PEOPLE'S DEMOCRATIC REPUBLIC OF ALGERIA

Ministry of Higher Education and Scientific Research

Serial No: .... /2022

Kasdi Merbah Ouargla University

Faculty of Hydrocarbons, Renewable Energy and Earth and Universe Science

Hydrocarbon Production Department

Graduation Thesis

To obtain the Master's degree

Option: Production

Presented by:

AMRAOUI RATIBA, MAHMOUDI YASSIN DJALLEL, MESBOUT MOHAMED

Theme:

Application of Interference Tests in Optimization Of the Productivity Index for an Oil Field

Defended: 07/06/2022 in front of the examination committee

Jury:

President: Mr. BOUCHIREB OUAHAB	**M.A.A**	Univ.Ouargla
Examiner: Mr.MILOUDI MUSTAPHA	**M.A.A**	Univ.Ouargla
Supervisor: Mdm. HAFSI FADILA	**M.A.A**	Univ.Ouargla
Co-Supervisor: Mr.ANNOU AHMED	**Enseignant**	Univ.Ouargla

2021/2022

Thanking

Now is the time to put an end to this manuscript and these years of research work We thank, first of all, Allah the Almighty for having given us the will and the patience to carry out this modest work.

We would also like to express our deepest gratitude to our supervisor MDM **HAFSI FADILA** and Mr. **ANNOU AHMED** for the time they devoted to us and the help that brought us despite their occupations.

We would like to thank Mr. **Bouchireb Ouahab** for the honor of agreeing to chair the jury for this thesis.

We also present our deepest gratitude to Mr.**MILOUDI Mustapha** who accepted to examine this work.

AMRAOUI Ratiba, MAHMOUDI Yassin Djallel, MESBOUT Mohamed.

DEDICATIONS

"Praise be to God, the one and only"

To my very dear parents, brothers, sisters

And all my friends.

To all those who participated directly or indirectly to accomplish this work to all those we love, we dedicate this modest work to you.

Thanks

AMRAOUI Ratiba, MAHMOUDI Yassin Djallel, MESBOUT Mohamed.

الملخص

يرتكز مجهود الشركات البترولية في شقه المتعلق بتطوير المنظومة الإنتاجية للآبار والحقول النفطية، بشكل أساسي على تحسين مؤشر الإنتاجية بكل الطرق الممكنة، سواء بالتجارب الميدانية أو عن طريق تطوير برامج المحاكاة. ويشكل التداخل بين الآبار بسبب التشققات و تقاطع الأبعاد الجيولوجية للمكامن النفطية (قطر الاستخراج)؛ تحدياً كبيراً للتحكم في منظومة الاستخراج للحقل بسبب التأثيرات الناجمة عن تشغيل أو توقف مجموعة من الآبار بشكل اختياري أو اضطراري، و ما يترتب عنها من إختلالات في مؤشرات الإنتاج بسب التداخل بينها. تعتبر تجارب الآبار من أهم الأدوات المستعملة في قياس مؤشرات الأداء للآبار أو الحقل، كما أنها أهم مفاتيح تحليل سلوك الخزان و التعرف عليه بشكل معمق، و من بين هذه التجارب تبرز تجارب التداخل ؛ التي هي موضوع هذه الدراسة، حيث سنحاول إبراز أهمية تحليل و تفسير البيانات المستخرجة من هذه التجارب وكيفية استغلالها في تحسين إنتاجية الحقل البترولي .

Abstract

Interference Tests is a Well test operation which allows to characterize the connectivity between the producing wells and the injector wells for a Block or oil field. The analytical principle of these tests is based on the selective opening and closing of a certain number of producing wells assisted by a Characterized injection of the injector wells, with the aim of determining the impact of these manipulations on production. The results of the interference well tests are directly linked to the number of open wells and the duration of each opening. In the exploitation phase, the productivity index of the oil field can be optimized following the proper application of the data obtained in the interference well test.

Résumé

Les Tests Interférences c'est une intervention sur le puits, qui permet d'effectuer quelques mesures dynamiques, afin de caractérisé la connectivité entre les puits producteurs et les puits injecteur pour un block ou champ pétrolier. Le principe analytique de ces tests ce base sur l'ouverture et fermeture sélective d'un certain nombre de puits producteurs assistés par une injection Caractérisée des puits injecteurs, dans le bute de déterminer l'impacte de ces manipulation sur la production. Les résultats du Well Tests Interférences, sont liés directement aux nombres de puits ouverts et à la durée de chaque ouverture. En phase d'exploitation l'indice de productivité du champ pétrolier, peut être optimisé suit à la bonne application des donnés obtenus dans le well teste interférence.

Figure list

Table list

Nomenclatures

***β*o**: Background Volumetric Factor (Oil) (bbl/STB).	***v*:** The speed, (ft/s²).
***β*w**: Background Volumetric Factor (Water) (bbl/STB).	***Z*:** Compressibility factor
***P**:** The extrapolated pressure, (psi).	***cj*:** The compressibility of fluid j, (Psi-1).
φ: The porosity, fraction.	***β*:** Background volumetric factor (bbl/STB).
rw : Well radius, (ft).	***rf*:** Radius of water front, (ft).
s: The skin effect,	***ro*:** Initial water front radius, (ft).
re: Drain radius (ft).	**Ei:** The Exponential integral
c: The capacity effect, (bbl/psi).	**γ :** Euler's constant, 0.5,772,156
tp: The production time, (hr).	***Et*:** The overall scanning efficiency.
tp: Pseudo time.	**ES**: Surface efficiency.
Δte: The equivalent time, (hr).	**EV**: Vertical efficiency.
(*p*): Pseudo pressure.	**NP**: The cumulative oil production.
A: Section, (ft2).	**Ni**: Oil production in layer i
***V*:** The volume, ft3..	r^2: $at+r^2$
r_f:Rayondefrontd'eau,(ft).	***qi***: Injection flow rate, (STB/day).
r_o: Rayondefrontd'eauinitial, (ft).	***qj***: Fluid flow j, (STB/day).
r_{tw}: $0.000264k_wt/(\phi\mu_wc_1)$	***k***: The permeability, (md).
r_{to}: $0.000264k_ot/(\phi\mu_oc_2)$	***krj***: The relative permeability of fluid j.
Ei: l'intégraleExponentiel	***kj***: The effective fluid permeability j, (md).
Pj: The fluid pressure j, (psi).	**μ*j***: The viscosity of fluid j, (cp).
Pi: The initial pressure (psi).	***ρj***: The fluid density j, (lb/ft3)
PC: The capillary pressure (psi).	***Fd*:** The fractional flow rate of displacing fluid, fraction.
Pws: Downhole Pressure During Well Closure, (psi)	***hi***: The thickness of layer i, (ft).
ki: Permeability in layer i (md)	***λj***: The fluid mobility j, (md/cp).
μ0: The oil viscosity (cp).	***M***: Mobility ratio,
μ: The viscosity (cp)	***Sj***: The Saturation of fluid j, (lb/ft3).
	***Swi*:** Initial Water Saturation, (lb/ft3).
	Swf: Final water saturation, (lb/ft3).

Summery

General Introduction

Improving the productivity index of oil reservoirs is one of the most important challenges that Oil Producing companies are working on ; by recruiting the human qualifications' and technical capabilities, and allocating the necessary funds to develop the production system, during the virtual life of the reservoir ; starting from natural depletion, passing through enhanced production, then the stages of improved recovery.

The well test services are one of the most important tools used in the oil industry in order to determine the technical values of production indicators ; their multiplicity and diversity (well test), allows access to an in-depth knowledge of the characteristics of the reservoir, in terms of homogeneity and heterogeneity, diversity of porosity and permeability, the presence of overlap and connectivity between wells and blocks, in addition to the possibility of characterizing the interference patterns' and optimizing the interference factors wishes affects the productivity index.

We will try through this modest study, using the theoretical knowledge's gained during the course of university study, as well as the information's that we found during the desk research; to highlight and improved the importance of applying the results of well tests, especially those related to interference; in improving the productivity indicator and controlling the production indictors during the stage of exploiting the reservoir.

In the applied part of this research, we presented very recent applied examples of types of well tests related to interference, to give practical importance to this study, which we hope will rise to the level of research studies related to petroleum production and reservoir engineering.

Chapter I

productivity index

I.1. Introduction:

The production engineering is the process of extraction of the hydrocarbons from the reservoir underground during its life to the surface, where we separate the mixture of hydrocarbons to oil, gas and water and removing solids and constitution which are not saleable. The exploitation of reservoir goes on a long period of production passing from natural depletion to the enhanced recovery (EOR).

I.2. Drive mechanisms:

The quantities of hydrocarbons in place are determined from geological and geophysical data in connection with the logs as well as the values obtained for porosity, saturation and the study of the fluids.

The quantities in place are classified according to various criteria that vary over time, depending on the gradual knowledge of the deposit obtained mainly from drilled wells as well as additional geophysical and/or geological studies.

There are three categories:

- Probable quantities in place: structural data, interpretations of logs and pressures make it possible to consider zones as impregnated, but without complete certainty.
- Possible quantities in place: the lack of knowledge on the fluid interfaces or the extension of the fractures in certain zones leaves great uncertainty, but the presence of rocks saturated with hydrocarbons is not.
- Proven quantities in place: considered as certain (areas crossed by wells in particular).

The extraction of reservoir hydrocarbons during exploitation life passes through three phases:

- Primary recovery: The field produces thanks to its own energy.
- Secondary recovery : The field produces assisted by an external energy injection , such as (water or gas)
- Tertiary recovery: the enhanced oil recovery (EOR), use complex methods (chemical, thermal, miscible, etc.). [1]

I.2.1. Natural recovery:

The natural energy of a reservoir can be used to move oil and gas toward the wellbore. Used in such a fashion, these source of energy are called primary drive mechanisms; early determined and characterization of the mechanisms present within a reservoir may allow a greater ultimate recovery.

There are two type of primary drive mechanisms “ solution gas drive “ “gas cap drive “.

I.2.1.1. Solution gas drive:

In a solution gas drive reservoir, the oil-bearing rock is completely surrounded by impermeable barriers. As the reservoir pressure drops during production, expansion of the oil and its dissolved gas provides most of the reservoirs drive energy (**figure I.1**). Additional energy is obtained from the expansion of the gas and its associated water.

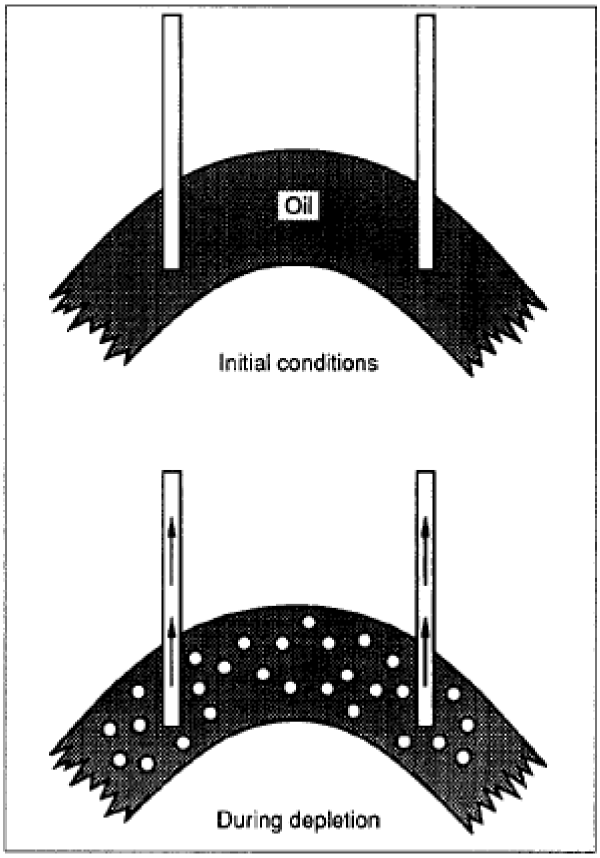


Figure I. 1 Solution gas drive reservoir.

I.2.1.2. Gas cap drive:

In a gas cap drive reservoir, the primary source of reservoir energy is an initial gas cap, which expends as the reservoir pressure drops (**figure I.2**). Additional energy is provided by the expansion of solution gas released from the oil less significant drive contributions are provided by the expansion of the rock and is associated water. [**1**]

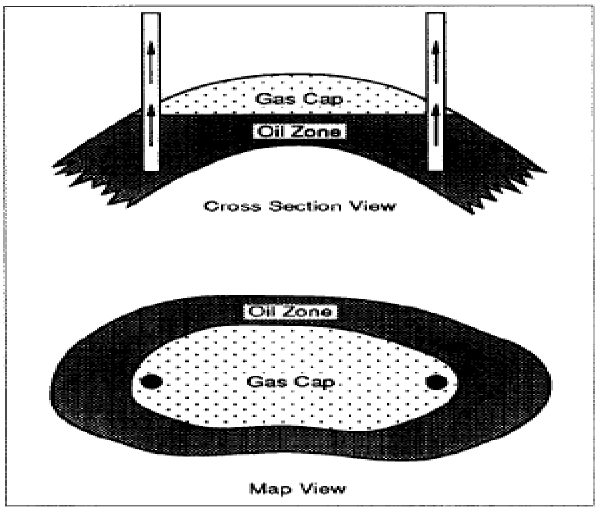


Figure I. 2 Gas cap drive reservoir.

I.2.2. Assisted recovery:

Recovery by natural drainage rarely exceeds 30%, and is often lower than this value with regard to oil deposits.

This is why the need to inject energy into these deposits very quickly appeared in order to have better recovery.

The most important Assisted Recovery process in the world, water injection is one of the most important concerns for operators. And there are Different configurations which used in injection.

I.2.2.1. Water injection:

Is a process used to inject water into an oil-bearing reservoir for pressure maintenance as well as for displacing and producing incremental oil after the economic production limit has been reached? This is done through the displacement of oil and free gas bay water.

Water injected into one or more injection wells while the oil produced from surrounding producing wells. [1]

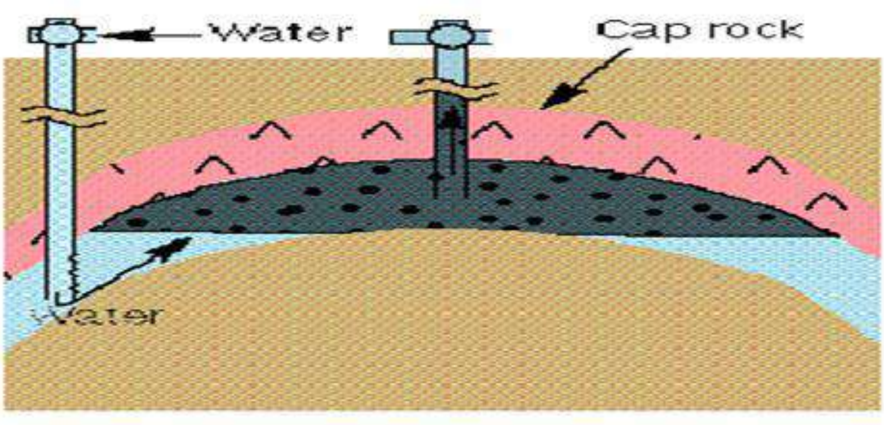


Figure I. 3 Water injection.

I.2.2.2. Gas injection:

The injection of production gas is almost as old as that of water, it has enjoyed a certain favor, particularly in the U.S.A. for shallow deposits (1000 to 2000 m) which require low gas recompression costs.

The injection of gas now has a more limited field of application because the gases from the deposits are valued and find other uses than injection, except in desert or remote areas (and sometimes offshore).

The injection of gas is however possible compared to water:

- When there's a gas dome.
- When the oil is light (the dissolution GOR is large and the viscosity of the oil is low).
- When the permeability is high.

Under these conditions, there will be a good vertical sweep of the oil through the gas-cap recovery will be good. In addition, the gas injected into an oil field can be recovered later.[1]

I.2.3. Factors that affect recovery:

- Characteristics of the reservoir and fluids like (Reservoir Geology, Permeability, and Fluid viscosity).
- Characteristics of the injection (Volume of fluid injected, Type of fluid, injection setup).

I.3. Well productivity index PI:

To assess the value of the well or the production potential of the well, this is obtained through well tests, which consist of measuring the flow rates and pressures of the fluids at the surface or at the bottom of the well. More precisely, the productivity index PI of the well is defined as the ratio of the total flow rate of the well **Q** to the difference between the average pressure **P** in the reservoir and the pressure at the draw-off point **Pwf:**

$$PI = \frac{q_0}{p_w - p_{wf}} = \frac{0.00708kh}{\mu B_o ln(\frac{r_e}{r_w})} \text{..............................} \textbf{(I.1)}$$

- The PI of a well is a function of pressure drops between the reservoir boundary and the wellbore.
- Well performance can be predicted. A higher PI indicates better influx performance.
- The PI of a well theoretically varies from 0 to infinity for a well
- A non-producing well (IP=0)
- Very mediocre oil well has an PI varying around 1 m3/d/bar (1 <Average well<10),
- Good well will have an IP higher than 10, even 100 or 1000 m3/d/bar. (Good well >10).[1]

I.3.1. PI test:

PI can be measured by producing the well at a constant, stabilized rate and measurement of the corresponding flowing pressure at bottom hole. Well completion efficiency after initial completion or at other time during the production life of the well can be carried out by calculating the well inflow quality indicator (WIQI):

$$\textbf{WIQI} = \frac{\textbf{PIactual}}{PIideal} \text{............................} \textbf{(I.2)}$$

In many oil and gas wells, the observed flow rate is different from that calculated theoretically. The concept of skin was developed to account for deviation from the theoretical rate. During pseudo-steady state flow, the oil flow rate can be calculated as:

$$\textbf{Q} = \frac{0.00708kh(p_w - p_{wf})}{\mu B_0 \ln\left(\frac{r_e}{r_w}\right) - 3/4 + S_T} \text{............................} \textbf{(I.3)}$$

Where s_t is the total skin factor, which includes the effect of partial penetration, perforation density's well.

I.3.2. Experiences and notes on PI:

Since the horizontal well gives us greater productivity than the vertical well, and therefore we can study PI better and deeper.

I.3.3. Definition of horizontal well:

In horizontal wells, the well bore remains in high angle trajectory roughly parallel to the formation, thereby exposing significantly more attention zone to production than would be exposed by a vertical well. In the presence of a one-phase flow, the production in a horizontal well is directly proportional to the pressure difference between the reservoir and the wellbore1. The constant of proportionality being the productivity index (PI).

I.3.4. The factors that affect the PI:

I.3.4.1. PI Variation with well length and anisotropy:

PI increases with increasing lateral length (**figure I.4**) Thus, longer horizontal well length enhances productivity. This is explained by the fact that a large portion of the reservoir has been contacted and the pressure drop along the well bore is reduced, thereby enhancing productivity. In the case of anisotropy (**Table I-1**), it shows that horizontal wells are more suitable for reservoirs with high vertical permeability (Kv) as this increases horizontal well PI.[2]

Table I-1 PI variation with well length and anisotropy.

Length	Kv/Kh = 0.1	Kv/Kh = 0.5	Kv/Kh = 1
100	2.15	3.13	3.46
500	5.58	6.66	6.92
900	8.19	9.45	9.73
1,300	10.94	12.39	12.68
1,700	14.02	15.978	16.47

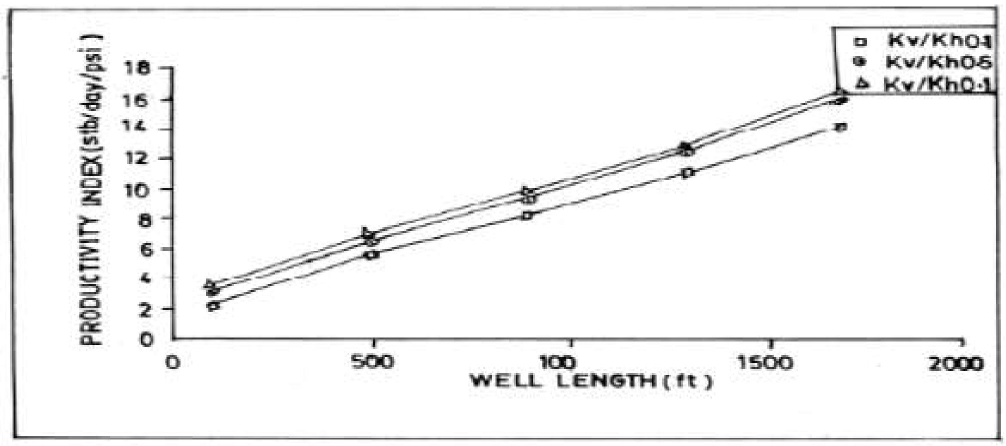


Figure I. 4 PI variation with well length and anisotropy.

I.3.4.2. PI Variation with well length and thickness:

The incremental gain in productivity is higher in a thick reservoir (**Table I-2**, **figure I.5**) than in a thin reservoir. But considering productivity ratio Jh/Jv for reservoir thickness, a thin reservoir produces more than a thick reservoir. This is as a result of more gain in contact area, which can be achieved in a thin reservoir than in thick reservoir. Hence, horizontal wells are more productive in thin reservoir than in thick reservoir. In a thick reservoir, a horizontal well behaves like a vertical well because of the small exposure of the borehole to the formation. [2]

Table I- 2 PI variation with well length and thickness.

Length	Thickness = 25ft	Thickness = 50ft	Thickness = 100ft
100	3.46	5.48	7.54
500	6.93	12.52	20.77
900	9.77	18.25	30.93
1,300	12.81	23.76	41.37
1,700	16.42	30.64	53.30

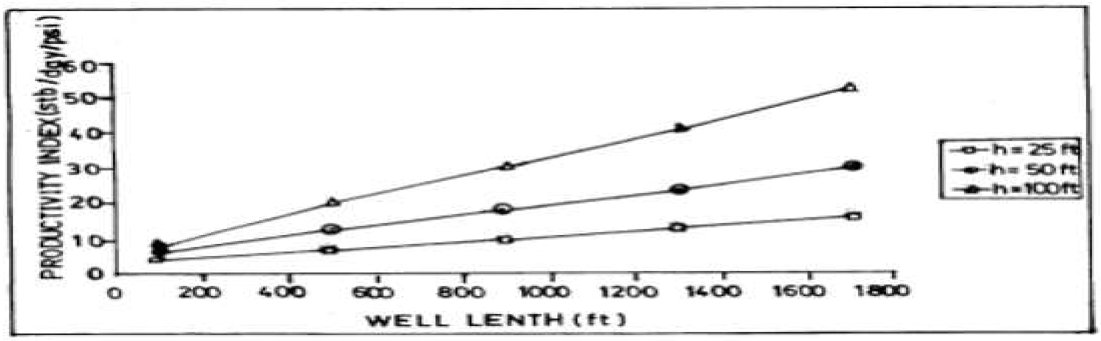


Figure I. 5 PI variation with well length and thickness.

I.3.4.3. PI variation with drainage area and anisotropy:

Smaller drainage area with higher anisotropy causes an increase in productivity index as against a large drainage area (**Table I- 3, figure I.6**). [2]

Table I- 3 PI variation with drainage area and anisotropy.

Drainage area	Kv/Kh = 0.1	Kv/Kh = 0.5	Kv/Kh = 1
20	7.3304	9.3226	9.8855
40	6.3274	7.7586	8.1446
60	5.8590	7.0658	7.3845
80	5.5302	6.6423	6.9232

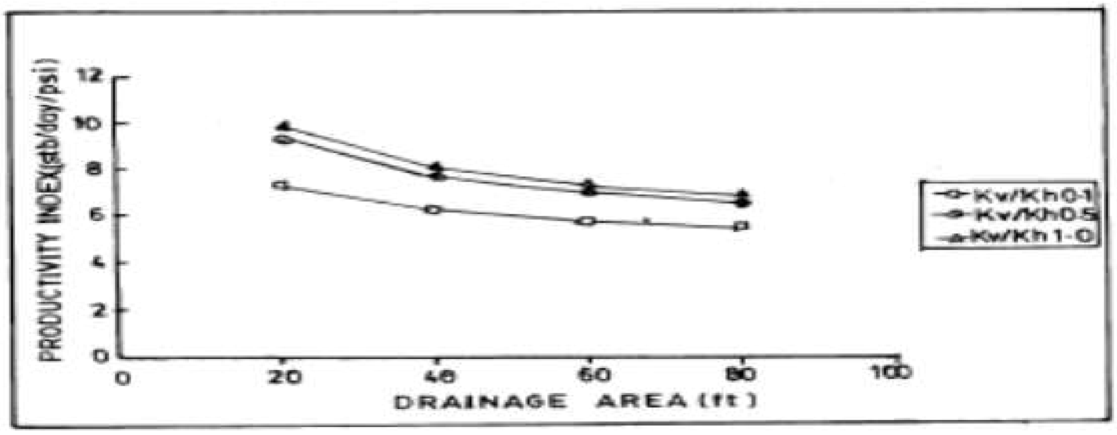


Figure I. 6 PI variation with drainage area.

I.3.3. Nodal analyses:

Nodal Analysis is a tool used to assess a complete production system and predict throughput. It is an optimization technique that can be used to analyze production problems and to improve well performance. It consists combining the possibilities of the reservoir to produce the fluids (in flow) towards the bottom of the well with the capacity of the product tubing to convey the effluent to the surface (out flow).

The method of analysis of a production system was called "nodal analysis" by “K-E-Brown.” (**Figure I.7)** shows a simplified diagram of the flow of the effluent during production and the various pressure drops that can occur throughout the system from the tank to the separator. It can be subdivided as follows: [**3**]

- Flow in the porous medium.
- Completion (simulation, perforation and gravel pack).
- The flow in the vertical or directed tubing (restriction, safety valve).
- The surface flow in the collection networks (chokes, pipes, valves, etc.).

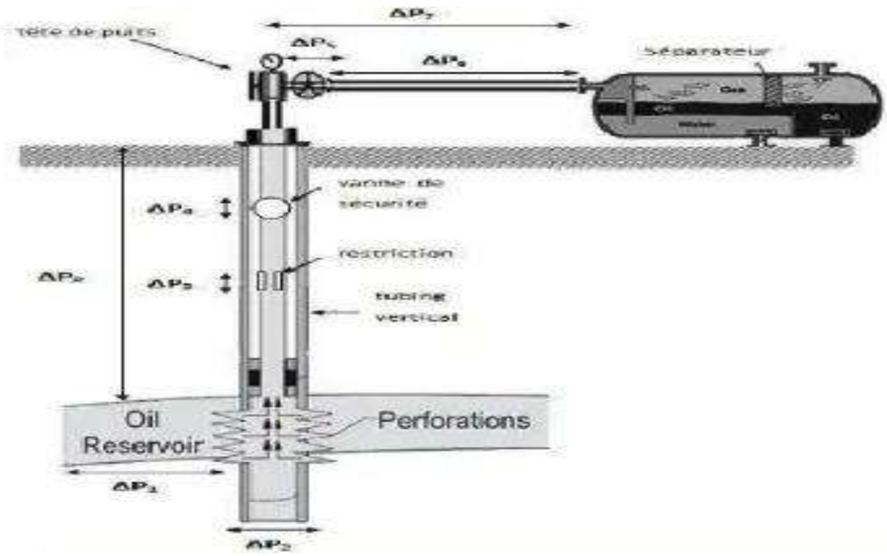


Figure I. 7 Possible pressure losses in a production system.

I.3.3.1. Nodal Analysis Concept:

In order to solve all the problems of the production system, nodes are placed in parts or segments which are defined by the different equations or correlations. (**Figure I-8)** shows the locations of the various nodes.[3]

I.3.3.2. Procedure for application nodal analysis:

Nodal analysis is applied to analyze the performance of systems that consist of several elements acting on each other. The method consists of choosing a node in the well and dividing the system at this node. The nodes used are illustrated in **(figure I.8)** All the components upstream of the node compose the Inflow section, while the Outflow section is composed by all the elements downstream of the node. A relation between the flow rate and the pressure drop must be established for each element of the system node, the pressure at the latter is determined by the inflow and the outflow.

The pressure drop in any component varies with flow **Q**, a representation of pressure versus flow produces two curves whose intersection will give a point that satisfies the two conditions cited above; this is the system operating point. The effect of change in any component can be analyzed by recalculating node pressure versus flow using the new component characteristics. The procedure is as follows:

- Choose the components to optimize,
- Select the place of the node which will feel the effect of change in the selected component.
- Develop expressions for inflow and outflow,
- Obtain the data necessary for the construction of the IPR,
- Determine the effect of changing the characteristics of the chosen components between the in-flow and out-flow : [3]

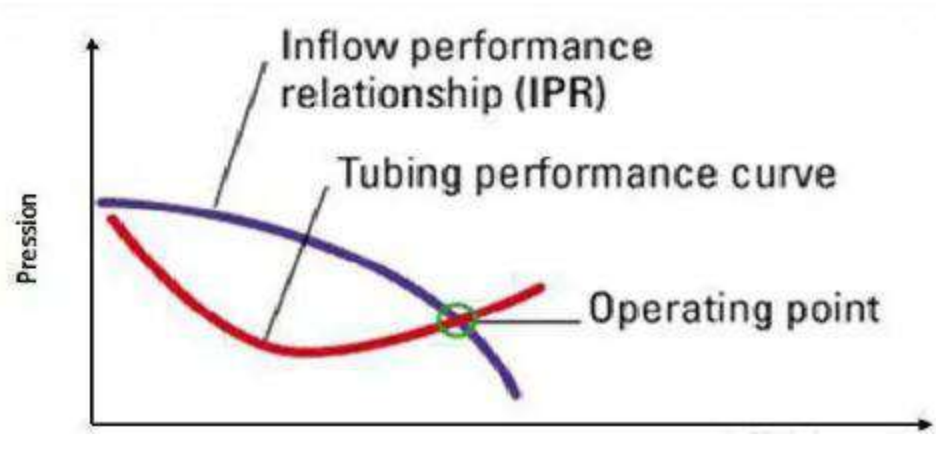


Figure I. 8 Operating point.

I.3.3.3. Objectives of nodal analysis:

The objectives of nodal analysis are:

- Determine the rate at which an oil or gas well will produce with consideration of the limitations of well geometry and completion (first by natural flow).
- Determine under what flow conditions (which may be time related) a well will flow or run
- Optimize the system to produce with a planned flow rate
- Check each component in the system (determine if it greatly affects the production rate)
- Define the most economical time for the installation of the artificial facelift and help choose the method.[3]

I.3.3.4. Conclusion:

Nodal analysis is a modeling tool used by drilling, subsurface, and well test engineers to help achieve an optimum well design in terms of perforations, tubing size, and fluid and under balance design, as well as to provide some of the key data inputs for the design of surface facilities.

Nodal analysis models both the inflow performance of reservoir fluid into the wellbore and the outflow performance of reservoir fluid through the tubing. [3]

I.3.4. The Inflow:

The inflow performance relationship (IPR) plots the drop in reservoir pressure with the production rate to produce a characteristic curve for a given set of conditions, that is, reservoir permeability, thickness, pressure drop, wellbore radius, fluid viscosity, and skin ,The construction of the IPR curve "Inflow Performance Relationship" is very important in production. This curve represents the capacity of a well to evacuate a fluid from the reservoir to the bottom of the well

So we can defined that every change in the reservoir like the presence of the skin or the used of hydraulic fracturing to the formation is an inflow. [3]

$$Q = \frac{kh(P_G - P_{wf})}{141.2B\mu(ln\frac{re}{rw}+S)} \quad \text{.......................... (I.4)}$$

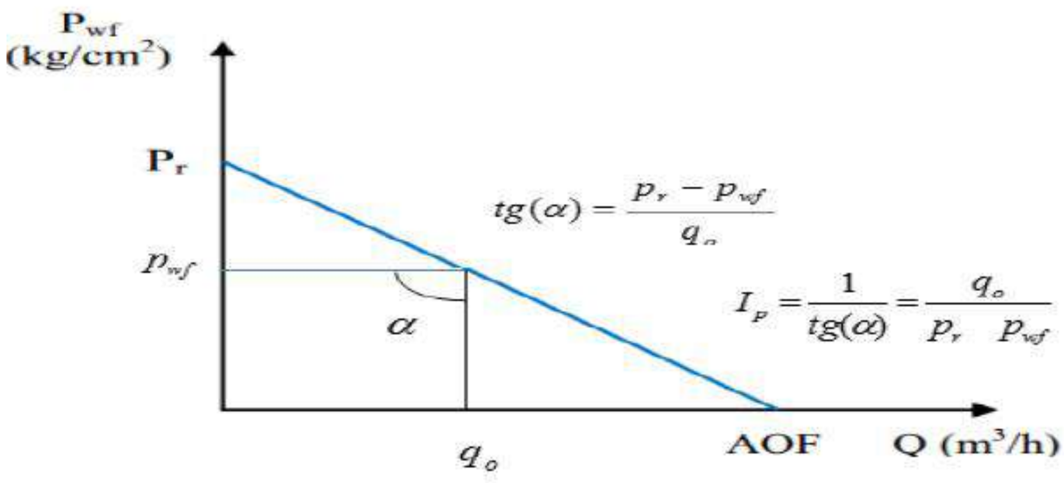


Figure I.9 The inflow performance.

A passive component installed as part of a well completion to help optimize production by equalizing reservoir inflow along the length of the wellbore. Multiple inflow control devices can be installed along the reservoir section of the completion, with each device employing a specific setting to partially choke flow. The resulting arrangement can be used to delay water or gas breakthrough by reducing annular velocity across a selected interval such as the heel of a horizontal well. Inflow control devices are frequently used with sand screens on open-hole completions. [3]

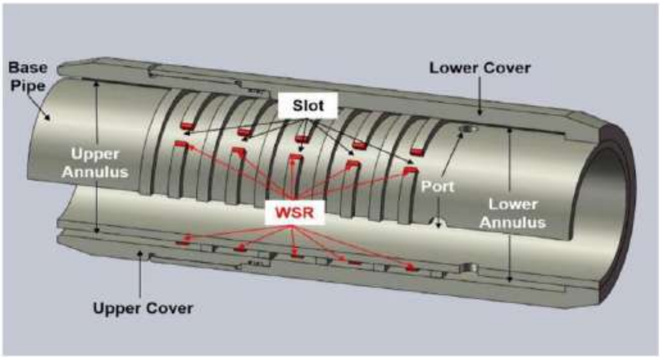


Figure I.10 Inflow control device.

I.3.5. The out flow:

The outflow, or tubing performance, plots pressure loss in the tubing against increasing flow rate for a given set of conditions, including fluid weight, friction losses, and wellhead pressure. Friction loss in turn is a function of the tubing size and condition. The plotted results produce a characteristic outflow performance curve.

And the graphic representation is called "Vertical lift Performance" (VLP) which represents the capacity of the installation and its influence on the flow according to the pressure drops generated. The VLP curve (Vertical Lifting Performance) represents the capacity of the installation (tubing) to bring the fluid from the bottom of the well to the wellhead, it is drawn from the dynamic bottom pressures calculated by conferencing correlations the vertical head losses according to the different flow rates.

Outflow performance results are most often represented graphically. The most popular graph is the one that shows the variation of the dynamic bottom hole pressure (flowing bottom hole pressure) as a function of the flow rate, at a fixed downstream pressure (head pressure, or separator pressure).

Each point on the curve gives the required down-hole pressure **Pwf** to produce a given flow at the surface, with the known downstream pressure. This is a two-phase or even three-phase flow (water, oil and gas) in a vertical pipe so we will have the general pressure gradient equation including the different types of pressure drops that can be encountered: [**4**]

Outflow:

$$p_{node} = p_{sep} + \Delta p \quad \text{(I.7)}$$

So we can defined that every change in the pressure of the tubing or every injection in the tubing (injection of water or gas) and in the result change between the pressure of the bottom-hole and the surface is an outflow.

I.4. Field productivity index PI:

I.4.1. The number of wells:

Thanks to the diagram of the deposit thus obtained, the engineer is able to establish a development project which aims to optimize the profitability of the reservoir according to the number of wells, their location, their architecture, the injection processes for this, he must make a number of assumptions in accordance with the data collected during the exploration phase. To compare the profitability in terms of production of the different types of wells envisaged, the concept of productivity index (PI) of the well is conventionally used, as well as the cost of drilling the well, which depends on its complexity, and on the uncertainty about natural data. [**4**]

We present here a classic diagram of a development project on a reservoir:

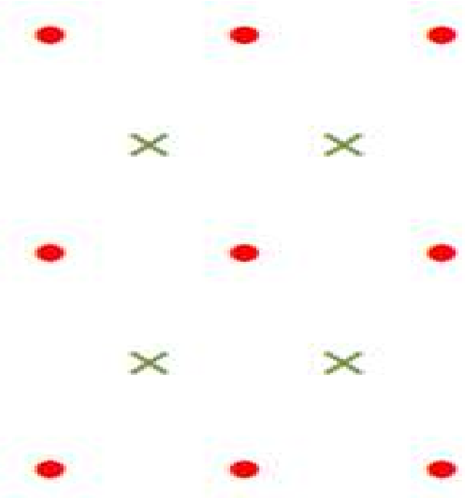


Figure I.11 Designates a producer well, and × designates injection well.

I.4.2. Injection pattern:

The particular arrangement of production and injection wells. The injection pattern for an individual field or part of a field is based on the location of existing wells, reservoir size and shape, cost of new wells and the recovery increase associated with various injection patterns. The flood pattern can be altered during the life of a field to change the direction of flow in a reservoir with the intent of contacting unwept oil. It is common to reduce the pattern size by infill drilling, which improves oil recovery by increasing reservoir continuity between injectors and producers.

Common injection patterns are direct line drive, staggered line drive, two-spot, three-spot, four-spot, five-spot, seven-spot and nine-spot. Normally, the two-spot and three-spot patterns are used for pilot testing purposes. The patterns are called normal or regular when they include only one production well per pattern. Patterns are described as inverted when they include only one injection well per pattern.[**5**]

I.4.2.1. Example injection pattern 5 spots:

An injection pattern in which four input or injection wells are located at the corners of a square and the production well sits in the center. The injection fluid, which is normally water, steam or gas, is injected simultaneously through the four injection wells to displace the oil toward the central production well.

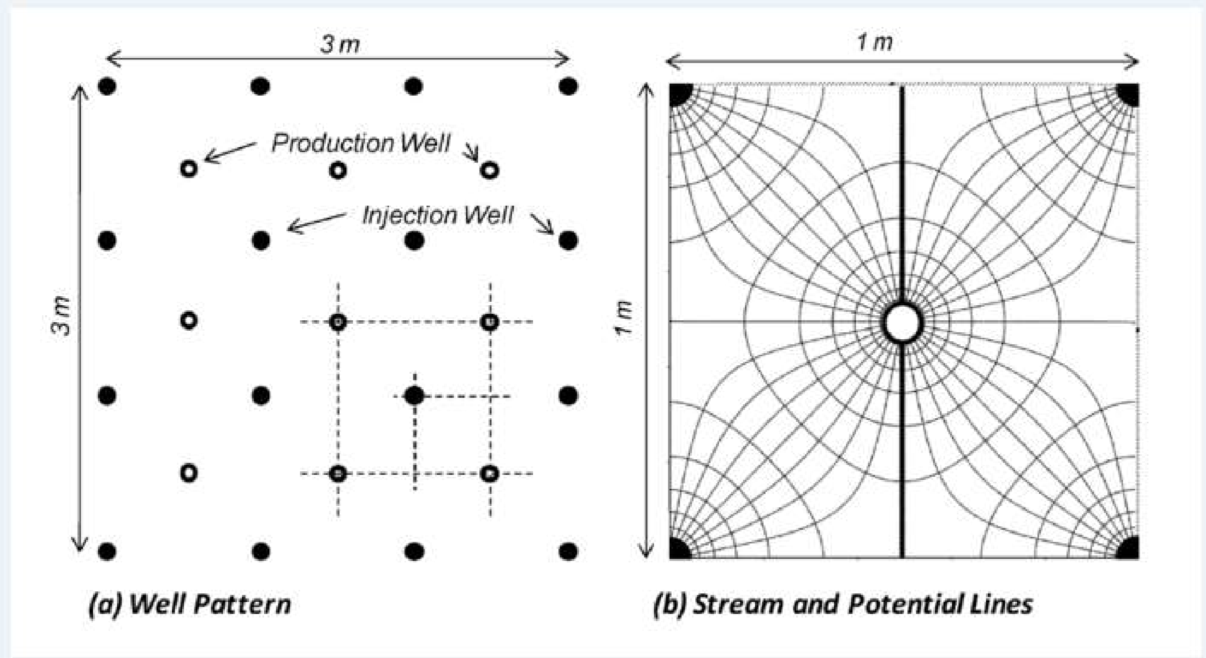


Figure I.12 Injection pattern 5 spots.

I.4.3. Performance for each well (multi-well interference test):

Analysis of the interference tests were conducted using the aforementioned type curve matching and automated history matching procedure intentionally ignoring the effects of other wells. In all cases a lower flow capacity and storage capacity were obtained at the end of each analysis (**Table I-4**). On the other hand, larger skin and wellbore storage value were obtained for the active well in all cases. It was observed that the confidence intervals for all parameters were larger than 25% regardless of number of wells used in the matching process. The confidence intervals were very wide (>100%) for wellbore storage, skin, inter porosity flow parameter and storability ratio values decreasing the reliability of the estimates.

I.4.4. Synthetic Example:

This are Resultsofwelltestanalysisignoringproductionandinjectioneffectsofexisting wells:

Table I- 4 Table of test interference analysis.

	K, md	ω	λ	ϕ	skin	C bbl/psi	S (m/bar)	Flow Capacity Darcy – m
One Well Producing	16.3	0.999	$2.54x10^{-5}$	0.0339	0.873	0.0391	0.000737	8.15
Two Wells Producing	26.9	0.999	$2.35x10^{-5}$	0.0351	0.814	0.0424	0.000763	13.45
Three Wells Producing	26.9	0.999	$2.13x10^{-5}$	0.035	0.714	0.047	0.000761	13.45
Four Wells Producing	26.9	0.999	$2.13x10^{-5}$	0.0351	0.63	0.0433	0.000763	13.45
Four Wells Producing Longer Time	26.8	0.999	$2.09x10^{-5}$	0.0359	0.747	0.0479	0.000781	13.40
Four Wells Producing Double Production	25.4	0.259	$2.22x10^{-5}$	0.0406	0.375	0.0451	0.000883	12.7
True	33.3	0.1	$1.0x10^{-6}$	0.1	0	0.01	0.002175	16.65

I.4.5. Interpretation of the table:

In the synthetic example the total compressibility is taken as $4.35113x10^{-5}$, bar^{-1} and the thickness is 500 m. As can be seen from Table 1-4 when the effects of other active wells are ignored, storage capacity is underestimated roughly three times less than the original value .Similarly the deliverability rate is also underestimated two times the original value seriously affecting the well spacing estimates .If the development of the field is considered with these values it is obvious that the reservoir developmentconsiderationssuchproduction–reinjectionaswellasproduction– production well spacing will be negatively affected

I.5. Conclusion:

Interference test results can be used to estimate storage capacity of the reservoir (that can be used in the estimation of the reserves) and the bulk transmissivities (that can be used to determine deliverability rate from the reservoir). The amount of fluid in storage in the reservoir can be calculated from the storage capacity values estimated from matching of the test results. Storage capacity **(S, m/bar**) is defined as: $S=ØC_t h$ ……………………….. **(I.8)**

Where Φ is the porosity of the reservoir, fraction; c_t is total compressibility of the reservoir rock and fluid, bar^{-1}; and h is reservoir thickness, m, respectively.

Chapter II
well tests

II.1. General Concept:

II.1.1. Introduction:

The reservoir engineer must have sufficient information about the reservoir to properly analyze reservoir performance and to predict future production under various operating modes the production engineer must know the conditions of the producing and injecting wells to have the best performance of wells. Much of this information can be obtained from well testing. [6]

II.1.2. Well Testing Principle:

During a well test, a transient pressure response is created following a flow rate variation. Depending on the purpose of the test, the response of the well is recorded for a specific period of time. The pressure response is analysed as a function of the time elapsed since the start of the period.[6]

II.1.3. Well test objectives:

Well test analysis provides information about the reservoir and the well. Well test results, combined with geological and geophysical studies, are used to construct the reservoir model, which will be used to predict field behavior and recovery, depending on operational conditions. The quality of the communication between the reservoir and the well indicates the possibility of improving the productivity of the well. In general, the purpose and objective of well testing are: [6]

- Evaluate the production capacity, or potential of each well.
- Determine the nature and characteristics of the effluent produced.
- Measure the prevailing pressure in the deposit.
- Measure the pressure during production.
- Evaluate the permeability of the layers around the well (weathered zone).
- Evaluate the permeability of the layers beyond this zone (intrinsic permeability).

II.1.4. Darcy's Law:

It expresses the flow rate of fluid (q) which crosses a sample of rock, it is given by the following equation: [6]

$$\boldsymbol{Q = \frac{k}{u} A \frac{P_1 - P_2}{L}} \qquad \textbf{(II.1)}$$

Q: flow rate (bbl/DAY).

L: length (ft).

u: fluid viscosity (cp).

A: cross section (ft^2).

ΔP: deferential pressure (psi).

K: permeability (Darcy).

Darcy's Law applies only under the following conditions:

- Low speed (laminar) flow;
- Permanent flow;
- Homogeneous formation;
- No reaction between the fluid and the formation.

For turbulent flow, which occurs at higher velocities, a special modification of Darcy's equation is needed

Darcy's low in radial flow:

$$\boldsymbol{Q} = \frac{2\,\pi\,h\,k\,P_1 - P_2}{\mu \ln\frac{r_1}{r_2}} \text{.......................... (II.2)}$$

II.1.5. Continuity equation:

This equation explains the principle of Lavoisier (conservation of mass), the variation of the mass of the fluid contained in the volume element is equal to the difference between the quantity of fluid entering and leaving during the time interval, and can be formulated .Mathematically with:

$$\boldsymbol{div}\,(\boldsymbol{e}\ \ \boldsymbol{v} \rightarrow) + \frac{\partial(\partial\varphi s_o)}{\partial t} = 0 \text{.......................... (II.3)}$$

II.1.6. The diffusivity equation:

Using DARCY's law and the law of conservation of mass, one can obtain an equation called diffusivity equation.[1]

$$\boldsymbol{div}\,\left(\rho\frac{k}{\mu}\underset{\nabla}{\rightarrow}p\right) = \rho\varphi C_t\frac{\partial P}{\partial t} \text{.......................... (II.4)}$$

II.2. The types of well test:

II.2.1. Drill stem test DST:

The principle of a DST is the installation of a temporary completion lining In order to put the reservoir into production, and therefore to reduce the hydrostatic pressure of the sludge at the right of the reservoir for the output.

A seal called a packer is anchored above the tank, which serves to support the column of mud. The pressure inside the test train is very low compared to that of the deposit, and is equal to the hydrostatic pressure of the buffer liquid, which allows the effluent to exit as soon as the valve is anchored and opened of the tester, and ascend through the interior of the test train until it comes to the surface. There it passes through a system of valves called the production head and a small choke manifold before leaving for the separation and storage or disposal facility.[7]

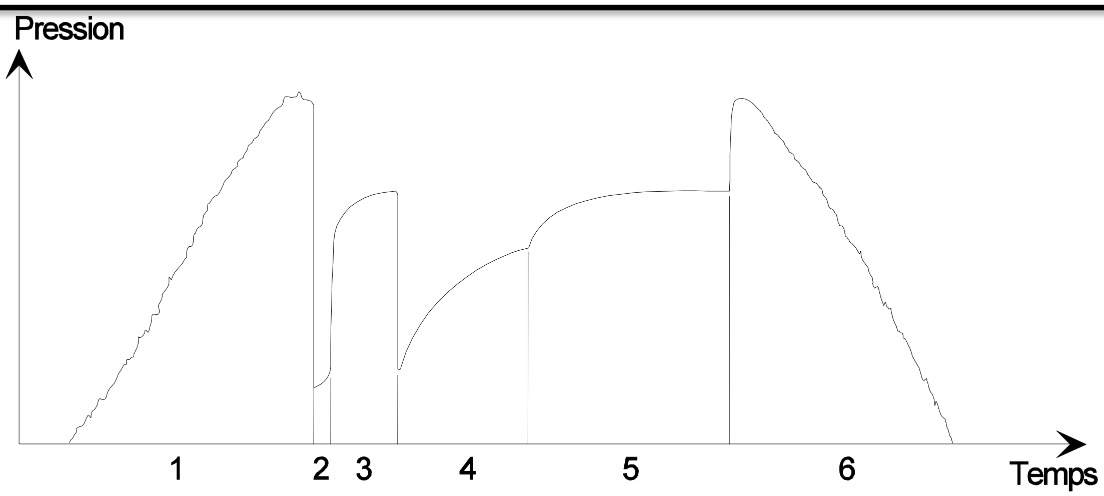


Figure II. 1 Conduct of a short-term test.

1. Lowering the test pad and anchoring the packer.
2. Pre-flow (open tester).
3. Initial closure (tester closed).
4. Initial pressure (blank pressure).
5. Main flow (open tester).
6. Final closing (tester closed).

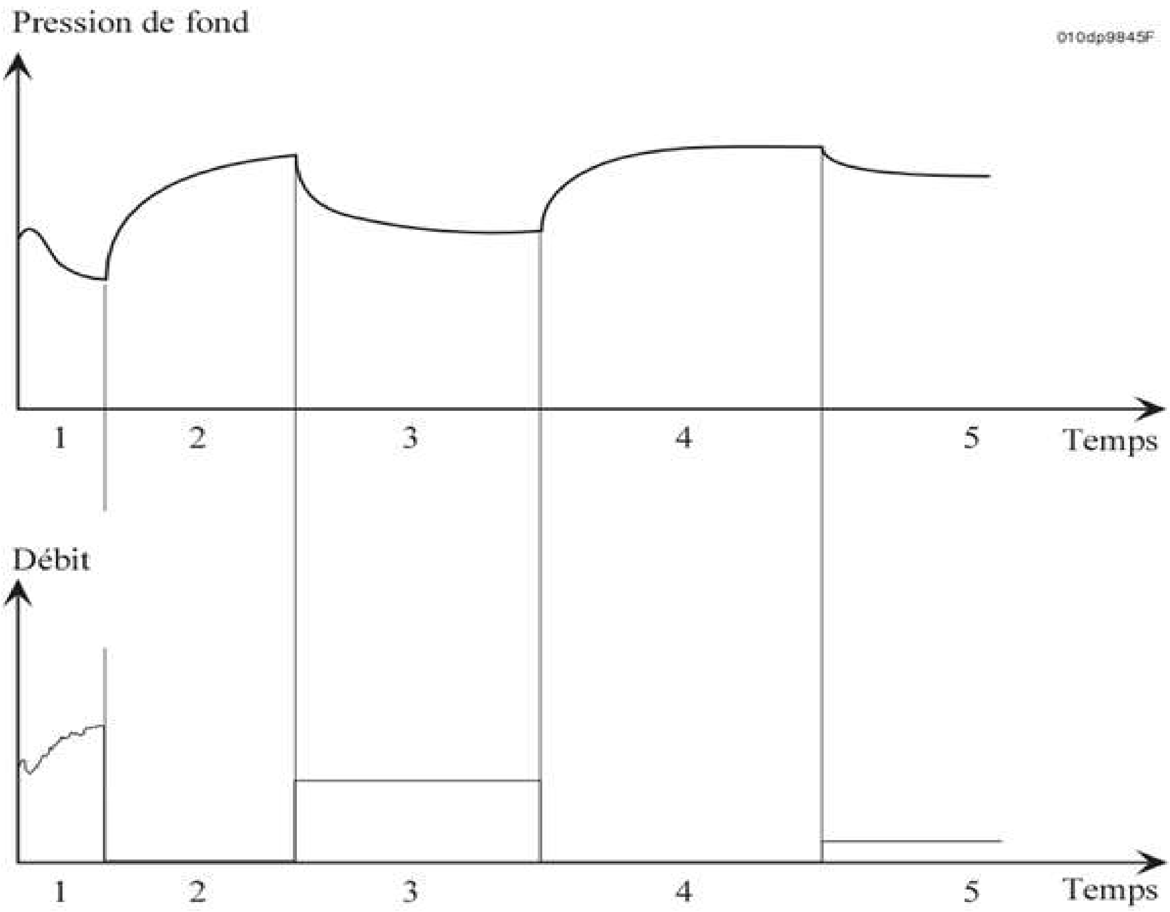


Figure II. 2 Progress of a long-term oil test.

1- Disgorging of wells.

2-initial closing.

3-main flow (draw down).

4-closure for build-up registration

5-reduced rate for sampling.

II.2.2. Build-up test:

The build-up test requires closing the well and recording the increase in pressure as a function of time. Conventional analysis techniques require a constant flow during the production time, either from the start or after a last flow period long enough to have a stable pressure distribution before closing (**Figure II.3)** his analysis of the build-up results is used for determining the reservoir model. [1]

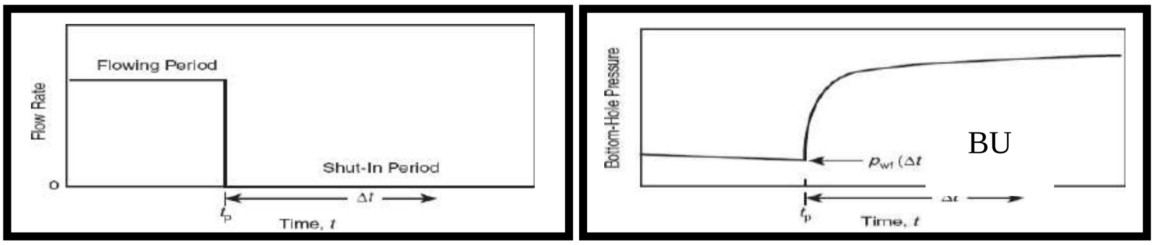


Figure II. 3 Buildup test.

II.2.3. Draw down test:

The drawdown test is a series of down-hole pressure measurements during the constant flow production period. Generally, the well is closed before the test for a sufficient time to reach the reservoir pressure.[2]

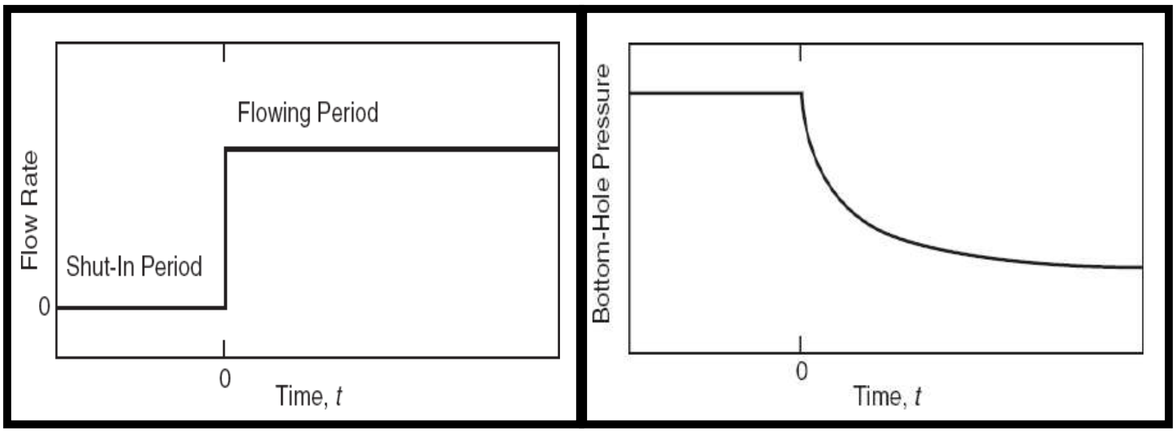


Figure II.4 Draw down test.

II.2.4. Multiple well testing:

In single-well testing, the primary target is the nearby well region. However to investigate the inter well region, more than one well must be directly involved in the test. In multiple-well testing, the flow rate is changed in one well and the pressure response is monitored in another .These tests are conducted to investigate the presence or lack of hydraulic communication with in a reservoir region .They are also used to estimate inter-well reservoir transmissivity and storability .The two main types of multiple-well testing are interference tests and pulse tests. Some vertical interference tests are classified as multiple-well tests .As subsequently discussed, they are performed between two sets of perforations or test intervals in a well to investigate vertical communication and estimate vertical permeability .Multiple-well tests are more sensitive to reservoir horizontal anisotropy than single-well tests .Therefore, multiple-well tests are typically conducted to describe the reservoir anisotropy based on directional permeability.

II.2.5. Interference test:

Interference tests required long duration production or injection rates changes in the active well .The associated pressure disturbance recorded in the observation well yields valuable information regarding the degree of hydraulic communication within the inter-well region (**figure II-5**) shows a plan view of two wells used in an interference test.

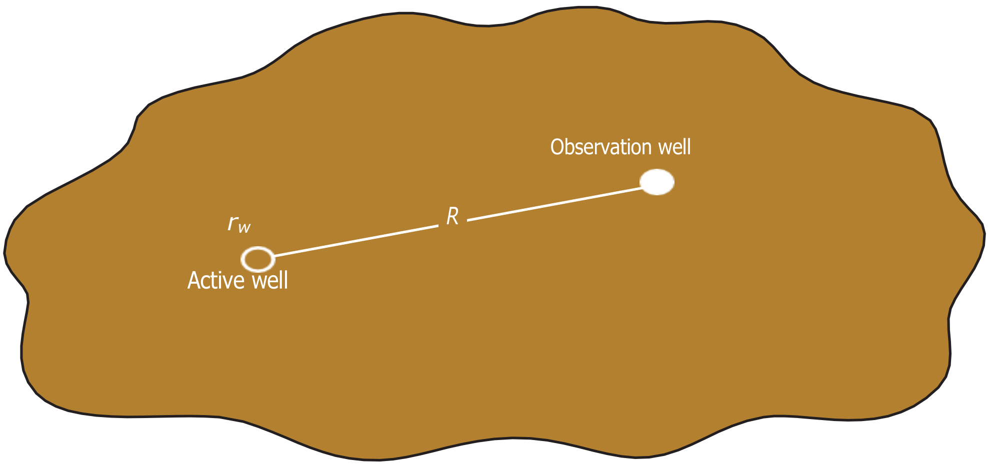


Figure II. 5 Active well and the observation well.

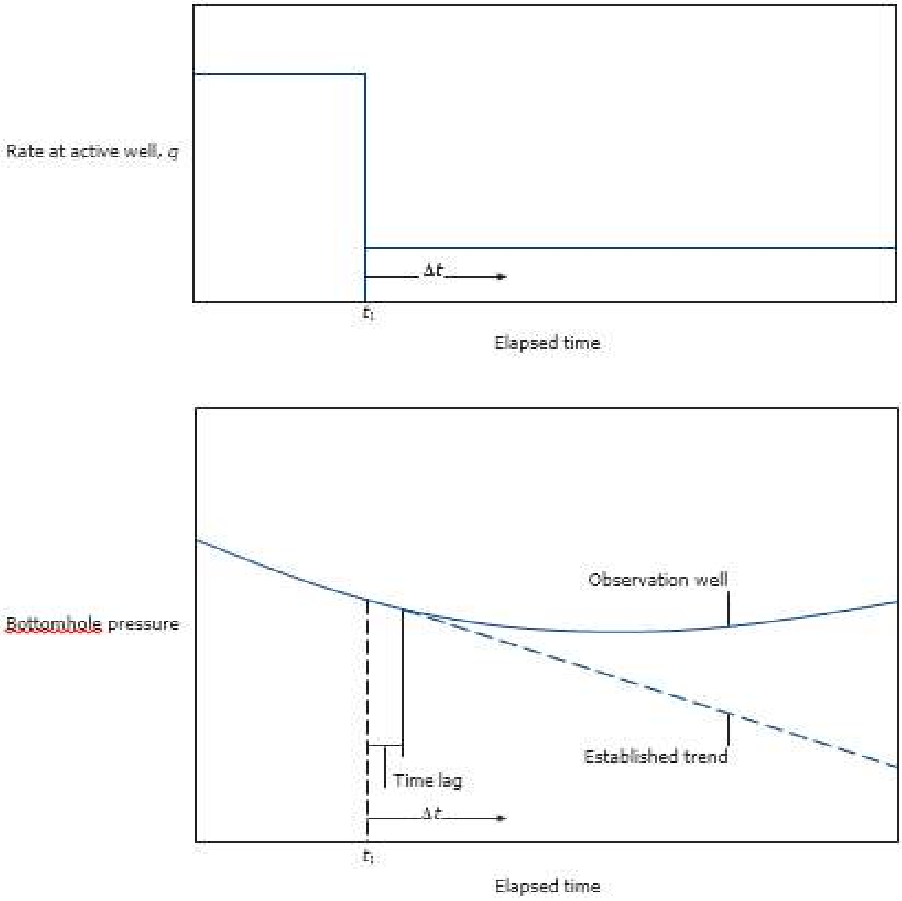


Figure II. 6 Active and observation wells and their respective rate and pressure changes during an interference test.

II.3. Well test analysis:

II.3.1. Drill stem test DST:

II.3.1.1Test description:

With the drill stem testing technique, the well is controlled by a down-hole shut-in valve. For safety reason, the drill string is not usually used for the test, and production tubing is preferred. Before the test, the well is partially filled with a liquid cushion designed to apply a hydrostatic pressure p0 above the valve smaller than the formation pressure p, when the tester valve is opened, an instantaneous drop of pressure is transmitted to the sand face, and the formation fluids start to flow into the well. [9]

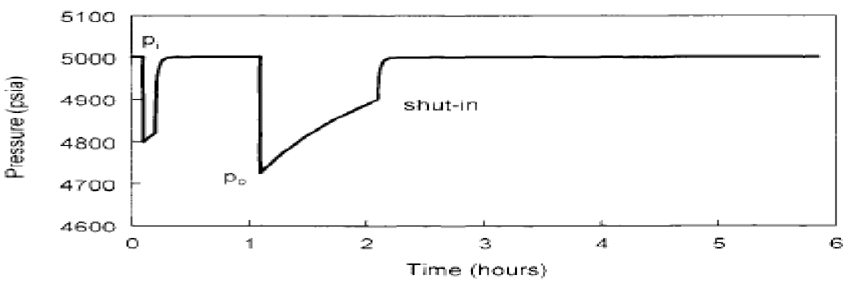


Figure II. 7 Example of DST pressure response. The sequence is initial flow, initial shut-in, flow period and final shut-in. The rate is less than critical.

In case of liquid flow, the *level rises* in the production string and the backpressure due to the liquid column increases. As long as the liquid level has not reached the surface (and provided the flow rate is less than critical, Ramey et al., 1975 a), the rate decreases. This is called a ***"slug test»,*** which requires specific analysis techniques.

The well is then shut-in for a pressure build-up. When no flow to surface is desired, the down - hole valve is closed before the liquid level has reached the surface. As illustrated in Figure 9.1, the usual drill stem test procedure consists of a first short initial flow followed by the initial shut-in to reach **p,** the well is then opened for the slug test and, due to the backpressure of the rising liquid column, the bottom hole pressure increases. Finally, the well is shut-in for a build-up period.

If surface production is possible, the flow time is extended until the well produces at surface and the rate tends to stabilize. The **DST** procedure then becomes similar to that of a standard production test.

In low-pressure wells, the flowing pressure can reach the initial reservoir pressure before the down-hole valve is closed. In these cases, the well kills itself and the pressure build-up cannot be monitored after the liquid flow has stopped. Only a slug test analysis can be attempted.

When the flowing condition is *critical,* the rate is not controlled by the downstream pressure but by the completion or perforations configuration. The rate is *constant* and the pressure increases linearly with time during the flow. The flowing bottom-hole pressure is not suitable for interpretation and only the shut-in period can be used for analysis of such tests.

II.3.2. Draw down test:

A pressure drawdown test is simply a series of bottom-hole pressure measurements made during a period of flow at constant production rate. Usually the well is closed prior to the flow test for a period of time sufficient to allow the pressure to stabilize throughout the formation, i.e., to reach static pressure. As discussed by (Odeh and Nabor), 1 transient flow condition prevails to a value of real time approximately equal to:[10]

$$t \approx \frac{\emptyset \mu_0 r_e^2}{0.00264\ k} \text{.......................... (II.5)}$$

Semi-steady-state conditions are established at a time value of

$$t \approx \frac{\emptyset \mu_0 c r_e^2}{0.00088\ k} \text{.......................... (II.6)}$$

In this section, we will discuss drawdown tests in infinite-acting reservoirs and developed reservoirs including two-rate, variable, multiphase, multi-rate drawdown tests. An analysis technique applicable to pressure drawdown tests during each of these periods including other types of tests is presented in the following sections.

II.3.2.1 Pressure-Time History for Constant-Rate Drawdown Test

(Figure II.8) Shows the flow history of an oil well and can be classified into three periods for analysis:

• Transient or early flow period is usually used to analyze flow characteristics;

• Late transient period is more completed.

• Semi-steady-state flow period is used in reservoir limit tests.

II.3.2.2. Transient Analysis - Infinite-Acting Reservoirs

An ideal constant-rate drawdown test in an infinite-acting reservoir is modeled by the logarithmic approximation to the $\boldsymbol{P_{wf}}$ function solution:

$$\boldsymbol{P_{wf} = P_i - 141.2\,\frac{q_0\mu_0\beta_0}{kh}\,[P_D(t_D) + s\,]} \text{.......................... } \textbf{(II.7)}$$

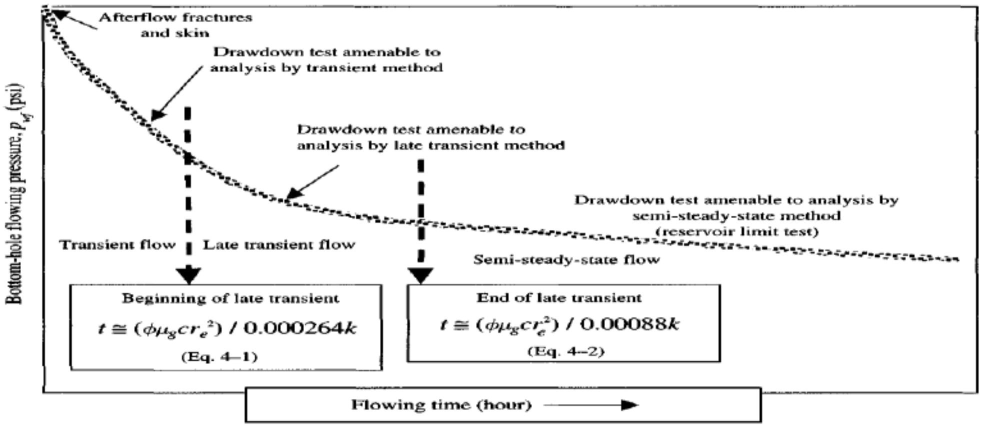


Figure II. 8 Schematic pressure-time histories for a constant-rate drawdown test.

Assuming initially the reservoir at initial pressure, ***Pi***, the dimensionless pressure at the well **(*r_D* = 1)** is given as:

$$\boldsymbol{P_D = 0.5\,[\ln(t_D) + 0.80907]} \text{.......................... } \textbf{(II.8)}$$

After the wellbore storage effects have diminished and (***$tDlr^2D$)*** **> 100**, dimensionless time is given by:

$$\boldsymbol{t_D = \frac{0.0002637k_t}{\emptyset\mu_0 c_t r_w^2}} \text{.......................... } \textbf{(II.9)}$$

Combining and rearranging **Eqs II.7** through **II.9**, we get a familiar form of the pressure drawdown equation:

$$\boldsymbol{P_{wf} = P_i - \frac{162.6\;q_0\mu_0\beta_0}{kh}} \text{.......................... } \textbf{(II.10)}$$

Eqs II.10 describes a straight line with intercept and slope term together and it may be written as:

$$\boldsymbol{P_{wf} = m\log t + P_{1hr}} \text{.......................... } \textbf{(II.11)}$$

A plot of flowing bottom-hole pressure data versus the logarithm of flowing time should be a straight line with slope ***m*** and intercept (***p\hr***) (**figure II.9**). Semi-log straight line does appear after wellbore damage.

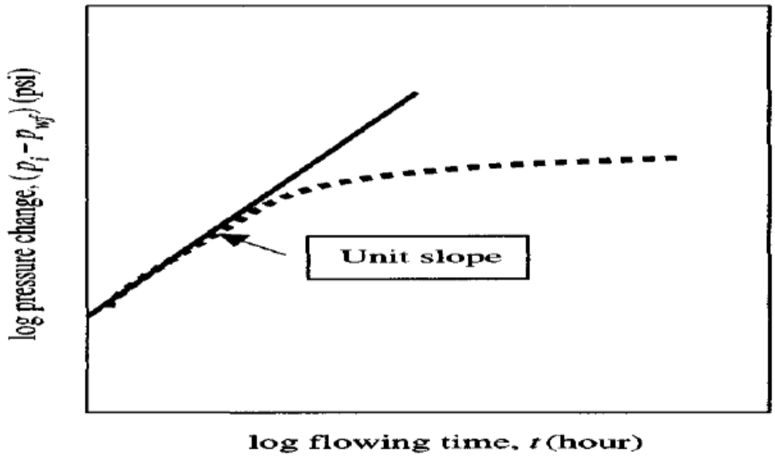


Figure II. 9 Semi-log pressure drawdown data plot.

And storage effects have diminished. The slope of the semi-log straight line may be given by:

$$m = -\frac{162.6\, q_0 \mu_0 \beta_0}{kh} \quad \text{(II.12)}$$

The intercept at log ***t* = 0**, which occurs at ***t* — 1,** is also determined from **Eqs II.10**:

$$P_{1h} = P_i + m\left[\log\left(\frac{k}{\emptyset \mu_0 \beta_0 c_t r_w^2}\right) - 3.23 + 0.869S\right] \quad \text{(II.13)}$$

The skin factor is estimated from a rearranging form of **Eqs II.13:**

$$S = 1.151\left[\frac{P_i - P_{1hr}}{m} - \log\left(\frac{k}{\emptyset \mu_0 \beta_0 r_w^2}\right) + 3.23\right] \quad \text{(II.14)}$$

The beginning time of the semi-log straight line may be estimated from log-log plot of **[Log *(Pi — Pwf)]*** versus **log *t* (figure II.10**); when the slope of the plot is one cycle in Δ***p*** per cycle in *t*, wellbore storage dominates and test data give no information about the formation. The wellbore storage coefficient may be estimated from the unit-slope straight line using the following equation:

$$C = \frac{q_0 \beta_0}{24} \cdot \frac{\Delta t}{\Delta P} \quad \text{(II.15)}$$

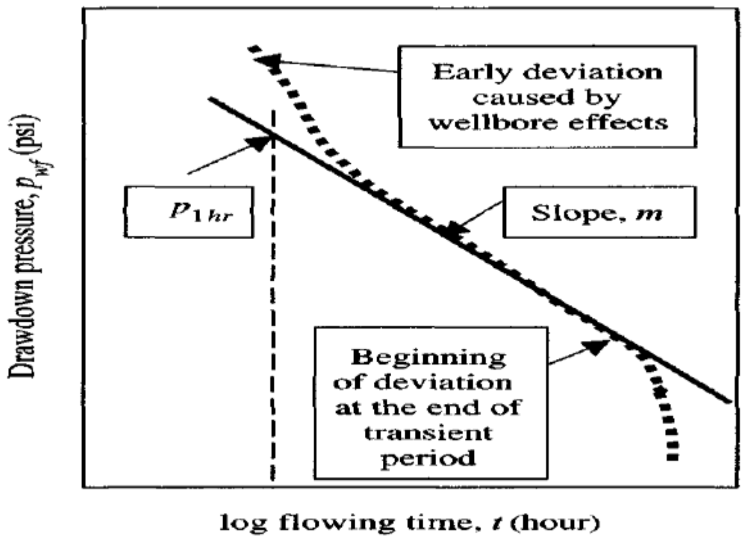


Figure II. 10 log-log pressure drawdown data plot.

Where Δ**t** and Δ***p***are the values read from a point on the log-log unit slope straight line. **C** is calculated using the previous equation and lets agree that c equal to:

$$C = \frac{V_u}{(\rho/_{144g})g_c} \text{.......................... (II.16)}$$

Where V_u is the wellbore volume per unit length in barrels per foot. Duration of wellbore unloading can be estimated from:

$$t_{wbs} = \frac{(200{,}000+120{,}005)C_s}{kh/\mu_0} \text{.......................... (II.17)}$$

And:

$$C_s = \frac{25.65\, A_{wb}}{\rho} \text{.......................... (II.18)}$$

The apparent wellbore radius ***rwa*** may be estimated by:

$$r_{wa} = r_w e^{-s} \text{.......................... (II.19)}$$

Radius of investigation at the beginning and end of the apparent middle time line may be checked by the following equation:

$$r_i = \left(\frac{kt}{848\, \emptyset\, \mu_0 C_t}\right)^{0.5} \text{.......................... (II.20)}$$

III.3.3. Build up test:

Pressure Build-up Test Analysis in Infinite-Acting Reservoir:

For any pressure buildup testing situation, the bottom-hole shut-in pressure, ***Pws****, in* the test well may be expressed using the principle of superposition for a well producing at rate *q0* until time ***tp****,* and at zero rate

Thereafter. At any time after shut-in: [11]

$$P_{ws} = p_i - \frac{141.2 q_0 \mu_0 \beta_0}{kh}\left[P_D(t_p + \Delta t)_D - P_D(\Delta t_D)\right] \text{.......................... (II.21)}$$

Where P_D is the dimensionless pressure function and *to* the dimensionless time and t_D is defined by the following equation:

$$t_D = \frac{0.000264\, kt}{\emptyset \mu_0 c_t r_w^2} \text{.. (II.22)}$$

During the infinite-acting time period, after wellbore storage effects have diminished and assuming there are no major indeed fractures, ***PD*** in **EqsII.22** may be replaced by the logarithmic approximation to the exponential integral:

$$P_D = 0.5(\ln t_D + 0.80907) \text{.................................. (II.23)}$$

EqsII.23 applies when t_D**>100**, which occurs after a few minutes for most un-fractured systems. **EqsII.22**through Eqs **II.23** may be rewritten as:

$$P_{ws} = P_i - 162.6\frac{q_0 \mu_0 \beta_0}{kh}\ log\ \left(\frac{t_p + \Delta t}{\Delta t}\right) \text{.......................... (II.24)}$$

Eqs II.24 gives the pressure response during shut-in BHP, ***pws***. This equation indicates that plotting ***pws*** versus (***tp + At)/At*** on semi-log coordinates will exhibit a semi-log straight line of slope m, where:

$$\boldsymbol{m = \frac{162.6 q_0 \mu_0 \beta_0}{kh}} \text{.........................} \textbf{(II.25)}$$

II.3.3.1. Calculation of Flow Capacity and Formation Permeability:

The formation permeability ***k*** can be obtained as:

$$\boldsymbol{k = \frac{162.6 q_0 \mu_0 \beta_0}{mh}} \text{.........................} \textbf{(II.26)}$$

And ***kh*** is the flow capacity **(mDft).** Both Theis and Horner proposed the estimating permeability in this manner. The ***pws*** versus **log *[(tp+ At)) At]*** plot is commonly called the Horner plot (graph method) in the petroleum industry. Extrapolation of the straight-line section to an infinite shut-in time ***[(tp+ Ai) I At) = 1*** gives a pressure and we will denote this aspect throughout this book. In this case ***pw*pi*** the initial pressure. However, the extrapolated pressure value is useful for estimating the average reservoir pressure.

II.3.3.2. Estimation of Skin Factor:

The skin factor does affect the shape of the pressure buildup data. In fact, an early-time deviation from the straight line can be caused by skin factor as well as by wellbore storage. Positive skin factor indicates a flow restriction, i.e., wellbore damage. A negative skin factor indicates stimulation. To calculate skin factor, **S** from the data available in the idealized pressure buildup test. at the instant a well is shut-in, the flowing BHP**, *pwf*** is:

$$\boldsymbol{S = 1.151\left(\frac{P_{ws}-P_{wf}}{m}\right) + 1.151\log\left(\frac{1866\emptyset\mu_0\mu_0\beta_0 r_w^2}{k\Delta t}\right) + 1.151\log\left(\frac{t_P+\Delta t}{\Delta t}\right)} \text{..........} \textbf{(II.27)}$$

It is a convenient practice in the petroleum industry to choose a fixed shut in time Δt of 1 hour and the corresponding shut-in pressure, p_{1hr} to use in this equation. The pressure, p_{1hr}, must be on the straight line on its extrapolation. Assuming further that **log** $(t_p+\Delta t)/\Delta t$ is negligible. ***Pwf*** is the pressure measured before shut-in at $\Delta t = 0$. With these simplifications, the skin factor is:

$$\boldsymbol{S = 1.151\left[\frac{P_{1hr}-P_{wf}(\Delta t=0)}{m} - \log\left(\frac{k}{\emptyset C_t \mu_0 r_w^2}\right) + 3.23\right]} \text{.........................} \textbf{(II.28)}$$

II.3.4. Interference test:

II.3.4.1. Introduction:

Conventional interference testing in geothermal fields is one of the major tools used to determine bulk transmissivities (permeability-thickness product) and storativities (porosity - compressibility-thickness product), and to locate boundaries. Changes in the hydrology of geothermal reservoirs in geologic time can be caused through mineral dissolution and/or deposition, changes in the heat flux into or out of the system, crustal movements, changes in fluid components (brine and gas) moving into or out of the reservoir, and exploitation. Exploitation increases the rate

of occurrence of natural processes in the reservoir, with mineral dissolution/deposition and reduction in the heat capacity of the system being the most significant. Interference tests are both an essential and economical tool in assessing the extractable heat capacity of a geothermal field and monitoring changes in reservoir characteristics as the geothermal field maturates through exploitation. They serve to prove the existence of productive reservoir between the wells.

A typical interference test involves producing from or injecting into one well called the active well, and observing the pressure response in another well or wells, called observation wells, located a distance ***r*** from the active well.[**12**]

Figure II. 11 Active and observation wells, interference or pulse test (Earlougher, 1976).

Pressure behavior as a function of time reflects the reservoir properties between the active and observation wells. Interference test can be conducted with more than one active well and/or more than one observation well. A time lag exists between the time at which a rate chance is made at the active well and the time at which the pressure transient is seen in the observation well. Area investigated in an interference test is defined by the radius of investigation ***ri***which is given by the following equation.

$$r_i = \sqrt{\frac{kt}{948\ \emptyset \mu C_t}} \quad \text{(II.29)}$$

Where ***k***, is permeability**,** ***t*** is time, **Φ** is porosity, ***μ*** is viscosity**,** ***ct*** is total compressibility, respectively.

In an infinite-acting, homogeneous, and isotropic reservoir, the exponential integral solution of the line source solution (Theis, 1935) describes the pressure behavior at the observation well with the following equation.

$$P_i - P_r = \Delta P = -70.6 \frac{q\mu\beta}{kh}\ Ei\left(\frac{-948\emptyset\mu C_t r^2}{kt}\right) \quad \text{(II.30)}$$

Where ***Ei*** is exponential integral, ***pr*** is the pressure at the observation well located a distance r from the active well, ***k*** is permeability, ***q*** is flow rate, ***B*** is formation volume factor, and ***h*** is thickness, respectively.

Since the skin factor of the active well does not affect the drawdown at the observation well, skin factor does not appear in the equation. From this solution, it can be observed that by suitable observation of the pressure change, it may be possible to identify two important parameters: the permeability-thickness and the storability (Earlougher, 1977; Horne, 1995). Usually, type curve matching is used to analyse pressure data from an interference test with constant rate production at the active well. Using appropriate dimensionless variables the aforementioned solution can be written as follows.

$$P_d = -\frac{1}{2}\, Ei\left(\frac{-r_d^2}{4t_d}\right) \qquad \text{(II.31)}$$

So the pressure down time is:

$$\psi = \frac{P_w(t_a) - P_i}{P_w(t_b) - P_i} = \frac{g(D, t_a)}{g(D, t_b)} \qquad \text{(II.32)}$$

III.3.4.2. Synthetic Example:

Let's assume that in a faulted – fractured geothermal field an interference test is to be conducted. In this hypothetical scenario, it is assumed that four production wells (Well 1, 2, 5, and 6) and 3 injection wells (Well 3, 4 and 4) are used for an existing power plant. It is further assumed that the wells produce and inject to the same feed zone in the reservoir. Two wells that will be used in a new power plant are to be tested by flowing one well and observing the pressure change in the other well. The locations of the wells and finite conductivity (1.524 Darcy - m) faults in the field are given in Figure 2. Using Kappa's Saphir software (Houze et al, 2013) this situation as well its variations were modeled. The model simulated an interference test conducted in a double porosity reservoir with wellbore storage and skin effects. In order to consider the effects of existing wells production wells while keeping all injectors active, production wells are kept open (**Figure II.13**). The pressure recorded in the observation well as a result of flowing active well was simulated by including the effects of other flowing wells using superposition in time and space (**Figure II.12**) The complex production history due to the presence of other active wells induces distortions that diffuses and progressively absorbed by the overall pressure profile (**Figure II.13).**[12]

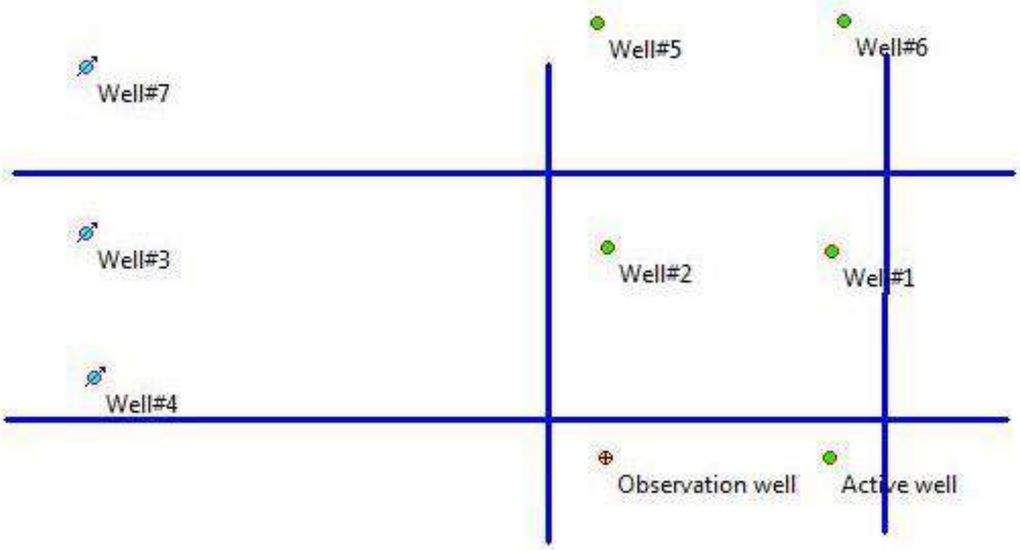


Figure II. 12 Synthetic Interference Test Well Field.

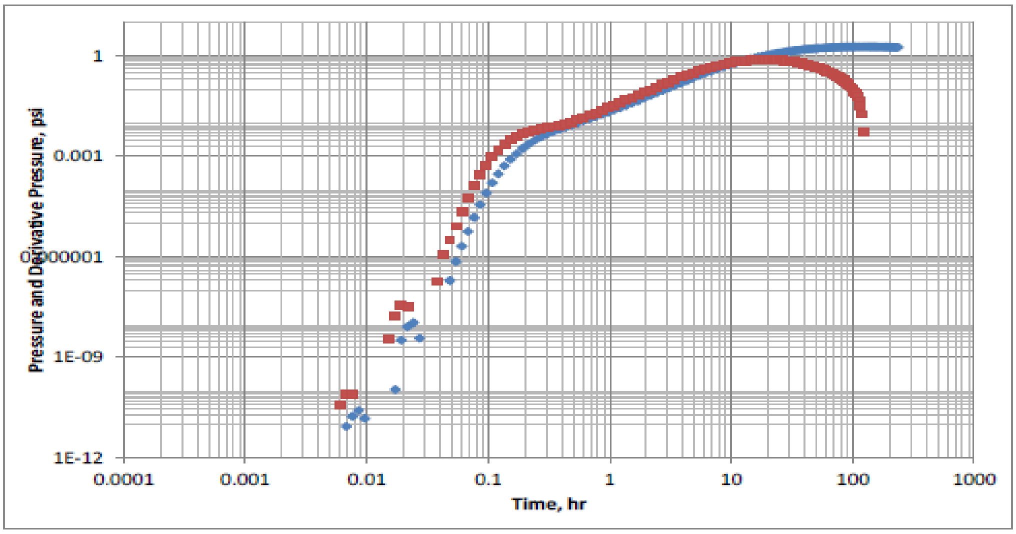


Figure II. 13 Synthetic Pressure and Derivative of Pressure four wells producing.

Analysis of the interference tests were conducted using the aforementioned type curve matching and automated history matching procedure intentionally ignoring the effects of other wells. In all cases a lower flow capacity and storage capacity were obtained at the end of each analysis (**Table II-1**). On the other hand, larger skin and wellbore storage value were obtained for the active well in all cases. It was observed that the confidence intervals for all parameters were larger than 25% regardless of number of wells used in the matching process. The confidence intervals were very wide (>100%) for wellbore storage, skin, inter porosity flow parameter and storability ratio values decreasing the reliability of the estimates.

As discussed in the previous sections, interference test results can be used to estimate storage capacity of the reservoir (that can be used in the estimation of the reserves) and the bulk transmissivities (that can be used to determine deliverability rate from the reservoir). The amount of fluid in storage in the reservoir can be calculated from the storage capacity values estimated from the matching of the test results. Storage capacity (S, m/bar**)** is defined as:

$$\boldsymbol{S = \emptyset C_t h} \text{.......................... } \textbf{(II.33)}$$

Where **Φ** is the porosity of the reservoir, fraction; **ct** is total compressibility of the reservoir rock and fluid, bar-1; and h is reservoir thickness, m, respectively.

In the synthetic example the total compressibility is taken as 4.35113×10^{-5}, bar-1 and the thickness is 500 m. As can be seen from (**Table II-1**) when the effects of other active wells are ignored, storage capacity is underestimated roughly three times less than the original value. Similarly the deliverability rate is also underestimated two times the original value seriously affecting the well spacing estimates. If the development of the field is considered with these values it is obvious that the reservoir development considerations such production – reinjection as well as production – production well spacing will be negatively affected.

Table II- 1 Results of well test analysis ignoring production and injection effects of existing wells.

	K, md	ω	λ	ϕ	skin	C bbl/psi	S (m/bar)	Flow Capacity Darcy – m
One Well Producing	16.3	0.999	2.54×10^{-5}	0.0339	0.873	0.0391	0.000737	8.15
Two Wells Producing	26.9	0.999	2.35×10^{-5}	0.0351	0.814	0.0424	0.000763	13.45
Three Wells Producing	26.9	0.999	2.13×10^{-5}	0.035	0.714	0.047	0.000761	13.45
Four Wells Producing	26.9	0.999	2.13×10^{-5}	0.0351	0.63	0.0433	0.000763	13.45
Four Wells Producing Longer Time	26.8	0.999	2.09×10^{-5}	0.0359	0.747	0.0479	0.000781	13.40
Four Wells Producing Double Production	25.4	0.259	2.22×10^{-5}	0.0406	0.375	0.0451	0.000883	12.7
True	33.3	0.1	1.0×10^{-6}	0.1	0	0.01	0.002175	16.65

III.3.4.3. Interference Test Analysis by Type Curve Matching:

Type curve matching technique is applied to interference test analysis. Type curve matching is simpler for interference testing than for single-well testing because there is only one type curve (**Figure II.14**). To consider for infinite acting system, the following steps are used to analyze an interference test:

• Plot pressure drawdown data in an observation well, ***Ap = pt — pwf(t),***versus time***, t***, on Tracing paper using the grid of **Figure II.14**

• Slide the plotted test data over the type curve (horizontal or vertical) until a match is found.

• The match point data are used to estimate formation properties. In **Figure II.14**the ordinate of the type curve is dimensionless pressure:

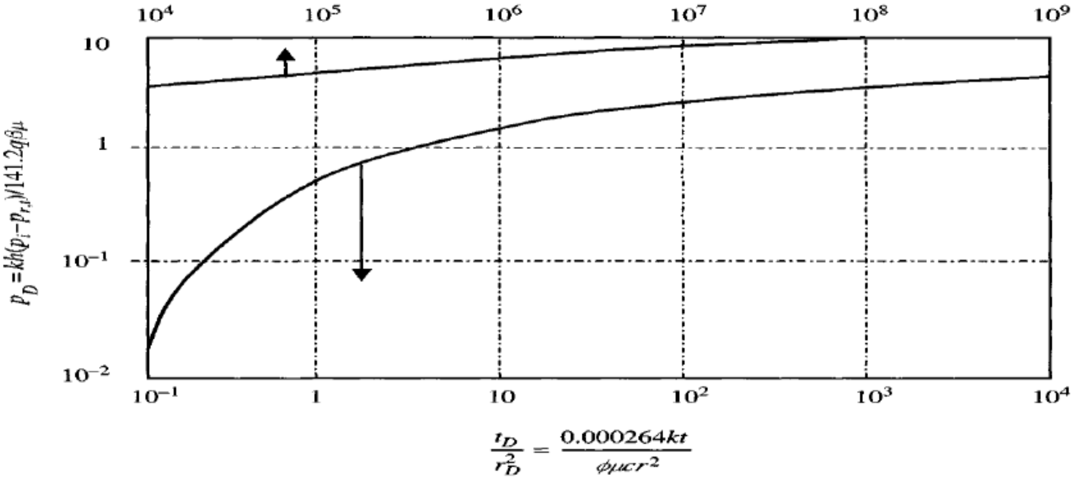


Figure II. 14 Exponential integral solution type curve.

Which is estimated using the pressure match points and the following equation:

$$P_D = \frac{\left(P_i - P_{wf}(t)\right)kh}{141.2 q_w \mu_w \beta_w} \text{.......................... (II.34)}$$

By substituting match point values and rearranging **Eqs II.34**, we estimate permeability in the test region using the pressure match points and the following equation:

$$k = 141.2 \frac{q_w \mu_w \beta_w}{h} \frac{(P_D)}{(\Delta P)} \text{………………………..} \quad \textbf{(II.35)}$$

Similarly, use the definition on the abscissa of the type curve in **figure III-4- 1**, to estimate the dimensionless time and dimensionless radius.

$$t_D = \frac{0.00026372\ kt}{\emptyset \mu_w C_t r_w^2} \text{………………………..} \quad \textbf{(II.36)}$$

$$r_d = \frac{r}{r_w} \text{………………………..} \quad \textbf{(II.37)}$$

With the time scale match point data and the permeability just determined, estimate the product$\emptyset C_t$, using the following equation:

$$\emptyset c_t = \left[\frac{0.0002637\ k}{\mu_w r^2}\right] \frac{(\Delta t)MP}{(t_D/r_D^2)MP} \text{………………………..} \quad \textbf{(II.38)}$$

Where *r* is the distance between the two wells. The type curve analysis method is simple, fast, and accurate when the exponential integral (figure**II.14)** applies; that is, when ***rD= r/rw*>20** and ***to/r2D* >0.5.** Knowing **Φ,** we can calculate total system compressibility, ***ct***, and hence estimate liquid saturation from the following equation. [**1**]

$$S_o = \frac{C_t - C_w - C_f}{C_o - C_w} \text{………………………..} \quad \textbf{(II.39)}$$

Chapter III

Optimization of the productivity index

III.1. What's optimization?

Production Optimization refers to the various activities of measuring, analyzing, modeling, prioritizing and implementing actions to enhance productivity of a field: reservoir/well/surface. Production Optimization is a fundamental practice to ensure recovery of developed reserves while maximizing returns. Production Optimization activities include:

Near-wellbore profile management

- gas–water coning and fingering
- near-wellbore conformance management

Removal of near-wellbore damage

- matrix stimulation or acidizing

Well integrity

- prevention and remediation of casing and cement failure

Design of well completion

- optimization of artificial lift performance at field and well level
- sand control management

Efficiency of oil and gas transport

Design of surface facilities and fluid handling capacity

Production system debottlenecking

Maximize the productivity index

- hydraulic fracturing
- maximum-reservoir-contact well with multilateral completion

III.1.1. Key factor in production optimization:

Is the capability to mitigate formation damage during well construction and production routine operations? [13]

Formation damage mitigation can be accomplished assuring that operational details are achieved before reaching the pay zone to the last production parameters recorded.

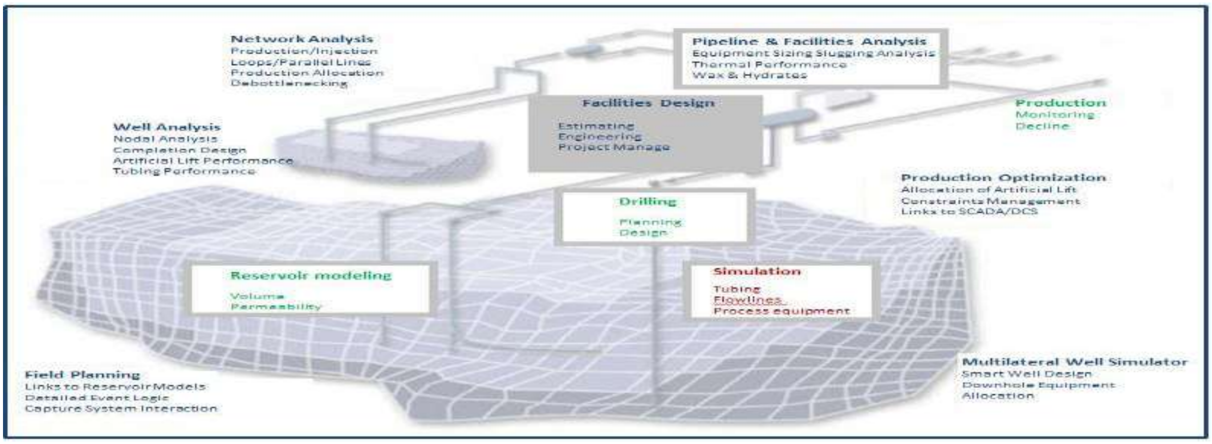


Figure III. 1 Various approaches to petroleum system production optimization.

III.1.2. Optimization of the productivity index for oil wells:

It is generally done for the purpose of increasing the well's productivity, by remediating damage near the wall of the well or by creating a structure of high conductivity in the formation. For this, several stimulation techniques are introduced: [13]

III.2. In Flow:

An ideal well productivity is the final goal of Production Optimization. In particular, well productivity is determined by a well inflow performance and in this context, a common approach is "Nodal Analysis". It is a system analysis approach applied to analyze the performance of systems composed of interacting components.

The Inflow Performance Relationship (IPR) is defined as the functional relationship between the inflow production rate and the inflowing pressure at node.

The optimization of the inflow index matched (correlate) multi-factors of PVT and type of drainage mechanism plus estimated reserve in place , all these factors can be study from wells tests and observant from measuring data of each well in the field .

If the data show incompatible signs of production we tack decision to do stimulation of reservoir for optimize parameters using one of the stimulation technical like hydraulic fracturing , acidizing , re-perforation ….

III.2.1. Example A Hydraulic fracturing:

Productivity index and inflow performance of wells intersecting multiple hydraulic fractures are of great importance. This importance comes from the fact that the fracturing process has become a common stimulation technique in the petroleum industry.

Hydraulic fracturing is an operation that consists of creating, after breaking the rock, a permeable drain extending as far as possible into the formation so as to facilitate the flow of oil towards the well. This process applies to the case where the flow rate of a well is insufficient; because of the low natural permeability of the rock (a few tens of millidarcys for oil deposits, even less for gas deposits), or because of clogging which is difficult to remove with acidification, in order to have a sufficient conductivity contrast between the fracture and the formation. Hydraulic fracturing is intended to remedy the damage to the well, and even improve the normal agreement of the well with the reservoir, in order to increase the permeability and therefore its productivity.

Hydraulic fracturing means the process of creating conductivity in a rock, from a well, by injecting fluid carrying a propane at sufficiently high pressures. Most often it is said that the hydraulic fracturing of a reservoir results in the opening of an existing fracture (case of a naturally cracked reservoir) and very rarely in the initiation of a new fracture (compact reservoir). Hydraulic fracturing treatment is generally applied in reservoirs with low original permeability or in heavily damaged formations, where production always remains low.

Fracturing is only suitable for sufficiently consolidated formations (sandstone, limestone) as opposed to plastic formations (clay, poorly consolidated sand). Moreover, it is strongly discouraged when it risks encouraging the arrival of an undesirable fluid more or less close (presence of an interface). [In the favorable case, productivity or injectivity gains can be expected].[15]

Therefore the treatment by hydraulic fracturing is for the purpose of decreasing the value of skin helps to increase the value of the IP of a well where the treatment of the damage due to the skin is the key to the optimization of the productivity index.

The presence of fractures considerably improves the IP of a well in fact hydrocarbons flow very easily in the fractures: the permeability can vary from 1 mD in the rocks up to 10000 mD in the fractures, it is elsewhere for this reason techniques have been developed to form artificial fractures around a producing well

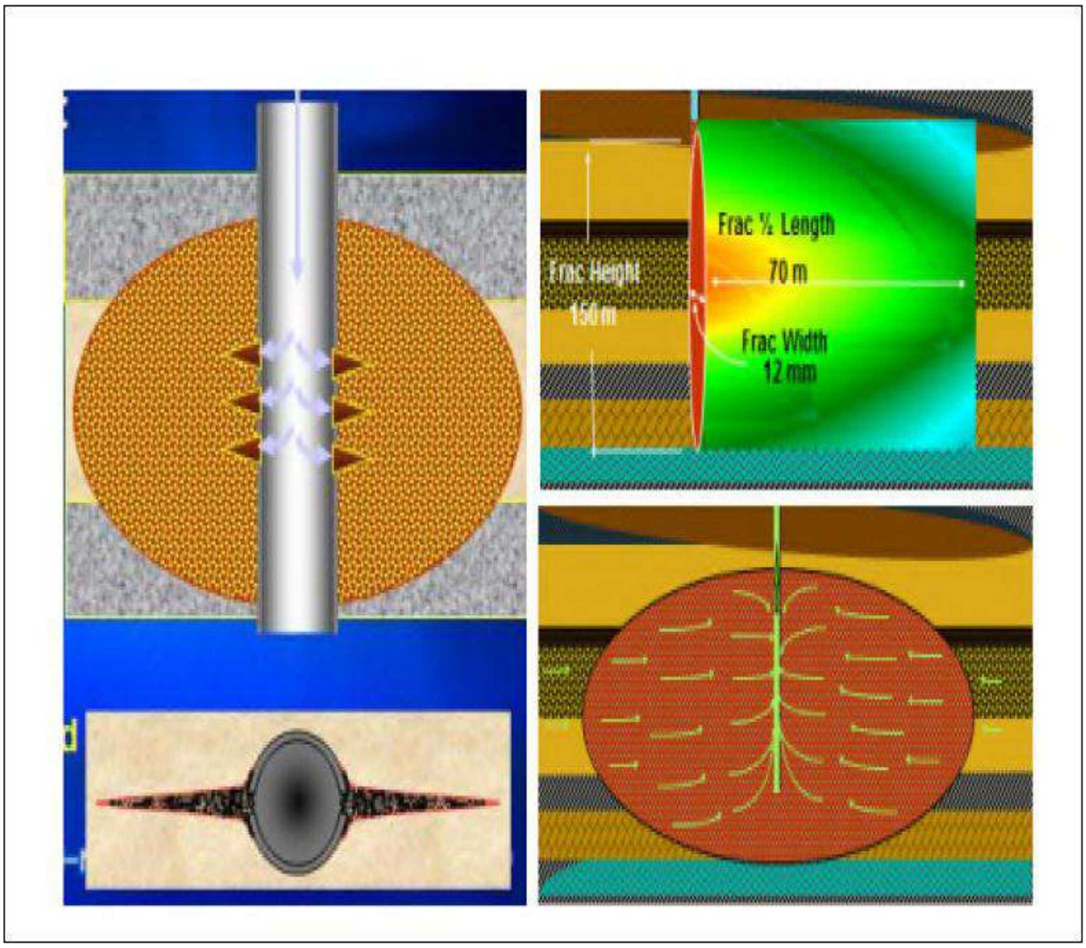


Figure III. 2 Principle of hydraulic fracturing.

III.2.2. Example B Acidizing:

Acidizing is a technique used to extend the useful life of an oil and gas well. The process of acidizing involves pumping acid into the well in order to dissolve the rocks that line the contours of the well.

Acidizing increases production rates by creating channels into the rock through which the oil and gas can flow into the reservoir. An additional benefit of acidizing a well is that it can help dissolve any loose debris found in the well. It is a technique aimed at improving the productivity of oil and gas producing wells. In matrix stimulation, acids are injected at injection pressures lower than the rock's fracturing limit pressure, to avoid passing the damage into the formation. It is especially effective when the natural permeability of the rock is good. Formations with degraded permeability are candidates for restoration by acidizing .

Acidizing may be more useful than hydraulic fracturing in some situations. Hydraulic fracturing–also called fracking– is a process that creates channels in underground rock formations by injecting a mixture of water and fracking chemicals into the well at very high pressures. Unlike hydraulic fracturing, acidizing does not require the same high-pressure injections. Rather, acidizing relies on the acid substance to dissolve any permeable sediments in the well. In regions where underground shale deposits are not uniformly arranged–for example in regions with
substantial tectonic activity, acidizing may prove to be more effective at unlocking oil deposits than hydraulic fracturing. However, in some cases, both methods are used in tandem. This process is known as acid fracking. The types and concentrations of acids used in the acidizing process are often not disclosed by the companies that manufacture them, although hydrochloric and hydrofluoric acids have been known to be used. Because of this ambiguity, it can be difficult to accurately assess the safety and environmental risks associated with this practice.[**15**]

III.2.2. Out Flow:

The optimization of the out-flow performance can be executed by flowing technical elements**:**

III.2.2.1. Completion configuration:

The objective of this part is to determine the effect of well completion types and other reservoir/ well parameters on the productivity index of a well.

The productivity of a petroleum well depends on the length of the section embedded in the reservoir and the perforation percentage of the section.

In the presence of one phase flow, it is assumed that the production in a well is directly proportional to the pressure difference between the reservoir and the wellbore.

The constant of proportional is the productivity index, 'j' or 'PI ' defined as Q / Δ**p**, where 'Q' is the flow rate and Δp is the pressure.

A lot of factors affect pressure in the reservoir and wellbore, thereby affecting the productivity index of the well. These factors include reservoir drainage area, pay zone thickness, anisotropy$_{\mathbf{kv/kh}}$, well length, fluid viscosity etc.

Another factor that greatly affects pressure drawdown is the well completion method. In this case, we can have pressure loss due to perforation (ΔP perf), pressure loss due to partial penetration (ΔPp), pressure loss due to gravel pack environment (ΔP gp) i.e. if gravel packing is done. During drilling, permeability can be damaged around the wellbore region and so pressure loss due to damage can also occur.

Productivity index is a valuable methodology for predicting the future performance of well so the correct choice of well completion mode plays a critical role in well design, and more importantly, the performance of the well in its entire life.

The major objective is to provide some guidance in the design of completion configuration by a series of simulation with different completions under different flow and reservoir environments. The reservoir outflow and inflow and the wellbore hydraulics under complex completion environment will be fully coupled in the study. The most popular completion options, including open hole, slotted liner, inflow control devices (ICD), intelligent well completions (DIACS), perforated cemented liner, wire wrapped screen, ECPs, gravel pack, and frac pack, will first be briefly introduced and reviewed.

The performance of the completions will be explored and compared for different wells under different flow conditions, including fluid type, well type, well rate, pressure drawdown, and reservoir geology.

Well performance will then be studied in details by evaluating the total well production, annular flow and flow inside the liner/tubing, pressure profiles along the annulus and along the liner, inflow from reservoir to annulus and fluid transfer between annulus and liner, and so on. Impacts of key parameters like skin factor, wellbore length, well completion configuration, and pressure drawdown, will be investigated. [**16**]

III.2.2.2. Types of completion:

Completions can be divided into three categories:

- open hole completions,
- liner completions,
- Perforated casing completions.

In most wells, conventional single perforated casing completions are used; however, multiple, alternate, or slim hole completions may be used under certain conditions. The choice of completion type should be closely coordinated with the development of the reservoir management plan. For example, the size, weight, and grade of the tubular goods will be determined based upon the ultimate use of a wellbore. An injection well may require stronger casing than a production well.

- open hole completions
- liner completions
- Perforated casing completions
- Single completion
- multiple completions
- Alternate completions
- Slim hole completion

Several types of liner completions are commonly employed in well completions. These include

- Slotted liner
- Screen and liner
- Cemented liner

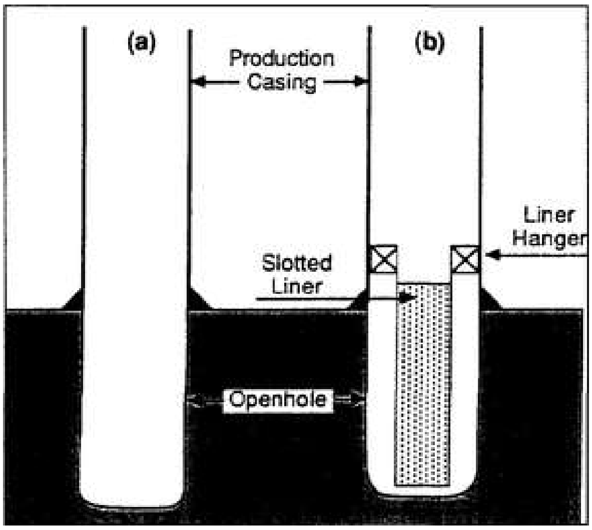


Figure III. 3 Wellbore diagram of (a) an open hole completion and (b) a slotted liner completion.

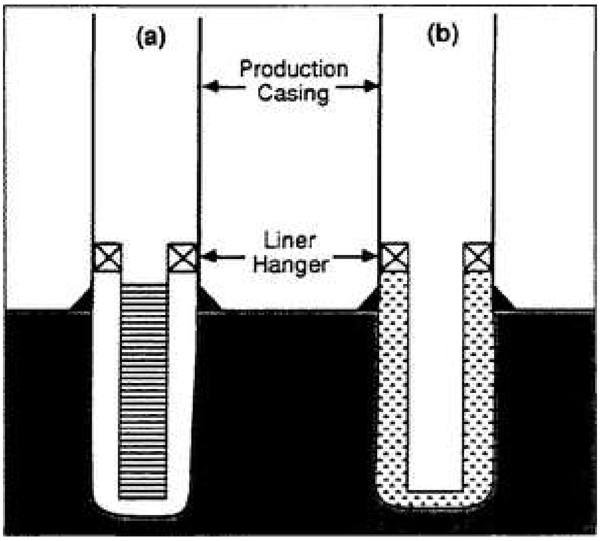


Figure III. 4 Wellbore diagram of (a) a screen and liner completion and (b) a cement liner completion.

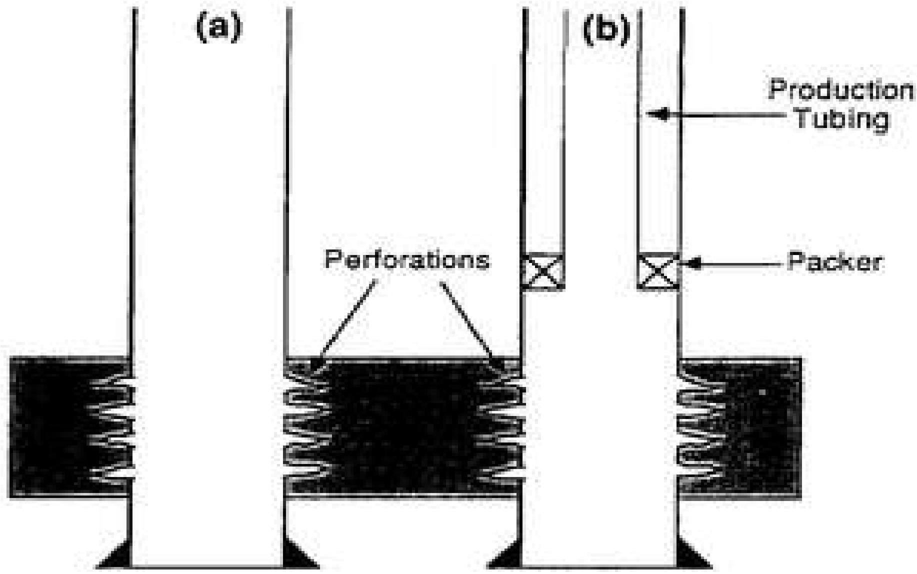


Figure III. 5 Simple completion.

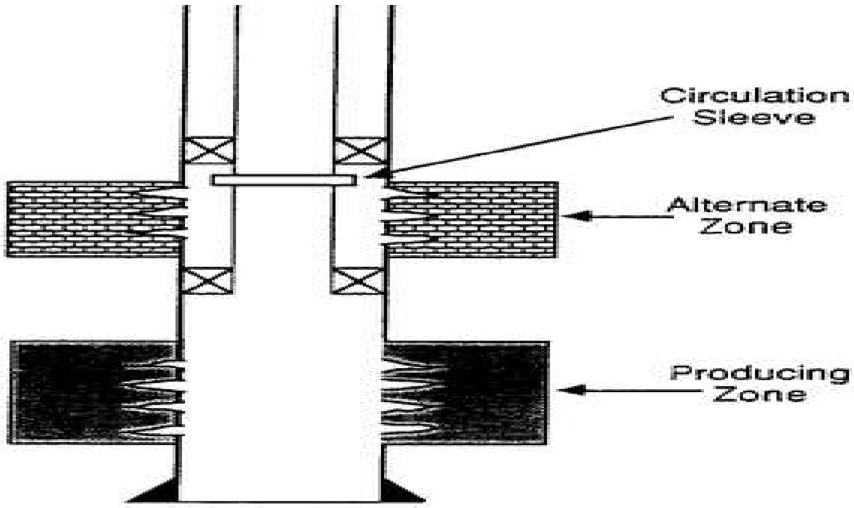


Figure III. 6 Alternate completions.

III.2.2.3. Effect of Well Completion's type on Productivity Index:

When a well undergoes completion, three types of skin occurs

- Skin due to perforation, **Sp**
- Skin due to penetration, **Sa**
- Skin due to crush zone permeability, **Sc**

Considering the case of skin due to penetration, some wells are fully penetrated along the interval of interest. In this case, **Sa** tend to zero (0); other wells are partially penetrated along the interval of interest, this results in pseudo skin due to partial completion. This kind of completion restricts fluid entry into the wellbore. The analyses on effect of completion on productivity will only be considered for a partially completed well.

III.2.2.4. Result and analysis:

Completion Effects on Productivity Index (Partially Completed Wells) In this case, only partially well completion was considered and the effect of partially penetration which results in skin productivity index.[18]

Table III- 1 Variation of productivity index with penetration ratio and pseudo skin for partially completed well (Brons and Marting correlation).

b'	CASE A SP	Jh (STB/day-psi) PI
0.2	16.254	0.675
0.4	6.635	1.137
0.6	2.878	1.552
0.8	0.992	1.899
	CASE B	
0.2	13.848	0.7513
0.4	5.5956	1.2276
0.6	2.4157	1.6245
0.8	0.8185	1.9394
	CASE C	
0.2	6.977	1.1098
0.4	3.1803	1.5073
0.6	1.3423	1.8235
0.8	0.4160	2.0391

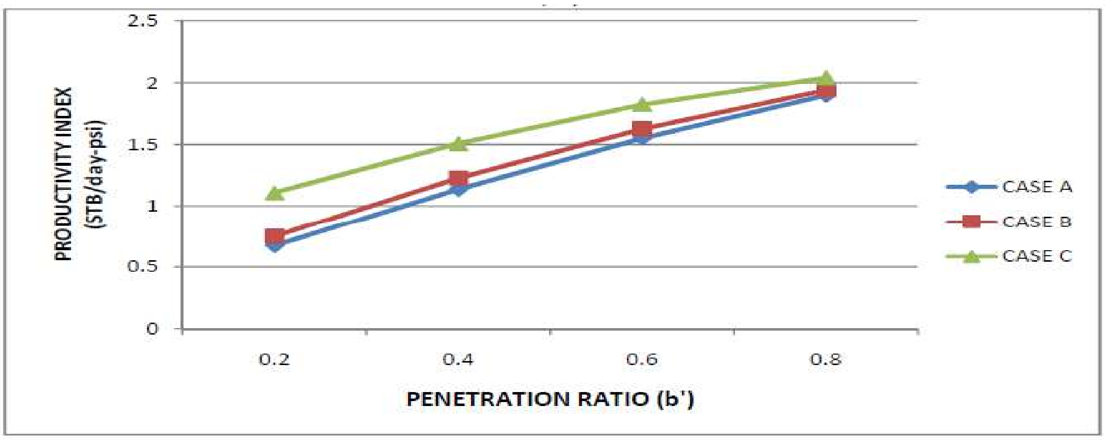


Figure III. 7 A plot of PI variation with penetration ratio for three different well completion configurations.

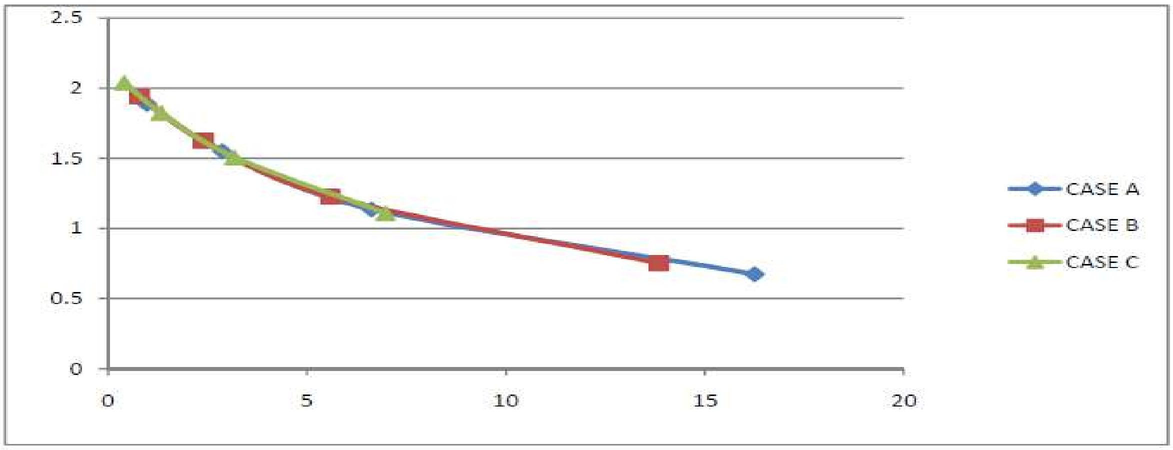


Figure III. 8 A plot of PI variation with pseudo-skin for three different well completion configurations Discuss of results obtained from plots and previous table.

III.2.2.5. Effect of Pseudo-Skin Due To Partial Penetration on Productivity Index:

Generally, the larger the skin, the lower the productivity index (PI) of a well. This effect is however more pronounced for the vertical well. This is due to the multiplier h/L on the horizontal well skin.

H is the pay zone thickness and L is the lateral length of the horizontal well. As L increases, the effect of skin on horizontal well productivity index reduces appreciably as shown in fig III-8 (effect of pseudo-skin on PI ratio).

III.2.2.6. Effect of Penetration Ratio on Productivity Index:

- Productivity index increases with increasing penetration ratio. The analysis done for the three (3) well configuration shows that the case C i.e., the well with N interval opens to production, and it is the best configuration for any partial well completion.
- The no opened interval on the liner allows for less pressure drop and allows for easy fluid entry into the wellbore. In doing so, the problems associated with skin will be reduced. In some cases, there are cases of no skin, hence no damage around the wellbore.

III.2.2.7. Resume of discussion:

- The factors which affect pressure drop between reservoir and the wellbore such as well length, permeability, reservoir thickness, drainage area, fluid viscosity and perforation percentage are also factors affecting productivity index**.**
- Productivity does not only depend on the well length, but also on the type of completion used and the efficiency of the completion of work done
- Productivity index is affected by skin, those caused by completion include:

(a) Pseudo skin due to perforation

(b) Pseudo skin due to partial penetration

(c) Skin factor due to reduced crushed – zone permeability

(d) Rate – dependent skin factor due to near wellbore turbulence

- For the three partial well completion configuration method as proposed by Brons and Marting, the third configuration i.e. wells with N intervals open to production is the most acceptable completion method.

III.2.2.8. Conclusion:

Partial completion is the completion of or flow from less than the entire producing interval. This situation causes a near-well flow constriction that result in a positive skin effect in a well-test analysis.

III.3. Applications of interference tests to optimize a well's PI:

The interference testing as all Well testing types, it is a subdivision of reservoir and production engineering, which is usually considered as a significant step toward qualitatively and quantitatively characterization of hydrocarbon reservoirs. The identification of well test interpretation models and estimation of reservoir parameters are two important parts of a well test analysis process.

The information provided by an interference well test is also important for estimating the reservoir productive capacity and average pressure. The analysis of reservoir performance and predicting its future production is based on having appropriate information about the reservoir properties and circumstances. Generally, oil and gas well test analyses are performed to achieve several objectives:

- characterizing the reservoir and evaluating the well condition,
- predicting the skin factor (a measure of formation damage),
- describing the reservoir through the calculation of reservoir parameters,

Therefore, the elementary application of interference test is for the objective of:

- Determining the productive zones of a drilled well.

The interference test as part of well testing can reveal a great deal about well performance and reservoir behaviour. During the flowing period essential parameters are recorded:

- Oil flow rate.
- Gas flow rate.
- Gas oil ratio.
- Water cut.
- Flowing pressure (surface).
- Flowing pressure (down-hole).
- Flowing temperature (surface and down-hole).
- Solids production.

A properly designed and conducted test provides valuable information about:

- Formation permeability.
- Reservoir pressure.
- Reservoir boundaries.
- Reservoir layering and zonal contributions heterogeneity.
- Near wellbore damage (skin).
- Well productivity index and absolute open flow potential.

In interference well testing the pressure variation with time recorded in observation wells resulting from changes in rates in production or injection wells. In commercially viable reservoirs, it usually takes considerable time for production at one well to measurably affect the pressure at an adjacent well. Consequently, interference testing has been uncommon because of the cost and the difficulty in maintaining fixed flow rates over an extended time period. With the increasing number of permanent gauge installations, interference testing may become more common than in the past.

III.4. When the test is applicable?

Interference is applicable whenever one needs to know whether two or more wells in a formation are in pressure communication. It is also used in improved recovery processes (water, gas, or other fluid injection projects) in which knowledge of directional permeability differences and reservoir description generally are critical to the success of the project.

This test work best in formations that have higher permeability's, closer spacing, and single-phase flow. In gas reservoirs, high formation pressure is more desirable than low pressure in achieving a successful test. [18]

Chapter IV

Experimental section

IV.1. DST Interpretation:[19]

IV.1.1. Introduction:

The signs of the interference can be detected from the exploration phase through a good interpretation of the DST test which can suspect or even confirm the non-heterogeneity of the reservoir which can be a direct cause of the interference (existence of a major fault). As so the flowing example.

IV.1.2. Information obtained from Well Testing:

IV.1.2.1. Reservoir description:

- Reservoir responses.
- Reservoir in dynamic condition (flow lines are established).
- Large volume investigated (averaging).
- Results.
- Permeability (horizontal *k* and vertical *kv*).
- Reservoir heterogeneities.
- Natural fractures.
- Layering.
- Change of characteristics.
- Pressure (initial *pi* and average p).
- Boundaries (distance and Shape).

IV.1.2.2. Well description:

•Results.

•Production potential.

•productivity index PI.

•skin factor S.

•Well geometry.

IV.1.3. Principle:

The basic principle of well testing is to create a perturbation in the state of the reservoir fluids this perturbation is caused by opening or closing the well or by changing the rate. The fluids, initially at a steady state, go to a transient state (A) during flow, then to a new transient state (B) during build up, before reaching the final steady state.

Continuous and precise recording of pressure and flow rate variations are made during the transient periods A and B. The parameters which control the reservoirs performance are evaluated, using Darcy's law and the diffusivity equation which relate the change of pressure to:

• The well conditions.

• The type of reservoir.

• The external boundaries.

IV.1.4. Test Design:

All available data on this well, open-hole DST, RFT* (Repeat Formation Tester) logs and core analysis were input to the test design module of the ZODIAC* (Zoned Dynamic Interpretation Analysis and Computation) program. This was done to help in selecting test intervals, the type of test to attempt, and the choice of test program and equipment to use, as well as to ensure that the objectives could be met within acceptable costs (**Figure IV.1**).

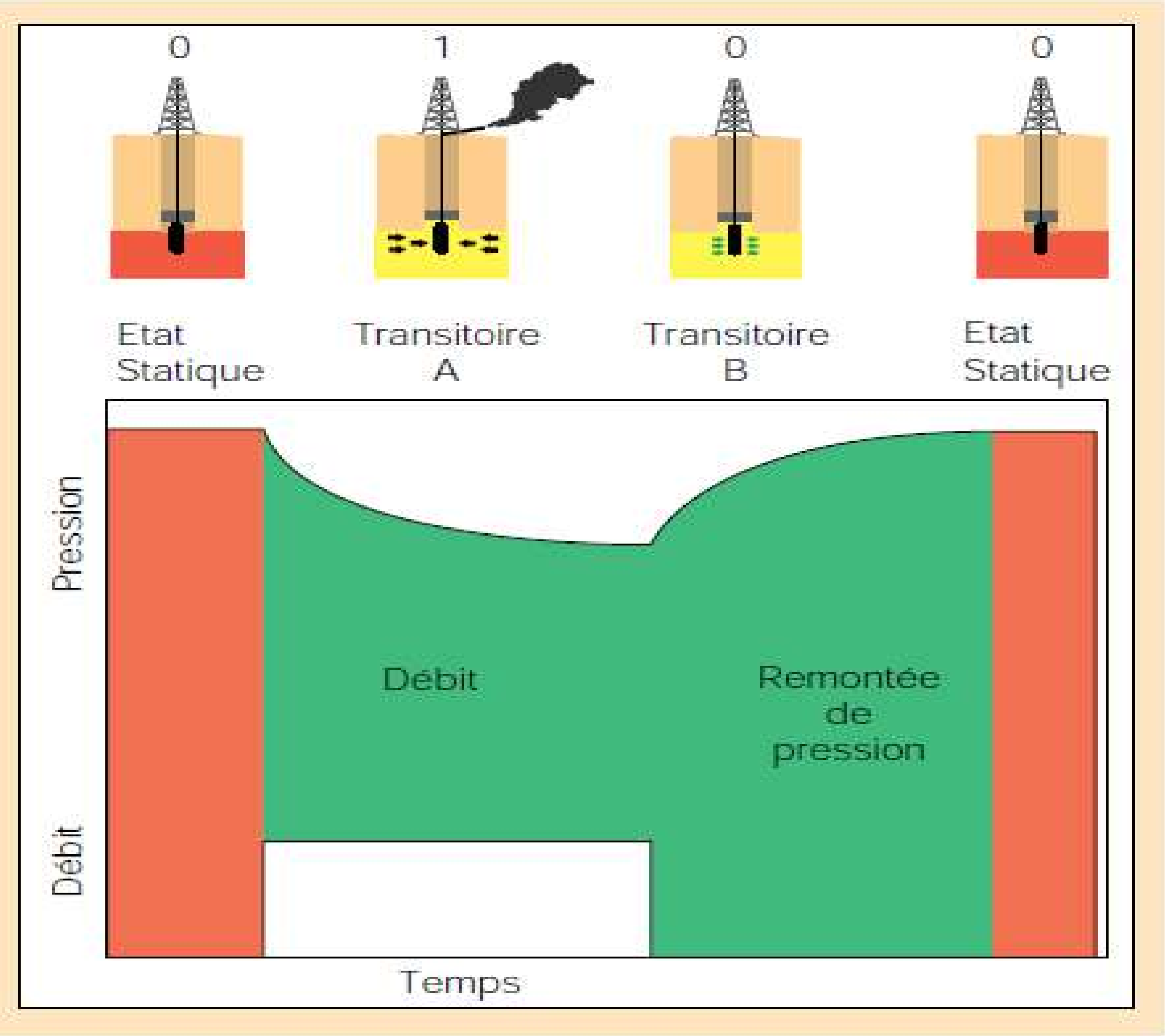


Figure IV. 1 The basis of well testing is to create a perturbation in the physical state of reservoir fluids.

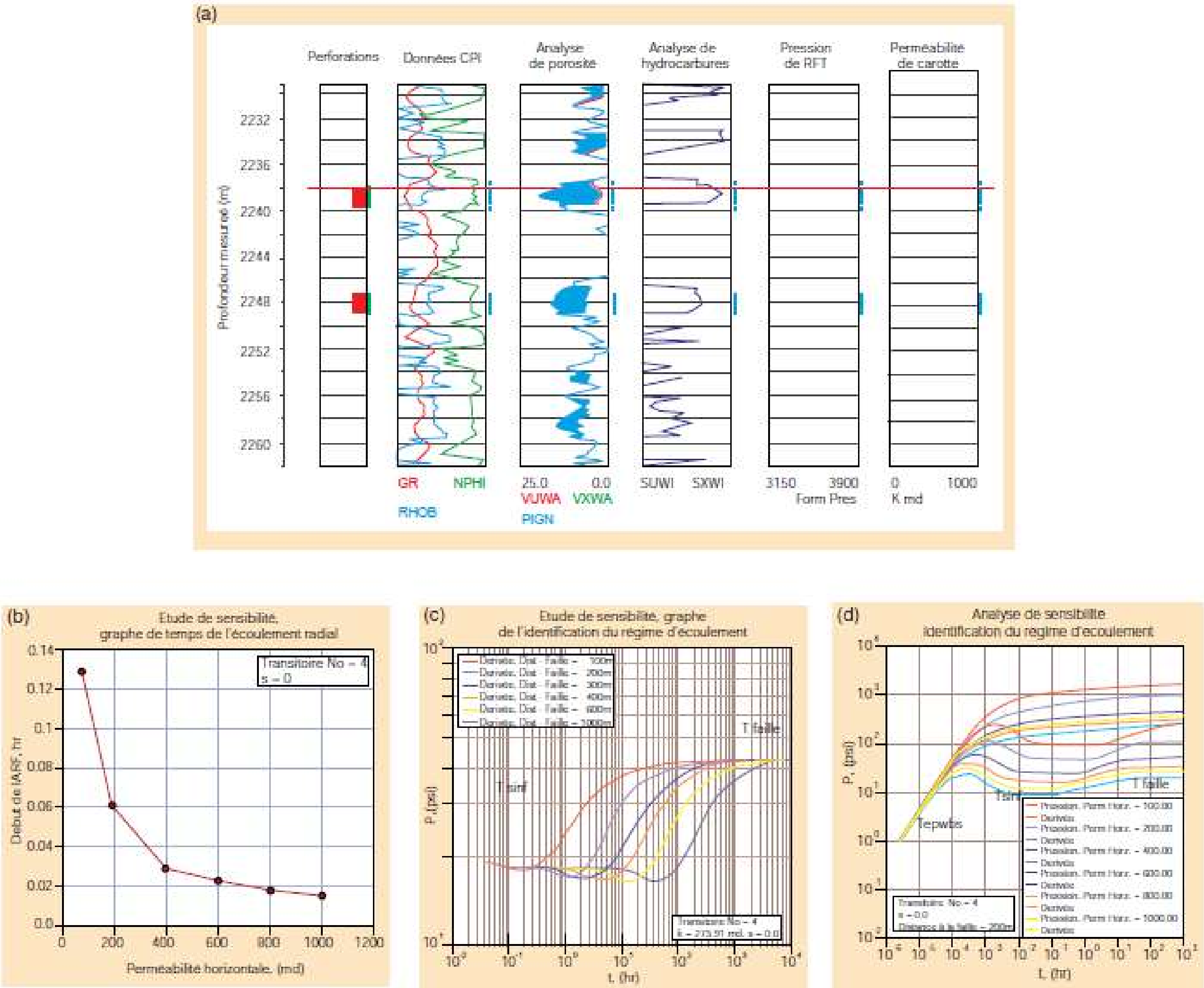


Figure IV. 2 Test design in cased hole well.

The data entry into ATLANTIS* (interactive workstation) where ZODIAC was installed made access simple. In this case the program picked the test intervals from the open-hole logs and determined the average permeability to use in the model design from core data. The response of the well and reservoir during the test could be predicted from the open-hole DST.

The test design module outputs sensitivity plots of time and pressure as a function of the reservoir parameters to be tested.

For example, the sensitivity plot for radial flow shows the time required to reach the start of the IARF (Infinite Acting Radial Flow) as a function of reservoir permeability. In this well, using the average core permeability of 273 md, the plot indicated that radial flow started approximately 0.04 hours (2.4 minutes) after the start of the transient.

The reservoir model from the results of the open-hole test indicated the presence of at least one fault. One of the objectives of the cased hole DST was to find the distance between the well and the fault(s) and determine the fault type. For a permeability of 273 md, the sensitivity plot 'flow regime identification' shows the effect of the presence of fault(s) on the pressure response for distances varying from 100m to 1000 m. At a distance of 100 m, the effect on the derivative starts 0.4 hours (24 minutes) after the beginning of the shut in. The effect of a fault at 200 m is seen after 2 hours. Selecting a fixed distance of 200m for the fault allows us to examine pressure behavior for a range of different permeability's.

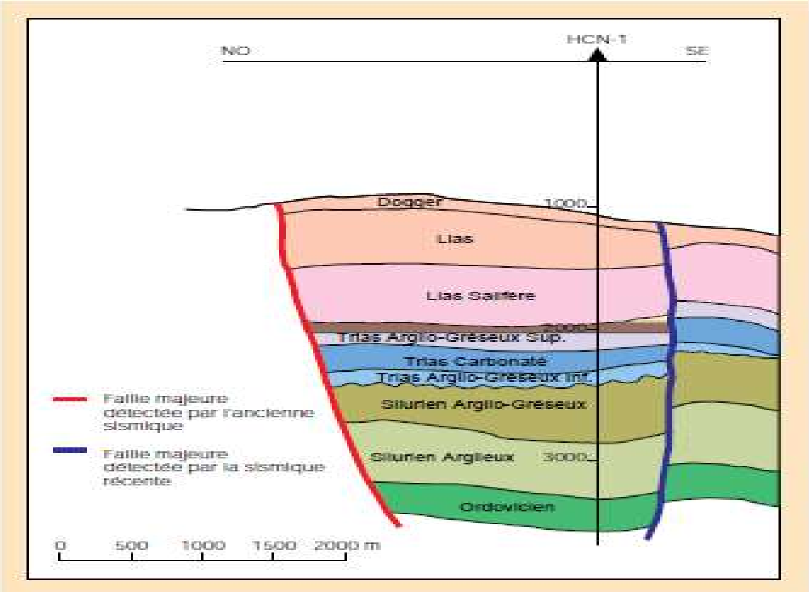


Figure IV. 3 Before drilling (of well HCN-1) this area was believed to have a single major fault west of the well drilled to explore the Triassic reservoir.

IV.1.4.1. Interpretation:

The diagnostic plot (**Figure IV.4b**) of the pressure behavior during the last build-up identifies:

❖ At early time:

- A very small wellbore storage effect which dissipates rapidly after shut-in (30 seconds), thus validating the choice of a down-hole
- Shut-in valve; at intermediate time:
- A radial flow regime (IARF) represented by a plateau in the derivative between 0.02 hr. (1.2 min.) and 0.08 hr. (4.8 min.);

❖ At late time:

An indication of a fault system defining the reservoir limits, showing on the derivative by two ascending plateau, the effect of fault 1 (the fault nearest to the well) starting at 0.2 hr.(12 min.) and that of fault 2, (which is further away) starting at 3 hr.

The specialized analysis for the radial flow period, (Horner plot - see **Figure IV.4c**) gives the following reservoir and well parameters:

• Skin S= 0.9.

• Transmissivity kh = 1300 md-m. | •Permeability k = 330 md.

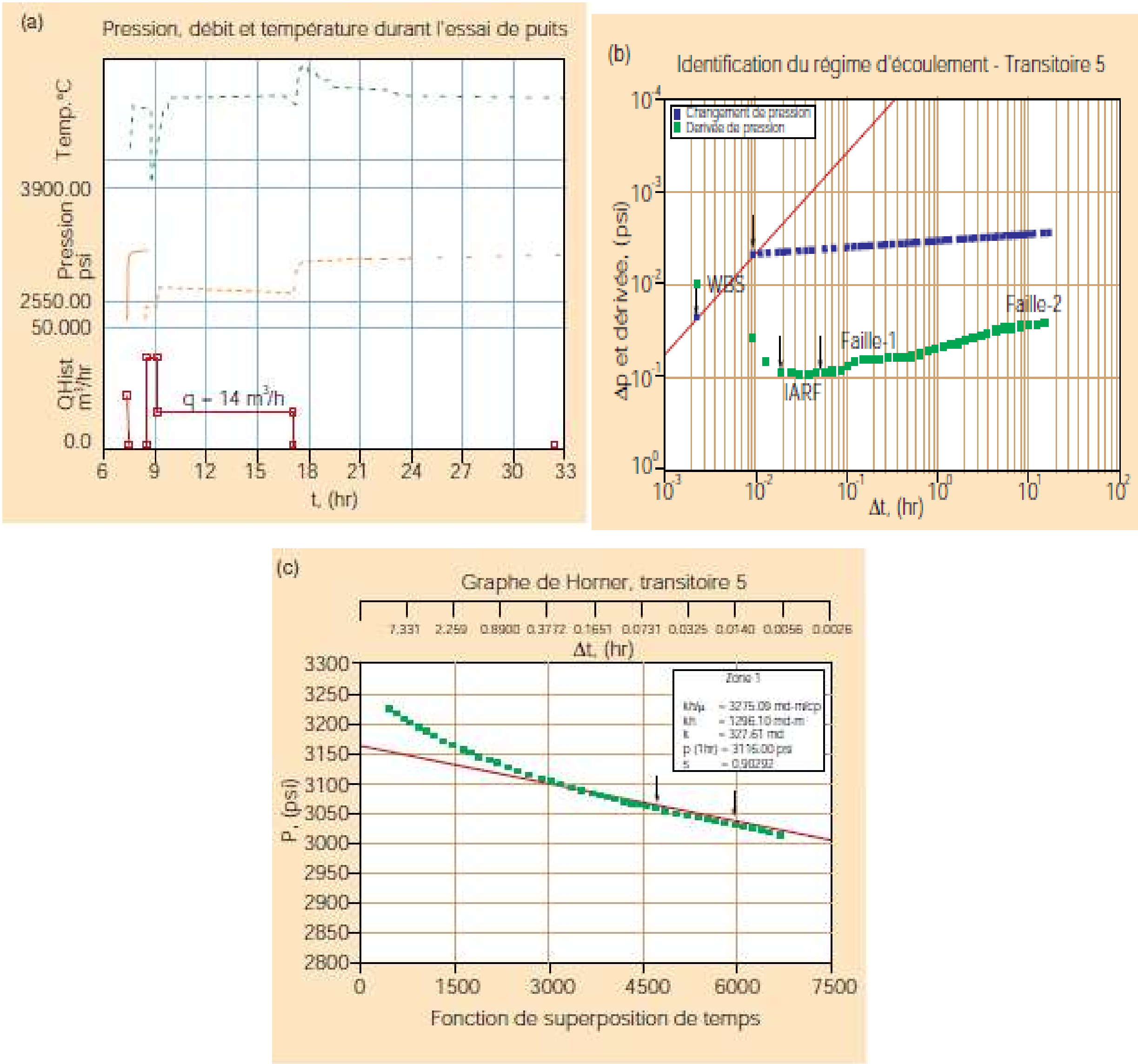


Figure IV. 4 The diagnostic pressure plot (b) identifies a low wellbore storage (early time), radial flow regime (intermediate time), a system of faults defining the reservoir limits (late time). The specialized analysis of the radial flow (Horner plot) (c) evaluates the well and. reservoir parameters

These results were used in a non-linear analysis for construction of a reservoir model in an effort to optimize the match for the entire transient period.

The response of the pressure and its derivative show that there is more than one fault affecting the behavior of the system. The shape of the curve is typical of a well which is located between two intersecting sealing faults. Non-linear analysis is used to quantify the relationships of angle between faults and the distance from the well to the point of intersection. This technique gave a perfect fit of the pressure and its derivative for a model of the reservoir limited by two sealing faults intersecting at a distance of 185m with an angle of 88° between them (**Figure IV.5a**).

The Horner verification plot (**Figure IV.5b**), confirmed the correlation between the model and the measured data. The type curve is presented along with the data on a semi-log scale. DP is plotted on a linear scale for greater sensitivity in confirming the initial reservoir pressure. Here also the match is excellent. The surface flow rate measurements were used throughout the entire test to construct the theoretical pressure history. This also compares very well with the measurement (**Figure IV.5c**).

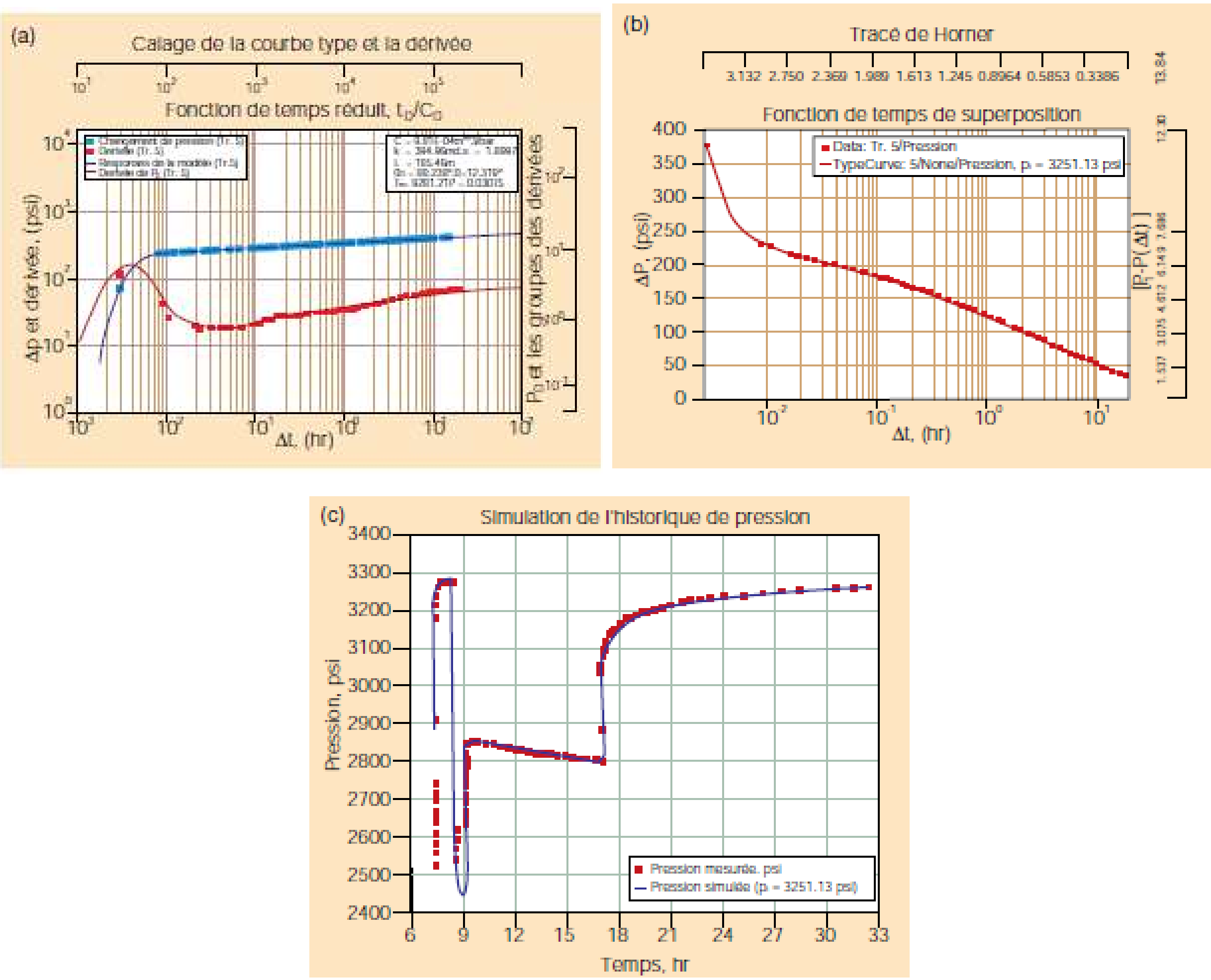


Figure IV. 5 The pressure and pressure derivative data show a reservoir limited by two sealing.

Faults (a). The Horner verification plot (b) confirms the correlation between model and measured data. There is a close match between theoretical and measured pressure histories

IV.1.4.2. Discussion:

The results of this interpretation confirm the existence of the faults seen on the open-hole DST, adding more information on their nature and position in relation to the wells (**Figure IV.6**).

However, it is difficult to confirm these results with surface seismic which only identified the major faults in the area. No faults were found in the zone around the well, because the seismic resolution is not good enough to detect localized faulting, especially if the faults in question are characterized by small throws.

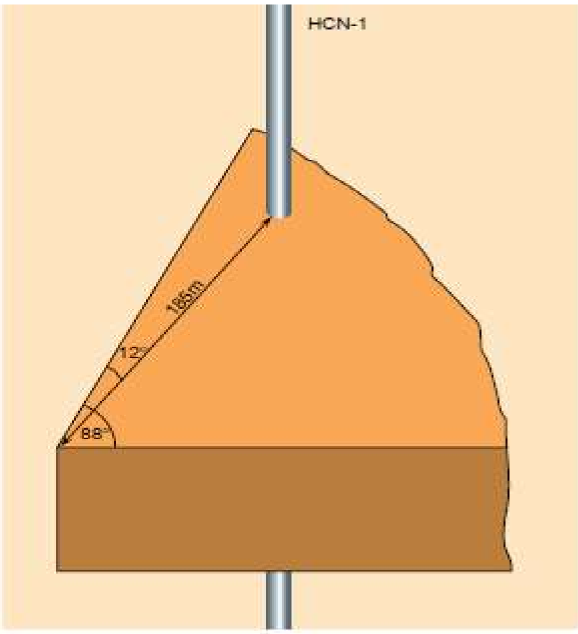


Figure IV. 6 The two faults intercept at 185m from the well at an angle of 88°.

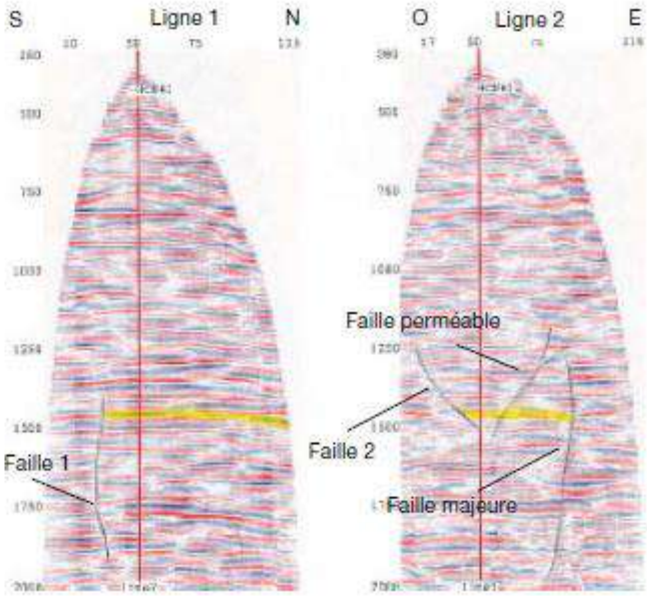


Figure IV. 7 Seismic (VSP Walkaway) results confirm the model derived from the well test interpretation.

To confirm the test analysis, a walkaway VSP survey was run on HCN-1 with two lines - line 1 which was oriented N-S and line 2, E-W. The results of the seismic interpretation (**Figure IV.7**) confirm the model derived from the DST interpretation, as follows:

• On line 1, a fault can be observed approximately 250m south of the well (fault 1);

• On line 2, a fault is observed approximately 50 m west of the well (fault 2).

These are the two faults (confirmed by their occurrence at comparable distances from the well) which were identified as barriers during the well test. The fault which is situated on line 2, 150m east of the well, appears to be permeable, since it was not detected by the well test.

The fault located 1000m to the east of the well is the major fault which had already been detected by surface seismic. It did not appear in the well test results because it is located outside the range of investigation.

A definitive model for the Triassic reservoir in the area was finalized by combining all of these data

IV.2. Interference test Interpretation:[20]

IV.2.1. Introduction:

With the extensive exploitation of shale gas fields such as Changning-Weiyuan, Zhaotong and Jiaoshiba, the engineering technologies represented by factory-like drilling and volume fracturing have been widely used in recent years. For purpose of optimal development, it is necessary to clarify the production performance characteristics of wells/blocks. The factors affecting the production performance are mainly divided into uncontrollable factors (e.g. porosity, water saturation, initial pressure, permeability and natural fracture distribution) and controllable factors (e.g. well spacing, completion pattern, and working system). The controllable factors can be optimized to enhance the well deliverability. As the most critical one, horizontal well spacing directly affects shale gas recovery factor, estimated ultimate recovery (EUR) and economic benefits, and can only be adjustable in a limited extent once the drilling is finished. Therefore, preliminary verification of well spacing is very important. As demonstrated by practical development of unconventional gas wells, when interference exits between wells, the ultimate cumulative gas production of a single well declines with the reduction of well spacing, but the inter-well reserves can be effectively produced. Overall, the recovery of the gas reservoir is enhanced, and the investment also increases. It is thus believed that shale gas development corresponds an optimal well spacing/number of wells.

IV.2.2. Overview of the study area:

In the Ning 201 well block in the Changning National Shale Gas Demonstration Area, southern Sichuan Basin, the shale gas reservoir from Wufeng Formation (O_3w) to Longmaxi Formation (S_1l) is buried in a depth of 2500-3300 m. The structure is relatively gentle. The high-quality layers include the first member of Wufeng Formation (O_3w_1) and the $S_1l_1^1$-$S_1l_1^4$ of Longmaxi Formation, which are mainly composed of deep-water shelf sub-facies, with an effective thickness of about 35 m. Within the block, the gas reservoir is relatively stable, with a total gas content of 4-8 m^3/t, and the reserve abundance of about (500-600) $*10^6$ m^3/km^2, varying from layer to layer. Horizontal well is targeted to the $S_1l_1^1$ and S_1l^2 layers, which are totally 8-10 m thick and contain a high content of organic matters. Due to tight matrix and presence of micro pores, as well as faults and natural fractures locally, the two layers can only be effectively developed by way of horizontal well þ volume fracturing. The landform is dominated by mountains with crisscross ravines, which expose great challenges to the construction of well sites and pipelines and fracturing treatment. For purpose of economic development, it is essential to adopt the pad-based horizontal well placement, factory-like drilling and fracturing, and extensive and continuous operations. As of the end of 2020, a total of 29 pads had been deployed in the Ning 201 well block, and 136 horizontal wells were drilled and fractured. At the 13 pads deployed before 2017, the development well spacing ranges from 400 m to 500 m. As more field test data (e.g. interference test, and micro-seismic monitoring) and production performance data become available, the relationship between effective fracture length and micro-seismically monitored fracture length is obtained. Through analogy and considering the factors such as horizontal stress in two directions and development degree of natural fractures, the well spacing has been reduced from 400 to 500 m before 2017 to 300-400 m currently. The production performance evaluation results show that the well spacing can be further optimized after verification from multiple perspectives.

IV.2.3. Interference pattern:

Inter-well interference is a key indicator for well spacing optimization. It is defined differently in each development stage. For example, in the fracturing stage, inter-well interference refers to the fracturing interference caused by fracture breakthrough (or fracturing breakthrough) between wells. The concept of fracture breakthrough was originated in the infilling test of shale gas wells in the United States. During the test, new well fracturing made the inter-well stress shadow increase to form stress vortex, and thus the fractures between old wells and new wells were connected, causing a sudden increase in pressure and water content in old wells. In addition to geological factors and rock mechanical properties, well spacing and fracturing scale are important controllable factors that affect fracture breakthrough. As the sanding intensity and well spacing increase, the fracture length (the area in contact with the formation) also increases. shows the fracture connection between wells spaced differently under same fracturing scale in the Marcellus shale gas field. When the well spacing is 528 m, no effective fracture breakthrough is formed between the two wells. When the well spacing is reduced to 301 m, significant fracture breakthrough occurs. The probability or degree of inter-well fracture breakthrough is apparently higher under the condition of small well spacing. The optimal well spacing is 301-528 m. According to the connecting media between wells, the interference patterns can be further divided into two types: interference connected by induced fractures and interference connected by matrix or natural micro fractures. In case of matrix-connected, only a very low tracer content or a weak pressure response is obtained from the observation well, suggesting that there are no connected fractures. Numerous practices have shown that a production interference caused by fracture breakthrough to different degree is highly probable between wells during shale gas development. It needs to be emphasized that the strong inter-well connection corresponding to the fracturing breakthrough cannot survive in the lifecycle of the gas wells, so the corresponding well spacing when significant fracturing breakthrough occurs can be used as the upper limit of the optimal well spacing. In the fracturing process, the migration distance of the fracturing fluid is much greater than that of the proppant, so the breakthrough-induced fractures are mostly formed by the filling of fracturing fluid, not the effective filling of proppant. The breakthrough-induced fractures mean that all the inter-well areas can be swept by volume stimulation. In the production (flow back) process, however, the breakthrough-induced fractures gradually close and will never be connected, so they cannot cause significant production interference. Interference in this paper mainly refers to the pressure disturbance in the production process, which is divided into two types: fracture-connected and matrix-connected, as shown in (**figure IV.8)**.The fracture-connected production interference is relatively strong the response signal can be received in a few seconds to a few minutes, depending on the degree of fracturing breakthrough. The matrix-connected production interference can be acquired in a few or even decades of years. The response characteristics of these two types of interference are quantitatively analyzed using the mathematical model.

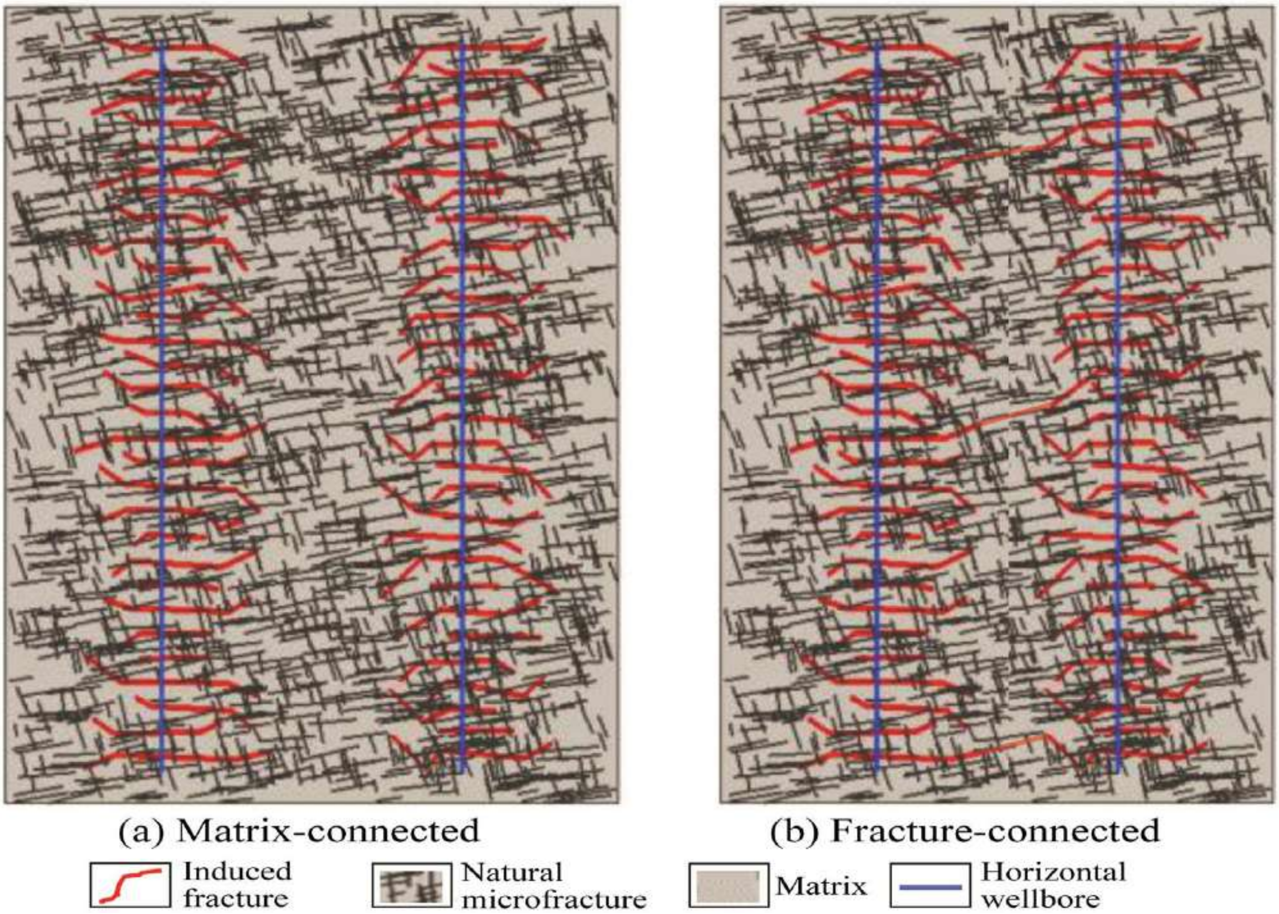


Figure IV. 8 Inter-well interference pattern (modified from Ref).

IV.2.4. Interference model:

A rational method is established to quantitatively evaluate how the fracturing breakthrough and degree of fracturing breakthrough affect the production performance. When multiple wells are simultaneously opened/closed in the same flow system, the resulting pressure disturbance propagates in the medium. When the pressure disturbances interfere with each other, the change in the working system of a well will affect the bottom hole pressure or production of adjacent wells; as a result, the formation energy is redistributed among wells. The propagation law of pressure wave in the formation is usually evaluated by the detection radius. It is necessary to establish a pressure interference model for quantitative research. (**Figure IV.9)** shows a double-well interference model with breakthrough-induced fractures. As shown in (**figure IV.9)** a, assuming that Well 1 is shut in for a long enough time, its pressure equals to the initial pressure, and Well 2 maintains producing under a normal pressure. By simulating the bottom hole pressure corresponding to Well 1 and Well 2, the degree of interference between the two wells is quantitatively characterized.

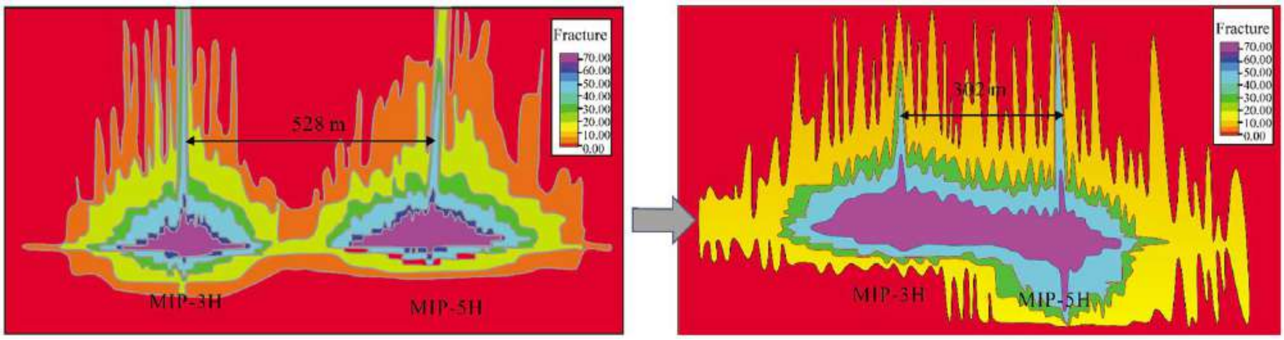


Figure IV. 9 Fracture connection at different well spacing (fracture thermal imaging).

This model uses two basic theories. Theory 1 is the linear flow equation: according to the linear flow equation, the correlation between the production-corrected pseudo-pressure difference and time can be obtained, as follows:

$$\frac{m(p_i)-m(p_w)}{q_{sc}(t)}=\frac{0.196B_{gi}}{\sqrt{k_{SRV}}n_f L_f h}\sqrt{\frac{1.23\mu_{gi}t}{\phi_{SRV}c_{gi}}} \quad \text{..............................} \ \textbf{(IV.1)}$$

where, m(p) is the gas pseudo-pressure function; Lf is the fracture half-length, m; pi is the original formation pressure, MPa; pw is the bottom hole pressure, MPa; qsc is the production rate of the gas well under standard conditions, 104 m3/d; Bgi is the gas volume factor under the original formation pressure; kSRV is the average permeability of the formation in the volume fractured zone, 10_3 mm2; nf is the number of fractures; h is the thickness of the formation, m; 4SRV is the average porosity of the formation in the volume fractured zone, %; mgi is the gas viscosity at the original formation pressure, mPa$s; cgi is the gas compressibility factor at the original formation pressure, MPa_1; t is the time, d. Taking the relevant parameters in Equation below as the slope symbol mCR, the linear flow equation can be simplified as:

$$\frac{m(p_i) - m(p_w)}{q_{sc}(t)} = m_{CR}\sqrt{t} \quad \text{.............................. (IV.2)}$$

Theory 2 is the material conservation equation: for Well 1 (shut-in), the amount of material flowing from formation to Well 1 ¼ the amount of material flowing from Well 1 to Well 2; for Well 2, the produced amount from wellbore ¼ the amount flowing from formation to the fractures of this well þ the amount flowing from Well 1 to Well 2. The linear flow equations for Well 1 and Well 2 are as follows:

$$\begin{cases} \dfrac{m(p_i) - m(p_{wf,1})}{q_{sc1}(t)} = m_{CR1}\sqrt{t} \\ \dfrac{m(p_i) - m(p_{wf,2})}{q_{sc2}(t)} = m_{CR2}\sqrt{t} \end{cases} \quad \text{.............................. (IV.3)}$$

According to the material conservation equation, there is:

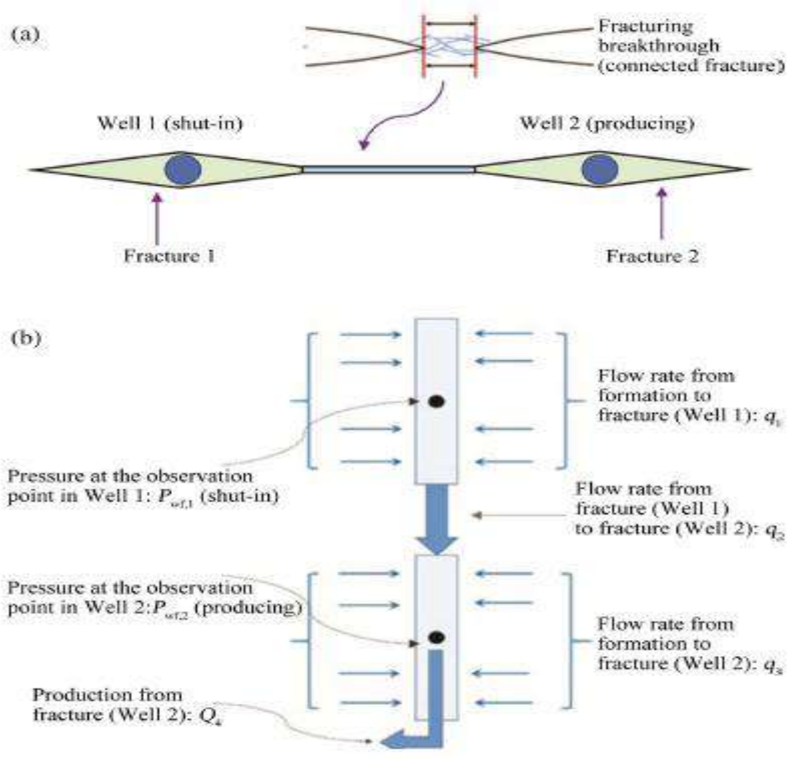


Figure IV. 10 Inter-well interference model with breakthrough-induced fractures.(a) Schematic diagram of physical model; (b) Conceptual model of equivalent calculation.

IV.2.4.1. Inter-well interference diagnosis and analysis:

Short-term production interference does not mean a decrease in EUR, and EUR can well represent the benefits of inter-well interference. Based on the simulation results of inter-well interference, inter-well interference and interference degree are diagnosed with actual dynamic data. When adjacent wells are shut in or opened, the dynamic (production, pressure) responses of the target well can be analyzed to intuitively judge whether there is inter-well interference. Moreover, in order to quantitatively characterize the impact of inter-well interference on production performance, the production decline, dynamic analysis and productivity evaluation techniques are used for evaluation.

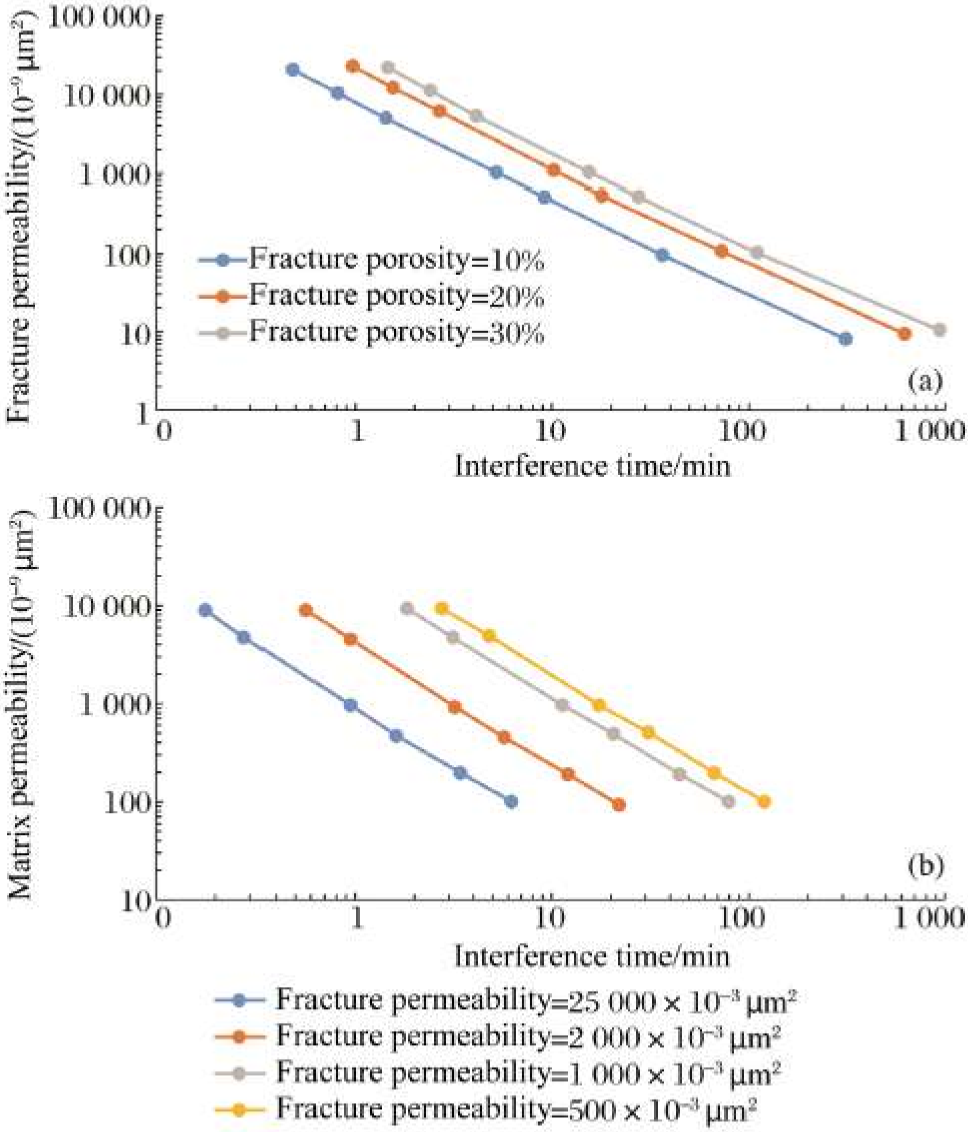


Figure IV. 11 Interference time under different connection patterns. (a) Fracture-connected; (b) Matrix-connected.

IV.2.4.2. Production performance analysis:

To analyze inter-well interference through production performance, a relatively intuitive approach is to analyze the changes in production performance of a well before and after interference between it and adjacent wells. After the interference occurs, the well productivity deteriorates, in other words, a slight increase in pressure at wellhead will cause a great decline in production. With the data of X-1, the inter well pressure interference is calibrated by using the productivity index method and production decline analysis. The productivity index PI is defined as follows:

$$PI = \frac{q_{sc}}{m(p_{avg}) - m(p_w)} \quad \text{(IV.4)}$$

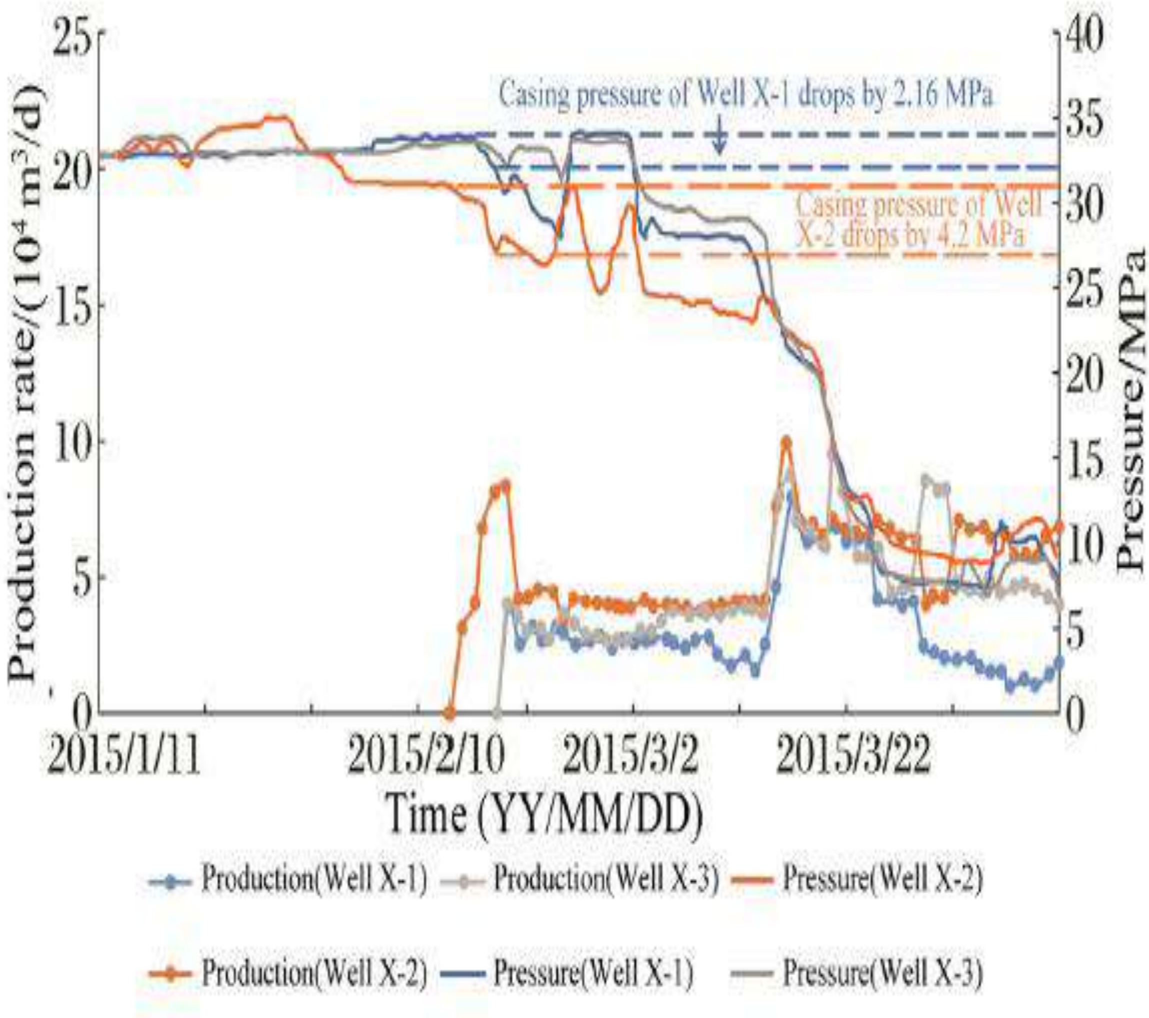


Figure IV. 12 Inter-well interference test on the X pad.

IV.2.5. Conclusion:

Design and optimization of well spacing is a key indicator for evaluating the development effect of shale gas reservoirs. On the basis of theoretical understanding, and after the verification by analogy, numerical simulation, and economic evaluation, a complete workflow from inter well interference simulation and dynamic data diagnosis to multi-well production simulation and well spacing optimization was formed. First, a pressure detection boundary propagation model is established to simulate the response degree of inter-well interference under different connected conditions. Second, inter-well interference is identified and diagnosed depending on the inter-well interference response behaviors and the interpretation of performance data from gas wells. Third, taking the geological interpretation and dynamic analysis results as basic parameters, a multi-well numerical model for volume fracturing in gas reservoirs is established to simulate the production performance of gas field, and then well spacing is optimized in combination with the net present value model. The application in the Ning 201 well block in the Changning National Shale Gas Demonstration Area has shown that a smaller well spacing can allow a premature inter-well interference and also the enhancement of recovery in the entire block. Given the current fracturing scale and parameter system, the well spacing of 300-400 m can be optimized to 260-320 m, that is, the number of wells per unit area increases by 20%-30%. As a result, the recovery percent of reserves in the block increase by about 10%. The net present value of the block rises, but the corresponding optimal well spacing does not change, with the production period

IV.3. Production interference test interpretation:

IV.3.1. The test principle:

In this well test, a recording of the production parameters, is produced with a Vx40 Phase Tester which is installed on the production line for the MDZ=615 well in Hassi Messaoud field as shows the following Fig=XXX

The test is alternated by a closure of candidate interference well inside the block, for duration of one hour; from 08:00 to 09:00 (25 minutes of well storage + 35 minutes responding time).

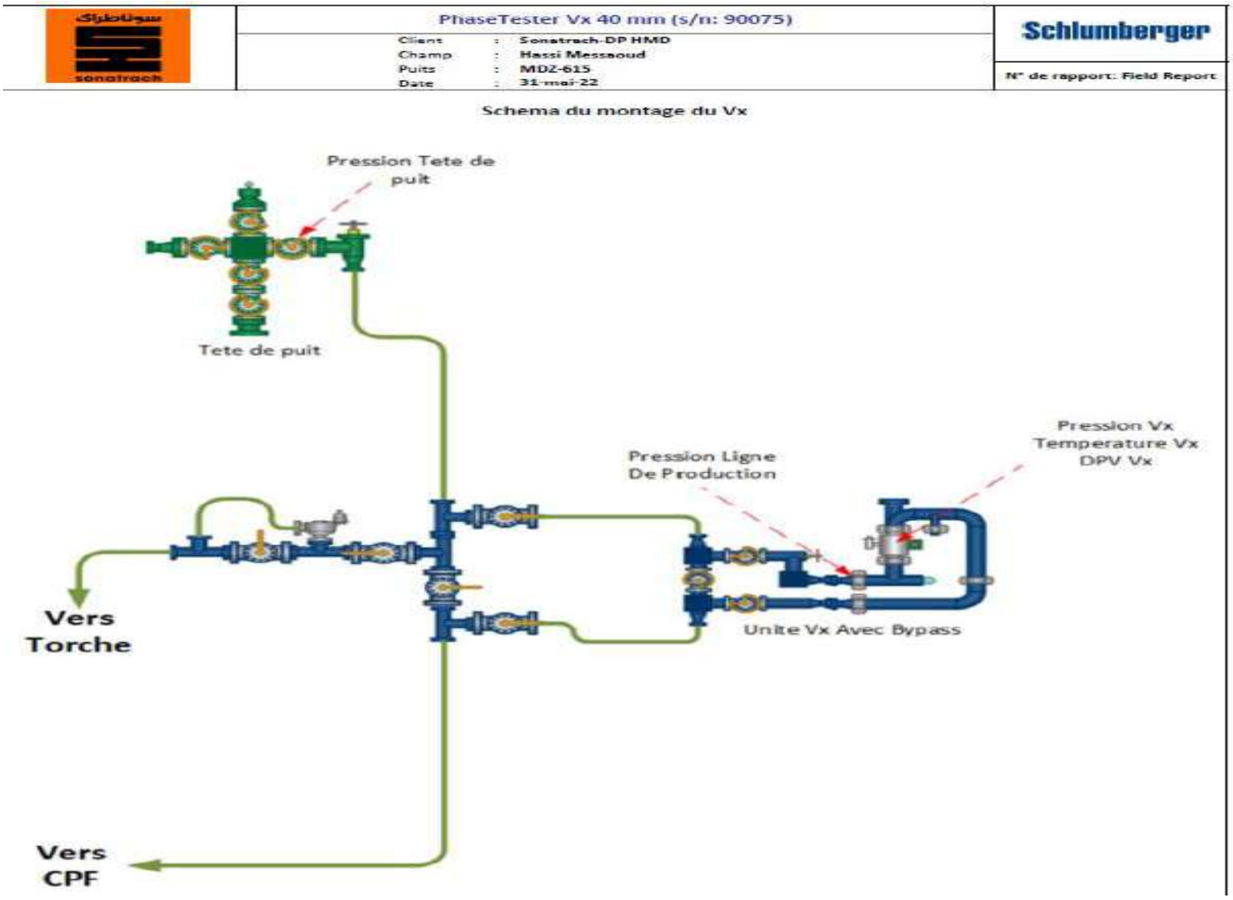


Figure IV- 13 Test design.

Table IV-1 The test sequences.

سوناطراك sonatrach	PhaseTester Vx 40 mm (s/n: 90075) Client : Sonatrach-DP HMD Champ : Hassi Messaoud Puits : MDZ-615 Date : 31-mai-22	Schlumberger N° de rapport: Field Report

Date & Time		Phase Tester Séquence des événements
jj-mmm-aa	hh:mm	
31-mai-22	05:05	Arrivée de l'équipe Schlumberger Testing sur le site du puits MDZ-615.
31-mai-22	05:10	Réunion de sécurité (Barrières, PPE, SIPP, feu, pression, source radioactive, direction du vent).
31-mai-22	05:15	Verification des vannes de la tete de puits : vanne maitresse Ouverte vanne hydraulique Ouverte.
31-mai-22	05:20	Début de montage des équipements de surface.
31-mai-22	05:50	Fin de montage des équipements de surface.
31-mai-22	05:55	Début test en pression à 14.8 barg.
31-mai-22	06:05	Test en pression positif.
31-mai-22	06:10	Pression en tête 34.7 barg, Pression de ligne = 14.8 barg avant passage sur Vx 40 mm.
31-mai-22	06:15	Passage du flow sur Vx 40 mm.
31-mai-22	06:25	Pression en tête 34.9 barg, Pression de ligne = 15.1 barg aprés passage sur Vx 40 mm.
31-mai-22	06:30	**Début du comptage des débits volumétriques par le Vx.**
31-mai-22	06:30	Gaz SG: 0.810, Densité Huile: 0.810 g/cc @ 26.9 DegC, Viscosité: 1.6 cP @ 26.9 DegC, BSW = 15 % eau. Densité d'Eau 1.030 g/cc @ 27.3 DegC.
31-mai-22	07:00	Gaz SG: 0.810, Densité Huile: 0.808 g/cc @ 27.6 DegC, Viscosité: 1.6 cP @ 27.6 DegC, BSW = 10 % eau. Densité d'Eau 1.030 g/cc @ 28.5 DegC.
31-mai-22	07:30	Gaz SG: 0.812, Densité Huile: 0.808 g/cc @ 28.2 DegC, Viscosité: 1.6 cP @ 28.2 DegC, BSW = 20 % eau. Densité d'Eau 1.028 g/cc @ 29.2 DegC.
31-mai-22	08:00	Gaz SG: 0.812, Densité Huile: 0.806 g/cc @ 30.5 DegC, Viscosité: 1.5 cP @ 30.5 DegC, BSW = 10 % eau. Densité d'Eau 1.028 g/cc @ 30.6 DegC.
31-mai-22	08:30	Gaz SG: 0.814, Densité Huile: 0.806 g/cc @ 29.7 DegC, Viscosité: 1.5 cP @ 29.7 DegC, BSW = 20 % eau. Densité d'Eau 1.026 g/cc @ 31.8 DegC.
31-mai-22	09:00	Gaz SG: 0.814, Densité Huile: 0.804 g/cc @ 31.3 DegC, Viscosité: 1.5 cP @ 31.3 DegC, BSW = 15 % eau. Densité d'Eau 1.024 g/cc @ 33.4 DegC.
31-mai-22	09:30	Gaz SG: 0.816, Densité Huile: 0.804 g/cc @ 32.1 DegC, Viscosité: 1.5 cP @ 32.1 DegC, BSW = 25 % eau. Densité d'Eau 1.026 g/cc @ 32.7 DegC.
31-mai-22	10:00	Gaz SG: 0.816, Densité Huile: 0.802 g/cc @ 33.4 DegC, Viscosité: 1.4 cP @ 33.4 DegC, BSW = 20 % eau. Densité d'Eau 1.024 g/cc @ 33.9 DegC.
31-mai-22	10:30	Gaz SG: 0.818, Densité Huile: 0.802 g/cc @ 34.8 DegC, Viscosité: 1.4 cP @ 34.8 DegC, BSW = 25 % eau. Densité d'Eau 1.022 g/cc @ 35.1 DegC.
31-mai-22	10:30	**Fin du comptage des débits volumétriques par le Vx.**
31-mai-22	10:45	Début de la référence Water InSitu (Densité d'eau 1.022 g/cc @ 35.7 degC).
31-mai-22	11:15	Fin de la référence d'eau.
31-mai-22	11:30	Début de la référence Oil InSitu (Densité d'huile 0.802 g/cc @ 35.2 degC, Viscosité 1.3 cp @ 35.2 degC).
31-mai-22	12:00	Fin de la référence d'huile.
31-mai-22	12:15	Début de la référence Empty Pipe.
31-mai-22	14:15	Fin de la référence Empty Pipe.
31-mai-22	14:20	Début démontage des équipements de surface.
31-mai-22	14:50	Fin démontage des équipements de surface.
31-mai-22	14:55	Départ du site.

Bride plaine (vanne de jaugeage)	**4"**	Existante	**Oui avec 2 boulons**
Bride plaine (vanne de jaugeage)	**4"**	Existante	**Oui avec 2 boulons**
Nombre de colliers			

Représentants Sonatrach: Mr.	**Représentants Schlumberger:** Mr. Y. Attab Mr. M. R. Maamar (Job Delivery Lead)

IV.3.2. Then results of test:

Table IV-2 The well test results.

sonatrach

PhaseTester Vx 40 mm (s/n: 90075)

Schlumberger

Client : Sonatrach-DP HMD
Champ : Hassi Messaoud
Puit : MDZ-615
Date : 31-mai-22

N° de rapport: Field Report

Données Du Phase Tester Vx

Date & Heure		Tête de puits			Ligne de production	Vx		Huile		Eau		Gaz		GVF	GORT	DPV	Gas Lift	
		Duse	Pression	Temp	Pression	Pression	Temp	Débit	Cumule	Débit	Cumule	Débit	Cumule				Débit	Pression
jj-mmm-aa	hh:mm	mm	Barg	DegC	Barg	Barg	DegC	Sm3/h	m3	Sm3/h	m3	Sm3/h	m3	%	Sm3/Sm3	mbar	m3/h	Bar
31-mai-22	06:10		34.7		14.8													
31-mai-22	06:30				Début du comptage des débits volumétriques par le Vx.													
31-mai-22	06:30	N/A	34.9	N/A	15.1	14.8	34.6	5.297	0.000	1.108	0.000	2741.0	0.0	96.3	517	306	1550	85
31-mai-22	06:35	N/A	34.7	N/A	15.0	14.7	34.9	4.980	0.415	1.190	0.099	2763.1	230.3	96.0	555	304		
31-mai-22	06:40	N/A	34.6	N/A	15.1	14.8	35.1	4.367	0.779	1.529	0.227	2765.7	460.7	96.1	633	297		
31-mai-22	06:45	N/A	34.7	N/A	15.1	14.8	35.4	5.179	1.210	1.231	0.329	2690.2	684.9	96.2	519	300		
31-mai-22	06:50	N/A	34.7	N/A	15.2	14.9	35.7	5.106	1.636	1.270	0.435	2694.2	909.4	96.0	528	300		
31-mai-22	06:55	N/A	34.8	N/A	15.1	14.8	35.9	5.373	2.084	1.205	0.535	2658.6	1131.0	96.1	495	302		
31-mai-22	07:00	N/A	34.8	N/A	15.2	14.9	36.0	5.990	2.583	0.795	0.602	2645.8	1351.5	95.9	442	302	1548	85
31-mai-22	07:05	N/A	34.9	N/A	15.2	14.8	36.2	4.767	2.980	1.487	0.726	2734.1	1579.3	96.4	573	304		
31-mai-22	07:10	N/A	34.9	N/A	15.2	14.9	36.4	5.474	3.436	0.985	0.808	2707.7	1805.0	96.2	495	303		
31-mai-22	07:15	N/A	34.7	N/A	15.1	14.8	37.4	5.653	3.907	1.002	0.891	2660.1	2026.6	96.1	471	304		
31-mai-22	07:20	N/A	34.6	N/A	15.2	14.9	37.8	5.037	4.327	1.126	0.985	2716.8	2253.0	96.4	539	297		
31-mai-22	07:25	N/A	35.0	N/A	15.2	14.9	37.2	5.836	4.813	1.027	1.071	2650.8	2473.9	95.9	454	308		
31-mai-22	07:30	N/A	35.1	N/A	15.4	15.1	36.6	4.955	5.226	1.289	1.178	2802.4	2707.5	96.4	566	309	1558	85
31-mai-22	07:35	N/A	35.2	N/A	15.4	15.1	36.4	4.937	5.638	1.343	1.290	2782.1	2939.3	96.4	563	306		
31-mai-22	07:40	N/A	35.2	N/A	15.6	15.3	36.3	5.258	6.076	1.107	1.382	2774.5	3170.5	96.2	528	303		
31-mai-22	07:45	N/A	35.3	N/A	15.7	15.3	36.4	5.465	6.531	1.094	1.473	2758.8	3400.4	96.1	505	307		
31-mai-22	07:50	N/A	35.9	N/A	15.7	15.4	36.5	5.252	6.969	1.291	1.581	2847.9	3637.7	96.2	542	321		
31-mai-22	07:55	N/A	36.0	N/A	15.6	15.2	36.4	5.502	7.428	1.036	1.667	2879.0	3877.7	96.3	523	325		
31-mai-22	08:00	N/A	35.0	N/A	15.5	15.2	36.2	5.877	7.917	0.478	1.707	2826.7	4113.2	96.3	481	307	1557	85
31-mai-22	08:05	N/A	33.7	N/A	15.1	14.9	36.3	5.213	8.352	0.503	1.749	2697.5	4338.0	96.6	517	273		
31-mai-22	08:10	N/A	34.4	N/A	15.2	14.9	37.1	4.931	8.763	1.805	1.899	2558.5	4551.2	95.9	519	298		

Schlumberger-Private

sonatrach

PhaseTester Vx 40 mm (s/n: 90075)

Schlumberger

Client : Sonatrach-DP HMD
Champ : Hassi Messaoud
Puit : MDZ-615
Date : 31-mai-22

N° de rapport: Field Report

Données Du Phase Tester Vx

Date & Heure		Tête de puits			Ligne de production	Vx		Huile		Eau		Gaz		GVF	GORT	DPV	Gas Lift	
		Duse	Pression	Temp	Pression	Pression	Temp	Débit	Cumule	Débit	Cumule	Débit	Cumule				Débit	Pression
jj-mmm-aa	hh:mm	mm	Barg	DegC	Barg	Barg	DegC	Sm3/h	m3	Sm3/h	m3	Sm3/h	m3	%	Sm3/Sm3	mbar	m3/h	Bar
31-mai-22	08:15	N/A	35.2	N/A	15.2	14.9	37.7	4.710	9.155	2.014	2.067	2676.2	4774.2	96.1	568	315		
31-mai-22	08:20	N/A	35.4	N/A	15.2	14.9	38.1	5.006	9.572	1.671	2.207	2686.1	4998.1	96.1	537	313		
31-mai-22	08:25	N/A	35.4	N/A	15.3	15.0	38.3	5.395	10.022	1.434	2.326	2703.9	5223.4	96.0	501	318		
31-mai-22	08:30	N/A	35.5	N/A	15.2	14.9	38.4	5.403	10.472	1.224	2.428	2663.1	5445.3	96.1	493	305	1552	85
31-mai-22	08:35	N/A	35.4	N/A	15.3	15.0	38.8	5.964	10.969	1.184	2.527	2661.8	5667.1	95.7	446	320		
31-mai-22	08:40	N/A	36.1	N/A	15.3	15.0	39.0	5.630	11.438	1.336	2.638	2715.7	5893.4	95.9	482	324		
31-mai-22	08:45	N/A	35.9	N/A	15.6	15.3	39.3	5.698	11.913	1.011	2.722	2760.1	6123.5	96.1	484	315		
31-mai-22	08:50	N/A	35.5	N/A	15.7	15.4	39.7	5.647	12.384	1.144	2.818	2699.6	6348.4	95.9	478	307		
31-mai-22	08:55	N/A	35.4	N/A	17.7	17.4	40.3	5.555	12.847	0.920	2.894	2637.3	6568.2	95.5	475	258		
31-mai-22	09:00	N/A	34.5	N/A	18.5	18.2	40.7	5.556	13.310	0.800	2.961	2596.8	6784.6	95.3	467	241	1558	85
31-mai-22	09:05	N/A	35.1	N/A	18.3	18.1	41.1	5.888	13.800	1.071	3.050	2543.8	6996.6	94.8	432	254		
31-mai-22	09:10	N/A	35.3	N/A	17.6	17.4	41.4	5.527	14.261	1.563	3.180	2576.8	7211.3	95.0	466	275		
31-mai-22	09:15	N/A	35.6	N/A	16.5	16.2	41.5	5.709	14.736	1.508	3.306	2625.6	7430.1	95.3	460	303		
31-mai-22	09:20	N/A	35.7	N/A	15.4	15.1	41.3	5.438	15.190	1.587	3.438	2699.2	7655.0	95.9	496	326		
31-mai-22	09:25	N/A	35.0	N/A	14.9	14.6	41.0	5.074	15.612	1.264	3.544	2725.6	7882.2	96.4	537	314		
31-mai-22	09:30	N/A	35.6	N/A	14.9	14.6	41.2	5.158	16.042	1.534	3.672	2651.6	8103.1	96.1	514	316	1552	85
31-mai-22	09:35	N/A	35.9	N/A	15.0	14.6	41.3	5.516	16.502	1.596	3.805	2671.3	8325.8	95.9	484	334		
31-mai-22	09:40	N/A	36.1	N/A	15.1	14.7	41.5	5.530	16.963	1.538	3.933	2733.8	8553.6	96.0	494	338		
31-mai-22	09:45	N/A	36.0	N/A	15.2	14.8	41.5	4.870	17.369	1.480	4.056	2839.0	8790.2	96.5	583	329		
31-mai-22	09:50	N/A	36.3	N/A	15.3	14.9	41.6	5.577	17.833	1.264	4.161	2755.0	9019.7	96.1	494	329		
31-mai-22	09:55	N/A	36.0	N/A	15.2	14.9	41.7	5.928	18.327	0.927	4.239	2736.8	9247.8	96.1	462	324		
31-mai-22	10:00	N/A	35.6	N/A	15.2	14.9	41.9	5.190	18.760	1.305	4.347	2785.2	9479.9	96.4	537	323	1558	85
31-mai-22	10:05	N/A	36.0	N/A	15.2	14.9	42.0	5.120	19.186	1.409	4.465	2762.9	9710.1	96.3	540	323		

Schlumberger-Private

sonatrach	PhaseTester Vx 40 mm (s/n: 90075)	Schlumberger
	Client : Sonatrach-DP HMD Champ : Hassi Messaoud Puit : MDZ-615 Date : 31-mai-22	N° de rapport: Field Report

Données Du Phase Tester Vx

Date & Heure		Tête de puits			Ligne de production	Vx		Huile		Eau		Gaz		GVF	GORT	DPV	Gas Lift	
		Duse	Pression	Temp	Pression	Pression	Temp	Débit	Cumule	Débit	Cumule	Débit	Cumule				Débit	Pression
jj-mmm-aa	hh:mm	mm	Barg	DegC	Barg	Barg	DegC	Sm3/h	m3	Sm3/h	m3	Sm3/h	m3	%	Sm3/Sm3	mbar	m3/h	Bar
31-mai-22	10:10	N/A	35.4	N/A	15.2	14.9	42.2	5.667	19.659	1.029	4.550	2727.7	9937.5	96.2	481	318		
31-mai-22	10:15	N/A	35.6	N/A	15.3	14.9	42.4	5.874	20.148	1.242	4.654	2669.2	10159.9	95.8	454	326		
31-mai-22	10:20	N/A	35.2	N/A	15.2	14.9	42.5	5.570	20.612	1.235	4.757	2707.0	10385.5	96.1	486	320		
31-mai-22	10:25	N/A	35.5	N/A	15.2	14.9	42.6	5.485	21.069	1.248	4.861	2704.0	10610.8	96.1	493	318		
31-mai-22	10:30	N/A	35.7	N/A	15.3	14.9	42.8	5.223	21.505	1.603	4.994	2714.7	10837.0	96.1	520	327	1563	85
31-mai-22	10:30				Fin du comptage.													
Valeur moyenne		NA	35.3	N/A	15.5	15.2	38.8	5.375	21.505	1.246	4.994	2709.9	10837.0	96.0	504	307.9	1555	85

IV.3.3. The interpretation of test:

IV.3.3.1. Presentation of recording parameters:

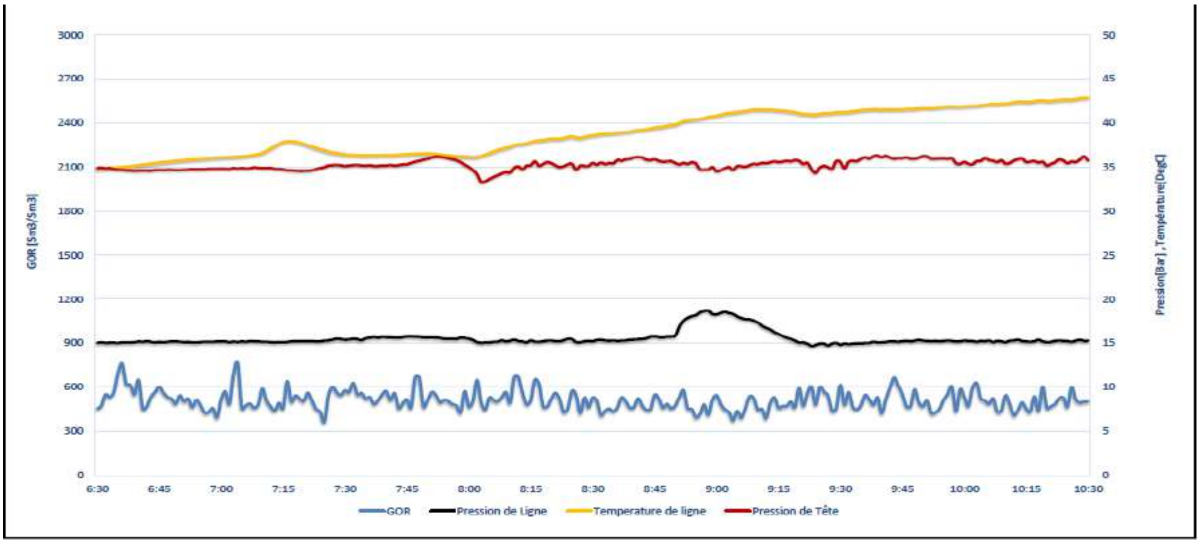
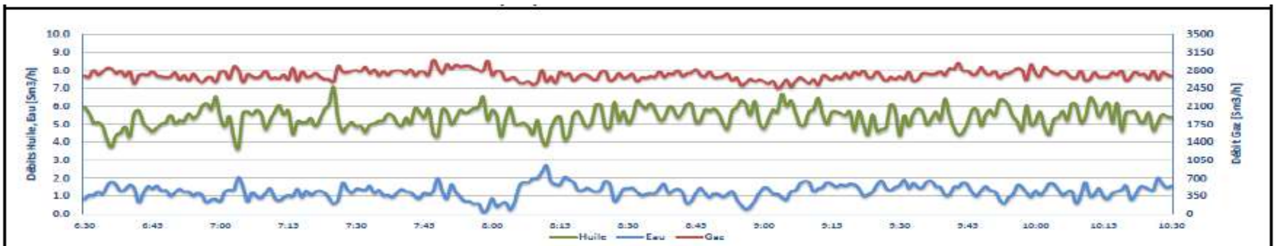


Figure IV- 14 GOR, Line and Head pressure, line Temperature.



31-mai-22

Observation	Durée HH:MM	Tête du Puits		Ligne de production	VX		Huile		Eau		Gaz		GOR T	Gas Lift	
		Pression	Température	Pression	Pression	Température	Débit	Cumule	Débit	Cumule	Débit	Cumule		Débit	Pression
		Barg	DegC	Barg	Barg	DegC	Sm3/h	m3	Sm3/h	m3	Sm3/h	m3	Sm3/Sm3	m3/h	Bar
Valeur moyenne	4:00	35.3	N/A	15.5	15.2	38.8	5.375	21.505	1.246	4.994	2709.9	10837.0	504	1555.3	85

Paramètres utilisés durant le post-process

	Référence	Manuelle	Densité @ Température ou gravité		
Huile	X		0.802 g/cc @ 35.2 DegC	Injection de gaz (oui/non)	Oui
Eau	X		1.022 g/cc @ 35.7 DegC	Injection d'eau (oui/non)	Oui
Echantillon d'eau récupéré (oui/non)			Oui	Existence d'un compteur sur la pompe d'injection (oui/non)	Non
Fraction (WLR) forcée (oui/non) - Valeur			Non		
Gaz		X	0.814		

Figure IV- 15 Oil, Water and Gas rates on Vx40 Phase tester.

IV.3.4. Analyze of graphics:

- The completed diagram's show that the pressure in the production line, begins to change after 25 minutes of closing the witness well(at 08:40), which is the estimated well boor storage time ; which reflects the presence of interference with the well under measurement and possibility of effects on the extraction system.
- Production parameters' show, remarkable changing in water production of the well, according with small changing of Oil recovery, but with considerable change in BSW.
- The graph show significant change of well head Temperature
- The pressure at the well head remains almost stable during the period of closing the witness well.
- A Small decrease in the quantities of produced gas, with the same observation recorded on GOR of the well.

General Conclusion
& Recommendations

At the end we can say that there are numerous ways for improving the productivity index, one of these ways is the interference tests that would allow the discovery of the connection between the wells that are following the same patterns

And based on both the data that should be collected from the reservoir and the information that should be gathered from the analysis tests, the right configuration would be able to be made between wells In order to have the best productivity index

- Well performance is often measured in terms of the well's productivity which is dependent on a number of factors such as the reservoir's configuration, the type of completion, petro physical and fluid properties, formation damage, etc.
- The partial completion is the main focus of this study since almost all vertical wells are partially completed due to the reasons of water coning or gas cap issue, etc.
- Productivity of a well is usually evaluated on the long time performance behavior, thus the pseudo-steady state (late time) approach has been employed for the calculation of the productivity index. Closed system (no-flow boundary) and constant pressure boundary (mixed boundaries) cases are investigated
- Several key factors have been tested on productivity index such as pseudo skin, shape factors, penetration ratio, reservoir drainage area and etc. The effects of these factors have been analyzed on productivity index by well testing

Annex:

[1]: “Development geology reference manual “by Diana Morton-Thompson & Arnold M. Woods PAGE 504

[2] “Journal of scientific & industrial research VOL 63 December 2004 page 979 -984 “.

[3] “The use of nodal analysis for the choice of candidate wells for matrix treatment .BAKELLI BABA Hammou“.

[4] “Dynamic Well Testing in Petroleum Exploration and Development (Second Edition), 2020

[5] “Design and Analysis of Multi-well Interference Tests Serhat Akin “

[6] “Mémoire fin d’étude “contribution d’essaie de puits dans l’analyse d’injection d’eau “

[7] “Mémoire fin d’étude “ étude sur l’opération de dst “

[8] “Well test interpretation by Schlumberger 2008 edition “page 87

[9] “Tarek Ahmed; Advanced Reservoir Engineering “

[10] “Oil well test hand book “page 131

[11] “Oil well test hand book “page 181

[12] “Article by serhat akin in SPE published in 2015 “page 1 – 9

[13]Oil-gas portal petroleum production optimization

[14]Oil-gas portal petroleum production optimization

[15]Productivity Index and Inflow performance of Hydraulically Fractured Formations Al Rbeawi D.Tiab

[16] https://www.investopedia.com By JASON FERNANDO Updated July 20, 2021 Fact checked by SUZANNE KVILHAUG.

[17]Well-Completion Effects on the Performance of Horizontal and Multilateral Wells Paper presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas, October 2005, Paper Number: SPE-96530-MS.

[18]Page 14-18 - Greener Journal of Petroleum and Gas Exploration bb-A Comparative Study of the Productivity Index of Horizontal Well OaikhenaE.Emmanuel and Oloro J.

[19]Contribution of Testing to Exploration Contribution from SONATRACH Exploration Division

[20]Inter-well interference and well spacing optimization for shale gas Reservoirs Jungian Chen a, Yunsheng Wei b,*, Junlei Wang b, Wei Yu c, Yadong Qi b, Jianfa Wu a, Wanjing Luo d Available online 17 September 2021