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Département de Production des Hydrocarbures

MEMOIRE

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Présenté Par :

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-THÈME-

Application of Gas shut-off technic in horizontal wells using semi-intelligent completion

Soutenue le : / 06 / 2021 devant la commission d'examen

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Dedication

In the name of love, obedience and respect,
I dedicate this work,

To the soul of my father ***KRIM Rachid*** *who passed away too early, who always pushed and motivated me in my studies,*

To my dear Mother ***CHEFFAI Djemaa*** *for all her sacrifices, her love, her prayers*

To my second mother ***CHEHILI Naima*** *for her tenderness, her support throughout my studies,*

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May this work be the fulfillment of your earnest wishes, and the fruit of your unfailing support.

Thank you for always being there for me.

Nour

ملخص

إن هدف الاستخراج الثانوي عن طريق حقن الغاز بهدف الحفاظ على ضغط المكمن البترولي لحقل حاسي مسعود ساهمت بفعالية في تحسين الإنتاج بالنسبة لمعظم الآبار عن طريق زيادة تدفق النفط إن هذه العملية هي السبب الرئيسي في ارتفاع نسب الغاز المنتج في البئر المدروس بل وحتى الآبار الأخرى في المنطقة. يتمحور عملنا حول البحث عن أسباب تقدم الغاز في البئر المدروس عن طريق تحليل مختلف العوامل التي قد تكون السبب في هذه المشكلة. إن تحليل بيانات جس الآبار النفطية وكذا عمليات الضخ التي بينت أن 49 بالمائة من الغاز المنتج يأتي من المجرى الأفقي 4 و51 بالمائة يأتي من المجرى الأفقي 5. إن عملية الاستكمال شبه الذكي قد أعطت نتائج ملحوظة في الحد من تقدم الغاز واستعادة الحالة الأولية للبئر.

الكلمات المفتاحية: الغاز، تقدم الغاز، الإكمال شبه الذكي، الإنتاج، مؤشر الإنتاجية.

Résumé

La récupération assistée par injection du gaz a pour but le maintien de la pression de gisement du champ de Hassi Messaoud à contribuer efficacement dans l'amélioration de la production des puits producteurs par augmentation du débit d'huile. Mais ce processus de récupération est la cause majeure de l'élévation du GOR dans le puits MDZ627 et même dans les autres puits de la zone. Notre travail consiste à chercher les causes de cette percée du gaz dans le puits étudié, en analysant les différents facteurs qui peuvent être l'origine de ce problème. L'interprétation des data PLT de production et celles des tests jaugeage a montré que 49 % du gaz produit vient de D4 et 51 % de D5. La mise en place d'une complétion semi-intelligente a montré une efficacité remarquable afin d'éliminer la percée de gaz et restaurer l'état initial du puits.

Mots clés : Percée, GOR, complétion semi-intelligente, débit, indice de productivité.

Abstract

The recovery assisted by gas injection in order to maintain the reservoir pressure of the Hassi Messaoud field to contribute effectively in the productivity improvement of oil producing wells by increasing the flow of oil. But this process of recovery is the major reason of the GOR rise in MDZ627 well and even in the other wells of the zone. by analyses of the various factors that may be the cause of this problem. The PLT production data and the gauging tests showed that 49% of the gas produced comes from the D4 drain and 51% from the D5. The implementation of a semi-intelligent completion has shown remarkable efficiency in eliminating the breakthrough and restoring the initial state of the well.

Keywords: Breakthrough, GOR, semi-intelligent completion, throughput, productivity index.

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CHAPTER II: Gas breakthroughs and excess water production

CHAPTER III: Recommended solutions to minimize gas and water penetration

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Symbols and abbreviations

BOPD: barrel of oil per day

Bo : volumetric factor

EOR: enhanced oil recovery

GOR: gas oil ratio

HASD: horizontal alternating steam drive

HMD: hassi messoud

LCP: cemented perforated liner

OWC: Oil water contact

PFD: dynamic pressure in bottom hole

PLT: production logging tool

$P_{w.h}$: Well head pressure

RPM: relative permeability modifer

TFD: dynamic temperature in bottom hole

WFL: water flow logs

WOR : water oil ratio

WPM: water production mechanism

ρw: water density

μo: oil viscosity

ρo: oil density

General Introduction

Introduction

The exploitation of oil fields requires very expensive investments, which in addition to the operating expenses, consist mainly of drilling, well equipment and surface installations.

Particular attention is paid to the deposit in order to ensure the longest possible life, with economically acceptable productivity and good prospects for secondary and tertiary recovery.

In the case of secondary recovery by injection of gas or water into one or more cells of the deposit, do not guarantee a complete breast sweeping efficiency of the cell one always observes a large part of oil is passed through the water or gas as a result of the speed of the gas flow through the most permeable areas, some areas will never be invaded, because the gas can quickly form preferential pathways leading to direct circulation between the injector and the producer. Sonatrach and its partners are seeking to conduct a study to determine the appropriate method to reduce water and gas leakage.

Based on previous reasons SONATRACH has implemented a semi-intelligent completion program

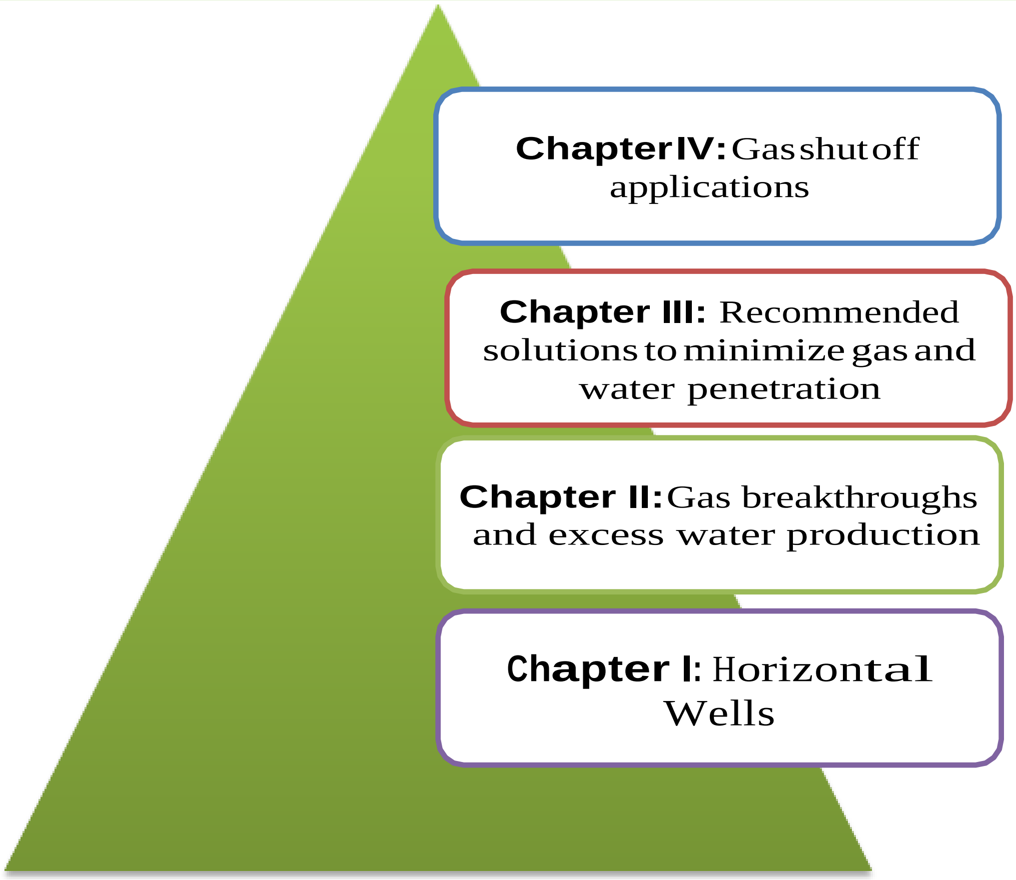
The main objectives of this work are:

- Sources of water and gas leakage
- Analysis of well gauge and pipesim data MDZ627
- Semi-intelligent completion program optimization to minimize gas breakthroughs

The methodology we will follow to achieve our research objectives is as follows:

- Definition of horizontal wells and their applications
- Analysis of gas and water supply problems
- Presentation and interpretation of gauging and Pipesim data
- Optimization of MDZ627 well performance after semi-intelligent completion descent

In order to achieve these objectives, the brief is presented in four chapters, as it follows:


Chapter IV: Gas shut off applications
Chapter III: Recommended solutions to minimize gas and water penetration
Chapter II: Gas breakthroughs and excess water production
Chapter I: Horizontal Wells

Chapter I

Horizontal Wells

Introduction

Horizontal wells have become an established method of recovery for oil and gas, a horizontal well offers greater contact area with a productive layer than does a vertical well. Larger contact areas allow lower drawdowns to recover more oil or gas.

Economics aside, these facts imply that a horizontal well should be as long as possible. However, frictional effects in the wellbore limit the useful length of a horizontal well. However, the increase in wellbore length and exposure to different reservoir facies came at a cost. Frictional pressure drop caused by fluid flow in horizontal sections resulted in higher drawdown-pressure in the heel section of the completion, causing an unbalanced fluid influx. Hence, coning of water and gas toward the heel of the well was observed. Variable distribution of permeability along the wellbore also results in variation of the fluid influx along the completion and an uneven sweep of the reservoir [1].

Definition

Horizontal wells are drilled vertically from the surface at a predetermined depth and then horizontally at an additional length, extending from 100 to thousands of feet.

This increases the contact surface area between the oil well and the oil-soaked rock, thereby increasing the productivity of the oil well indeed, a vertical well is in contact with the tank only on the thickness of the latter [2].

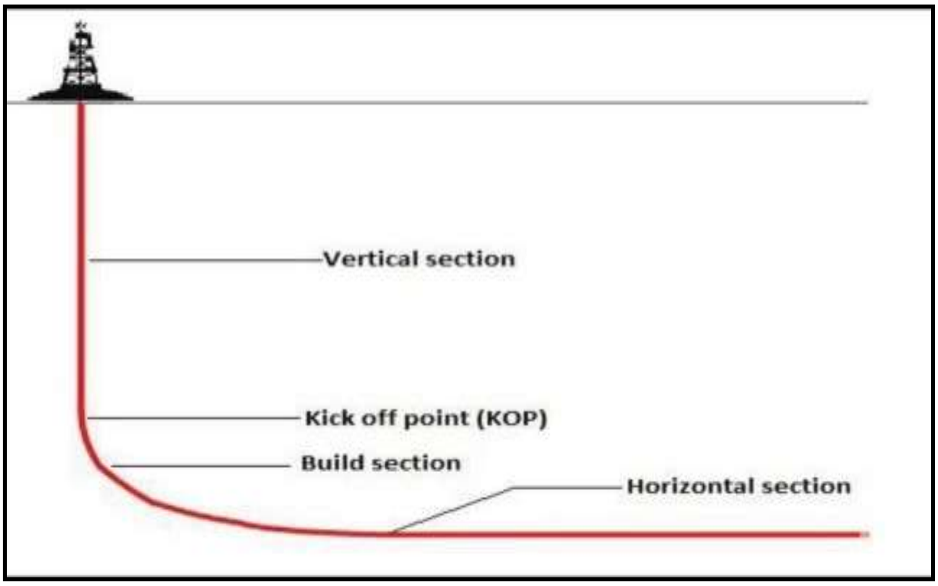


Figure I. 1: The horizontal well [3].

Types of horizontal wells

Horizontal Wells

Horizontal wells are subdivided into several categories as shown in Figure I.9 below: **a.**

Short radius

This type has a tubing radius of 4¾ to 6 inches and a bending radius of 20 to 40 ft. The length of the drain varies between 250 & 450 ft., and its build up rate between 2 and 5°/ft. The first wells were drilled by the use of flexible rods to facilitate the operation, but currently the MWDs are being used with a “Down Hole Mud Motor” that allow better trajectory control. They can be deflected from a vertical well tubed or not tubed. They are completed as open hole or slotted liner [2].

b. Medium radius

The drain length of this well ranges from 500 to 3000 ft with a radius of curvature of 300 to 700 ft. respectively and a build-up rate of 8 to 20°/100 ft. Its radius of deflection facilitates the descent of the casing and gives the possibility to intervene on the bottom. All types of completion are possible, logging, sampling and stimulation can also take place [2].

c. Long radius

This type of well has a radius of curvature of 1000 to 3000 ft, with a drain length of 1000 to 4000 ft, and a buildup rate of 1 to 6°/100ft. All types of completion as well as logging, sampling and stimulation are feasible. They allow the use of all conventional drilling procedures.

In this type of well, drilling with standard equipment and for wells with no diameter restriction is possible [2].

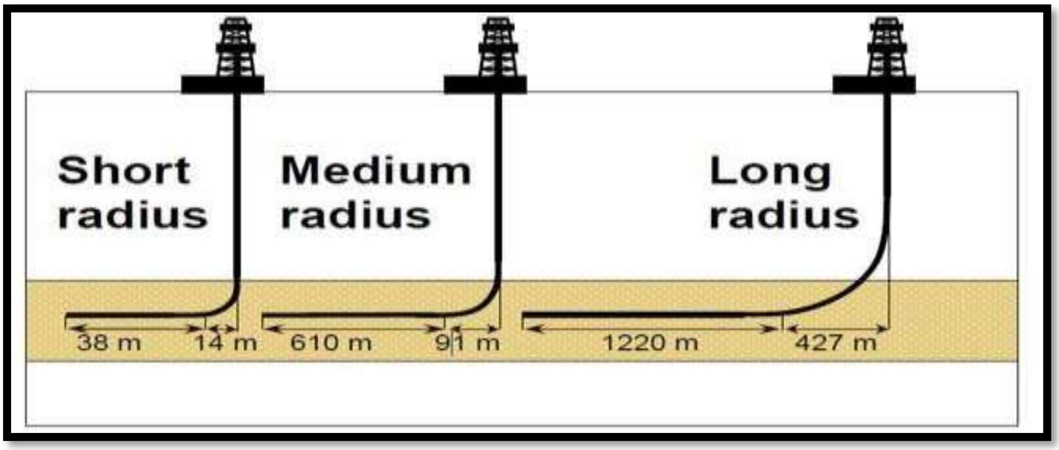


Figure I. 2: Types of horizontal wells [2].

Multilateral Well

Multilateral well drilling involves the drilling of two or more horizontal production holes from a single surface location [4].

This is a development of horizontal drilling can be vertical, deviated or horizontal. These wells allow multiple layers to be exploited by drilling a single well at the surface. The refore they are applicable for the operation of multilayer tanks (layered).

The normal objective of both horizontal and multilateral wells is to produce more oil or gas from a well and to reduce the overall cost of producing each barrel of oil or each cubic foot of gas [4].

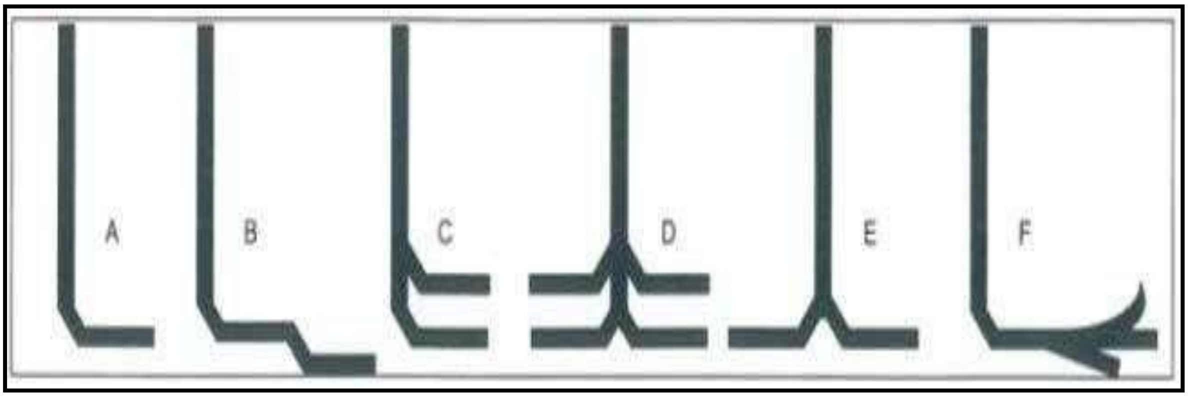


Figure I. 3: Multilateral Well Configurations [4].

The Sloping Well

It is a well drilled with a slope from the surface as shown in figure I.4 below. This type requires a special drilling rig called tilt or slant rig on the surface. The angle of inclination varies from one well to another and can reach the maximum at 45°. Shallow horizons are exploited by using sloped wells [1].

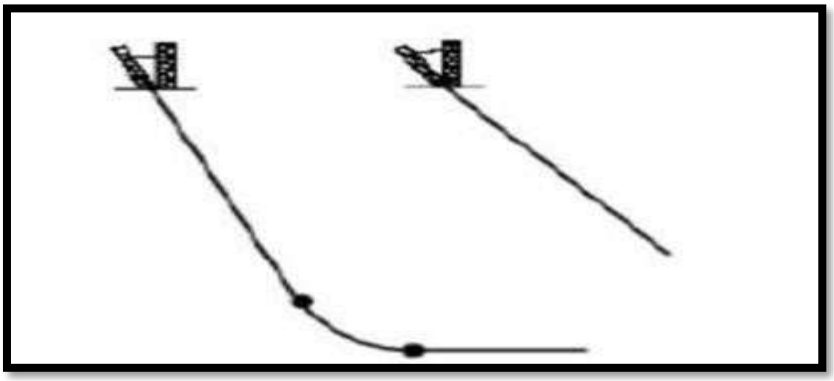


Figure I. 4: Sloped Wells [5].

The Wells in Re-entry

The re-entry wells are another horizontal drilling sequel and consist of a restart of an existing well, vertical or deflected which is then abandoned and plugged to drill a side well most often ending horizontally as shown in Figure I.5 below [2].

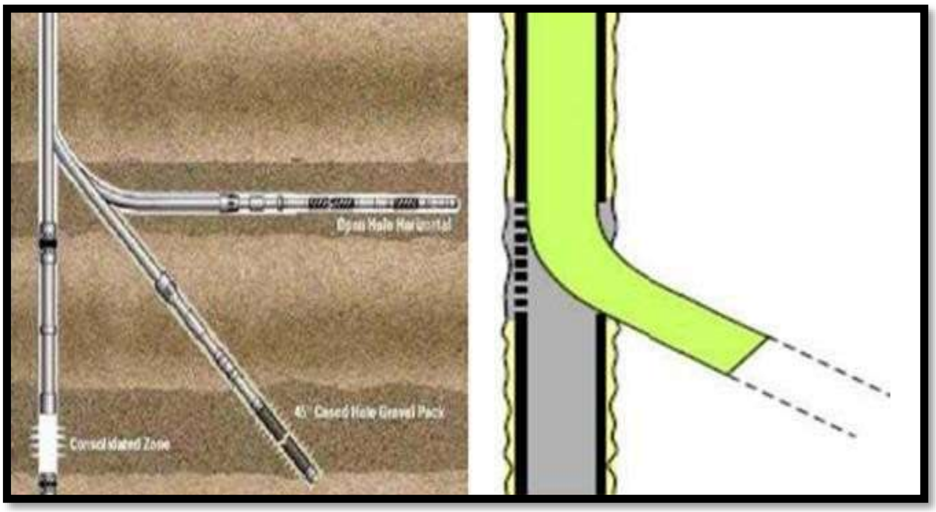


Figure I. 5: Re-entry wells [2].

Applications of horizontal wells

In naturally fractured reservoirs

Horizontal wells are used to capture production flowing from vertical or sub-vertical fractures. This would enable to drain a larger reservoir volume [6].

Unconventional gas development

Horizontal wells or hydraulic fracturing, or both, are required to produce tight gas reservoirs, which are considered to below-permeability rock. Horizontal wells are also employed to enable Shale gas production [6].

In gas production

Contained in high-permeability reservoirs where near-wellbore velocity is high in vertical wells. Hence, horizontal wells are used to reduce the extra pressure loss induced by turbulent flow [6].

Long horizontal wells

Are also beneficial in secondary or (EOR) applications to provide higher injectivity rates [6].

In subsea development

Where drilling cost is a real issue. A recent application is Alvheim field in Norway, which started production in June 2008. Fifteen horizontal wells tied back to an FPSO are to be drilled with five drill centers [6].

In heavy oil fields

In order to increase oil recovery, horizontal wells are drilled acting alternatively as oil producers and steam injectors. The best ex-ample to illustrate this application is the Bare heavy oil field located in the Orinoco oil belt, Venezuela. The recovery process known as horizontal alter-nating steam drive (HASD) consists of injecting steam in one set of wells while a second set of wells is producing oil [6].

Reservoir under cities [1].

Gas and Water Coning

In the case of an aquifer-fed or cap gas-fired reservoir, production drops rapidly with the arrival of water or gas as shown in Figure I.6 below.

The phenomenon of water coning means the local deformation of the water-oil interface to take a roughly conical shape.

This is one of the problems encountered during the exploitation of reservoirs linked to an aquifer, because it leads to an increase in water production, for this, it must be minimized. Horizontal drilling increases the production of such reservoirs:

- Increasing the distance between the drain and the oil/water contact.
- Improving productivity by dispersing racking and thus reducing suction on the water body
- Similar considerations may be made with respect to the arrival of gas.

The horizontal wells reduce the pressure drop relative to the vertical ones, which reduces the speed of the fluid and therefore the coning phenomenon, thus helping the oil sweep.

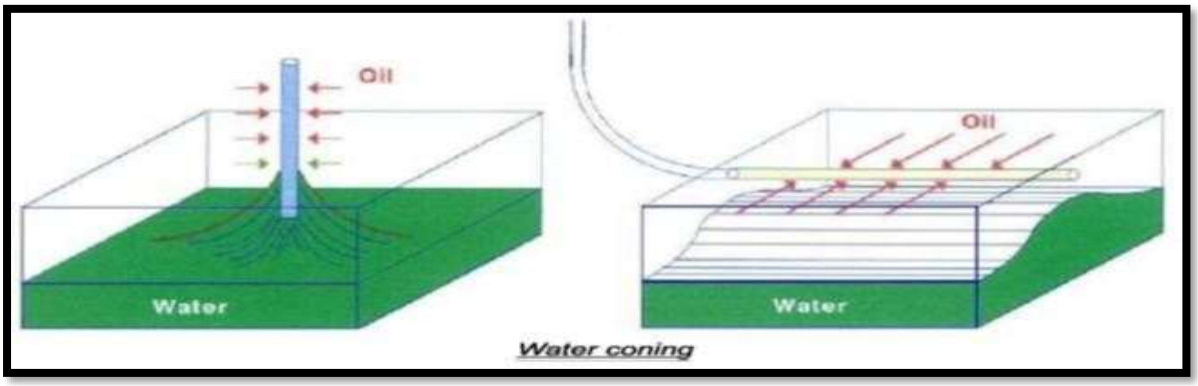


Figure I. 6: Water coning phenomenon [5].

Horizontal well completion

Well completion creates a dependable pathway to the surface for the hydrocarbons. Once the well is drilled, it has to be made ready for the safe and efficient production of oil.

The completion

Types of completion

The type of completion plays a very important role in the performance of horizontal wells: [7]

- Open hole.
- Slotted liner.
- Liner with partial insulation.
- Cemented and perforated liner.
- Parallel selective completion

The productivity index (Jp)

The productivity index is important in the technical economic study of reservoir exploitation; it expresses the potential of the well, which is very important to have an idea on the quality of reservoir and its major interest in the forecast calculation of flow and pressure. The key parameters for the operations needed to maximize production are considered.

The productivity index is the significant size of the production of a well since it takes into account the production flow, the pressure drop in the reservoir.

In the study of the performance of horizontal wells, what interests us is the efficiency translated by the ratio of the productivity indices (Jh/Jv) [8].

The expression of productivity index for a vertical well

The ratio of well inflow rate to reservoir pressure drop (draw down) has often been expressed as a productivity index J [9].

Where:

$$J = \frac{0{,}00708 \cdot k_0 \cdot h}{\mu_0 \cdot B_0 \cdot \ln\left(0{,}472 \cdot \frac{r_e}{r_w}\right)} \qquad \text{(I-1)}$$

Equation (II-1) is valid only if the pressure function $f(P) = \frac{k_0}{\mu_0 \cdot B_0}$ is constant.

The productivity index can always be expressed as:

$$J = \frac{0,00708 \cdot h}{-\left(P_R - P_{wf}\right) \cdot \ln\left(0,472 \cdot \frac{r_e}{r_w}\right)} \cdot \int_{P_{wf}}^{P_R} \frac{k_o}{\mu_0 \cdot B_0} dP \qquad \text{(I-2)}$$

Expression of Productivity Index for a Horizontal Well

I.6.2.a. For an isotropic reservoir

A-4) the Joshi Method (1991)

A horizontal well is studied from a number of vertical wells close to each other and completed in a reservoir of limited thickness. Figure II-1ci below shows the drainage area of a horizontal L-length well in a reservoir of a thickness h. Each end of a horizontal well will drain a semi-circle of a radius b, with a rectangular form of drainage of a horizontal well. [10]

Assuming that each end of a horizontal well is represented by a vertical well that drains an area of half a circle of b-radius, Joshi (1991) proposes the following two methods for calculating the horizontal drainage zone.

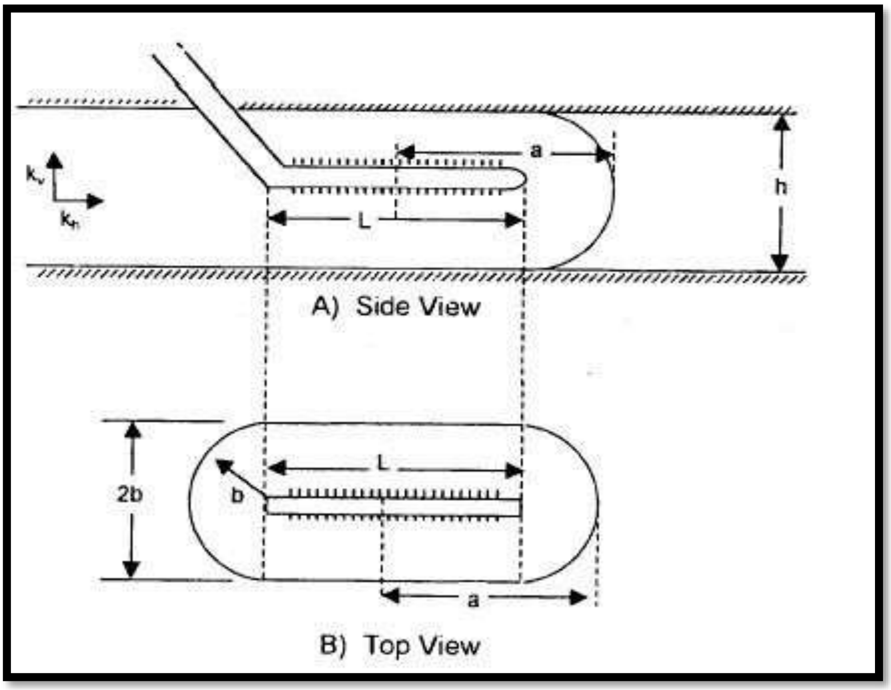


Figure I. 7: The drainage surface of a horizontal well. [10]

<u>The first method</u>

Joshi proposed that the watershed be represented by two half-circles of a radius b (equivalent to a radius of a vertical well r at each end and a rectangle of L (2b) in the center. The drainage area of the horizontal well is given by:

The expression of the drainage surface

$$A = \frac{L(2b) + \pi b^2}{43,560} \quad (I-3)$$

The second method

Joshi assumes that the drainage surface of a horizontal well is an ellipse and given by this formula: [10].

$$A = \frac{\pi ab}{43,560} \quad (I-4)$$

With:

$$a = \frac{L}{2} + b \quad (I-5)$$

Joshi noted that the two methods give different values for drainage area A and suggested assigning the mean value for horizontal well drainage.

In 1988, Joshi solved the problem of 3-D like that of 2D, that is, he summarized that the flow of the fluid can be divided into two flows: horizontal and vertical. Joshi's equation becomes widely used in the oil industry. Joshi's equation has summarized that the drainage area is elliptical [10].

Joshi (1991) used the following expression to estimate the productivity index of a horizontal well in isotropic reservoirs. As: a is the half length of the main axis of the drainage ellipse and given by: [11].

$$a = (L/2)\left[0.5 + \sqrt{0.25 + (2r_{eh}/L)^4}\right]^{0.5} \quad (I-6)$$

$$R = \frac{a + \sqrt{a^2 - (L/2)^2}}{(L/2)} \quad (I-7)$$

$$J_h = \frac{0.00708\, h\, k_h}{\mu_o B_o \left[\ln(R) + \left(\frac{h}{L}\right)\ln\left(\frac{h}{2r_w}\right)\right]} \quad (I-8)$$

I.6.2.b.For an anisotropic reservoir

The Joshi Method:

Joshi introduced vertical permeability to explain the influence of reservoir anisotropy: this is formula are applicable for L>0.4BH [10].

The first method

$$J_h = \frac{\square.\square\square\square\square\square\square\square\square\square}{\mu\square\square(\square\square(\square)+(\frac{\square\square}{\square})\square\square(\frac{\square\square}{\square\square\square}))} \qquad \text{(I-9)}$$

$$J_h = \frac{0.00708\, h\, k_h}{\mu_o B_o \left[\ln(R) + \left(\frac{B^2 h}{L}\right) \ln\left(\frac{h}{2 r_w}\right) \right]} \qquad \text{(I-10)}$$

The second method

According to Joshi, equation (II-16) is drawn more rigorously than equation (II-15) there is a difference of 14 in the productivity index calculated by these two formulas; for a higher L length of 0.4*BH [10].

Limitations and Issues

From reservoir stand point, a horizontal well produces from one pay zone, unless a slanted well is drilled where the well tunnel intersects more than one layer. Another method is, after cementing the well, to make vertical fractures intersecting multiple zones. However, it may not be possible in interconnect the layers in case of the rock strength is an issue or intermediate barriers exist (Joshi 1991).

Another drawback of horizontal wells is their cost. It ranges from 1.4 – 3 times the cost of a vertical well. The over budget comes from the drilling technology being used. For example, to reach the target within the planned azimuth, the operator company has to call a deviation service company to do the job. Also, logging the horizontal section needs to be done by either a coiled tubing unit, drill pipe (LWD), or tubing. the. All these factors would increase the total cost.

Wellbore access during intervention (cleanouts, slikline, flow survey, stimulation ...etc.) is difficult and costly job compared with vertical wells. On the one hand, the lack of weight on tools has to be replaced by downhole motors or tractors. On the other hand, higher volumes of acid. likelihood the tools get stuck especially in open hole type of completion.

Pressure loss: when we talk about horizontal wells performance, pressure drop due to frictions along the horizontal wellbore should have a great part of the discussion when evaluating the total pressure loss of the system. The pressure drop may be ignored for conditions where single phase laminar flow takes place in the wellbore. However the effect of ignoring it for high well productivity or multiphase flow (injection fluid breakthrough) is to over predict the well deliverability (Folefac et al. 1991). The consequence of high friction losses is a reduced drawdown in the far downhole, resulting in a total production leveling off as function of well length (Dikken 1990).

Gas and water coning: these problems are the direct consequences of the excessive pressure drop occurring in the wellbore. The gas or water may cone at point of minimum pressure in the horizontal well. at the heel of the well (heel effect) [12].

The advantages and disadvantages of horizontal wells

Advantages:

- Allows the development of a field that cannot be exploited commercially (low permeability reservoirs) by vertical wells.
- Allows the increase of the production and this by increasing the surface of contact.
- Improve the recovery rate of reserves with better drainage of the producing layer.
- Reduces the speed of the fluid thus reducing the sand flow and the phenomenon of turbulence (especially in the high permeability gas field) [7].

Disadvantages:

- additional cost
- operational risks
- Cleaning the well [3].

Chapter II

Gas breakthroughs and axcess water production

Introduction

Water production and gas breakthroughs are major technical, environmental and economic problems associated with gas and oil production. It can limit the productive life of the wells and cause various problems including corrosion of the tubular material, heaving of the hydrostatic column, frequent boring, problems of treatment and separation. The environmental impact of water treatment and storage significantly affects the profits of gas and oil production **[13]**.

Sources of gas breakthrough

Injected gases

A. Gas injected into the gas cap

The gas cap gas plays the role of an engine fluid that pushes the oil towards the well and to reinforce this fluid, an injector well is placed in the gas cap. As the oil is extracted from the reservoir, the gas above the oil (the heading gas) expands and occupies the available space quickly. The gas/oil interface will be located at the area of the perforations and the gas will accompany the production of the oil and at this time a gas coning will be formed consequently the proportion of gas in the fluids produced becomes rapidly very important so the GOR increases this which puts the producing well in front of the danger of gas entry problem.

This problem can be corrected by condemning the original hole with cement and allowing the new hole to go deeper into the well [13].

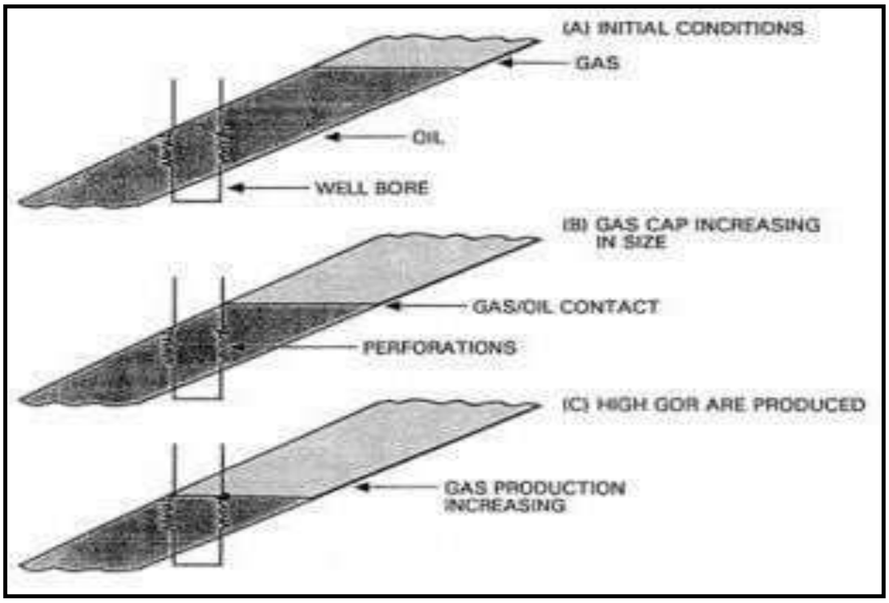


Figure II- 1: Oil-gas contact displacement[13].

The gas coning phenomenon is related to the deformation of the oil-gas interface in the fuel tank, the flow is circular in the radial direction, but at the edge of the well, the current cloth deforms and the flow becomes a pseudo-spherical shape. This movement of oil and gas will deform the oil and gas on the contact surface and keep it rotating and approximately conical.

Therefore, when the gas/oil interface approaches the height of the perforations, gas cones will occur. This is because gas has a lower viscosity and is easier to move compared to liquids.

Once the well is put into production, the deformation of these interfaces is inevitable. At the beginning, this deformation is very small, but with the passage of time, it can reach important amplitude, especially in the case of strong fluidity, the strength is also very strong, if it does not exceed a certain limit, there is no disadvantage.

Conversely, if the deformation exceeds the so-called "critical" limit, the gas will penetrate into the well. Then confirm this by passing the hole through the test separator and seeing a higher GOR value. The processing efficiency of the well is inefficient because the result will be to produce only a gas cap. If the gas cone is activated, the only solution is to shut down the well for a few hours (sometimes a few days). With the gradual opening of production waste, the oil well will restart and stabilize at a lower production flow, that is, the oil flow; the maximum possible value without a breakthrough (breakthrough) is called the critical flow. You can try to solve or limit this problem by intervening in the layer hole link [13].

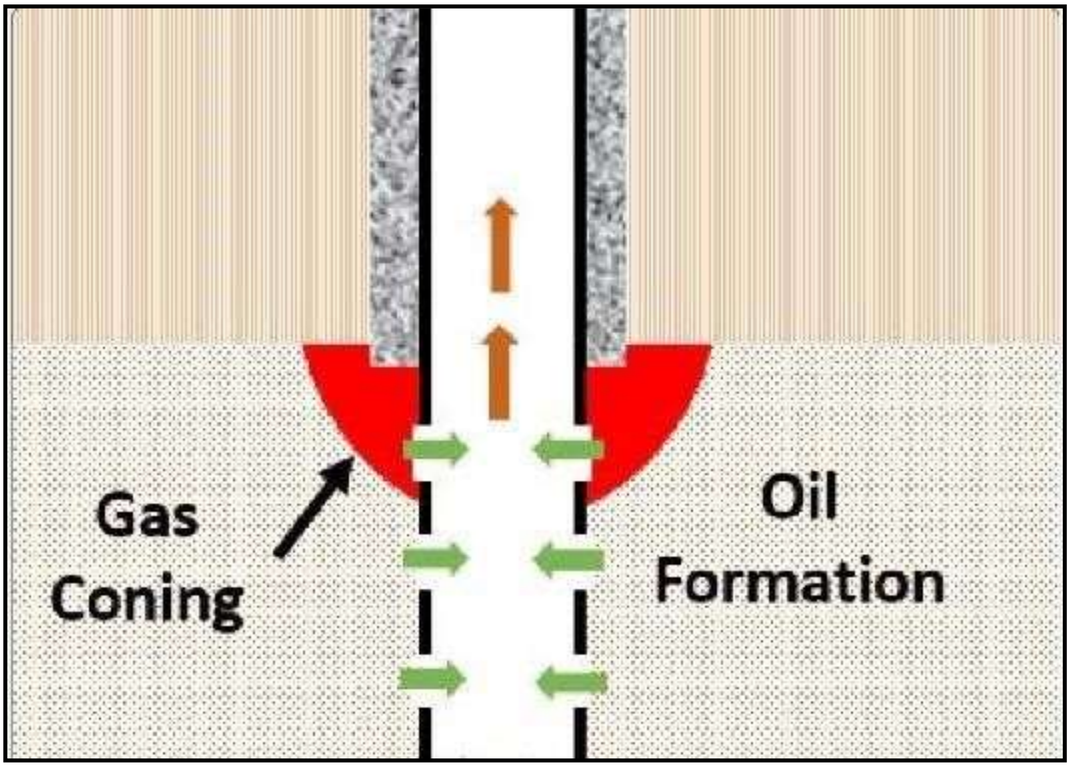


Figure II- 2: Gas coning [13].

Consequences of increasing GOR:

- ✓ Well bottom flow pressure: decreases.
- ✓ Tubing head pressure: increases.
- ✓ Tubing head temperature: decreases.
- ✓ Pressure difference at Duse: increases.
- ✓ Temperature difference at Duse: increases

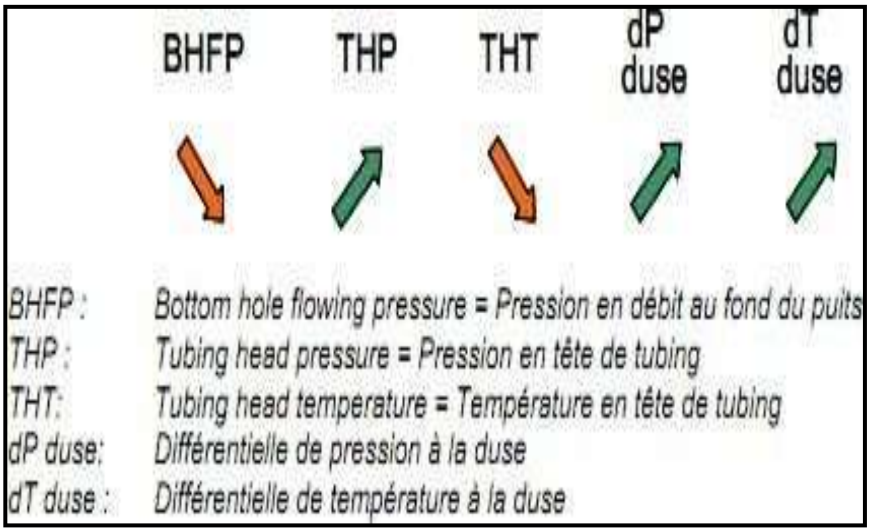


Figure II- 3: Consequences of increased GOR [13].

B. The gas injected directly into the oil

The injected gas will form a direct preferential path to the producing well (the gas moves faster along the roof of the layer) As a result the proportion of gas in the produced fluids quickly becomes very important so the GOR increases which puts the producing well in front of the danger of problem of gas penetration [13].

Release of gas dissolved in oil

Once the reservoir pressure is lower than the bubble pressure, the release of dissolved gas will cause the proportion of gas in the produced fluid to quickly become very important, so the GOR increases, which puts the producing well facing the risk of gas problems, penetration. It appears in the next curve [13].

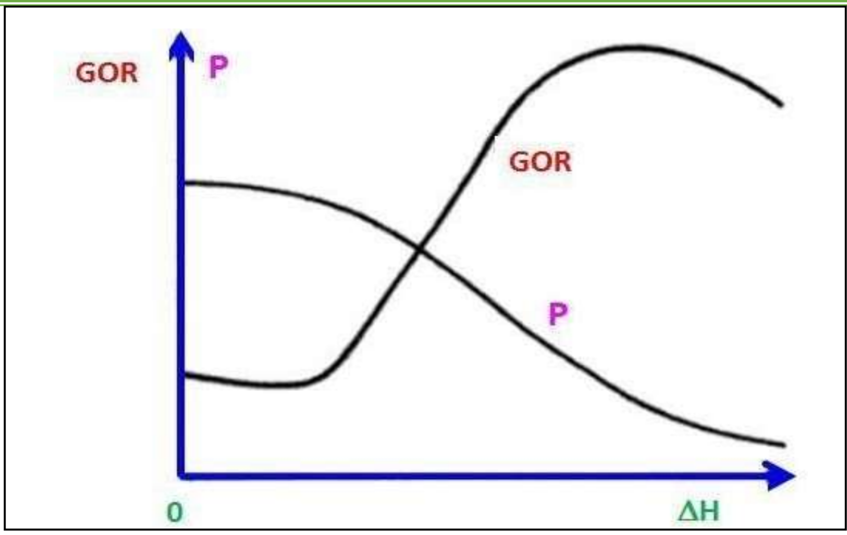


Figure II- 4: Change in pressure and GOR as a function of the cumulative oil production of a reservoir [13].

According to the cumulative production of oil, the change in the average pressure of the tank and GOR can be observed. Initially, the pressure and GOR decrease slightly. The flow in the storage tank remains single-phase, and the gas saturation is not enough to make this fluid (gas) flow. The degree of enrichment of dissolved gas in the produced liquid is slightly worse than that of the initial oil, which can explain the slight decrease in GOR. Then, the gas saturation reaches a value sufficient to allow the fluid to flow. Therefore, its share of production has increased, which explains the rapid growth of GOR. At the same time, the pressure is steadily falling and rising rapidly. This puts the producer at risk of gas ingress problems. Finally, when the pressure drop exceeds the increase in gas permeability, the GOR decreases. The recovery rate at this time is usually in the range of 15-25% [13].

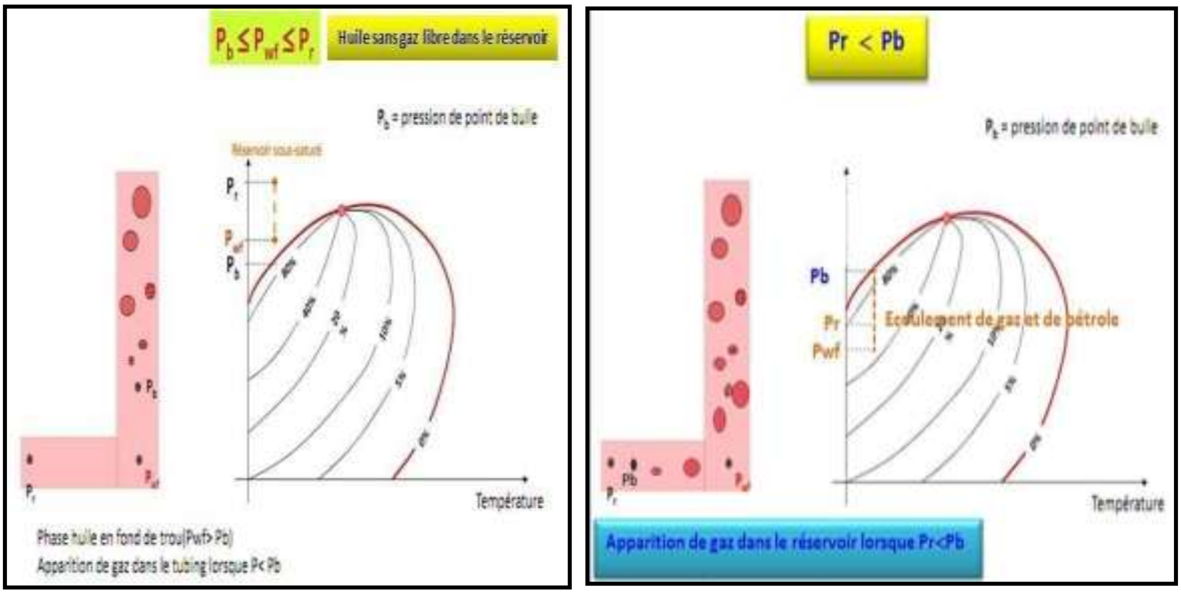


Figure II- 5: Phase de libération de gaz dissous [13].

Note:

- ✓ Above the pressure of the bubble point, the productivity index is constant. It depends on the properties of the rock and the fluid.
- ✓ Below the pressure of the bubble point, two phases flow simultaneously into the tank: the friction between the two phases uses part of the pressure drawdown. Production yield decreases.
- ✓ Typical reservoire performance
  - Dissolved gas expansion tanks generally have a rapid drop in pressure and therefore a rapid drop in production
  - the GOR increases rapidly from the initial value to a maximum value, before falling rapidly
- ✓ The effects of compressibility of fluids and pores are negligible compared to the expansion of the released gas; therefore, or consider that the volume of pore is constant.
- ✓ Other adverse effects of increased gas saturation include:
  - The launch of the dissolved gas will increase the viscosity of the oil, ensuing in decreased go with the flow and oil production.
  - the increase in gas saturation has the effect of decreasing the relative permeability to the oil, which also leads to a reduction in the flow and production of oil has the effect of decreasing the relative permeability to the oil, which also leads to a reduction in the flow and production of oil

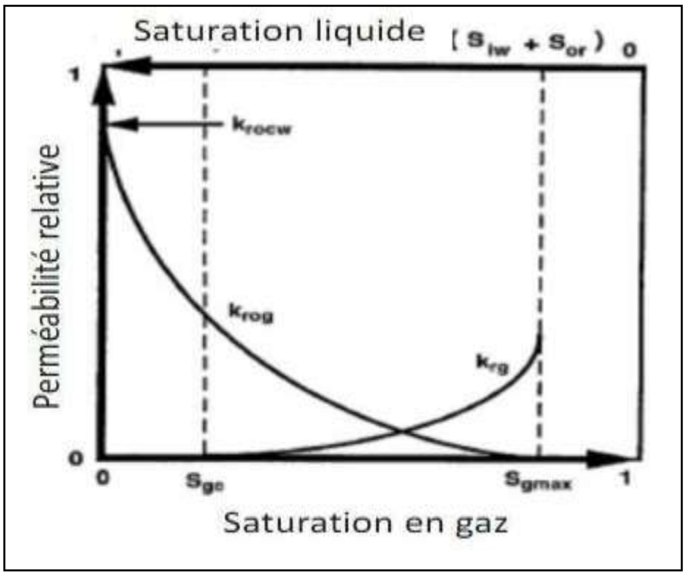


Figure II- 6: The evolution of relative oil permeability as a function of gas saturation [13].

Causes of breakthroughs

These causes can be divided into several categories, mainly encompassing the operation and the reservoir.

The reservoir

A. Effect of permeability

High permeability speeds up the flow of injection fluid and generates premature production at the producer wells [13].

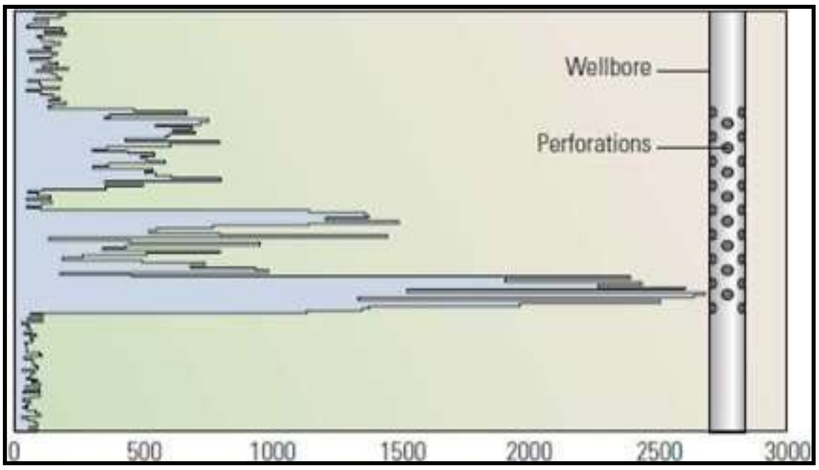


Figure II- 7: Effect of permeability [13].

B. Cracked tank and leakage

They are of a tectonic nature. Faults and cracks represent preferential paths (gas or water) between the injection wells and the producing wells. In these cases, the well's production puts the well at risk [13].

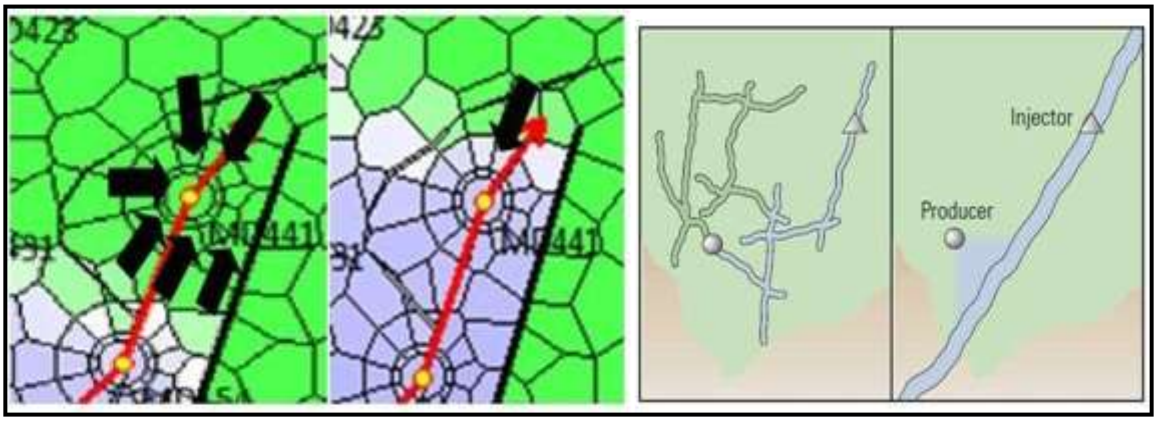


Figure II- 8: Effects of cracks and barriers [13].

C. Hydraulic fracturing

Hydraulic fracturing stimulation accelerates the flow of gas, once a passage (communication) between the oil drain and the gas drain has been created by fracturing [13].

Causes related to exploitation

A. Production flow rate (Duse)

Hydrocarbon production is achieved by creating a pressure gradient through the formation However; the flow to a partially penetrated or perforated well creates a vertical pressure gradient. Similarly, the pressure gradient increases as the flow rate increases. As a result, high flow rates accelerate extraction and lead to excessive production of injected fluids [13].

B. The injection rate

In order to maintain pressure, the conditions of the flow of oil equivalent to the flow of injection must be met.

The continuous extraction of oil leads to the reduction of its volume inside the tank this volume is immediately replaced by that of the injection. So if the volume of fluid injected becomes greater than that of the oil produced, the danger of drilling the producing wells will increase which becomes worrisome, and this because of the poor prediction of the gas front [13].

Analysis of operational problems

A. Well

1) Reduction of oil flow: under the effect of the great mobility of gas and that great pressure compared to that of oil, the gas will slow down the latter and it has been shown by the increase of gas flow and the decrease of oil flow [13].

2) Mechanical problems such as communication creating by corrosion or erosion in areas with low thickness: Erosion is an undesirable phenomenon created by the physical action of the molecules of the gas against the walls of the middle of the flow, when the gas speed is high these actions are very active, friction forces and shocks between the equipment undergo metalogical variations [13].

3) Destabilize the reservoir rock by the appearance of cellars in the formation: the gas will cool the rock, in this case, the rock will become easy to break, which causes the collapse of the formation and consequently the formation of cellars [13].

- **Network**

Disturbance of the flow on the collection network: the wells with strong GOR usually at the beginning of the breakthrough when the well and connected to a manifold, disturbs all the producing wells that have a low GOR, by completely slowing down the system, hence the need to reconnect the well on a direct line [13].

1) High gas saturation presents an abrasive corrosive medium; CO2 in the presence of free water form very corrosive acid solution on collection equipment example: whistled Duse. The impurities contained in the gas at the exit of wells can endanger both facilities, the distribution system and personnel [13].

2) Inflation of the network requires the redevelopment of a collection to the new conditions of the well from the point of view of quantity of gas and operating pressure [13].

3) Additional collection is required to remove the gas example: the three-phase pumps transport the oil with the gas but once the gas exceeds a certain quantity it needs a secondary exhaust line [13].

4) Requires a review of the collection in addition to evacuate the gas: in case of wells with high GOR, it is necessary direct lines (HP) High Pressure not to disturb the network whose pressure is low [13].

5) Hydrates are similar to ice crystals that gather and eventually block pipes. It is particularly difficult to get rid of hydrates. They form under high pressure and low temperature conditions and in the presence of light hydrocarbon molecules (gas) and steam water [13].

6) Increased gas saturation in the tank has the effect of decreasing the relative permeability to the oil, which also leads to a reduction in the flow and production of oil.

We have S oil+ S gas+ S water =1 if the volume of gas in the tank increases we have S gas increases therefore S oil decreases the relative permeability to oil decreases [13].

B. Réservoir

1) Difficulty in locating the path taken by the gas injected to the producing wells due to the heterogeneity of the Cambrian reservoir rock, and the impossibility of quantifying the volumes by passed by the gas in the reservoir [13].

2) Bad sweeping causes a lot of area by passed through the gas (preferential gas flow problem and one has oil trapped in the tank) since the gas seeks the easiest way or there is a good permeability [13].

3) Difficulty in following the gas front in the reservoir due to the large thickness of the injection area, and the distance between the wells (injectors and producers).

4) The coning problem [13].

If the drawdown is excessive, free gas (from the heading gas zone) can be sucked into the tubing.

This coning can transform a non-experiptive well into an eruptive well. In the case of a gas cap sweep, this effect is generally favourable as long as the GOR is not significant but generally, rapidly affects the oil flow if the oil zone is not supported [13].

Water Sources

Water is present in every oil field and is the most abundant fluid in the field. No operator wants to produce water, but some waters are better than others are. When it comes to producing oil, a key issue is the distinction between sweep, good (or acceptable), and bad (or excess) water [14].

- **"Sweep" water Sweep:**

Water comes from either an injection well or an active aquifer that is contributing to the sweeping of oil from the reservoir. The management of this water is a vital part of reservoir management and can be a determining factor in well productivity and the ultimate reserves [14].

- **"Good" water:**

This is water that is produced into the wellbore at a rate below the water/oil ratio (WOR) economic limit (previous page, top).3 It is an inevitable consequence of water flow through the reservoir, and it cannot be shut off without losing reserves. Good-water production occurs when the flow of oil and water is commingled through the formation matrix. The fractional water flow is dictated by the natural mixing behavior that gradually increases the WOR [14].

Another form of acceptable water production is caused by converging flow lines into the well- bore. For example, in one quadrant of a five-spot injection pattern, an injector feeds a producer. Flow from the injector can be characterized by an infinite series of flowlines the shortest is a straight line from injector to producer and the longest follows the no-flow boundaries from injector to producer. Water breakthrough occurs initially along the shortest flowline, while oil is still produced along slower flowlines. This water must be considered good since it is not possible to shut off selected flow- lines while allowing others to produce. Good water needs to be produced with oil. It cannot be shut off without shutting off oil. Downhole separation may be a solution. Bad water does not help production, and it depletes pressure[14].

- **"Bad" water**

The remainder of this article deals principally with the problems of excess water. Bad water can be defined as water that is produced into the wellbore and produces no oil or insufficient oil to pay for the cost of handling the water that is produced above the WOR economic limit. In individual wells, the source of most bad water problems can be classified as one of ten basic types. The classification of water problem types presented here is simplistic many variations and combinations can occur but it is useful for providing a common terminology [17].

Causes of excess water production

The ten basic problem types vary from easy to solve to the most difficult to solve.

A. Casing, tubing or packer leaks

Leaks through casing, tubing or packers allow water from non- oil-productive zones to enter the production string. Detection of problems and application of solutions are highly dependent on the well con- figuration. Basic production logs such as fluid density, temperature and spinner may be sufficient to diagnose these problems.

In more complex wells, WFL Water Flow Logs or multiphase fluid logging such as the TPHL three-phase fluid holdup log can be valuable. Tools with electrical probes, such as the Flow View tool, can identify small amounts of water in the production flow. Solutions typically include squeezing shutoff fluids and mechanical shutoff using plugs, cement and packers. Patches can also be used. This problem type is a prime candidate for low-cost, inside-casing water shut- off technology [15].

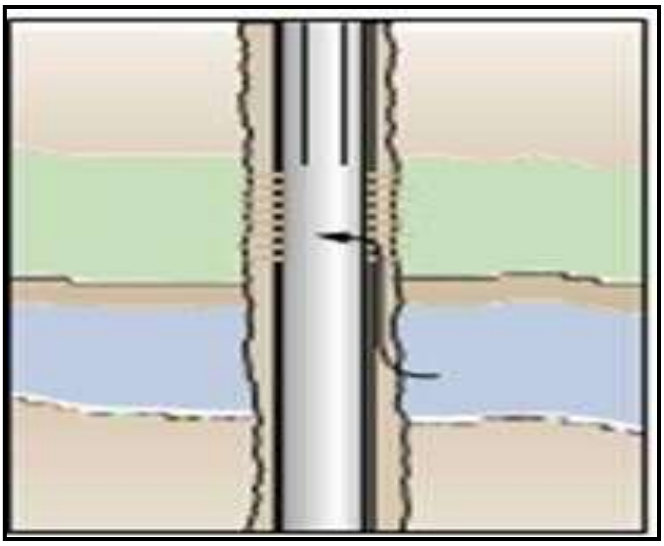


Figure II- 9: Casing, tubing or packer leaks [15].

B. Channel flow behind casing

Failed primary cementing can connect water-bearing zones to the pay zone. These channels allow water to flow behind casing in the annulus. A secondary cause is the creation of a 'void' behind the casing as sand is produced. Temperature logs or oxygenactivationbased WFL logs can detect this water flow. The main solution is the use of shutoff fluids, which may be either high-strength squeeze cement, resin-based fluids placed in the annulus, or lower strength gel-based fluids placed in the formation to stop flow into the annulus.

Placement is critical and typically is achieved with coiled tubing [15].

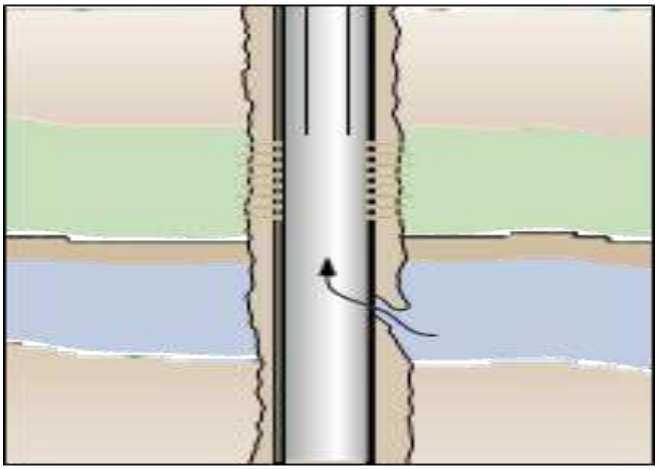


Figure II- 10: Flow behind casing [15].

C. Moving oil-water contact

A uniform oil- water contact moving up into a perforated zone in a well during normal water-driven production can lead to unwanted water production. This happens wherever there is very low vertical permeability. Since the flow area is large and the rate at which the contact rises is low, it can even occur at extremely low intrinsic vertical permeability's (less than 0.01 mD). In wells with higher vertical permeability (Kv > 0.01 Kh), coning and other problems discussed below are more likely. In fact, this problem type could be considered a subset of coning, but the coning tendency is so low that near-wellbore shutoff is effective.

Diagnosis cannot be based solely on known entry of water at the bottom of the well, since other problems also cause this behavior. In a vertical well, this problem can be solved easily by abandoning the well from the bottom using a mechanical system such as a cement plug or bridge plug set on wireline. Retreatment is required if the OWC moves significantly past the top of the plug. In vertical wells, this problem is the first in our classification system that extends beyond the local wellbore environment.

In horizontal wells, any wellbore or near- wellbore solution must extend far enough uphole or downhole from the water-producing interval to minimize horizontal flow of water past the treatment and delay subsequent water breakthrough. Alternatively, a sidetrack can be considered once the WOR becomes economically intolerable [18].

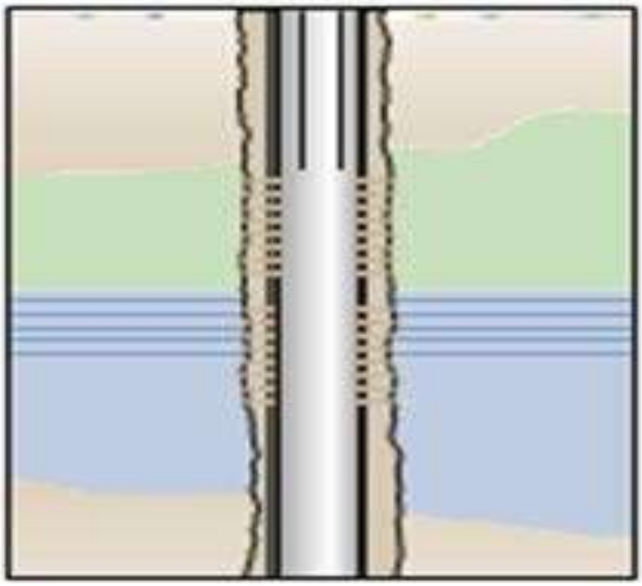


Figure II- 11: Moving oil-water contact [18].

D. Watered-out layer without crossflow

A common problem with multilayer production occurs when a high-permeability zone with a flow barrier (such as a shale bed) above and below is watered out. In this case, the water source may be from an active aquifer or a waterflood injection well. The watered-out layer typically has the highest permeability. In the absence of reservoir crossflow, this problem is easily solved by the application of rigid, shutoff fluids or mechanical shutoff in either the injector or producer. Choosing between placement of a shutoff fluid typically using coiled tubing or a mechanical shutoff system depends on knowing which interval is watered out. Effective selective fluids, discussed later, can be used in this case to avoid the cost of logging and selective placement. The absence of crossflow is dependent on the continuity of the permeability barrier [18].

Horizontal wells that are completed in just one layer are not subject to this type of problem. Water problems in highly inclined wells completed in multiple layers can be treated in the same way as vertical wells [18].

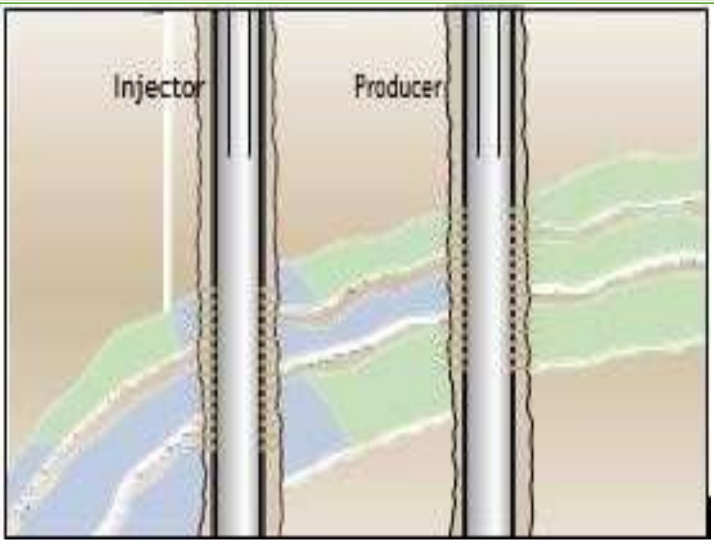


Figure II- 12: Watered-out layer without crossflow [18].

E. Fractures or faults between injector and producer

In naturally fractured formations under waterflood, injection water can rapidly break through into producing wells. This is especially common when the fracture system is extensive or fissured and can be confirmed with the use of interwell tracers and pressure transient testing [19].

In horizontal wells, the same problem can exist when the well intersects one or more faults that are conductive or have associated conductive fractures [19].

Fractures or faults from a water layer Water can be produced from fractures that intersect a deeper water zone. These fractures may be treated with a flowing gel; this is particularly successful where the fractures do not contribute to oil production. Treatment volumes must be large enough to shut off the fractures far away from the well [19].

However, the design engineer is faced with three difficulties. First, the treatment volume is difficult to determine because the fracture volume is unknown. Second, the treatment may shut off oil-producing fractures; here, an overflush treatment maintains productivity near the wellbore. Third, if a flowing gel is used, it must be carefully tailored to resist flowback after the treatment [19].

In cases of localized fractures, it may be appropriate to shut them off near the wellbore, especially if the well is cased and cemented. Similarly, a degradation in production is caused when hydraulic fractures penetrate a water layer. However, in such cases the problem and environment are usually better understood and solutions, such as shutoff fluids, are easier to apply [16].

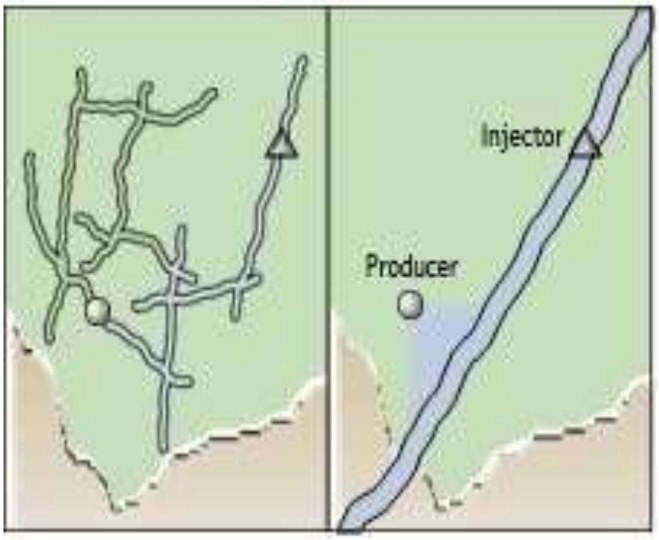


Figure II- 13: Fractures or faults between an injecter and a Producer [16].

F. Coning or cusping

Coning occurs in a vertical well when there is an OWC near perforations in a formation with a relatively high vertical permeability. The maximum rate at which oil can be produced without producing water through a cone, called the critical coning rate, is often too low to be economic. One approach, which is sometimes inappropriately proposed, is to place a layer of gel above the equilibrium OWC. However, this will rarely stop coning and requires a large volume of gel to significantly reduce the WOR. For example, to double the critical coning rate, an effective gel radius of at least 50 feet [15 m] typically is required. However, economically placing gel this deep into the formation is difficult. Smaller volume treatments usually result in rapid water re-breakthrough unless the gel fortuitously connects with shale streaks [19].

In horizontal wells, this problem may be referred to as duning or cusping. In such wells, it may be possible to at least retard cusping with near-wellbore shutoff that extends sufficiently up- and downhole as in the case of a rising OWC [16].

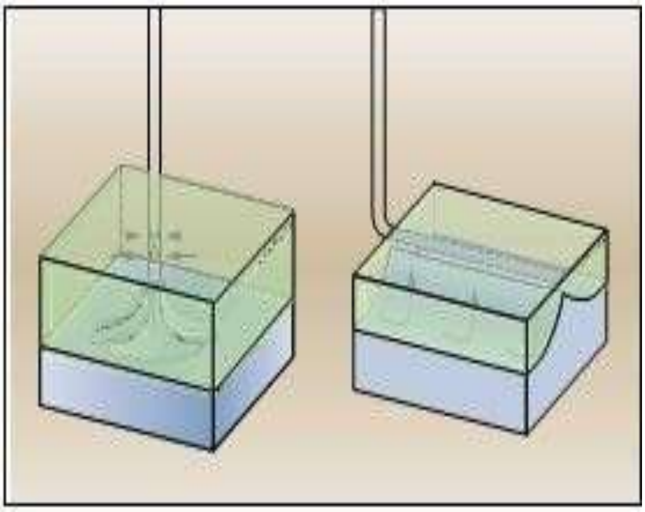


Figure II- 14: Coning or cusping [16].

G. Poor areal sweep

Edge water from an aquifer or injection during waterflooding through a pay zone often leads to poor areal sweep. Areal permeability anisotropy typically causes this problem, which is particularly severe in sand channel deposits. The solution is to divert injected water away from the pore space, which has already been swept by water. This requires a large treatment volume or continuous viscous flood, both of which are generally uneconomic. Infill drilling is often successful in improving recovery in this situation, although lateral drain holes may be used to access unswept oil more economically [16].

Horizontal wells may extend through different permeability and pressure zones within the same layer, causing poor areal sweep. Alternatively, water may break through to one part of the well simply because of horizontal proximity to the water source. In either case, it may be possible to control water by near-wellbore shutoff sufficiently up- and downhole from the water [16].

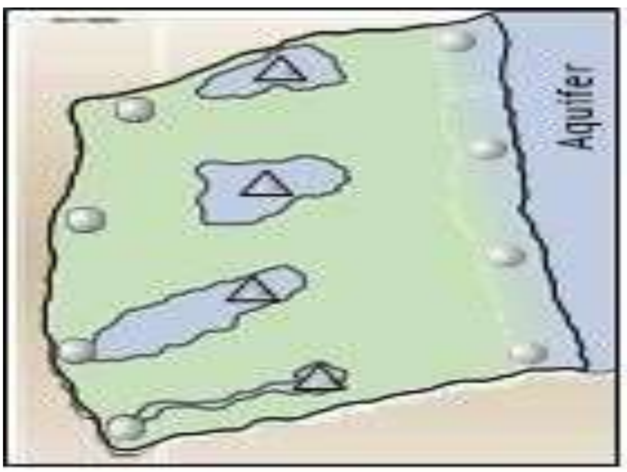


Figure II- 15: Poor areal sweep [16].

H. Gravity segregated layer

In a thick reservoir layer with good vertical permeability, gravity segregation sometimes called water under-run can result in unwanted water entry into a producing well. The water, either from an aquifer or water flood, slumps downward in the permeable formation or sweeps only the lower part of the reservoir. An unfavorable oil-water mobility ratio can make the problem worse. The problem is further exacerbated in formations with sedimentary textures that become finer upward, since viscous effects along with gravity segregation encourage flow at the bottom of the formation [19].

Any treatment in the injector aimed at shutting off the lower perforations has only a marginal effect in coning and, just as for the coning case described earlier; gel treatments are unlikely to provide lasting results. Lateral drain holes may be effective in accessing the upswept oil. Foamed viscous-flood fluids may also improve the vertical sweep.

In horizontal wells, gravity segregation can occur when the wellbore is placed near the bot- tom of the pay zone, or when the local critical coning rate is exceeded [19].

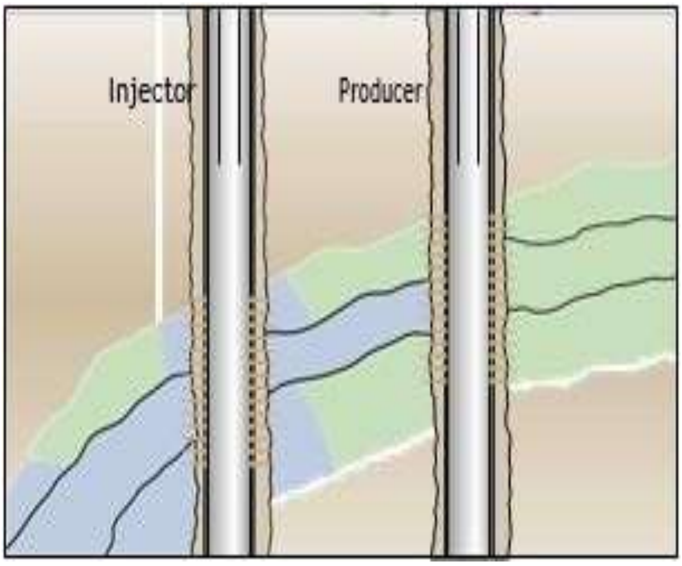


Figure II- 16: Gravity-segregated layer [16].

I. Watered-out layer with crossflow

Water crossflow can occur in high-permeability layers that are not isolated by impermeable barriers. Water production through a highly permeable layer with crossflow is similar to the problem of a watered-out layer without crossflow, but differs in that there is no barrier to stop cross- flow in the reservoir. In these cases, attempts to modify either the production or the injection profile near the wellbore are doomed to be short-lived, because of crossflow away from the wellbore. It is vital to determine if there is crossflow in the reservoir since this alone distinguishes between the two problems. When the problem occurs without crossflow, it can be easily treated. With crossflow, successful treatment is less likely.

However, in rare cases, it may be possible to place deep penetrating gel economically in the permeable thief layer if the thief layer is thin and has high permeability compared with the oil zone. Even under these optimal conditions, careful engineering is required before committing to a treatment. In many cases, a solution is to drill one or more lateral drain holes to access the undrained layers [16].

Horizontal wells completed in just one layer are not subject to this type of problem. If a highly inclined well is completed in multiple layers, then this problem occurs in the same way as in a vertical well [16].

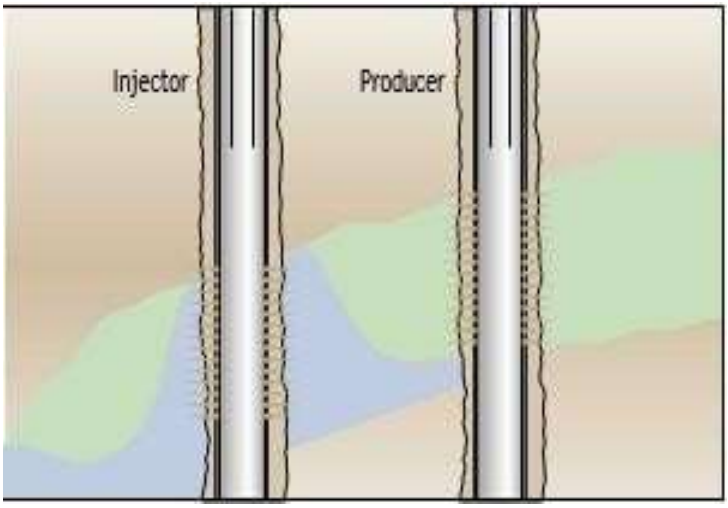


Figure II- 17: Watered-out layer with crossflow [16].

Problems caused by water production

1) Deposits

The drop in pressure and temperature when the effluent is raised in the tubing results in a decrease in salt solubility in the water, which will cause the crystallization and deposition of salt dissolved in the water produced on the production tubing walls. The continuous injection of fresh water to inhibit salt deposits, also leads to the formation of hard and compact deposits such as barium sulphate ($BaSo_4$), calcium sulphate ($CaSo_4$), because of the incompatibility between the injection water and that of the deposit.

Hydrates formed between gas and water under certain pressure and temperature conditions are caused by the production of water at the collection level.

These different deposits can cause a significant drop in production, by reducing the flow section, or by completely clogging the production column, as well as surface and collection facilities [19].

2) Corrosion

The high salinity of the produced water can cause the corrosion of tubular equipment to worsen [19].

3) The heaviness of the hydrostatic column

The production of water causes an increase in the production column. The increase in the average density of the water-oil mixture leads to an increase in the bottom pressure and therefore a drop in production flow [19].

4) Water blocking

Inappropriate interventions lead to increased water saturation around wells and lower oil production [19].

5) The production of sand

Water can weaken cement materials that hold grains and formation in place, allowing sand to be produced [19].

6) The emulsions

The simultaneous production of hydrocarbons and water is often the origin of associations of a physical nature such as emulsions between water and oil that will significantly reduce well productivity [19].

7) Hydrates

Hydrates are physical associations that form between gas and water under certain pressure and temperature conditions [20].

8) The Decrease in Relative Oil Permeability

Oil well productivity is strongly related to the relative permeability of oil in the vicinity of wells, which is affected by the simultaneous presence of water [20].

Chapter III
Recommended solutions to minimize gas and water penetration

Water and gas shut off definition

Water and gas Shut-off is defined as any operation that prevents water and gas from reaching and penetrating production wells in order to improve oil or gas production. There are countless chemical and mechanical techniques.

The selection of candidates

D. Permana (2013) defines the best candidate wells for the WSO as:

- Closed wells or wells producing at or near the economic limit.
- Benefit the most from an effective treatment.
- Low risk if treatment fails (other than cost of treatment).
- Large amount of mobile oil remaining in place.
- Economic constraints.
- High water-oil ratio.
- High production flow.
- High initial productivity.
- Wells associated with active natural water supply.
- Structural position.
- High permeability contrast between oil and water-saturated rock (fractured reservoir).
- Successful treatments have been performed in similar cases.

Strategies to minimize gas breakthroughs

Several solutions are used to stop the gas breakthroughs either by intervention on the injection wells or the producing wells [13].

The main solutions that have been made to reduce the problem of gas breakthrough (gas breakthrough) and increase oil recovery are:

Injector Well

Some solutions used as the first remedies at the injector wells are:

- Reduce the gas injection rate (this reduction should be considered).
- Plugging in the most permeable drains to allow gas to pass through the less permeable drains for effective sweeping;

The previous solutions have given poor results due to:

- The affect of gas digitization limits scanning efficiency in particular in less permeable intervals [13].

III.3.2.Producing Well

Gas shut-off:

Was made in producer wells in order to stop the flow of gas from well-defined intervals, using a gel, polymer or cement plug, to stop the flow of gas and increase the recovery of oil [13].

- **Re-complete wells with LCP or with a mixed liner:**

These techniques are most commonly used to solve the problems of breakthroughs in the HMD field.

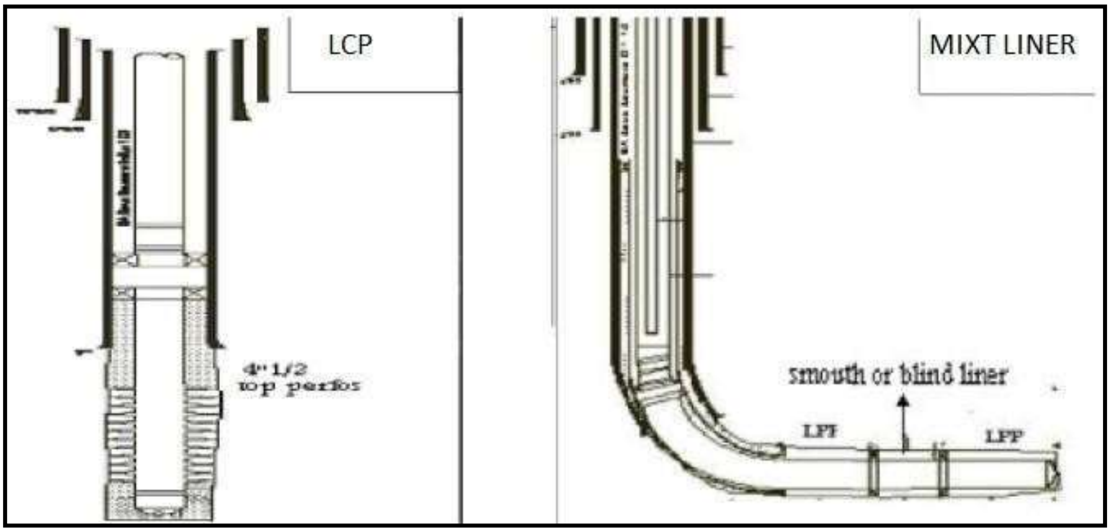


Figure III. 1: Examples of completion with a LCP and LPP [13].

- **Expandable Steel Patch**

Note: we have the flex patch, the expandable liner, and the casing patch.

- **Flex patch**: it is a chemical resin that inflates with the heat of a resistance, the disadvantage of this technique is that the flex patch does not resist a large P (P= 500 psi).
- **Expandable liner**: it is a casing that sticks to the liner, this technique reduces the diameter, but its advantage is that it resists high P (P=5000 psi).
- **Casing patch**: it is a casing that sticks to the liner, it reduces the diameter can be $2^{7/8}$ so we cannot intervene with tools that have a D $2^{7/8}$ [13].
- **Les SES Patches (Saltel Expandable Steel Patches):** it is one of the new technologies of the expandable liner, the SESP are tubular that stick on the liner or the casing by inflating the inflatable packer, these SESP are at different lengths that meet the need of the customers (can range from 6 m to 36m).

They are permanent solutions to ensure a long life for a well

• Repairing damaged casings or tubings

• Plugging obsolete or unwanted punctures,

• And ensures a reliable barrier in the annular preventing gas migration.

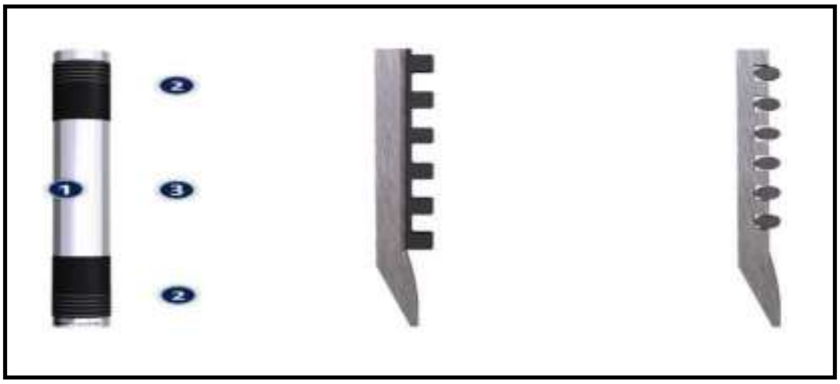


Figure III. 2: SES – patch [13].

Figure III. 3: Real photo of the rubber part of the Casing Patch [13].

Double completion

With double completion it is possible to isolate the zone which produces the oil from that which produces the gas in this case the gas is produced by the annular space between 4 ½ and 2 7/8, and the oil is produced in 2 7/8.

Conventional solutions give good performance against the problem of breakthrough, but after a period of production the breakthroughs have appeared again, because these solutions are considered as temporary solutions, This made us think of another permanent solution by ensuring the continuous control and maintenance of production parameters (gas and oil flows).

Recently, intelligent completion technologies have become an effective solution to various problems (water and gas penetration) and show encouraging results in the world compared to conventional techniques [13].

Smart completion

Definition

Intelligent completion is defined as a completion that combines a series of components that collect, transmit production and reservoir data, and allow selective control of the areas to optimize the production process without intervention at the bottom of the well.

This completion is controlled remotely (from the surface) with devices that allow controlling the production flow, it can be used for producing wells or injectors. The parameters (flow rate, pressure, and temperature) are collected in real time by permanent bottom gauges (permanent downhole gauges) [13].

Figure III. 4: intelligent completion [13].

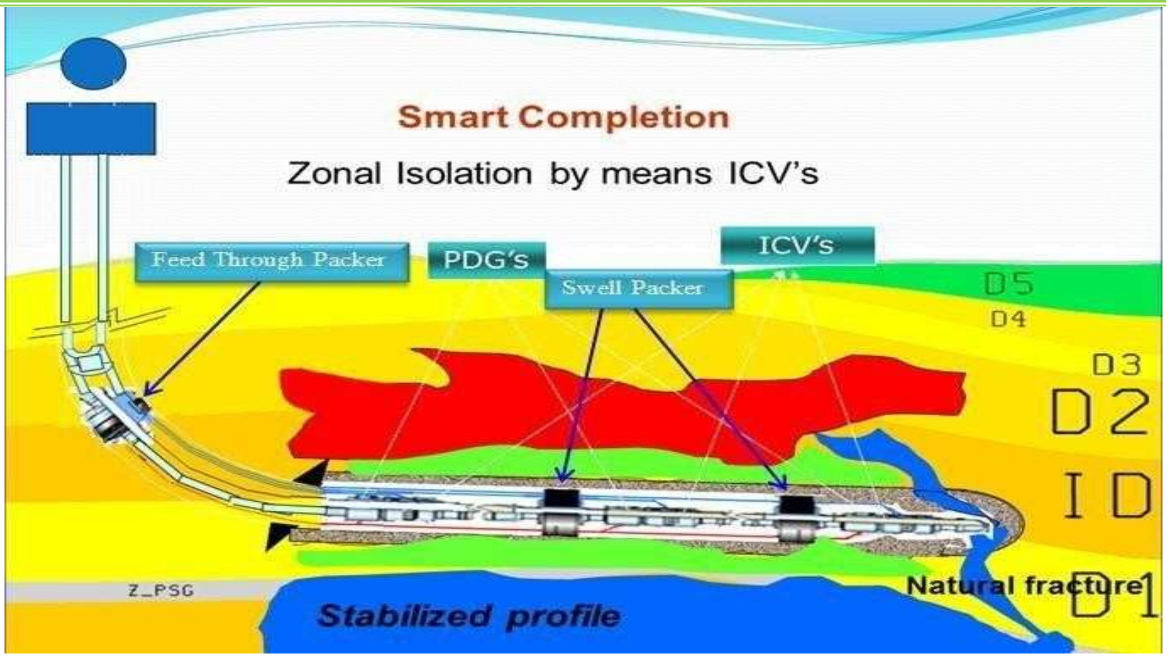


Figure III. 5: Intelligent completion [13].

The main elements of intelligent completion

Industry generally admits the definition of intelligent completion, such as that in which the flow-in (or injection) is controlled along the hole at the reservoir level, without any intervention, and with or without monitoring [13].

To achieve this completion, the following elements are generally required:

Inflow Control Valves

This device has a bottom duse operating from the surface either electrically or hydraulically. This duse which is made of tungsten carbon with a metal- metal sealing surface is used to provide accurate flow control from the tank or injection into the formation. These valves are classified according to pressure and different according to the direction of orientation. They have a locking mechanism to block the duse in such a position by preventing accidental operation due to the background conditions [13].

In the event of damage to the hydraulic control lines, the ICVs are “failed” to return to the hydraulic operating system of these valves, the ICV is equipped with a slide in its profile to allow it to move using the coiled tubing or wire line. The tool also has polished surfaces on both sides to allow the placement of an insulation tube through all the damaged duse. The ICV’s are operated using an electrical or hydraulic system or a hydraulic force is applied to each side of the piston inside the ICV to move the valve to the open or close position. There are hydraulic lines in the well to control each ICV by varying the value of the hydraulic pressure applied in these lines, each of these ICV’s can operate without affecting the other [13].

Figure (Figure.III.6) shows a hydraulic flow control valve. The control section consists of a stop coil and actuator; the indexing and blocking spindle (Schlumberger 2002) controls it. The pressure drop in the valve depends on the ICV's models, the most common types are:

- **Sub-critical valve: created by flowing fluid through a restriction.**
- **Labyrinth device: force the fluid into a series of channels.**
- **Spiral ICV: the fluid flow takes the form of a spiral.**
- **Autonomous ICV: like the configuration of a spiral.**

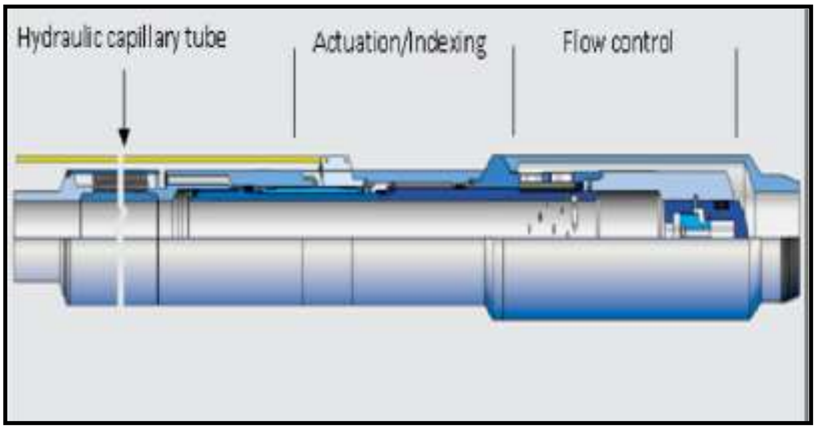


Figure III. 6: Interval control valve (ICV) [13].

The characteristics of ICV

- 6 manoeuvring positions;
- A manual control;
- Corrosion resistance;
- Operating at 5000 psi to 10000 psi and 275°F;
- Dimension 2 7/8"Dex max=4,660", Dintmin=2,250";
- Max flow rate 3000 bbl/d for liquids and 5 MMscf/d for gases.

Feed-through insulation packers

Its purpose is to carry out an individual control of the zones and to ensure the separation of the production of the different layers, so each zone must be isolated from the other using the embedded packers (packers incorporing feed-through). Thus, to facilitate the control, communication and passage of electrical cables. The pressure required for isolation, i.e., the pressure required to close the ICV, is provided by the connections at the top of the by-pass ports. Packers are classified by the pressure difference between the bottom and the top.

The example of MC packer (multi control packer) is shown in the following figure:

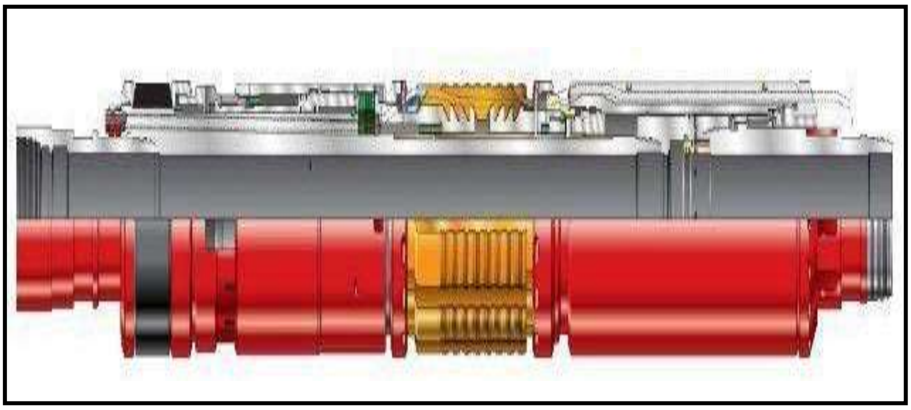


Figure III. 7: isolation Packer [13].

- **Control, communication and electrical cables**

Current smart well technology requires multiple controls and piping to transmit power and data to monitor the bottom of the well. These devices can operate hydraulically by control lines or electrically by conducting cables or also by optical fibers.

These can be installed in a special control line, or with a hydraulic line in the same control line. For extra protection and ease of deployment, the lines are usually wrapped [13].

Figure III. 8: Communication cables [13].

Downhole sensors

Varieties of bottom sensors are available to monitor well parameters for each affected area. Several electrical sensors (single-point quartz crystal) of pressure and temperature can be connected on a single electrical conductor, thus allowing giving very precise measurements of the temperature of several zones. Fiber is widely used currently to observe the temperature distributed over the entire length of a well drill and provide temperature values for each meter of depth. Fiber optic pressure sensors are available for one point but sensors for several points are still in development. There are also bottom flowmeters based on the venturi principle, or pressure drop correlations through flow control devices. There is another new generation of flowmeters based on passive acoustic fiber optic detection that are in development.

There is also another technology under development that includes:

- Water-cut detector.
- Density meter.
- Injector of bottom chemicals.

Figure III. 9: Bottom sensor [13].

Surface Data Acquisition and Control (CADS)

Thanks to multiple background sensors that provide production data in ‘’ real time’. The resulting data can be overwritten. This requires the use of a system to acquire, validate, filter and store data.

Processing tools are required to review, analyze data and have good well and reservoir performance, combining the information obtained during the analysis with the predictive models. This combination can give good results especially with the release of the new generation of the control process in order to optimize the production of the wells [13].

Problems affect smart completion elements

Since the bottom sensors (gauges) are electronic devices, they are very sensitive to the bottom temperature, which is the main challenge of electronic systems. Sealing is another major problem. Due to high pressure and bottom temperature, packers cannot provide insulation of areas, salt deposits can be plugged the bottom valves and thus reduce their control capacity [13].

Strategies to Minimize Water breakthrough

Water Shut-Off is defined as any operation that prevents water from reaching and entering producing wells. There are an incomplete number of techniques such as polymers and polymer/gel injection, different types of gel system, organic or metal cross linkers and a combination of them, mechanical solutions, cement plug solutions and other hundreds of different mechanical and chemical methods for the WSO. [21].

Well Configuration and Completion

The number of injector wells and producers required to produce a field suggests the approach to model selection and optimum spacing. Different well models, including linedrive, five, seven and nine spot, normal or inverted, can be developed for spacing different wells under different well and reservoir conditions. The optimal design of the well configuration, completion and replacement using new technologies starting with drilling techniques up to the reservoir simulation, have the ability to increase oil recovery and decrease water production. Drilling strategies and completion options are numerous [21].

Mechanical solution

In several problems near the wells, such as leaks in the casing, the flow behind the casing, rising water level and wet layers without crossflow, and in the event that the bottom water begins to dominate the production of the fluid, The perforations are sealed with a cement squeeze, packer or plug. The well is re-drilled above the selected area and oil production is resumed.

This procedure is repeated until the useful area is fully wet. This method is one of the easiest ways to control water coning [21].

Mechanical treatment and cement

Plugs and Packer

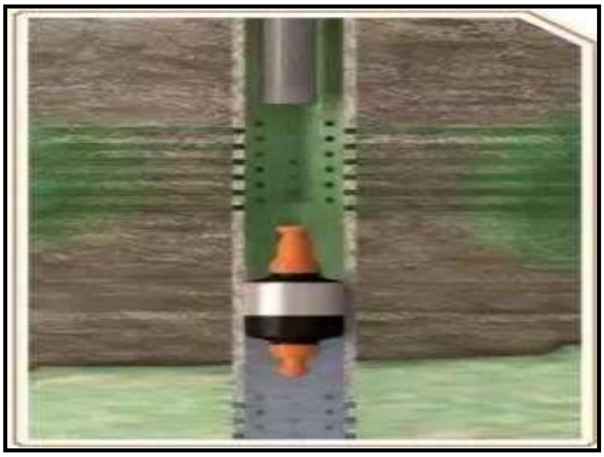
Simply put, the concept of packers and stoppers is a small diameter element, mainly made of rubber, which can enlarge creating an insulating seal. The installation of packers and plugs (plugs) is one of the most well-known mechanical solutions for shutting down and isolating water inside the well. They manage to eliminate production from unwanted water areas [22].

This material is known to be economical and reliable in the realization of the insulation because it can be installed without pulling the production tube and without the drilling platform. They can be installed using coiled tubing. Moreover, the results can be obtained relatively quickly, in a few hours to a few days [22].

There are different types of packers and stoppers with different properties and adjustment techniques. Some elements develop by interacting with certain types of fluids (oil, water or hybrid) called 'swell able packers'. They also depend on preconceived properties such as temperature, pressure, and salinity of the forming fluid. This can be a disadvantage in some cases and leads to failure in establishing the element. The other packers and plugs inflate by pressing the element to expand and seal.

Packers and plugs can be used to isolate unwanted water production inside the well in some cases.

An easy example would be the completion of an open-hole well and the water area is identified as being at the bottom of the well. A bridge plug can be installed to isolate the lower part and stop the additional water production to improve the production performance of the higher oil zones (Figure III.6) [22].



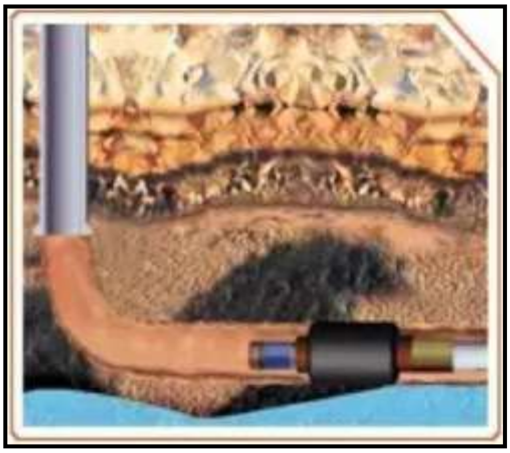


Figure III. 10: Representation of mechanical processing and cement [22].

Similarly, for water injection wells, these plugs can be used to ensure better compliance results and to eliminate water production contaminated production wells in flight zones, high permeability layers or connected open elements. (Figure III.11).

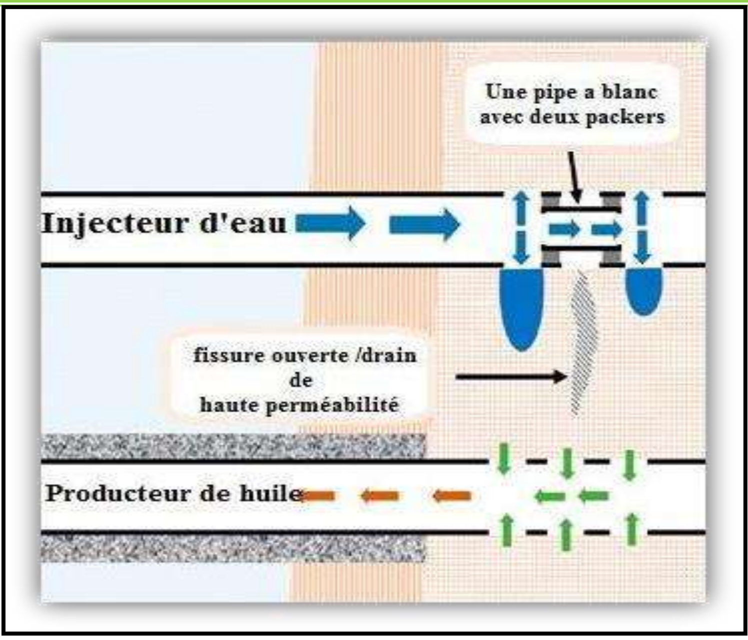


Figure III. 11: Two packers above and below a blank pipe to avoid injecting water into open structures or high permeability layers [22].

Apart from this, inflatable packers are also used in chemical injection for water shutdown. Packers are used to direct the flow of chemicals injected into the desired layers and prevent the fluid from entering the production formation.

Chemical solution

Chemical treatments require precise fluid placement, and include polymer/gel injection, different types of gel systems, organic cross-linkers, Metal cross-linkers and a combination of them as a solution to improve flood efficiency are needed in heterogeneous reservoirs to reduce water production and improve oil recovery [23].

Sealing gels

Sealing gels block the gap that produces water. They compete with cement or packers. Polymer gels have been widely used to reduce water production [23].

The gels are intended to block the pores of the matrix and the fractures of the waterproducing zones. Polymer gel systems designed for fractured conventional tanks are generally partially cross-linked during placement and have a high initial viscosity. This is done to reduce gel leakage in the matrix [21].

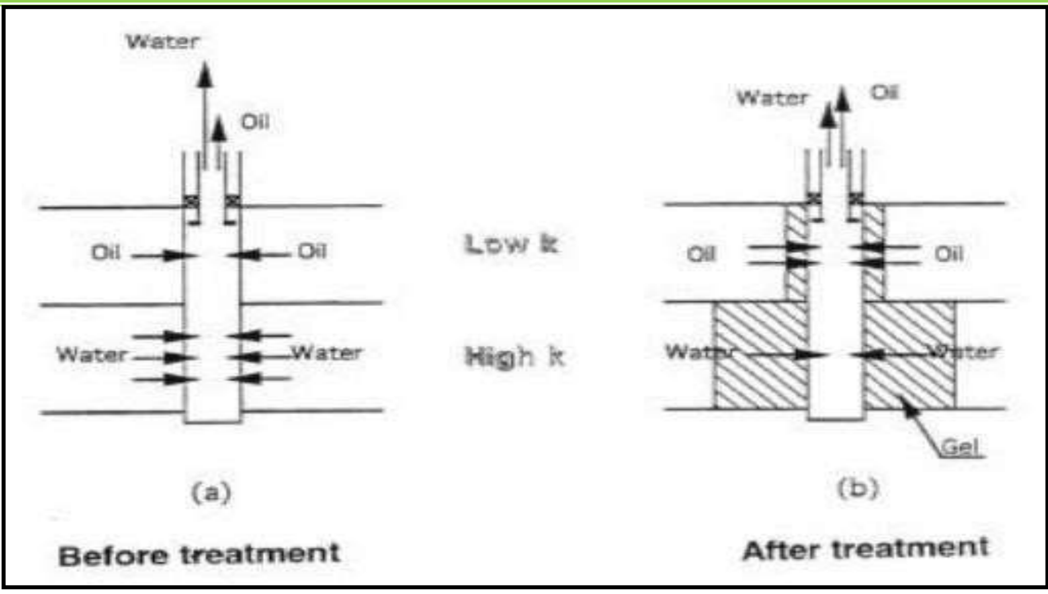


Figure III. 12: Principle of gel treatment [21].

Change in relative permeability (RPM)

Relative Permeability Change (RPM) is the property that is operated during WSO treatments of certain oil fields and a property by which several water-soluble polymers and aqueous polymer gels reduce the permeability of the water flow to a greater extent to the flow oil and water. WSO RPM treatments are applicable to oil and gas producing wells. Also referred to as disproportionate permeability reduction (DPR). Some practitioners reserve the term “DPR” for relatively strong polymer gels that result in a large degree of reduction in water permeability, while the term “DPR” is reserved [21].

For solutions of polymers soluble in water or relatively 'low' gels which give more disproportionate reduction of subtle permeability and more subtle reduction in water permeability. However, the terms RPM and DPR are considered synonymous. Over time in the literature, DPR and RPM also refer to ‘selective permeability reduction’ and ‘selective permeability blocking’ [21].

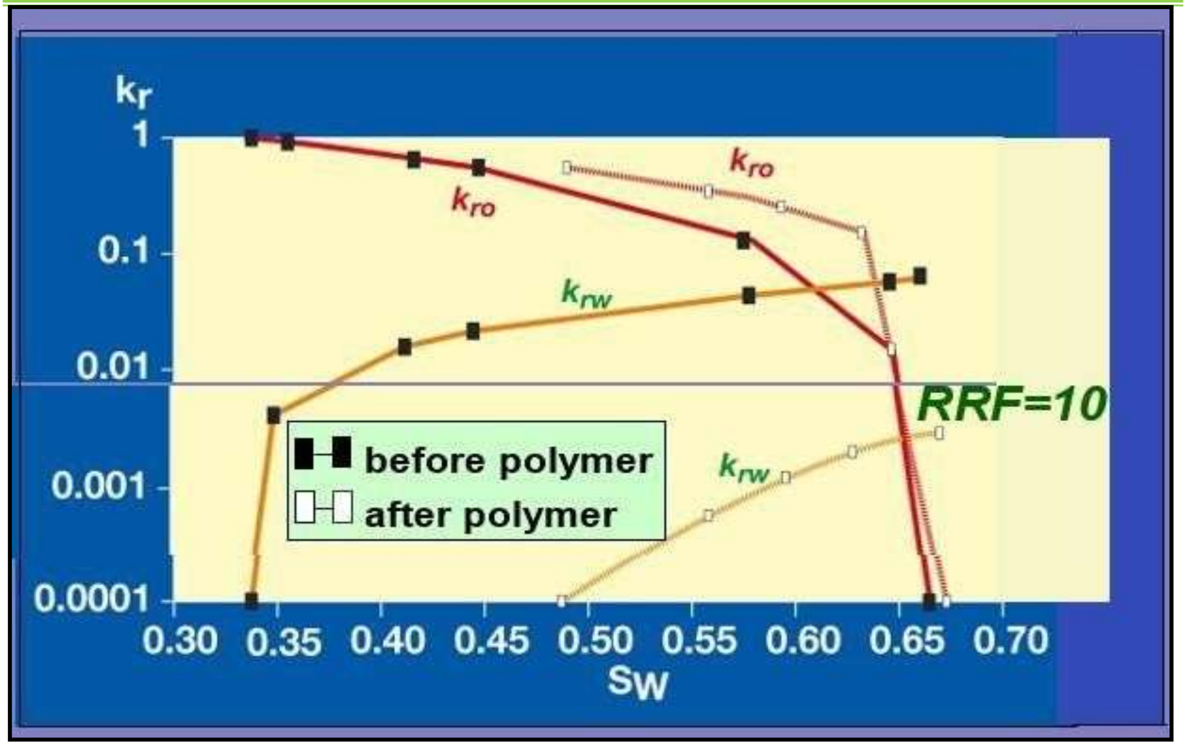


Figure III. 13: Change in relative permeability after polymer adsorption in sandstone wettable with water [24].

The advantages of gel treatments over cement treatment

Les gelling can penetrate porous rocks while cement can seal the rock surface only. Cement can seal the natural permeability of the rock near the canals of the well. Sufficient injection pressure and a significant distance are required to fracture or separate rock or sand. Cement may not sufficiently seal the channels if the cement does not adhere as strongly to the rock And also, cement cannot penetrate narrow channels. [21]

There are four advantages of gel over cement:

1. The gel may form a deeper impermeable barrier within porous media.
2. The gel may flow into narrow channels behind the tubing.
3. The gel can form a non-permanent plug plug plug that can be easily removed.
4. Gel treatments are cheaper than cement because of crews and reduced time.

Chapter IV

Gas

shut off

applications

IV.1.Location of the deposit

The large oil field of HASSI MESSAOUD (HMD) is located in the central part of the Algerian Sahara, it was discovered in 1956 by drilling MD1 which crossed the sandstone reservoirs of the Cambro-Ordovician at 3337 meters of depth. The deposit, 40 x 40 km, is located 800 km south of Algiers (fig.I.1), and 350 km from the Tunisian border. This field is the largest in Algeria and contributes to more than 50% of Algerian production.

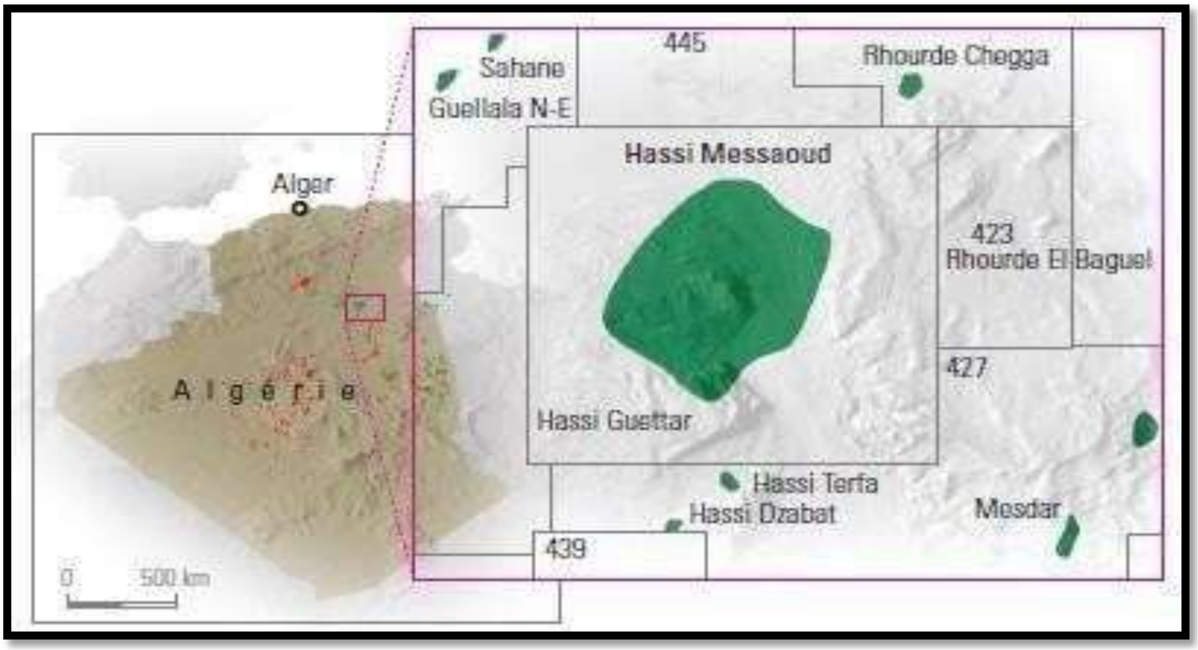


Figure IV.1: Location of the HASSI MESSAOUD deposit

VI.2.Field Zoning

The deposit is rapidly compartmentalized by regional fault systems running north-eastsouthwest to north-north-north-east-south-west, and by complex small-scale networks, perpendicular and parallel to the main system. Fault-associated crack networks contribute to production by increasing permeability when open and connected. The compartmentalization character of the HMD reservoir was demonstrated in the 1960s after production, based on the differences in reservoir pressure observed between nearby wells, attributed to the presence of faults more or less tight to the circulation of fluids.

This led to the subdivision of the deposit into 25 dynamic units (Fig.I.2) called “production areas”, with wells with similar pressures separated by major fault areas called “interzones”. “Out-of-area” refers to fault passage areas located on the outer limits of the deposit.

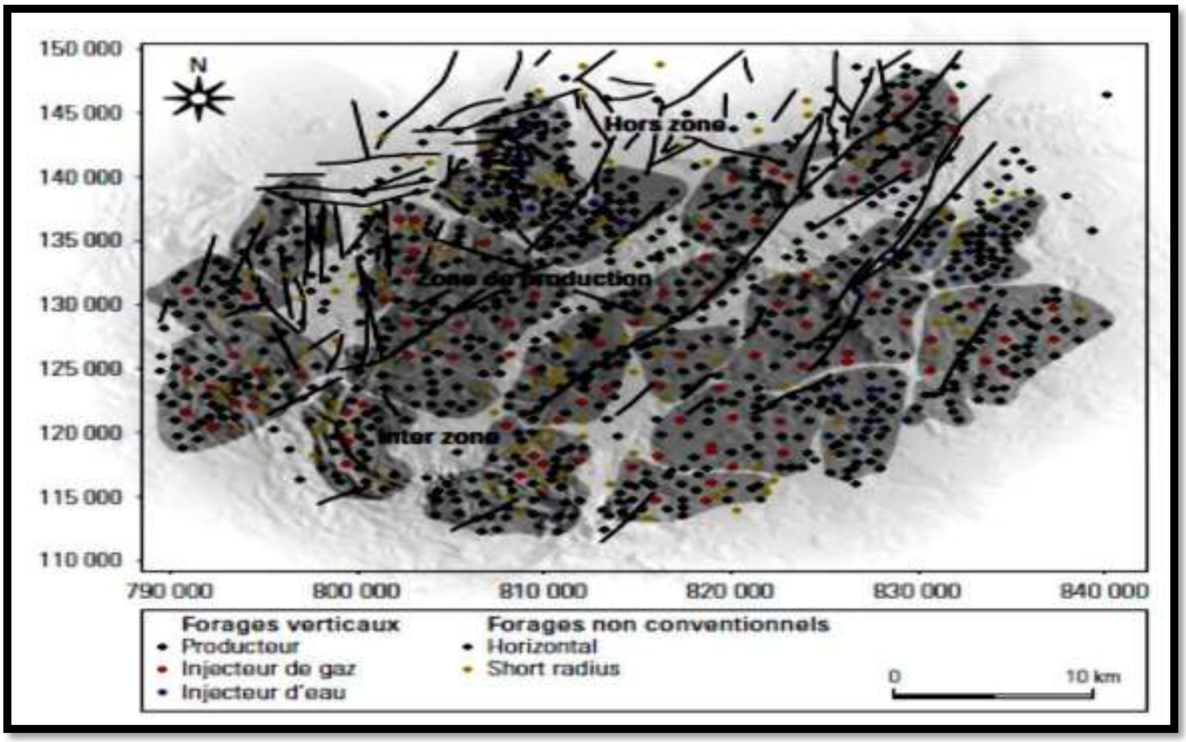


Figure IV. 2: HMD reservoir compartment

It should be noted that the current subdivision is unsatisfactory as the same area can be subdivided into sub-zones.

Field geology IV.3.1Structure

The super-giant HMD field has an anticline dome structure of nearly 1,600 km2, largely inherited from the Hercynian orogenic phase, whose peak occurred at the end of the Paleozoic period.

The episode of erosion, at the end of the Hercynian tectonic phase, is at the origin of the progressive disappearance of the upper units of the reservoirs, from the center towards the periphery of the deposit and the digging of deep and narrow valleys in favour of the major Fault (fig.I.3).

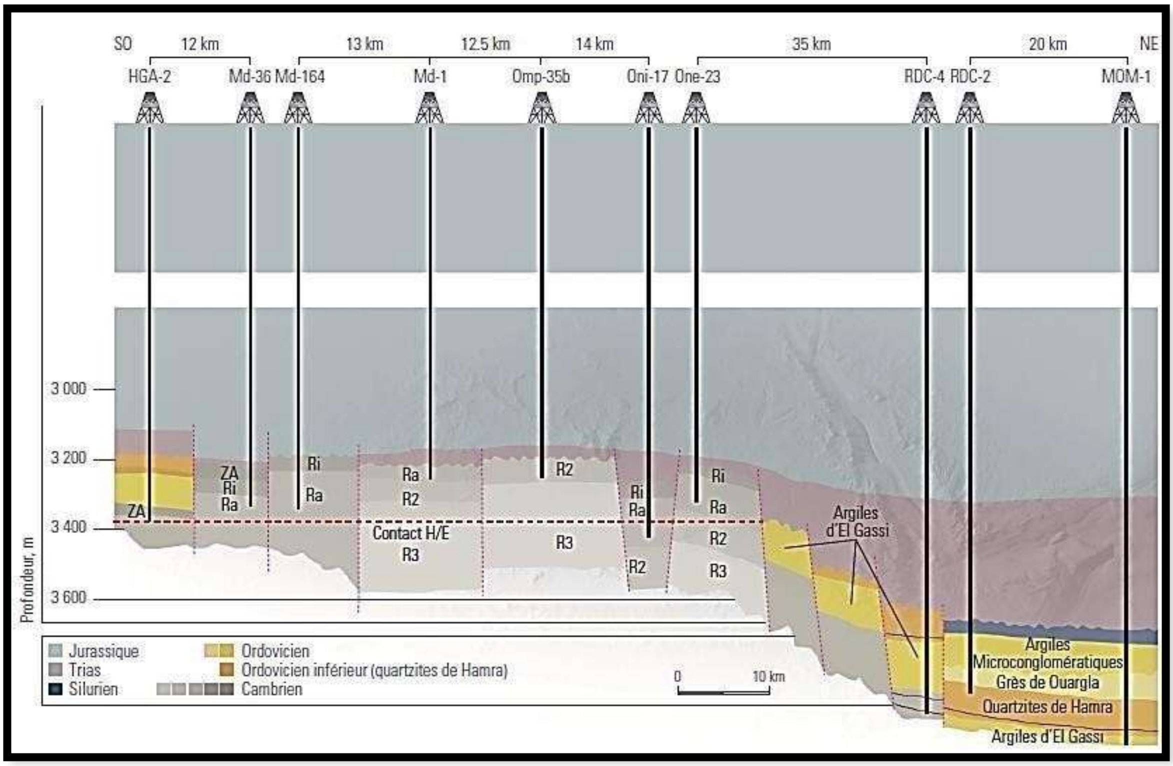


Figure IV. 3: Schematic cross-section of the HMD field

The Cambrian deposits represented by sandstones and quartzites are the best known and constitute important reservoirs (Cambrian Ri, Ra). The Ordovician reservoir (quartzites of Hamra), eroded under the Hercynian discordance and constituting the halo of HMD, is an oil Play of great potential.

Stratigraphy of the reservoir

Stratigraphy reservoir

As well as productive deposits of HMD and ElAgreb-El Gassi oil in the Cambrian Reservoir, the majority of the structures drilled revealed new but relatively limited accumulations (caseOL and HGA). In terms of area and closure, the Ordovician (Hamra quartzites) showed impregnated columns of more than 100 m and areas exceeding 500 km2 (HTF-HDZ zone). The tests yielded flows ranging from 6 to 14 m3/h of oil. The halo-shaped configuration of this tank is of great interest.

The stratigraphic sequence of the Cambro-Ordovician HMD deposit consists of a silico clastic series which is based in discordance on a metamorphic and eruptive base.

✦ **The Cambrian:** is subdivided into three litho-zones:

Table IV.1: Thickn ss of lith -zones the Ordovician reservoir

Reservoir cambrian	R3	R2	Ra inferior	Ra superior
thikness (m)	300	100	70 to 95	40 60

✦ **Ordovician:** partially preserved on the western periphery of the deposit:

table IV.2: Thickness of litho-zones of the Ordovician reservoir

Reservoir ordovician	Ri	Quartzites of Hamra
thikness (m)	40 to 50	75

a) Petro-physical characteristics of the Cambro- Ordovician reservoir

The permeability (K) and porosity (Φ) distribution in the HMD reservoir is characterized by very high heterogeneity, with matrix permeability values ranging from 0.1 to more than 100 mD (mili-Darcy), and porosities ranging from 4 to 12 %.

Well Information MDZ627 :

WELL SELECTION

Due to layering and compartmentalization of Hassi Messaoud field and natural fracture network, the secondary recovery via gas flooding cannot still efficient for a long time in many gas injection patterns. This could be explained from two sides. In one hand, starting from the gas injector wells, a gas front advances easily within the more permeable layer and faster through the network of natural fractures towards oil producers. On the other hand, starting from the oil producer wells, the oil is produced more easily from the more permeable layer which is expected to be in gas breakthrough soon after. Consequently, theses tow combined processes are probably the main accelerator of an early gas breakthrough occurred in many horizontal wells, leading to reach quickly the maximum capacity of surface facilities in terms of handling high volumes of the produced gas.

In addition to the principle of composite IPR in horizontal section of well, the lowering of gas injection rate within the gas breakthrough layer permits to maximize the oil recovery coming from the non breakthrough layers based on relative permeability aspect.
Horizontal wells in Hassi Messaoud generally exhibit good production performances, but they start to decline rapidly when gas begins to break through. Reservoir pressure as wells gas injection history confirm that this amount of gas is coming from injectors, especially there is short distance separating the producer and injector wells.

MDZ627, is an horizontal well selected as candidate for intelligent completion installation.

The well was drilled in the zone 1B of Hassi Messaoud field, where the main objective is to develop this part of field.

From a structural point of view, this well is defined by an important network of faults on the direction NW-SE and a fault on the EW direction.

History of Well MDZ627

It is a horizontal well drilled in 28/03/2010; in area 13.it is surrounded by several gas injection wells MD61; MD170; MD354.

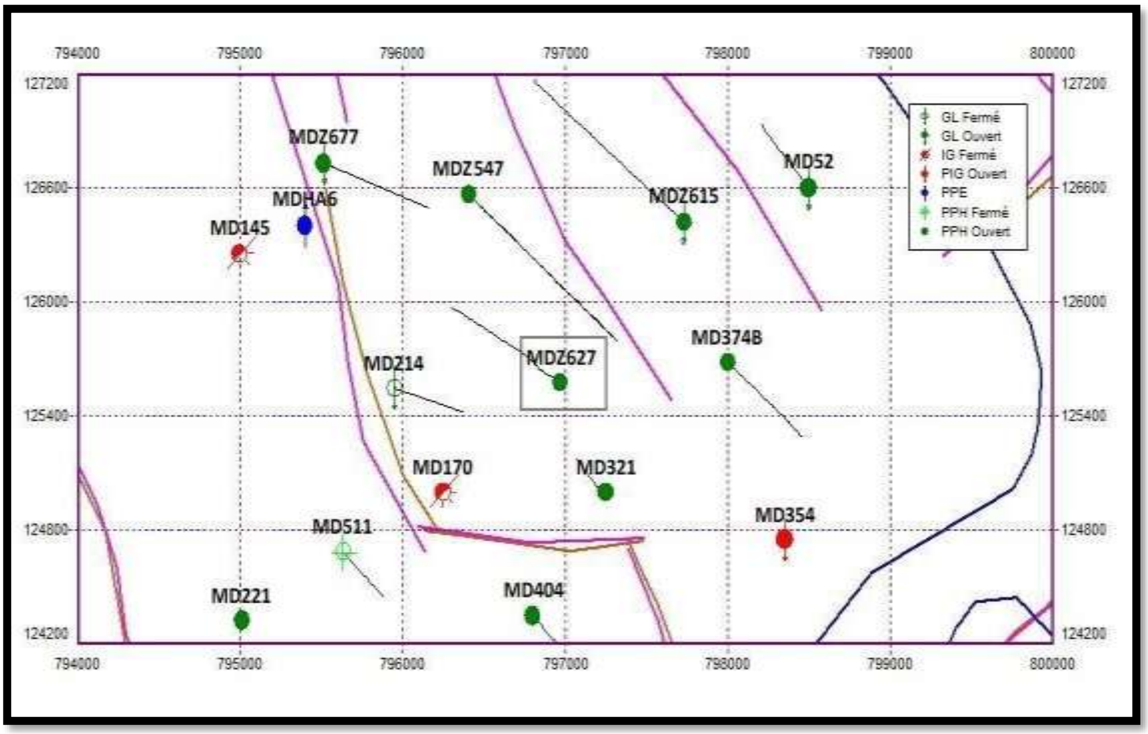


Figure IV4: Location of MDZ627 wells in the Hassi Messaoud field

The neighbouring wells:

Distance MD145: 2085 m closed

Distance MD354:1607m open

Distance MD170: 922m closed

Analysis of production data

MDZ627 is a horizontal open hole well; the well is put into production on 20/07/2010 whose Qoil is 14.82 m3/h, with a duse of 10 mm; and a GOR of 2040 Sm3/m3; in July 2016 the Qoil became 3.62 m3/h while the GOR is of the order of 2143 Sm3/m3, which means that it appears that the well is drilled as soon as it enters production and that is shown in the curves of the oil and gas production history and also the curve of the evolution of GOR below. And that's due to the gas injection wells that surround them, so its drilling is inevitable. **Well's profile**

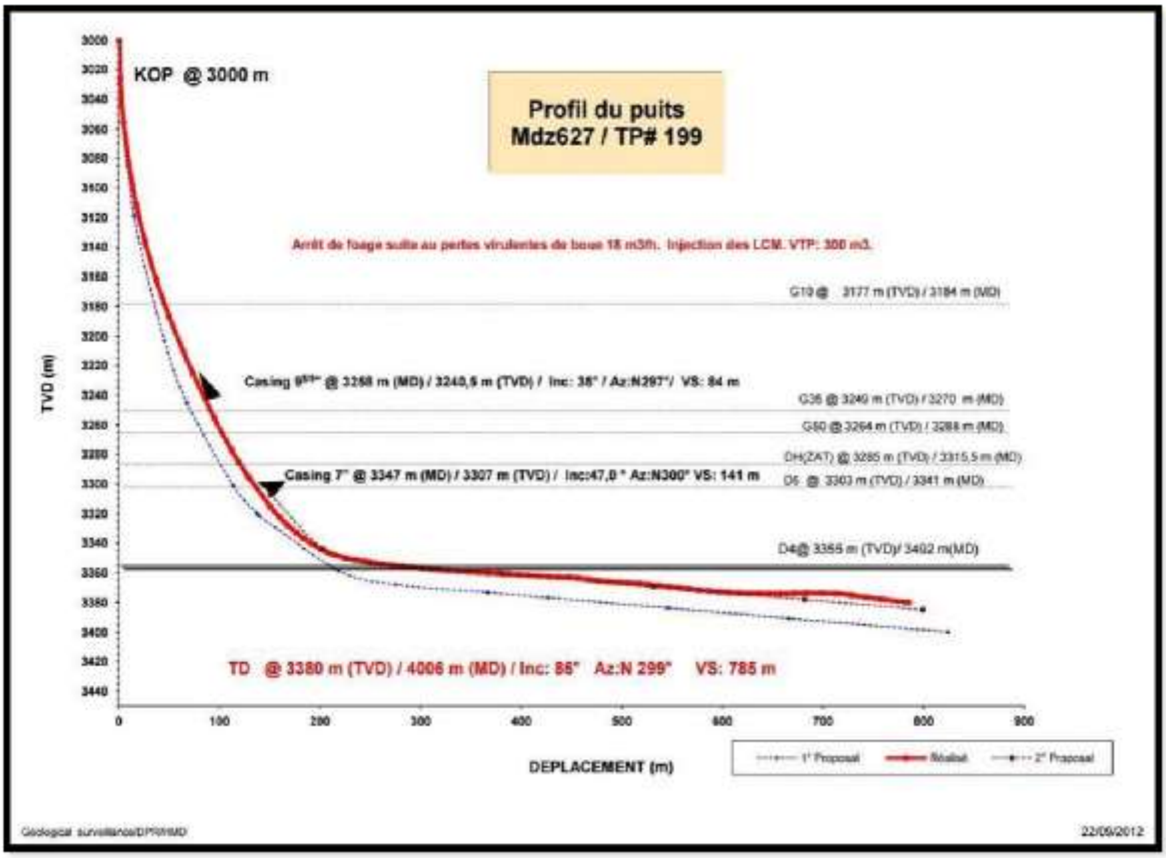


Figure IV.5: Well MDZ-627 Profil

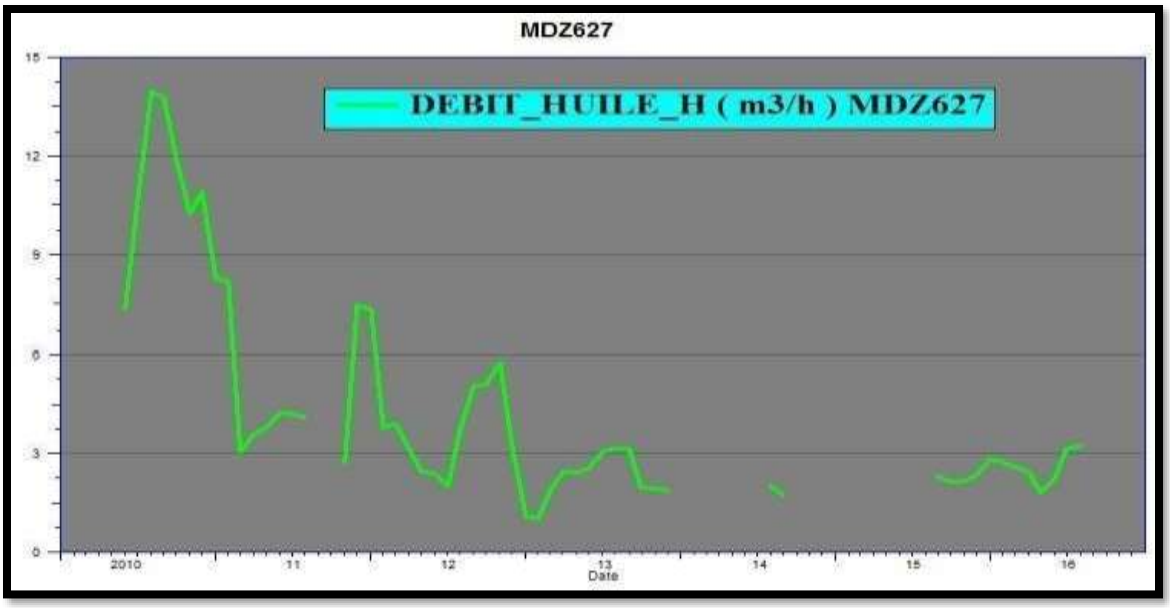


Figure IV.6: The history of oil production in well MDZ627

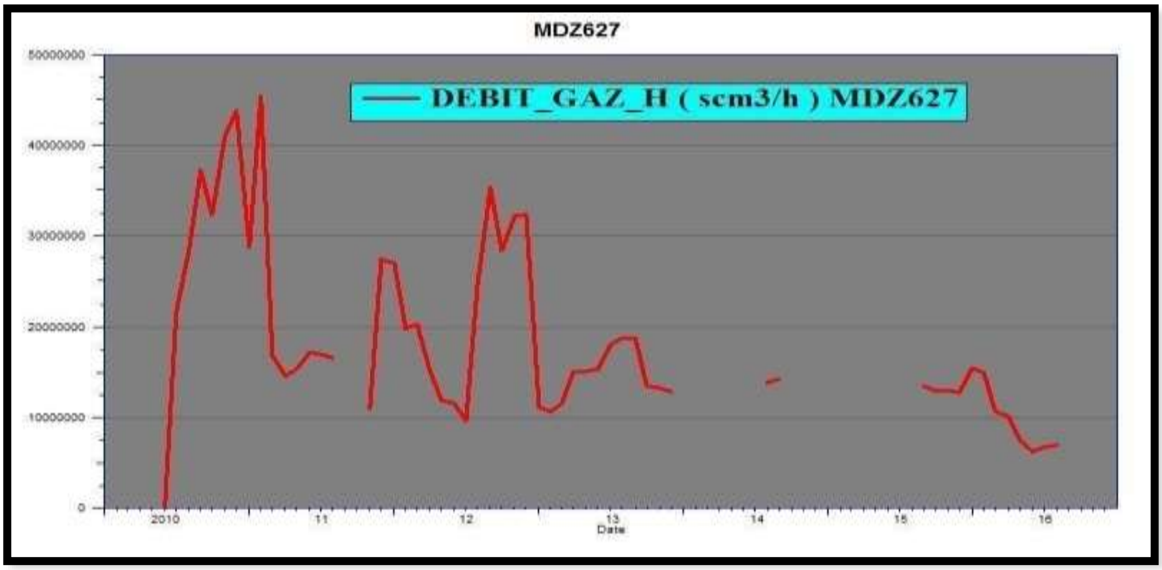


Figure IV.7: History of gas production in well MDZ627

Note :

Like in all horizontal wells. MDZ627 has started producing in such a good way with a high flow rate but this accompanied with a production of an important quantities of gas under saturated. Which caused an important oil rate decrease.

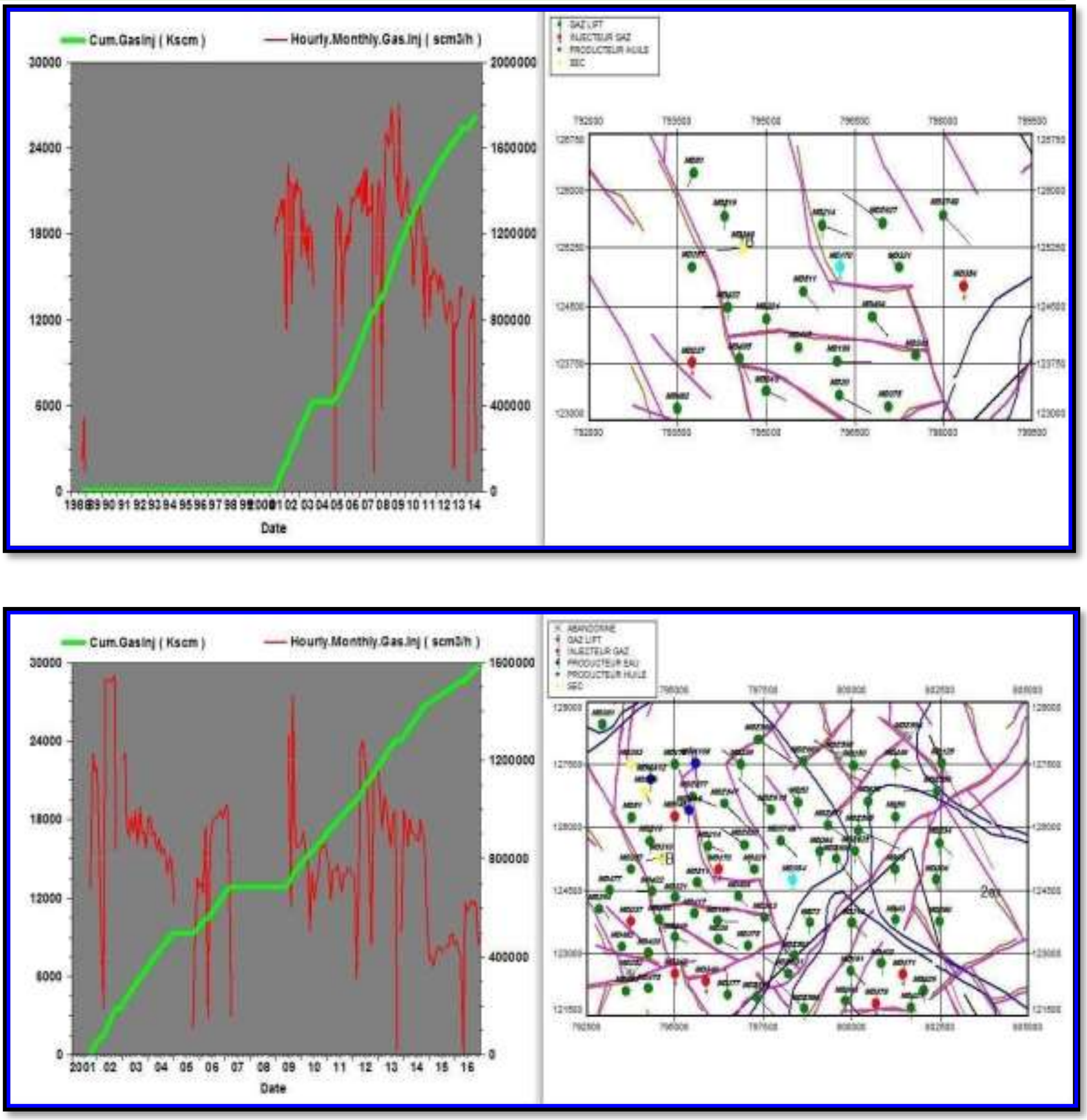


Figure IV.8: Evolution of MDZ627 well parameters, also the accumulation and flow of gas injected into neighboring gas injection wells.

Note : the gas injection has taken a larg interests for hydrocarbons production and this appears in the huge amounts of the gas that has been injected and it's being injected till nowadays.

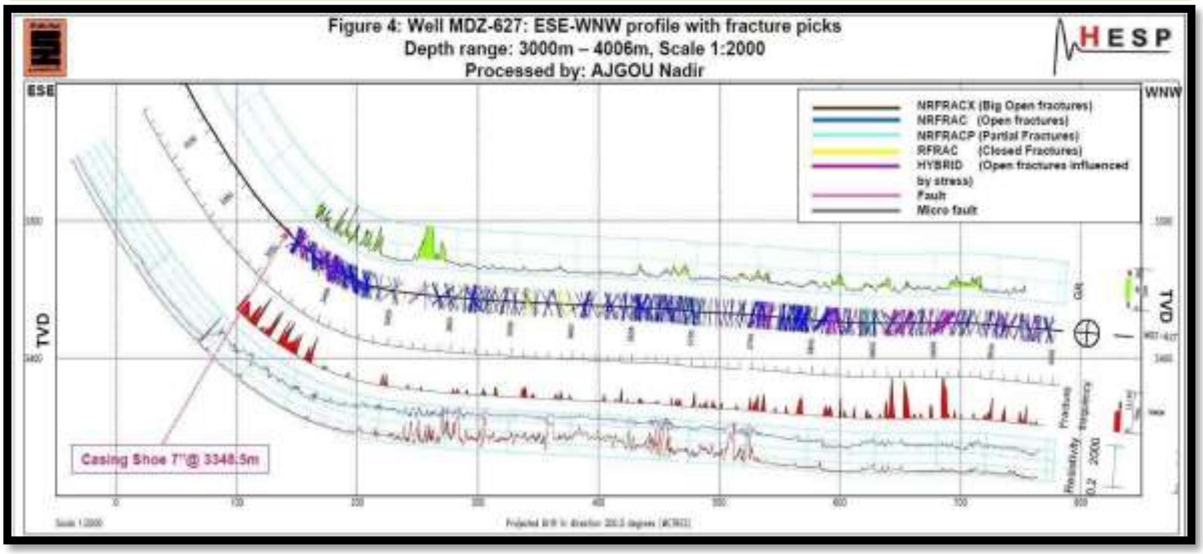


Figure IV.9: MDZ-627 Section Imagery

Table IV.3: The drains traversed by the MD497 well and the surrounding injection wells:

MDZ627	**MD170**	**MD354**
D4A, D4B	**D5, D4,D3, D2,**	**D5, D4, D3, D2, ID**

FSI Results: (See annex B): Running an FSI test allows us indicte the zones that produces gas and oil **(Table.4)**

TableIV. 4 : results from FSI test

Reservoir Zones	Inflow zones	From m	To m	Temperature °C	Pressure kg/cm2	Zonal Oil production			Zonal gas production		
						dQo res m3/D	dQo s.c m3/D	%	dQg res m3/D	dQg s.c m3/D	%
D5	Inflow 1	3439	3449	115.1	272.1	12	7	8	89	19811	5
D4	Inflow 2	3509	3557	115.1	272.4	0	0	0	756	156200	45
	Inflow 3	3563	3604	115.1	272.5	77	45	54	700	154300	42
	Inflow 4	3608	3686	115.9	272.6	53	31	37	118	30888	7
				Total		143	83		1663	361199	

Build up data in the table below

Table IV.5: last build up test data before the descent

Type Test	Date	PG	PFD	IP	HKP	HKL (Hw * Kyz)	Débit
SBU	11/10/2015	274.74	228.61	.073	97.7	--	2.77
PFD	27/04/2016	--	170.55	--	--	--	2.44

The results obtained from test build up, allow:

- Have the potential of wells
- Information relates to changes in dynamic bottom pressure
- Vertical and horizontal permeability values

Simulation Software Presentation

The Pipeline Simulator (PIPESIM) is a multi-phase, steady-state flow simulator used to:

- Design of oil and gas production systems.
- Modeling of the polyphasic flow from the tank to the separator.
- Analysis of the performance of production systems.
- Optimizing production and injection operations using its rigorous simulation algorithms.
- Accurately predicts flow, pressure and temperature in tubing and pipelines

PIPESIM software applications

PIPESIM offers a wide modelling capability from entire production systems from the tank to the treatment facility. Typical applications included in this software are:

1. Analysis of well performance

- Design and optimization of producer and injector wells.
- Modelling of well performance.
- Design and modeling of lift gas.
- PSE and PCP performance design and modeling.
- Modelling of horizontal wells.
- Detailed sensitivity analysis.

2. Pipes and Facilities

- Generation of temperature and pressure profiles.
- Prediction of solids formation (hydrates, wax, asphaltenes, etc.)
- Choice of equipment (pumps, compressors, etc.)
- Pipe design.

3. Network Analysis Module

- Rigorous thermal modeling of all network components.
- Pipeline capacity / flowlines.
- Complete pipeline equipment models.
- Collection and distribution networks.
- Optimization of gas lift**.**

MDZ627 Well Modeling (See Annex E)

So, to find a solution to the problem of gas penetration in this well, a study has been done with the Pipesim simulator to see the performance of the well when it isolates the gas from D5 and the upper part of D4.

Based on the PFD Test data in 27/04/2016 and FSI 18/06/2016 and the gauge of 06/03/2016 the well model consists of **4 producing zones**. They are mentioned in table (IV.6):

Table IV.6: traversed zones by MDZ627 well

	Intervals	Temperature C°	PFD kg/cm2	Qoil m3/d	Qoil %	Qgas m3/h	Qgas %	Pg kg/cm2	PI	GOR
D5+D4A	3439-3557	115,1	178,55	5.2704	9	136259.8	51	240,29	0.085364	25853.8
D4B	3563-3604	115,1	178,95	31.62224	54	112214	42	240,348	0.51504	3548.56
D4C	3610-3770	115,9	179	21.6672	37	18702.33	7	240,4	0.352886	863.1633
D4D	3770-3975	115,9	179	0	0	0	0	240,4	1,00E10	0

Q_{oil} of 2.51/h (given by the PFD test).

Well data before semi-intelligent completion descent are represented in table

Table IV.7: Well data MDZ627 before descent

Date Mesure	Diam, Duse (mm)	Unité Sépar,	Débit (m³/h)		GOR	Pression (kg/cm²)				
			Huile	Gaz		Press, Tete	Press, Pipe	W cut	débit total	IP
30/10/2015	14	600	2,19	13269.09	6073	158	19,8	0	2,19	3.763786
23/12/2015	14	1440	2,77	15149.64	5465	145,7	23,8	0	2,77	2.487396
03/06/2016	11	Vx40	2,51	6905.1	2751	125,6	15,9	0	2,51	6.11123
15/07/2016	14	1440	3,62	7761.48	2143	101,5	18,7	0	3,62	2.366312

- The well condition simulation is based on the insertion of the following data:

- **PVT data : p_b=155 bars, d=0,812 (g/cm^3), GOR=186,9 (cm^3/STBm^3) API gravity=42,8**
- **BUILD UP test data (see table)**
- **Well trajectory data :** they are mentioned in the table bellow (the rest see annex): measured depth, Azimuth, total vertical depth …

Table IV.8: well trajectory data

N°	MD (m)	Incl (°)	Azimuth (°)	TVD (m)	Latitude N/S (m)	Longitude E/W (m)	DLS (°/30m)	VS (m)	Remarques
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
2	2970.00	0.00	0.00	2970.00	0.00	0.00	0.00	0.00	
3	2981.22	0.19	11.19	2981.22	0.02	0.00	0.51	0.01	
4	3084.90	12.70	301.33	3084.16	5.49	-8.88	4.12	10.01	
5	3113.17	17.25	299.78	3111.46	9.19	-14.67	4.85	17.31	
6	3139.71	21.53	297.23	3136.49	13.37	-22.42	4.93	26.11	
7	3167.44	25.21	296.34	3161.94	18.32	-32.24	4.00	37.09	
8	3195.3	29.29	296.39	3186.71	23.99	-43.67	4.39	49.82	
9	3222.74	32.46	295.95	3210.25	30.20	-56.31	3.48	63.86	
10	3240.31	34.10	296.20	3224.94	34.43	-64.97	2.81	73.48	
11	3277.16	35.97	297.89	3255.11	44.06	-83.80	1.71	94.60	
12	3304.61	40.41	297.73	3276.68	51.97	-98.81	4.85	111.56	
13	3315.71	42.70	298.75	3284.99	55.46	-105.29	6.45	118.92	
14	3329.53	45.05	297.62	3294.95	59.98	-113.74	5.38	128.49	
15	3330.00	45.12	297.75	3295.28	60.13	-114.03	7.41	128.82	Sabot 7" @ 3347

- Mdz627 well simulation in pipesim software

After the insert of the necessary data in pipesim and the matching and the necessary data for the producing zones:

	Name	Geometry pro...	Fluid entry	Top MD	Middle MD	Bottom MD	Type	Active	IPR model
				m	m	m			
1	Res_4	Horizontal	Distributed	3608		4006	OpenHole	√	Distribute...
2	Res_1	Horizontal	Distributed	3439		3449	OpenHole	√	Distribute...
3	Res_2 (Gas)	Horizontal	Distributed	3509		3557	OpenHole	√	Distribute...
4	Res_3	Horizontal	Distributed	3563		3604	OpenHole	√	Distribute...

Figure IV.10: Production areas for well MDZ627 simulated in pipesim

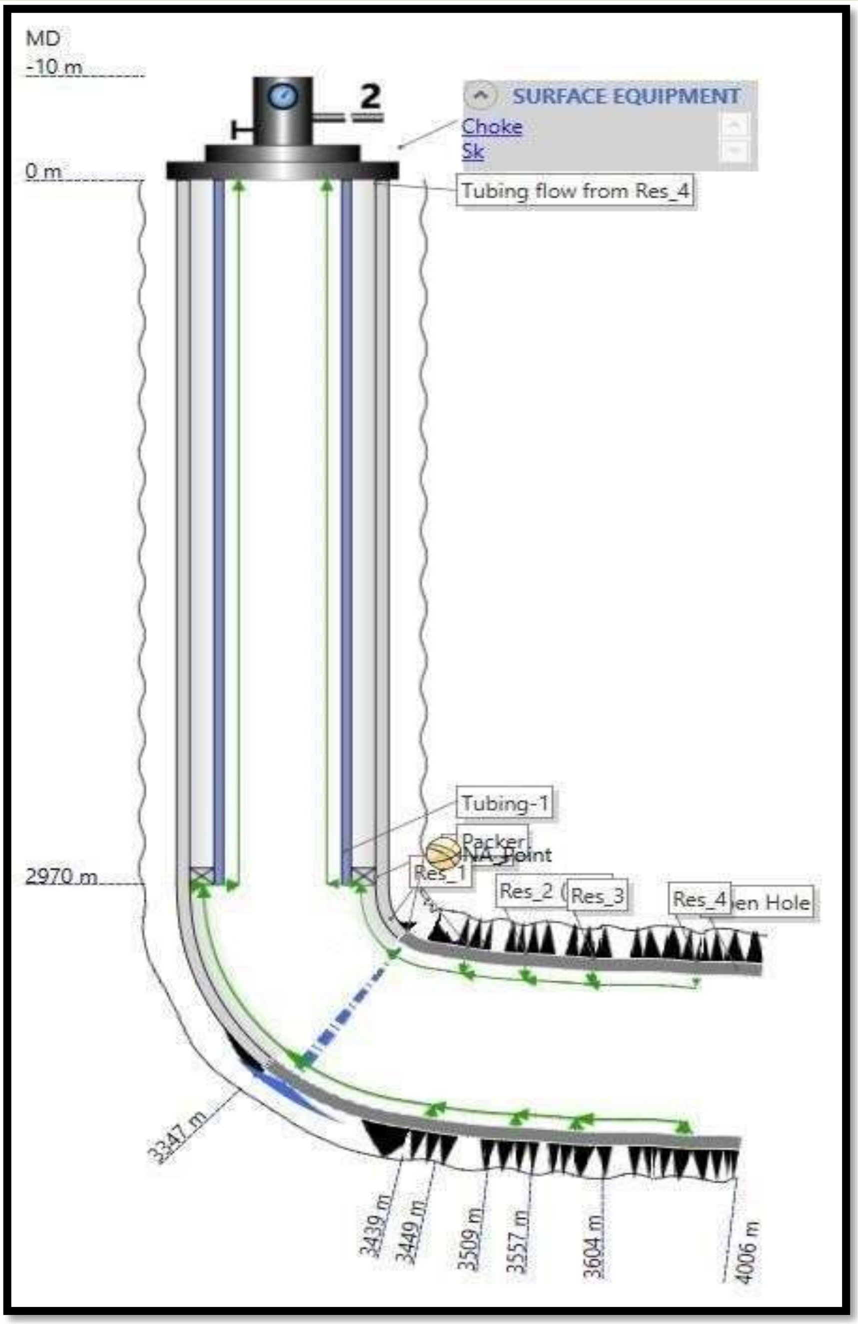


Figure IV.11: le model du puits MDZ627.(see Annex E)

So, after Matching the correlation that corresponds to the model of my well is: To get the working point that corresponds to my well I set the pipe pressure value =18.7 kg/cm2.

1- Oil flow rate:

To get the operating point for MDZ627 a matching must be done to get the curve that shown in figure**(IV.12)**

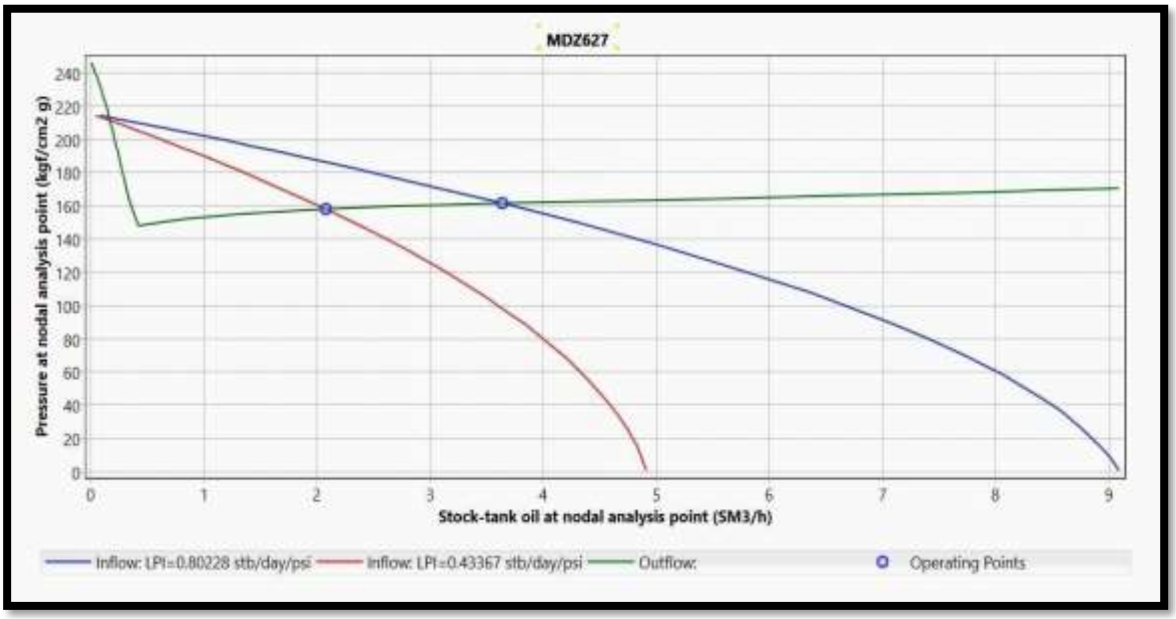


Figure IV.12: the operating point of well MDZ627 before and after the descent of the semiintelligent completion

- ❖ Based on the well operating point curve:

- Operating point before insulation: Q_{oil}= 3.65 m3/h • Operating point after insulation: Q_{oil} = 2.1 m3 /h

2- GOR:

Flow rate's sensitivity in relation to GOR to see the effect of insolation of the zones that produces gas.

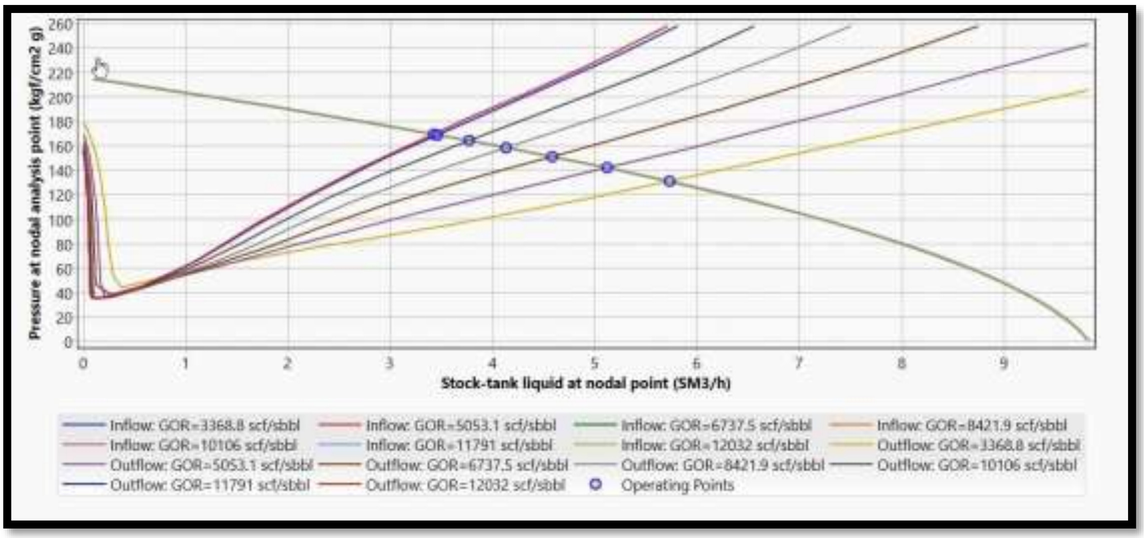


Figure IV.13: flow sensitivity in relation to GOR

Note:

- Simulating the wells performance based on the data mentioned before. The results were more related to the real performance of the well.
- whenever we isolate zone with a higher GOR we get an increase in the oil flow rate (theoretically)

Table IV.9: Results after the simulation

	Before insulation of gas drains	After insulation of gas drains
Q_{oil} m3/h	3.65	5.75
GOR sm3/m3	12032	3368.8

Based on the gauging data (See Annex A)

Before the descent of completion

See the pre-descent well data table

Figure IV.14: Pipe pressure and wellhead pressure before completion placement

Note: Well head pressure reached 101.5 kg/cm^2 in the last gauging just before the placement of the completion.

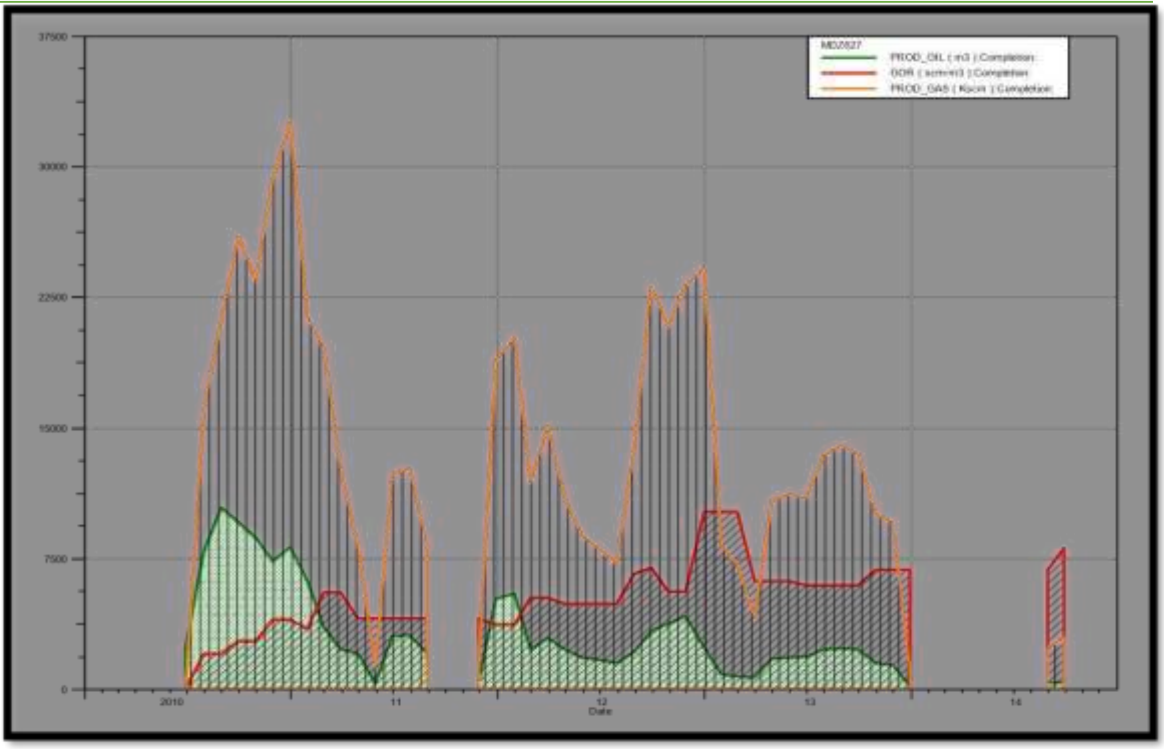


Figure IV.15: Historical Oil and Gas Production

The well started producing just well in the first period of its production then the GOR started to go up as the figure up shows **Well data after descent:**

Table IV.10: Well data MDZ627 after descent

Date Mesure	choke Diam (mm)	Separa. unit	Flow rate (m^3/h)		GOR	pressure (kg/cm^2)		W cut	total flow rate	IP
			oil	Gas		Well head press	Pipe Press,			
10/01/2017	14	1440	2,9	1914.02	661	54,7	13	6,842274	3,113	0.964856
30/01/2017	14	-	2,08	1773.67	852	67,7	13,9	8,77193	2,28	0.815084
11/03/2017	14	1440	0,6	466.55	772	15,9	13,1	0	0,6	0.130307
03/04/2017	14	600	3,18	2028.22	637	30,8	13,5	11,66667	3,6	0.917904
23/04/2017	14	1440	3,22	1710.88	531	35	13,5	0	3,22	0.836122

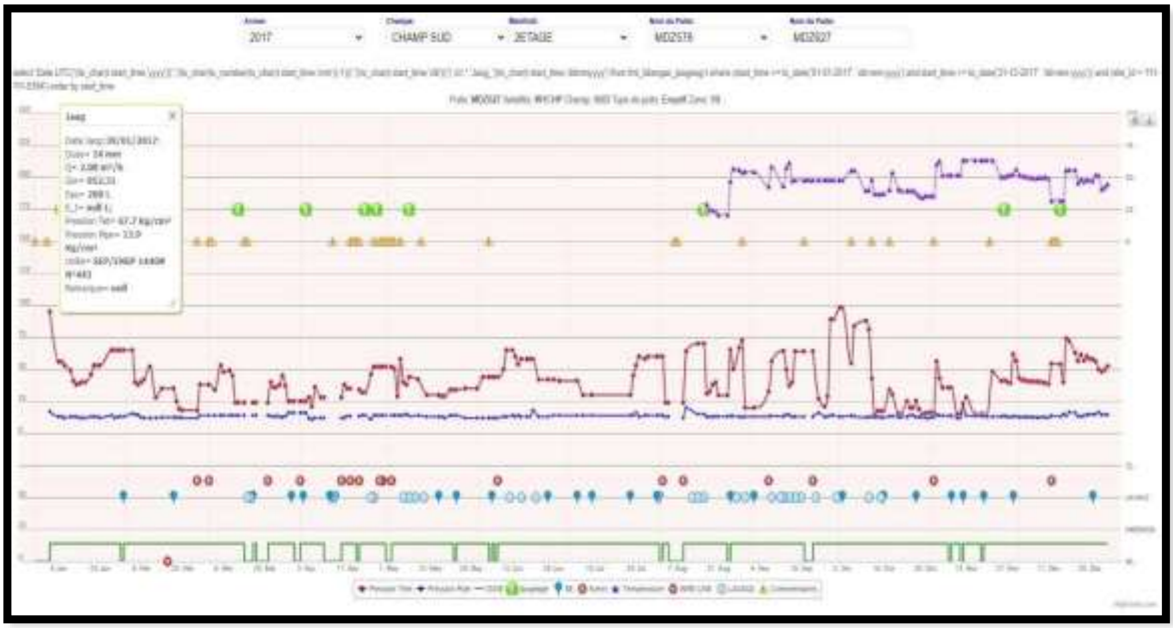


Figure IV.16: Well head pressure just after the completion has been descent

Note: well head pressure was stable and didn't reach a higher values of pressure for a year . It can be explained by the good functioning of the completion in this period in isolating the incoming gas.

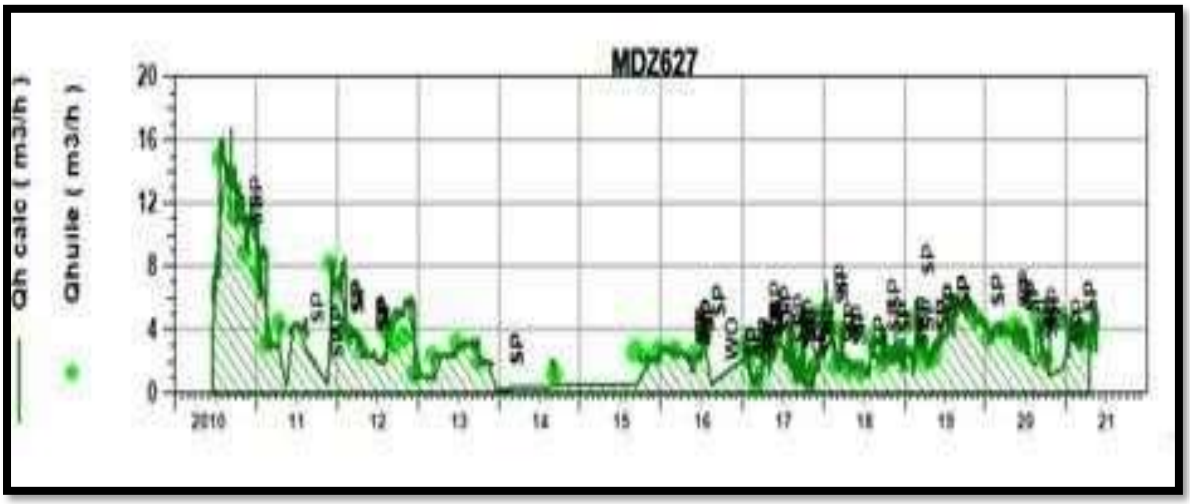


Figure IV.17: Oil rate of well MDZ627

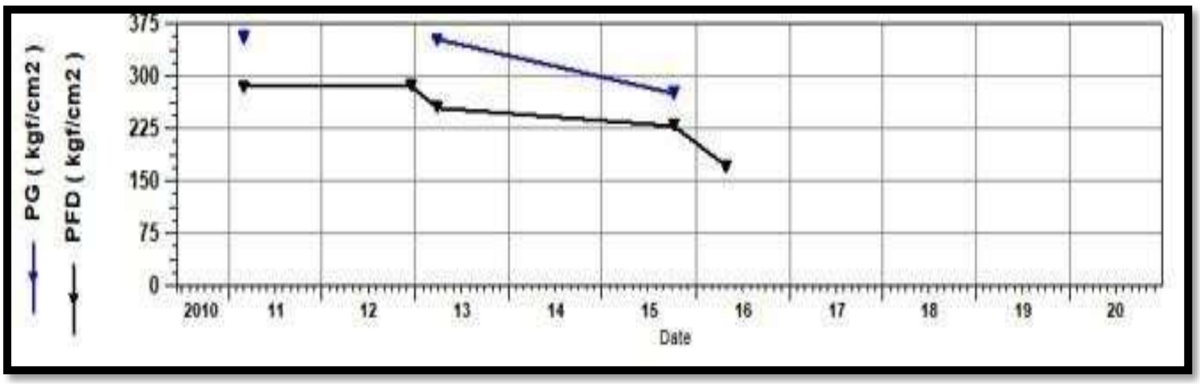


Figure IV.18: La pression de gisement et pfd

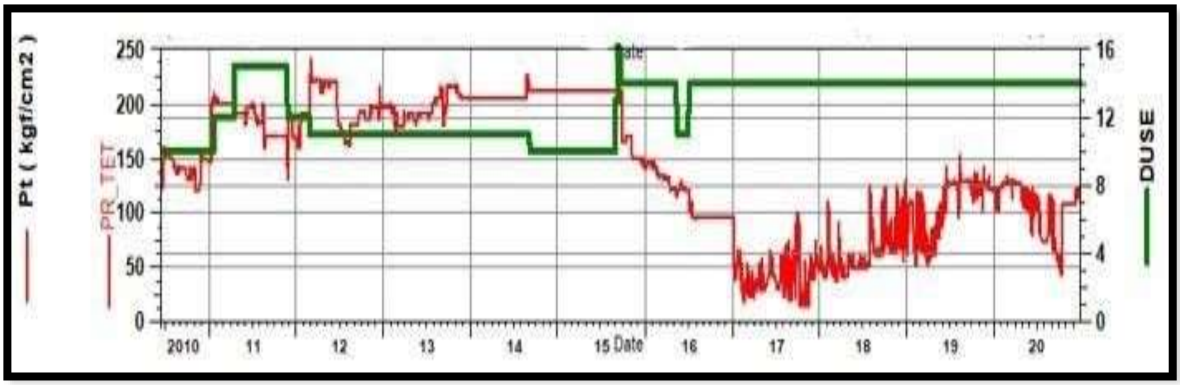


Figure IV.19: Well head pressure

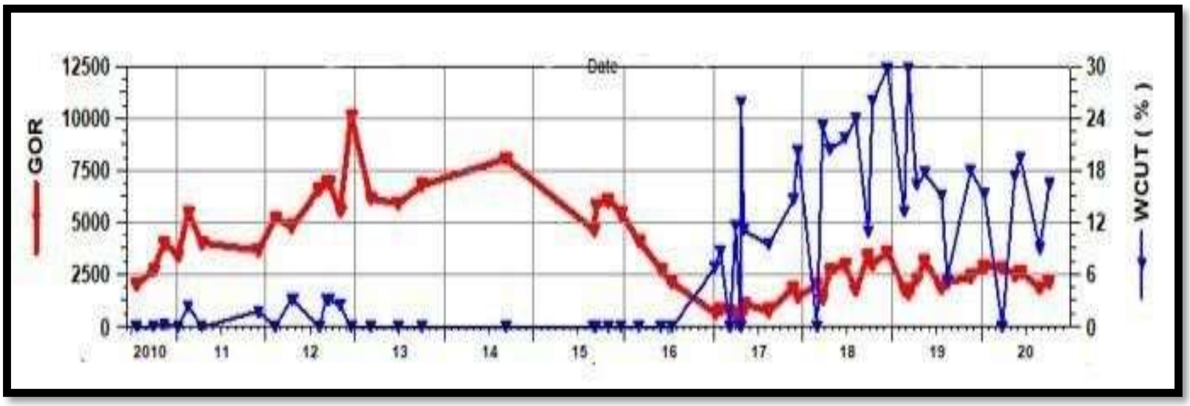


Figure 20: Evolution of GOR during well production

Comparison between simulation results and gauging data after the descent of the semi-intelligent completion in well MDZ627:

the last gauging made after the descent of the intelligent completion, it gave $\mathbf{Q_{oil}}$=2.9 sm3/h, $\mathbf{Q_{gas}}$=1914.02 sm3/h, **GOR**= 661, with a $\mathbf{P_{w.h}}$ =54.7 kg/cm2, and $\mathbf{P_{pipe}}$ =13 kg/cm2, these are primary data it is necessary to wait a period for the flow in the tank to stabilize at this time can-We will have the increase and flow of oil and GOR and have the same results as that obtained by the pipesim.

The data after some gauging (03/04/2017) that they made after the descent of the semiintelligent completion and well stabilization (see Annex A)

$\mathbf{Q_{oil}}$ = 3.18m3/h, $\mathbf{Q_{gas}}$= 2028.22sm3/h, $\mathbf{Q_{water}}$= 400l/h, **GOR**= 637

According to the model that we do with the Pipesim simulator we obtained that if we reduce the quantity of gas produced the Q_{oil} will increase, while if we analyze the gauging data that they made after the descent of the semi-intelligent completion we find four problems:

1. A decrease in Q_{oil} after isolation of a significant amount of gas.
2. Production of saturated salt water and recovery of salt from choke.
3. Increased well head pressure after a certain period of time of production.

4. Increase in GOR after some time

The difference between the simulator and the gauging results is justified by:

- After the well stabilization justifies the reduction of the flow by the reduction of the zone which does not produce only the gas
- the quantities of water that we have recovered It goes back to the emulsion of the fluids in the reservoir
- Data used for pipesim modeling is not well defined

The increase in well head pressure and GOR is justified by:

- well head pressure increases when the ratio of the produced gas is going up.
- GOR increases in two cases: when it finds another path to penetrate towards the zones we produce from because of the fractured reservoir and especially the area around the wellbore
- Malfunctioning of the swell packers or one of the sleeves.

Conclusion

and

recommendations

Conclusion

The study carried out allowed us to bring the following conclusions:

- In reservoirs with high vertical permeability such as naturally fractured reservoirs, horizontal wells are more efficient because they intercept the fractures and benefit from their permeability to improve vertical drainage and therefore have a good productivity.
- The problems of gas and water breakthroughs on the Hassi Messaoud field resulting from secondary recovery whatever the gas or water injection are considered as an obstacle to the production of the well.
- The gas breakthroughs are therefore inevitable in this case, we just have to try to escape them once they arrive.
- The wells in gas breakthrough are always able to be recovered by the techniques adequate to the problems of gas-shut off, without risk on the investment.
- Whatever the GOR in a well, we note the presence of oil by past, requiring further investigation to recover them, (case of the well MD426 or the well MD251). The presence of several gas blocking techniques are currently available to avoid inflating the cost of the operation and minimize the GOR in order to exploit the well with affordable GOR.
- The presence of several gas blocking techniques are currently available to not inflate the cost of the operation and minimize the GOR so as to operate the well with affordable GOR. Reducing gas from high GOR wells, increasing pressure maintenance and advancing gas to far zones

Recommendations

- We propose running another PLT for this well (MDZ627) to indicate which one of the zones the gas is breaking through from. Fastest possible
- There are wells in Hassi Masoud with a high GOR which caused an oil block could be a perfect candidate for a gas shutoff technics such as MD166 and MD158.
- Take into consideration the positioning of the injector wells and the quantity of gas injected "mesh".
- It is necessary to intervene before the gas break through happens by a good study and a necessary investigation about the situation and the parameters of the reservoir we are producing from and the neighboring injector and producer wells to avoid any unwanted contact of drainage
- Foreign companies are proposing a new techniques and strategies for the gas shutoff such as Heavy-metal free flowing gel for fracture sealing from schlumberger
- Horizontal wells are relatively more susceptible to gas breakthrough and it is hard to deal with it we recommend going with verticals instead.
- Algeria needs gas (see Annex F) it doesn’t need to burn or reinject the produced gas so we recommend the immediate stop of the injection because of its negative effect on oil production and rely on water drive resulting from the Cambrian Ordovician super aquifer (see Annex G) based on Mr kennedy’s studies

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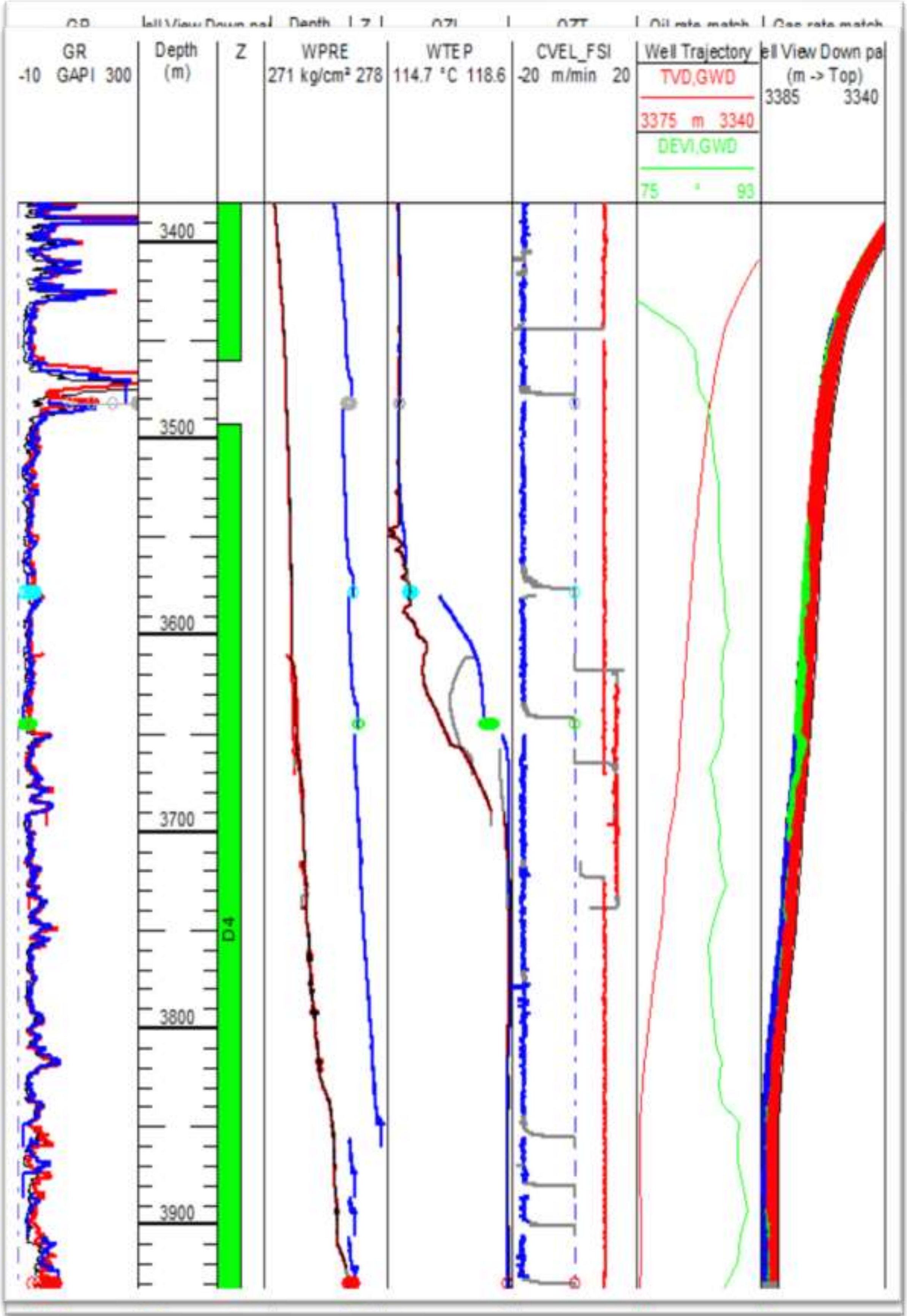
Annex A

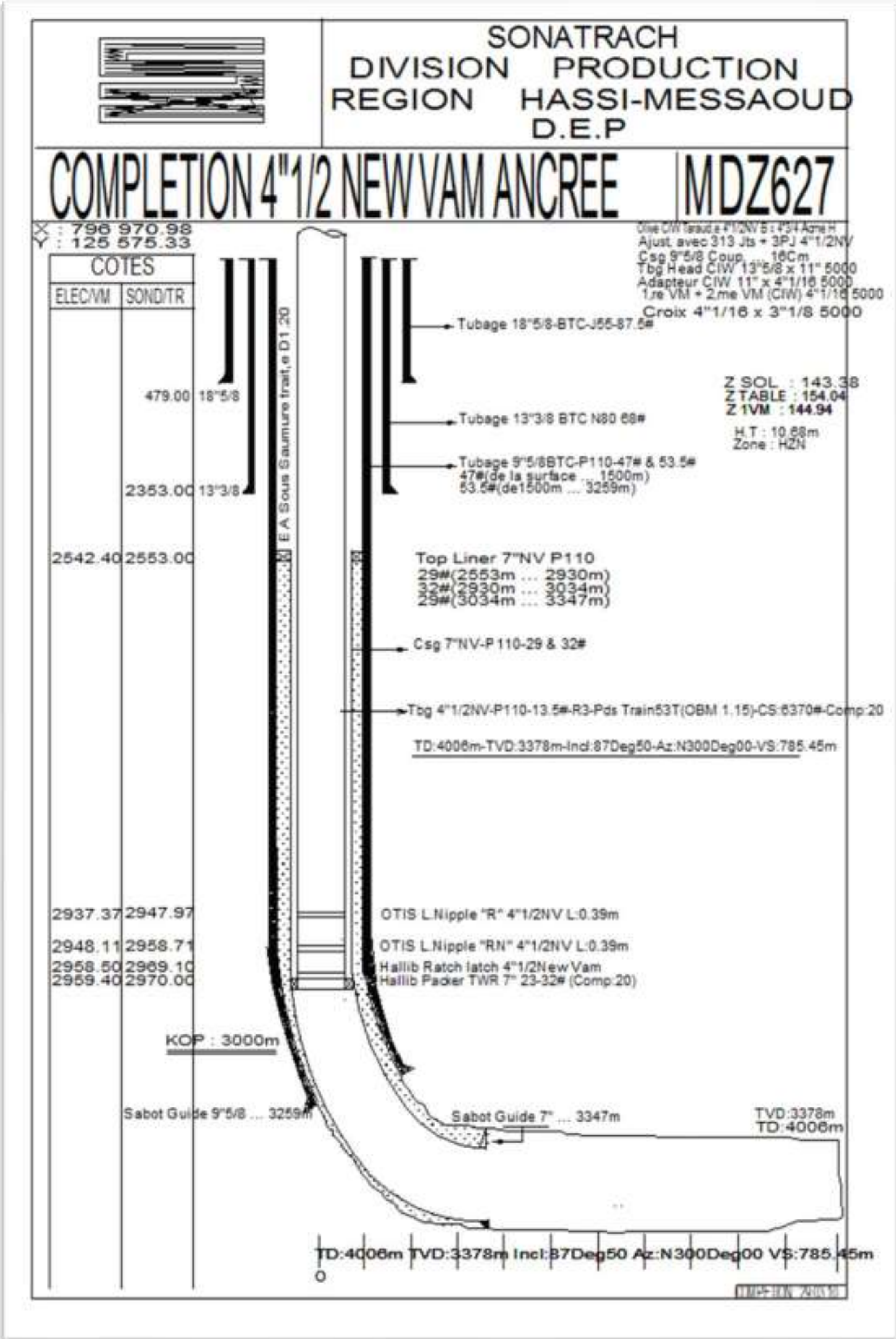
Date Mesure	Diam. Duse (mm)	Unité Sépar.	Débit (m^3/h)		GOR	Pression (kg/cm^2)			Temp. Huile (°C)	K Psi	Débit Eau (l/h)
			Huile	Gaz		Tête	Pipe	Sépar.			Récupérée
Puits											
20/07/2010	10	Vx52	14.82	30231.67	2040	150.5	38.5		41	.6407	0
29/09/2010	10	655	11.06	29984.86	2711	130	43	28.55	28	.7416	0
11/11/2010	10	Vx52	8.84	35404.40	4005	120.8	41.3		30	.8621	25
07/01/2011	10	655	7.56	26171.78	3461	145	32.5	23.66	20	1.2097	0
17/02/2011	12	-	3.15	17430.74	5529	204	21.1		23	5.6689	77
16/04/2011	15	655	4.34	17585.60	4048	190	27	14.28	28	5.725	0
01/12/2011	12	-	8.15	29918.86	3669	191.6	32.2		20	2.0585	145
10/02/2012	12	-	4	20854.54	5214	190.5	25.6	24.07	15	4.1722	0
18/04/2012	11.11	1440	2.72	13227.21	4854	224.7	23.5	23.45	11	6.2885	90
06/08/2012	11.11	-	3.93	26004.39	6614	165	31.2	21.41	33	3.2	0
06/09/2012	11.11	1440	3.05	21316.00	6986	111.99	28.02	32.43	28	2.7991	100
16/09/2012	11.11	1440	2.99	20763.59	6937	112.08	29.67	31.71	26	2.8554	100
31/10/2012	11.11	1440	3.51	19617.75	5588	112.07	29.33	30.08	29	2.4345	90
15/12/2012	11.11	655	1.2	12164.42	10147	214	18.3	6.42	16	13.613	0
06/03/2013	11.11	-	2.39	14777.85	6181	183	22	12.85	19	5.8369	0
22/06/2013	11.11	1440	3.12	18496.41	5936	190.25	25.07	29.23	33	4.6564	0
01/10/2013	11	655	1.99	13588.40	6834	216	18	6.73	21	8.1369	0
08/09/2014	10	600	1.19	9638.99	8096	218	15	9.18	23	11.5525	0
02/09/2015	13	655	2.53	11824.18	4683	182.8	14.7	6.42	25	7.3251	0
11/09/2015	16	1440	2.77	16279.05	5879	173	22	19.37	26	9.1865	0
30/10/2015	14	600	2.19	13269.09	6073	158	19.75	9.99	22	8.3604	0
23/12/2015	14	1440	2.77	15149.64	5465	145.7	23.76	23.7	16	6.0766	0
06/03/2016	14.28	1440	2.7	11132.34	4123	134.46	20.26	20.34	20	5.9664	0
03/06/2016	11	Vx40	2.51	6905.10	2751	125.6	15.9		30.1	3.7478	0
15/07/2016	14	1440	3.62	7761.48	2143	101.5	18.7	18.25	32	3.2395	0
10/01/2017	14	1440	2.9	1914.02	661	54.7	13	12.49	9	2.1827	213
30/01/2017	14	-	2.08	1773.67	852	67.7	13.9	13.77	12	3.7613	200
11/03/2017	14	1440	.6	466.55	772	15.9	13.1	12.64	24	2.7962	0
03/04/2017	14	600	3.18	2028.22	637	30.8	13.5	4.69	21	1.1192	420
23/04/2017	14	1440	3.22	1710.88	531	35	13.5	13.15	23	1.2567	0

27/04/2017	14	-	2.29	1376.99	602	53.6	12.9	4.18	20	2.7074	800
08/05/2017	14	600	3.17	3531.94	1115	44	13.5	5	26	1.6063	400
16/08/2017	14	Vx40	2.84	2264.67	798	78.3	13.3		38.4	3.1903	298
26/11/2017	14	Vx40	1.7	3252.17	1909	41.4	13.8		23	2.8103	294
15/12/2017	14	1440	4.96	7168.79	1446	102	16	15.6	24	2.3793	1273
02/03/2018	14	Vx29	1.76	3624.29	2057	42.5	14.3		32	2.7885	0
23/03/2018	14	1440	3.98	5426.10	1362	81.3	14	6.32	19	2.3592	1200
25/04/2018	14	Vx40	1.38	3715.71	2694	42	14.3		33	3.5203	356
25/06/2018	14	1440	1.34	3974.81	2975	51.5	14	14.17	36	4.4571	372
06/08/2018	14	600	3.36	5967.31	1775	93	13.57	7.55	27	3.199	1060
27/09/2018	14	600	1.79	6063.10	3394	62	12.5	6.42	23	4.0129	220
13/10/2018	14	Vx40	2.46	7425.07	3022	81.8	15.9		32	3.8488	871
13/12/2018	14	1440	2.79	10106.73	3616	112.3	18.9	18.76	16	4.646	1188
23/02/2019	14	Vx40	4.61	8330.42	1808	93.9	18.8		21	2.3557	703
12/03/2019	14	1440	2.59	4264.63	1645	58	12.4	5	18	2.5867	1100
14/04/2019	14	1440	1.93	4438.83	2294	63.4	15.8	15.5	26	3.7891	378
16/05/2019	14	Vx40	2.3	7202.21	3136	74.4	15.9		26	3.7451	500
23/07/2019	14	1440	5.12	9731.50	1901	129.9	24.4	22.43	28	2.9342	920
18/08/2019	14	1440	5.62	11985.03	2133	132.14	24.21		35	2.7184	324
20/11/2019	14	1440	4.7	11424.95	2431	129.1	24.3	22.54	28	3.1765	1037
15/01/2020	14	1440	3.48	10027.84	2884	107.6	21.62	21.73	25	3.578	630
26/03/2020	14	1440	3.95	11068.14	2803	130	19.5	14.07	29	3.8071	0
19/05/2020	14	1440	4.23	10425.33	2463	123.88	22.67	22.23	34	3.3841	895
10/06/2020	14	1440	3.09	8249.26	2673	88.2	19.7	19.52	41	3.304	750
26/08/2020	14	1440	4.81	8885.34	1848	120	22.3	22.33	37	2.8855	480
06/10/2020	14	1440	2.02	4403.88	2181	49.6	17	17.18	23	2.8402	400
07/01/2021	14	1440	4.38	6736.58	1537	120.56	30.2	9.75	19	3.1797	400
26/04/2021	14	1440	3.1	4503.91	1453	59.01	29.48	5.05	26	2.2008	546

Annex B


GR
-10 GAPI 300
Depth (m)
Z
WPRE
271 kg/cm² 278
WTEP
114.7 °C 118.6
CVEL_FSI
-20 m/min 20
Well Trajectory
TVD,GWD
3375 m 3340
DEVI,GWD
75 ° 93
ell View Down pa
(m -> Top)
3385 3340
3400
3500
3600
3700
3800
3900
D4

Annex C


SONATRACH
DIVISION PRODUCTION
REGION HASSI-MESSAOUD
D.E.P
COMPLETION 4"1/2 NEW VAM ANCREE
MDZ627
X : 796 970.98
Y : 125 575.33
COTES
ELEC/VM
SOND/TR
Ajust. avec 313 Jts + 3PJ 4"1/2NV
Tbg Head CIW 13"5/8 x 11" 5000
Adapteur CIW 11" x 4"1/16 5000
Croix 4"1/16 x 3"1/8 5000
Tubage 18"5/8-BTC-J55-87.5#
Z SOL : 143.38
Z TABLE : 154.04
Z 1VM : 144.94
H.T : 10.68m
Zone : HZN
479.00
18"5/8
Tubage 13"3/8 BTC N80 68#
Tubage 9"5/8BTC-P110-47# & 53.5#
47#(de la surface ... 1500m)
53.5#(de1500m ... 3259m)
2353.00
13"3/8
E A Sous Saumure trait,e D1.20
2542.40
2553.00
Top Liner 7"NV P110
29#(2553m ... 2930m)
32#(2930m ... 3034m)
29#(3034m ... 3347m)
Csg 7"NV-P110-29 & 32#
Tbg 4"1/2NV-P110-13.5#-R3-Pds Train53T(OBM 1.15)-CS:6370#-Comp:20
TD:4006m-TVD:3378m-Incl:87Deg50-Az:N300Deg00-VS:785.45m
2937.37
2947.97
OTIS L.Nipple "R" 4"1/2NV L:0.39m
2948.11
2958.71
OTIS L.Nipple "RN" 4"1/2NV L:0.39m
2958.50
2969.10
Hallib Ratch latch 4"1/2New Vam
2959.40
2970.00
Hallib Packer TWR 7" 23-32# (Comp:20)
KOP : 3000m
Sabot Guide 9"5/8 ... 3259m
Sabot Guide 7" ... 3347m
TVD:3378m
TD:4006m
TD:4006m TVD:3378m Incl:87Deg50 Az:N300Deg00 VS:785.45m

Annex D

HALLIBURTON

Proposed Installation

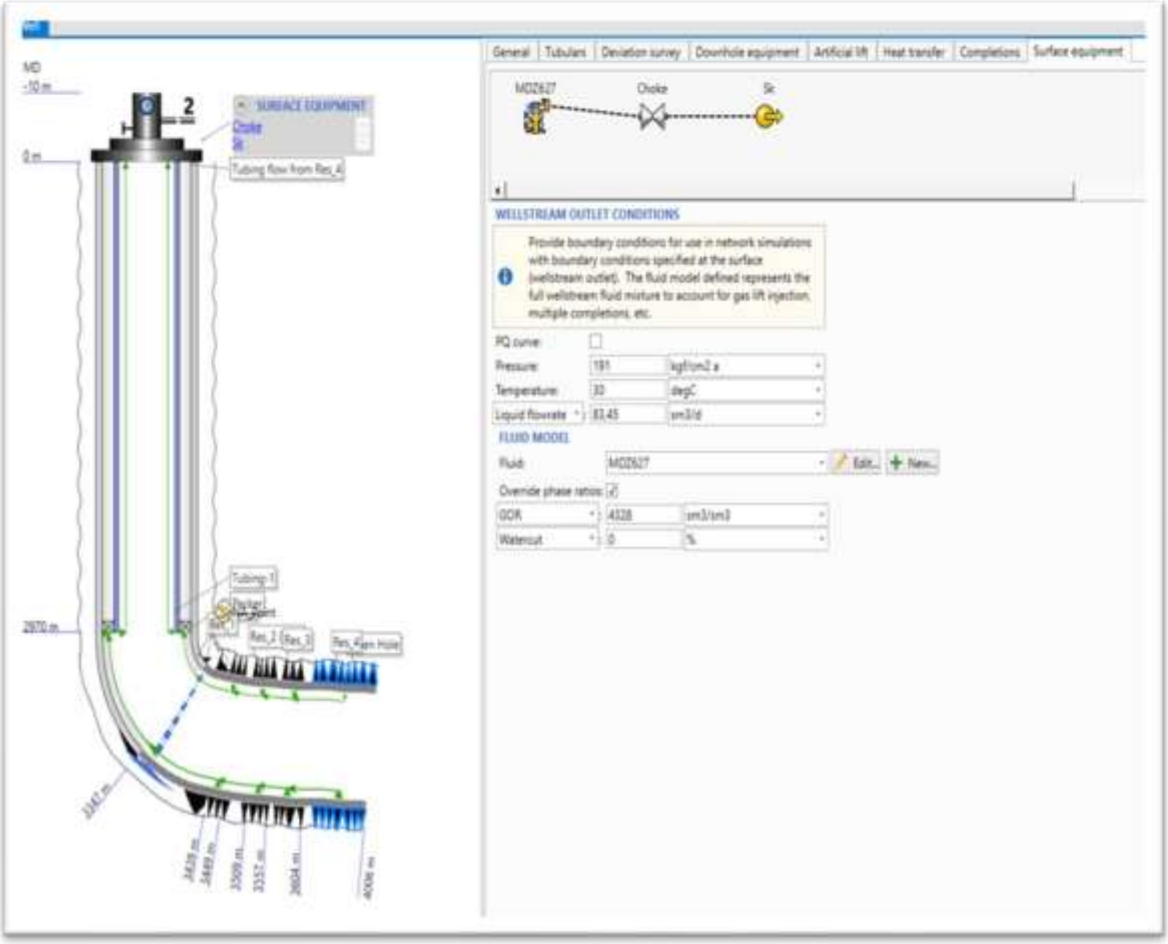
Company

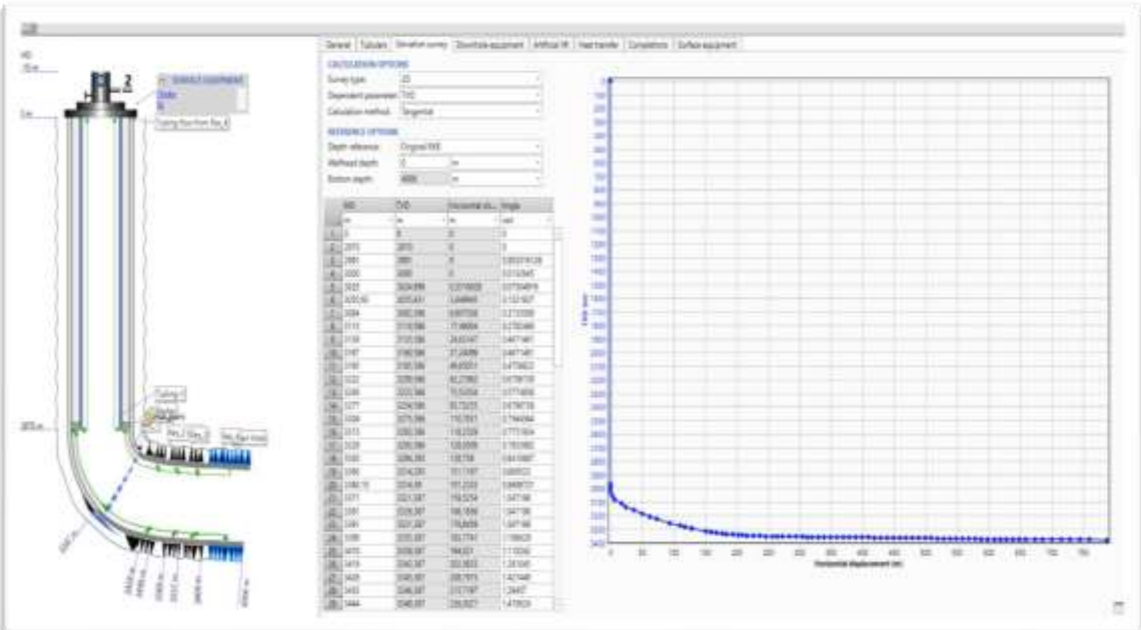
Well Name: MDZ-627 — Company Rep: Naamane Belaieb
County: Algeria — Sales Rep: Gerard De Groot
31-May-21 — Office: Hassi Messaoud

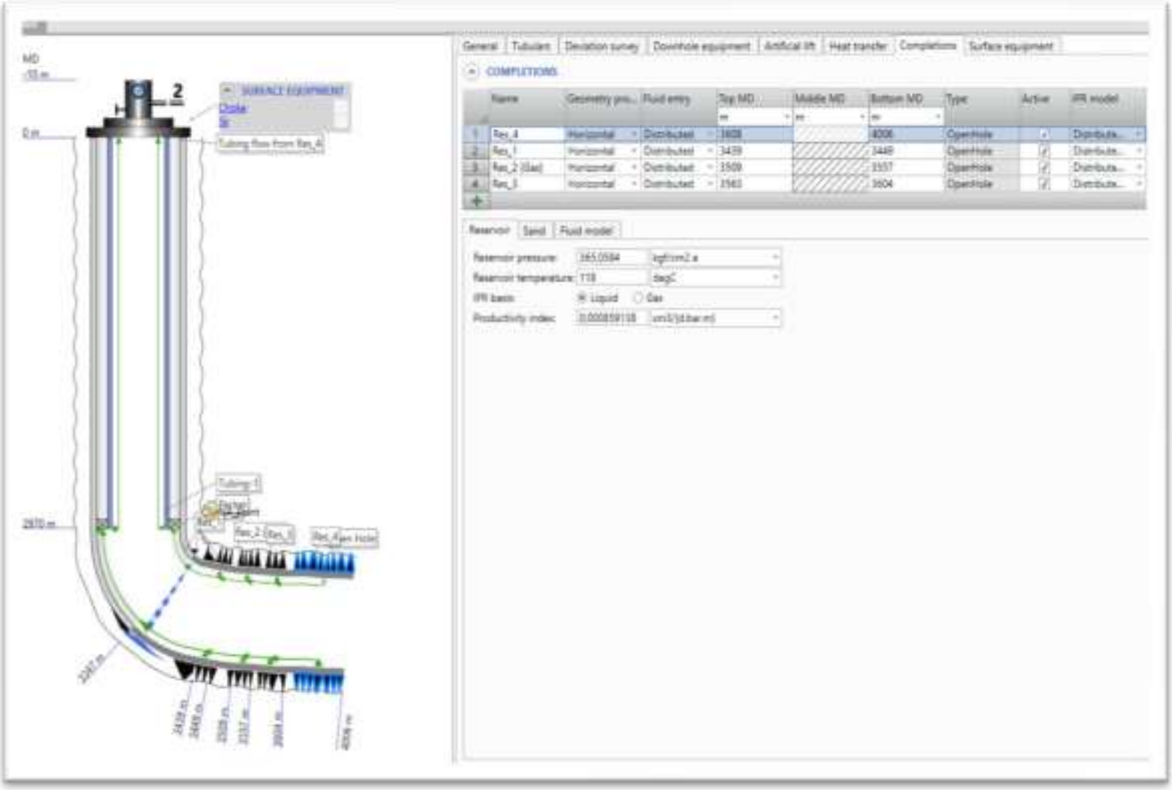
Installation	Depth	Length	Jts.	Description	OD	ID
	2,960.00	7.64		5"x7" VersaFlex® Expandable Liner Hanger P/N:101320333	5.885	3.90
	3,330.00	11.00		Swellpacker, 4.5in 13.5lbs,P110-, New Vam	5.750	3.79
	3,347.00			*7", 29ppf Casing Shoe*		
	3,560.00	11.00		Swellpacker, 4.5in 13.5lbs,P110-, New Vam P/N:102293783	5.750	3.79
50%	3,575.00	1.77		RapidShift Sleeve 4.5", 13.5ppf, New Vam P/N:102284022	5.700	3.75
25%	3,590.00	1.77		RapidShift Sleeve 4.5", 13.5ppf, New Vam P/N:102284022	5.700	3.75
	3,610.00	11.00		Swellpacker, 4.5in 13.5lbs,P110-, New Vam P/N:102293783	5.750	3.79
25%	3,650.00	1.77		RapidShift Sleeve 4.5", 13.5ppf, New Vam P/N:102284022	5.700	3.75
75%	3,700.00	1.77		RapidShift Sleeve 4.5", 13.5ppf, New Vam P/N:102284022	5.700	3.75
50%	3,750.00	1.77		RapidShift Sleeve 4.5", 13.5ppf, New Vam P/N:102284022	5.700	3.75
	3,770.00	11.00		Swellpacker, 4.5in 13.5lbs,P110-, New Vam P/N:102293783	5.750	3.79
50%	3,790.00	1.77		RapidShift Sleeve 4.5", 13.5ppf, New Vam P/N:102284022	5.700	3.75
75%	3,850.00	1.77		RapidShift Sleeve 4.5", 13.5ppf, New Vam P/N:102284022	5.700	3.75
25%	3,930.00	1.77		RapidShift Sleeve 4.5", 13.5ppf, New Vam P/N:102284022	5.700	3.75
	3,975.00	11.00		Swellpacker, 4.5in 13.5lbs,P110-, New Vam P/N:102293783	5.750	3.79
	3,986.00	0.45		Collar Landing, 4.5" New Vam 13.5ppf, P110 P/N:101963369	5.260	3.45
	3,995.00	0.4		Collar Float, 4.5" New Vam 13.5ppf, P-110 P/N:101281622	5.260	3.701
	4,005.00	0.55		Shoe Float, 4.5" New Vam 13.5ppf, P-110 P/N:101363656	4.971	3.45
	4,006.00			*Well TD*		

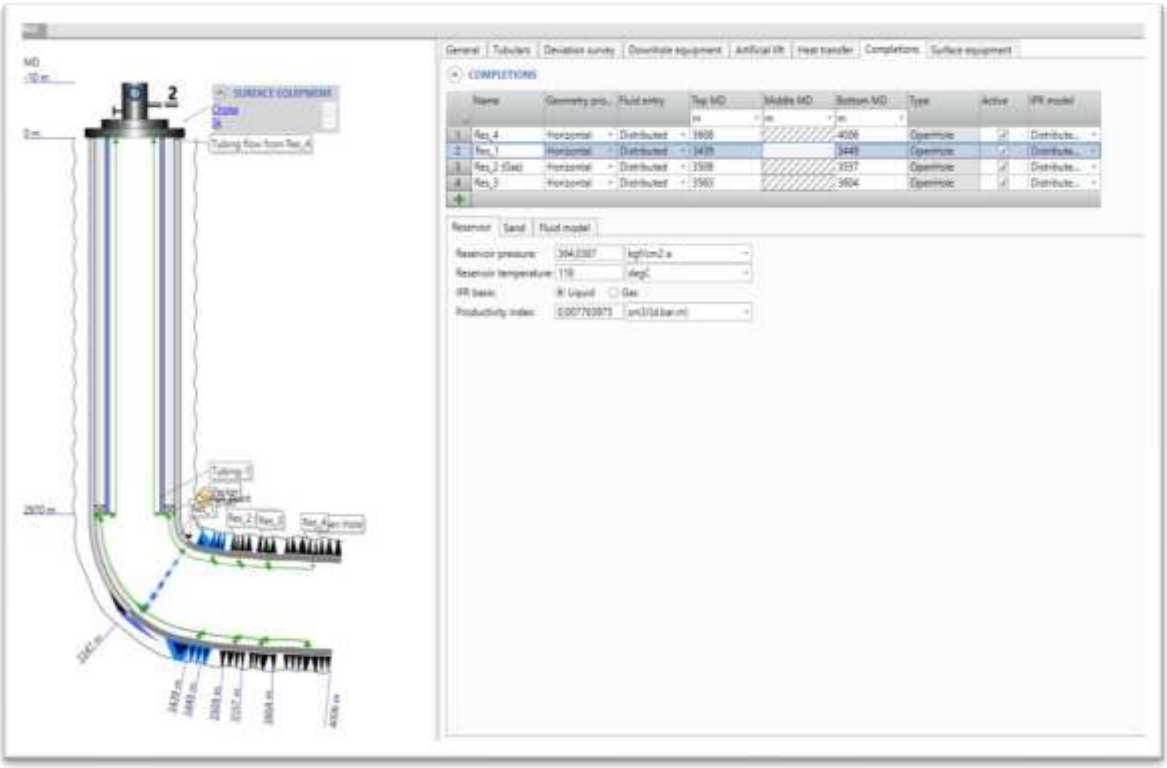
Percentages are flow capacity of the Rapid Shift sleeves
25% 18 ports need to be plugged
50% 12 ports need to be plugged
75% 06 ports need to be plugged

Annex E

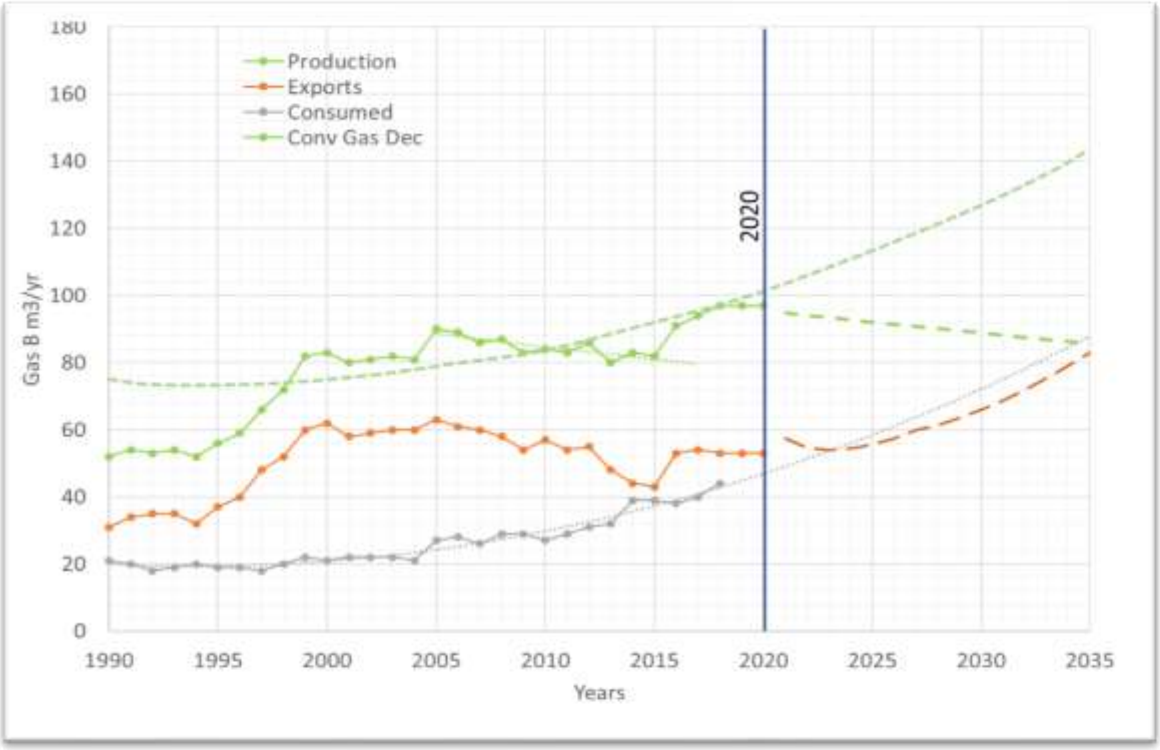

General
Tubulars
Deviation survey
Downhole equipment
Artificial lift
Heat transfer
Completions
Surface equipment
MDZ627
Choke
Sk
SURFACE EQUIPMENT
Choke
Sk
Tubing flow from Res_4
WELLSTREAM OUTLET CONDITIONS
Provide boundary conditions for use in network simulations with boundary conditions specified at the surface (wellstream outlet). The fluid model defined represents the full wellstream fluid mixture to account for gas lift injection, multiple completions, etc.
PQ curve:
Pressure:
191
kgf/cm2 a
Temperature:
30
degC
Liquid flowrate
83.45
sm3/d
FLUID MODEL
Fluid:
MDZ627
Edit...
New...
Override phase ratios:
GOR
4328
sm3/sm3
Watercut
0
%
MD
-10 m
0 m
2970 m
Tubing 1
Res_2
Res_3
Res_4
Open Hole





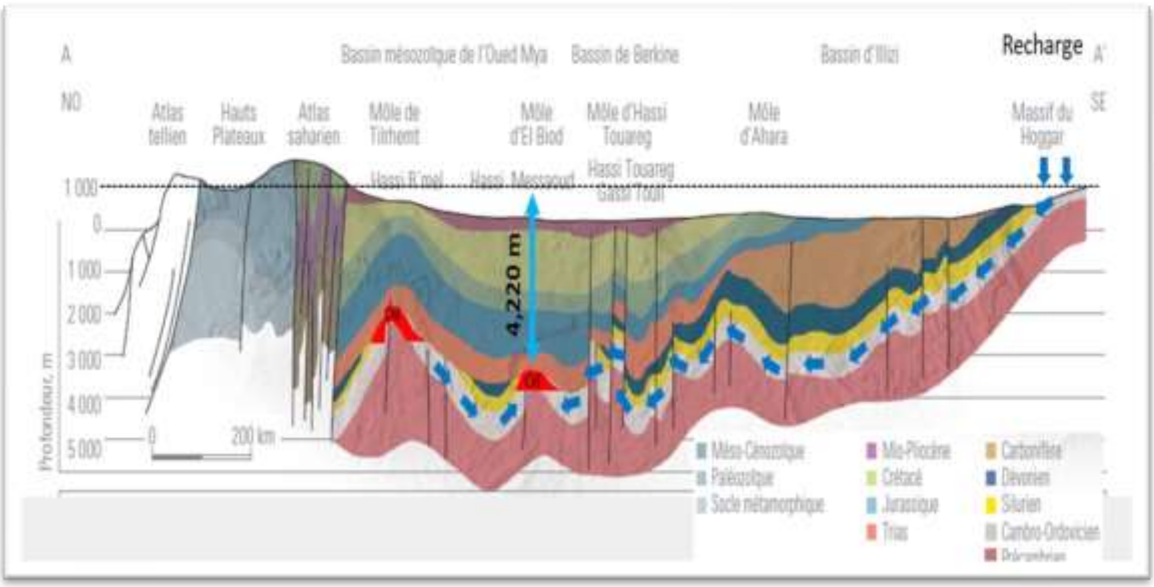


Annex F



- **Algerian domestic gas needs exceed export demand**
- **New gas is needed for domestic and international sales which HMD can provide**
- **Selling gas will decrease ops costs, make money from gas, improve oil production**
- **HMD can rapidly produce at about 12 B m^3/yr.**

Annex G



Annex H

N°	MD (m)	Incl (°)	Azimuth (°)	TVD (m)	Latitude N/S (m)	Longitude E/W (m)	DLS (°/30m)	VS (m)	Remarques
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
2	2970.00	0.00	0.00	2970.00	0.00	0.00	0.00	0.00	
3	2981.22	0.19	11.19	2981.22	0.02	0.00	0.51	0.01	
4	3000.38	0.76	329.34	3000.38	0.16	-0.06	0.99	0.13	
5	3025.96	4.30	306.62	3025.93	0.88	-0.91	4.23	1.23	
6	3055.92	8.72	300.75	3055.69	2.71	-3.77	4.47	4.62	
7	3084.90	12.70	301.33	3084.16	5.49	-8.88	4.12	10.01	
8	3113.17	17.25	299.78	3111.46	9.19	-14.67	4.85	17.31	
9	3139.71	21.53	297.23	3136.49	13.37	-22.42	4.93	26.11	
10	3167.44	25.21	296.34	3161.94	18.32	-32.24	4.00	37.09	
11	3195.31	29.29	296.39	3186.71	23.99	-43.67	4.39	49.82	
12	3222.74	32.46	295.95	3210.25	30.20	-56.31	3.48	63.86	
13	3240.31	34.10	296.20	3224.94	34.43	-64.97	2.81	73.48	
14	3277.16	35.97	297.89	3255.11	44.06	-83.80	1.71	94.60	
15	3304.61	40.41	297.73	3276.68	51.97	-98.81	4.85	111.56	
16	3315.71	42.70	298.75	3284.99	55.46	-105.29	6.45	118.92	
17	3329.53	45.05	297.62	3294.95	59.98	-113.74	5.38	128.49	
18	3330.00	45.12	297.75	3295.28	60.13	-114.03	7.41	128.82	**Sabot 7" @ 3347**
19	3360.00	49.82	305.53	3315.57	71.76	-132.79	7.41	150.88	
20	3360.15	49.84	305.57	3315.67	71.83	-132.88	7.41	150.99	
21	3371.36	54.91	310.98	3322.52	77.83	-139.84	17.76	159.77	
22	3381.07	59.29	316.15	3327.79	82.95	-145.73	19.05	167.69	
23	3391.54	61.83	318.25	3332.94	89.64	-151.93	8.97	176.39	
24	3399.36	65.26	317.71	3336.42	94.84	-156.61	13.29	183.05	
25	3410.44	68.02	316.91	3340.81	102.32	-163.51	7.73	192.76	
26	3419.62	70.96	313.88	3344.03	108.44	-169.55	13.35	201.05	
27	3426.72	73.64	311.80	3346.19	113.03	-174.51	14.08	207.64	
28	3433.04	76.78	309.44	3347.80	117.01	-179.14	18.42	213.65	
29	3444.83	81.48	305.53	3350.03	124.05	-188.33	15.44	225.12	
30	3454.89	83.39	304.06	3351.35	129.74	-196.52	7.16	235.06	

31	3464.59	83.69	302.31	3352.44	135.02	-204.58	5.46	244.68	
32	3475.32	84.11	301.93	3353.58	140.69	-213.62	1.58	255.35	
33	3482.00	85.39	301.36	3354.19	144.18	-219.28	6.29	262.00	
34	3491.89	85.74	300.94	3354.96	149.28	-227.72	1.66	271.85	
35	3502.16	86.14	300.81	3355.69	154.54	-236.51	1.23	282.10	
36	3512.14	86.32	299.90	3356.34	159.57	-245.11	2.78	292.05	
37	3522.26	86.91	298.47	3356.94	164.50	-253.93	4.58	302.16	
38	3530.68	86.84	298.41	3357.40	168.50	-261.32	0.33	310.56	
39	3537.90	87.02	298.30	3357.78	171.92	-267.67	0.88	317.77	
40	3547.49	86.96	298.19	3358.29	176.46	-276.10	0.39	327.34	3558 a 3569 3575 (50%)
41	3557.35	87.14	297.81	3358.80	181.08	-284.80	1.28	337.18	
42	3567.37	87.45	298.03	3359.27	185.77	-293.64	1.14	347.18	
43	3577.66	87.83	299.12	3359.69	190.68	-302.67	3.36	357.46	
44	3587.52	87.83	299.69	3360.07	195.52	-311.25	1.73	367.31	3590 (25%)
45	3597.72	88.34	299.44	3360.41	200.55	-320.12	1.67	377.51	
46	3607.66	87.51	299.01	3360.77	205.40	-328.79	2.82	387.44	
47	3617.57	87.27	298.72	3361.22	210.18	-337.46	1.14	397.34	3607 a 3617
48	3627.20	87.53	298.95	3361.65	214.82	-345.88	1.08	406.96	
49	3637.16	87.42	298.68	3362.09	219.61	-354.60	0.88	416.90	
50	3647.80	87.66	298.49	3362.55	224.70	-363.94	0.86	427.53	3650 (25%)
51	3657.51	87.01	299.29	3363.00	229.39	-372.43	3.18	437.23	
52	3667.43	85.70	299.33	3363.00	234.23	-381.06	3.96	447.13	
53	3677.33	86.22	299.41	3363.63	239.08	-389.67	1.59	457.00	
54	3687.36	86.39	299.47	3364.33	244.00	-398.39	0.54	467.01	
55	3697.59	87.08	299.54	3365.56	249.03	-407.27	2.03	477.22	3700 (75%)
56	3707.50	87.04	299.35	3366.07	253.89	-415.89	0.59	487.12	
57	3717.46	87.24	299.23	3366.56	258.76	-424.57	0.70	497.07	
58	3727.33	87.93	299.39	3366.98	263.59	-433.17	2.15	506.93	
59	3737.51	87.04	299.77	3367.43	268.61	-442.01	2.85	517.10	
60	3747.19	86.07	299.34	3368.01	273.37	-450.42	3.29	526.76	3750 (50%)
61	3757.51	85.48	299.26	3368.77	278.41	-459.39	1.73	537.05	

62	3767.54	85.67	299.16	3369.54	283.29	-468.12	0.64	547.05	3770 a 3779
63	3777.56	85.80	298.86	3370.29	288.13	-476.86	0.98	557.04	
64	3787.33	85.91	298.69	3370.99	292.83	-485.40	0.62	566.78	
65	3797.36	86.25	299.01	3371.68	297.65	-494.16	1.39	576.79	
66	3807.65	86.52	299.13	3372.33	302.64	-503.14	0.86	587.05	
67	3817.76	87.32	298.65	3372.87	307.52	-511.98	2.77	597.15	
68	3828.47	87.01	298.57	3373.35	312.16	-520.49	0.99	606.84	
69	3837.45	87.42	298.13	3373.84	316.90	-529.27	1.81	616.81	
70	3847.54	89.93	298.69	3374.07	321.70	-538.14	7.64	626.89	3790 (50%)
71	3857.24	89.79	298.71	3374.09	326.35	-546.65	0.44	636.59	
72	3867.49	89.72	298.77	3374.14	331.83	-555.63	0.27	646.83	
73	3877.58	90.34	299.50	3374.13	336.20	-564.45	2.85	656.92	
74	3892.04	91.20	299.83	3373.94	343.35	-577.01	1.91	671.38	3850 (75%)
75	3904.81	90.10	300.28	3373.79	349.75	-588.06	2.79	684.15	
76	3919.11	89.62	300.48	3373.83	356.98	-600.40	1.09	698.45	
77	3934.34	87.56	300.16	3374.20	364.66	-613.54	4.11	713.67	
78	3948.65	84.80	299.42	3375.16	371.76	-625.93	5.99	727.95	3930 (25%)
79	3963.65	84.52	299.34	3376.57	379.18	-639.12	0.57	743.08	3960 a 3969
80	3978.47	85.01	299.22	3377.90	386.30	-651.82	1.03	757.64	
81	4006.00	86.00	299.00	3380.06	399.65	-675.80	1.10	785.08	*Proj-TD*

Annex I

Type de Test	Date	Pression (kg/cm²)			Débit (m³/h)		Index Prod./Inj.	HK			Skin	Duse	Remarque
		Gisement	Fond Dyn.	Tete				Proche	Lointain	(Hw*Kyz)			
BUILD UP	27/02/2011	354.98	283.81	200	Huile	3.15	.052	-	246	71	-.3	12	Pfd @-2817.06m
PFD	16/12/2012	0	286	220.14	Huile	5.52	0	-	-	-		11.11	PFD@-2948m.
BUILD UP	26/03/2013	351.89	254.94	178	Huile	2.3	.026	-	112	-	.43	11.11	Puits en percee de gaz, Pfd @ -2803.06 m.
BUILD UP	11/10/2015	274.74	228.61	158	Huile	2.77	.073	-	-	97.7	-1.17	14	PFD @-2812.06 m.
PFD	27/04/2016		170.55	123.46	Huile	2.44		-	-	-		14.28	PFD @-2815.06.