be characterized by three dimensionless parameters: $\boldsymbol{p_D}$**,** $\boldsymbol{\frac{t_D}{C_D}}$, and $\boldsymbol{C_D e^{2s}}$**.**

A common approach for interpreting well test data is the graphical representation of : $\boldsymbol{p_D}$ and its derivative $\boldsymbol{p_D}$',($\boldsymbol{\frac{t_D}{C_D}}$) versus $\boldsymbol{\frac{t_D}{C_D}}$ on logarithmic scales. The pressure derivative is calculated with respect to the natural logarithm of time (lnt) and corresponds to the slope of the pressure response on a semi-logarithmic plot. This derivative enhances the visibility of formation characteristics and their influence on transient pressure behavior [16].

Figure II.8 presents a family of type curves generated for various values of $\boldsymbol{C_D e^{2s}}$**.** During the early-time period, all curves converge into a unit-slope straight line, indicating a regime dominated by pure wellbore storage. At late times, the derivative curves merge into a single horizontal line, which is characteristic of pure radial flow. The differences in curve shapes, governed by the parameter $\boldsymbol{C_D e^{2s}}$**.**, are more pronounced on the derivative plots, making them particularly useful for identifying reservoir and near-wellbore effects [10].

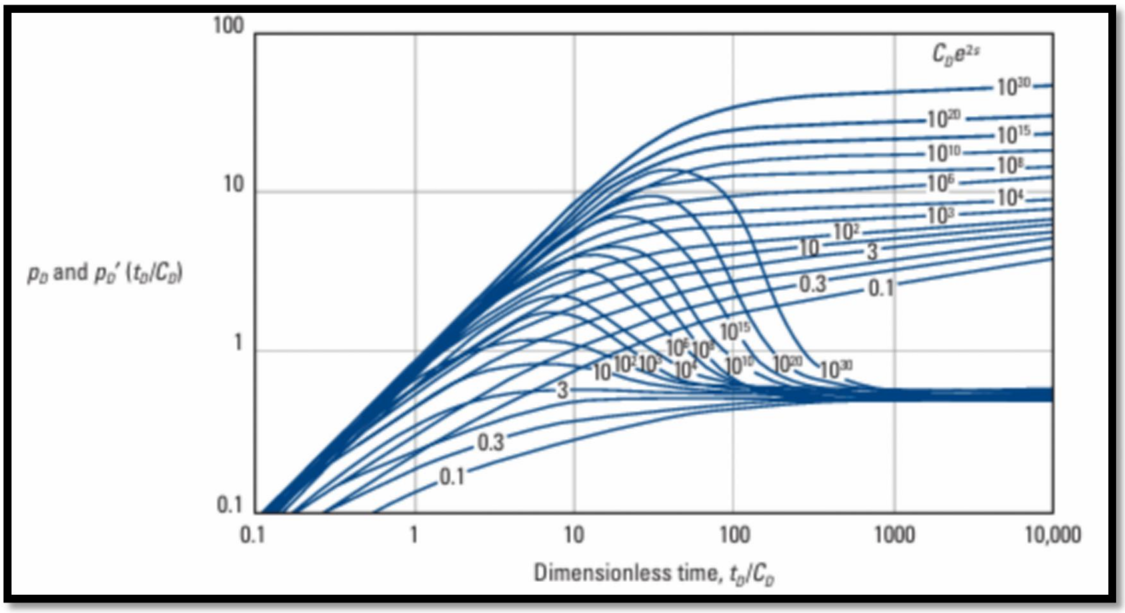

Figure II.8 : Type curves for a well with wellbore storage and skin effects in a reservoir with homogeneous behavior [10] .

Test data are plotted in terms of the pressure change dp and its derivative dp¢dt versus the elapsed time dt and superimposed over the type curves. Once a match is found for both the pressure change and its derivative, the $\boldsymbol{C_D e^{2s}}$. svalue of the matched curve pair, together with the translation of the axes of the data plot with respect to the type-curve axes, is used to calculate well and reservoir parameters. The permeability-thickness product is derived from the pressure match as [11] :

$$\boldsymbol{kh = 141.2qB\mu\left(\frac{p_D}{\Delta p}\right)_M} \quad \text{(II.19)}$$

Where :

q = flow rate

B= formation volume factor

and the subscript M notes a type-curve match.

The wellbore storage coefficient is derived from the time match as:

$$\boldsymbol{C = \left(\frac{0.000295Kh}{\mu}\right)\frac{\Delta t}{\left(\frac{t_D}{C_D}\right)_M}} \quad \text{(II.20)}$$

Where:

- C = Wellbore storage coefficient , bbl/psi
- k = Reservoir permeability , md
- h = Reservoir thicknes , ft
- μ = Fluid viscosity , cp
- Δt = Time interval , hr
- tD = Dimensionless time
- CD = Dimensionless wellbore storage coefficient
- M = Conversion constant

Skin factor is from the $\boldsymbol{C_D e^{2s}}$ curve :

$$\boldsymbol{s = 0.5ln\left[\frac{(C_D e^{2s})_M}{C_D}\right]} \qquad \text{(II.21)}$$

Figure II.9 illustrates the application of type-curve matching to estimate reservoir permeability (**kh**) and the skin factor **(s)**. in this example, the well test was ended before a complete radial-flow regime was established. Consequently, using the conventional semi-log analysis method would likely have produced inaccurate interpretations.

The presence of radial flow can be identified more reliably through the pressure-derivative plot, where it appears as a horizontal (flat) trend. In addition, pressure-derivative analysis facilitates the detection of reservoir heterogeneities and flow-regime transitions, making the log-log pressure and pressure-derivative plot a highly effective tool for reservoir model identification.

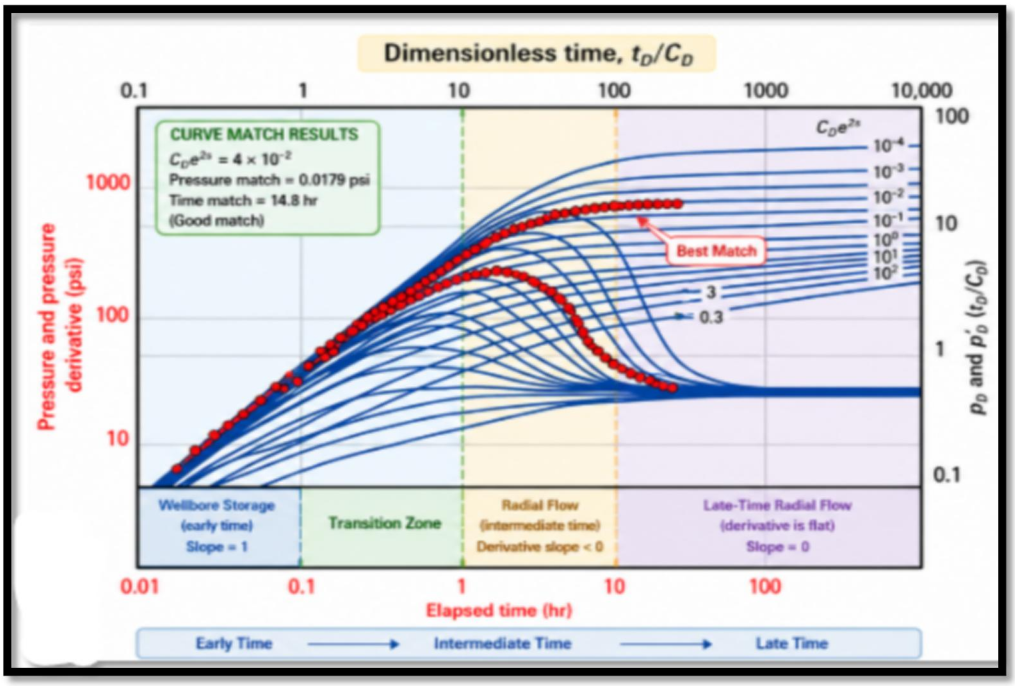

Figure II.9 : Well test type-curve matching using Bourdet derivative method showing different flow regimes [15].

Additionally, the skin factor can be estimated by determining which type curve provides the best match and reading the associated parameter value corresponding to that curve.

Figure II.10 shows the effect of the skin factor on pressure and pressure derivative type curves during well test interpretation. The curves are represented on a log-log plot using dimensionless pressure and derivative versus dimensionless time.

At early time, all curves exhibit a unit-slope straight line corresponding to wellbore storage effects. As time progresses, the response transitions toward radial flow behavior. The figure illustrates that positive skin values shift the pressure response upward, indicating additional pressure losses near the wellbore due to formation damage or reduced permeability. Conversely, negative skin values reduce the pressure drop and indicate improved near-wellbore conditions caused by stimulation treatments such as acidizing or hydraulic fracturing.

Therefore, type curve matching allows the estimation of the skin factor by identifying the theoretical curve that best matches the measured field data.

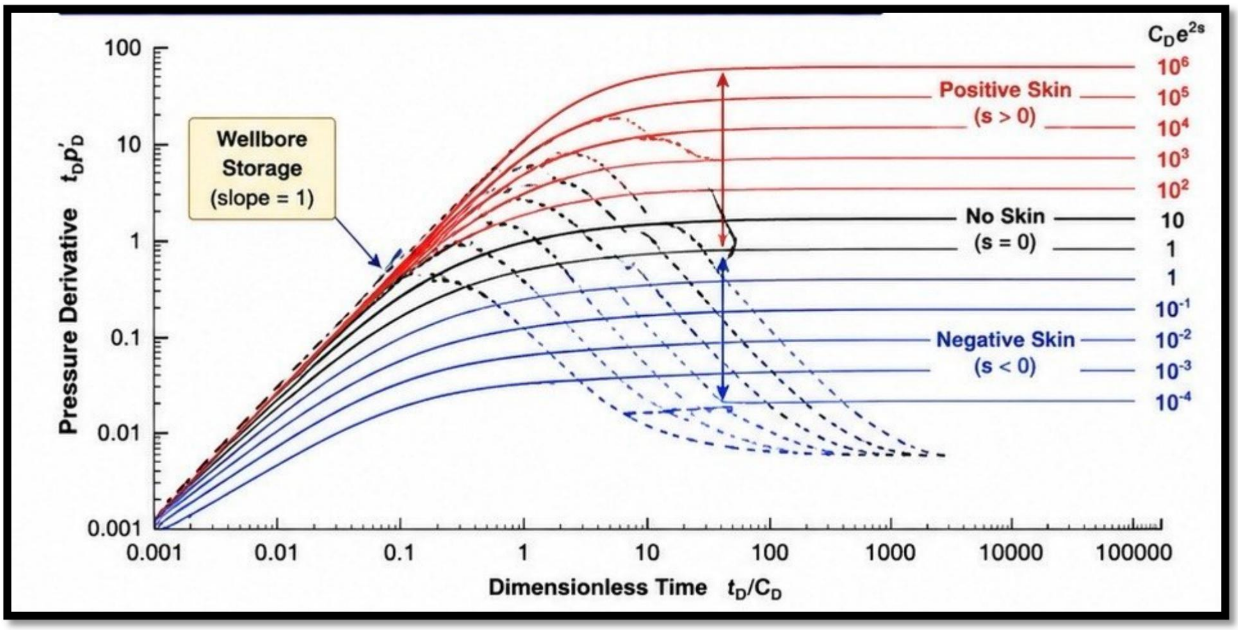

Figure II.10 : Effect of skin factor (s) on pressure derivative type-curves[12].

Figure II.11 illustrates the methodology of modern well test interpretation using pressure and pressure derivative analysis on a log-log scale. The early-time response is characterized by a unit-slope straight line corresponding to wellbore storage dominance, where most of the produced fluid originates from the wellbore itself.

As the transient pressure wave propagates farther into the reservoir, the influence of wellbore storage decreases and the system enters the radial flow regime. This regime is identified by a horizontal stabilization of the pressure derivative curve, which is one of the most important signatures in pressure transient analysis because it permits the calculation of reservoir permeability and skin factor [15].

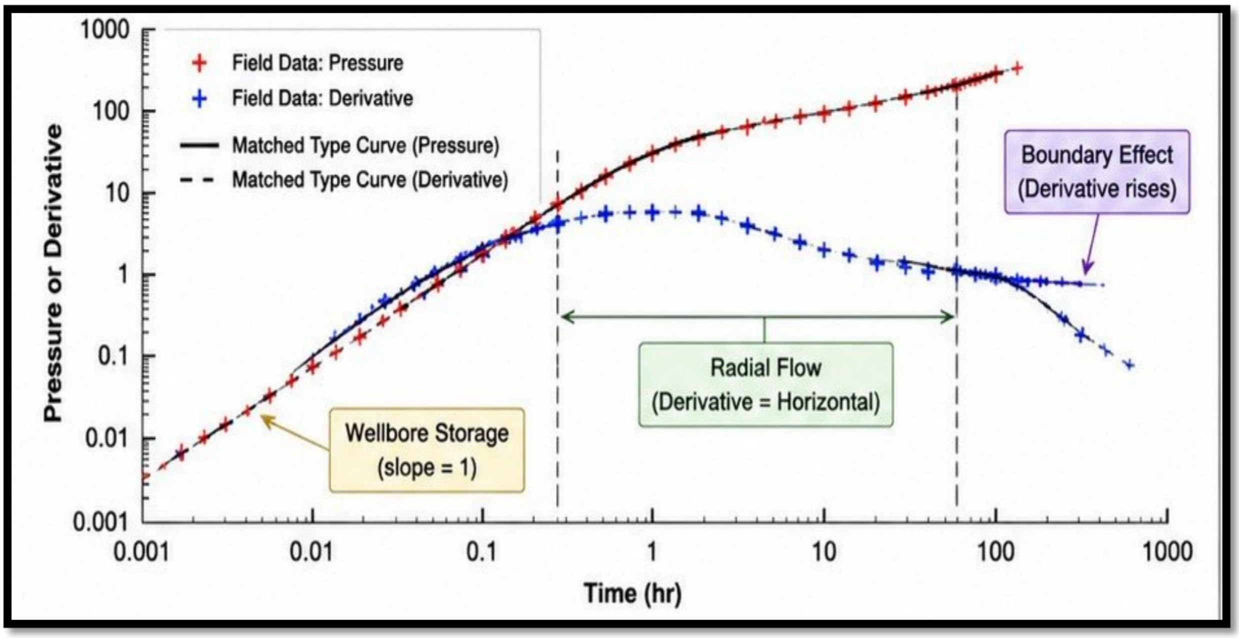

Figure II.11 : Match of field pressure and derivative data with theoretical type-curves showing flow regimes[15].

II.9.2. The Derivative Plot :

Different types of plots are used for different purposes, and a complete well test analysis often requires the use of several representations. Modern well test interpretation has been significantly improved by the introduction of the derivative plot by Bourdet, Whittle, Douglas, and Pirard (1983), further discussed by Bourdet, Ayoub, and Pirard (1989). The derivative plot simultaneously presents the pressure change $\log(\Delta p)$ Versus $\log(\Delta t)$ and the pressure derivative $\log\left(\frac{dp}{dt}\right)$ versus $\log(\Delta t)$ [9] .

An example of the derivative plot representation is given in Figure II.12.

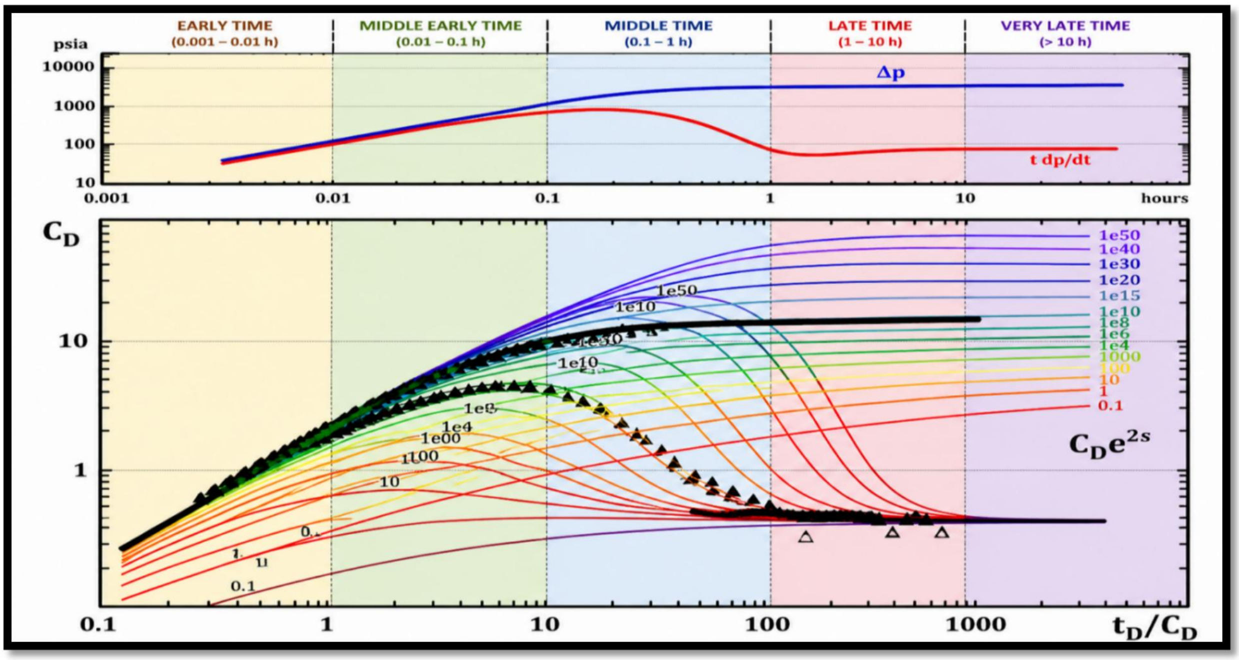

Figure II.12 : Type Curve Matching With Time Sequences

Note :

The main advantage of the derivative plot is that different flow regimes can be identified more clearly, as each regime exhibits a distinct characteristic signature on the derivative curve.

In particular, behaviors such as dual-porosity systems become much easier to recognize on a derivative plot, even when the early semi-log straight line is masked by wellbore storage effects.

Although the derivative plot is extremely powerful for diagnostic interpretation, it is not always the most accurate method for parameter estimation. Therefore, traditional plots, especially semi-log analysis, are still required for reliable quantitative calculations.

case study

Chapter III :
Well Test evaluation & Interpretation Using KAPPA Saphir

III. Chapter III : Well Test Interpretation Using KAPPA Saphir

III.1. Introduction:

Several interpretation methods are used in well testing, ranging from conventional analytical techniques to modern software-based approaches.

In this chapter, a practical interpretation study is carried out on Well-1 located in the HMD. The interpretation is performed using both the conventional Horner method and the KAPPA Saphir software in order to evaluate the reservoir behavior and determine the main reservoir parameters. A comparative analysis between the two interpretation approaches is also presented to highlight the accuracy and advantages of modern interpretation techniques in pressure transient analysis.

III.2. Hassi Messaoud Field presentation:

The Hassi Messaoud oil field was discovered on January 16, 1956, by SN-REPAL, following a refraction seismic survey conducted on June 15 of the same year. The first exploratory well, MD1, was drilled to a depth of 3,338 meters and revealed the presence of oil within Cambrian sandstone formations. In May 1957, CFPA drilled another well, OM1, located about 7 km northwest of MD1, which confirmed the existence and extent of the reservoir. This reservoir is characterized by a thickness reaching up to 200 meters and an initial pressure estimated at 482 kg/cm². The field was later divided into two main concessions: the northern sector was assigned to CFPA, while the southern sector remained under SN-REPAL. Production began in1958 with around 20 active wells. At the early stage, production relied mainly on the natural expansion of dissolved gas as the primary drive mechanism. Over time, this shifted to secondary recovery methods, particularly through water injection and miscible gas injection to maintain reservoir pressure and improve recovery efficiency. Following the nationalization of hydrocarbons on February 24, 1971, development activities intensified, leading to a significant increase in drilling operations. Since then, the HMD has remained a major source of crude oil production in Algeria for several decades [12].

III.3. Location And General Description of Hassi Messaoud :

The HMD is located within the Triassic platform, on the Amguid shoal; it is geologically limited; to the north by the Djamâa-Touggourt structure, to the south by the mole of Amguid

El Biod, to the east by the shoals of Dahar, Rhourde El Baguel and the depression of Ghadames and to the west by the depression of Oued –My as shown in Figure III.1 [12].

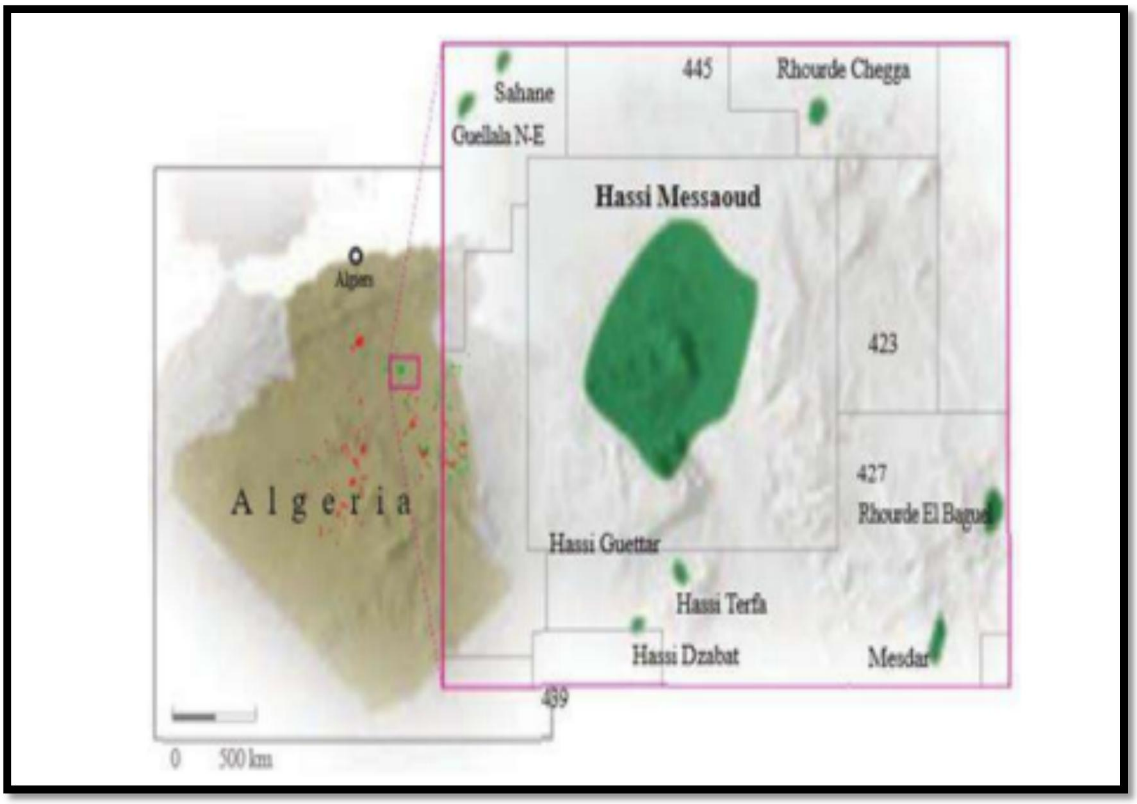

Figure III.1 : Location of Hassi Messaoud [12] .

III.4. Stratigraphy of The Field Hassi Messaoud :

Figure III.2 presents the stratigraphic succession of the HMD, which is characterized by a complex series of geological formations deposited during different geological periods. These formations consist mainly of sandstone, shale, carbonate, and evaporitic rocks, showing significant variations in lithology and petrophysical properties. The reservoir formations are particularly known for their favorable porosity and permeability, allowing the accumulation and circulation of hydrocarbons within the subsurface.

The geological structure of the field is also influenced by several tectonic features such as faults and unconformities, which play an important role in controlling reservoir continuity and fluid flow behavior. Among the different stratigraphic units, the Cambrian and Ordovician formations represent the principal productive reservoirs of the HMD. Understanding the stratigraphic succession and reservoir characteristics is essential for reservoir evaluation and well test interpretation, as these parameters directly affect pressure behavior and production performance.

ERE	SYST	ETAGES		Ep moy	DESCRIPTION
CENO-ZOIQUE	NEOGENE		MIO-PLIOCENE discordance alpine	240	Sable, calcaire, marne sableuse
			EOCENE	120	Sable, calcaire à silex
MESOZOIQUE	CRETACE	SENONIEN	CARBONATE	107	Calcaire, dolomie, anhydrite
			ANHYDRITIQUE	219	Anhydrite, marne, dolomie
			SALIFERE	140	Sel massif et traces d'anhydrite
			TURONIEN	90	Calcaire crayeux avec quelques niveaux argileux
			CENOMANIEN	145	Anhydrite, marne, dolomie
			ALBIEN	350	Grés, sable avec intercalations d'argile silteuse
			APTIEN	25	Dolomie cristalline avec niveau argileux, calcaire
			BARREMIEN	280	Argile, grés, dolomie
			NEOCOMIEN	180	Argile, marne, dolomie, grés
	URASSIQUE		MALM	225	Argile, marne, calcaire, grés et traces d'anhydrite
		DOGGER	ARGILEUX	105	Argile silteuse, marne dolomitique avec fines passées de grés
			LAGUNAIRE	210	Anhydrite, marne dolomitique, marne grise
		LIAS	L.D 1	65	Dolomie, anhydrite, argile
			L.S 1	90	Alternances sel, anhydrite et argile
			L.D 2	55	Anhydrite et dolomie cristalline
			L.S 2	60	Alternances sel et argile
			L.D 3	30	Alternances de dolomie et de marne
	TRIAS	SALIFERE	TS 1	46	Alternances de sel, d'anhydrite et de dolomie
			TS 2	189	Sel massif à intercalations d'anhydrite et argile gypsifère
			TS 3	202	Sel massif et traces d'argile
			ARGILEUX	113	Argile rouge dolomitique ou silteuse injectée de sel et d'anhydrite
			GRESEUX	35	Grés, argile
			ERUPTIF discordance hercynienne	0-92	Andésites altérées
PALEOZOIQUE	ORDOVICIEN		QUARTZITES D'EL HAMRA	75	Quartzites fines avec traces de tigillites
			GRES D'EL ATCHANE	25	Grés fins à ciment argileux, bitumineux
			ARGILES D'EL GASSI	50	Argiles schisteuses, vertes ou noires, glauconieuses à graptolithes
			ZONE DES ALTERNANCES	20	Alternance de grés et argile. Présence de tigillites
	CAMBRIEN		Ri	50	Grés isométriques, fins, silteux
			Ra	120	Grés à grés quartzitiques anisométriques à niveaux de silts
			R2	100	Grés moyens à grossiers à ciment argileux silteux
			R3	300	Grés grossier à ciment argileux, argile silteuse
	INFRA-CAMBRIEN			45	Grés argileux rouges
S O C L E					Granite porphyroide rose

Figure III.2 : Stratigraphic Colum of Hassi Messaoud.

III.5. KAPPA Saphir software:

KAPPA Saphir is an advanced software package dedicated to pressure transient analysis and well test interpretation in petroleum engineering. It is extensively employed to process and interpret pressure data acquired during production and shut-in operations, with the objective of characterizing reservoir behavior and evaluating well performance.

The software integrates analytical and numerical reservoir models with diagnostic interpretation techniques, enabling the estimation of key reservoir parameters such as permeability, skin factor, reservoir boundaries, and formation heterogeneity. Owing to its accuracy and reliability, Saphir has become a widely adopted tool for reservoir evaluation and production analysis in the oil and gas industry.

Figure III.3 presents the main interface of the KAPPA Saphir software used during the interpretation and analysis process.

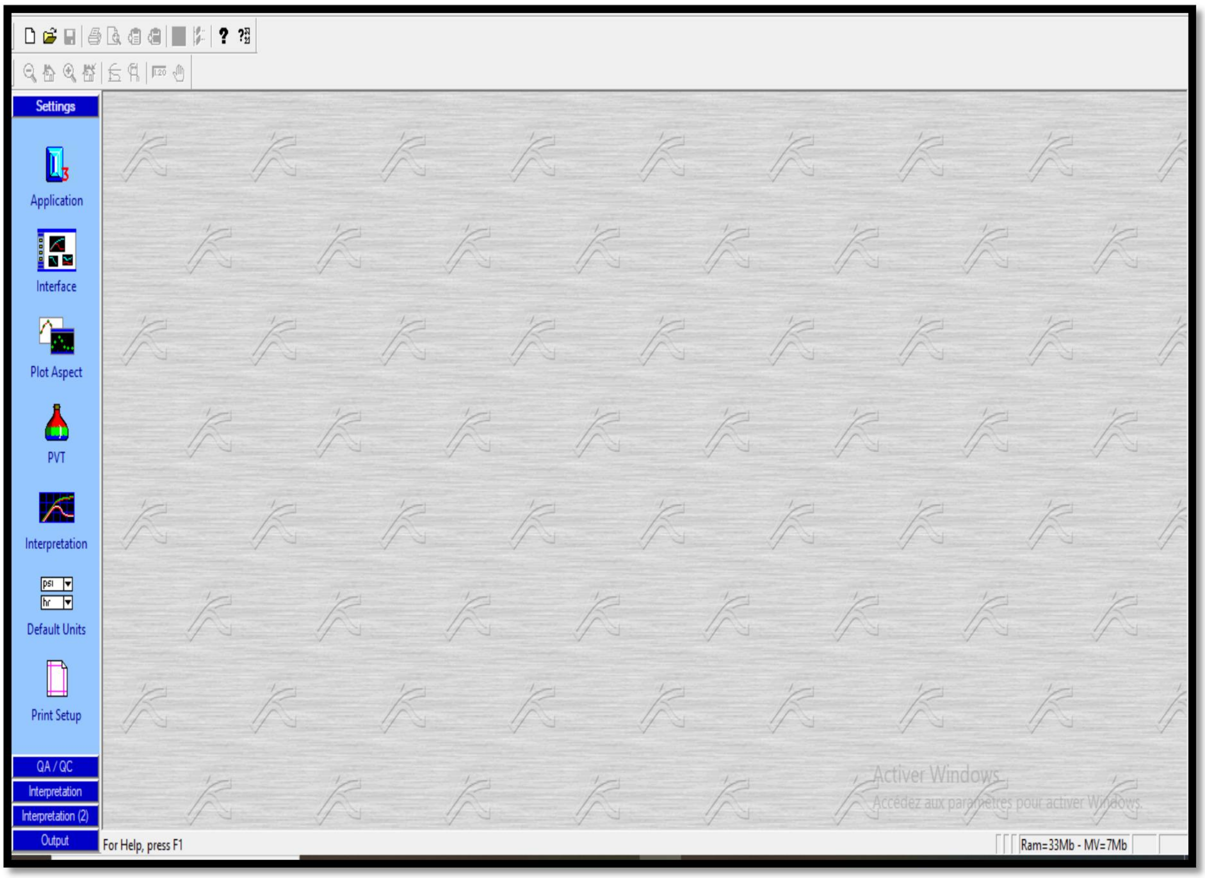

Figure III.3 : Graphical User Interface of KAPPA Saphir Software.

III.5.1.Kappa Saphir Key Roles And Functions:

The following figure presents the main stages and methodologies used in well test analysis to estimate reservoir properties and evaluate flow behavior.

Figure III.4 : Main Functions of KAPPA Saphir .

III.5.2.Specialized Analysis Tools:

- **MiniFrac:** A dedicated tool to analyze injection/fall-off tests to determine fracture closure pressure and reservoir properties.
- **Gas Well Analysis:** Evaluates rate-dependent skin and determines the Absolute Open Flow (Aof) potential.
- **Interference Testing:** Analyzes the pressure communication between wells [13].

III.5.3.Typical Procedure in Saphir:

The main stages of the interpretation process are summarized in the following workflow

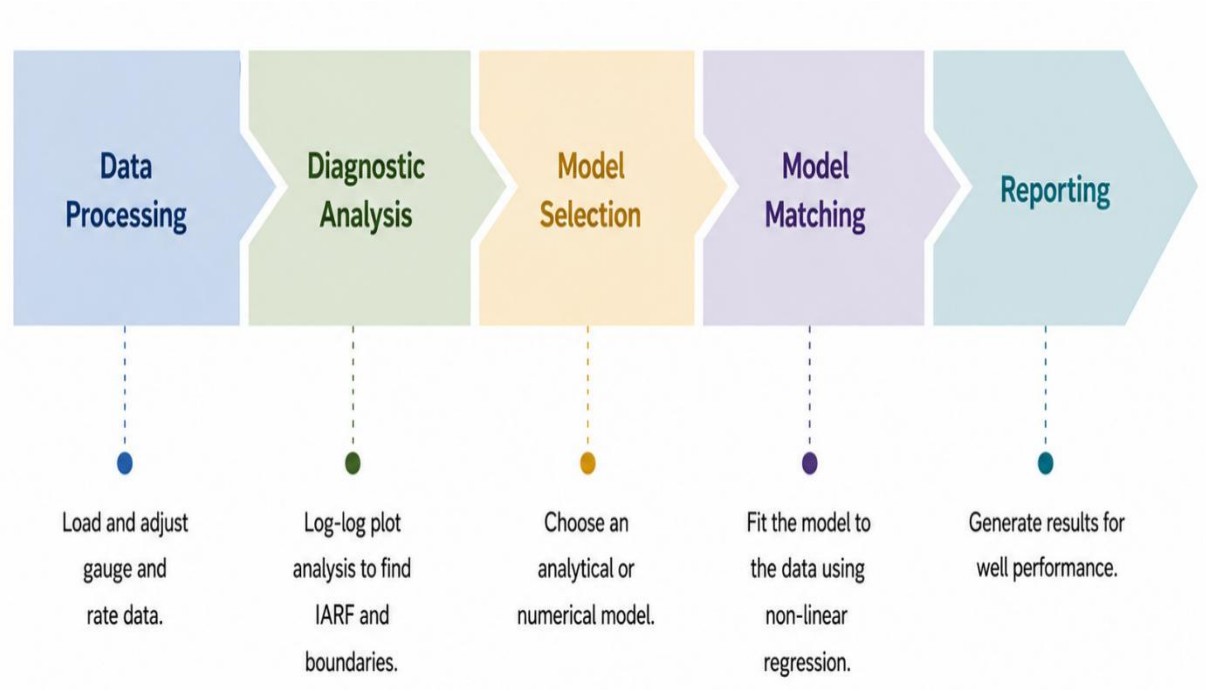

Figure III.5 : Workflow of Well Test Interpretation Using KAPPA Saphir.

III.6. Interpretion Well Test Using Kappa Saphir for Well-1:

III.6.1. Well-1 Information:

As part of the development of the Ordovician reservoir in the HMD, the vertical Well-1 was planned as an oil producer well within the Touggourt III perimeter. The main objective of this well is the exploitation of the Ordovician IV-3 reservoir.

The Well-1 is located at approximately **1.16 km south of well-0**. The targeted reservoir interval extends from **4023 m** to **4053 mRT**. The well was completed using a temporary completion configuration as indicated in the technical report.

Table III.1: General Information About Well-1

Parameters	Values
Perimeter	Touggourt III
Well location	1.16 km South of wel-01
X coordinates	UTM 313912.056 m

Y coordinates	UTM 3548015.967 m
Zs	132.742 m
Zt	143.5 m
Planned final depth	4180 m
Drilling termination formation	Hamra Quartzites
Drilling duration	04 months
Drilling rig	TP-226

In order to evaluate the reservoir potential and investigate the flow conditions around the well, including the reservoir model, a DST test on1 was carried out between **02/01/2026** and **13/01/2026.**

- Test type / time: **DST-TCP-1** ;
- Tested interval: **4023 m – 4053 mRT** ;
- Fluid type: **Oil** ;
- Well type : **vertical**
- Gauge reference depth: **3974.8 mRT** ;
- Drill pipe size: **3½ in**;
- Mud type: **OBM** ;
- Unit system: **Metric**.

Additional technical and operational information concerning Well-1 is presented in Figure III.6.

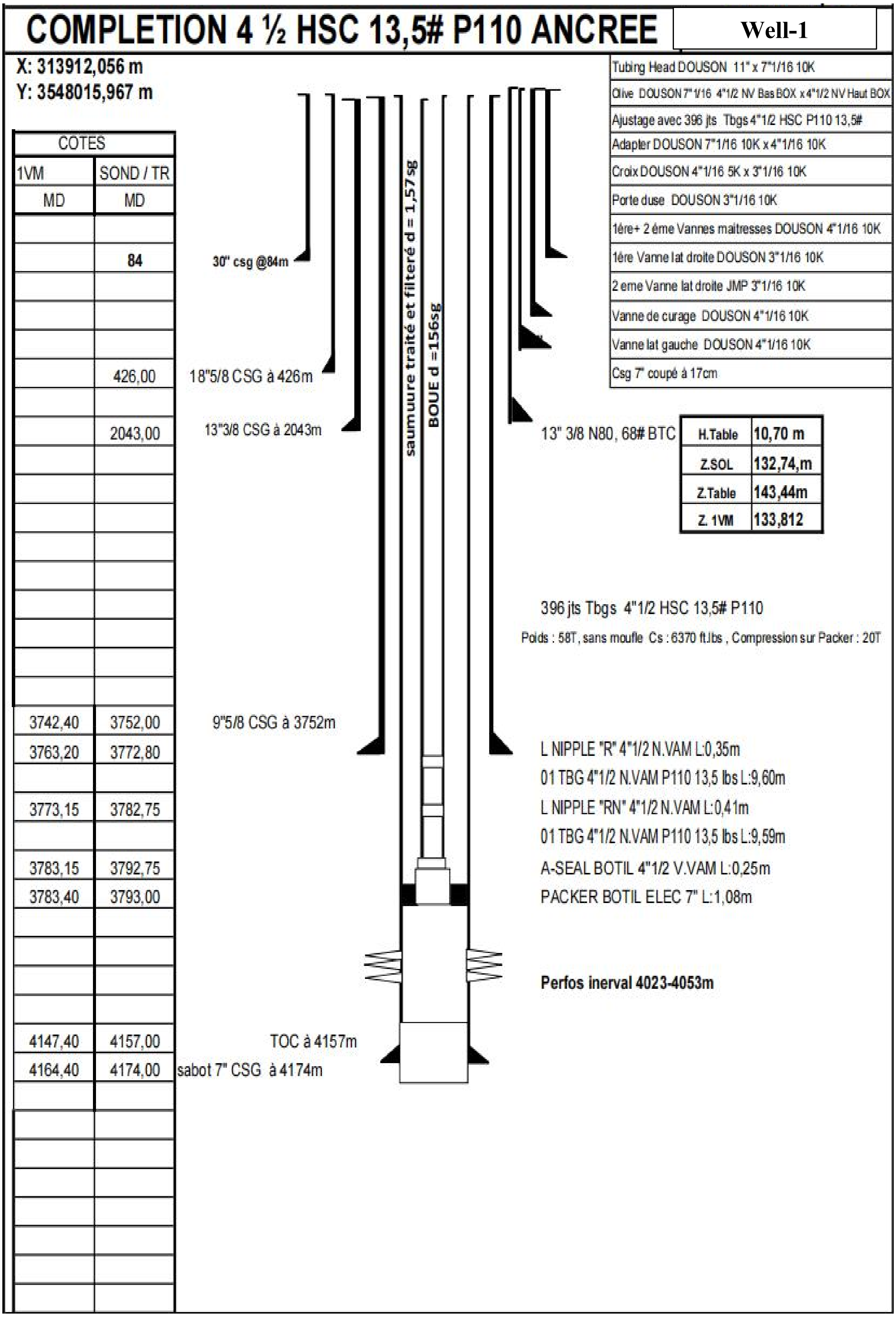

Figure III.6 : Technical Data Sheet of1 Well

III.6.2.Reservoir Characteristics:

The targeted reservoir inWell-1 corresponds to the Ordovician IV-3 unit. The reservoir top is located at approximately 4020 m MD and 3876.5 m TVDSS. This reservoir is mainly composed of sandstone formations characterized by low to moderate petrophysical properties.

Table III.2 : Reservoir Depth Information of Well-1

TVDSS (m)	MD (m)	Reservoir
3876.5	4020	Ordovician IV-3

the petrophysical properties of the Ordovician reservoir were evaluated using available reservoir data from the surrounding wells. These properties include in Table III.3 and Figure III.7

Table III.3 : Petrophysical Properties of The Ordovician Reservoir

Well	Reservoir	Gross Thickness (m)	Net Thickness	Porosity(%)	SW (%)	NTG
Well-1	Ordovician	75.86	7.92	7.5	7.2	10.4

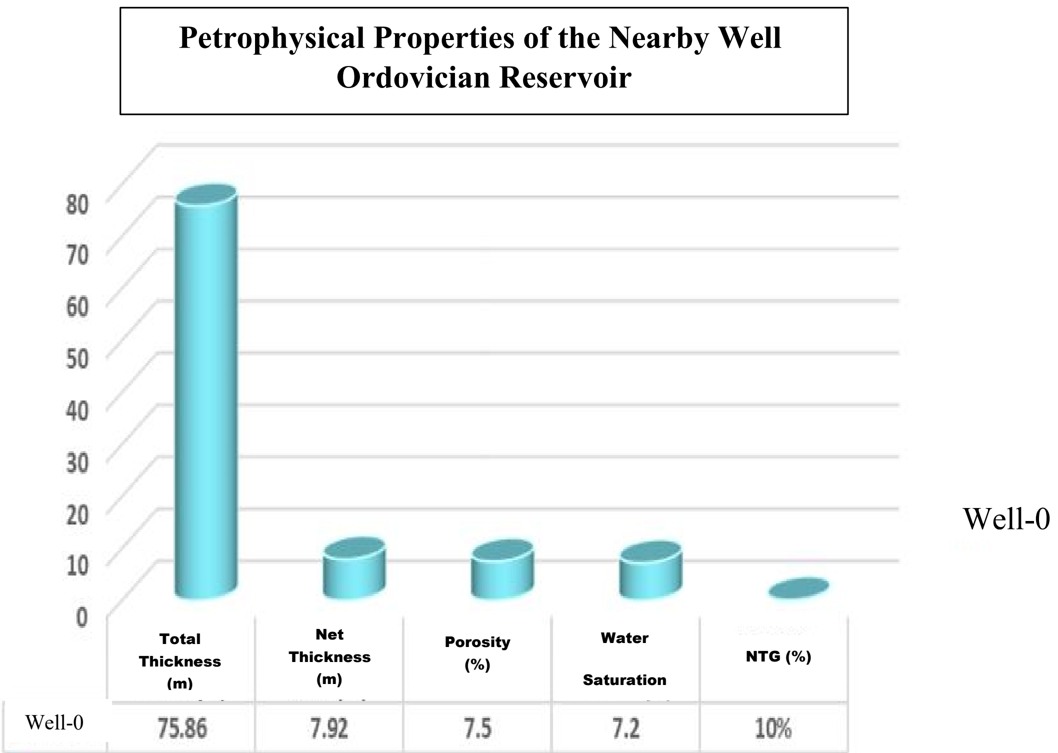

Figure III.7 : Distribution of The Petrophysical Properties of The Ordovician Reservoir**.**

III.6.3.Pressure Build-up Test Data Preparation :

The interpretation of the pressure buildup test for Well-1 was based on bottom-hole pressure data recorded during the shut-in period following the production phase. During the test operation, pressure measurements were continuously acquired using down-hole electronic gauges installed inside the wellbore in order to monitor the reservoir pressure response over time.

The recorded data set mainly consists of shut-in time values **(Δt)**, bottom-hole pressure measurements **(Pwf)**, temperature data, and liquid production rates. These data were organized, filtered, and prepared before applying the interpretation methods.

Figure III.8 presents the evolution of pressure and liquid production rate during the pressure buildup test of Well-1. The figure illustrates the production and shut-in periods used for the transient analysis.

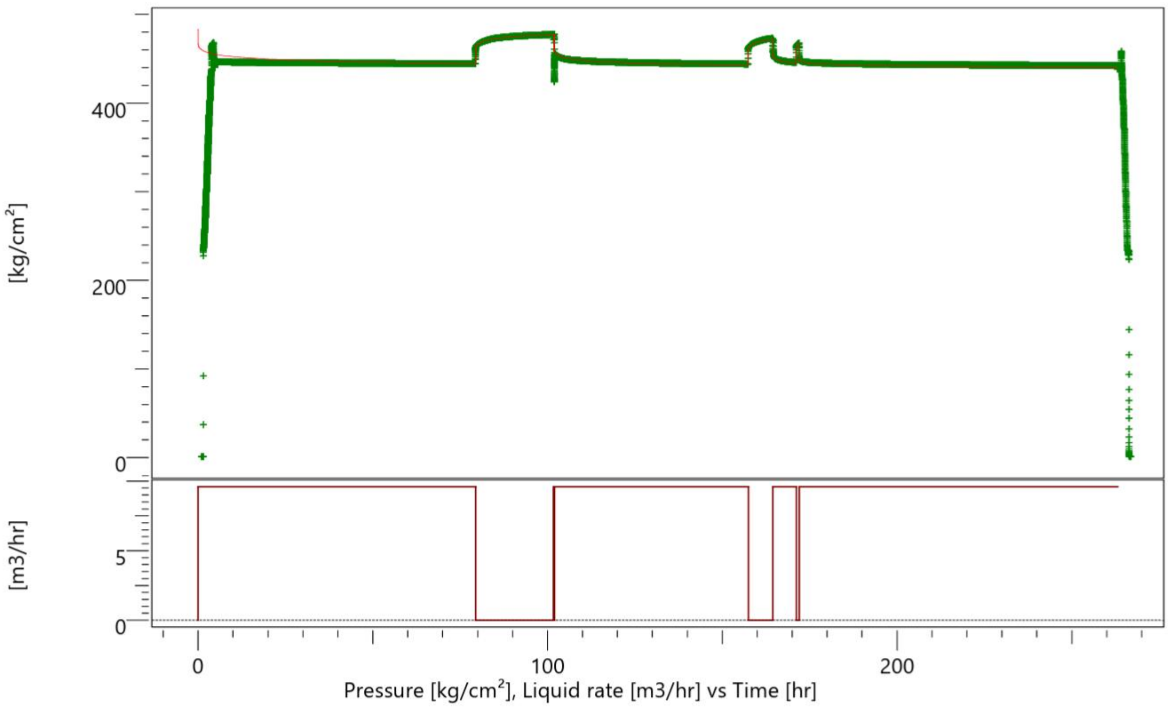

Figure III.8 : Pressure and Liquid Rate Evolution During The Pressure Buildup Test of Well-1

In addition, Table III.4 shows a sample of the recorded pressure buildup data obtained with a measurement cadence of 5 seconds during the shut-in period. These data constitute the basis for both the conventional Horner interpretation and the interpretation performed using KAPPA Saphir software.

Table III.4 : Horner Data Preparation For Well-1

Gauge Serial Number: D8040
Gauge Model Number: Quantum Quartz
Gauge Manufacturer: Kuster Company
Maximum Recorder Range: 10000
Date of Last Calibration: 01/17/2026
Pressure Units: Psig
Temperature Units: C

dd/mm/yyyy	Time	Delta (Hours)	Pressure	Temperature
28/02/2026	12:03:15	0.404167	0.00000	37.279
28/02/2026	12:03:20	0.405556	0.00000	37.269
28/02/2026	12:03:25	0.406944	0.00000	37.258
28/02/2026	12:03:30	0.408333	0.00000	37.248
28/02/2026	12:03:35	0.409722	0.00000	37.237
28/02/2026	12:03:40	0.411111	0.00000	37.226
28/02/2026	12:03:45	0.412500	0.00000	37.216
28/02/2026	12:03:50	0.413889	0.00000	37.205
28/02/2026	12:03:55	0.415278	0.00000	37.194
28/02/2026	12:04:00	0.416667	0.00000	37.184
28/02/2026	12:04:05	0.418056	0.00000	37.173
28/02/2026	12:04:10	0.419444	0.00000	37.162
28/02/2026	12:04:15	0.420833	0.00000	37.152
28/02/2026	12:04:20	0.422222	0.00000	37.141
28/02/2026	12:04:25	0.423611	0.00000	37.130
28/02/2026	12:04:30	0.425000	0.00000	37.120
28/02/2026	12:04:35	0.426389	0.00000	37.109
28/02/2026	12:04:40	0.427778	0.00000	37.099
28/02/2026	12:04:45	0.429167	0.00000	37.088
28/02/2026	12:04:50	0.430556	0.00000	37.077
28/02/2026	12:04:55	0.431944	0.00000	37.067
28/02/2026	12:05:00	0.433333	0.00000	37.056
28/02/2026	12:05:05	0.434722	0.00000	37.046
28/02/2026	12:05:10	0.436111	0.00000	37.035
28/02/2026	12:05:15	0.437500	0.00000	37.025
28/02/2026	12:05:20	0.438889	0.00000	37.014
28/02/2026	12:05:25	0.440278	0.00000	37.003
28/02/2026	12:05:30	0.441667	0.00000	36.993
28/02/2026	12:05:35	0.443056	0.00000	36.982
28/02/2026	12:05:40	0.444444	0.00000	36.972
28/02/2026	12:05:45	0.445833	0.00000	36.961
28/02/2026	12:05:50	0.447222	0.00000	36.951
28/02/2026	12:05:55	0.448611	0.00000	36.941
28/02/2026	12:06:00	0.450000	0.00000	36.930
28/02/2026	12:06:05	0.451389	0.00000	36.920
28/02/2026	12:06:10	0.452778	0.00000	36.910
28/02/2026	12:06:15	0.454167	0.00000	36.899
28/02/2026	12:06:20	0.455556	0.00000	36.889
28/02/2026	12:06:25	0.456944	0.00000	36.879
28/02/2026	12:06:30	0.458333	0.00000	36.868
28/02/2026	12:06:35	0.459722	0.00000	36.858
28/02/2026	12:06:40	0.461111	0.00000	36.848
28/02/2026	12:06:45	0.462500	1.18555	36.838
28/02/2026	12:06:50	0.463889	511.66891	36.829
28/02/2026	12:06:55	0.465278	1294.08704	36.829
28/02/2026	12:07:00	0.466667	3220.64209	36.839
28/02/2026	12:07:05	0.468056	3299.23096	36.869
28/02/2026	12:07:10	0.469444	3279.93091	36.891
28/02/2026	12:07:15	0.470833	3304.70703	36.912
28/02/2026	12:07:20	0.472222	3306.01611	36.940
28/02/2026	12:07:25	0.473611	3311.76392	36.976
28/02/2026	12:07:30	0.475000	3315.30200	37.019
28/02/2026	12:07:35	0.476389	3317.36499	37.068
28/02/2026	12:07:40	0.477778	3320.22900	37.121
28/02/2026	12:07:45	0.479167	3322.24292	37.178
28/02/2026	12:07:50	0.480556	3324.86401	37.237
28/02/2026	12:07:55	0.481944	3326.80908	37.300
28/02/2026	12:08:00	0.483333	3328.71606	37.365
28/02/2026	12:08:05	0.484722	3330.35889	37.432
28/02/2026	12:08:10	0.486111	3331.76611	37.501

III.6.4.Well-1 Test Data Interpretation Based on Horner Method:

One of the most popular traditional methods for interpreting pressure buildup tests is the Horner method. The semi-log analysis of bottom-hole pressure data collected during the post-production shut-in phase serves as its foundation.

By analyzing the straight-line radial flow regime found on the semi-log plot, this method enables the estimation of critical reservoir characteristics such reservoir pressure, permeability, and skin factor.

In this study , the recorded shut-in pressure measurements made during the well test operation were used to apply the traditional Horner interpretation method to the pressure buildup data of Well-1.

Horner Semi-Log Plot Construction:

The bottom-hole pressure measurements were plotted against the logarithm of the Horner ratio on semi-logarithmic coordinates to create the traditional Horner plot.

The plot's semi-log straight line represents the reservoir's radial flow regime. The average reservoir pressure is estimated and the near-wellbore behavior is assessed using this straight-line section.

The following graphic in Figure III.9 displays the obtained Horner semi-log plot for Well-1.

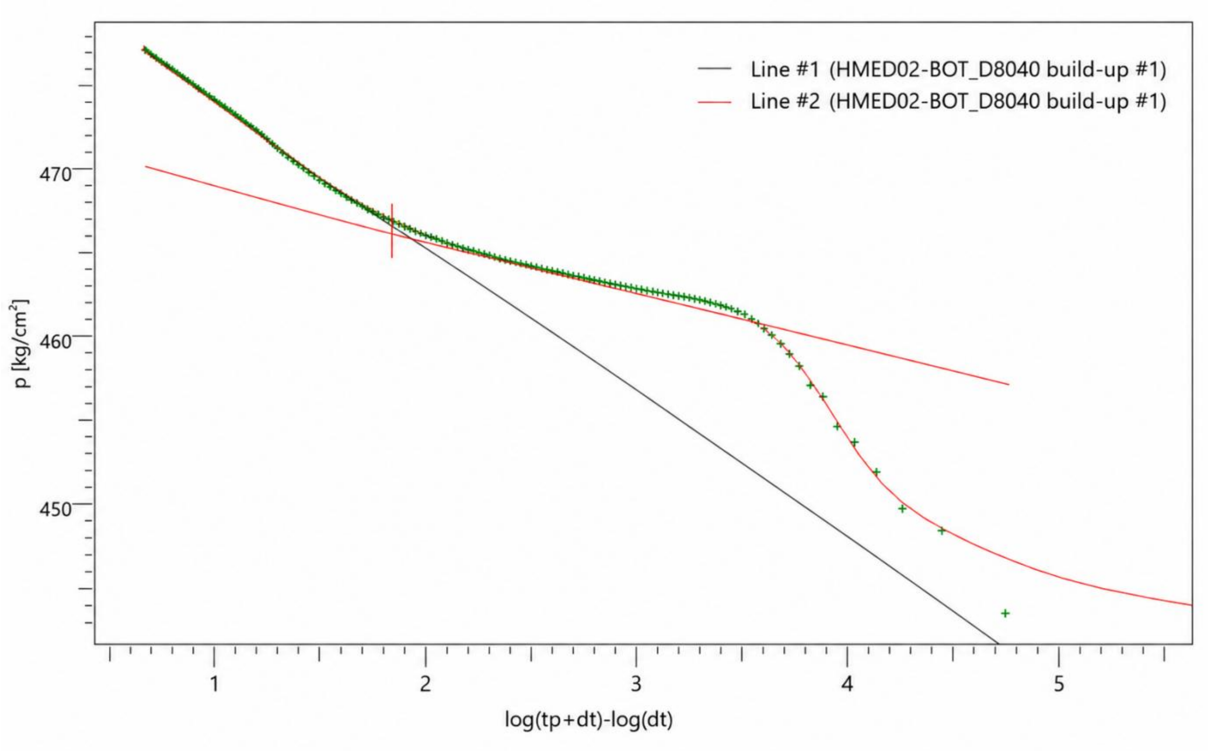

Figure III.9 : Semi-Log Horner Plot of Well-1 .

Reserevoir Caracterisation Result:

The Horner interpretation method enabled the estimation of the principal reservoir parameters of Well-1 from the pressure buildup test data.

The results obtained from the semi-log Horner analysis are summarized in the following table**:**

Table III.5 : Conventional Interpretation Results Using The Horner Method

Parameter	Symbol	Value
Initial Reservoir Pressure	P_i	**483.229 kg/cm²**
Bottom-Hole Pressure at Shut-in	$P_{wf}(\Delta t = 0)$	**444.183 kg/cm²**
Flow Rate Change	Q	**9.6 m³/h**
Horner Slope	m	**-3.193 kg/cm²**
Intercept Pressure	P*	**472.358 kg/cm²**
Pressure at 1 Hour	P_{1hr}	**466.275 kg/cm²**
Permeability-Thickness Product	k.h	**960 md·m**
Permeability	k	**32 md**
SkinFactor	s	**1.17**

Interpretation:

• The reservoir pressure indicates relatively stable reservoir energy and satisfactory pressure support during the buildup test.

• The permeability value (k = 32 md) suggests a reservoir with moderate flow capacity and acceptable transmissibility. This classification is based on typical reservoir permeability ranges, where values around tens of millidarcies are considered moderate: they allow hydrocarbon flow but are lower than highly permeable reservoirs (hundreds to thousands of md).

• The positive skin factor (s = 1.17) indicates additional flow resistance near the wellbore, which may be related to formation damage.

• The semi-log straight-line behavior observed on the Horner plot confirms the existence of radial flow during the pressure buildup period.

• The Horner conventional interpretation provided representative reservoir parameters from the pressure transient data of Well-1.

III.6.5.KAPPA Saphir Method:

After preparing the pressure buildup test data of Well-1, the interpretation procedure was carried out using KAPPA Saphir software through the following steps.

First, the required fluid type and PVT parameters were introduced into the software in order to initialize the reservoir model before starting the interpretation process, as shown in Figure III.10.

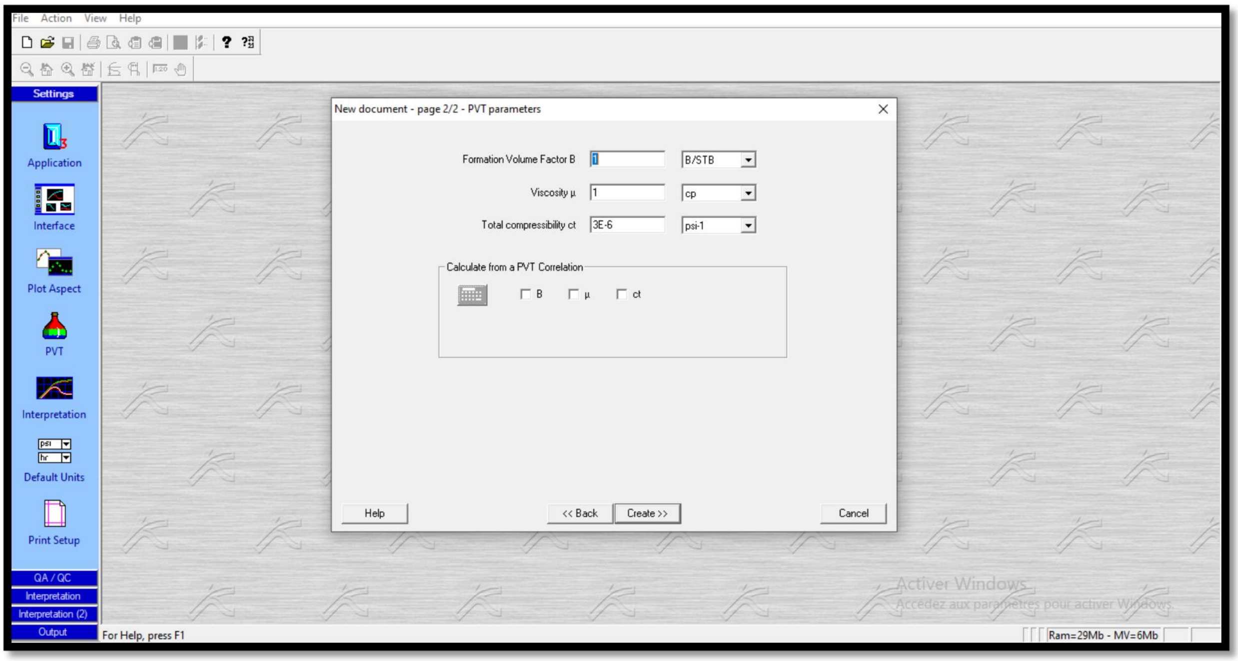

Figure III.10 : Selection of Fluid Type and Definition of Pvt Parameters.

Next, the well test data file of Well-1 was selected and imported into KAPPA Saphir using the import function. The recorded data in ASCII/PRN format were loaded into the software environment for pressure transient interpretation, as illustrated in Figure III.11.

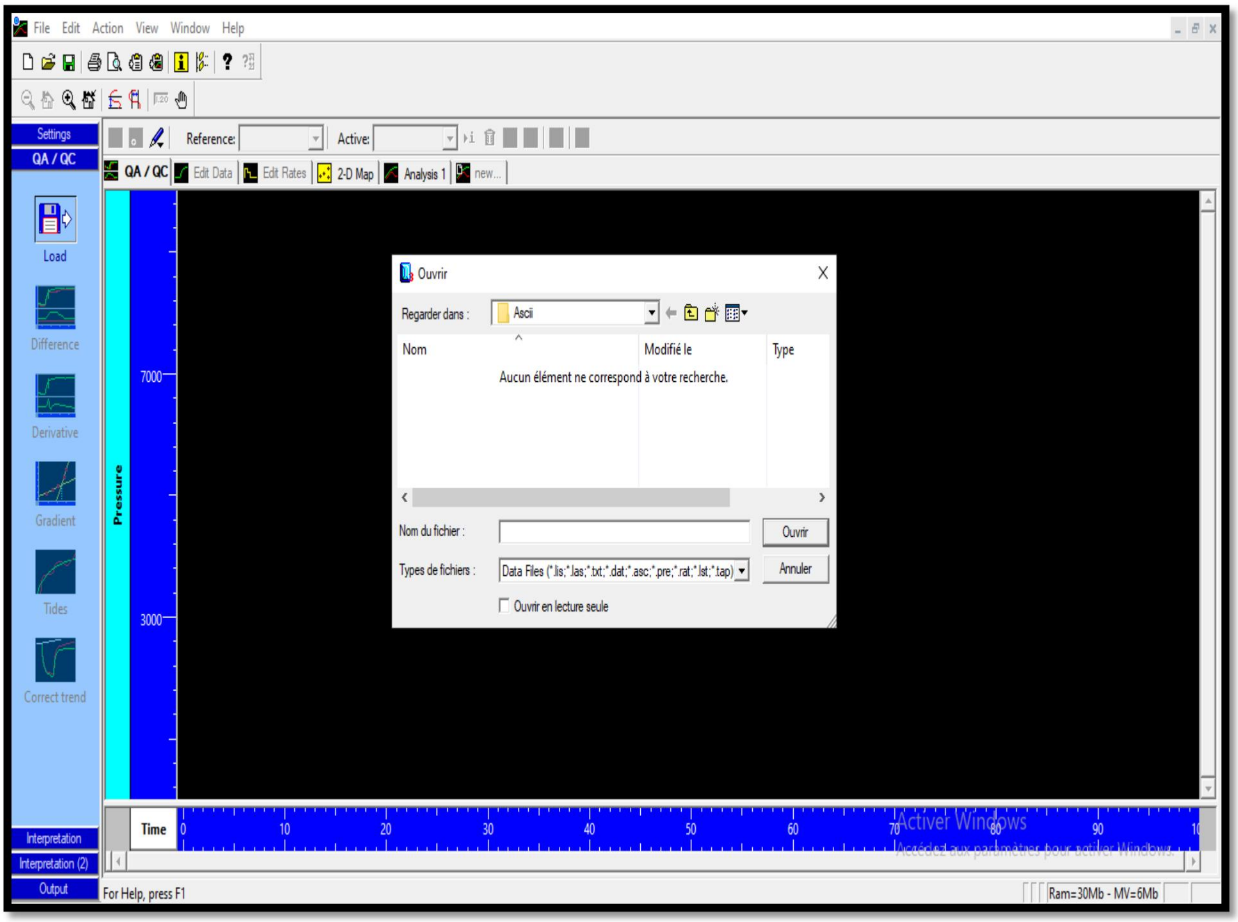

Figure III.11 : Selection of Well-1 Test Data File.

After importing the data, the pressure and flow-rate curves were generated and checked before starting the interpretation stage. The imported dataset was verified and prepared for diagnostic analysis.

Finally, the interpretation and diagnostic tools available in KAPPA Saphir were applied in order to analyze the pressure transient behavior of Well-1. The software generated several interpretation plots, including the derivative plot, semi-log plot, Horner plot, and production history analysis, as presented in Figure III.12.

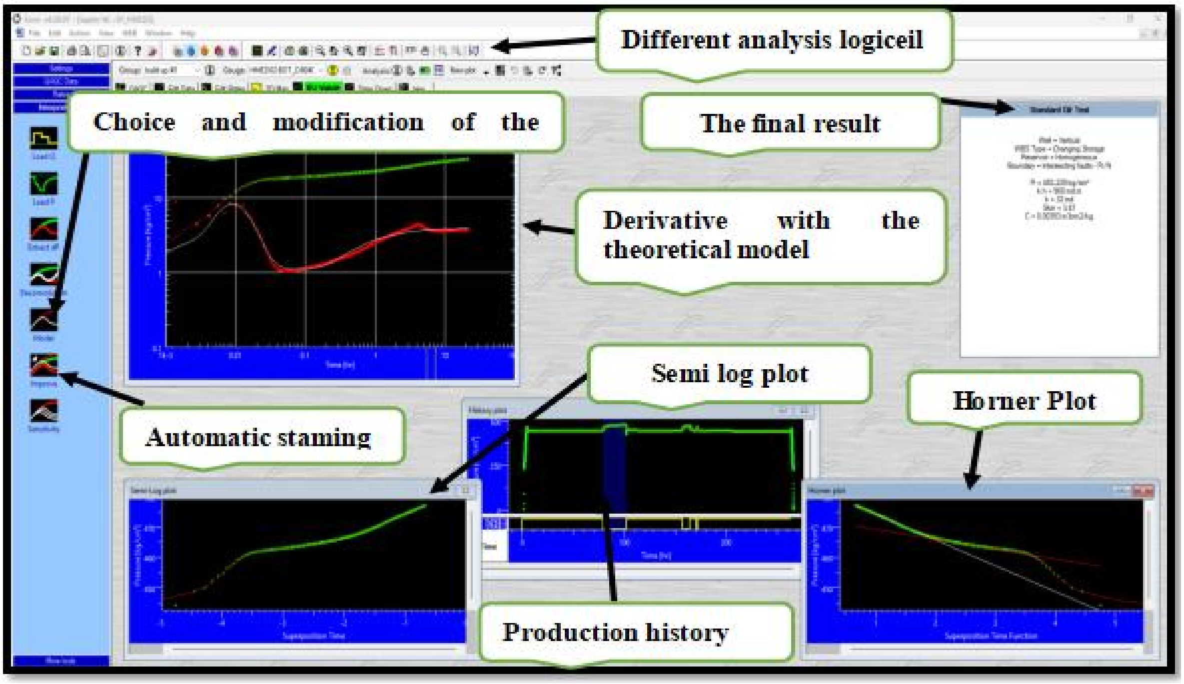

Figure III.12 : Final Interpretation Result Obtained Using Kappa Saphir Software.

Plotting The Log-Log and Semi-Log Curves and Their Matching (Calibration) :

The derivative curve is obtained by differentiating the pressure of each build-up using Saphir, which displays them in the form of log-log and semi-log plots . Then, several models can be generated by Saphir to match the obtained curve, but the one selected is the model that provides the closest fit to the real behavior , as shown in Figure III.13.

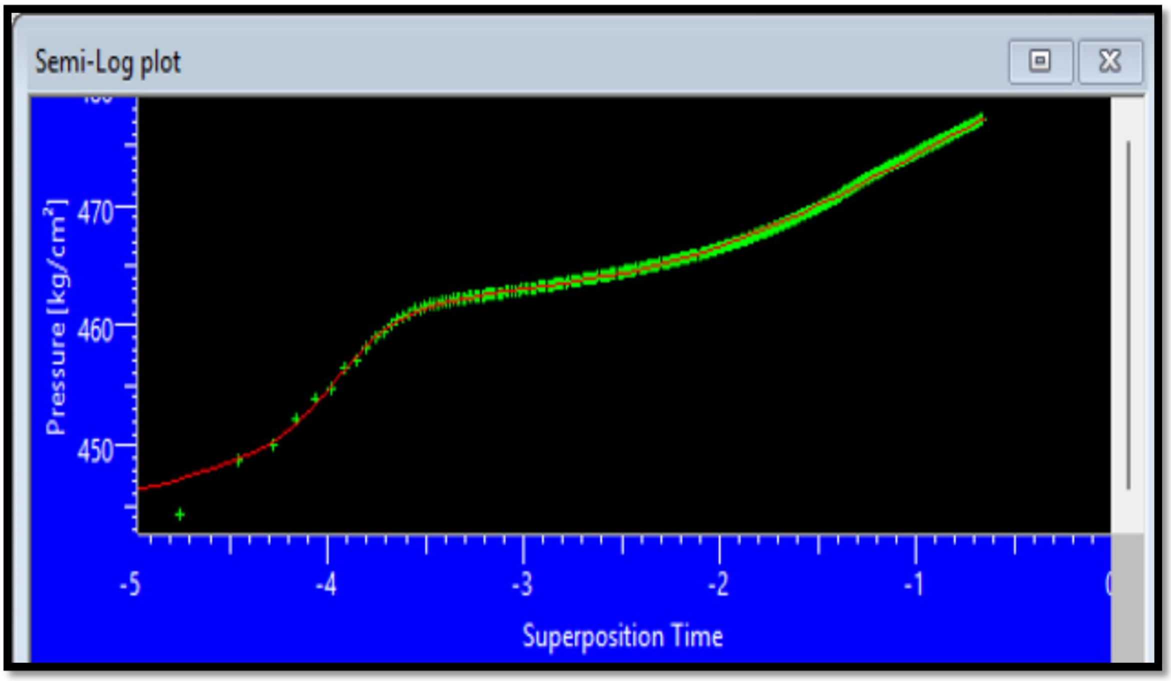

Figure III.13 : Trace of The Semi-Log Curve of The Well-1.

Interpretation By Kappa Saphire Reserevoir Caracterisation Result:

Figure 14 and 15 illustrates the pressure and derivative behavior with a good match to the selected type curve. Early-time wellbore storage, mid-time radial flow, and late-time boundary effects are clearly identified .

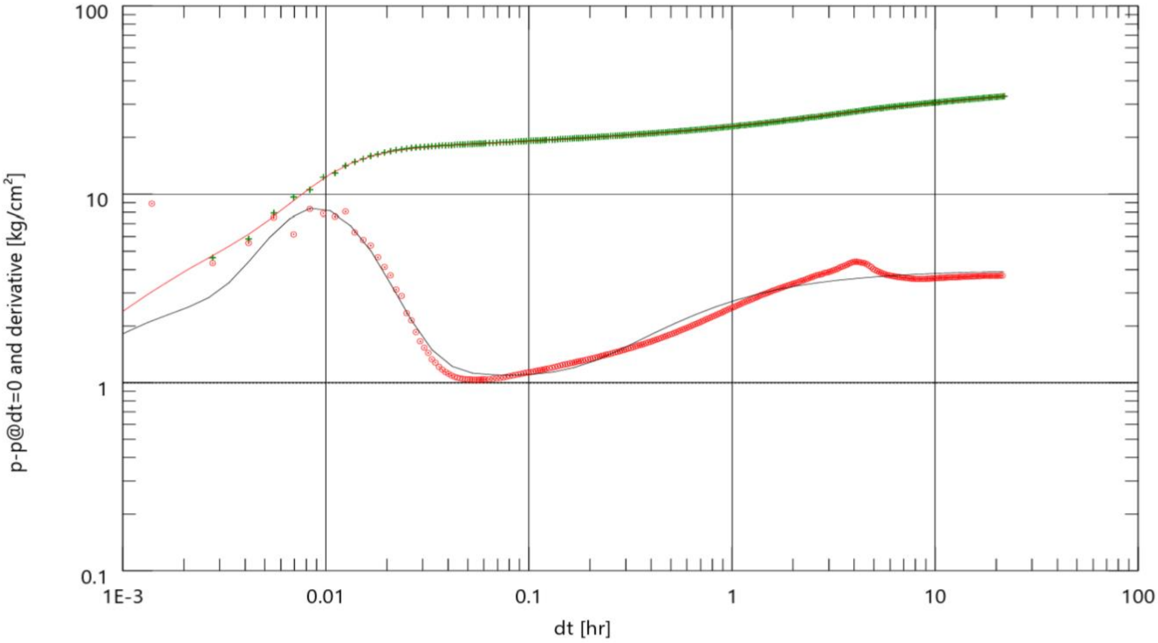

Figure III.14 : Trace of The Log-Log Curve of The Well-1 [15].

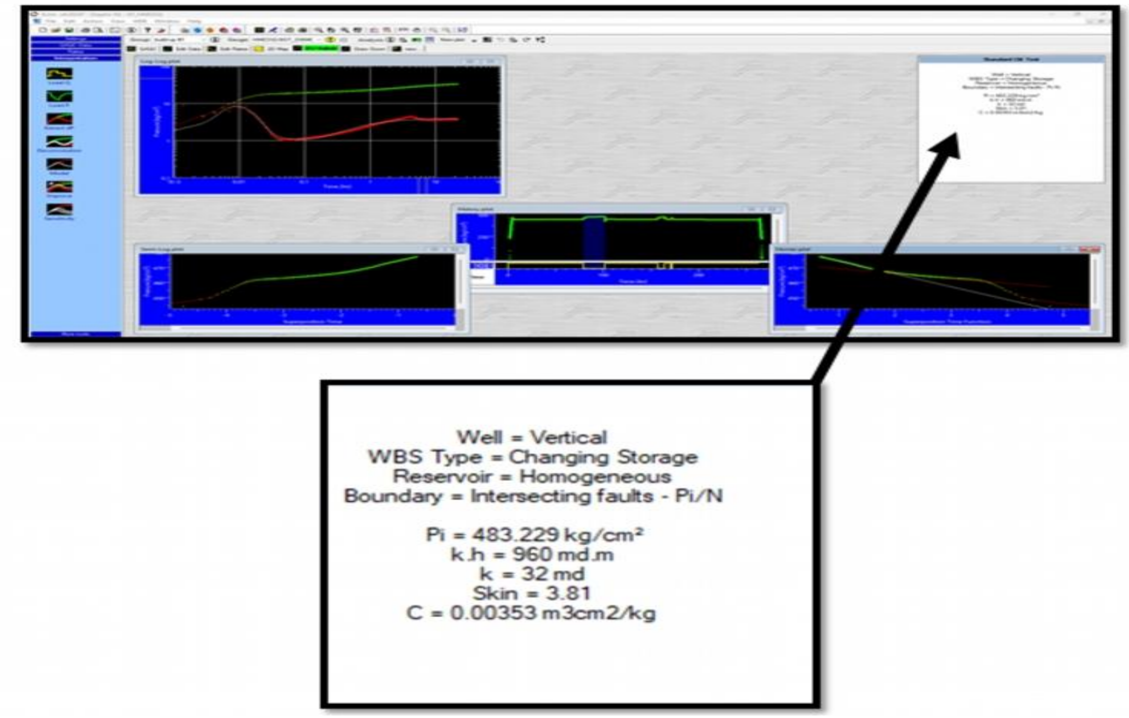

Figure III.15 : Log-Log and Semi-Log Matching Result Obtained Using KAPPA Saphir Software.

Reserevoir caracterisation result:

The interpretation results obtained from KAPPA Saphir are summarized in the following table:

Table III.6 : Reservoir Characterization Results

Parameter	Symbol	Value
nitial Reservoir Pressure	P_i	**483.229 kg/cm²**
Permeability-Thickness Product	k.h	**960 md·m**
Permeability	k	**32 md**
SkinFactor	s	**3.81**
Wellbore Storage Coefficient	C	**0.00353 m³·cm²/kg**
Well Model	—	**Vertical Well with Changing Storage**
Reservoir Model	—	**Homogeneous Reservoir**
Boundary Behavior	—	**Intersecting Fault Boundaries**
Porosity	ϕ	**5.4 %**
Well Radius	r_w	**0.10795 m**
Reservoir Thickness	h	**30 m**
Oil Viscosity	μ	**0.14 cp**
Formation Volume Factor	(B_o)	**3.12 B/STB**
Total Compressibility	(C_t)	**2.54E-4 cm²/kg**

Interpretation:

- The reservoir pressure indicates relatively high reservoir energy and good pressure support.
- The permeability value suggests a reservoir with moderate flow capacity and acceptable transmissibility.
- The positive skin factor (s=3.81) indicates formation damage or additional flow resistance near the wellbore.
- Early-time behavior confirms the influence of wellbore storage effects during the pressure buildup test.
- The late-time derivative deviation suggests the presence of intersecting fault boundaries, indicating a limited reservoir system rather than an infinite-acting reservoir.
- The overall match between measured and simulated data confirms the reliability of the selected interpretation model.

III.6.6.Comparison of Interpretation Results:

To evaluate the reliability of the interpretation results, a comparison was carried out between the conventional Horner interpretation method and the modern interpretation performed using KAPPA Saphir software.

The objective of this comparison is to analyze the consistency between both approaches in estimating the main reservoir parameters and to highlight the advantages of modern pressure transient analysis techniques.

Table III.7 : Modern and Conventional Method Result of Well Test Interpretation

Parameter	Conventional Method (Horner)	KAPPA Saphir Method
Reservoir Pressure (Pi)	**483.2 kg/cm²**	**483.229 kg/cm²**
Permeability (k)	**32 md**	**32 md**
Permeability-Thickness (kh)	**960 md.m**	**960 md.m**
SkinFactor (s)	**1.17**	**3.81**

Wellbore Storage Coefficient (C)	–	**0.00353 m³·cm²/kg**
Reservoir Model	–	**Homogeneous Reservoir**
Boundary Behavior	–	**Intersecting Fault Boundaries**

Interpretation :

• The reservoir pressure obtained from both methods shows very close values, indicating a good consistency between the conventional and modern interpretation approaches.

• The permeability estimated using KAPPA Saphir is slightly higher than the value obtained from the Horner method due to the use of derivative analysis and model matching.

• The Horner method provides only basic reservoir characterization based on semi-log straight-line analysis.

• KAPPA Saphir interpretation offers more detailed information concerning wellbore storage effects, reservoir boundaries, and reservoir model identification.

• The presence of intersecting fault boundaries was identified only through the modern interpretation method using pressure derivative analysis.

• The comparison confirms that modern pressure transient analysis techniques provide more reliable and comprehensive reservoir characterization than conventional interpretation methods.

General Conclusion

General Conclusion

A study of well test interpretation and reservoir characterization was carried out. During this work, both conventional interpretation methods and modern interpretation techniques of Well-1 located in the HMD were applied in order to analyze the pressure buildup data. First, the conventional Horner method was used to estimate the main reservoir parameters. Then, the interpretation was refined using KAPPA Saphir software through pressure derivative analysis, type-curve matching, and reservoir model calibration.

The obtained results revealed that the reservoir presents moderate permeability with a permeability value of approximately 32 md and a permeability-thickness product around 960 md.m. The initial reservoir pressure was estimated at about 483 kg/cm², indicating relatively good reservoir energy.

The interpretation also revealed a positive skin factor (s = 3.81), which confirms the existence of near-wellbore damage affecting the productivity of the well. This damage may be caused by drilling operations, mud invasion, or perforation effects. Consequently, stimulation operations such as acidizing or hydraulic fracturing may be recommended in order to reduce the skin effect and improve well productivity.

Moreover, the pressure derivative behavior observed during late times showed the presence of intersecting fault boundaries. The good agreement between the measured pressure data and the simulated model obtained using KAPPA Saphir confirms the reliability of the adopted interpretation model.

Finally, this study demonstrates the importance of conventional interpretation methods and modern interpretation software in order to improve reservoir characterization accuracy and reduce uncertainties related to reservoir evaluation and production analysis.

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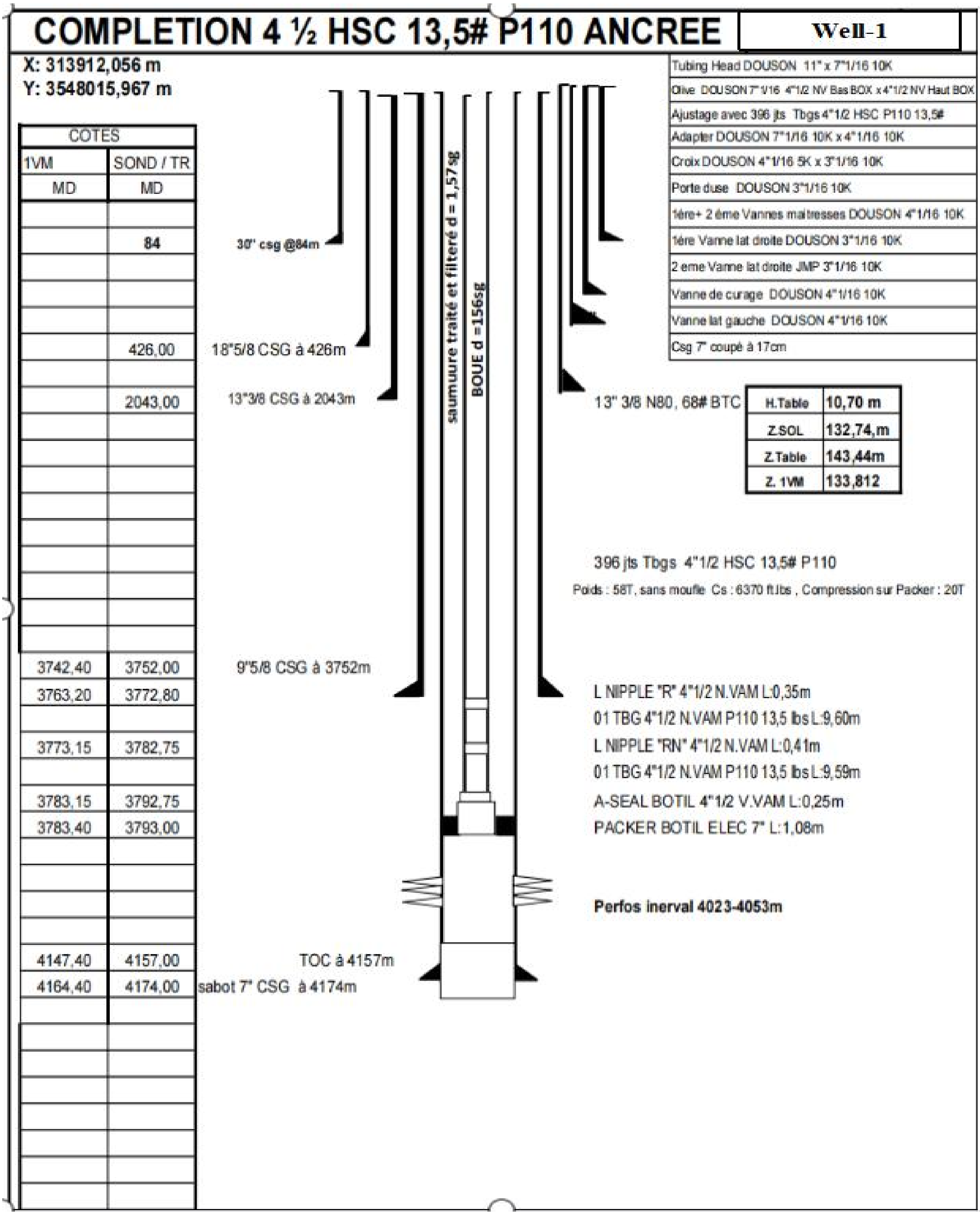
[26] SONATRACH, Pressure Buildup Test Data of Well-1, Excel Data File Used for Conventional and KAPPA Saphir Interpretation, HMD, Internal Operational Data, Algeria, 2026

Appendix A



COMPLETION 4 ½ HSC 13,5# P110 ANCREE
Well-1
X: 313912,056 m
Y: 3548015,967 m
COTES
1VM
SOND / TR
MD
MD
84
426,00
2043,00
3742,40
3752,00
3763,20
3772,80
3773,15
3782,75
3783,15
3792,75
3783,40
3793,00
4147,40
4157,00
4164,40
4174,00
30" csg @84m
18"5/8 CSG à 426m
13"3/8 CSG à 2043m
9"5/8 CSG à 3752m
TOC à 4157m
sabot 7" CSG à 4174m
saumuure traité et filteré d = 1,57sg
BOUE d =156sg
Tubing Head DOUSON 11" x 7"1/16 10K
Olive DOUSON 7"1/16 4"1/2 NV Bas BOX x 4"1/2 NV Haut BOX
Ajustage avec 396 jts Tbgs 4"1/2 HSC P110 13,5#
Adapter DOUSON 7"1/16 10K x 4"1/16 10K
Croix DOUSON 4"1/16 5K x 3"1/16 10K
Porte duse DOUSON 3"1/16 10K
1ère+ 2 ème Vannes maitresses DOUSON 4"1/16 10K
1ère Vanne lat droite DOUSON 3"1/16 10K
2 eme Vanne lat droite JMP 3"1/16 10K
Vanne de curage DOUSON 4"1/16 10K
Vanne lat gauche DOUSON 4"1/16 10K
Csg 7" coupé à 17cm
13" 3/8 N80, 68# BTC
H.Table 10,70 m
Z.SOL 132,74,m
Z.Table 143,44m
Z. 1VM 133,812
396 jts Tbgs 4"1/2 HSC 13,5# P110
Poids : 58T, sans moufle Cs : 6370 ft.lbs , Compression sur Packer : 20T
L NIPPLE "R" 4"1/2 N.VAM L:0,35m
01 TBG 4"1/2 N.VAM P110 13,5 lbs L:9,60m
L NIPPLE "RN" 4"1/2 N.VAM L:0,41m
01 TBG 4"1/2 N.VAM P110 13,5 lbs L:9,59m
A-SEAL BOTIL 4"1/2 V.VAM L:0,25m
PACKER BOTIL ELEC 7" L:1,08m
Perfos inerval 4023-4053m