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Presented by:

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- THESIS-

EXPERIMENTAL SIMULATION AND REMEDIATION OF THE WATER BLOCK PHENOMENON IN LOW PERMEABILITY RESERVOIRS

Defended on: 06 /06/ 2022before the examination board

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Dedication

With immense joy and emotion, I dedicate this thesis and this important step of my whole life to the memory of my dear deceased father FETHI, I hope that from this world he would have appreciated this humble gift as a proof of gratitude from his daughter who always prayed for the salvation of his soul.

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To whom no dedication can express fully my respect,
My eternal love and consideration for their sacrifice that they consented for my education and my well-being.
May God grant them health, happiness and long life.

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To my little nieces: sourse of positive energy,
To all my dear friends,

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Résumé

Le blocage d'eau est défini par le piégeage de l'eau après des opérations d'intervention de forage en cas d'utilisation de boue à base d'eau ,de complétion, de reconditionnement ou de stimulation dans un réservoir à faible perméabilité. L'augmentation de la saturation en eau dans l'espace poreux bloque le flux de pétrole et de gaz du réservoir vers le puits. L'écoulement d'eau et son influence sur la pression de seuil d'huile ont été évalués avec injection à pression constante. Les produits comprennent des alcools et des tensioactifs chimiques ont été utilisés pour réduire la saturation en eau, la pression capillaire en diminuant la tension interfaciale et inverser la mouillabilité de la roche par adsorption. En conséquence, une faible saturation en eau irréductible estimé à 30% à un gradient de pression de réservoir donné (1173 hPa) sera générée. Le développement d'un modèle simulant le phénomène ainsi que l'étude de l'état du puits « HGANE2 » permet de mettre en évidence l'effet de ce phénomène sur la productivité avec une récupération de 400 (l /h) d'eau avec des perméabilités 1 115 (D), 1 476 (D), 1171(D).

Mots clé : Blocage d'eau, faible permiabilité, mouillabilité, tension interfaciale, tensioactif.

ملخص

تظهر معظم آبار النفط انخفاضًا ملحوظًا في الإنتاج بعد تدخل أو عمليات استرجاع معينة مباشرة عند استخدام الطين ذو الأساس المائي، وقد وجد التحقيق في هذه المشكلة أن غزو محيط البئر بواسطة سوائل التدخل يتسبب في حبس المياه "كتلة الماء" التي تعيق تدفق النفط في قاع البئر. إن تطوير نموذج يحاكي الظاهرة أيضًا أن دراسة الحالة الجيدة «HGANE2» يجعل من الممكن تسليط الضوء على تأثير هذه الظاهرة على الإنتاجية باستعادة 400 (م / ساعة) من المياه ذات النفاذية 1115 (د) ، 1476 (د) ، 1171 (د).

الكلمات المفتاحية :انسداد الماء، انخفاض النفاذية، الرطوبة، التوتر ، خافض للتوتر السطحي.

Abstract

Water block is defined by water entrapment after drilling intervention operations when using water-based mud, completion, workover or stimulation in a low permeability reservoir. Increased water saturation in the pore space blocks the flow of oil and gas from the reservoir to the well. Water flow and its influence on oil threshold pressure were evaluated with constant pressure injection. Products including alcohols and chemical surfactants were used to reduce water saturation, capillary pressure by decreasing interfacial tension and reverse rock wettability by adsorption. As a consequence, low irreducible water saturation estimated at 30% at a given reservoir

pressure gradient (1173 hPa) will be generated. The development of a model simulating the phenomenon as well as the study of the state of the well "HGANE2" allows to highlight the effect of this phenomenon on the productivity with a recovery of 400 (l/h) of water with permeabilities 1 115 (D), 1 476 (D), 1171(D).
Key Words: Water block, low permeability, wettability, interfacial tension, surfactant

Summary

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CHAPTER III: STUDY CASE HGANE2

Symbols and Abbreviation

Q	**Flow rate**	**m^3/s**
K	**Permeability**	**darcy**
S	**The area of the medium**	**m^2 or cm^2**
μ	**Viscosity of the fluid**	**Pas.s or cp**
ΔP	**Pressure difference**	**atm or Pas**
ΔL	**The thickness of the medium**	**m or cm**
λ	**Fluid mobility**	**m.s-1**
DST	**Drill stem test**	
PLT	**Production Logging Tool**	
SIP	**Shut in pressure**	
BHFZ	**Bottom hole formation zone**	
ESP	**Electrical submersible pump**	
TCP	**Tubing-conveyed perforating**	
UTCP	**Under Tubing-conveyed perforating**	
TD	**Total depth**	
FL	**Fluid loss**	
F	**Force**	**kgf**
HGA	**HASSI GUETTAR**	
RT	**Rotary table**	
LCP	**Local Content Policy**	
TW	**Treated water**	
CT	**Coiled tubing**	
CP	**Casing pressure**	
TS	**Transgressive Stand**	

Introduction

Introduction

The word petroleum comes from the Latin Petra Oleum "oil of stone». It is an oil resulting from a mixture of hydrocarbons composed of plankton with an organic base. Gathered and agglomerated and fermented in a mother rock full of pores and holes, which presents a deposit that is called crude oil basin. This oil occupies the voids of porous rocks called reservoir. The Algerian territory covers an area of 2 381 741 km2, which makes it the largest country in Africa and the Arab world. Our country occupies several productive basins of hydrocarbons where the giant deposits of Hassi Messaoud, Ain Amenas, TFT Tinfouitanbankok, Hassi R'mel, Hassi Berkine ,Ourhoud, etc ....

The oil industry seeks to achieve the highest production yield and recover the maximum amount of oil reserves in place. To achieve this goal, it fights against all the problems that hinder productivity. After the remarkable fall in pressure in oil fields, and consequently, the fall in production. This requiring the maintenance of wells and their stimulation. This increases the chances and costs of exploitation to exorbitant figures. [1]

One of the problems encountered in the oil and gas industry is the phenomenon of water block. Water can become trapped by capillary forces in the reservoir rock near the wellbore and significantly reduce the rate of oil or gas production. The general term for wells suffering from loss of productivity due to capillary trapped water is "water block."

The purpose of this thesis is to study this phenomenon to include the effects of this capillary forces near the well or hydraulic fracture and analyze the impact of fluid compressibility, wettability and various reservoir and well proprieties.

To solve this problem we will distribute our work according to the following plan: The first chapter is dedicated to the generalities on permeability more precisely the low permeability reservoirs. In the second chapter we dig deeper on the "water block phenomenon" by citing its main causes and the common solutions used in the industry nowadays, and then we are going to interpret the well HGANE as a case study of the phenomenon in the third chapter. Finally, our work ends with a general conclusion and some recommendations.

Chapter Ⅰ

Low permeability reservoirs

I.1. Permeability

I.1.1.Definition

The knowledge of the permeability and its characteristics (type, orientation...) is considered an important aspect for the producers because it allows the comprehending of the behaviors and the productivity's variation during the exploitation, as it helps in the selection of the right methods in well interventions.

The permeability of a rock characterizes its ability to allow the flow of fluids contained in its porous space. The latter does not allow the movement of fluids only insofar as its pores are interconnected; it's then said to be permeable. The permeability is given by Darcy's improved law: which is ahead loss law [2].

$$Q = K.\frac{S}{\mu}.\frac{\Delta P}{\Delta L} \ldots\ldots\ldots\ldots\ldots \text{(I.1)}$$

So the permeability (k) is the constant of quotient that relates to the flow (Q) of a fluid of consistence (μ) that passes through a sample of rock of section (S) and length (ΔL), underneath a differential pressure (ΔP) necessary for its passage.

I.1.2.The Main Types of Permeability

a. Absolute permeability

It is the permeability measured with a single fluid present, for example: the permeability of air, water permeability, oil permeability.

b. Effective permeability

When a rock contains more than one fluid the ability of each fluid to flow is impaired by the presence of the other fluids. So it is a rock's permeability to a specific fluid in the presence of a mixture of fluids.

$\mathbf{k_o}$ = Effective permeability to oil

$\mathbf{k_g}$ = Effective permeability to gas

$\mathbf{k_w}$ = Effective permeability to water

c. Relative Permeability kr

As a measure of absolute rock permeability, the ratio of effective permeability to a specific fluid is used.

Fluid saturation and phase wettability play a big role.

$\mathbf{k_{ro} = k_o/k}$ = relative permeability to oil

$\mathbf{k_{rg} = k_g/k}$ = relative permeability to gas

$k_{rw} = k_w/k$ = relative permeability to water[2].

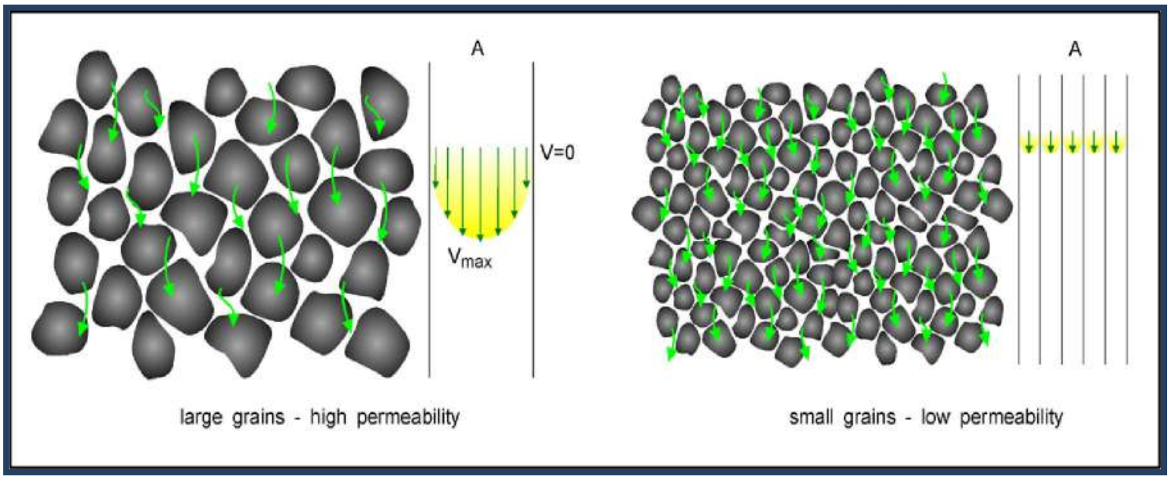


Figure I. 1: A microscopic view of sandstone ranging from very low porosity-permeability rock to a high one.[3]

I.2.Permeability measurement methods

I.2.1.Core analysis

In the case of consolidated and less permeable materials the permeability is measured in the laboratory as follow:

The test consists of injecting a pressurized fluid (P1) and measuring the pressure (P2) andthe flow rate (Q) at the outlet of the specimen. The pressure gradient is (P1-P2)/L. knowing the radius of the specimen, it is easy to calculate the permeability[4].

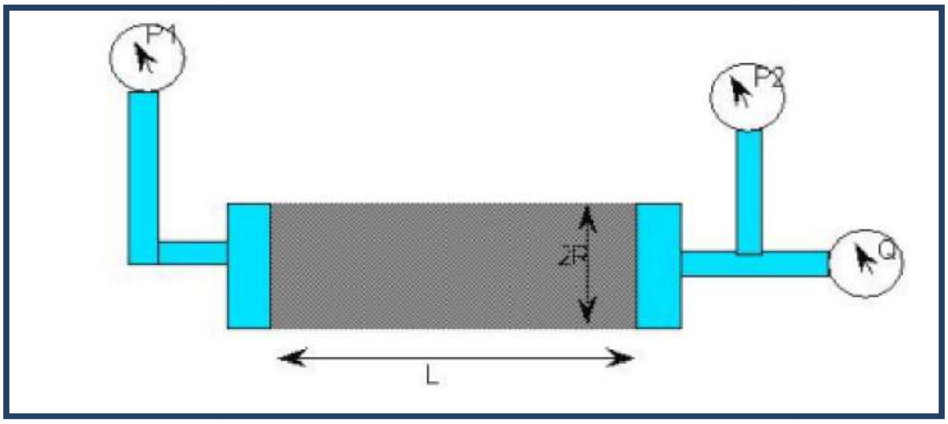


Figure I. 2: Device for measuring permeability on consolidated material. [4]

From laboratory data on samples, the range of variation in permeability for the same material is wide. This variability illustrates the fact that permeability depends on a certain number of porosity characteristics (volume, dimensions, shape, connectivity) which are themselves variable for a material. This variability is maximum for carbonates. On the other hand, the measurements taken in soundings generally show higher values than the measurements taken in the laboratory. At this scale, the discontinuities involved are fractures or faults, whereas in the laboratory the discontinuities are cracks and tubes [4].

I.2.2.Permeability from Pressure test logs

- **Fluid Mobility**

Fluid mobility can be defined as follows.

$$\lambda = \frac{k}{\mu} \ldots\ldots\ldots\ldots\ldots \text{(I.2)}$$

- **λ** : Fluid mobility
- **k** : Permeability
- **μ**: Viscosity of the fluid.

If we know the viscosity and the mobility of a fluid, we can obtain the permeability of the rock through which this fluid passes.

I.2.3.DST

A well test or DST is the provisional production start-up carried out without modifying Well equipment, in this test permeability can be obtained:

- During drilling,
- After drilling,
- After cementing a column.

I.2.4.PLT

The efficiency of simulation operations has been greatly improved due to the better knowledge of the state of the stresses of the formations, thanks to the use of digital modeling, real-time monitoring of the various parameters (bottom pressure, flow, density, temperature) during the operation of the PLT. The PLT is a set of tools that are used to perform the production logging records, these tools are combined and their configuration is well defined in the planning of the PLT operation. They provide us with a point-by-point information diagnosis of the arrivals of fluids such as water; oil and gas give us an indication of the efficiency perforations. The PLT is essential in the forecasts as an essential tool because it allows the SIP measurements and transient background recordings [5]

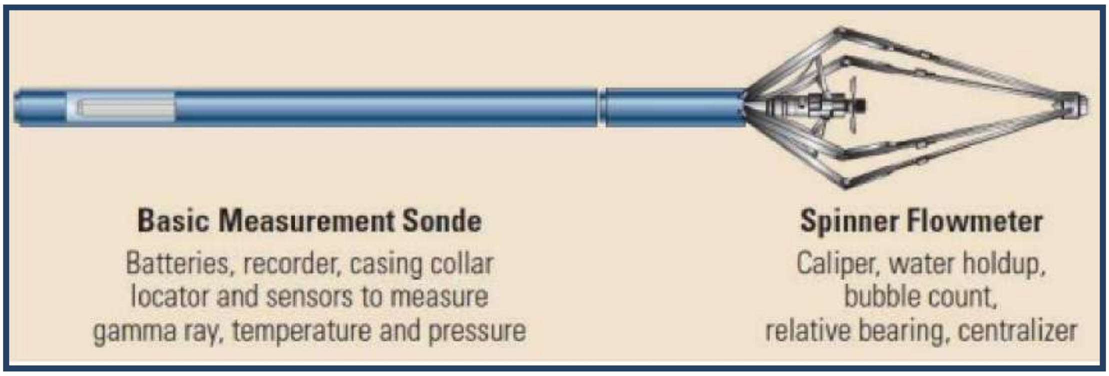


Figure I. 3: Tool PLT.[5]

$$K_{plt} = \frac{c * qi * \mu o * \beta o}{(pe - pwf)} \left[Ln\left(\frac{rd}{rs}\right) + s'\right] \ldots\ldots\ldots\ldots\ldots \text{(I.3)}$$

where C is the constant of the equation , q_i is the flow that is H_2 achieved by Emeraude software, μo is the viscosity, pe is the external border pressure, pwf is the internal well pressure, S is the skin factors , βo is the oil formation volume factor, rd: radius , rs : is the radius. of is the well.

I.3.The affecting factors on permeability

I.3.1.The dimension of the pores

The size of the grains of the rock is composed of uniformly arranged flat grains of the greatest horizontal dimension. In this case, the horizontal permeability is very high compared to the vertical permeability. If the rock is composed of large and mostly rounded grains, the permeability is high in the same order of magnitude in both directions.

I.3.2.The fluids present

When several fluids are present in the pores, there will be reduction in permeability for each of them. The absolute, effective and relative permeabilities will then be defined.

I.3.3.Flow direction

Horizontal permeability is generally higher than vertical permeability.

I.3.4. Effect of grain size on permeability

Mineralization Layered minerals such as muscovite and Schist strata act as permeability barriers. In this case, the ratio of the horizontal permeability (Kh) to the vertical permeability varies from 1.5 to 3. Sometimes the vertical permeability is greater than the horizontal permeability due to fractures.

I.3.5.Cementation Porosity and permeability

Are effected by the same degree of cementation and location of the cementing materials in the pore space.

I.3.6.Fracturing and solution in sandstone

I.4.Permeability classification

I.4.1.Primary permeability

Reservoir rocks can have a primary permeability, which is matrix permeability. This permeability is created during the deposition of the sedimentary rock.

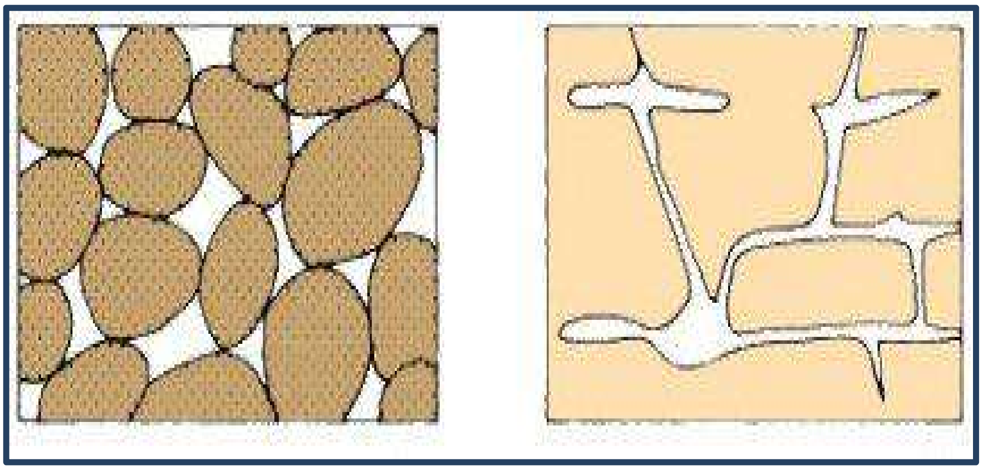


Figure I. 4: Microscopic view of matrix permeability.[2]

I.4.2.Secondary permeability

It is created from the alteration of rock, cementation, or fracturing of rock.

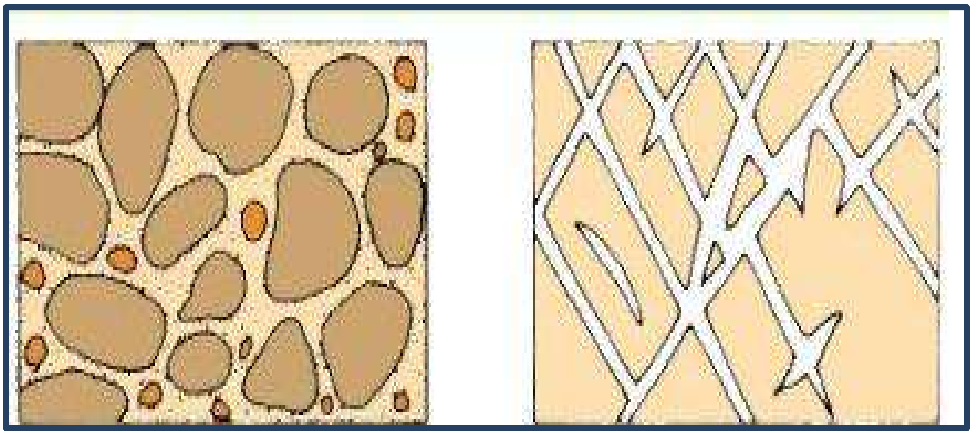


Figure I. 5: Microscopic view of a rock's secondary permeability.[2]

I.5.Fluid flow in petroleum reservoirs

During hydrocarbon production, fluids flow from the formation to the well bottom hole. At a relatively large distance from the well, oil or gas moves horizontally in parallel with a uniform front throughout the homogeneous formation.

Approaching the well bottom hole, the formation fluid flow lines begin to thicken, and the fluid velocity increases. The area around the well in which the greatest flow resistance occurs is called the BHFZ.[6]

Reservoir fluids, including heavy oil, vary greatly in composition. In some fields, the fluid is in the gaseous state and in others it is in the liquid state but gas and liquid frequently coexist in a reservoir. The rocks which contain these reservoir fluids also vary considerably in composition and in physical and flow properties and this can serve to complicate the sampling procedure.[7]

Other factors, such as producing area, height of the column of hydrocarbon fluid, fracturing or faulting, and water production also serve to distinguish one reservoir from another[8].The combination of all these factors affects the choice of sampling methods and preparations for sampling.[9]

I.6.The impact of permeability in reservoir classification and evaluation

Permeability is an important property of various media. Great attention is given to permeability as a property of a medium by the oil and gas industry since it characterizes how efficiently hydrocarbons are extracted. [7]

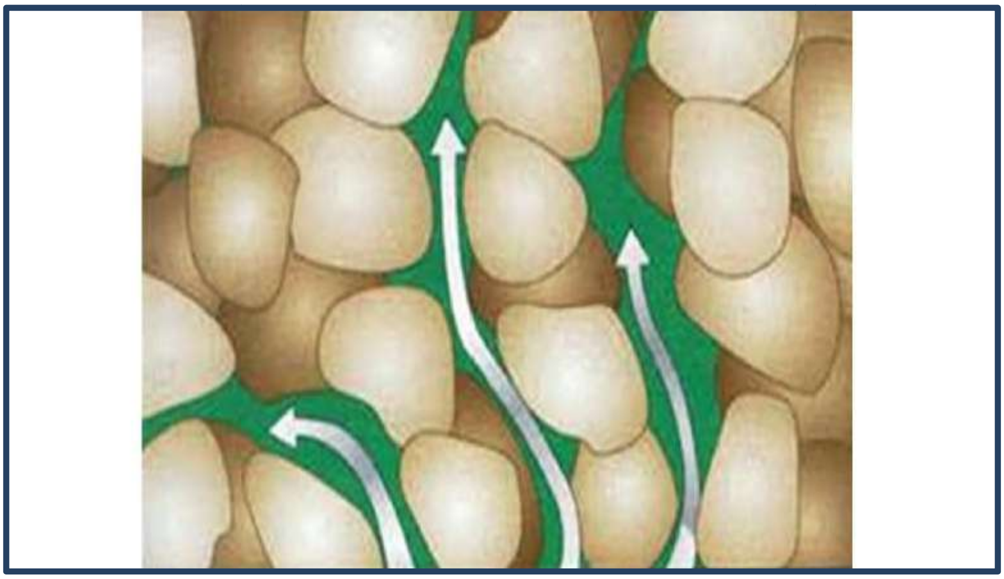


Figure I. 6: Fluids permeability in porous media.[7]

Not only that but the reservoir geology in term of permeability is a game changer in its stimulation potentials later on, specially injection as this last represents the core of the secondary oil recovery either is executed by gas or water when the lack of sufficient natural drive in most reservoirs has led to the practice of supplementing the natural reservoir energy by introducing this form of artificial drive. So this is how we find reservoir engineers in the industry having the ability to evaluate the reservoir's quality on a permeability basis, as:

I.6.1.High permeability reservoir

In these reservoirs we find a huge homogeneity between porosity and permeability (correlations) as most of the pores are connected just enough for high permeability propriety get created in this porous environment.

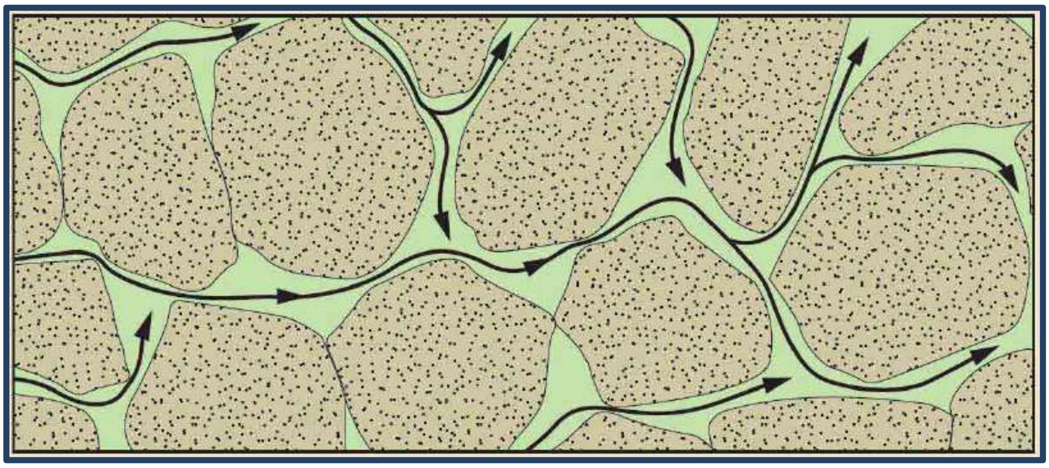


Figure I. 7: High permeability media with connected pores. [10]

I.6.2.Low permeability reservoirs

Vast reserves of valuable hydrocarbons exist trapped in low permeability intercrystalline and microfractured carbonate and sandstone formations throughout the world. Due to the low inherent viscosity of the fluid (natural gas case) [9] or when the pores in the rock is unconnected, what it calls a strong heterogeneity between permeability and porosity.

I.7.Low permeability formations

I.7.1.Definition of Low permeability formation

The permeability of a material is defined by how much it opposes the flow of fluids, low permeability means it requires a lot of pressure to squeeze fluid through the substance, These kind of reservoirs are around 0, 1 md and 1 md.

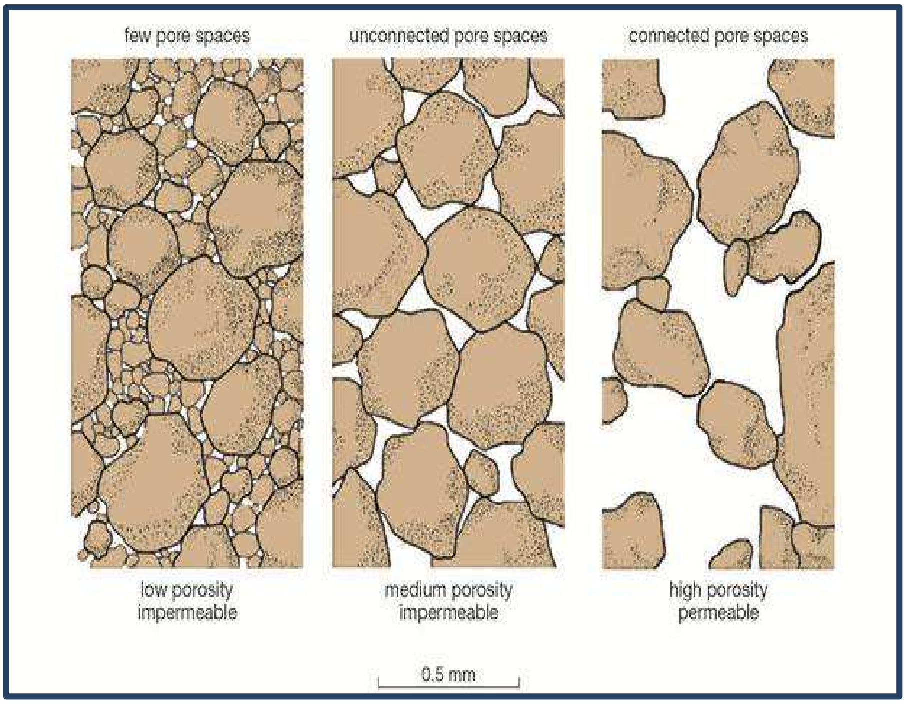


Figure I. 8: A microscopic view of sandstone's pore spaces. [**10**]

I.7.2.Problems due to low permeability formation

Low permeability formation can cause many problems that can lead to a formation damaged which are

1. Condensate banking
2. Bacteria
3. Wettabiliy alterations
4. Water blocking, liquid blocking
5. Emulsions generation
6. Scaledeposition
7. Fines migration
8. Paraffins, wax and asphaltene formation

I.7.3. Solutions

Low permeability reservoirs are the most vulnerable to damage, which is why it's critical to minimize damage throughout some process and of strategies using optimum fluid systems and process parameters. The following are some of the most frequent ways for generating low permeability reservoirs, however they are not exhaustive:

- Infill drilling, this result in near well spacing
- Horizontal drilling using a single or many laterals.
- Well stimulation

Hydraulic fracturation:

It is a stimulation technique used for natural low permeability reservoirs to extract trapped hydrocarbons. This technique consists of continuing to drill to very deep depths, thousands of meters from passing aquifers and conventional gas pockets. The drilling operation ends until the appearance of the shale layer [11], once arrived at this drilling layer we deviate and start horizontally as shown in the figure below.

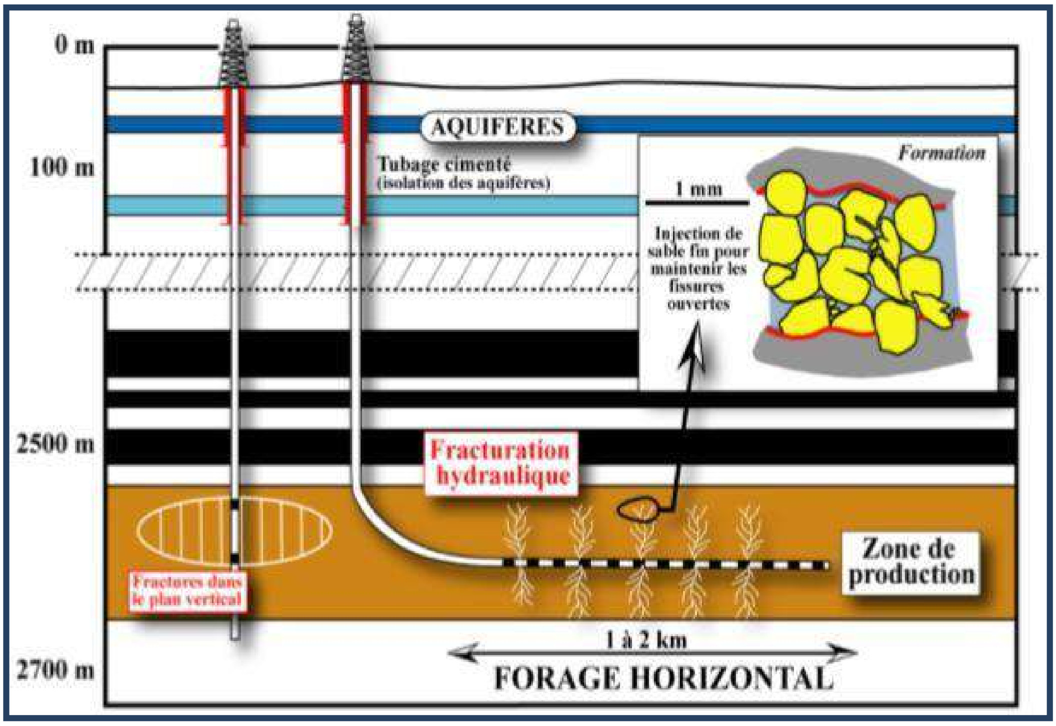


Figure I. 9: Hydraulic fracturation process.[11]

Acidification

It is a technique aimed at improving the productivity or infectivity of oil and gas wells. In matrix stimulation, acids are injected into the formation to remove damage to the edges of the well that reduce well productivity. Process fluids are injected at injection pressures below the rock fracturing pressure limit.

- ✓ **Suitable solvents for damage due to mineral deposits**

Suitable solvent is one, which readily dissolves the solid (solute) when the solvent is hot. But not when it is cold. The best solvents exhibit a large difference in solubility over a. reasonable range of temperatures.

- ✓ **Aromatic solvents for damage due to (paraffins, asphaltenes, sludges)**

So, any solvent contains an aromatic hydrocarbon, such as naptha, toluene, or xylene, is known as an aromatic solvent. Aromatic solvents are utilized as solvents and diluents in a variety of industrial applications. Toluene and other aromatic solvents are widely employed in paints, varnishes, adhesives, and as chemical intermediates.

These solvents are typically produced in the oil-refining sector by distilling crude petroleum stock. Aromatic solvents are employed as thinners and diluents in a variety of end-user goods, including paints, coatings, and cleansers. In the oil and gas business, aromatic solvents are often utilized as corrosion inhibitors.[12]

- ✓ **Surfactant for damage due to resersal of wettability**

Surfactant (short for surface-active-agent) is a term used to describe a chemical that has some surface or interfacial action. It's worth noting that not all amphiphiles exhibit this behavior; in fact, only those with roughly balanced hydrophilic and lipophilic inclinations are likely to migrate to the surface or contact. If the amphiphilic molecule is excessively hydrophilic or hydrophobic, it will remain in one of the phases.

Chapter II

Water Block Formation

II.1. Water Block Formation

II.1.1. Water block definition

In oil or gas production wells, water can become trapped by capillary forces in the reservoir rock near to the wellbore [13]. The trapped water dramatically reduces the production rate of oil or gas and defining “the water block mechanism”. So, the forces at work during the flow from the reservoir into the wellbore are the major emphasis of this phenomenon. It looks into how the presence of water trapped near the wellbore affects the flow rate in particular**.** [14]

II.1.2. Water block effecting factors

The severity of the water block is the result of the combined effects of wettability, capillary forces, viscous forces, fluid compressibility, and various other reservoir and well properties, but the focusing on the most important factors is as follow:

a) Capillary end effects

The pressure of the fluid between the reservoir and the wellbore will remain constant throughout steady flow from the reservoir into the wellbore. Both phases will exhibit pressure continuity if there is a constant flow of two phases. As a result, between the reservoir and the wellbore, capillary pressure will remain constant. The capillary pressure in the wellbore is comparably minimal since the wellbore pipe has a much larger diameter than the pore space of the reservoir. The capillary pressure inside the reservoir pore space is insignificant at the point where the reservoir rock reaches the wellbore due to the continuation of capillary pressure. Capillary pressure can be significantly higher further from the wellbore. As a result, there may be a drop in capillary pressure. Capillary pressure can be significantly higher further from the wellbore. When a result, as we approach the wellbore, there may be a reduction in capillary pressure in the reservoir pore space. This, in turn, will have an impact on water saturation.

Once steady state was established, this effect was observed repeatedly in laboratory core floods. After steady state was reached, the saturation profiles were calculated by weighing different parts of a core. In situ saturation profiles were measured using nuclear imaging methods. Upon exiting the core, both authors found an increase in water saturation. These following theoretical explanations were provided: The capillary pressure at the outflow is insignificant during water-oil or water-gas core flooding of water wet porous medium.

Water will accumulate at the core outflow until the water pressure equals the pressure of the other phase. Water can pour through the outlet if this happens. The "capillary end effect" refers to the rise in water saturation at the exit as a result of reduced capillary pressure.

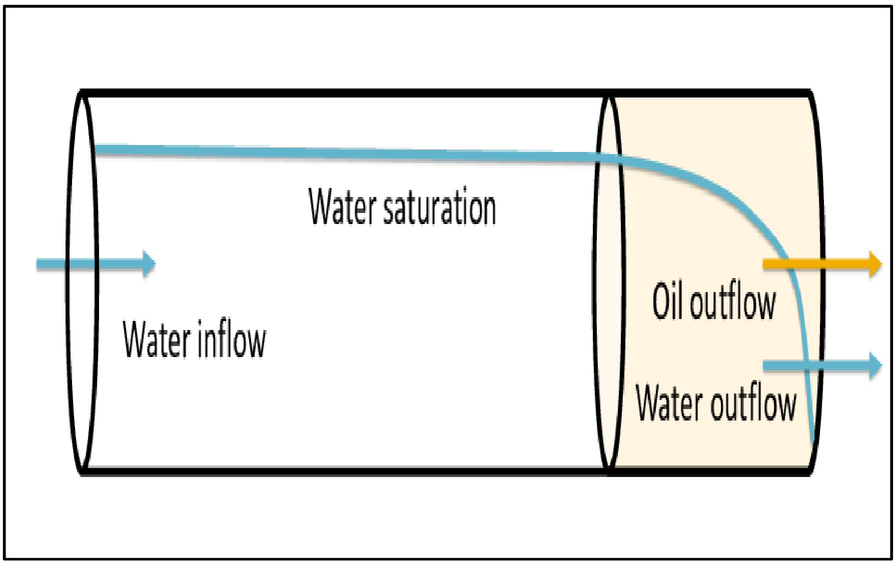


Figure II. 1: Capillarity end effect on the flow of water and oil in a productive well.[15]

If not taken into consideration, this phenomenon can lead to mistakes in core flood evaluations of relative permeability– saturation relationships. The rise in water saturation obstructs gas passage, resulting in a pressure drop. The additional pressure drop was discovered in laboratory core floods by two scientists and developed a mathematical approach to account for the excess pressure drop owing to capillary end effects at low flow rates when calculating relative permeability.

The capillary forces determine the water saturation at the core's outflow. The saturation dictated by viscous forces, on the other hand, may differ from the outlet saturation. The size of the capillary end effect is determined by the competition between viscous and capillary forces. The capillary end effect can be negligible at high rates, when viscous forces are significant. End-effects created inaccuracies in relative permeability curve measurements at low rates, but they were minimal at high rates, according to laboratory studies conducted. The residual saturation in the core has been demonstrated to tend toward a constant at high rates in several laboratory experiments.

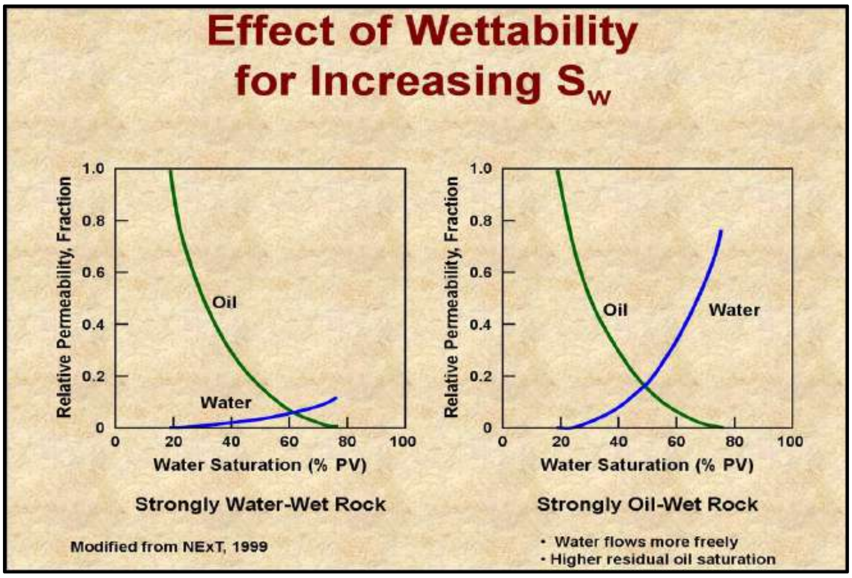


Figure II. 2: Effect of wettability on increasing Sw. [16]

The total water block can occur if the pressure drop between the reservoir and the wellbore is not great enough to counteract the capillary end effect. As a result, depleted reservoirs are more prone to water blockage.

The differential in capillary pressure between inside the porous medium and at the exit or wellbore can be significant in porous media with limited permeability. As a result, low permeability gas reservoirs are more prone than high permeability reservoirs to be water obstructed.[16]

b) Reservoir Rock Wettability

Wettability of the pore surface is one of the important factors influencing the distribution and transport of various fluid phases and therefore the extent of formation damage in petroleum-bearing formations. Because the wettability of rocks is altered by the rock and fluid interactions and variations of the reservoir fluid conditions, prediction of its effects on formation damage is a highly complicated issue. Although mineral matters forming the reservoir rocks are generally water-wet, deposition of heavy organic matter, such as asphaltenes and paraffins, over a long reservoir lifetime may render them mixed-wet or oil-wet, depending on the composition of the oil and reservoir conditions. [16]

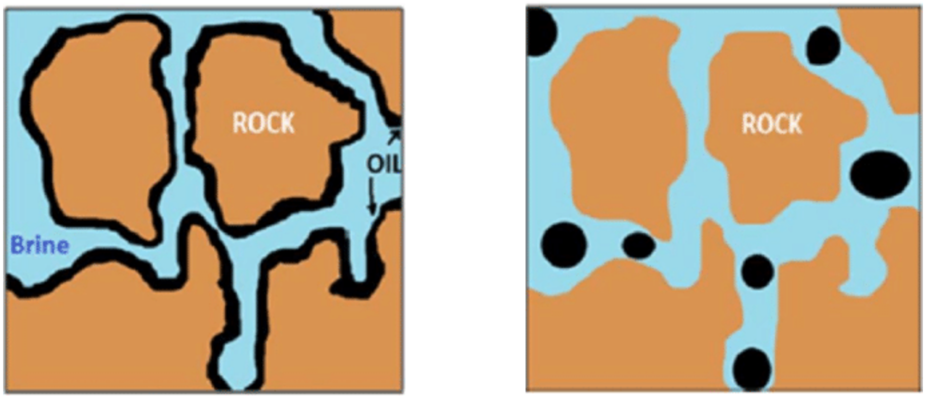


Figure II. 3: The different two cases of wettability in the reservoir rock. [17]

c) Intervention Operations Fluids and its interactions with the reservoir rock

The water that makes up the capillary end effect or water block comes from a variety of places. Fluid loss from drilling, fracturing, or completion operations can be added to any water already existing in the reservoir. So for the profound studying of water block mechanism it is necessary to analyses the fluids nature used in these kind of operations:

- **Drilling Fluid**

Drilling fluid is any fluid that is circulated in the borehole to help in carrying out a cost-effective and efficient drilling operation resulting in stable and gauged borehole to targeted depth with minimum possible damage to prospective formations [18]. A major component in drilling operation success is drilling fluid performance [19]. The successful completion of borehole and its cost depend, to a great extent, on the properties of the drilling fluid. The functions of drilling fluid, which are critical to the drilling process.

Selection of drilling fluid mainly depends on the type of formation and the borehole depth. The various kinds of drilling fluid normally used are water, bentonite mud, cutting oil, and polymers (both water-based and mud-based).

- Water: It is freely available fluid and is primarily used in core drilling operation. It has very good cooling properties and acts as moderate lubricant and vibration dampener.
- Bentonite Mud: This increases the viscosity and gives better cleaning of the hole. Bentonite mud solution has gelling properties and thus it keeps the cutting in suspension even when the circulation is stopped.
- Polymer*:* The polymer has similar properties as that of bentonite mud except gel strength. It has excellent flushing capacity. The only drawback is that circulation

is to be maintained all the time else the cuttings will quickly settle at the bottom and jam the string. [19]

- **Work overand Completion fluid (well-control fluid)**

Completion and workover fluids are any fluids used in the completion of a well or in a workover operation. These fluids range from low-density gases such as nitrogen to high-density muds and packer fluids. The application and requirements vary for each fluid.

Workover fluids are fluids used during the reworking of a well after its initial completion. They may be gases such as nitrogen or natural gas, brine waters, or muds. Workover fluids are used during operations such as well killing, cleaning out a well, drilling into a new production interval, and plugging back to complete a shallower interval.

Completion fluids are used during the process of establishing final contact between the productive formation and the wellbore. They may be a water-base mud, nitrogen, oil mud, solids-free brine, or acid soluble system.

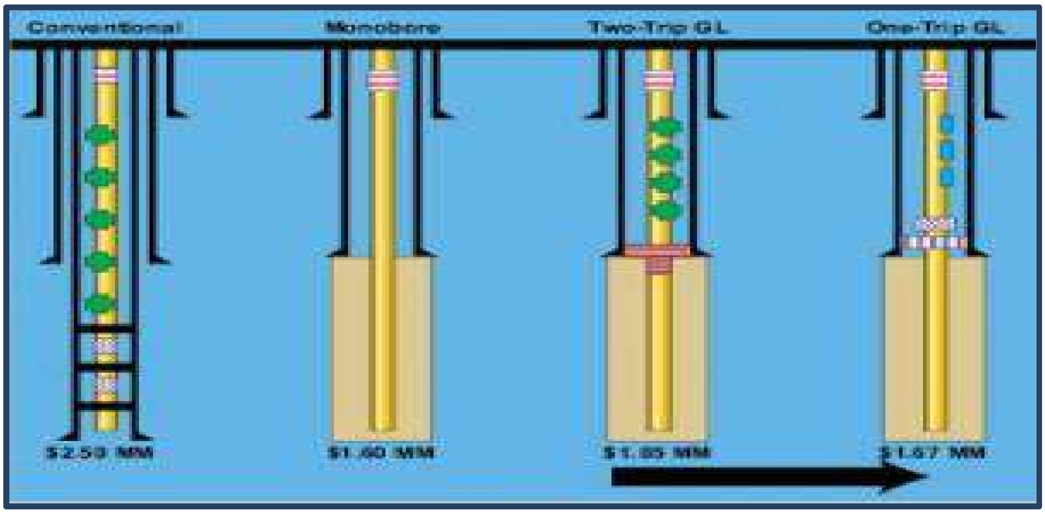


Figure II. 4: Completion accessories landing on the bottom hole of an eruptive well. [17]

Three types of completion or workover fluids are

- ✓ Clear liquids (dense salt solutions)
- ✓ Weighted suspensions containing calcium carbonate weighting material, a bridging agent to increase the density above that of saturated solutions.
- ✓ Water-in-oil emulsions made with emulsifiers for oil mud.[20]

- **Hydraulic Fracturation fluid**

The fracturing fluids used for gas shale stimulations consist primarily of water but also include a variety of additives. The number of chemical additives used in a typical fracture treatment varies depending on the conditions of the specific well being fractured. A typical fracture treatment will use very low concentrations of between 3 and 12 additive chemicals depending on the characteristics of the water and the shale formation being fractured. Each component serves a specific, engineered purpose. [21]

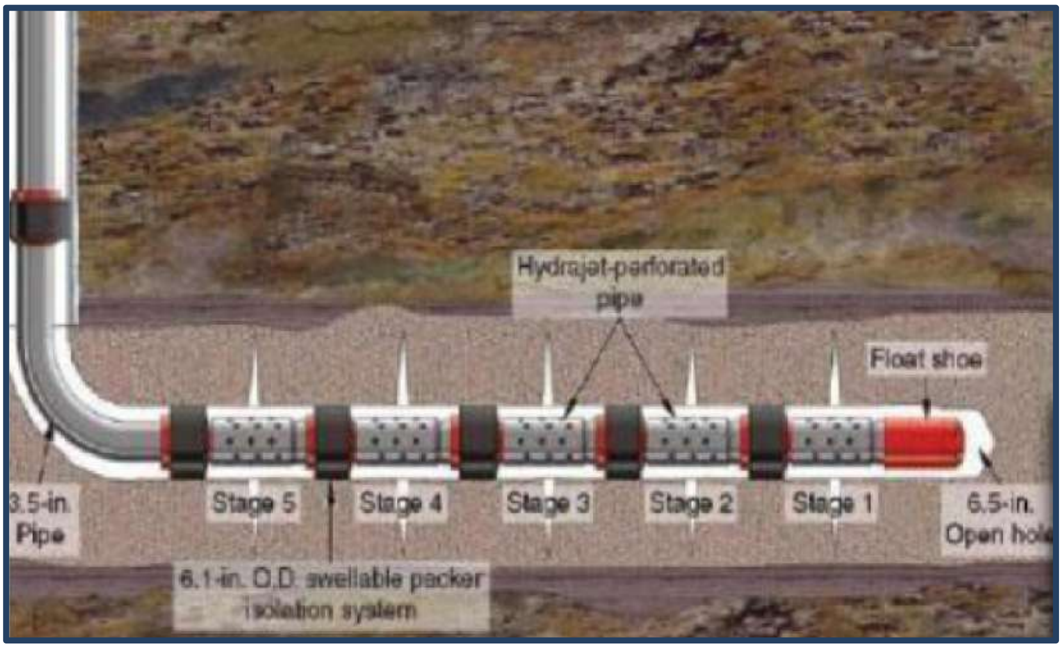


Figure II. 5: Hydraulic fracturation process. [22]

- **Cementation**

The cement used for oil well cementing differs from concrete or masonry work in that it consists of thin slurry of primarily cement and water. The cement used in oil wells must possess three primary properties. They must possess a proper water-to-cement ratio, a sufficient fluid time to allow placement, and must develop enough strength in a minimum time to bond the pipe to the formation. [23]

II.2. Water Block Control

II.2.1. Fluid-Loss in well intervention (Filtration)

Loss of intervention fluids to permeable formations results in increased water saturation, scaling or emulsion generation, or fines migration, which can severely impair production. Additionally, excessive losses can compromise well control, complicate fluid management, and increase project costs. [24]

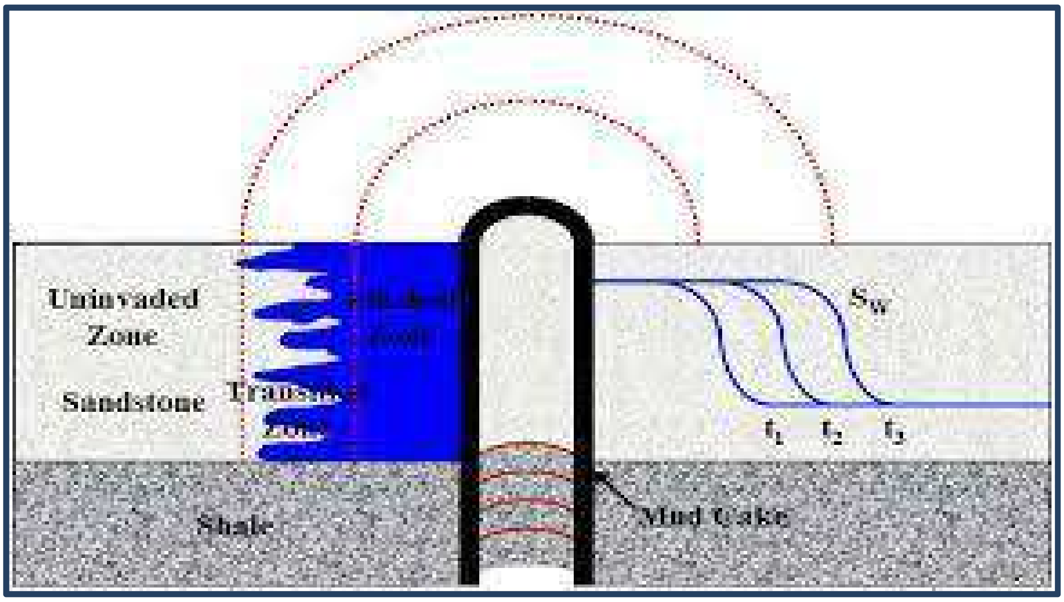


Figure II. 6: Water invasion during drilling operation. [25]

II.2.2. Fluid-Loss Problems and Causes

During workovers, gravel-pack completions, ESP replacement, underbalanced TCP (UTCP), and other applications, aqueous well fluids are usually circulated continuously between the surface and TD. Maintenance of a hydrostatic column is necessary for well control and to enable treatment fluids to be injected into the targeted intervals downhole, without fear of overdisplacing the treatment fluids. [26]

II.2.3. Methods of Preventing Fluid-Loss

The loss of pumped fluids that are circulated from surface to total depth (TD) and back during various drilling, completion, and intervention operations poses numerous problems affecting wells and reservoirs. Fluid loss (FL) to the formation is costly not only in terms of the fluid itself, diverted from its task, but in the time and expense required to mitigate the problem. Well control can be compromised, wellbore cleanouts impaired, and reservoirs damaged, sometimes permanently, as a result of fluids entering the formation.

A low-viscosity, solids-free FL treatment can help (1) cure lost circulation, (2) prevent loss of expensive drill-in fluid during workovers, (3) improve well control by maintaining a hydrostatic column, and (4) provide FL control in vertical- and horizontal-well gravel-packing operations.

As an example of the treatment technology, developed by Halliburton as the LO-Gard fluid-loss-control system, relies on an associative polymer to decrease matrix permeability to aqueous fluids, limiting leakoff into treated zones. A significant property of the treating fluid is that it causes little or no damage to the flow of hydrocarbons.

The treatment fluid may be used in various applications.

- Well intervention cleanouts by coiled tubing and hydraulic workover
- Gravel packing
- Most lost-circulation events occurring during cementing, fracturing, and drilling
- After tubing-conveyed perforating (TCP) operations
- FL control before, during, and after gravel packing
- Electrical submersible pump (ESP) replacement operations
- Circulation maintenance in horizontal openhole completions across unconsolidated sands
- Formation permeabilityreduction in :
  - High-permeabilitystreaks
  - Thinned or eroded drill-in fluid wall cake
  - Breeched or fracturedwall cake
  - Natural- or hydraulic-fracture networks.[26]

II.2.4. The importance of emulsion system

Emulsion-breaking products are designed to break water-in-oil emulsions. Emulsions can increase the amount of waste material to be collected by up to three times the volume of oil spilled. They are usually more soluble in water than in oil, although the commercial products available have a wide range of solubility. The amount of demulsifier required depends on the product, the type of oil, and the quantity of oil. Some demulsifiers are more toxic than modern dispersants. These products are not commonly used since the formation of stable emulsions is not common. [27]

Figure II. 7: Emulsion Mixture of viscous fluids. [28]

Emulsion inhibitors prevent water-in-oil emulsions from forming. No product has ever been marketed as an emulsion inhibitor. However, dispersants have been considered by some for this purpose. [27]

II.3. Water Block Remediation

Where we focus on the remediation's innovations applied in multiple wells scenarios affected by water block

II.3.1. Hydraulic fractured fluid damage remediation by X-ray CT imaging

The injected fluid should not linger near the wellbore or fracture face, since this will induce water blockage. There are two operations that may be performed after the fracture operation to help in the evacuation of water from the close fracture face region. The procedures are to either return the fracturing fluid or to plug the well. The fracturing fluid might absorb into the reservoir and spread away from the crack during the shut-in period.

Figure II. 8: Coiled Tubing unit of oil and gas well. [29]

Experiments were conducted to investigate the effects of prolonged dwell time. X-ray CT imaging was used to determine saturation distributions and permeability after a pulse of water was injected into a core for 48 hours. They concluded that formation characteristics, such as the relative permeability curve, dictated the benefit of extended dwell times. On the other hand, extended downtime can have some disadvantages. Researchers analyzed field data and performed a simulation analysis for a block of 18 wells. They found that increasing the amount of downtime before flow resumed improved early gas production, but significantly reduced fracturing fluid recovery...

A numerical simulation has been utilized to show that productivity recovery time increased with the depth of fracturing fluid leakage, and that waiting too long for flow to return and increasing fluid leakage can affect peak production. In their numerical simulations, other researchers found that a shorter shut-in period can increase production at the end of the day while allowing higher recovery of fracturing fluid and total gas.

If the fracturing fluid is returned, two procedures will be in action to remove the water. During a two-phase flow, X-ray scanner was employed the first process they found was viscous displacement, and the second was evaporation. By monitoring the ejected liquid, gas flow, and weight change of the cores during two-phase coring, two investigators arrived at the same result. They found that the displacement phase can last a few weeks, while the evaporation phase can continue for months. Alcohol can enhance the impact of evaporation, according to laboratory results obtained...

II.3.2. Changing the wettability of the rock by the chemical remediation using alcohol

As demonstrated in field case trials chemical remediation options for minimizing water block can include a mix of interfacial tension decrease, wettability adjustment, and the use of alcohols. Wettability alteration can be a permanent solution if the reservoir is not dry or there is water leaking from the wellbore into the reservoir. Another searcher conducted a review of the literature on the effect of wettability on capillary pressure curves. His analysis of multiple laboratory-measured capillary pressure curves revealed that the capillary pressure curve for intermediate wettability was closer to zero. This suggests that if the porous media is changed to an intermediate wettability, the difference in capillary pressure between the two can be reduced.The wellbore and porous medium is both smaller, resulting in a lower saturation deviation at the wellbore.

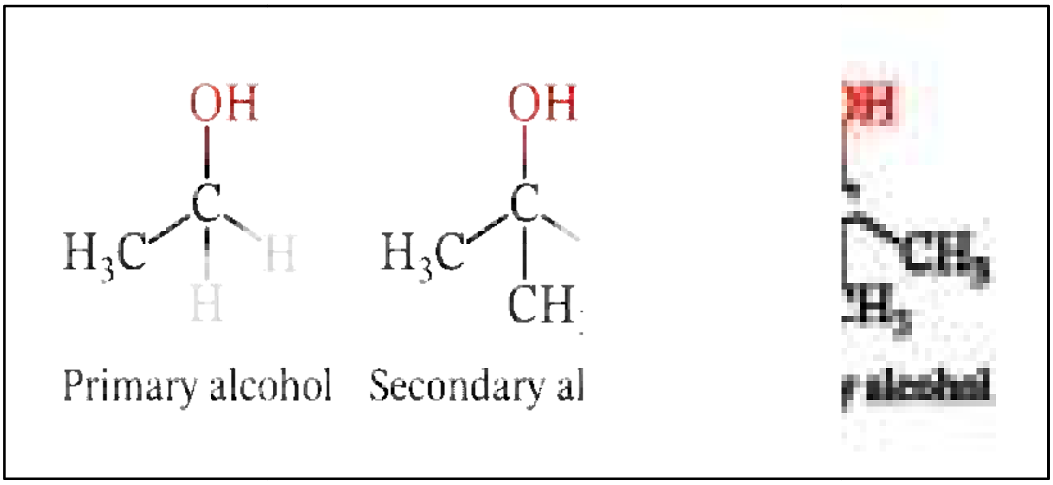


Figure II. 9: Types of alcohols. [30]

The water block effect can be reduced by changing the wettability to a more gas-wet state. There is, however, a disadvantage. A seeker conducted a review of the literature on the influence of wettability on relative permeability. They discovered that changing the wettability to the hydrocarbon phase lowered the relative permeability to the hydrocarbon phase in various test conditions. Because of the two competing effects, there may be an ideal contact angle.

There are several techniques to change wettability, but surfactants are the most prevalent. A surfactant's main job is to lower interfacial tension and/or change wettability. In the laboratory, a variety of surfactants have been examined for wettability changes. Fluoro-surfactants,fluorinated polymers, amine surfactants, cationic surfactants , anionic surfactants .

In the laboratory, nanoparticles such as Al_2O_3, SiO_2, TiO_2, and ZrO_2. Many experimental research have been conducted to evaluate the efficiency of nanoparticles, however field applications of nanoparticles have yet to be reported, to the best of our knowledge.

Wettability changes in sandstone and carbonate reservoirs have been investigated extensively. There have been a few lab investigations on wettability changes in unconventional reservoirs such shale and tight sandstone oil reservoirs. It is not, however, complete, and research on wettability modification in unconventional rocks such coals and shales are relatively restricted.

Chemical treatments can be tailored to certain contact angles. Two searchers investigated the effects of several kinds of amines, fluorinated surfactants, fluorosilanes, and fluorinated polymers on the wettability of sandstone and carbonate rocks in an experimental setting. They discovered that the quantity of fluoro groups in fluorosilanes decreases hydrophilicity.

Engineers will be able to define the contact-angle with which to adjust the reservoir pore surface in the future, given the large variety of chemicals and nanoparticles available for wettability alteration. Contact-angle optimization for maximum gas productivity has yet to be explored or reported in the literature. [14]

Chapter III

Study case HGANE2 well

III.1. Hassi-Messaoud Field oil interest

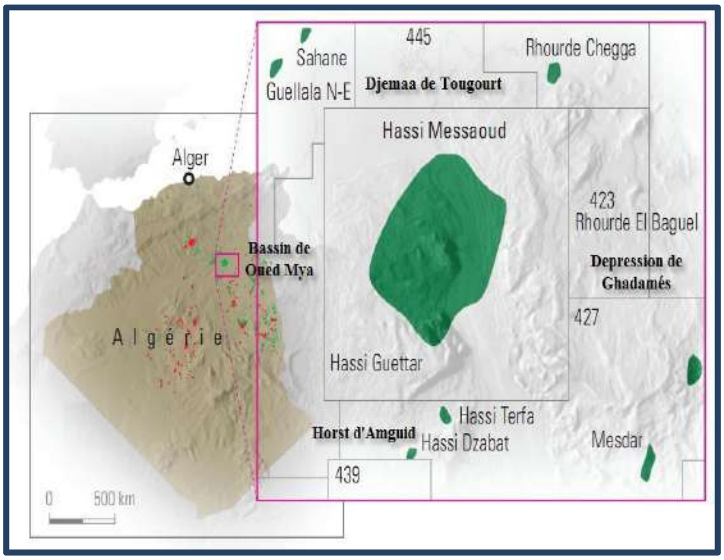
The Hassi-Messaoud field by its surface and its reserves is considered among the largest deposits in the world with a deposit pressure varying from 120 to 400 (kgf/cm²), a temperature of about 118°C to 123°C and a permeability varying between 0 to 1darcy.The reservoir is related to the Combrian sandstone-quartzite, the most productive horizon is related to the Ra and RI lithozones whose petrophysical qualities are quite good. The cover is provided by a thick and tight Triassic clay-salt bed. The Hassi-Messaoud field is considered as a mosaic of deposits, delimited by permeability barriers. [31]

III.2. Case study: HGANE2 well

III.2.1 Geographical location of Hassi Guettar

The region of Hassi Guettar (HGA) is located 20 (km) southwest of Hassi Messaoud "Figure (III.1)". It is part of the Triassic province which is located in the North East of the Saharan platform. It is located between the meridian 5° and 6° East and the parallels 31° and 32°. According to Sonatrach's division exploration, it is part of the HassiDzabat permit Block 427, between the Hassi Messaoud deposit and El Gassi.

Hassi Guettar corresponds to a satellite structure located in the South West of the Hassi Messaoud field, in block n°427, between longitudes 5°30' and 6°30' west and latitudes 30°50' and 31°40' North. . **[32]**



Figue III. 1: Geological situation of Hassi Guettar. [32]

III.2.2. Geological situation of hassi Guettar

The periphery of the Hassi Messaoud field consists of faulted zones. These high peripheral zones located downstream from the Hassi Messaoud field contain oil accumulations. Among these structures, the HASSI GUETTAR structure is located southwest of theHassi Messaoud field.The Hassi Guettar structure is located on the Amguid El Biod /HassiMessaoud ridge, its limits are:

- The Touggourt siltation in the North
- The Amguid ridge, which separates the basin of Illizi from that of Mouydir, in the south
- The Berkine basin in the East
- The Oued Mya basin in the West
- The dome of Dahra in the North-East

The region of HassiGuettar is distributed on three high zones which are:

- The bulge of Hassi Brahim in the East
- The dome of Hassi Messaoud
- The bulge of El Agreb - El Gassi in the South

III.2.3. History of exploration research of hassi guettar

A seismic campaign having highlighted an anticlinal dome; since then, more than 1000 drillings have been carried out. Aquifer wells such as QL-1, SG-1, BST-1 and ONJ-76 have been drilled on the periphery of the Hassi Messaoud field. They allowed the delineation of the regional oil/water plan. The seismic interpretations carried out by the national company Sonatrach/Exploration Division and by MC.CONRAD and its associates have shown the existence of high zones outside this (plan). These interpretations did not allow the evaluation of the height of these zones in relation to the Hassi Messaoud oil/water plane.

In June 1990, the first well (HGA-1) was drilled in the area. It produced oil from the levels of the alternations zone as well as the El Atchane Sandstone (Cambro-Ordovician After this positive discovery, other wells were drilled as indicated in the table (III.1). The oil results from these wells allowed to delineate the deposit and to prepare it for production while planning further drilling. [32]

Table III. 1: History of drilled wells

Year	Drilled well's name
1995	HGA-2
1996	HGA-3
1998	HGA-4
2000	HGA-5
2002	HGA-6/ HGA-7 /HGA-8 /HGA-9
2003	HGA-10 /HGA-11/ HGA-12 /HGA-13
2004	HGA-14 /HGA-15

With the wells from HGA-16 to HGA-46, are currently being drilled

III.3. General Information on the HGANE2 well

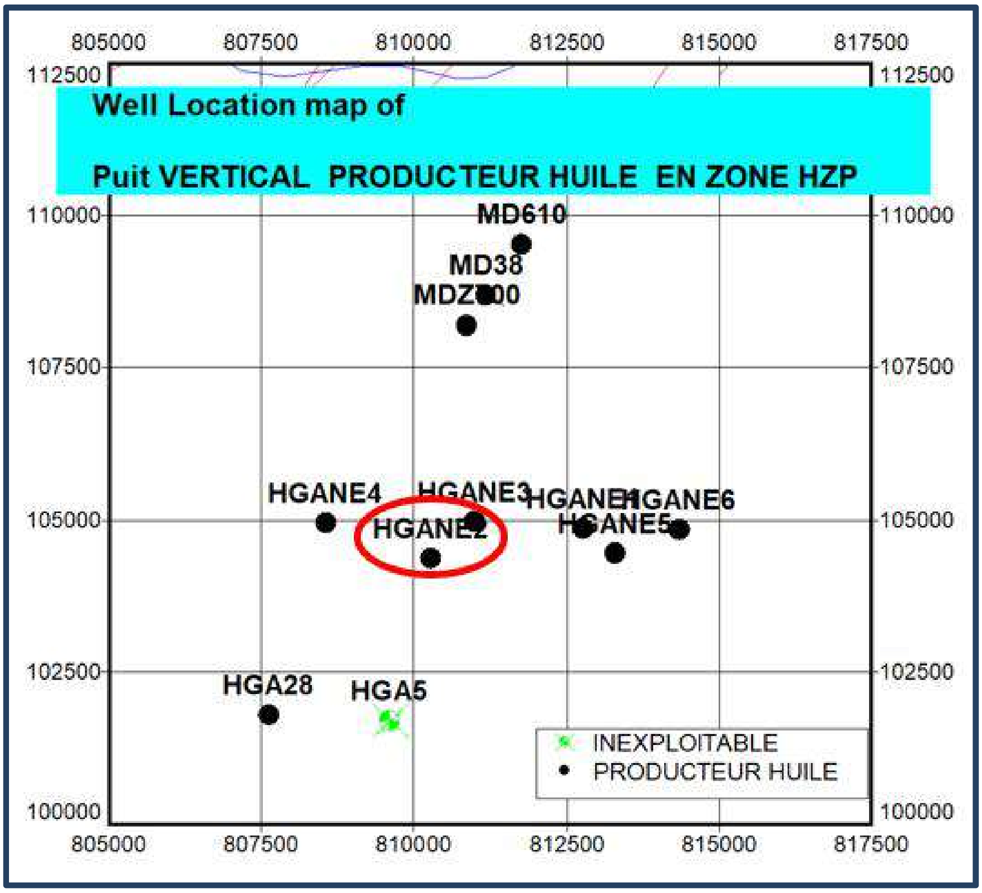
III.3.1. History of the well

HGANE2 is a vertical oil producer well, located in HGA field. The well was drilled on 20/01/2017; total depth of 3516 m RT, then it was completed with 3"$^{1/2}$ tubing and perforated in LCP of 4"$^{1/2}$ as it shown in table (III.3). According to lab sample analysis, the well tends to form organic deposits (Asphaltenes & Paraffins) and mineral deposits. (See annex A)

Table III. 2: The well information.

Field	**Hassi Guettar**	
Well	**HGANE2**	
Area	**HZP**	
date of drilling	**20012017**	
Situation	**Oil producer**	
State	**Closed**	
Z sol : 141.96(m)	**Z Table : 150 (m)**	**The bottom : 3368 (m)**
X : 810277,6802	**Y: 104362,2048**	
Manifold : EPF-HGA	**sub-manifold : HGAM3**	

The Figure (III.2) show map in relation with other offset wells:



Figue III. 2: HGANE2 Well Location Map

Table III. 3: Well data. (See annex B)

HGANE2	
Tubing 3-1/2in NV P110 9.2#	**@ 3418.19 m RT**
OTIS L. Nipple "X"3-1/2in NV	**@ 3397.81 m RT**
OTIS L. Nipple "XN" 3-1/2in NV	**@ 3407.65 m RT**
Casing 7"	**@ 3572 m RT**
TD	**@ 3516 m RT**
Perforations	**3489.5 – 3490.5 (RI)** **3505.0 – 3510.0 (RI)**

III.3.2. Petro physic characteristics

This test will allow us to know the depth of the existing zones and determine the different characteristics such as porosity,water saturation as it is indicated in the table below

Table III. 4: Petrophysical characteristics

Zones	Name	Top	Bottom	Unit	Gross	Net	Av-Shale volume	Av-Shale porosity	Av-water saturation
RI	Rock	3469	3516	m	47	46,919	0,296	0,031	0,400
RI	RES	3469	3516	m	47	32,136	0,207	0,038	0,371
RI	PAY	3469	3516	m	47	12,802	0,148	0,053	0,111
RA	ROCK	3516	3525	m	9	9	0,341	0,019	1,000
RA	RES	3516	3525	m	9	2,002	0,264	0,023	1,000
RA	PAY	3516	3525	m	9	0			

III.3.3. Well test data

The well has shown a decrease in productivity in 2016, which continues to increase till 2018, the specialists have carried out this test in order to:

- Estimate the potentiality of the well
- Determinate the origin of the productivity reduction from 31/12/2016 to 01/11/2018
- Find out the type of damage of the device
- Determine the skin damage

As it showed in table (III.5)

Table III. 5: Well test data

Test	Date	PG (kg/cm²)	PFD (kg/cm²)	PT (kg/cm²)	Flow rate (m/h)		IP	HKP	HKL	HKL (Hw * Kyz)	Skin	Duse	Remarks
DST	31/12/2016	452.83	403	173	Oil	16.25	.3055	--	-	621	1.64	9.53	Vertical well in the combrian(RI+RA), PFD@-3254.19m abs.
PFD	01/11/2018	Nul	271	71.77	Oil	9.8	--	--	-	-	-	11	PFD @ -3321.54m
PFD	05/01/2019	Nul	258.76	64.45	Oil	8.69	--	--	-	-	-	11	PFD@-3336.55 m
BUILD UP	07/06/2020	356.39	270.3	62.2	Oil	6.5	.077	--	-	515	-.06	10	PFD@-3254.54m.

III.3.4. Production test

The main purpose of this test is to measure the production rate;however, this test has allowed us to obtain other parameters characterizing the crude oil such as GOR, oil temperature, density, the pipe and the test pressure.

The results obtained are shown in the table (III.6)

Table III. 6: Production test data

Measurement Date	Duse diam (mm)	Sépar unit.	Flow rate (m³/h)		GOR	Pressure (kg/cm²)			Density		OilTemp. (°C)	K Psi	Water flow rate (l/h)	
			Oil	Gas		Press. Tete	Press. Pipe	Press. Separ.	oil	Gaz			Recovered	Injected
29/12/2016	9.53	1440	16.25	3082.8	190	173.	10	9.85	.78		42	0.6162	325	0
17/06/2017	9.53	600	1.19	91.59	77	35	14	2.55	.801		27	1.7068	0	0
28/06/2017	9	-	10.22	1095.9	107	149	23	4.59	.79		33	0.7609	0	0
05/07/2017	9	-	11.47	222.9	197	137.	25	--	.8		25	0.6243	0	0
07/08/2017	9	Vx29	9.98	1771.3	177	117.	15.4	--	.799		36.8	0.6148	0	0
09/10/2017	9	Vx29	9	1593.8	177	103.	13.8	--	.8		28	0.602	0	0
27/11/2017	9	-	10.65	1352.8	127	102.	18	17.34	.792		23	0.5023	0	0
12/12/2017	9	Vx29	10.33	1797.0	174	100.	18	--	.798		22	0.5081	0	0
12/02/2018	9	1440	6.16	1085.5	176	107.	14.4	4.28	.804		22	0.9085	0	0
02/03/2018	9	1440	8.84	1195.	135	93.8	17	17.13	.788		21	0.5536	0	0
07/06/2018	9	Vx29	7.94	1451.6	183	84.5	14.6	--	.803		25	0.5555	0	0
15/07/2018	9	600	8.22	155.7	183	83	14.8	4.28	.804		39	0.5273	0	0
27/07/2018	11	1440	11	15323	139	78.7	19.7	19.07	.787		48	0.5359	0	0
23/09/2018	11	-	8.17	116.7	143	73.1	20.7	--	.795		31	0.6702	0	0
19/10/2018	11	Vx29	7.86	126.1	161	69.6	19.8	--	.799		28	0.6631	0	0
04/11/2018	11	1440	9.84	1295.6	132	68.6	21.7	21.62	.786		26	0.5223	0	0
22/12/2018	11	1440	8.59	1246.4	145	63.1	18.7	18.66	.796		25	0.5505	0	0
29/12/2018	11	Vx29	8.69	1466.3	169	62.1	18.7	--	.806		17	0.5353	0	0
04/03/2019	11	1440	7.86	1120.5	143	59.2	20	19.85	.793		27	0.5638	0	0
05/07/2019	11	1440	7.89	108.6	138	57.7	17.6	17.1	.794		46	0.5484	0	0
10/09/2019	11	1440	7.41	1171.0	158	57.9	16	16.11	.782		39	0.5851	0	0
30/10/2019	9	600	5.54	1033.3	186	70.3	13.8	3.87	.8		26	0.6621	0	0
03/12/2019	10	1440	7.29	1114.1	153	65.7	14.7	14.54	.783		23	0.5687	0	0
13/02/2020	10	1440	7.03	996.52	142	64.3	15.5	15.78	.788		34	0.5771	0	0
12/03/2020	10	1440	7.47	1006.6	135	63.1	13.9	13.66	.782		23	0.5332	0	0
30/04/2020	10	1440	6.33	1253.0	198	60	9.6	3.71	.798		26	0.5977	0	0
01/06/2020	10	1440	6.5	1305.3	201	62.2	12.6	4.38	.801		31	0.6036	0	0
27/08/2020	10	1440	5.97	937.00	157	51.9	12.8	12.64	.788		37	0.5486	0	0
04/11/2020	10	1440	4.82	1340.4	278	44.4	10.6	2.85	.794		26	0.582	0	0
01/12/2020	10	1440	3.97	684.25	173	32.9	18.4	4.3	.794		24	0.5235	0	0
17/01/2021	10	1440	4.68	568.95	122	37.7	15.2	14.79	.814		21	0.5086	0	0
22/06/2021	10	1440	4.35	525.85	121	41.8	16.1	--	.794		28	0.6071	0	0
14/07/2021	10	1440	4.71	777.15	165	39	10	--	.793		34	0.5215	0	0
14/08/2021	14	1440	3.38	404.23	119	52.6	13	--	.786		42	1.7957	0	0
25/08/2021	10	1440	4.97	711.67	143	44.5	15.3	15.55	.78		42	0.5647	0	0
17/11/2021	10	1440	4.31	534.09	124	43.8	14.9	4.87	.796		36	0.6409	0	0
17/01/2022	10	1440	1.8	468.54	261	20	14.3	3.95	0.793		17	0.7024	40	0
27/02/2022	10	1440	2.56	134.08	52	22	12.3	11.85	.793		19	0.5411	400	0

III.3.5. Well intervention history

- 09/06/2017, CT Clean Out / Load well w/Treated water
- 13/06/2017, CT Clean Out / Load well w/Treated water
- 14/06/2017, CT Clean Out / Load well w/Treated water
- 15/06/2017, CT Clean Out / Load well w/Treated water
- 24/11/2017, CT Clean Out. **TAG TD @ 3508 m**
- 13/02/2018, CT Clean Out

- 13/02/2018, CT Clean Out with Reformat. **TAG TD @ 3508 m**
- 11/07/2018, CT Clean Out with Reformat (rig up & test)
- 24/10/2018, CT Clean Out with Reformat
- 26/12/2018, CT Clean Out with Reformat/Xylene. **TAG TD @ 3508 m**
- 20/08/2019, CT Reformat/Xylene Cleanout Day1 (rig up & test)
- 21/08/2019, CT Reformat/XyleneClean Out Day2
- 24/08/2019, CT cleanout with reformat.**TAG TD @ 3505 m**
- 18/10/2019, CT Clean Out Reformat/Xylene
- 10/08/2020, CT Clean Out Reformat/Xylene
- 21/08/2020, CT Clean Out with Reformat
- 15/10/2020, CT Clean Out with Naphtha/Xylene
- 11/11/2020, Snubbing Operation for cleaning utilizing Naphtha/Xylene
- 18/11/2020, Operation Wire Line: descent calibre 60, tag at 3505mCR, HS=03m. Descent calibre 71 mm tag at 3391mCC, at level LN X (+/- 114 m from bottom).
- 23/11/2020, CT Kick off after SNB
- 07/07/2021, CT Clean Out with Naphtha/Xylene.**TAG TD @ 3505 m**
- 10/08/2021, CT Clean Out with Naphtha/Xylene. **Hard Tag at 33m.** CT @ 3350m, Check Weight **Over pull (10-12k lb)** start pooh to release weight, CT @ 3300m **weight not released continue pumping naph/xyl** with pooh, **CT @ 2800m weight released and return to normal**, CP =2800psi WHP=200psi/gas, fluid pumped + heavy oil at flare. Stop operation due no more naph/xyl on location.
- 29/10/2021, CT Clean Out with Naphtha/Xylene.
- 26/12/2021, CT Clean Out with Reformat/Xylene. **TAG TD @ 3508 m.**
- 06/01/20222, CT Reformat/Xylene matrix treatment (**Tag TD @ 3508 m Q = 0.8 bpm @ CP = 4700 psi**).
- 12/01/2022, WL GrattageControle (**TS:3512mCC=33504mCR H.S=04m**)

Comment

According to the history of well intervention on HGANE2, it can be seen that it has undergone several cleaning treatments due to asphalten and salt deposit.After each treatment a significant increase in flow is observed but it is still not enough.

III.3.6. Sampling data

The main purpose of the sample process is to have a general idea on the nature of the deposits in each area of the well, first of all the deposit has been recovered at the bottom of the well, more specifically in the area of interest through a slick line, once the deposit was at the surface it was destined to the laboratory level of Hassi messoud for making the quantitative analysis using many methods: calcinations (by temperature rise) is one of them, the results of this step are showed in the table below (III.7)

Table III. 7: Sampling data

Data	Depth	Results
06/02/2018	/	**74%paraffins, 24%asphaltenes ,2%salts**
24/10/2019	**3509 m**	**97%salts (Nacl)**
14/08/2020	**3481 m**	**100%salts (Nacl)**
04/08/2021	**3475 m**	**98% remaining salt: fine sandstone formation with trace of oil**
12/08/2021	**3476 m**	**100%salts**

III.4. Results and discussion

- All samples show presence of salt (majority), as well in combination with asphaltens and formation fines.
- Several Clean Outs with Aromatic fluid are done in the well regularly to maintain the production; the Clean Out preformed showing positive results.
- The last stimulation job with Reformat/Xylene performed on 06/01/2022 showed negative result, and the well productivity remain low.
- According to the last production tests, the well has shown significant drop in the production rate. Water formation was observed during the last production (water salinity is 314 g/l & Oil salinity is 702 mg/l).
- As from production parameter analysis, the issue has more to do with water block than with organic and mineral deposits, and hence it is thought that formation water might have taken place in the nearby area leading to oil relative permeability decrease. It is therefore recommended to focus on water block issue and squeeze an alcoholic treated water as follow:

- **Day1:**

Intensive washing of the target interval using high pressure jetting tool. Wash with pumping reformat and treated water; unload spent treatment fluid with pumping nitrogen.

- **Day2:**

Continue with CT operation to stimulate the nearby area with alcoholic treated water, its composition is well defined in table (III.8).

- **Day3:**

Perform CT kick off until well able to flow naturally then evaluate the well. An alcoholic treated water matrix treatment was carried out in HGANE2 (oil producing well) to get rid of water block issue resulting from formation water coning in the near-wellbore area.

Table III. 8: Mixture composition to be adjusted by SERVICE COMPANY in case of fluid incompatibility during tests.

Alcoholic TW mixture (*)	
Fluid	**Concentration %**
Water	**66,5%**
NH_4Cl	**3,0%**
Methanol	**20,0%**
MutualSolvent	**10,0%**
Surfactant	**0,5%**

Note:

Treating the well with alcoholic TW allowed increasing the well productivity, the oil rate increased from 0 to 2.56 m^3/h (table III.9).

Table III. 9: Well data before and after treatment

Date Measurement	Diam. Duse (mm)	Sépar unit.	Flow rate (m^3/h)		GOR	Pressure (kg/cm^2)			Density		Oil Temp (°C)	K Psi	Water flow rate (l/h)		Observations
			Oil	Gas		Press. Tete	Press. Pipe	Press. Separ.	oil	Gas			Recovered	Injected	
14/08/2021	14	1440	3.38	404.23	119	52.6	13	--	.786		42	1.7957	0	0	-
25/08/2021	10	1440	4.97	711.67	143	44.5	15.3	15.55	.78		42	0.5647	0	0	-
17/11/2021	10	1440	4.31	534.09	124	43.8	14.9	4.87	.796		36	0.6409	0	0	-
17/01/2022	10	1440	1.8	468.54	261	20	14.3	3.95	.793		17	0.7024	40	0	-
The well has been closed since 22/01/2022 due to no productivity The well stimulated with Alcoholic Treated Water on 14/02/2022															
27/02/2022	10	1440	2.56	134.08	52	22	12.3	11.85	.793		19	0.5411	400	0	-

Note:

The water recovered (40 l/h) during the production test done on 17/01/2022 is a formation water (salinity = 314 g/l), however the last one (400 l/h on 27/02/2022) is a mixture of formation and injected water

III.5.Economical study

After the diverse experiences this study had, a rooted discussion on a financial and economic prospective is provided in this part. From the consequences of the problematic and the cost of the treatment. First and for most, the decrease of productivity indices of oil due to the phenomenon of water block during the exploitation of the deposit leads to a destabilization of the production system whose losses and gains can be evaluated by:

- Barrel Price: 119.45 Dollars (27 /05 /2022)
- production downtime :37 days
- minimum lost volume : 95,28m^3/ D

So for 37 days of loss we have:

$$95,28*37= 3525,36\ m^3 =3525,36 *10^3\ L$$

The lost quantities are:

$$\frac{3525,36 *103}{159,6} = 22088,7218 \text{ barils.}$$

From which the losses are:

$$22088,7218 *119,45 = 2638497,82 \text{ dollars.}$$

By a generalization of the gain obtained from the micro-models, we find that:

- Water block is limited to 5 days with a daily lost volume of 25,89m3/day. With the same reasoning we find that the losses are reduced to: 96884.7274
- This confirms the efficiency of treatment by surfactants.

Conclusion and recommendations

Conclusion

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

- Permeability is one of the main factors for evaluating the quality of any petroleum reservoir, causing the low permeability ones plenty of production problems.
- Water invasion which is a common occurrence in low permeability reservoirs results from excessive water production and reduces the economic life of the well, it happens when the fluid of the intervention operations executed in the productive wells interacts with the formation around the wellbore and creates the capillary end effect which is the source of the water block.
- The fluid-loss reduction during these operations contributes to water block control.
- After several jobs in the HGANE2 well for trapped water's recovery, only with alcoholic treated water stimulation (using co-surfactants), an increasement of 360(l/h) is determined.
- The reduction of capillary pressure is conditioned by the interfacial tension's decreasing, where this last could only be manipulated by the co-surfactants. Where the butanol (with 20% of concentration) got 30.31(Nm/m) of interfacial tension, the Propanol (with 60% of concentration) reaches 29.08, the EG of the same concentration with 133.69.
- Butanol, Propanol, and Ethylene glycol cause monolayer adsorption at any surface under the Langmuir adsorption isotherm model.
- Surfactants can change the wettability of the rock, where the butanol in particular can reverse it (from a water-wet formation to an oil-wet formation).
- The butanol is rating at the top of surfactant's efficiency in water recovery 72.575 (%) with only 20% of concentration.

Recommendation

From the above work we recommend the following:

- Additional laboratory experiments of water block modeling for a circular radial-flow study case.
- Since this study was made in ambient conditions, high recommendations on simulating reservoir pressure and temperature by numerical simulation models.
- Alcohols being water-solvents was an advantage in our water block remediation of ours. However, 'Multisolvants' is soluble in oil, water, and acid-based treatment fluids, a huge possibility of better results on the oil displacement.
- Focusing on the fluid-loss control methods while executing any intervention operations.
- Development of percolation model accounting for wettability, pore network topology, pore size distributions and imbibition for calculation of capillary pressure and relative permeability curves.
- Incorporation of nano-scale effects such as gas slip, Knudsen-diffusive flow and molecular interactions on the capillary curvature in the aforementioned models.
- Incorporation of rock compressibility into the aforementioned models.
- Profond study on determining the exact wettability rate, for avoiding the trappement of reservoir oil.

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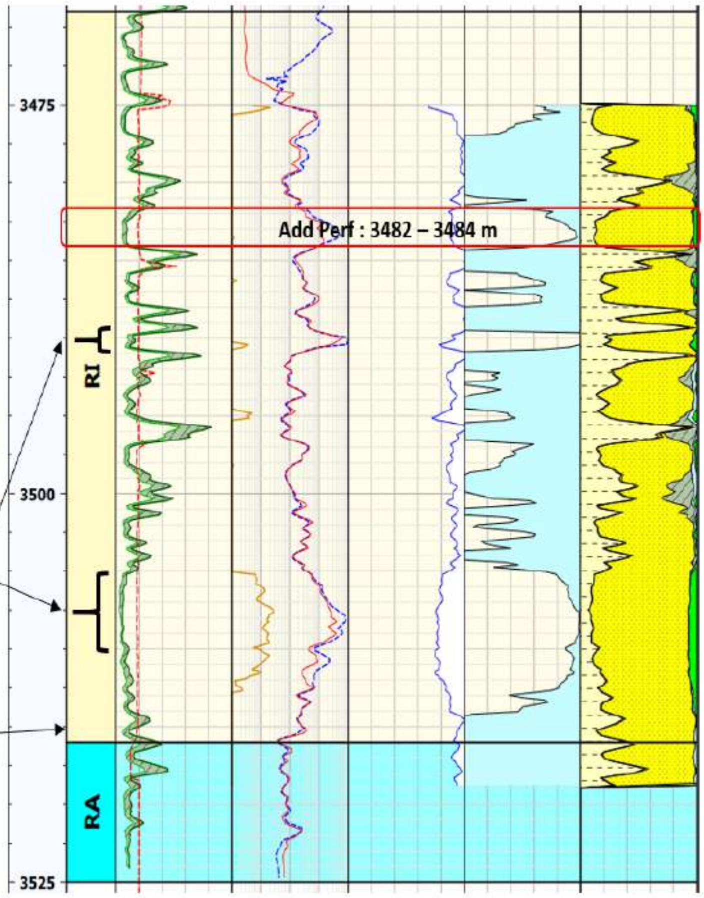
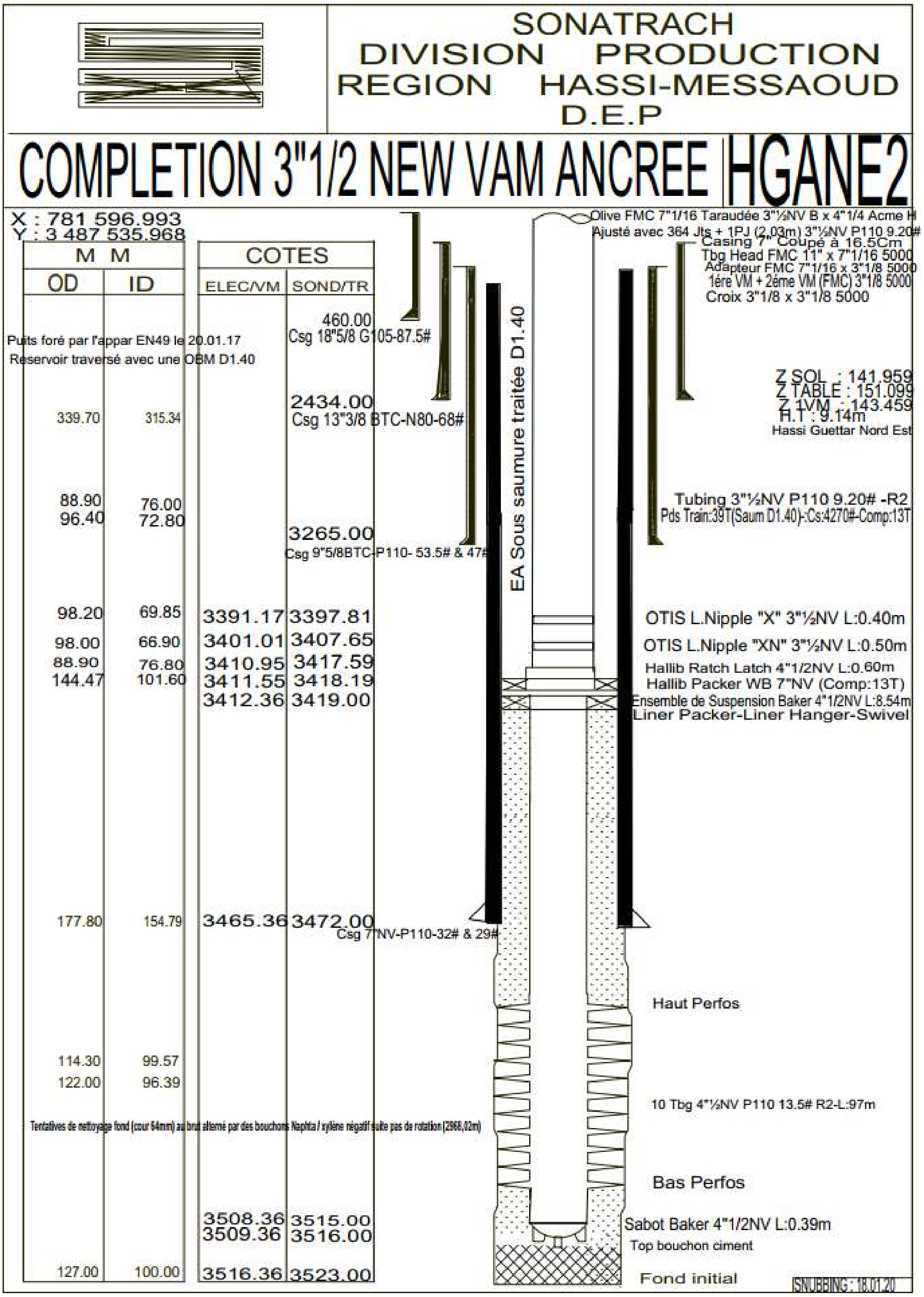
Annex

Annex A



Perforations	
RT	VM
3489.50 – 3490.50	3481,86 – 3482,86
3505.00 – 3510.00	3497,36 – 3502,36

Annex B


SONATRACH
DIVISION PRODUCTION
REGION HASSI-MESSAOUD
D.E.P
COMPLETION 3"1/2 NEW VAM ANCREE HGANE2
X : 781 596.993
Y : 3 487 535.968
M M
OD
ID
COTES
ELEC/VM
SOND/TR
Puits foré par l'appar EN49 le 20.01.17
Reservoir traversé avec une OBM D1.40
460.00
Csg 18"5/8 G105-87.5#
2434.00
Csg 13"3/8 BTC-N80-68#
339.70 315.34
88.90 76.00
96.40 72.80
3265.00
Csg 9"5/8BTC-P110- 53.5# & 47#
98.20 69.85 3391.17 3397.81
98.00 66.90 3401.01 3407.65
88.90 76.80 3410.95 3417.59
144.47 101.60 3411.55 3418.19
3412.36 3419.00
177.80 154.79 3465.36 3472.00
Csg 7"NV-P110-32# & 29#
114.30 99.57
122.00 96.39
3508.36 3515.00
3509.36 3516.00
127.00 100.00 3516.36 3523.00
EA Sous saumure traitée D1.40
Olive FMC 7"1/16 Taraudée 3"½NV B x 4"1/4 Acme H
Ajusté avec 364 Jts + 1PJ (2,03m) 3"½NV P110 9.20#
Casing 7" Coupé à 16.5Cm
Tbg Head FMC 11" x 7"1/16 5000
Adapteur FMC 7"1/16 x 3"1/8 5000
1ère VM + 2éme VM (FMC) 3"1/8 5000
Croix 3"1/8 x 3"1/8 5000
Z SOL : 141.959
Z TABLE : 151.099
Z 1VM : 143.459
H.T : 9.14m
Hassi Guettar Nord Est
Tubing 3"½NV P110 9.20# -R2
Pds Train:39T(Saum D1.40)-:Cs:4270#-Comp:13T
OTIS L.Nipple "X" 3"½NV L:0.40m
OTIS L.Nipple "XN" 3"½NV L:0.50m
Hallib Ratch Latch 4"1/2NV L:0.60m
Hallib Packer WB 7"NV (Comp:13T)
Ensemble de Suspension Baker 4"1/2NV L:8.54m
Liner Packer-Liner Hanger-Swivel
Haut Perfos
10 Tbg 4"½NV P110 13.5# R2-L:97m
Bas Perfos
Sabot Baker 4"1/2NV L:0.39m
Top bouchon ciment
Fond initial
SNUBBING : 18.01.20