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AhmimaElhadi,Ben Amor Omar

-THÈME-

Different methods used in well test interpretation and analysis of the results for well modeling

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Jury :

Président : Brahmia Nabil	Docteur	Univ. Ouargla
Rapporteur :Miloudi Mustapha		Univ. Ouargla
Examinateur :Djebbas Fayçal		Univ. Ouargla

Gratitude

First and foremost we thank God the Almighty who gave us the strength and courage to carry out this work.

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Finally, we thank all those who contributed directly or indirectly to the production of this dissertation.

Dedication

First, praise God who gave me success.

Secondly, I dedicate this work to the light of my eyes:

My dear parents to whom I owe all the merit in the world

To my brothers for their encouragement, support and love

Especially my little brother: Saib, God bless you

A special dedication to my friends Al-Tijani, Muhammad Al-Mundhir and Rashid

Also to my dear friends, without whose encouragement this work would not have seen the light of day.

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Also to my dear friends, without whose encouragement this work would not have seen the light of day.

Abstract

In this work, we studied well test interpretation methods and their importance in the oil industry. The aim of well testing is to obtain essential information about the well and the reservoir by interpreting these measurements to understand their conditions.

We used both traditional and modern interpretation methods and explained important concepts such as flow equations and the diffusivity equation. We also discussed factors affecting production, such as permeability and skin factor.

In the case study, we analyzed DST Build-Up test results for well RC-5 in the Rodh El Nos field using the Saphir software. The results showed low permeability and a negative skin factor, leading us to recommend measures to improve the well's productivity.

Keywords: test interpretation, permeability, damage factor, diffusion equation, Saphir.

Summary:

Dans ce travail, nous avons étudié les méthodes d'interprétation des tests de puits et leur importance dans l'industrie pétrolière. L'objectif des tests de puits est d'obtenir des informations essentielles sur le puits et le réservoir en interprétant ces mesures pour comprendre leurs conditions.

Nous avons utilisé des méthodes d'interprétation traditionnelles et modernes et expliqué des concepts importants tels que les équations de flux et l'équation de diffusivité. Nous avons également discuté des facteurs affectant la production, tels que la perméabilité et le facteur de skin .

Dans l'étude de cas, nous avons analysé les résultats du test de build-up DST pour le puits RC-5 dans le champ de Rodh El Nos en utilisant le logiciel Saphir. Les résultats ont montré une faible perméabilité et un facteur de peau négatif, ce qui nous a conduit à recommander des mesures pour améliorer la productivité du puits.

Mots clés : interprétation des tests, perméabilité, skin, équation de diffusivité, Saphir

الملخص :

في هذا العمل، درسنا طرق تفسير اختبارات الآبار وأهميتها في الصناعة النفطية. يهدف اختبار الآبار إلى الحصول على معلومات عن حالة البئر والخزان من خلال تفسير القياسات.

استخدمنا طرق تفسير تقليدية وحديثة، وشرحنا مفاهيم مهمة مثل معادلات التدفق ومعادلة الانتشار. كما تناولنا العوامل المؤثرة على الإنتاج، مثل النفاذية وعامل الضرر.

في دراسة الحالة، حللنا نتائج اختبار بناء الضغط للبئر RC-5 في حقل روض النص باستخدام برنامج Saphir. أظهرت النتائج نفاذية ضعيفة ومعامل ضرر سلبي، واقترحنا توصيات لتحسين الإنتاجية.

كلماتمفتاحية: تفسيراختبار، النفاذية، عاملالضرر،معادلةالإنتشار، saphir.

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Symbols –Notation- Abbreviations

A:Total cross-sectional area of the rockm^2

B:Formation volume factor bbl/STB

C :Wellbore Storage Coefficient bbl/psi

C_D: Dimensionless wellbore Storage bbl/psi

H :Thicknessft

k:Permeability Darcy (D)

ks:Permeability of the drainage zoneDarcy (D)

m:Slope of a straight linedimensionless

P:Pressurepsi

Pi:Initial pressurepsi

IP:Index of ProductivitySTB/psi·day

r:Radiusft

rw: Radius of the well ft

rs:Radius of damage ft

ri:Investigation radiusft

re:The drainage radius): ft

ρ :The density of the fluid lb/ft^3

S:Skin factordimensionless

q:The total flow rate STB/day

qw: Flow from the well STB/day

qsf:Flow of the fluid from the reservoir STB/day

t:Timehr

tp: Time of productionhr

t_D:Dimensionless timedimensionless

V:The volumeft^3

v:The velocity of the fluid m/s

η:Apparent velocity m/s

Φ:Porosity dimensionless

μ:The fluid viscositycp (centipoise)

α:Coefficientdepends on the context

General Introduction

Introduction

A well test is animportant procedure in the oil and gas industry used to evaluate the properties and performance of a well and the reservoir it taps into. This process involves measuring the flow rates and pressures of fluids (such as oil, gas, and water) over a period of time to gain insights into the reservoir's characteristics, such as permeability, pressure, and the extent of the reservoir.

Well tests can help determine the productivity of the well, identify potential issues like wellbore damage or reservoir heterogeneity, and provide essential data for reservoir management and future drilling operations by the interpretation and analyzing of the test response .

Common types of well tests include drill stem tests (DST), pressure buildup tests, and production tests, each tailored to specific objectives and conditions.

the interpretation is a critical aspect of reservoir engineering, aimed at understanding the behavior and characteristics of a reservoir through analysis of pressure and flow data collected during well tests.

By interpreting this data, engineers can gain insights into the reservoir's properties, such as permeability, porosity, and boundaries, which are essential for effective reservoir management and optimization of production.

Two primary methods of interpretation are used to understand reservoir behavior: conventional methods, often associated with semi-log analysis, and type curve and derivative methods, which essentially involve various sets of type curves.

In this context, we present our study titled "**Different methods used in well test interpretationand analysis of the results for well modeling**."

The pressure buildup 03 interpretation for well RC 05 indicates a negative skin factor and a poor permeability and thickness product .

The objectives of the project:

- To explore the various types of well tests, including Draw Down, Build Up, and several well tests.
- To delve into the fundamentals of the diffusivity equation and its development.
- To understand the different flow regimes and the main concepts in well test interpretation .
- To identifie various analytical methods, such as conventional curves, type curves, and pressure derivatives, to determine well and reservoir parameters.
- To analyzing a case of well RC 05 and concluec and recommend the solutions of the poor proprieties .

the project consists of four 04 chapters :

- **Chapter 01 : well test generalities**

This part is dedicated to the objectives and the principe of well test, in addition to the different types of test and the main concepts in well testing including the diffusivity equation, skin and wellbore storage identification.

- **Chapter 02 : well test interpretation methods**

The identification and explain the principe for interpreting and analyzing the different tests .

- **Chapter 03 : saphir software**

On this chapter we will learn how we use the interpretation software and the procedures of that.

- **Chapter 04 : case study**

Studying a case of well RC 05 by saphir software and we interpret the results of the software before making the conclusion and the recommendations.

Chapter I

Well test generalities

Introduction

In well testing, analyzing pressure transient data is essential for understanding reservoir behavior and optimizing recovery. The intermediate period, called the infinite acting period, is crucial. Here, the reservoir behaves as if infinite, with radial flow dominating. This phase guides interpretation techniques and informs decisions in reservoir engineering for development and production optimization.

well tests (often a combination of several) provide detailed information at an average scale around the well that reflects static quantities such as geometry, boundaries, drilling or production efficiency; and dynamic quantities such as reservoir pressure, permeability, productivity index..etc.

1.Principals of well testing

Introduction

Well testing is a valuable and economical formation evaluation tool used in the hydrocarbon industry. It has been supported by mathematical modeling, computing, and the precision of measurement devices. The data acquired during a well test are used for reservoir characterization and description. **[1]**

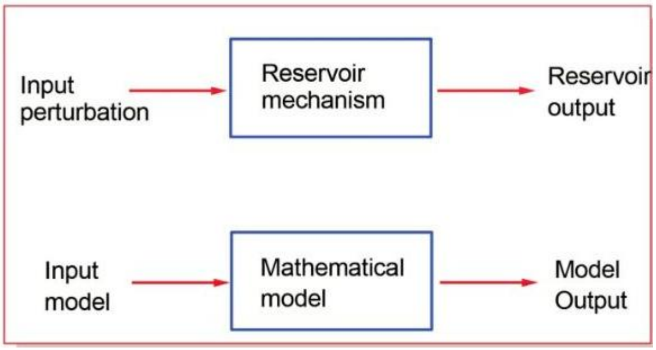
Generally speaking, the objective of well testing is information about a well and a reservoir.

To get this information, the well flow rate is varied and the variation disturbs the existing pressure in the reservoir.

Measuring variations of pressure as a function of time interpreting them gives data on the reservoir and well.**[2]**

1.2.Prnicipe of well test:

Pressure test fundamentals come from the application of Newton's law, especially the third one: Principle of action-reaction, since it comes from a perturbation on a well**.[1]**



FigureI.1. Diagram of the mathematical representation of a pressure test.

During a well test, a transient pressure response is triggered by a temporary adjustment in production rate. Typically, the well's reaction is observed over a relatively brief timeframe relative to the reservoir's lifespan, determined by the test objectives. **[3]**

Well evaluations are often completed within a span of two days, although reservoir boundary testing might require several months of pressure data.
In most cases, the flow rate is measured at surface while the pressure is recorded down- hole. Before opening, the initial pressure **pi**, is constant and uniform in the reservoir.

During the flowing period, the drawdown pressure response $\Delta \mathbf{p}$ is defined as follows:
$\Delta(\boldsymbol{p}) = \boldsymbol{pi} - \boldsymbol{p}(\boldsymbol{t})$

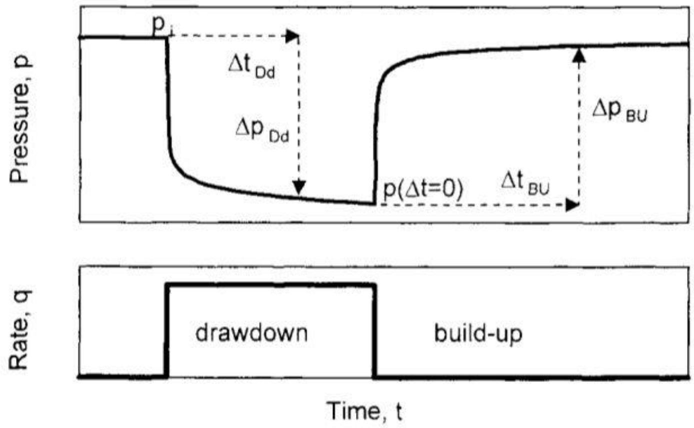


Figure I.2. Diagram of drawdown and build up sequence

When the well is closed off, the increase in pressure (Δp) during the build-up phase is calculated based on the final pressure recorded during the flowing phase.**[3]**

$$p(\Delta t = 0)$$

$$\boldsymbol{\Delta p} = \boldsymbol{p}(\boldsymbol{t}) - \boldsymbol{p}(\boldsymbol{\Delta t} = \mathbf{0})$$

2.Well test objectives :

Well testing is crucial for understanding reservoir and well dynamics, integrating geological, geophysical, and petrophysical data to forecast field behavior and fluid recovery. Effective communication between the well and reservoir can enhance productivity.

Exploration Phase: Initial tests verify exploration hypotheses, determine initial production forecasts, and characterize reservoir properties.

Appraisal Phase: Tests in appraisal wells refine reservoir descriptions, confirm productivity, and identify reservoir heterogeneities and boundaries.**[3]**

Development Phase:

- Establish hydraulic connectivity to bridge reservoir characterization with the geological model.
- Prepare the well for stimulation operations that can economically determine production.

Assess the extent of well damage (Skin). **[4]**

3.Types of well test :

Pressure tests in oil and gas wells can indeed be classified in various ways based on different criteria. One common classification is based on whether the well is producing or shut-in, as you mentioned. Another way to classify them is by the number of flow rates involved.

3.1.Pressure tests run in producer wells

3.1.1. drawdown test

In a drawdown test, a well that is static, stable and shut-in is opened to flow. For the purposes of traditional analysis, the flow rate is supposed to be constant (Figure I.3).

Many of the traditional analysis techniques are derived using the drawdown test as a basis. However, in practice, a drawdown test may be rather difficult to achieve under the intended conditions.

In particular: (a) it is difficult to make the well flow at constant rate, even after it has (more-or-less) stabilized, and (b) the well condition may not initially be either static or stable, especially if it was recently drilled or had been flowed previously. **[5]**

Drawdown testing is an effective approach for reservoir limit testing because it allows sufficient time to observe boundary responses, reducing the significance of operational flow rate fluctuations over extended periods.

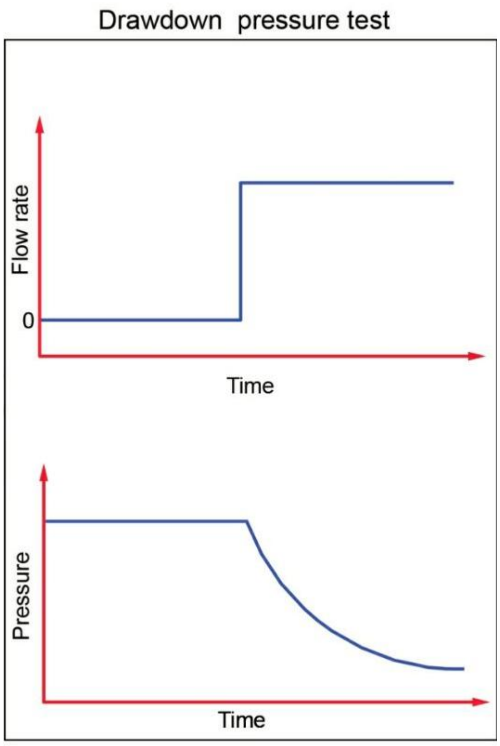


Figure I.3. Schematic representation of pressure drawdown

3.1.2. Pressure buildup test

In this test, the well is shut-in while recording the static bottom hole pressure as a function of time. This test allows obtaining the average pressure of the reservoir.

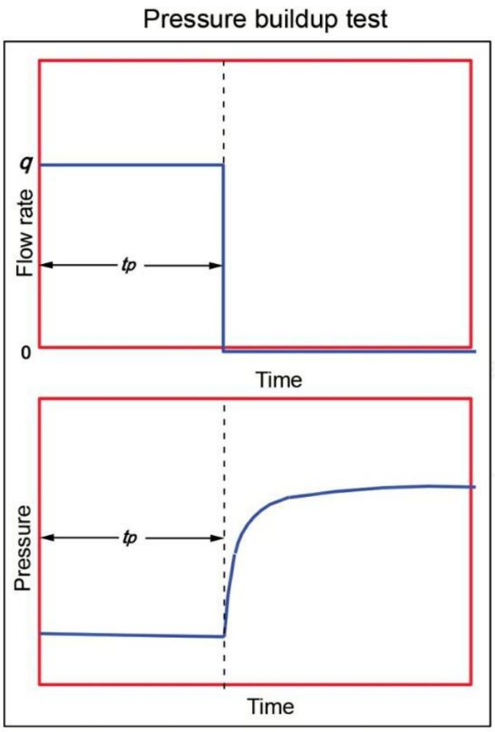


Figure I.4. Schematic representation of pressure build up

Analysis of a buildup test often requires only slight modification of the techniques used to interpret constant rate drawdown test.**[1]**

The practical advantage of a buildup test is that the constant flow rate condition is more easily achieved (since the flow rate is zero)

(a) It may be difficult to achieve the constant rate production prior to the shut in. In particular, it may be necessary to close the well briefly to run the pressure tool into the hole.

(b) Production is lost while the well is shut in.

3.2.Pressure tests run in injector wells

3.2.1. injection test

Since it considers fluid flow, it is a test similar to the pressure drawdown test, but instead of producing fluids, fluids, usually water, are injected.**[1]**

Injection tests are used in well testing to evaluate the injectivity and reservoir properties of an injection well. During an injection test, a known volume of fluid is injected into the well at a controlled rate, and the pressure response is monitored.

❖ This information helps determine the reservoir's ability to accept fluids, the formation permeability, and other important parameters for reservoir management.

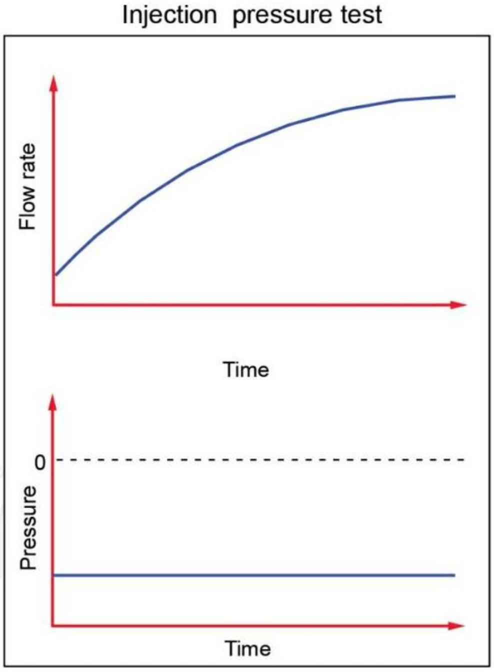


Figure I.5. Schematic representation of pressure injection tests

3.2.2. fall of test

This test considers a pressure drawdown immediately after the injection period finishes. Since the well is shut-in, falloff tests are identical to pressure buildup tests.**[1]**

During a pressure drawdown test, the well is shut-in at the end of the injection period to allow pressure to stabilize. After this shut-in period, the pressure is then allowed to decline, and this fall off period is analogous to a pressure buildup test.

Both tests provide valuable information about the reservoir, including its permeability, skin factor, and reservoir pressure.

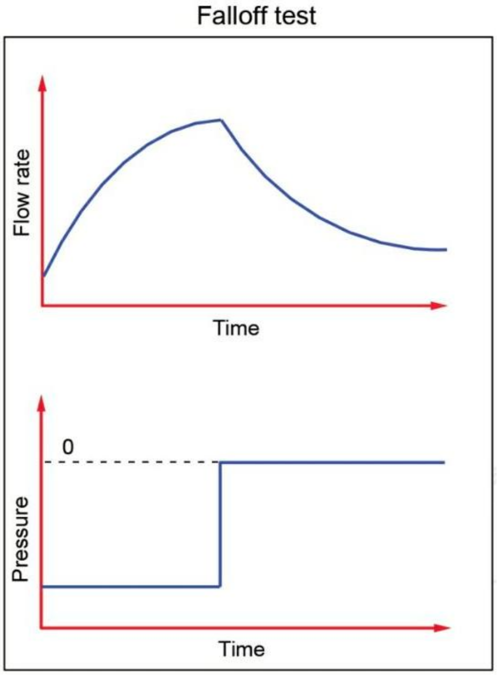


Figure I.6. Schematic representation of fall of tests

Other tests

3.3.Interference and/or multiple tests:

Interference tests involve multiple wells and are used to assess communication between them. Unlike previous tests that focus on a single well, interference tests measure the effects of a pressure disturbance caused in the reservoir by varying the flow rate of a neighboring well, known as the transmitter, on a specific well, known as the receiver.

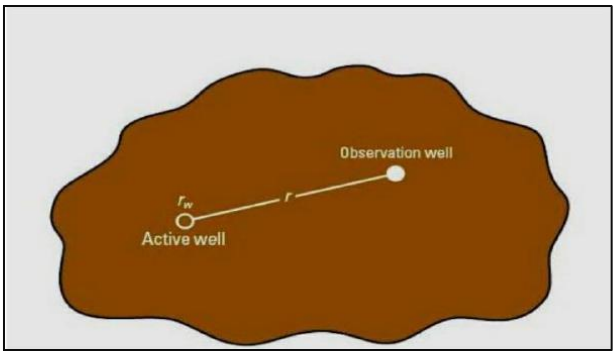


Figure I.7. Interference tests. [7]

These tests help to better understand reservoir heterogeneity, water-hydrocarbon interfaces, and aquifer activities, which are crucial for reservoir simulation and modeling. **[6]**

A more recent method called "pulse testing" involves regularly opening and closing a well for short periods, suitable for reservoirs with relatively high permeabilities and short distances between wells.

3.4.drill stem test:

This test is used during or immediately after well drilling and consists of short and continuous shut-off or flow tests. Its purpose is to establish the potential of the well. **[1]**

A Drill Stem Test can be considered as a form of temporary well completion, as it allows for the temporary isolation of a specific section of the well to evaluate the formation properties. During the DST, fluid samples are collected, and the formation pressure is measured, providing insights into the reservoir characteristics, including:

- the nature and characteristics of the fluids,
- reservoir pressure and temperature.
- reservoir rock properties.

These insights are crucial for making informed decisions regarding the future production of the well and overall reservoir management. **[7]**

4. Diffusivity equation:

At the beginning of production, the pressure in the vicinity of the well falls abruptly and the fluids near the well expand and move toward the area of lower pressure.

Such movement is retarded by friction against the walls of the well and the inertia and viscosity of the fluid itself. As the fluid moves, an imbalance of pressure is created, which induces the surrounding fluids to move toward the well.

The process continues until the pressure drop created by the production dissipates throughout the reservoir.**[1]**

the diffusivity equation is often used to model the flow of fluids in porous media surrounding a well. The diffusivity equation in this context is derived from Darcy's law, which relates the flow rate of a fluid through a porous medium to the pressure gradient in the medium.
According to the volume element given in

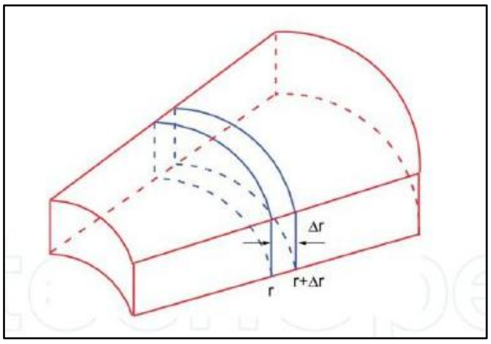


Figure I.8. Radial volume element

4.1. Darcy’s Law

The fundamental law of fluid motion in porous media is Darcy’s Law.

The mathematical expression developed by Henry Darcy in 1856 states the velocity of a homogeneous fluid in a porous medium is proportional to the pressure gradient and inversely proportional to the fluid viscosity.

For a horizontal linear system, this relationship is:

$$\boldsymbol{v = \frac{q}{A} = -\frac{k}{u} . \frac{dP}{dx}} \qquad \text{(I.1)}$$

v is the apparent velocity,

q is the volumetric flow rate

A is total cross-sectional area of the rock .

In other words, **A** includes the area of the rock material as well as the area of the pore channels. **[8]**

The fluid viscosity, **μ**, and the pressure gradient, **dp/dx**. The **k**, is the permeability of the rock.

The Darcy’s equation can be expressed in the following generalized radial form:

$$\boldsymbol{v} = \frac{\boldsymbol{qr}}{\boldsymbol{Ar}} = -\frac{\boldsymbol{k}}{\boldsymbol{u}}.\left(\frac{\boldsymbol{dP}}{\boldsymbol{dx}}\right)\boldsymbol{r} \qquad \text{(I.2)}$$

where

qr = volumetric flow rate at radius r

Ar = cross-sectional area to flow at radius r

(∂p/∂r)r = pressure gradient at radius r

v = apparent velocity at radius r

in steady radial circular flow , Darcy law is written :

$$\vec{q} = \frac{\mathbf{K}}{\mathbf{u}}\mathbf{S}\overrightarrow{\mathbf{grad}}\mathbf{P} \qquad \text{(I.3)}$$

It can be integrated between two values of well radius **rw** and the drainage radius **re**:

$$\mathbf{q} = \left(\frac{\mathbf{2\pi kh}}{\mathbf{u}}\right)\left(\frac{\mathbf{pe-pw}}{\mathbf{ln}\frac{\mathbf{re}}{\mathbf{rw}}}\right) \qquad \text{(I.4)}$$

4.2. equation of state:

Compressibility:

In well testing, the compressibility of both the reservoir rock and the fluids is a crucial factor. Compressibility is a measure of how much a substance's volume changes in response to a change in pressure, under constant temperature conditions.

During a well test, engineers analyze pressure data to estimate the compressibility of the reservoir rock and fluids. This information is essential for characterizing the reservoir, optimizing production strategies, and making informed decisions about reservoir development. **[2]**

The compressibility of any material is defined by the relative change in the material volume per unit of pressure variation constant temperature.

$$\mathbf{c} = -\frac{\mathbf{1}}{\mathbf{V}}\frac{\partial\mathbf{V}}{\partial\mathbf{P}} \qquad \text{(I.5)}$$

the density of the fluid varies with the pressure, this variation is translated by the equivalent compressibility of mobile fluids:**[4]**

$$\mathbf{ce} = \frac{\mathbf{1}}{\boldsymbol{\rho}}\left(\frac{\partial\boldsymbol{\rho}}{\partial\mathbf{P}}\right)\boldsymbol{T} \qquad \text{(I.6)}$$

4.3. equation of continuity :

The variation in the mass of fluid contained in the reservoir volume unit is equal to the difference between the amount of fluid input and output during the time interval.**[4]**

The continuity equation, often used in fluid dynamics, states that the rate of change of mass within a control volume is equal to the net rate of mass flow into or out of the control volume.

Mathematically, it is expressed as:

$$\boldsymbol{div\ \rho V} + \frac{\boldsymbol{\partial(\rho\emptyset So)}}{\boldsymbol{\partial t}} \qquad \text{(I.7)}$$

where:

- $\boldsymbol{\rho}$is the density of the fluid,
- **t** is time,
- **v** is the velocity vector of the fluid.

According to the volume element given in **figure**. **[1]**

Mass entering - Mass coming= system accumulationrate (I.*)
the elementout from the element

The right-hand side part of Eq. (I.*) corresponds to the mass accumulated in the volume element.

Darcy’s law for radial flow:

$$\mathbf{q} = -\frac{\boldsymbol{kA}}{\mu}\frac{\boldsymbol{dP}}{\boldsymbol{dr}} \qquad \text{(I.8)}$$

The cross-sectional area available for flow is provided by cylindrical geometry, **2πrh**. Additionally, flow rate must be multiplied by density, **ρ**, to obtain mass flow.

With these premises, Eq. (I.8) becomes:

$$\mathbf{q = -\frac{\boldsymbol{k}}{\mu} 2\pi\ rh \frac{\partial \boldsymbol{P}}{\partial \boldsymbol{r}}} \qquad \text{(I.9)}$$

Replacing Eq. (I.9) into (I.*) yields:

$$-\frac{k\rho}{u}(2\pi rh)\frac{\partial P}{\partial r}\bigg|r + \frac{k\rho}{u}(2\pi rh)\frac{\partial P}{\partial r}\bigg|r + dr = \frac{\partial}{\partial t}([2\pi rhdr\emptyset]\rho) \qquad \text{(I.10)}$$

If the control volume remains constant with time, then, Eq. (I.10) can be rearranged as:

$$-(2\pi h)\frac{k\rho}{u}r\frac{\partial P}{\partial r}\bigg|r + (2\pi h)\frac{k\rho}{u}r\frac{\partial P}{\partial r}\bigg|r + dr = 2\pi rhdr\frac{\partial}{\partial t}(\emptyset\rho) \qquad \text{(I.11)}$$

Rearranging further the above expression:

$$\frac{\frac{1}{r}\left[\frac{k\rho}{u}r\frac{\partial P}{\partial r}\Big|r+dr-\frac{k\rho}{u}r\frac{\partial P}{\partial r}\Big|r\right]}{dr} = \frac{\partial}{\partial t}(\emptyset\rho) \qquad \text{(I.12)}$$

The left-hand side of Eq (I.12) corresponds to the definition of the derivative; then, it can be rewritten as:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(\frac{k\rho}{\mu}r\frac{\partial P}{\partial r}\right) = \frac{\partial}{\partial t}(\Phi\rho) \qquad \text{(I.13)}$$

The definition of compressibility has been widely used;

$$\mathbf{c} = -\frac{1}{V}\frac{\partial V}{\partial P} = \frac{1}{\rho}\frac{\partial \rho}{\partial P} \qquad \text{(I.14)}$$

By the same token, the pore volume compressibility is given by:

$$\boldsymbol{Cf} = \frac{\mathbf{1}}{\boldsymbol{\Phi}}\frac{\boldsymbol{\partial\Phi}}{\boldsymbol{\partial P}} \qquad \text{(I.15)}$$

The integration of Eq. (I.14) will lead to obtain

$$\boldsymbol{\rho} = \boldsymbol{\rho_0 e^{c(P-Po)}} \qquad \text{(I.16)}$$

The right hand side part of Eq. (I.13) can be expanded as:

$$\frac{\boldsymbol{\partial}}{\boldsymbol{\partial t}}(\boldsymbol{\Phi\rho}) = \boldsymbol{\Phi}\frac{\boldsymbol{\partial}}{\boldsymbol{\partial t}}\boldsymbol{\rho} + \boldsymbol{\rho}\frac{\boldsymbol{\partial}}{\boldsymbol{\partial t}}\boldsymbol{\Phi} = \boldsymbol{\Phi}\frac{\boldsymbol{\partial\rho}}{\boldsymbol{\partial t}} + \boldsymbol{\rho}\frac{\boldsymbol{\partial\Phi}}{\boldsymbol{\partial P}}\frac{\boldsymbol{\partial P}}{\boldsymbol{\partial\rho}}\frac{\boldsymbol{\partial\rho}}{\boldsymbol{\partial t}} \qquad \text{(I.17)}$$

Using the definitions given by Eqs. (I.15) and (I.16) into Eq. (I.17) leads to:

$$\frac{\boldsymbol{\partial}}{\boldsymbol{\partial t}}(\boldsymbol{\Phi\rho}) = \boldsymbol{\Phi}\frac{\boldsymbol{\partial\rho}}{\boldsymbol{\partial t}} + \frac{\boldsymbol{\rho\Phi Cf}}{\boldsymbol{c\rho}}\frac{\boldsymbol{\partial\rho}}{\boldsymbol{\partial t}} = \boldsymbol{\Phi}\frac{\boldsymbol{\partial\rho}}{\boldsymbol{\partial t}}\left[\mathbf{1} + \frac{\boldsymbol{cf}}{\boldsymbol{c}}\right] = \frac{\boldsymbol{\Phi}}{\boldsymbol{c}}[\boldsymbol{cf} + \boldsymbol{c}]\frac{\boldsymbol{\partial\rho}}{\boldsymbol{\partial t}} \qquad \text{(I.18)}$$

Considering that the total compressibility,**ct** , is the result of the fluid compressibility, **c**, plus the pore volume compressibility, **cf**, it yields:

$$\frac{\mathbf{1}}{\boldsymbol{r}}\frac{\boldsymbol{\partial}}{\boldsymbol{\partial r}}\left(\frac{\boldsymbol{k\rho}}{\mu}\boldsymbol{r}\frac{\boldsymbol{\partial P}}{\boldsymbol{\partial r}}\right) = \frac{\boldsymbol{\Phi}\mathbf{Ct}}{\boldsymbol{c}}\frac{\boldsymbol{\partial\rho}}{\boldsymbol{\partial t}} \qquad \text{(I.19)}$$

The gradient term can be expanded as:

$$\frac{\boldsymbol{\partial P}}{\boldsymbol{\partial r}} = \frac{\boldsymbol{\partial P}}{\boldsymbol{\partial\rho}}\frac{\boldsymbol{\partial\rho}}{\boldsymbol{\partial r}} = \frac{\mathbf{1}}{\boldsymbol{c\rho}}\frac{\boldsymbol{\partial\rho}}{\boldsymbol{\partial r}} \qquad \text{(I.20)}$$

Combination of Eqs. (I.20) and (I.19) results in:

$$\frac{\mathbf{1}}{\boldsymbol{r}}\frac{\boldsymbol{\partial}}{\boldsymbol{\partial r}}\left(\frac{\boldsymbol{k}\mathbf{r}}{\mu\boldsymbol{c}}\frac{\boldsymbol{\partial\rho}}{\boldsymbol{\partial r}}\right) = \frac{\boldsymbol{\Phi}}{\boldsymbol{c}}\ \boldsymbol{Ct}\frac{\boldsymbol{\partial\rho}}{\boldsymbol{\partial t}} \qquad \text{(I.21)}$$

Taking derivative to Eq. (I.16) with respect to both time and radial distance and replacing these results into Eq. (I.21) yield:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(\frac{kr}{\mu c}\rho o\,.\,e^{c(P-Po)}c\frac{\partial P}{\partial r}\right)=\frac{\Phi}{c}Ct\rho o\,.\,e^{c(P-Po)}c\frac{\partial P}{\partial t} \quad \text{(I.22)}$$

After simplification and considering permeability and viscosity to be constant,
we obtain:

$$\frac{1}{r}\frac{k}{\mu}\frac{\partial}{\partial r}\left(r\frac{\partial P}{\partial r}\right)= \Phi\, Ct\,\frac{\partial P}{\partial t} \quad \text{(I.23)}$$

The hydraulic diffusivity constant is well known as

$$\frac{1}{\eta}=\frac{\Phi\mu\, Ct}{k} \quad \text{(I.24)}$$

Then, the final form of the diffusivity equation in oilfield units is obtained by combination of Eqs. (I.23) and (I.24): **[1]**

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial P}{\partial r}\right)=\frac{\Phi\mu Ct}{0.0002637\,k}\frac{\partial P}{\partial t}=\frac{1}{\eta}\frac{\partial P}{\partial t} \quad \text{(I.25)}$$

In expanded form**:**

$$\frac{\partial^2 P}{\partial r^2}+\frac{1}{r}\frac{\partial P}{\partial r}=\frac{1}{0.0002637\eta}\frac{\partial P}{\partial t} \quad \text{(I.26)}$$

4.4.Solving the Diffusivity Equation

The equation that describes the evolution of reservoir pressure as a function of time and distance to the well is obtained by solving the diffusivity equation with several boundary conditions. These boundary conditions describe:**[2]**

- The pressure status at the start of the test
- The limits of the reservoir;
- The condition of the well.

4.4.1.Infinite homogeneous reservoir resolution (Transient flow):

The hypothesis most often made is to assume that the reservoir is homogeneous, isotropic, of constant thickness and limited by impermeable hanging walls. The shaft passes through the seam over its entire thickness. The compressibility and viscosity of the fluids are constant and uniform. Using the following boundary conditions:**[7]**

- ✓ P = Pi to t = 0 in all tank (Uniform initial pressure: Pi).
- ✓ P = Pi to r = ∞ all the time (Infinite Tank).
- ✓ Constant flow rate in the well considered to have an infinitesimal radius.

The evolution of pressure as a function of time and distance to the well is governed by the following equation:

$$\mathbf{P_i - P_{(r,t)} = -\frac{qoBo\,\mu o}{4\pi kh} E_i\,(-x)} \qquad \text{(I.27)}$$

Ei (-x): is the integral exponential function defined by: $-Ei(-x) = \int_x^{\infty} \frac{e^{-u}}{u} du$

- **Logarithmic approximation:**

When the pressure evolution is measured at the level of the active well of radius rw, the diffusivity equation for an infinite homogeneous reservoir becomes:

$$\mathbf{P_i - P_{wf}(t) = -\frac{qBu}{4\pi kh} E_i\left(-\frac{rw^2}{4Kt}\right)} \qquad \text{(I.28)}$$

As soon as the ratio ($\frac{-rw^2}{4Kt} < 10^{-2}$), which is usually realized before the end of the well capacity effect, the function Ei can be replaced by its logarithmic approximation:

$$P\mathbf{i - Pwf = -\frac{qBu}{4\pi kh}\left(\ln\frac{kt}{rw2} + 0.81\right)} \qquad \text{(I.29)}$$

In practical units U.S. and taking into account the damage of the well, equation (I.29) is written as follows:**[7]**

$$P_i - P_{wf}(t) = -\frac{162.6qBu}{kh}\left(\log t + \log\frac{k}{\Phi\mu ct r_w^2} 3.23 + 0.87S\right) \qquad (I.30)$$

4.4.2.Infinite Acting Radial Flow

After wellbore storage effects subside, the pressure transient in the wellbore influences the reservoir's pressure transmission. During the intermediate period, known as the infinite acting period, the reservoir behaves as if it were infinite in extent, with radial flow dominating. Understanding infinite acting radial flow is crucial for estimating key reservoir properties and interpreting pressure data accurately. Techniques like type-curve matching and numerical simulation rely on this concept. Overall, infinite acting radial flow is fundamental in optimizing hydrocarbon recovery and managing reservoirs effectively.**[5]**

In the absence of wellbore storage and skin effects, the pressure transient due to infinite acting radial flow into a line source wellbore producing at constant flow rate is given by:

$$P_D = -\frac{1}{2} Ei\left(-r_D^2 / 4t_D\right) \qquad (I.31)$$

Here **Ei** represents the exponential integral function.

This solution is valid throughout the reservoir (r_D>1), including at the wellbore (r_D=1).

Thus it can be used for interference tests as well as drawdown and buildup tests. **Figure I.9** shows the exponential integral solution plotted in semi-log coordinates.

From this graphical presentation, it can be seen that the infinite acting radial flow response is directly proportional to the logarithm of time for all but early times. Examination of the solution numerically confirms this to be true.

For t_D > 10, the exponential integral solution at r_D=1 can be well approximated by :

$$PwD = \frac{1}{2}[\ln td + 0.80907] + s \qquad (I.32)$$

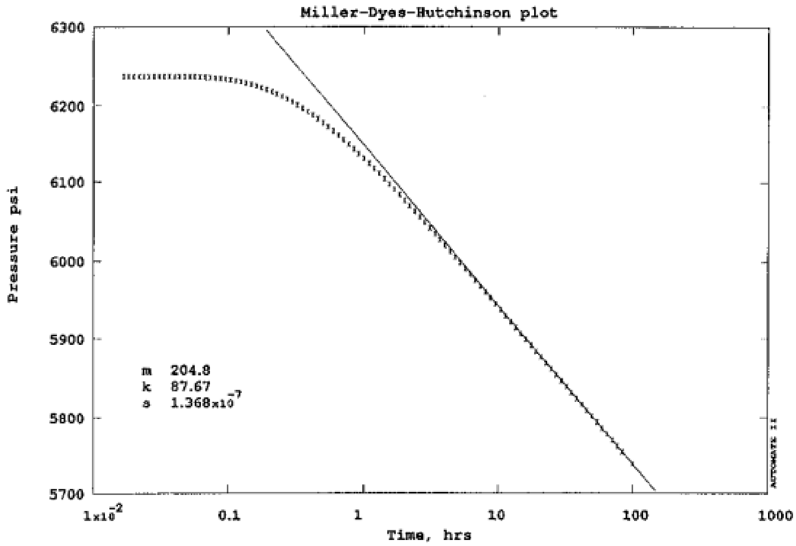


Figure I.9 exponential integral solution

Writing this in dimensional variables:

$$\mathbf{Pwf = Pi - 162.6\,\frac{qBu}{kh}\left(\log t + \log\frac{k}{\Phi\mu ctrw^2} + 0.8686s - 3.2274\right)} \qquad \text{(I.33)}$$

where the natural logarithm (In) has been replaced by a logarithm to base 10 (log). From this equation it is seen that a plot of pressure drop against the logarithm of time should contain a straight line with slope

$$\mathbf{m = \frac{162.6qBu}{kh}}$$

Hence the recognition of this slope makes it possible to estimate the permeability (k) or the permeability-thickness product (kh)**.[5]**

5. FLOW REGIMES

Flow regimes in well testing refer to the different types of flow behavior that can occur in a reservoir during a test. These regimes are typically classified based on the relationship between the flowing pressure and the production rate.

There are basically three types of flow regimes that must be recognized in order to describe the fluid flow behavior and reservoir pressure distribution as a function of time : **[8]**

- Steady-state flow
- Unsteady-state flow
- Pseudosteady-state flow

5.1. Transient flow

Transient flow is a fluid state in which the rate of change of pressure with respect to time at any position in the reservoir is not zero or constant.

This means that the pressure changes with time and/or position in the reservoir, indicating a dynamic and evolving process. **[7]**

$$\frac{\partial P}{\partial t} = f(x, t) \qquad \text{(I.34)}$$

When the compressible zone of the reservoir has not reached the boundaries or been influenced by other wells, the behavior of the reservoir can be approximated as infinite for testing purposes.

During this period, meaning that the pressure and flow rates are changing with time as the reservoir depletes.**[2]**

This transient period is crucial for well test analysis, as it provides valuable information about the reservoir properties and behavior.

5.2. Pseudo-steady state flow

When the compressible zone encounters boundaries where flow is zero, the flow regime transitions to pseudo-steady-state. This condition occurs when the pressure decreases linearly over time at various locations in the reservoir (exhibiting a constant decline rate), defining the fluid state as semi-permanent flow.

Mathematically, this means that the pressure change rate per unit time remains constant at every position. **[9]**

$$\frac{\partial P}{\partial t} = constant \qquad \text{(I.35)}$$

- although the pressure and flow rate appear to be steady, they are actually declining with time due to reservoir depletion.

However, the decline is slow enough that for practical purposes, the flow can be considered steady.

This is the flow regime that exists in a closed, non-fed reservoir.

Understanding the flow regime is crucial for interpreting well test data and estimating reservoir properties such as permeability, skin factor, and reservoir pressure.

5.3. steady state flow

The flow regime is considered steady-state when the pressure at every point in the reservoir remains constant, meaning it does not vary over time.

Mathematically, this is expressed as:**[8]**

$$\left(\frac{\partial P}{\partial t}\right)i = 0 \qquad \text{(I.36)}$$

Where **P** is the pressure and **t** is time. This indicates that there is no net change in pressure with respect to time, signifying a stable and constant pressure distribution throughout the reservoir.

In reservoirs, permanent flow cannot occur when the reservoir is completely recharged and supported by a strong aquifer or cap gas, or by pressure maintenance operations. **[10]**

6. RESERVOIR GEOMETRY

The shape of a reservoir significantly influences its flow behavior. Most reservoirs have irregular boundaries, and accurately describing their geometry often requires the use of numerical simulators.

However, for practical purposes, the actual flow geometry can be approximated by one of the following patterns: **[4]**

- Radial flow
- Linear flow
- Bilinear flow
- Spherical and hemispherical flow

6.1. Circular radial flow

In the absence of significant reservoir heterogeneities, fluid flow into or away from a wellbore will generally follow radial flow lines from a considerable distance around the wellbore.

This means that fluids move towards the well from all directions, and as they converge at the wellbore, the flow behavior is characterized as radial flow. **[8]**

Radial flow is the dominant flow regime in well test interpretation, this flow pattern is described by flow streamlines converging toward a circular cylinder. **[11]**

6.2. Linear flow

Linear flow occurs when the flow lines are parallel and the flow follows a single direction. This only occurs when the flow area is constant.

This type of flow is found in wells with communicating natural fractures or artificial fractures. Pressure data analysis during the test follows the equations of linear flow. **[7]**

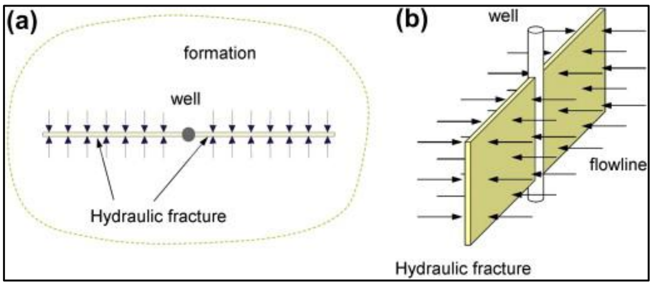


Figure I.10. linear flow

6.3. bilinear flow

Bilinear flow is a type of flow pattern in petroleum engineering being studied at well test, that sometimes occurs in hydraulically fractured wells.

Bilinear flow occurs due to pressure drop in the fracture resulting from fluid flow into it, causing parallel flow lines to exist within the fracture and at the same time parallel flow lines in the surrounding formation. **[12]**

This phenomenon is important in estimating the fracture conductivity, which is a critical factor in assessing well productivity and planning production operations.

This flow period is dominated mainly by finite-conductivity fracture flow and provides information about fracture properties. **[13]**

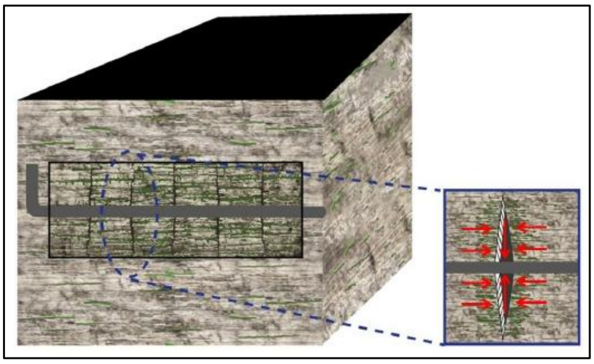


Figure I.11. bilinear flow regime with a linear flow in the hydraulic fracture and horizontal linear flow to the surface of the fracture.[13]

6.4. Spherical flow

In a well with partial penetration, the wellbore is connected to only a portion of the reservoir thickness, leading to a reduced contact area between the well and the reservoir.

This configuration typically results in a positive skin factor, the ratio of the length of the perforated interval to the formation thickness is called the penetration ratio (**h_w/h**). The horizontal and vertical permeabilities are denoted by **k_h** and **k_v**, respectively.

Initially, there is a radial flow regime near the perforated interval. As the flow continues, it transitions to both horizontal and vertical directions until reaching the top and bottom boundaries, creating a spherical flow regime.**[3]**

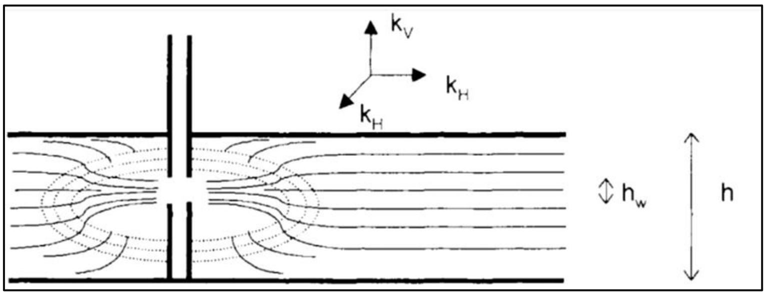


Figure I.12. spherical flow

7. The skin factor :

7.1. diffinition

During drilling, completion, or workover operations, materials like mud filtrate, cement slurry, or clay particles can infiltrate the formation, reducing its permeability near the wellbore. This is known as wellbore damage, and the affected area is called the skin zone.
The extent of this zone can vary from a few inches to several feet. Conversely, some wells are stimulated through acidizing or fracturing, which increases permeability near the wellbore.
As a result, the permeability near the wellbore differs from the permeability in unaffected areas of the formation away from the well.

The skin effect reflects the connection between the reservoir and the well. The difference in pressure drop in the vicinity of the wellbore can be interpreted in several ways:

-by using infinitesimal skin.
- skin of a finite thickness.
- the effective radius method**. [2]**

7.2. infinitesimal skin

The additional pressure drop due to skin effect is defined by :

$$\Delta \boldsymbol{ps} = \frac{\boldsymbol{\alpha q B u}}{\boldsymbol{kh}} \boldsymbol{S} \qquad (I.37)$$

With

α= 1/2 in SI

α= 141.2 in practical US

α= 18.66 in practical metric

In Hurst and Van Everdingen's approach, the pressure drop due to the skin effect is located in an infinitely thin film around the wellbore (Fig. I.13).**[2]**

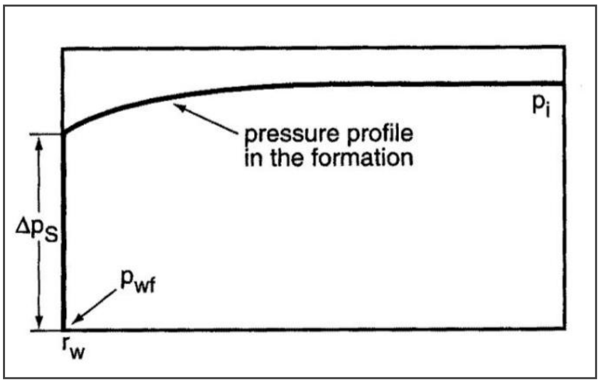


Figure I.13 Courbe pressure profile in the formation

☒ The skin effect, S, is homogeneous with a dimensionless pressure drop.

7.3. finite thickness skin

Another representation consists in assuming the pressure drop is located in an area with a radius **rs** and permeability **ks** around the well (Fig. I.14).

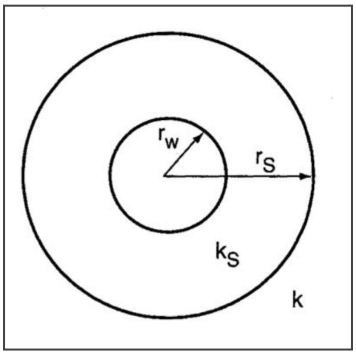


Figure I.14 finite thickness skin

When the compressible zone leaves this area, the flow can be considered pseudosteady-state and is governed by Darcy's law.

The difference in pressure drop between the real reservoir and a reservoir uniform right up to the wellbore is expressed as follows with Darcy's law:

$$\Delta p_S = \frac{qB\mu}{2\pi k_S h} \ln \frac{r_S}{r_w} - \frac{qB\mu}{2\pi kh} \ln \frac{r_S}{r_w} \qquad \text{(I.38)}$$

By Expressing Δps with equation I.38 we get :

$$\boldsymbol{s = \left(\frac{k}{ks} - 1\right) ln\ \frac{rs}{rw}} \qquad \text{(I.39)}$$

Nota bene:

the last equation shows that a damage (ks <k) corresponds to a positive skin. When the vicinity of the wellbore is plugged the skin can have very large values. The more permeable the medium and the greater the damage, the higher the values.

Let us imagine a sufficiently effective treatment so that **k/ks** is small compared to 1 on a radius **rs** of 2 m around the wellbore. Considering a wellbore with a radius of 10 cm, equation of the skin shows that under these conditions the skin is -3.

An improvement in permeability in the vicinity of the wellbore can correspond to a contribution of between 0 and 3 to the skin. A smaller skin value must be explained by other phenomena, e.g. fractures, fissures**. 2**

7**.4. effectiveradius**

The effective radius method consists in replacing the real well with a radius **rw** and skin **S** by a fictitious well with a radius**rw** and **S = 0**(Fig below).

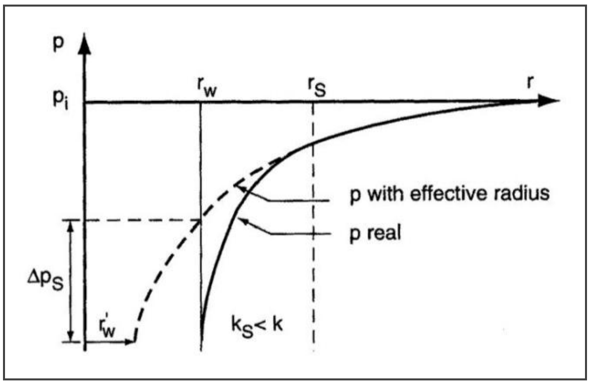


Figure I.15 pressure profile of real and effective radius

Radius**rw** is determined to have a pressure drop between **rs** and **rw**in the fictitious well equal to the pressure drop between rs and rw in the real well:

$$\Delta p(rw\ \ s\ = 0) = \Delta p(rw\ \ s\ )$$

Expressing the pressure drop with Darcy's law:

$$\frac{qB\mu}{2\pi kh}\ \ln\frac{r_S}{r'_w} = \frac{qB\mu}{2\pi kh}\ \left(\ln\frac{r_S}{r_w} + S\right) \qquad (I.40)$$

We get

$$\boxed{Rw = rw \exp (S)}$$

Nota bene:

The effective radius method is used to represent the skin analytically in all possible cases, including when the skin is negative. It expresses the effect of well treatments.

This can be illustrated by the case of a gravel pack. The effective radius of the well should normally fall between the screen radius and the underreaming radius.

An effective radius that is less than the liner radius would mean that the gravel pack is particularly ineffective.

The skin reflects the connection between the borehole and the reservoir. This is why it is recommended to use the inner radius of the borehole as radius rw tocompute the skin: the inner casing radius when there are perforations and the inner radius of the liners when there is a gravel pack**. [2]**

8. Wellbore storage

The analysis of well tests relies on understanding how pressure changes in the oil field due to changes in flow rate. While we often can control the flow rate at the wellhead, the effects within the wellbore itself can lead to changes in the flow rate from the reservoir to the well. This effect, known as "wellbore storage effect," occurs due to factors such as fluid expansion and changes in liquid level inside the well.

Consider the case of a drawdown test. When the well is first open to flow, the pressure in the wellbore drops. This drop causes an expansion of the wellbore fluid, and thus the first production is not fluid from the reservoir but is fluid that had been stored in the wellbore volume.**[14]**

Fluid expansion causes the wellbore to gradually deplete until it reaches its limit, at which point most of the flow comes from the wellbore itself. This phenomenon is known as wellbore storage due to fluid expansion.

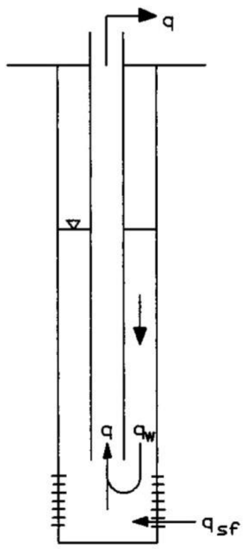


Figure I.16 wellbore storage

The second common type of wellbore storage is caused by a changing liquid level. This is easily visualized in completions with a tubing string and no packer. During a drawdown test when the well is flowing, the pressure drop causes the liquid level in the annulus to decrease. The liquid extracted from the annulus significantly increases the flow from the well. This type of completion typically experiences much more noticeable wellbore storage effects compared to fluid expansion alone.

The **wellbore storage coefficient**, C, is a parameter used to quantify the effect. C is the volume of fluid that the wellbore itself will produce due to a unit drop in pressure:

$$\boldsymbol{C = \frac{V}{\Delta P}}$$

V is the volume produced.

ΔP is the pressure drop.**[14]**

Chas units STB/psi (or sometimes MCF/psi in the case of gas wells).

It is also common to use a dimensionless wellbore storage coefficient, **C_D**. defined as

$$\boldsymbol{CD = \frac{5.615C}{2\pi\phi cthrw^2}} \text{where C is in STB/psi.} \qquad \text{(I.41)}$$

Assuming the fluid is of constant density, conservation of mass requires that the total flow rate q be equal to the flow of fluid from the reservoir (q_{sf}) added to that which flows from the well itself (q_w):

$$\mathbf{q = q_{sf} + q_w}$$

Thus the fraction of the total flow that originates from the reservoir is given by:

$$\mathbf{q_{sf}/\ q = 1 - q_w/\ q}$$

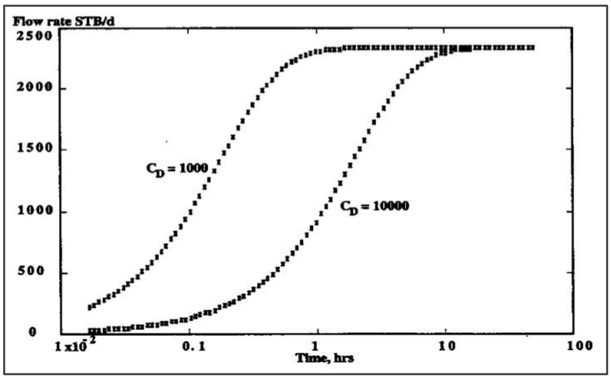


Figure I.17 overall effect of wellbore storage

The overall effect of wellbore storage can be seen in Fig. I.17. At early time the ratio **q/q** is close to zero, as all the fluid produced at the wellhead originates in the wellbore.

As time goes on, the wellbore storage is depleted, and eventually the reservoir produces all the fluid (as **qsf /q** tends to one).

The corresponding pressure transients due to the wellbore storage effects are seen in Figbelow.

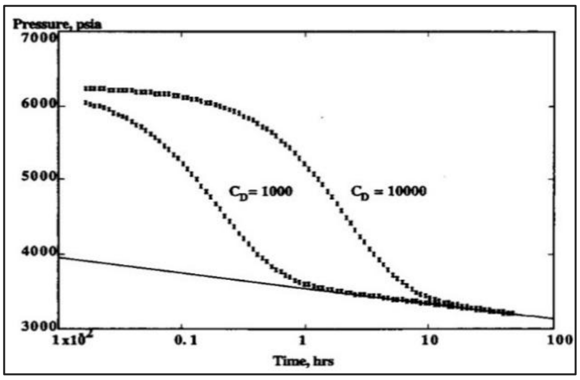


Figure I.18 pressure transients due to the wellbore storage

Recognizing the impact of the wellbore storage effect is crucial, as it causes the early transient response during a well test to reflect only the characteristics of the wellbore, not the reservoir. Therefore, a well test should be conducted for a duration sufficient to ensure that the wellbore storage effect has dissipated, allowing fluid to flow into the wellbore from the reservoir.
Alternatively, the issue of wellbore storage can be addressed by directly measuring the sandface flow rate (qsf) downhole.

- ✓ Estimating the wellbore storage coefficient is possible based on the completion configuration.**[14]**

- ➢ For a fluid expansion storage coefficient, $\mathbf{C = c_w . V_w}$

  where **V** is the volume of the wellbore, and **c** is the compressibility of the fluid in the wellbore. In principle, the wellbore compressibility includes the volume changes in the tubing and casing, however, these are usually small. Nonetheless, the compressibility is different from **ct**, the total reservoir compressibility, since **ct** includes the rock compressibility and will be under different pressure, temperature and saturation conditions than the wellbore.
- ➢ For a **falling liquid level** storage coefficient:

$$\boldsymbol{C} = \frac{\mathbf{144}\boldsymbol{Aw}}{\boldsymbol{\rho}} \qquad \text{ft}^3/\text{psi}$$

where **A** is the cross-sectional area of the wellbore in the region where the liquid level is falling (in ft^2) and $\boldsymbol{\rho}$ is the density of the fluid (in lbm/ft^3)

9. Radius of investigation

The pressure variations at the well give an indication of the properties of the part of the reservoir involved in the compressible zone. It is important to locate the compressible zone and this is what is involved in the concept of a test's radius of investigation.

Oil industry literature offers a large number of different definitions of the radius of investigation.**[2]**

1. **Jones's definition:**

The radius of investigation is the point in the reservoir where the pressure variations represent 1% of the variations observed at the well:

$$ri = \sqrt[4]{\frac{Kt}{\emptyset uct}} \text{(in Sl units)} \qquad \text{(I.42)}$$

2. **Poettmann's definition:**

The radius of investigation is the point in the reservoir where the flow is equal to 1% of the well flow rate:

$$ri = 4.29\sqrt{\frac{Kt}{\emptyset uct}} \quad \text{(in Sl units)} \qquad \text{(I.43)}$$

3. **J. Leeand Muskat's definition:**

The radius of investigation is the point where the pressure variations are the fastest.
The variations are given by the equation below:

$$pi - p(r,t) = -\frac{qBu}{4\pi Kh} Ei(\frac{-r2}{4Kt}) \qquad \text{(I.44)}$$

The pressure variations are equal to:

$$\frac{dp}{dt} = \frac{qB\mu}{4\pi kh} \frac{\exp(-r2)}{4Kt} \qquad \text{(I.45)}$$

In other terms:

$$ri = 2\sqrt{\frac{Kt}{\emptyset uct}}$$

Simulations using a grid-type well simulator indicate that events, such as faults, are detected in well pressure variations at a time similar to that calculated with the most recent formula mentioned. This formula appears to be the most appropriate for determining the radius of investigation in well tests.**[2]**

In practical units, it is expressed as follows:

$ri = 0.032\sqrt{\frac{Kt}{\emptyset uct}}$ (in SI units)

$ri = 0.038\sqrt{\frac{Kt}{\emptyset uct}}$ (in metric units)

10. Principe ofSuperposition

The principle of superposition makes it possible to characterize the evolution of the pressure in the tank for a multitude of flow variations. Since the evolution of the pressure is linear as a function of the flow rate, the evolution of the pressure due to several flows is equal to the sum of the pressure evolutions due to each of the flows.

This is the principle of superposition. The general equation of the evolution of pressure for any flow history is given by: **[15]**

$$P_i - P\,(t) = \frac{B\mu}{2\pi kh}\sum_{i=1}^{n}(q_i - q_{i-1})\,P_D(t - t_{i-1}) \qquad \text{(I.46)}$$

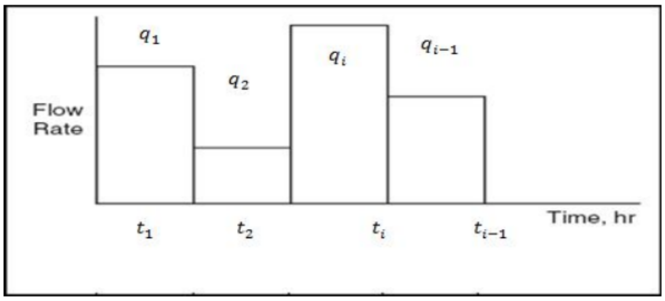


Figure I.19 flow rates history

Chapter II

Interpretation methods

Introduction

Well test analysis or interpretation is one of the fields of reservoir engineering that deals with understanding reservoir properties with the principles of fluid flow in porous rocks using different techniques, this analysis allows to determine parameters such as permeability, porosity, skin .

A lot of different methods can be used to analyze a well test, they can be classified into two main groups :

- Conventional methods.
- Modern methods.

Within these two large families, the methods depend on the nature and the model type of the well, the reservoir and these boundaries.

1.Data required for test analysis :

Test data:

variation of flow rates (complete sequence of events with all possible operational problems) and the bottom pressure as a function of time .

Well data:

well radius, geometry (vertical or deviated) and depth

Reservoir and fluid parameters:

formation thickness , porosity, compressibility of oil, water and formation, water saturation, viscosity of oil and volume factor.

Additional data may sometimes be required: production logs, bubble pressure, rosy pressure, PVT data ... etc. Geological and geophysical information is necessary to validate the interpretation results.**[9]**

2. The procedures of interpretation of well tests:

The interpretation of a well test involves several steps as follow :

Diagnostic :

This phase involves identifying and defining the various flow patterns observed during testing. Identifying these patterns helps establish the optimal reservoir well setup for interpretation. The pressure derivative is the primary diagnostic tool, while type curves serve as additional diagnostic aids.

Interpretation:

After clearly defining the flow regimes, we proceed to the interpretation stage using various methods such as the pressure derivative, conventional techniques, and type curves. The goal of interpretation is to quantify the parameters of the reservoir well configuration.**[4]**

Fig : Diagnostic and Interpretation of well test (Horner's method)

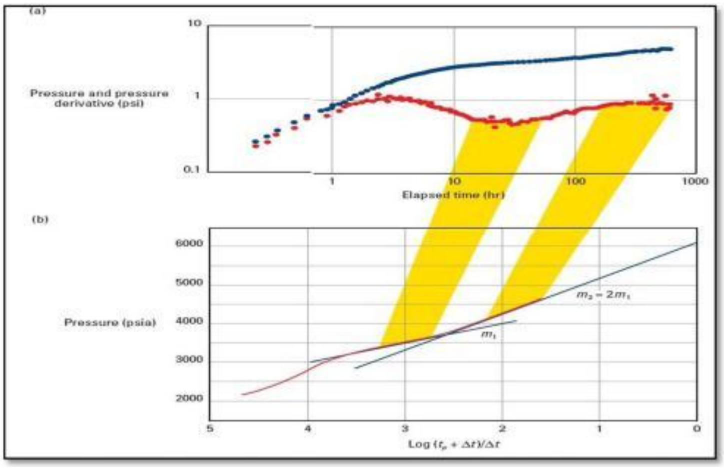


Figure II.1 Diagnostic and Interpretation of well test (Horner's method)

Validation: Validation of the interpretation involves creating a standard curve from the interpreted results using an analytical model. The extent of deviation between this curve and the recorded data reflects the reliability of the diagnosis and interpretation results.

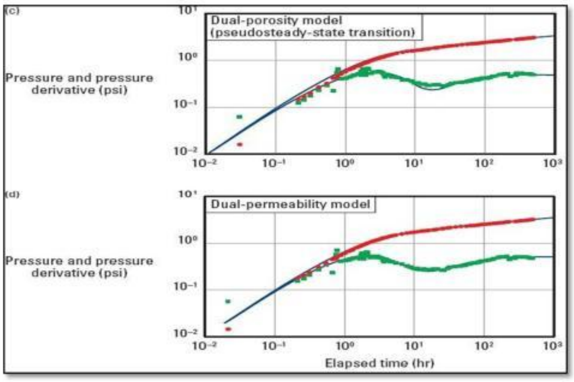


Figure II.2 validation of model and parameters

3. Conventional methods :

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:

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

3.1. Horner's method :

Horner's solution for pressure test analysis :

assumption for the Horner's solution:

- homogeneous reservoir permeability.
- The fluid compressibility is small or neglected.
- Infinite acting reservoir
- Single phase flow.
- The well is centered in circular reservoir.
- The well diameter approach to zero.**[16]**

The solution can be written as :

$$\mathbf{P_{ws} = P_i - \left(162{,}6\,\frac{qBu}{kh}\right).\log\left(\frac{tp + \Delta t}{\Delta t}\right)} \qquad \text{(II.1)}$$

The relation between **Pws** and **log (tp+Δt/Δt)** is <u>linear</u>.

Pi the intercept and **162.6 $\frac{qBu}{kh}$** Is the slope of the straight line .

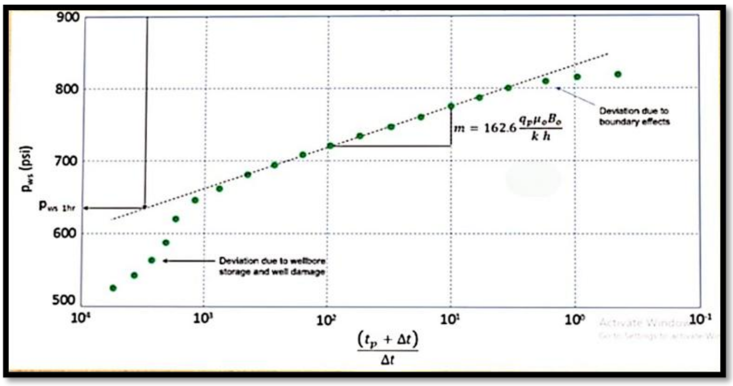


Figure II.3 Horner plot

Buildup Analysis, Horner Method-Recommended Procedure :

We recommend the following procedure for analyzing pressure-buildup data using « Horner semi-log analysis » :

a. Graph the shut-in bottomhole pressure, p, vs. the HTR , (tp+ Δt)/Δt, on a semilog scale.

b. Draw a straight line through the selected data, and find the slope m

$$\mathbf{m = \frac{162.6\ QBu}{Kh}}$$

c. Read **P(1h)** from the straight line or its extrapolation at an HTR corresponding to a shut-in time$\Delta t$of 1 hour, « HTR=(tp +1/ 1 ».

d. Calculate the permeability from the slope « m » as :

$$\mathbf{Kh = \frac{162.6\ QBu}{m}} \qquad \text{(II.2)}$$

e. Calculate the skin factors from the slope m, the flowing bottomhole pressure at the moment of shut-in‹Pws and P(1h) .

$$\mathbf{S= 1.151\ (\boldsymbol{S = 1.51\frac{P1h\text{–}Pwf}{|m|}} – log\left(\frac{k}{øuCtrw2}\right) +3.23\ )} \qquad \text{(II.3)}$$

f. The determination of the extrapolated pressure. **[17]**

We stretch the curve and then read on the pws axis

g. After determination the skin, we calculate

$\Delta Pskin$

IP réel = q / P_G– Pwf

IP ideal = q / P_G– Pwf – ΔPs

h . flow efficiency :

Ef= IP réel / IP ideal

The regions of the Horner plot :

a) Early-Time Region (ETR):

This is the region of the plot where we can obtain information concerning (Wellbore Storage, skin) .

b) Middle-Time Region (MTR) :

This is the plot region where we can obtain information on the reservoir properties and the model type of the reservoir (See figure below)

c) Late-Time Region (LTR) :

This is the region of the plot where we can obtain information concerning reservoir boundaries.**[16]**

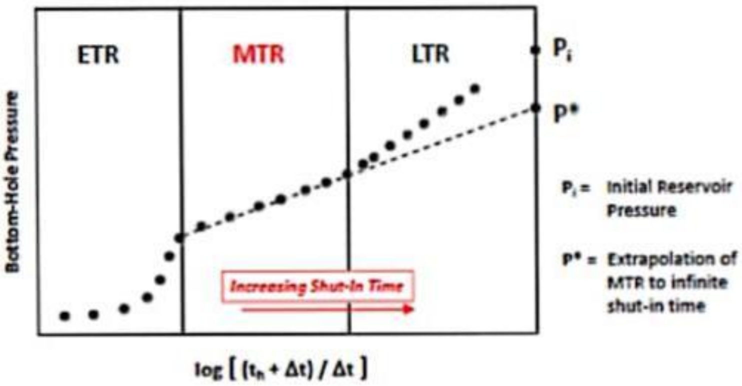


Figure II.4 times sequences in well interpretation

3.2.mdh (miller-dyes and hutchingson) method :

This method is based on the « HORNER method ». Therefore, the HORNER expression can take a simplified form each time the production time tp important compared to the pressure rise time (t).

The equation becomes :

$$\mathbf{Pws = Pi - (\frac{162.6qBu}{kh})(log\,tp - log\,\Delta\,t)} \qquad \text{(II.4)}$$

- From this equation, the bottom pressure evolves linearly as a function of the logarithm of the pressure rise time « log tp – log Δt ».
- The calculation of product permeability thickness (Kh) and the skin factor (S) are identical to that of the Horner's method.

Note:

The MDH method has the advantage of being a very simple application.

The disadvantage of this method is summarized in two points :

- ✓ It does not allow the determination of the extrapolated pressure like the method of HORNER.
- ✓ It can only be used for values of (Δt) small in front of tp. **[9]**

4. Modern methods

4.1. Type curves :

Type curves first appeared in oil industry in the seventies .

The pressure varies logarithmically as a function of time since the start of the test, and is then compared to theoretical dimensionless curves to determine the reservoir characteristics.

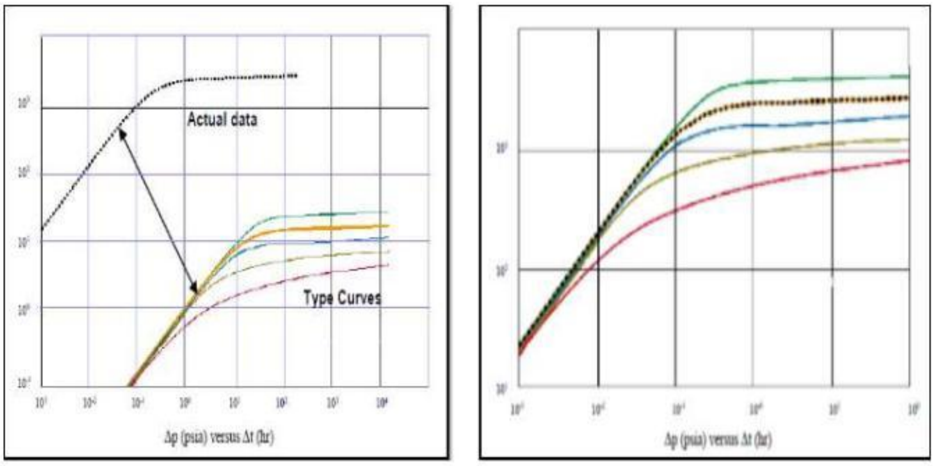


Figure II.5: log-log

Dimensionless quantities:

Dimensionless terms are used because they illustrate pressure responses independently of the physical parameters magnitude (such as flowrate, fluid or rock properties).

For example, describing the well damage with the dimensionless skin factor S is much more meaningful than using the actual pressure drop near the wellbore.**[18]**

The dimensionless pressure :

$$P_D = \left[\frac{kh}{141.2QBU}\right] \Delta P \text{(field units)}$$

$$P_D = \left[\frac{kh}{18.66QBU}\right] \Delta P \text{(metric units)}$$

- The dimensionlesstime :

$\mathbf{t_D}$= $[\frac{0.000264k}{ØUCtrw2}]\ \Delta t$(field units)

$\mathbf{t_D}$= $[\frac{0.000264k}{ØUCtrw2}]\ \Delta t$(metric units)

- The dimensionless well bore storage:

$\mathbf{C_D}$= $\frac{0.8936C}{ØCrhrw2}$(field units)

$\mathbf{C_D}$= $\frac{0.8936C}{ØCrhrw2}$(metric units)

Representation :

The type curves correspond to a representation of the forme :

$$\mathbf{PD= P_D\ (t_D,C_D,S)}$$

The Representation of the skin factor by an effective radius :

rwthe well radius is replaced by **rw = rw** $\mathbf{e^{-s}}$

$\mathbf{t_D}$the time is replaced by $\mathbf{t_D\ e^{2S}}$

$\mathbf{C_D}$the wellbore coefficient is replaced by $\mathbf{C_D\ e^{2S}}$

So we obtained this equation :

$$\mathbf{PD= P_D\ (t_D\ e^{2S},\ C_D\ e^{2S})}$$

We took the Gringarten method as an example, their representation is of the form :

$\mathbf{PD= P_D\ (t_D/C_D,\ C_D\ e^{2S})}$

the pressure is represented as a function of $\mathbf{t_D/C_D}$ on a log-log graph, each type curve differs from the next by the value of the parameter $\mathbf{C_D\ e^{2S}}$,which defines the condition of the well, it ranges from **0.3** for stimulated wells up to $\mathbf{10^{60}}$ for very damaged wells.

Method of interpretation:

1. Carry out the evolution of the measured pressure (and the derivative) on log log tracing paper, the scale of the plot must be the same as that of the type curves plot.

2.Calibrate the plot data on a curve type portion, the calibration is done by horizontal and vertical translations until the best possible calibration is obtained.

3.Once the setting is obtained, read the corresponding $\mathbf{C_D\ e^{2S}}$ value.

4. Find a reference point and read these coordinates on the plot and on the type curve plot $\mathbf{(P_D)_M}$, ΔP_{M} , $\mathbf{(t_D/C_D)_M}$ **,et** Δt_M

5. Based on the information obtained, calculate the required parameters (kh, C, S...)

Pressure :**$P_M = P_D/\Delta P$**

So the product permeability thickness :**ben mhidi**

$$Kh = \frac{141.2 \text{ q B u } (PD)M}{(\Delta P)M} \tag{II.5}$$

The matching of time : **$T_M = (t_D/C_D)/\Delta t$**

The wellbore storage coefficient

$$C = 0.000295 \, (\Delta t)_M \, / \, u \, .(t_D/C_D)_M$$

The matching curve : Skin

$$S = 1/2 \ln (C_D \, e^{2S} / C_D) \, .$$

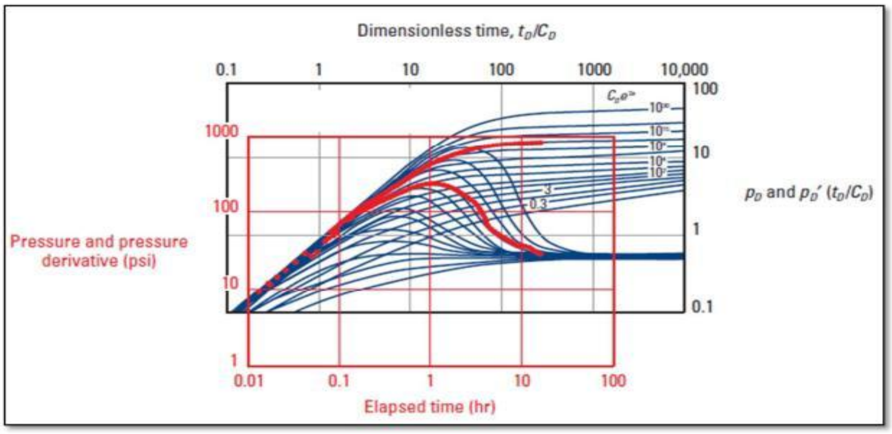


Figure II.6 : Method of a well test on type curves

5. The derivative:

The advantages of type curve representation are harnessed while mitigating the drawbacks of logarithmic representation through methods employing pressure derivatives.

These techniques capitalize on the insight from well tests that pressure variation holds greater significance than absolute pressure values. This is evidenced by the emphasis on slope analysis in conventional methods.

Notably, D. Bourdet's approach stands out among the various derivative forms proposed in petroleum literature during the early 1980s.**[6]**

Representation:

The pressure derivative as represented by D. Bourdet is calculated in relation to the time function of radial flow in the transient regime.

- ✓ **$dP_D/d \ln (t_D/C_D)$** for a drawdown
- ✓ **$dP_D /d \ln ((tp+ \Delta t)/\Delta t)$** for a bullidup after a constant flow rate period.
- ✓ **dP_D / d (superposition function)** more generally, with a varying flow rate

- The derivative is represented on a log-log graph like a type curve.**[2]**

Direct interpretation by means of the derivative:

Reservoir permeability, wellbore storage and skin can be determined directly using the type curve and its derivative provided that the stabilization of the derivative has been reached.

❖ **Reservoir kh:**

Permeability is calculated based on the value delta **$\Delta P'_{st}$** (Fig corresponding to the stabilization of the derivative.

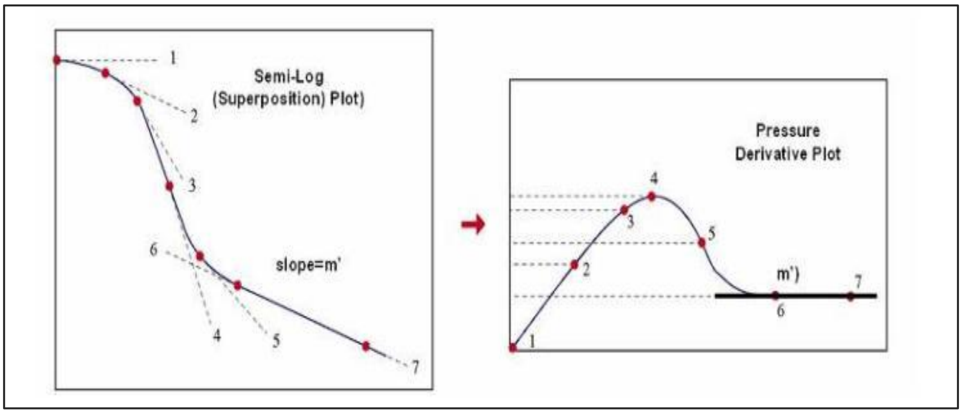


Fig II.7 : Interpretation using the derivative

The value of this derivative expressed in dimensionless terms is known, it is equal to 0.5. The expression of **$\Delta P'_{st}$**, in relation to 0.5 is equal to: (expressed in SI units).**[2]**

$$\Delta P'st = \frac{141,2qBu}{kh} 0.5 \qquad \text{(II.6)}$$

It is used to calculate the reservoir's kh:

$$kh=141.2qBu \frac{0.5}{\Delta P'st} \qquad \text{(II.7)}$$

❖ **Wellborestorage**:

Wellbore storage can be calculated if the coordinates of a point located on the slope 1 straight line are known:ΔP_1, and Δt_1, (Fig. II.7)

during dominating wellbore storage effect: **2**

$$\Delta P1 = \frac{qB}{24C}\Delta t1 \qquad \text{(II.8)}$$

So :

$$C = \frac{qB}{24\Delta P1}\Delta t1$$

❖ **The skin**

The skin can be calculated if the coordinates of a point located on the semi- log straight line are known: $\Delta Ps. \Delta ts$ (Fig. II.8)

The skin is calculated from the conventional expression given by the semi-log law. For a rise in pressure following a period at constant flow :

$$S=1.151\left(\frac{\Delta Ps}{2{,}303\Delta P'st} - \log\frac{\Delta ts}{1+\frac{\Delta ts}{tp}} - \log\frac{k}{\varnothing.u.ct.rw2+3.23}\right) \qquad \text{(II.9)}$$

In the case of any history it is possible and necessary to use a superposition function for this calculation .**[2]**

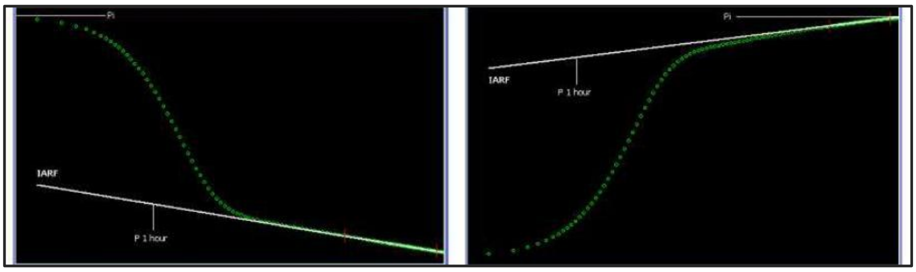


Figure II.8 Drawdown, Build-up by the conventional

Chapter III

Saphir software

Introduction

This tutorial provides a description of the options and workflow in KAPPA-Workstation. This includes creation of new documents and analyses, loading of pressure and rate data, extraction of a build-up, use of loglog analysis tools, example of analytical and numerical modeling, specialized plots, sensitivity.. .

2. Creating a new document

Click on ‘Blank’ (alternatively, you can use the ‘Ctrl’ + ‘n’ keyboard shortcut). This starts a wizard that will take the user through six steps to initialize a new document and its first analysis.

- Step 1: initialization of the main document options: reference time and location, general information, units and general comments. Keep everything as default and click **NEXT**.

- Step 2: main options of the first analysis in this document. Keep the analysis as ‘Standard’ and input the main test parameters. Those highlighted with red fields have a significant impact on the results and should not stay at default value. If the default happens to be the answer one may enter the same value or select ‘Accept default’ using a right mouse click.

If any field remains, a red warning message will be carried out throughout the interpretation. Set the pay zone (h) to 100 ft and the porosity (ϕ) to 0.23. Click **NEXT**. **[19]**

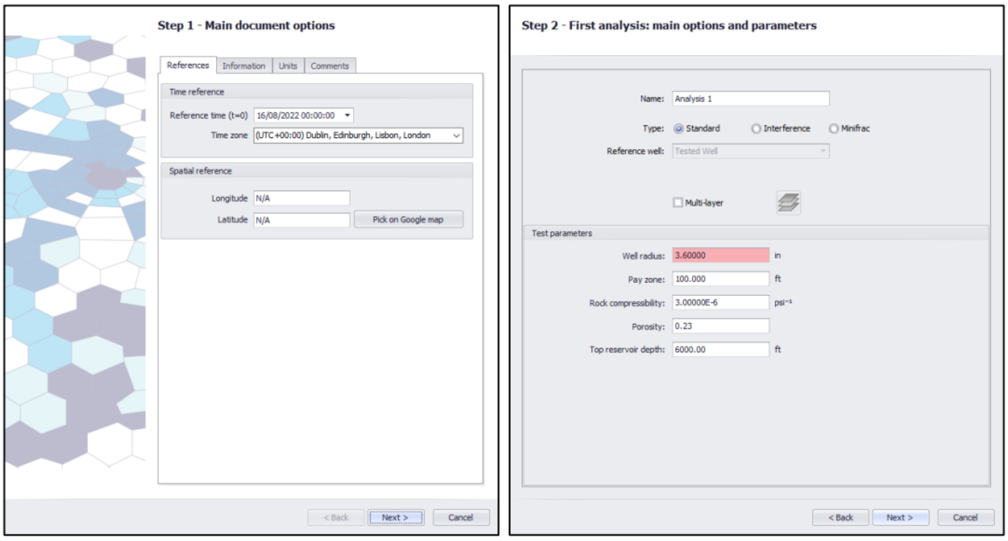


Figure III.1 main document and parameters options

- Step 3: definition of the fluid and its physical diffusion in the formation. Keep the default single phase oil. This does not require any further parameters at this stage, so click on **NEXT**.
- Step 4: definition of the constant parameters and/or pseudo-functions that will be used in analytical or linear numerical models (linearity is required for superposition). Set the viscosity (μ) to 1.5 cp and keep the compressibility and water saturation at their default values. Click on **NEXT**.

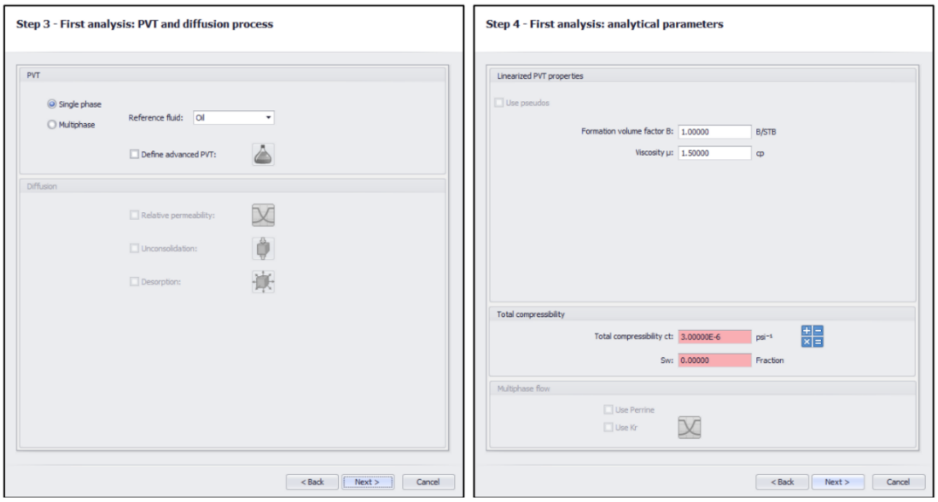


Figure III.2 PVT analysis

- Step 5: controls the level of complexity in the numerical model. The options in the left column are standard with Saphir and Topaze.

The options in the right columns are Rubis functionalities. Although these models can be directly built from Saphir or Topaze, they do require a Rubis license to be available. The default numerical settings will be largely sufficient in this tutorial, so click on **NEXT**.

- Step 6: the default model can be set at any stage of the analysis, even at initialization stage. If the user knows or suspects that a given model should apply there is no need to start with an irrelevant default. If the user knows that the well is horizontal, Saphir can be constrained at once. For this session, do not change the default at this stage. Click on **CREATE**.

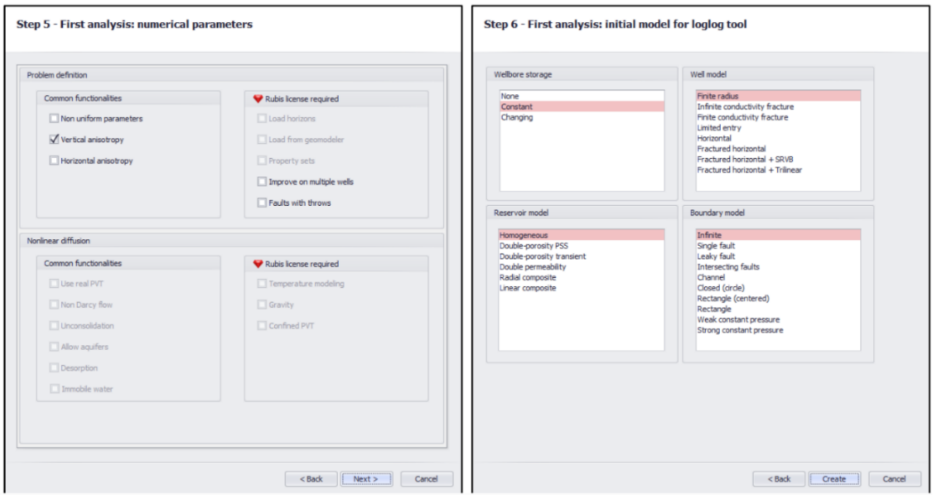


Figure III.3 initial model for log-log tool

The document and its first analysis are now initialized and the main Saphir window appears. The active tab is 'Analysis' with an empty workspace. The document is only in the active computer memory and it is named 'Untitled1'. Save it and call it 'PTA Tutorial 1' using the Ctrl+S shortcut or select 'Save' in the File menu.

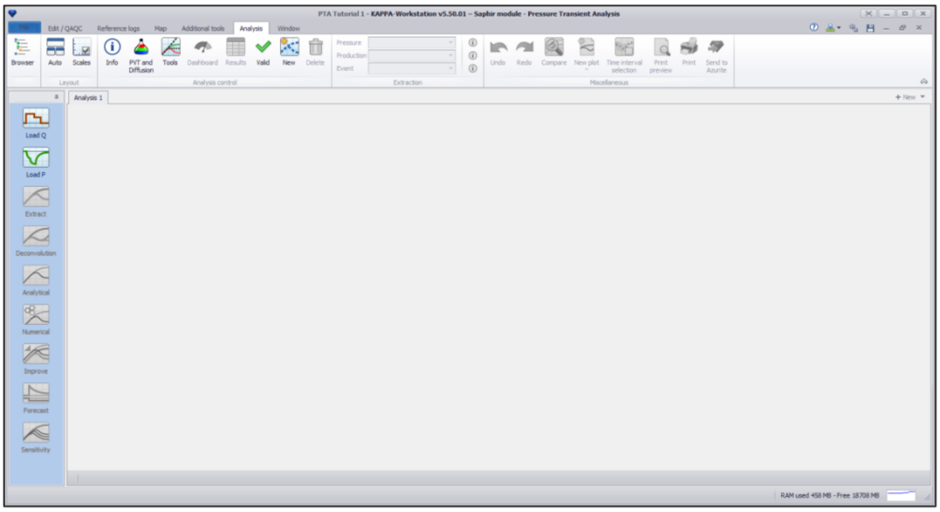


Figure III.4 home page of software

3. Loading data

Click on 'Load Q'in the control panel on the left to load the rate history. The rate information is stored in the ASCII file 'PTAEX01 Rates.txt'. Click on and select the file to bring a preview of its content (below, left). **NEXT** brings a dialog where the file information is interpreted line by line (below, right).

The collapsible panels on the left offer detailed load options. The top right section has a set of editable information while the bottom left window gives the result of the format processing. As the input file is very simple, with time stored as durations, the default format will work. Click on to **LOAD** proceed. **[19]**

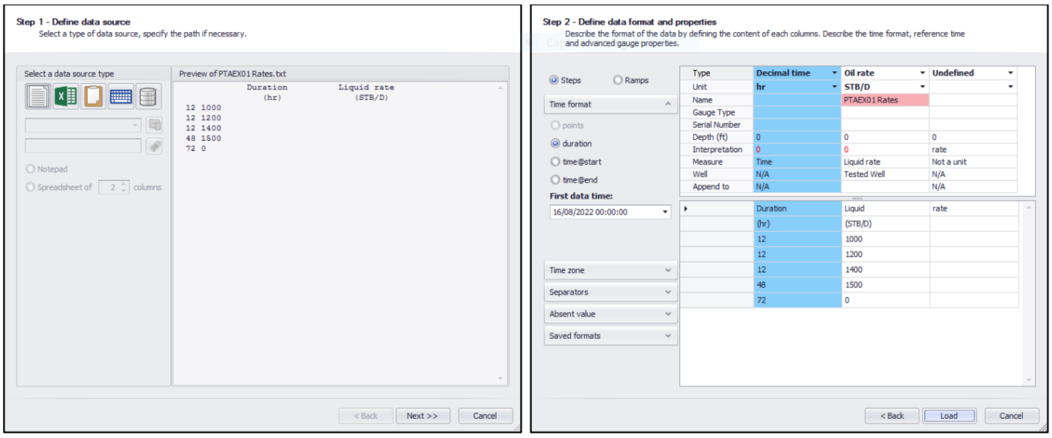


Figure III.5 loading the flow rate data of the well

The main Saphir screen is displayed again with a history plot showing the loaded rates.

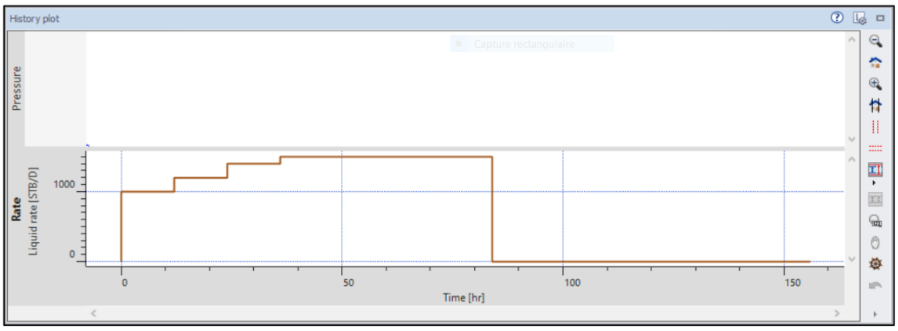


Figure III.6 flow rate plot

Click on 'Load P', to load the pressure history. Click on and select the Excel file 'PTAEX01 Pressures.xlsx'. A file preview is shown (below, left) with the possibility to change the tab/worksheet. Click on **NEXT**.

The dialog is the same as when loading rates, where the file information is being interpreted line by line (below, right). Again, the format is simple, so keep the defaults and click on to **LOAD** proceed.**[19]**

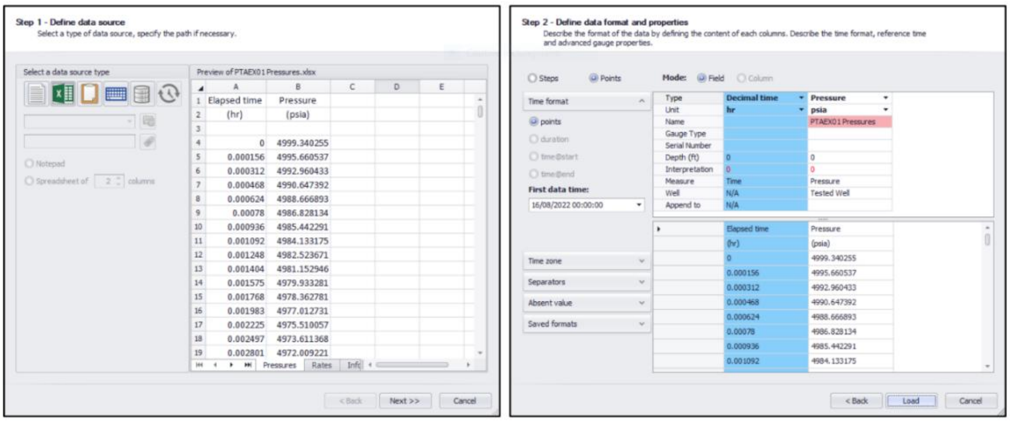


Figure III.7 loading pressure data of the well

Back in the Saphir main workspace, the history plot is displayed with both rate and pressure data.

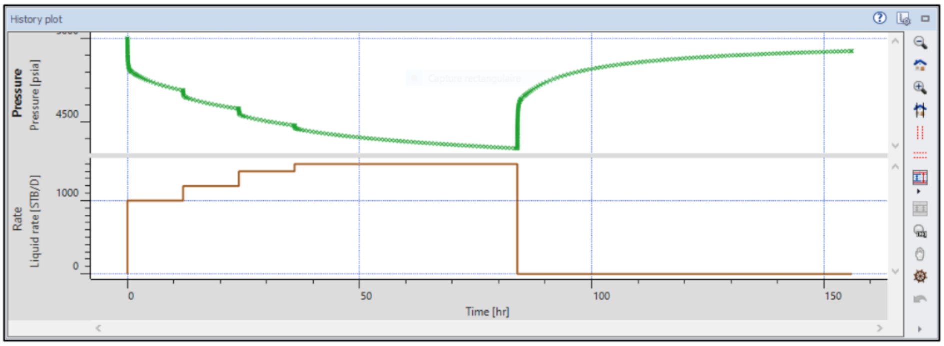


Figure III.8 pressure and flow rate plot versus time

Several sets of pressure and rate data may be loaded in the same PTA document. After the load of the raw data, it is possible to quality check, edit and synchronize the loaded data using the Edit / QAQC tab of the PTA window.

This will not be required in this tutorial as data is simple and already synchronized. In the next section, the focus will be on the unique build-up of this test.

4. Extracting the flow period and generating plots

Click on ‘Extract Δp’ to call the extraction dialog (below, left). From the controls at the top left the user may select one or several pressure gauges, one or several production data or one or several build-ups. Here, there is only one choice for each. In the dialog, the loglog plot resulting from the current extraction options is displayed. Click on **ok** to proceed. **[19]**

The main Saphir screen (below, right) has three plots (loglog, semilog & history) and a result window where a red warning indicates that some key parameters remain at default value.

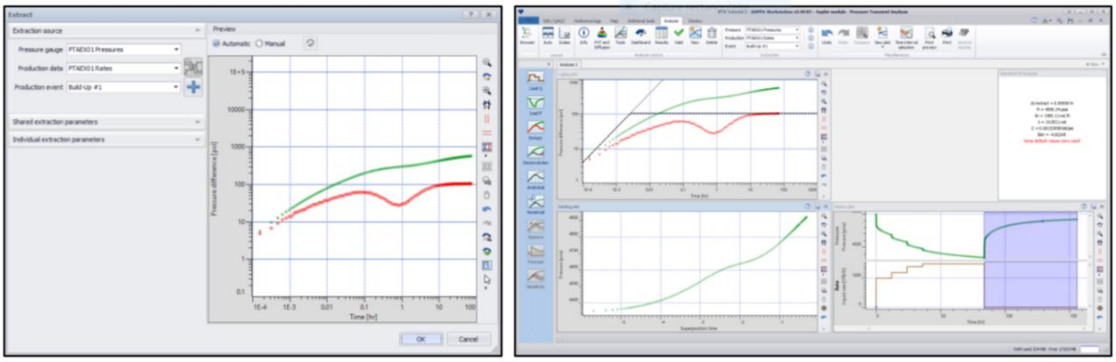


Figure III.9 extract Δp

Double clicking on the loglog plot title bar maximizes it, bringing additional options in the ribbon. Among them, the ‘Show tool parameters’ displays the wellbore storage, skin and permeability results related to the unit slope and horizontal lines. Moving any of these lines updates the corresponding parameter. Moving any line with the ‘Ctrl’ key pressed actually moves both at the same time.

After this, pressing the ‘Automatic Analytical’ option will generate the homogeneous infinite model, taking the current values of C, S and k.

As mentioned previously, such default behavior can be overridden with the Analysis Tools.

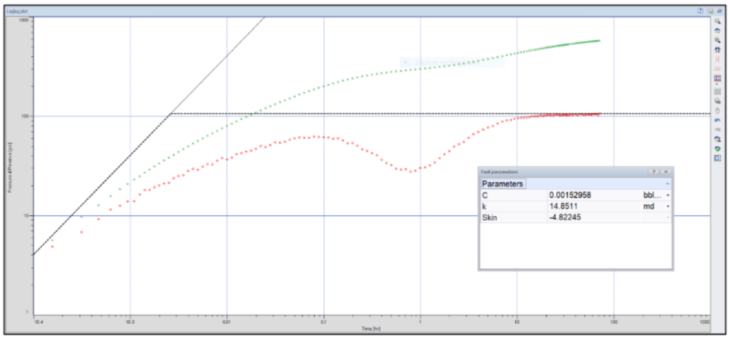


Figure III.10 log-log plot

5-Analysis tools

The behavior of the derivative shows an early time half slope, that we will attribute to a fracture, and a transition that we will attribute to double-porosity. Click on ‘Tools’, , in the ribbon at the top.

This recalls the Analysis tool dialog, Step 6 of the new document wizard (below, left). Change the Well model to ‘Infinite conductivity fracture’ and the Reservoir model to ‘Double-porosity PSS’. Click on **ok** to validate.**[19]**

We are back to the loglog plot (below, right). Two parallel half slope lines and a transition curve were added. The unit slope is now in blue and the IARF position is also controlled from the vertical level of the transition line. Additional parameters are displayed in the tool parameter box.

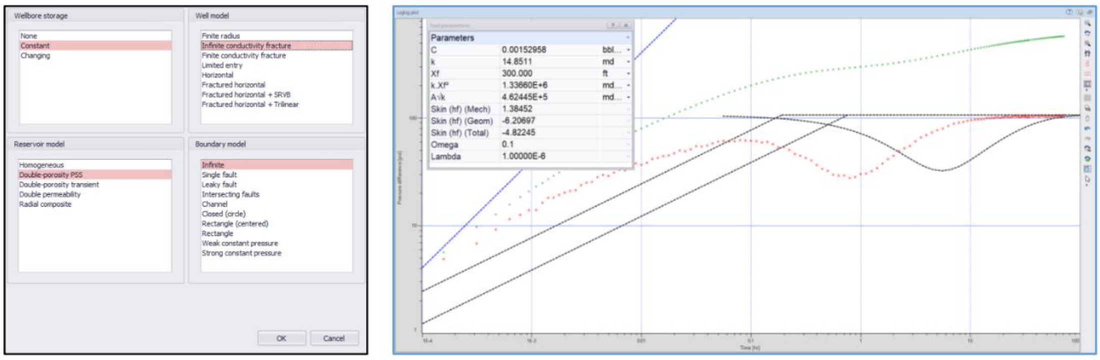


Figure III.11 standard models option

Since the well model is not vertical anymore, the single skin value is decomposed into its three constituents:

1. Total Skin: The total skin is computed from a semilog straight line drawn in the background.
2. Geometrical Skin: The computation is based on the difference in the pressure between the current well model and a fully penetrating well.
3. Mechanical Skin: Total Skin - Geometrical Skin.

The different lines and curves can now be played with, to interactively adjust the component behaviors to the data, until we get something similar to the display below.

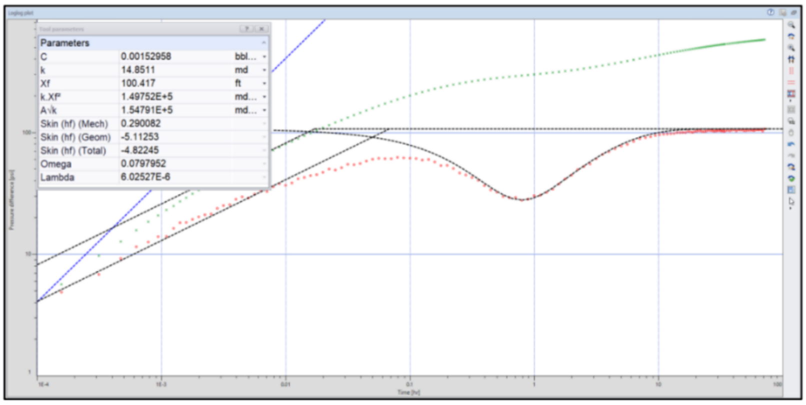


Figure III.12 matchingof standard model with the log-log

Hide the tool parameters and restore the loglog plot by double clicking on the plot title bar.

6. Manual and Automatic Analytical Model

The 'Analytical' icon in the control panel accesses the manual analytical dialog. Model and parameters have been initialized from the settings and results of the loglog analysis tool. Clicking on the **Generate** button would generate the model with these parameters, but we may as well call the automatic model directly. So, click on **Cancel** to exit the manual analytical model dialog. **[19]**

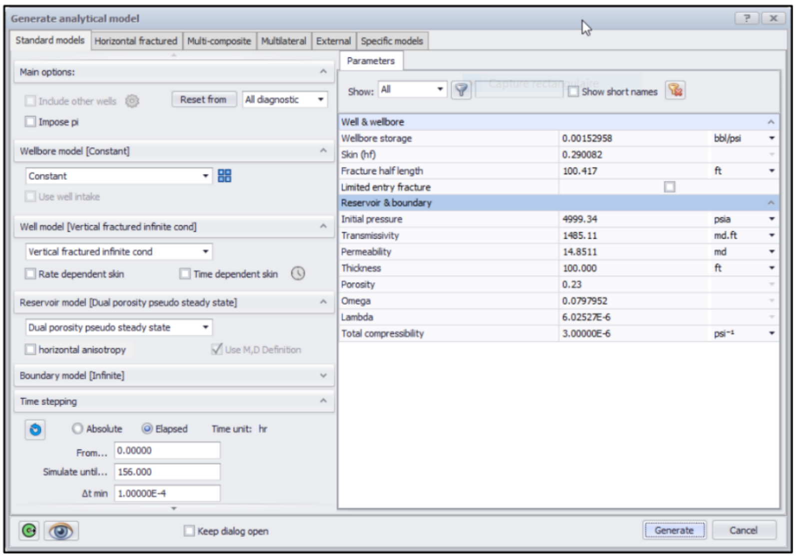


Figure III.13 analytical model generation

The ‘Automatic Analytical’ icon appears in lieu of the ‘Analytical’ icon when the shift key is pressed. In this state, click on the icon and the model is executed in a single command, with the resulting curves displayed on the three main plots.

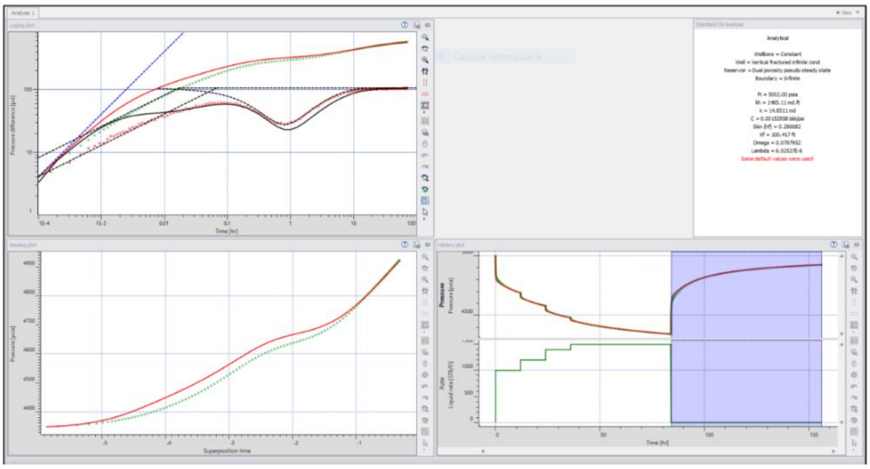


Figure III.14 Courbe analytical model processus

7. Manual and Automatic Improve

The ‘Improve’ icon in the control panel accesses the manual improve dialog with two tabs defining the parameter controls (below, left) and the targets (below, right). One can select the regression parameters, set their ranges and apply different weighting on various sections.

One may also choose between a match on the log-log or the history plot. Clicking on the **Run** button would run the regression with default settings.

The ‘Automatic Improve’icon appears in lieu of the ‘Improve’ icon when pressing the shift key.

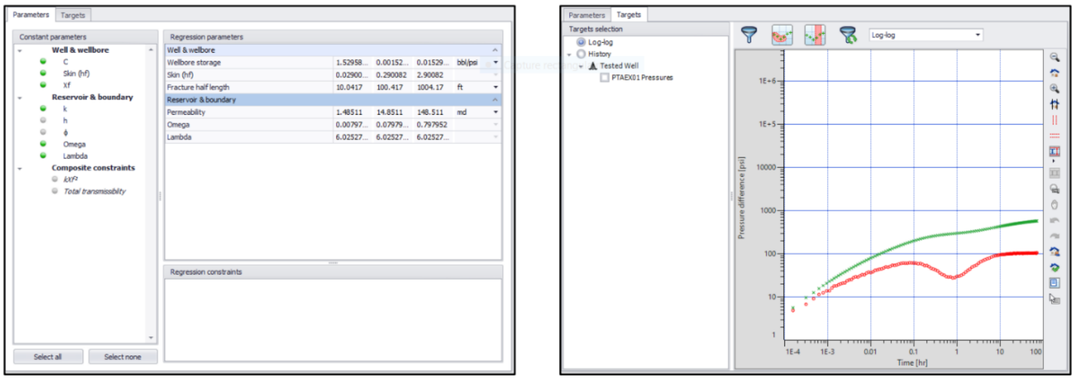


Figure III.15 improving of parameters

For this session, keep the default selection and click on **Run** The model response will be updated on the three main plots once improve has run:

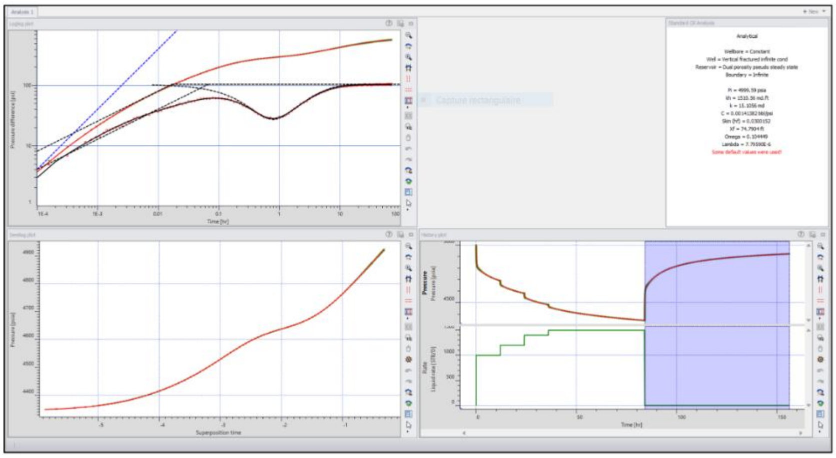


Figure III.16 the improvement in the plots

8. Straight line (specialized) Analysis

The default Saphir workflow follows the control panel options. Users can also create specialized plots and analyze individual well or reservoir behaviors by drawing appropriate straight lines on them. The corresponding parameter estimates can then be transferred to the analytical or numerical models. In this session, a Horner plot will be constructed, and the double porosity reservoir parameters evaluated from the plot.

Click on the ‘New plot’ icon in the ribbon at the top and choose ‘Horner’ from the drop down list.**[19]**

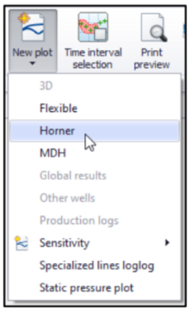


Figure III.17 straight line analysis

The Horner plot will be added to the main workspace.

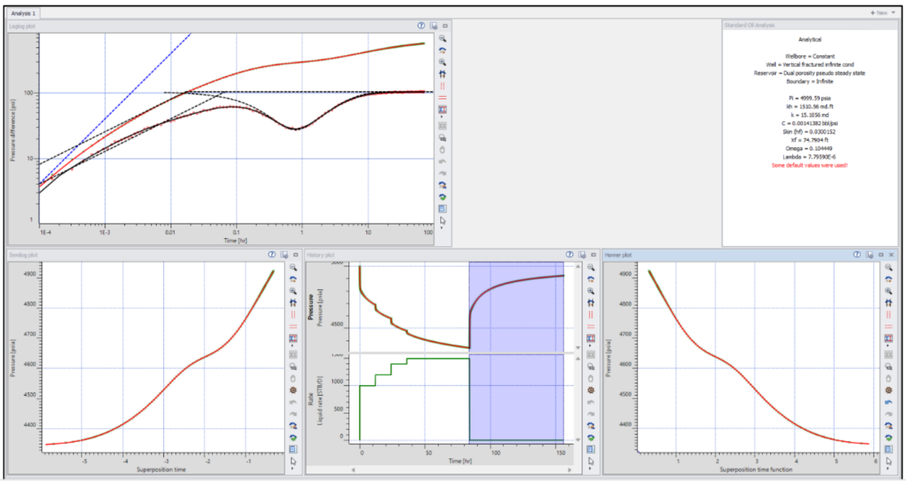


Figure III.18 addition of Horner plot

Maximize the Horner plot and click on the ‘Composed lines’ plot option in the ribbon at the top, choose ‘Double-porosity Pss’ from the list of analysis types. Three regions will be highlighted in the plot, marking early radial flow, double porosity transition and final radial flow. Adjust the highlighted regions interactively on the plot to end up with something similar to the display below, left. Validate the selection with **ok** .

Three lines now appear on the Horner plot, drawn by regressing on the data in the selected intervals (below, right).

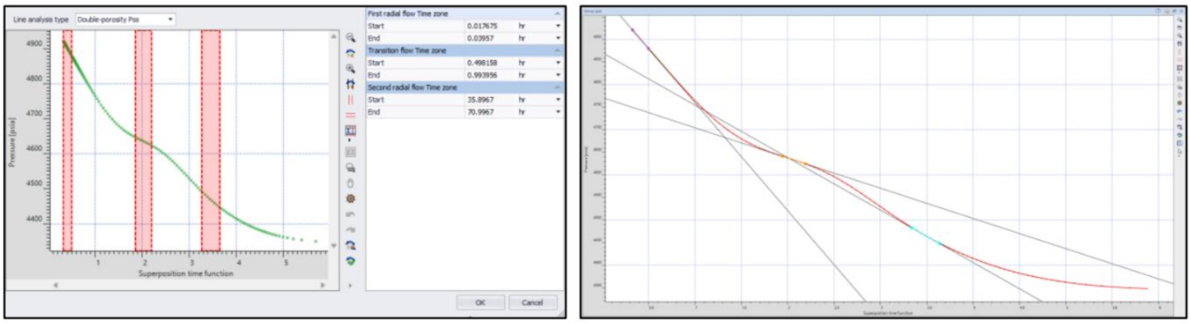


Figure III.19 horner plot options

Restore the Horner plot by double clicking on the plot title bar.

9. Introduction to the model dashboard

This option is accessible from ‘Dashboard’, in the analysis ribbon. It brings the dialog shown below. This feature allows results to be transferred from analysis tools, specialized analyses and models to the analytical and numerical models of the active analysis.

From the top set of icons on the left, the user can select the source analysis tool, the analytical model, the numerical model or any of the specialized analyses. The corresponding results are displayed in the right table.**[19]**

The destination model may be the analytical or numerical model at the bottom of the icons on the the model and execute the model at once. If for example you select the Analytical model in the top column and send to the numerical model, this will be just the same as calling the numerical model with the analytical values. However, the dashboard establishes a more flexible bridge between the different sources of results. In this session, select the Horner plot from the list of specialized analyses and click on the ‘To analytical’ icon:

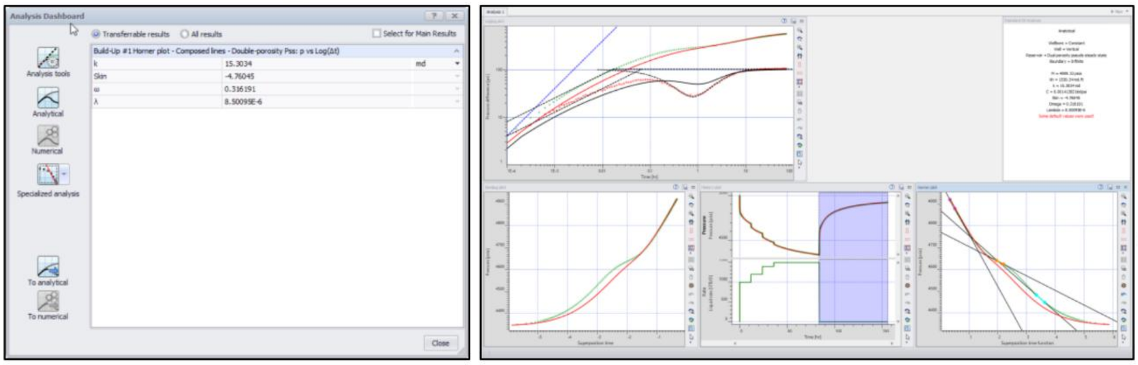


Figure III.20 model dashboard

Since the data don't show a clear early radial flow, the estimates of omega and lambda are not correct, which shows in model response. So basically, our initial model was better. Click on the 'Undo' icon in the ribbon at the top once to reset the model to the one before dashboard transfer.

10. Copying analysis

Before proceeding any further, let us create a copy of our work so far. Click on 'New', in the ribbon at the top. The following options are displayed, allowing the user to select the elements of the existing analysis to copy over to the new one:

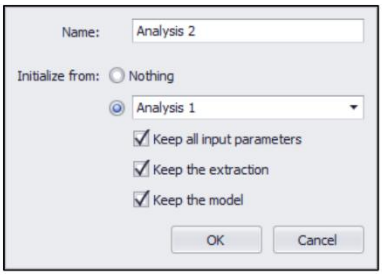


Figure III.21 Copying analysis

For this exercise, keep the default options checked. A duplicate of the existing analysis, called 'Analysis 2', will be created upon validation.

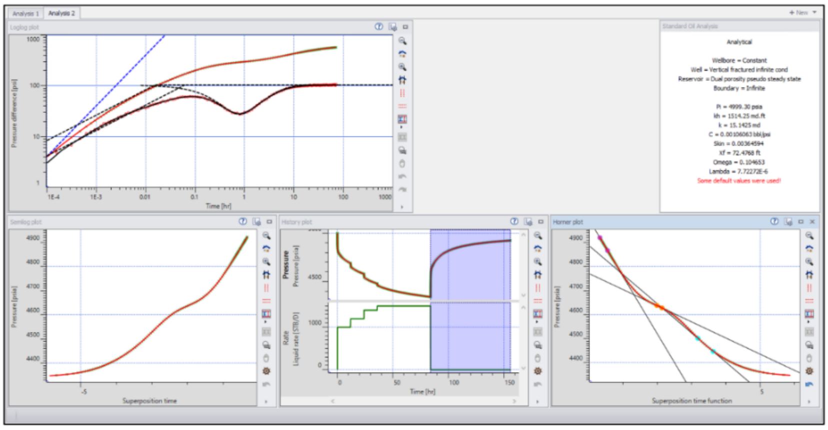


Figure III.22 coping analysis processus

11. Numerical model

In ‘Analysis 2’, click on ‘Numerical’ to access the manual numerical model dialog:

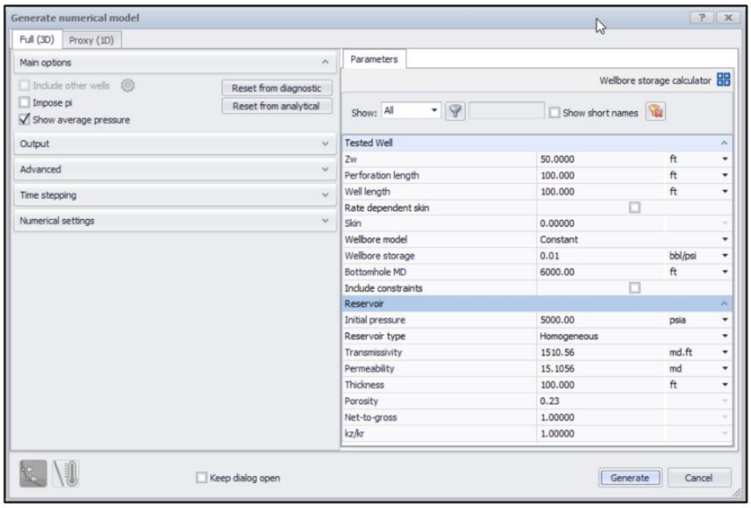


Figure III.23 numerical model generation

The numerical model can be defined automatically based on the diagnostics (analysis tools) or from the analytical model.

To initialize the numerical model from the analytical one click on **Reset from analytical** and click on **Generate**.

In addition to the model response at the well, a 3D plot with the reservoir geometry, the static and dynamic reservoir properties is also generated. The boundary model was reset to a square, the default numerical model contour. Had the analytical model included an outer boundary, this would have been copied instead.

With a numerical model initialized it is possible to consider many more complex options either geometrical (in the map ribbon), related to the fluid behavior (PVT), etc. This is not the intention of this tutorial. **[19]**

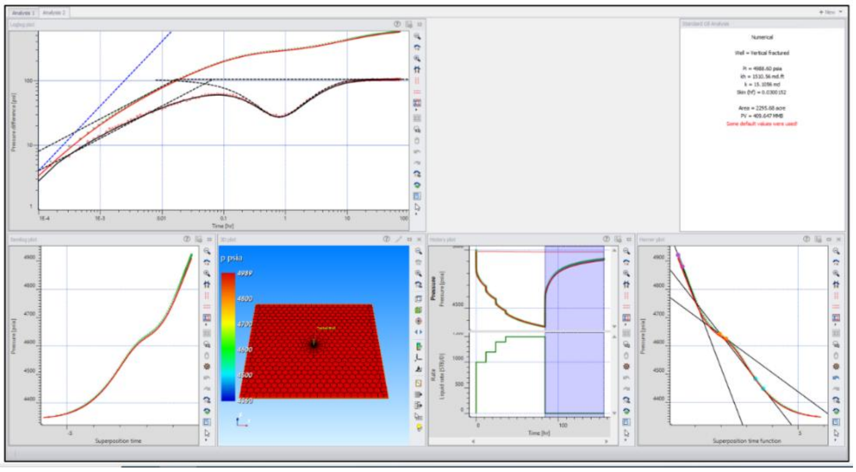


Figure III.24 numerical model

12. Sensitivity

So far, we have been dealing with single values of input parameters. In reality, these values are not known with absolute certainty. To evaluate the impact of the uncertainty in some model parameters on the model response and other parameters, a sensitivity can be run.

Let us go back to 'Analysis 1', where we had our analytical model. Click on 'Sensitivity', , to access the sensitivity dialog. Different type of sensitivity calculations can be run. Click on 'F1' in the sensitivity dialog to read about the different methods available.

For this exercise, select the 'Monte-Carlo + Improve' method and check 'ϕ' from the list of 'Variables' - keep the porosity distribution as default, as shown below, left.**[19]**

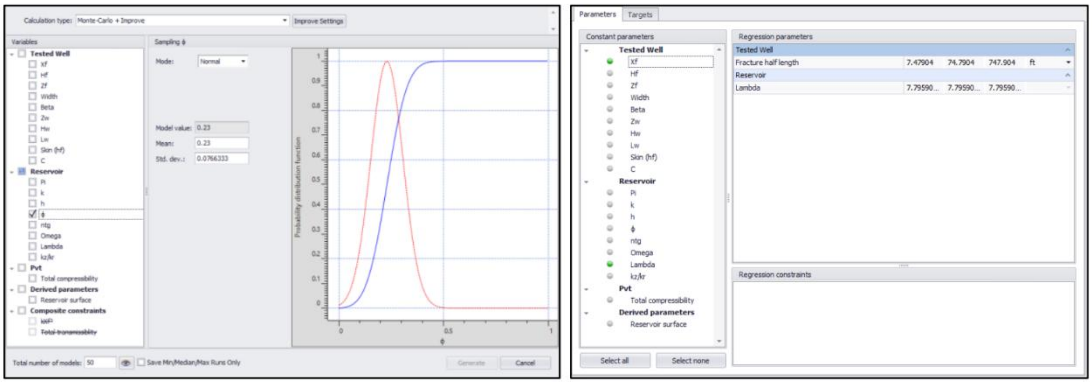


Figure III.25 Sensitivity prosseus

Click on **Improve settings** and select ‘Xf’ and ‘Lambda’ as regression variables as shown above, right. Validate the selection with **ok**. Keep the ‘Total number of models:’ to the default 50 and click on **Generate** to run the sensitivity.

From the sensitivity variable distributions defined, 50 samples will be taken to run the model following by an improve on the model with Xf and λ as regression variables.

The computation of the various responses is executed in parallel on a multicore PC and the results are displayed on the sensitivity loglog plot, which will automatically be created. The plot shows that the improve algorithm could match the data well for most runs with the current setup.

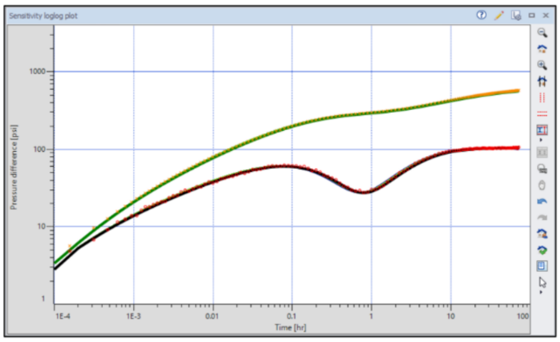


Figure III.26 Sensitivity results

To view the distribution of the objective function, create a ‘Sensitivity: Histogram’ plot from the ‘New plot’ list as shown below, left.

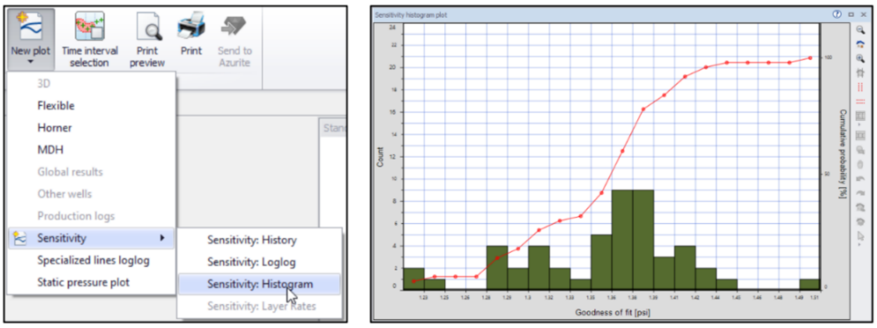


Figure III.27 Sensitivity options

The histogram plot shows that most runs could converge well on the data (the histogram plot will be different depending on the Monte-Carlo sampling and improve efficiency). This can also be verified on the scatter plot. Maximize the histogram plot and click on 'Scatter plot', in the plot options at the top.

The scatter plot shows, by default, the objective function against the sensitivity parameter, porosity in this case, as shown below, left. The 'Y-axis' could also be changed to the regression variables to see how they vary with the sensitivity parameters to obtain the model match. **[19]**

When the Y-axis is set to goodness of fit (based on the least squares distance between data and model), a red line threshold is also shown; this line can be interactively moved by the user. Points falling below this line (shaded in black) will be reported in the sensitivity results only. The blue point shows the model value.

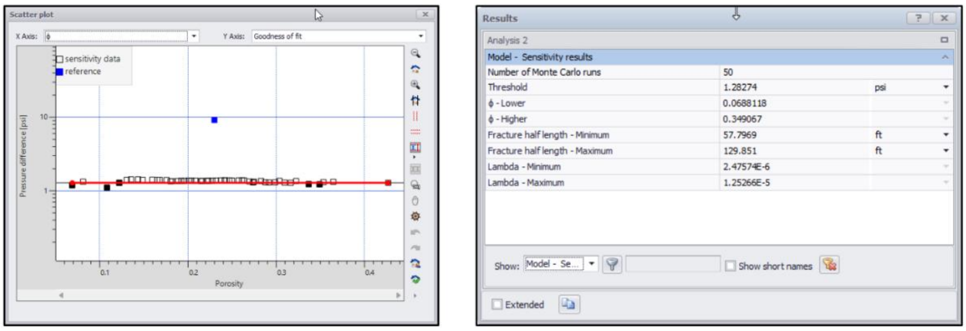


Figure III.28 histogram plot

Close the scatter plot and restore the histogram plot. Click on ‘Results’ in the ribbon at the top and display sensitivity results. The ‘Minimum’ and ‘Maximum’ values of the regression variable as well as the ‘lower’ and ‘higher’ values of the sensitivity variable are displayed in the results.

If the threshold line is modified, these values will be affected. These values will differ because of the Monte-Carlo sampling and improve efficiency.

Chapter IV

CaseStudy

Introduction:

In this part of the chapter four we will study a case of well that tested by a test (DST est) and we will do the analyzing and the interpretation by the software of Saphir that explained in the last chapter and we lean about the characteristics of the well,reservoir and the boundary of this reservoir, in addition to the model of each part of this series.

2. Geographiclocation:

The region of Rhourde - Nouss is located in the wilaya of ILLIZI, 280 km south-east of Hassi-Messaoud, and approximately 1000 km from ALGIERS, and is positioned between:
29°16' and 30° parallel.
06°24' and 07° meridian.
It is limited to the north by the region of GASSI-TAOUIL, to the south by the regions of HAMRA and TIN-FOUYE TABANKORT.**[20]**

3. Geologicallimits:

The Rhourde Nouss region is located on the southern edge of the Triassic basin. It is limited:

- ✓ To the West, by the Amguid -El Biod mole at the level of the Ramade fault. This mole presents a vast submeridian structural unit extending over 600km going from Amguid in the south to Rhourde El Baguel in the north.
- ✓ to the North East, by the Ghadames basin towards which the SW-NE axes of the RhourdeHamra and RhourdeChouff structures extend.
- ✓ To the South-East by the western part of the Ahara mole.**[20]**

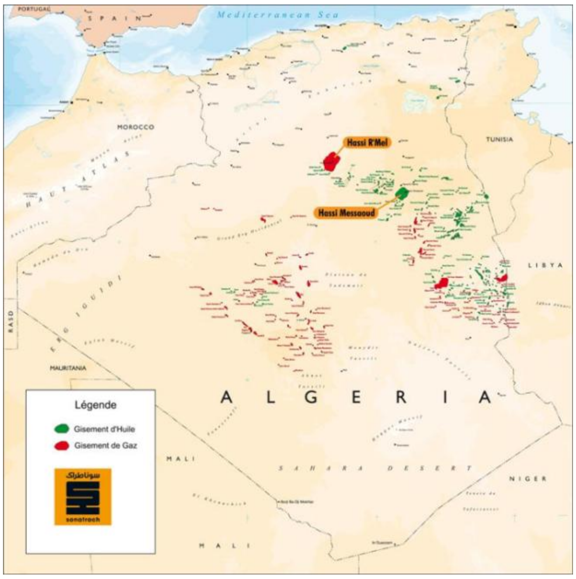


Figure VI.1 geological limits

4. Aspect structural:

The structure of Rhourde-Nouss is very complex. Two families of faults can be distinguished, the first family in a North-South direction and the second in a North-East, South-East direction. **[20]**

This structure would be 40 x 30 km2 in size, it is made up of four different structures to know:

1. RhourdeNouss Central (RNC)
2. RhourdeNouss South-East (RNSE)
3. RhourdeNouss South-West (RNSW)
4. Rhourde Adra (RA)
5. Rhourde-Nouss North-East (RNNE)
6. Rhourde-Chouff (RC)

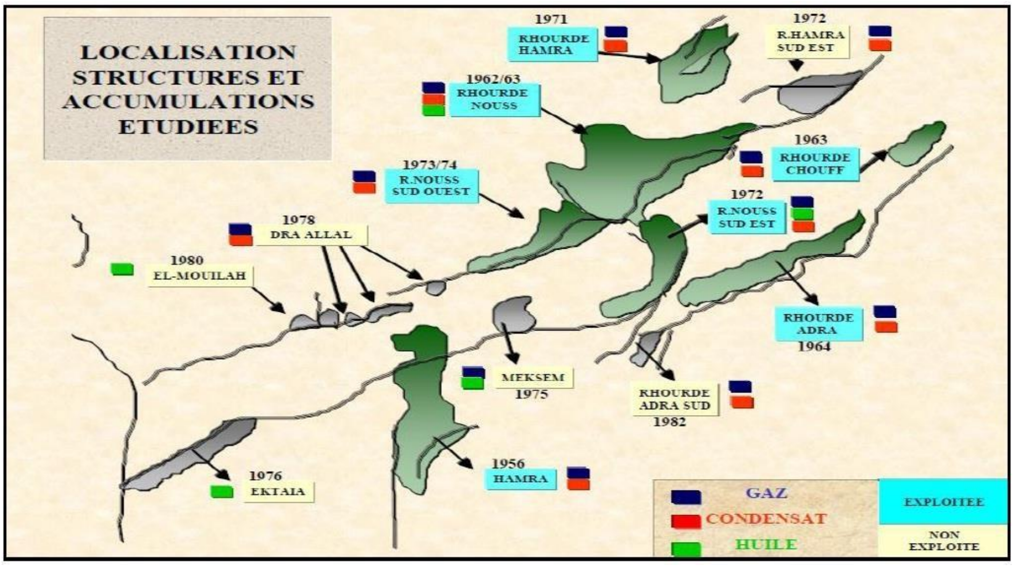


Figure VI.2 structure localisation and accumulations etudiees

Rhourde Chouff (RC)

This structure is aligned to the east of RNC over an area of 11 km2. The number of wells drilled in the reservoir is 5 wells, drilled in the Upper Triassic Clay Sandstone (TAGS).

5. Aspect stratigraphique :

the trias :

Considered as one of the drilling objectives, the Triassic in the region is represented by TAGS, Middle Triassic II, Middle Triassic Intermediate I and Lower Triassic for a total thickness of 389 m.**[20]**

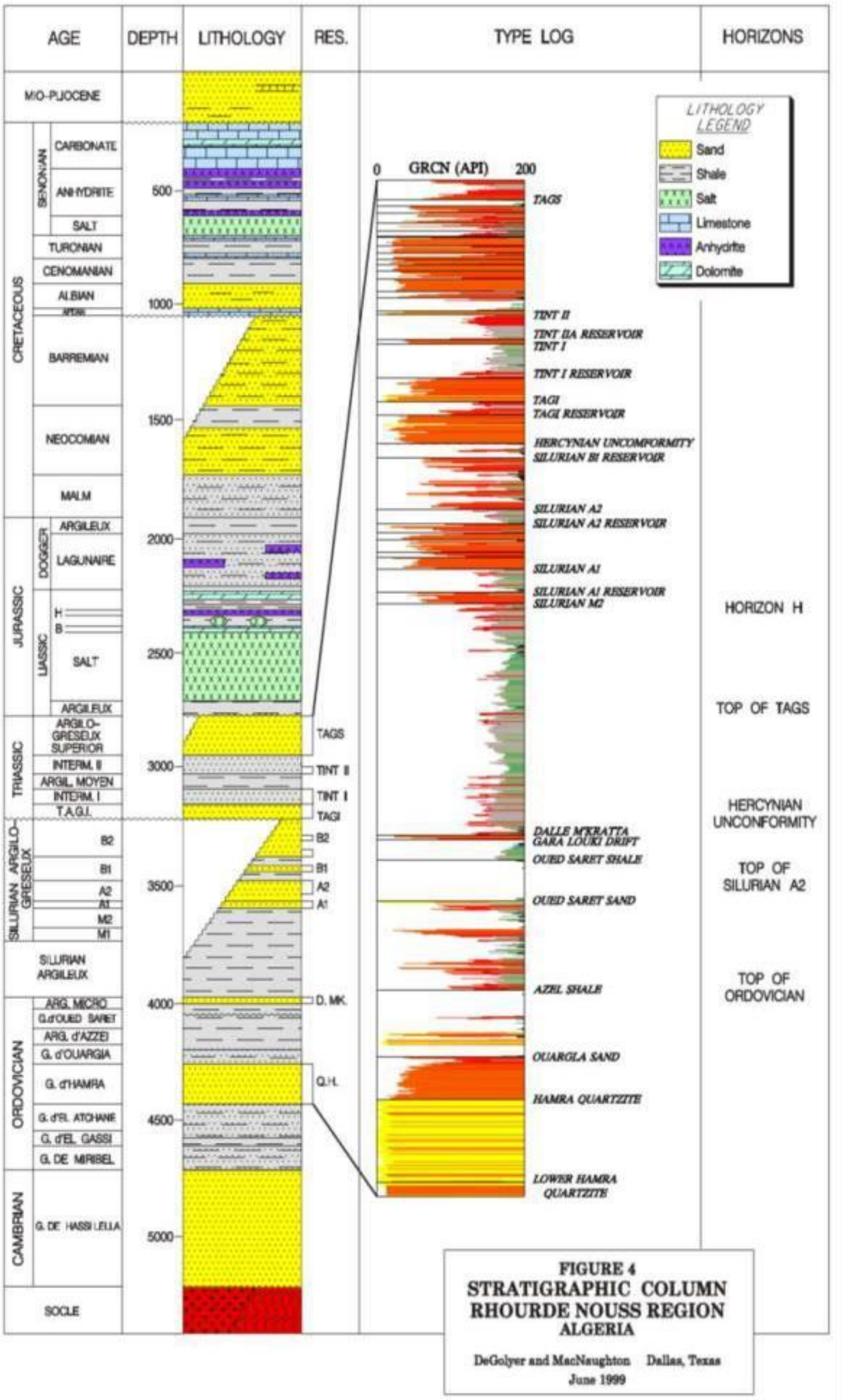


Figure VI.3 stratigraphic column Rhourde nouss

6. Well information :[21]

Compagnie : Sonatrach-DP RNS

Pays : ALGÉRIE

Province : Rhourd Enouss

Puits : RC -05

Rig / Installation : ENF 17

Table VI-01 : well informations [21]

Type de Puits	Vertical
Type de fluide	Condensate
Type de Complétion	N/A
Diamètre du Casing	7"
Restriction minimale	2.25"
Degré de déviation	0
Taille de drill pipe	3 1/2"
Côte forage	3036m
shoe 7"	2864m

Informations operationelles :[21]

Depth reference : rotation table

Recorder measuring point : 2604.43 m

Rib packer : 2615.4 m

Bottom packer : 2616 m

High packer : 2613 m

Well test report :[21]

	Separator setting						
Chock size 24/64"	Oil Meter Type / Size Tank Metering	Orifice Plate 1.500	Gas Meter Run Size 5.761	Separator type 1440 psi		Tank Capacity $25m^3$	Tank SAP N/A

	Wellhead Data		Gas Metering					Oil Metering						Ratios	
Time hh:mm (24 Hr Clock)	Wellhead Pressure Kg/cm2	Wellhead Temp (ºC)	Sep Pressure Kg/cm2	Diff Pressure (inH2O)	Gas Temp (ºC)	Gas Gravity (Air=1)	Gas Rate (sm^3/hr)	Oil Temp (ºC)	Tank Reading Cm	Tank Readings m3	Oil Rate (m^3/hr)	Oil Gravity SG @ 60 F	Water Rate (L/hr)	BS&W (%)	G.O.R. (sm^3/sm^3)
12:15	94.92	42	-	-	-	-	-	-	-	-	-	-	-	-	-
12:24	Diverted well flow through test separator.														
12:25	Commenced flow rate calculation .														
13:00	94.92	42	52.73	100.0	25.0	0.684	4568.027	15.0			0.720	0.711	13	0	6344.482
13:30	94.92	42	52.73	100.0	30.0	0.684	4610.010	15.0			0.720	0.711	13	0	6402.792
14:00	94.92	42	54.84	100.0	30.0	0.684	4610.010	15.0			0.720	0.711	13	0	6402.792
14:30	94.92	42	54.84	100.0	30.0	0.696	4582.850	15.0	18.00	2.160	0.720	0.711	13	0	6365.069
15:00	94.92	42	54.84	100.0	30.0	0.696	4582.850	15.0			0.720	0.712	13	0	6365.069
15:30	94.92	43	55.54	100.0	30.0	0.696	4615.720	15.0			0.720	0.711	13	0	6410.722
16:00	94.92	42	55.54	100.0	30.0	0.696	4615.720	15.0			0.720	0.712	13	0	6410.722
16:00	Bypassed test Separator														
Average	94.92	42.14	54.44	100.00	29.29	0.691	4597.884	15	N/A	N/A	0.72	0.711	13	0	6385.950

Figure VI.04data listing for 24/64" choke size

	Separator setting						
Chock size 28/64"	Oil Meter Type / Size Tank Metering	Orifice Plate 1.750	Gas Meter Run Size 5.761	Separator type 1440 psi		Tank Capacity $25m^3$	Tank SAP N/A

	Wellhead Data		Gas Metering					Oil Metering						Ratios	
Time hh:mm (24 Hr Clock)	Wellhead Pressure Kg/cm2	Wellhead Temp (ºC)	Sep Pressure Kg/cm2	Diff Pressure (inH2O)	Gas Temp (ºC)	Gas Gravity (Air=1)	Gas Rate (sm^3/hr)	Oil Temp (ºC)	Tank Reading Cm	Tank Readings m3	Oil Rate (m^3/hr)	Oil Gravity SG @ 60 F	Water Rate (L/hr)	BS&W (%)	G.O.R. (sm^3/sm^3)
11:45	82.96	43	-	-	-	-	-	-	-	-	-	-	-	-	-
11:58	Diverted well flow through test separator.														
12:30	Commenced flow rate calculation .														
12:30	82.96	43	52.73	85.0	29.0	0.698	5656.390	22.0			0.405	0.714	25	0	13966.395
13:00	82.96	43	52.73	88.0	30.0	0.698	5740.910	22.0			0.405	0.714	25	0	14175.086
13:30	82.96	43	52.73	88.0	32.0	0.698	5712.180	22.0			0.405	0.714	25	0	14104.148
14:00	82.96	43	52.73	88.0	34.0	0.698	5684.000	22.0	13.50	1.620	0.405	0.714	25	0	14034.568
14:30	82.96	43	52.73	88.0	35.0	0.698	5670.110	22.0			0.405	0.714	25	0	14000.272
15:00	82.96	43	52.73	88.0	35.0	0.698	5670.110	22.0			0.405	0.714	25	0	14000.272
15:30	82.96	43	52.73	88.0	35.0	0.690	5693.160	22.0			0.405	0.715	25	0	14057.185
16:00	82.96	43	52.73	88.0	35.0	0.690	5693.160	22.0			0.405	0.715	25	0	14057.185
16:00	Bypassed test Separator														
Average	82.96	43.00	52.73	87.63	33.13	0.696	5690.003	22	N/A	N/A	0.405	0.714	25	0	14049.389

Figure VI.05data listing for 28/64" choke size

The pressure plot :

By loading the pressure versus time date in saphir we will get and obtain at this below plot

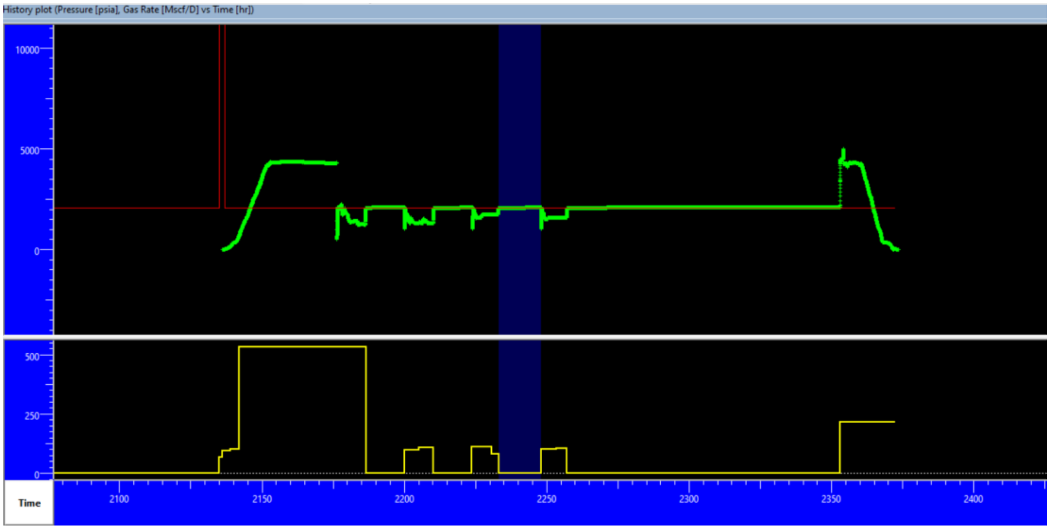


Figure VI.06plot of pressure vs time

The flow rate plot :

Table VI-04: the data of the flow rate versus time of the test

Date	ToD	FP #	Gas rate Mscf/D	Duration hr
11-08-2021	15:00:00	1	0	2135
08-11-2021	14:00:00	2	66.9527	1
08-11-2021	15:00:00	3	95.2073	3
08-11-2021	18:00:00	4	100.533	3
08-11-2021	21:00:00	5	532.546	44.5
10-11-2021	17:30:00	6	0	13.5
11-11-2021	07:00:00	7	96.5091	5
11-11-2021	12:00:00	8	107.811	5.2
11-11-2021	17:12:00	9	0	13.5
12-11-2021	06:42:00	10	111.509	7
12-11-2021	13:42:00	11	81.7989	2.4
12-11-2021	16:06:00	12	0	15
13-11-2021	07:06:00	13	101.509	5.4
13-11-2021	12:30:00	14	103.556	3.5
13-11-2021	16:00:00	15	0	96
17-11-2021	16:00:00	16	216.716	19

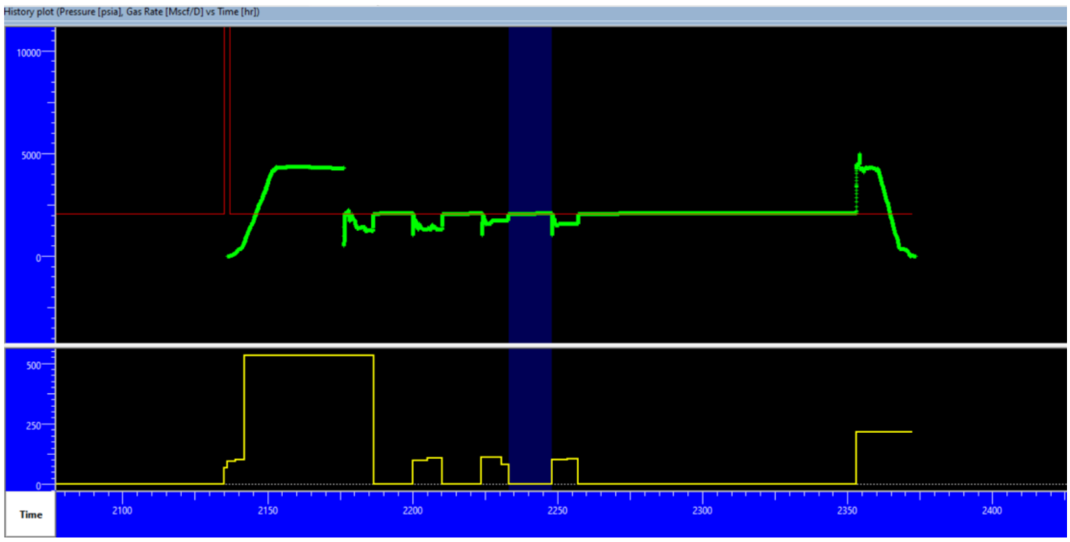


Figure VI.07plot of flow rate vs time

Extract Δp:

After loading the pressure and flow rate data, we choce the build up 03 thene we extract Δp which represent the pressure and the derivative plot.

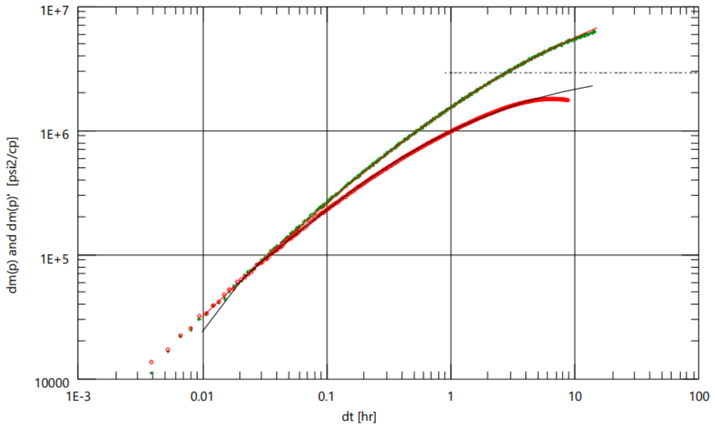


Figure VI.08Extract Δp derivative plot

7. The results :

Table VI-02 : the results of saphir software

Modele option		**Standard model**
Well model		**Vertical**
Reservoir model		**Homogenoues**
Boundary model		**Infinte**
Well and wellbore parameters	**C (bbl/psi)**	**0.189**
	Skin	**-4.2**
Reservoir and boundary Parameters	**Pi (Psi)**	**2130.2**
	Kh (md.ft) **K (md)**	**13.2** **0.161**
	Rinv(ft)	**53**

8. The interpretation :

The **buildup 03**period from DST test explain to us that we have a vertical well with a constant wellbore storage and the type of the reservoit is homogeneous model .

Discussion of the calibration results:

The curve of the derivative represents 3 flow periods:

1. Early time: The model is calibrated constant wellbore storage explained by the unit straigth line slop in the begginig of the build up period, the skin factor is negative so the well is stimulited and have a good connection between the compressible zone produced and the well bore .

2. Middle time: The timing shows the behavior of a homogeneous reservoir with a faible permeability and small conductivity.

showing a smooth transition from early-time wellbore storage effects to later-time radial flow, is consistent with a homogeneous reservoir model. Heterogeneous reservoirs often display more complex pressure behaviors and deviations from the idealized trends seen in homogeneous reservoirs.

3. Late time: The timing shows a IARFinfinte acting radial flow explained by the half slop (**1/2**).

GeneralConclusion

Recommandation:

- The well represents average characteristics with a negative skin (s= -4.2) so the well is stimulited .

we saw that the permeability is poor (k= 0.161 md) and the product thickness (kh = 132 md.ft).

- There are several causes of the poor permeability depend of the nature of the reservoir rock like the clay swelling, fine grained sediments, the bonding of mineral grains by natural cements …etc .

Therefore, from those results we find that the productive layer of this well requires a solution to increase the connection between the reservoir and the well bore and imroving the meduim flow.

Several operation are used for example acidizing or a hydraulic fracturing, horizontal drilling , the chemical stimulation like surfactants and polymers (the wettability of the rock)…ect, these methods are selected based on the specific characteristics of the reservoir , to improving the productivity and the performance of the well.

- The boundary response shows that there is a radial flow and infinte reservoir .

Conclusion

Our project has explored the fundamental aspects of well testing, focusing on various methods used in the interpretation of well test data.

Well testing is a critical component in reservoir engineering, providing essential information about reservoir properties and well performance. Different interpretation methods, including conventionell and modern methods, have been examined to highlight their principe and respective advantages and limitations.

In other side,we detailed the application of Saphir software, a robust tool for well test analysis. Saphir facilitates the interpretation process by offering advanced features such as automatic type curve matching, derivative, and multi-well analysis.

Through its comprehensive suite of tools, Saphir enables engineers to derive meaningful insights from well test data, including permeability, skin factor, and reservoir boundaries.

Acase study was conducted on a specific well Rc-05 to demonstrate the practical application of these interpretation methods and the use of Saphir software.
The case study provided a step-by-step analysis, from data acquisition to the final interpretation, showcasing the workflow and the interpretive power of the software.

The results from the case study highlighted the well's performance characteristics and the reservoir's propertieswhere identified the models of the well, reservoir and the boundary.

Finally, we found and learned about the characteristics of the well, which included a negative damage factor and weak permeability linked to a weak production index.

According to these results, the well needs several operations in order to enhance permeability, such as :

- ✓ hydraulic fracturing
- ✓ horizontal drilling

in order to improve production and optimal exploitation of the layer producing condensed gas.

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