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-THEME-

A study of Formation Damages Caused by Emulsions and Wettability Alteration during Drilling with Oil Based Mud.

Commission:

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Dedication

We dedicate this work to:

Our parents & Our Professors

Our brothers and sisters.

Our uncles and aunts.

The family OUCIEF & ZAIR.

The family SKAKIF & LAGUEB.

Petroleum Club Ouargla Family

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Our friends.

Hamza and Ibrahim.

Nomenclature

L600; L300: the respective readings at 600 rpm & 300 rpm on the FANN 35 Rheometer.

V: viscosity.

Va: apparent viscosity.

Vp: plastic viscosity.

OBM: Oil Based Mud.

WBM: Water Based Mud.

CMC: Critical Micelle Concentration.

HLB: Hydrophilic Lipophilic Balance.

O/W: Direct emulsion Oil in Water.

W/O: Invert emulsion Water in Oil.

Ø = porosity

S_f::saturation of the fluid, fraction or percent

V_f: total volume of fluid in reservoir or core sample, cm^3

V_p: total pore volume of reservoir or core sample, cm^3

S_w: water saturation

S_o: oil saturation

S_g: gas saturation

q: volumetric flow rate of the fluid through the medium, cm^3/s

k: permeability of the porous rock, Darcy

ΔP: difference in pressure between inlet and outlet of medium, atm

A: cross-sectional area of medium that is open to flow, cm^2

L: length of medium, cm

μ: viscosity of the flowing fluid, cp

K: Reservoir permeability, md

k_s: Permeability of altered zone, md

r_s: Outer radius of altered zone, ft

r_w: Wellbore radius, ft

PI: Productivity Index, STB/day/psi

q **:** Surface flow rate at standard conditions, STB/D

$\boldsymbol{pe}$**:** External boundary radius pressure, psi

$\boldsymbol{pwf}$**:** Well sand face Pressure, psi

h: Net thickness, ft

B: Formation volume factor, rb/STB

$\boldsymbol{re}$**:** External boundary radius, ft

S: Skin

Abstract

Summary

Formation damage is a serious problem in oil and gas industry. It causes many problems starting from reduction of the well productivity until the whole failure of the well. It is undesirable operational and economical problem that can occur during the various phases of oil and gas recovery from subsurface reservoirs including drilling, production, hydraulic fracturing, and workover operations.

Formation damage is one of the major problems in oil industry and still a fresh subject to search about.

The use of oil-based drilling fluid allows drilling of the producing layers by limiting damage but the non-compliance of the characteristics of the drilling muds may alters the petrophysical parameters of the reservoir rock. .

Key words: Drilling mud, Formation damage, Oil Based Mud (OBM), Water Based Mud (WBM), clogging, inversion of wettability, Tensioactif, Emulsion.

ملخص

يعد تضرر الطبقة الإنتاجية مشكلة خطيرة في صناعة النفط والغازو يتسبب في العديد من المشاكل بدءًا من تقليل إنتاجية البئر حتى فشل و يعد مشكلة تقنية واقتصادية غير مرغوب فيها يمكن أن تحدث أثناء المراحل المختلفة البئر بالكامل ، ويمكن أن يحدث بسبب العديد من العمليات لاسترداد النفط والغاز من الخزانات الجوفية بما في ذلك الحفر والإنتاج والتكسير الهيدروليكي وعمليات صيانة الآبارو أحد المشكلات الرئيسية في صناعة النفط ولا يعتبر موضوعًا جديدًا للبحث العلمي

يسمح استخدام سائل الحفر ذو أساس النفطي – زيتي– بحفر طبقات الإنتاج عن طريق الحد من الضرر يؤدي عدم امتثال خصائص طين الحفر إلى تغيير المعلمات الفيزيائية البتروفيزيائية لصخر المكمل

تؤدي الضغوط العالية ومحتويات المواد الصلبة المتبوعة بوقت التلامس الطويل لتشكيل طينة الحفر إلى تقليل نفاذية وانعكاس قابلية البلل للوسائط المسامية ، وهذا الأخير هو نتيجة اختيار مادة خافضة للتوتر السطحي غير متوافقة مع الصخور.

في هذا البحث ، تمت مناقشة الأسباب الميكانيكية والكيميائية وآليات تلف التكوين بشكل عام وتلف التكوين بسبب سوائل الحفر بشكل خاص ، بالإضافة إلى توضيح مؤشرات تلف التكوين مثل عامل الجلد وتقليل النفاذية.

يعد تجنب تلف التكوين أفضل بكثير من محاولة استعادته لأن استعادة ضرر التكوين قد يؤدي إلى ضرر إضافي للتكوين

Résumé

L’utilisation de fluide de forage à base d’huile permet de forer les couches productrices en limitant les endommagements. La non-conformité des caractéristiques des boues de forage altère les paramètres pétro physiques de la roche réservoir.

Une réduction de la perméabilité et une inversion de la mouillabilité du milieu poreux. Cette dernière est le résultat d’un choix de tensioactif non compatible avec la roche.

Les mots clés : boue de forage, endommagement, colmatage, inversion mouillabilité, altération mouillabilité, Tensioactif, Emulsion.

Introduction

Introduction

Contribution to Knowledge

The objective of this study is to experimentally analyze the reservoir damage process of the new drilled wells and work-over wells, which may have several origins such as the interaction of the drilling mud with formation fluids process.

A Micro-model Installation was previously built to facilitate the performance study which will be conducted on different acids for a purpose to determine this problem and remedy - solve - the well assumed to clogging phenomenon due to the drilling mud.

Recommendations will suggested for wells - acid stimulation operations -.

Problem Statement:

With the fall in the price of oil in recent years, several oil companies are lowering their exploration investments and focusing more on production activity. However, even during the exploitation of an oil field, several difficulties can be encountered, such as the case of damage which will be approached in our subject.

Damage can be found throughout the production chain, including: tank, well surroundings, perforations, production tubing and surface installation. They decline in production, resulting in considerable economic losses. In our project we are going to focus on the damage caused by drilling mud

In order to optimize production, the company tries to locate, identify, study and analyze this type of damage, then this will make it possible to find the appropriate solution, regardless of whether it is preventive or corrective.

Thesis Outline

In this context this thesis is comprised of the following chapters:

First chapter:

we defined the drilling fluids , their functions ,proprieties and types ,then we described the main mud products and we discussed the factors influencing the drilling fluid performance.

Second chapter:

We explained in details the fluid-rock interactions mainly, Tensioactifs, Emulsion and Wettability.

Third chapter:

In this part we discussed about the damage of the porous medium, started by the formation damage indicators then we named all the possible formation damage problems during various

well operations and the most common formation damage in the Hassi Messaoud field.
And for a better understanding the damage evaluation we went through chemical mechanisms of formation damage.
Finally we came to the heart of this study where we went deep in details about the formation damage during drilling and the Stimulation through matrix acidizing .

CHAPTER I:
Drilling fluids

CHAPTER I: Drilling fluids

I-1 Introduction:

The success of an oil and gas well drilling operation depends primarily on the properties of the drilling fluid (known as drilling mud).

It is the single component of the well-construction process that remains in contact with the wellbore throughout the entire drilling operation. Drilling-fluid systems are designed and formulated to perform efficiently under expected wellbore conditions.

The selection of the convenient mud to the specific characteristics of the traversed formations and to the geological conditions makes it possible to increase the performance of the drilling rigs and to avoid the damage of the producing layers, which will give a better productivity of the wells.

Advances in drilling-fluid technology have made it possible to implement a cost-effective, fit-for-purpose system for each interval in the well-construction process.

I-2 Definition:

The drilling fluid is a system composed of different combinations of two dispersed phases:

- A continuous phase: liquid (water, oil) and / or gaseous (air or natural gas).
- A solid phase: mineral and organic additives (clays, polymers, surfactants, cuttings, cements, etc. . .); **[1]**

I-3 functions of drilling fluid:

Basic Functions

Drilling fluids are formulated to carry out a wide range of functions. Although the list is long and varied, key performance characteristics are the following:

Controlling formation pressures: Drilling fluid is vital for maintaining control of a well. The mud is pumped down the drill string, through the bit, and back up the annulus. In open hole, hydrostatic pressure exerted by the mud column is used to offset increases in formation pressure that would otherwise force formation fluids into the borehole, possibly causing loss of well control. However, the pressure exerted by the drilling fluid must not exceed the fracture pressure of the rock itself; otherwise mud will escape into the formation a condition known as lost circulation.

Removing cuttings from the borehole: Circulating drilling fluid carries cuttings—rock fragments created by the bit—to the surface. Maintaining the fluid's ability to transport these solid pieces up the hole—its carrying capacity—is key to drilling efficiently and minimizing the potential for stuck pipe. To accomplish this, drilling fluid specialists work with the driller to carefully balance mud rheology and flow rate to adjust carrying capacity while avoiding high equivalent circulating density (ECD)—the actual mud density plus the pressure drop in the annulus above a given point in the borehole. Unchecked, high ECD may lead to lost circulation.

Cooling and lubricating the bit: As the drilling fluid passes through and around the rotating drilling assembly, it helps cool and lubricate the bit. Thermal energy is transferred to the drilling fluid, which carries the heat to the surface. In extremely hot drilling environments, heat exchangers may be used at the surface to cool the mud.

Transmitting hydraulic energy to the bit and downhole tools: Drilling fluid is discharged through nozzles at the face of the bit. The hydraulic energy released against the formation loosens and lifts cuttings away from the formation. This energy also powers downhole motors and other hard-ware that steer the bit and obtain drilling or formation data in real time. Data gathered downhole are frequently transmitted to the surface using mud pulse telemetry, a method that relies on pressure pulses through the mud column to send data to the surface.

Maintaining wellbore stability: The basic components of wellbore stability include regulating density, minimizing hydraulic erosion and controlling clays. Density is maintained by slightly overbalancing the weight of the mud column against formation pore pressure. Engineers minimize hydraulic erosion by balancing hole geometry against cleaning requirements, fluid carrying capacity and annular flow velocity. The process of clay control is complex. Clays in some formations expand in the presence of water, while others disperse. To some degree, these effects can be controlled by modifying the properties of the drilling fluid. Regardless of the approach used, controlling the fluid's effect on the formation helps control the borehole and the integrity of the cuttings and leads to a cleaner, more easily maintained drilling fluid.

Provide information about the wellbore /

Because drilling fluid is in constant contact with the wellbore, it reveals substantial information about the formations being drilled, and serves as a conduit for much data collected downhole by tools located on the drillstring and through wireline-logging operations performed when the drillstring is out of the hole. The drilling fluid’s ability to preserve the cuttings as they travel up the annulus directly affects the quality of analysis that can be performed on the cuttings. These cuttings serve as a primary indicator of the physical and chemical condition of the drilling fluid. An optimized drilling-fluid system that helps produce a stable, in-gauge wellbore can enhance the quality of the data transmitted by downhole measurement and logging tools as well as by wireline tools. **[2, 3]**

I-4 Drilling fluid properties:

I.4.1 Density:

It is the ratio of the weight per unit volume of an element to the weight per unit volume of a reference element under conditions which must be specified for both elements (water at 4 ° C for liquids and solids and air for gases). It is expressed as a dimensionless value. Density is an important parameter of drilling muds. It must be high enough so that the hydrostatic pressure exerted by the mud on the formations prevents the inflow of effluents and consequently the eruptions. But it must not exceed the resistance limit of the rocks so as not to fracture them and lead to circulation losses [4].

Figure (I-1): Drilling fluid balance used to measure fluid density. **[10]**

I.4.2 Viscosity:

I.4.2.1 Definition:

Viscosity is a measure of the drilling fluids internal resistance to flow,

It must ensure that it supports the walls, avoid landslides, mud loss, swelling of clay and keep the cuttings in suspension in the event of a sudden stop [5].

The flow properties of the mud depend on the depth of the hole and the annular viscosities. In the upper hole, water may be sufficient, but at greater depths more viscous fluids may be required. Deep wells, directional wells, high penetration rates, high mud weights, and high temperature gradients create conditions requiring close attention to the flow properties. The viscosity can be adjusted upward with polymers or clay material or adjusted downward with chemical thinners or water.

I.4.2.2 Types:

There are two types of viscosity that characterize drilling muds:

a) Apparent viscosity (VA): this is the total resistance to the flow of a plastic fluid, it is expressed in centi-poise and given by the following relation:

$$VA = L600/2 \text{ (cP)} \qquad \text{(I-1)}$$

b) Plastic viscosity (VP): for a fluid to flow, we tend to apply a force mainly to it. The internal frictions existing in this fluid are reflected by this plastic viscosity. The last one depends above all on the rate of solids contained in the sludge, the plastic viscosity is also linked to the size of the particles, and to their shape. It is expressed in centi-poise and given by the relation:

$$VP = L600 - L300 \text{ (cP)} \qquad \text{(I-2)}$$

L600 and L300 are the respective readings at 600 rpm and 300 rpm on the FANN 35 Rheometer.

Figure (I-2): Direct indicating viscometer (6 speed). **[6]**

I.4.3 Yield point:

Yield point is generally defined as the elastic limit at which a material will lose its elasticity and deform permanently. For drilling fluids, yield point refers to the resistance of initial flow

of the fluid or in other words, the stress required to start the movement of the fluid. It is a parameter of the Bingham plastic model.
The forces of attraction between the colloidal particles in the drilling fluid will prevent the fluid from flowing until the required stress is applied.

$$YP = L300 - VP = (VA - VP) \times 2 \ (lb/100ft2) \qquad \text{(I-3)}$$

I.4.4 Thixotropy:
The characteristic of a fluid, such as a drilling mud, to form a gelled structure which increases its rigidity gradually over time when it is left at rest and then to liquefy when agitated. This phenomenon is reversible and not instantaneous.
The viscosity of a thixotropic fluid changes with time under constant shear rate until reaching equilibrium.
Most drilling muds exhibit thixotropy, which is necessary for fast drilling,
efficient cuttings lifting and to support weighting material when mud flow stops. Gel strength measured at various time intervals indicates the relative thixotropy of a mud. Thixotropy is sometimes desirable to provide resistance to flowing, such as to avoid or reduce losses or flow into a weak formation. **[3, 8]**

I.4.5 Filtration and cake:
When the mud is in contact with a more or less permeable wall of the hole, the
Liquid part filters through the formation by depositing its solid part called "cake". In a well, we are dealing with two types of filtration: dynamic filtration which is produced when the fluid is circulating and the static filtration that occurs when the fluid is stationary and does not move. It is extremely important to know the parameters of filtration. Indeed, the high filtrates can disintegrate the delicate formations (clays, marls) and promote landslides. In addition, the deposited cake can be thick to the point of preventing passage of the tricone during tool change maneuvers [4].

Figure (I-3): API low-temperature, low-pressure filter press **[6].**

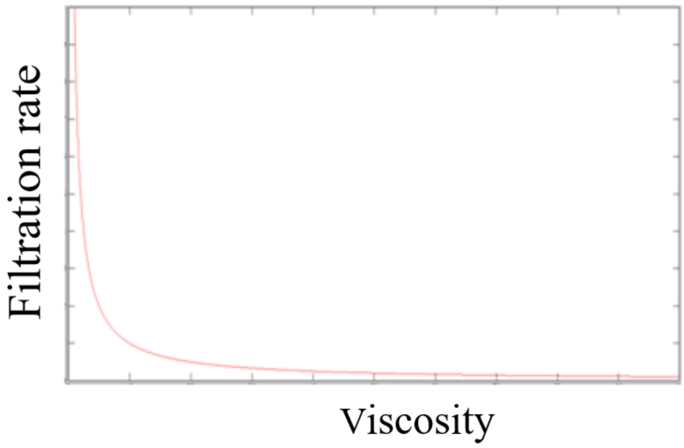


Figure (I-4): Variation of filtration rate as a function of viscosity. **[9].**

I.4.6 Concentration of solids, water and oil:

The Knowledge of the concentration of solids, water and oil is important in heavy mud and emulsified mud. To determine the percentages by volume of these different constituents, a sludge still is used [1].

$$\text{Solids}\,\% = 100\% - (\text{water}\,\% + \text{oil}\,\%) \qquad \text{(I-4)}$$

Low solids content is a stability factor for an inverse emulsion mud. An increase in the solids content can cause emulsion rupture.

A high solids content is a factor in increasing the density and viscosity of the mud.

I.4.7 Emulsion:

An emulsion is a mixture of two or more liquids that are normally immiscible (unmixable) owing to liquid-liquid phase separation.

Also it can be defined as an heterogeneous system consisting of the dispersion in the form of droplets of at least one liquid in another with which it is not miscible. The droplets constitute the dispersed phase in the other so-called continuous phase.

In emulsified mud, oil is dispersed in water. This is called a direct emulsion the opposite is the reverse emulsion where water is dispersed in the oil) **[4].**

Figure (I-5): Emulsion Stability Tester. **[10].**

I-5 Types of drilling fluids:

Many types of drilling fluids are used on a day-to-day basis. Some wells require that different types be used at different parts in the hole, or that some types be used in combination with others. The various types of fluid generally fall into a few broad categories based on the nature of the constituent of the continuous phase of these fluids We can thus distinguish three main families of drilling fluids

I.5.1 Air-gas drilling muds

These fluid systems are composed of air or natural gas mixed with water. They are commonly used in formations containing large amounts of water where there is high pressure **[11]**.

I.5.2 Water-based Mud (WBM)

Water-based mud is typically used to drill the upper sections of a well.

During drilling, the formation materials crossed become incorporated into the mud and can thus change its composition and properties. **[12]**

They are essentially as follows:

- Soft mud with a NaCl content not exceeding a few g / l. These are mainly formed by a colloidal suspension of clay, more precisely of sodium Bentonite in water, the concentration of which generally varies from 15 to 70 g / l depending on the bentonite efficiency and the desired mud characteristics.
- Salted mud whose NaCl content may be between a few tens of g / l to a saturation of (320 g / l). These drilling fluids are used for crossing salt areas to avoid the cavity appearing.

I.5.3 Oil-based mud (OBM)

I.5.3.1 Definition:

Oil-based mud (OBM): Oil-based mud is a mud where the base fluid is a petroleum product such as diesel fuel. Oil-based muds are used for many reasons, including increased lubricity, enhanced shale inhibition, and greater cleaning abilities with less viscosity. Oil-based muds also withstand greater heat without breaking down. The use of oil-based muds has special considerations, including cost, environmental considerations such as disposal of cuttings in an appropriate place, and the exploratory disadvantages of using oil-based mud. Using an oil-based mud interferes with the geochemical analysis of cuttings and cores and with the determination of API gravity because the base fluid cannot be distinguished from oil returned from the formation.

I.5.3.2 Types of oil-based mud.

There are two types of oil-based mud

a - Direct emulsion mud (O/W): where the continuous phase is oil and the dispersed phase is water with a low rate of 2 to 5% by volume.

b - Invert emulsion mud (W/O): in this case the continuous phase still oil but the percentage of water becomes from 5 to 50%. **[3]**

I.5.3.3 Oil-based mud advantages and disadvantages:

Oil-based muds were developed to prevent water from entering the pore spaces and causing formation damage. There are several advantages and disadvantages of this type of mud system.

a) Advantages of Oil-based mud:

- Shale inhibition: in highly smectitic or “gumbo” shales, the borehole maintains stability and cuttings samples are generally intact.

- Reduction of torque and drag problems: since oil is the continuous phase, the borehole and the tubulars are wetted with a lubricating fluid. This is a distinct advantage in deviated wellbores.
- Thermal stability: Oil-based muds have shown stability in wells, with BHTs of 585°F
- Resistance to chemical contamination: Carbonate, evaporite, and salt formations do not adversely affect the properties of an oil mud. CO2 and H2S can easily be removed with the addition of lime (CaCO3).

b) Disadvantages of Oil-based mud:

- High initial cost: the oil fraction alone of a barrel of oil mud may cost 40-70 USD per barrel. This is considerably higher than most water-based muds at any weight.
- Slow rates of penetration: Oil muds historically have had lower rates of penetration as compared to water-based muds.
- Pollution control: most areas where oil muds are used have environmental restrictions. Rig modifications may be necessary to contain possible spills, to clean up oil mud cuttings, and to handle whole mud without dumping.
- Disposal: Oil mud cuttings may have to be cleaned up before dumping. Some regulatory agencies require cuttings be sent to a designated disposal area.
- Kick detection: H2S, CO2 and CH4 are soluble in oil muds. If gas enters the wellbore, it can go into solution under pressure. As the gas moves up the wellbore, it can break out of solution at the bubble point and rapidly evacuate the hole, blowing the mud with it.
- Formation evaluation: some wireline logs should not be run in oil-based muds. Also, additional steps are needed to remove oil coatings from cuttings before they are described. **[12]**

I-6 Description of the main mud products:

a) Weighting agents: they are used to improve the density of the mud: barite or barium sulphate BaSO and calcium carbonate CaCO.

b) Fluidifying agents: the purpose of using these products is to reduce the viscosity of the mud, these products can be: long chain fatty acids, long radical nitrogenous

c) Plasticizers: These are products used to control the filtration and viscosity of the mud, these products can be: naphthenic acids, carbon black, sodium silicate, and essentially organophilic clays. The advantage of organophilic treatment is to give clay a greater affinity for organic media in order to improve the rheological properties of drilling fluids.

d) Slaked lime Ca (OH) 2: Slaked lime is used to increase the viscosity of a clay suspension (this leads to an increase in filtrate), thus as an activating agent for surfactants.

e) Viscosifiers: Bentonite, attapulgite, CMC and other polymers are used to increase viscosity and thus allow good suspension of solids.

f) Surfactants: these products are used to promote the formation and stability of a water-oil emulsion. They are used in the composition of most oil-based mud and differ depending on the type of mud used **[1, 4, 11, 14, 15].**

Here is this table which show various Products used in the preparation of drilling mud

N	Additives	N	Additives
1	Alkalinity controller	**9**	Lubricant
2	Bactericides	**10**	Deflocculant
3	Anti-calcium	**11**	Viscosifier
4	Defoamer	**12**	Weighting agents
5	Foaming agent	**13**	Corrosion inhibitor
6	Emulsifier	**14**	Filtrate reducer
7	Clogging	**15**	Aqueous base fluid (brine)
8	Flocculant	**16**	Oilseed based fluid

Table (I.1): Additives used in the formulation of drilling muds.

I-7 Factors influencing the drilling fluid performance:

- The change of drilling fluid viscosity.
- The change of drilling fluid density.
- The change of mud Ph.
- Corrosion or fatigue of the drill string.
- Thermal stability of the drilling fluid.

CHAPTER II:
Fluid –Rock Interaction
Tensioactif, Emulsion, Wettability

CHAPTER II: Fluid–Rock Interaction Tensioactif, Emulsion, Wettability

II-1 Surfactants

II.1.1 Definition

Surfactants are composed of amphiphilic molecules with a lipophilic side (affinity for oil) and a hydrophilic side (affinity for water) [16].

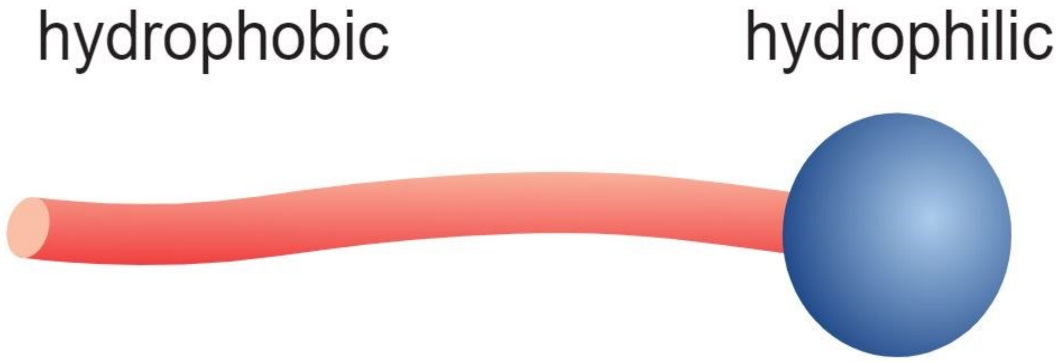


Figure (II-1): Schematic structure of a surfactant. **[17].**

A surfactant is a compound that changes the surface tension between two surfaces. The decrease in surface tension promotes the affinity of the two immiscible phases and the dispersion of one into the other **[18].** When surfactants are used to stabilize an emulsion, they are called emulsifiers. They position themselves so that their hydrophilic part establishes hydrogen bonds and ionic bonds with molecules of the hydrophilic phase, and their hydrophobic part establishes Van der Waals bonds with molecules of the lipophilic phase.

Surfactants are substances that create self-assembled molecular clusters called micelles in a solution (water or oil phase) and adsorb to the interface between a solution and a different phase (gases/solids) .

II.1.2 Types of surfactants: [17]

Surfactants can be classified according to the charge of their polar head group:

a) Anionic surfactants have a negatively charged head group.

b) Cationic surfactants have a positively charged head group.

c) Zwitterionic or amphoteric surfactants (negative charge in alkaline pH, positive charge in acidic pH, charged + and - in isoelectric medium).

d) Nonionic surfactants have an uncharged polar head group.

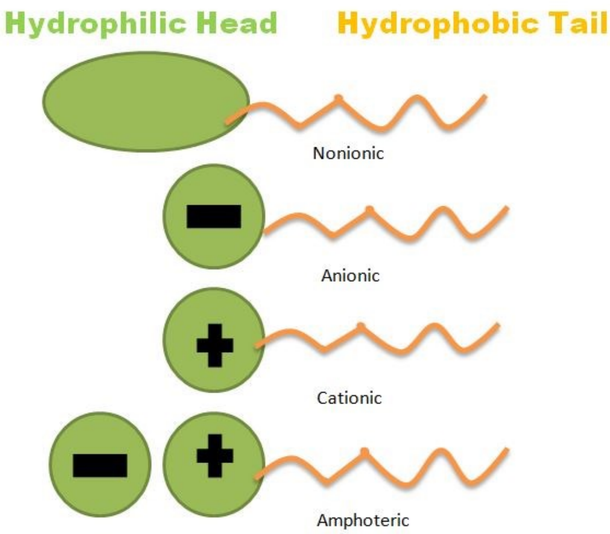


Figure (II-2): Schematic structure of surfactants' types **[17].**

II.1.3 Properties of surfactants:

II.1.3.1 Adsorption at interfaces:

Adsorption is a surface phenomenon which comes from the non-compensation in all directions of intermolecular attractions at interfaces. This results in inward-directed residual forces, which are attenuated when amphiphilic entities attach to the surface **[19].**

II.1.3.2 Elasticity:

The first of the properties conferred by the adsorbed surfactant monolayer is elasticity, which means the ability to regain its initial area after stretching (Gibbs-Marangoni effect) **[20]**.

II.1.3.3 Deformation of the interfacial film:

The second essential property is related to the deformation by curvature of the interfacial film. Due to the existing molecular interactions (and which are generally not strictly equal) on either side of the film with each of the two phases present, the interface can assume a spontaneous curvature, more easily observed in liquid-liquid systems. **[20]**.

Several works have been carried out testing the strength of this film, in order to determine its exact properties. This film can be broken by chemical means or by the action of an electric field **[21]**.

II.1.3.4 The Critical micelle concentration (CMC): The critical micelle concentration CMC is the surfactant concentration at and above which micelles are formed. It can be determined for surfactant solutions by measuring the surface tension at different concentrations. Below the CMC the surface tension decreases with increasing surfactant concentration as the number of surfactants at the interface increases. Above the CMC, in contrast, the surface tension of the solution is constant because the interfacial surfactant concentration does not change any more. In a logarithmic representation of the surface tension versus the surfactant concentration there are two linear regimes below and above the CMC (see Figure I.9). An extrapolation of respective regression lines yields the CMC at the intersection [**17**]

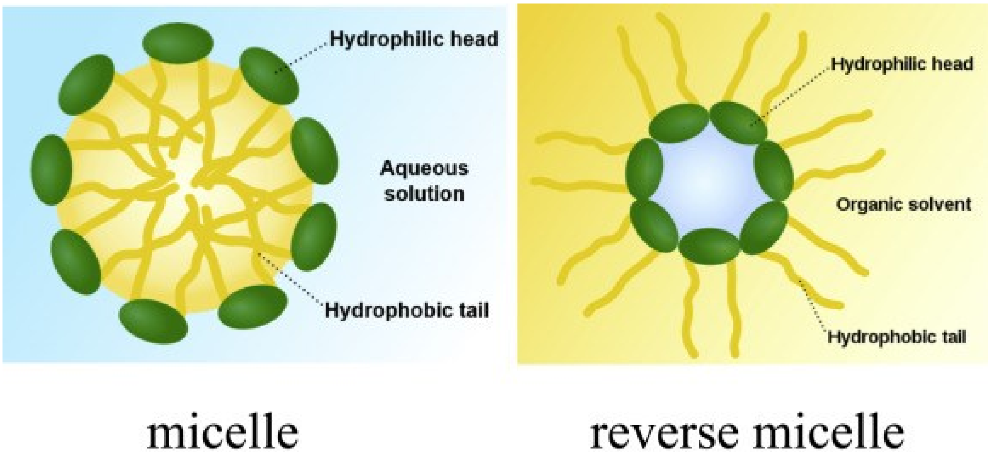


Figure (II-3) Schematic structure of a reverse and normal micelle **[22]**

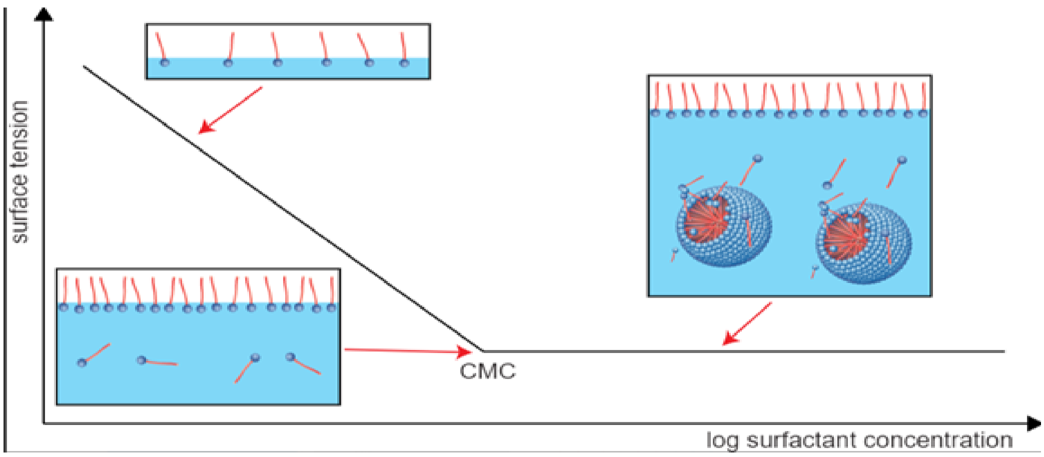


Figure (II-4) Surface tension as a function of the surfactant concentration **[17]**

II.1.3.5 Concept of HLB and its determination (hydrophilic-lipophilic balance): This system consists of assigning each surfactant a value illustrating its hydrophilic-lipophilic balance. The HLB ranges from 0 to 20, with 0 being assigned to a fully lipophilic product and

20 to a fully hydrophilic product. Knowing this HLB value of each surfactant is very important because:

- The various applied characteristics of surfactants (including their solubility in water) correspond to given values of the HLB.

- < 10 : Lipid-soluble (water-insoluble)
- > 10 : Water-soluble (lipid-insoluble)
- 1 to 3: anti-foaming agent
- 3 to 6: W/O (water in oil) emulsifier
- 7 to 9: wetting and spreading agent
- 13 to 16: detergent
- 8 to 16: O/W (oil in water) emulsifier
- 16 to 18: solubiliser or hydrotrope **[23]**

Propriété de l'agent tensioactif	HLB_{min}	HLB_{max}
Antimoussant	1,5	3
Emulsifiant eau dans l'huile	3	6
Mouillant	7	9
Emulsifiant huile dans l'eau	8	13
Détergent	13	15
Solubilisant	15	20

Figure (II-5): HLB scale showing classification of surfactant function. **[23]**

II.1.4 Roles of surfactants: [24]

II.1.4.1 Wetting: Surfactants allow the solution to adhere to a surface by reducing the surface tension and the liquid / solid contact angle, this property makes it possible to increase the liquid / solid contact surface.

II.1.4.2 Dispersing: it is the surfactant property to keep solid particles in suspension in a liquid. As an effect, the dispersion creates the mixture of two immiscible phases and one elements get distributed into fine particles within the other.

II.1.4.3 Emulsifying: The surfactant allows the droplets of one of the two immiscible liquids to remain dispersed within the other, by being disposed at the droplet / surrounding liquid interface. Each droplet surrounded by surfactant forms a micelle.

II.1.4.4 Solubilizing: Beyond the CMC. Surfactants, by forming micelles, allow the solubilization of some organic material, naturally insoluble in water (oil, hydrocarbon).

II.1.4.5 Foaming: The formation of foam, the dispersion of a large volume of gas in a small volume of liquid, requires the presence of surfactants which gets adsorb at the water-air interface.

I1-2 Emulsions:

II.2.1 Definition:

The emulsion is a heterogeneous system with two or more liquid phases, continuous and at least a second liquid, dispersed in the first in the form of fine globules. The emulsions come in various forms depending on the particle size of the liquid dispersed in the continuous phase **[25]**. In summary, the emulsion consists of:

- An external phase: Continuous.
- An internal phase: Dispersed.

II.2.2 Types:

Two emulsion types are used as muds:

(1) oil-in-water (or direct) emulsion, known as an "emulsion mud"

(2) water-in-oil (or invert) emulsion, known as an "invert emulsion mud"

The former is classified as a water-base mud and the latter as an oil-base mud.

Note: The transformation of an OW emulsion to a WO emulsion is possible by changing the two liquid phases' volume ratio (inversion).

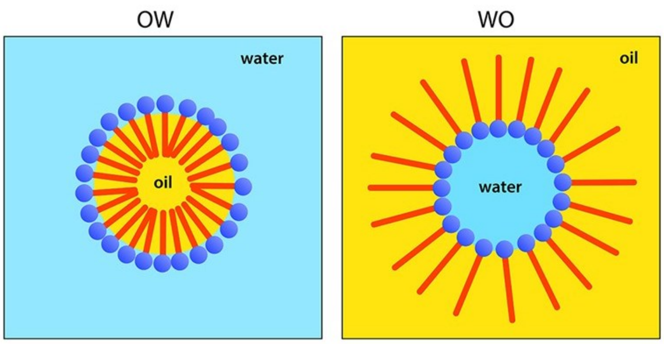


Figure (II-6) Schematic structure of WO and OW emulsions. **[25]**

II.2.3 Stability of an emulsion:

A liquid-liquid dispersion system is only classified as an emulsion if it has a certain stability. The stability of a system is achieved through adding emulsifying agents.

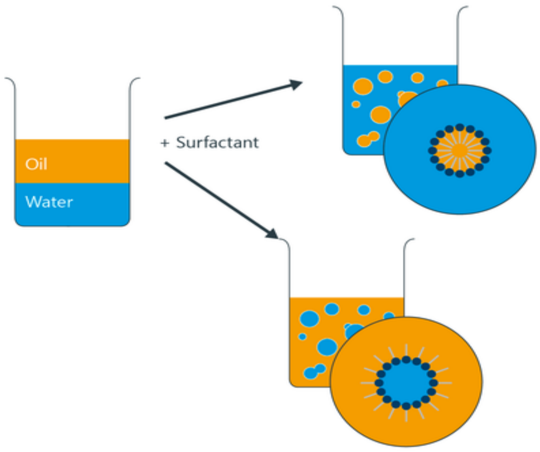


Figure (II-7) Formation of emulsions from oil and water after the addition of surfactants**. [26]**

It is measured by the speed of separation of the two liquids by forming two separate masses. **[27]**

According to the theory of emulsification, this stability is conditioned by:

1- Low interfacial tension.

2- The existence of a thick interfacial film.

The film envelops each dispersed drop and maintain it in suspension while

The lowering of the interfacial tension enhances the absorption of emulsifying agents at the surface thereby the miscibility of the two liquids **[28]**.

II.2.4 Oil-Mud emulsifier:

A chemical used in preparation and maintenance of an oil- or synthetic-base drilling fluid that forms a water-in-oil emulsion (invert emulsion). An oil-mud emulsifier lowers the interfacial tension between oil and water, which allows stable emulsions with small drops to be formed. Historically, oil-mud emulsifiers have been classified as primary and secondary. Secondary emulsifiers are generally not used alone to make a stable oil mud. Emulsifiers can be calcium fatty-acid soaps made from various fatty acids and lime, or derivatives such as amides, amines, amidoamines and imidazolines made by reactions of fatty acids and various ethanolamine compounds. These emulsifiers surround water droplets, like an encapsulating film, with the fatty acid component extending into the oil phase.

Emulsifier molecules that cannot fit around drops form clusters (micelles) in the oil phase or adsorb onto solids. Oil-mud emulsion drops each behave like a small osmotic cell. The emulsifier around the drops acts like a semipermeable membrane through which water can move but ions cannot pass. Thus, oil muds have the special capability (which water muds do not have) to control water transfer to and from the drops simply by adjusting salinity within the water phase of the oil mud. **[29, 30]**

II.2.5 How does an emulsifier work?

The emulsifier or the surfactant is positioned in the emulsion at the water-oil interface of such that its hydrophobic chain immerses in oil and its hydrophilic group turns towards the water and maintains this position with some force **[27]**.

The measure of the relative strength of the hydrophilic and lipophilic (hydrophobic) part is characterized by an empirical number called: Hydrophilic Lipophilic Balance (HLB).

This number is related to the chemical nature of the emulsifier as each group has its own value.

Exp:

Lipophobic group - SO_4 Na: 38.7

Lipophilic group - CH_3: 0.475.

- The value of HLB indicates the nature of the emulsion (W/O or O/W).
- High HLB gives an oil-in-water emulsion '
- A low HLB gives a water-in-oil emulsion '

The nature of the emulsifiers is inversely linked to the type of the emulsion, which means in an oil-in-water emulsion the emulsifiers are more hydrophilic than hypophilic, or the more lipophilic compounds tend to promote the water emulsion in oil.

II-3 Wettability:

II.3.1 Introduction to wettability:

II.3.1.1 Flow characteristic in porous media:

The porous media has a structure composed of a solid matrix considered continuous and a pores' network. The flows taking place there can be monophasic or polyphasic. These flows are therefore governed by adhesive forces (solid-fluid interface) and cohesive forces (fluid-fluid interfaces). In the case of polyphasic flow, the presence of each phase in the porous medium is characterized by its saturation and the flow of each phase is characterized by its relative permeability. The interactions at interfaces between phases are characterized by interfacial tensions, capillary pressures and wetting **[31]**.

a) Porosity: [32]

The porosity of a rock is a measure of the storage capacity (pore volume) that is capable of holding fluids. Quantitatively, the porosity is the ratio of the pore volume to the total volume (bulk volume). This important rock property is determined mathematically by the following generalized relationship:

$$\emptyset = (Pore\ Volume) \ / \ (Bulk\ Volume) \qquad \text{(I-5)}$$

Where Ø = porosity

As the sediments were deposited and the rocks were being formed during past geological times, some void spaces that developed became isolated from the other void spaces by excessive cementation. Thus, many of the void spaces are interconnected while some of the pore spaces are completely isolated. This leads to two distinct types of porosity, namely:

- Absolute porosity
- Effective porosity

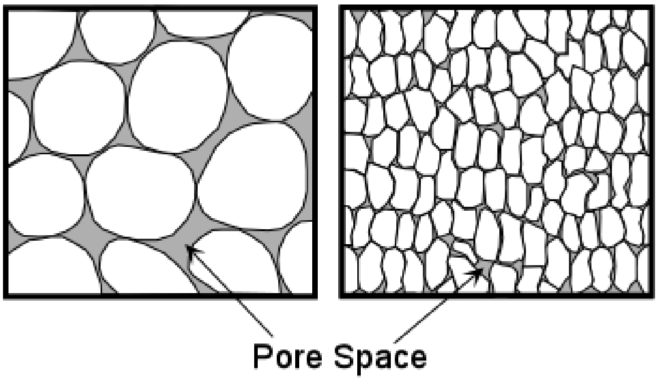


Figure (II-8): Schematic structure of the porous media. **[33].**

b) Saturation: [34]

The pore space of a petroleum reservoir is never filled completely with hydrocarbons; water is always present in the liquid state, and the hydrocarbons can exist in one or more states – gas, solid or liquid. The saturation of a given fluid is defined as the fraction of the pore space occupied by that fluid. In equation form:

$$\mathrm{Sf} = \mathrm{Vf/Vp} \qquad \text{(I-6)}$$

Where:

S_f:saturation of the fluid, fraction or percent

V_f: total volume of fluid in reservoir or core sample, cm^3

V_p: total pore volume of reservoir or core sample, cm^3

The sum of all fluid saturations in a reservoir is obviously equal to unity

$$1 = S_w + S_o + S_g \qquad \text{(I-7)}$$

Where:

S_w: water saturation

S_o: oil saturation

S_g: gas saturation

Knowledge of the average saturation of a fluid, say oil, in a reservoir allows the reservoir engineer to estimate the total volume of the fluid in the reservoir simply through application of Equ. I.6. this is the prime utility of saturation. Another, equally important utility, is how some fluid-dependent rock properties vary with saturation.

The saturation of a fluid in a reservoir seldom remains constant. Water can enter the reservoir either naturally - from an adjacent aquifer - or artificially by water injection. Oil saturation decreases with oil production and the replacement of oil by another fluid such as water. Gas saturation could increase with gas injection into the reservoir or as gas evolves naturally from the oil when the pressure drops. The saturations of the different fluids in a reservoir are, therefore, measured periodically employing direct and indirect methods.

c) Permeability: [32, 34]

Definition:

Permeability is a property of the porous medium that measures the capacity and ability of the formation to transmit fluids. The rock permeability, k, is a very important rock property because it controls the directional movement and the flow rate of the reservoir fluids in the formation.

This rock characterization was first defined mathematically by **Henry Darcy** in 1856. In fact, the equation that defines permeability in terms of measurable quantities is called **Darcy's Law.**

Darcy developed a fluid flow equation that has since become one of the standard mathematical tools of the petroleum engineer. If a horizontal linear flow of an incompressible fluid is established through a core sample of length L and a cross-section of area A, then the governing fluid flow equation is defined as:

$$q = k\ \frac{A}{\mu}\frac{\Delta P}{L} \qquad \text{(I-8)}$$

q: volumetric flow rate of the fluid through the medium, cm^3/s

k = permeability of the porous rock, Darcy

ΔP: difference in pressure between inlet and outlet of medium, atm

A: cross-sectional area of medium that is open to flow, cm^2

L: length of medium, cm

μ = viscosity of the flowing fluid, cp

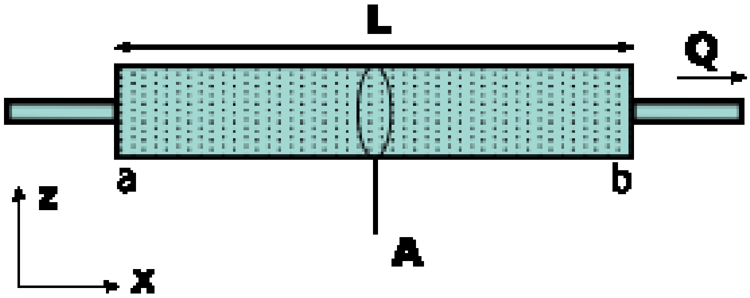


Figure (II-9): Diagram showing definitions and directions for Darcy's law **[35]**

Limitations of Darcy's Law: [36]

Darcy's law can be applied to many situations but do not correspond to these assumptions:

- Unsaturated and Saturated flow.
- Flow in fractured rocks and granular media.
- Transient flow and steady-state flow.
- Flow in aquitards and aquifers.
- Flow in Homogeneous and heterogeneous systems.

II.3.1.2 Capillary phenomena: Fluid-rock interaction:

The study of fluid-rock interaction is of fundamental importance to reservoir engineering. Not only does such interaction influence fluid flow through the reservoir, it also plays a dominant role in the distribution of fluids within the reservoir's pore space and, more importantly, it dictates the maximum amount of a fluid that can be withdrawn from the reservoir.

a) Surface and Interfacial tension:

In dealing with multiphase systems, it is necessary to consider the effect of the forces at the interface when two immiscible fluids are in contact. When these two fluids are liquid and gas, the term surface tension is used to describe the forces acting on the interface. When the interface is between two liquids, the acting forces are called interfacial tension. Surfaces of liquids are usually blanketed with what acts as a thin film. Although this apparent film possesses little strength, it nevertheless acts like a thin membrane and resists being broken. This is believed to be caused by attraction between molecules within a given system. All molecules are attracted one to the other in proportion to the product of their masses and inversely as the squares of the distance between them. **[32]**

Note: the surface tension of a water-hydrocarbon system varies from approximately 72 dynes/cm for water/gas systems to 20 to 40 dynes/cm for water/oil systems at atmospheric conditions. **[37]**

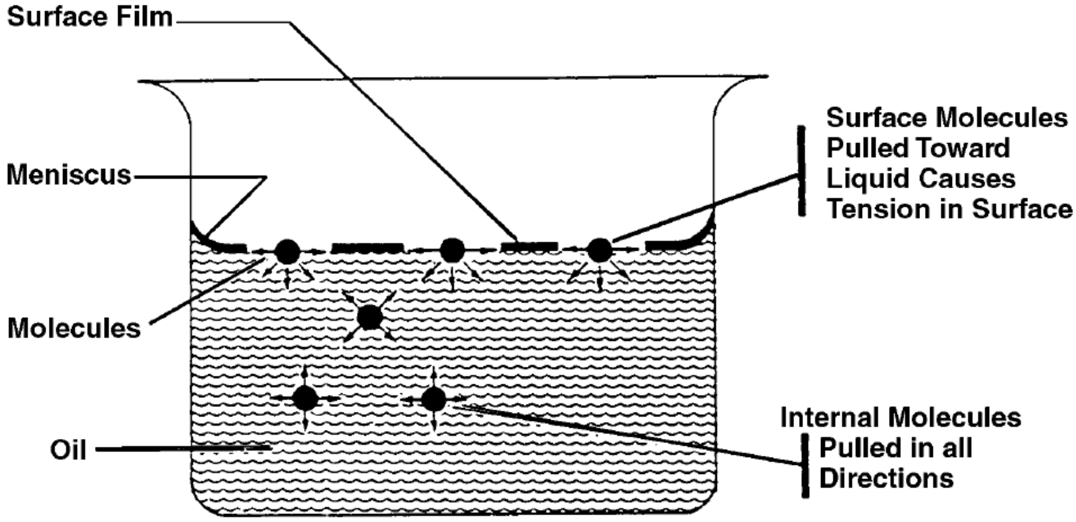


Figure (II-10): Illustration of surface tension. **[38]**

b) Capillary pressure: [39]

Capillary pressure is the difference in pressure between two immiscible fluids across a curved interface at equilibrium. Curvature of the interface is the consequence of preferential wetting of the capillary walls by one of the phases. Figure I.16 illustrates various wetting conditions. In Figure I.16 a, two immiscible fluids are shown in contact with a capillary. The water wets the walls of the capillary, but the oil is non-wetting and is resting on a thin film of the wetting fluid. The pressure within the non-wetting fluid is greater than the pressure in the wetting fluid and, consequently, the interface between the fluids is curved convex with respect to the non-wetting fluid. The capillary pressure is defined as the pressure difference between the non-wetting and wetting phases:

$$P_c = P_{nw} - P_w \qquad \text{(I-8)}$$

In Figure I.16b, the two fluids wet the walls of the capillary to the same extent, and the pressure of each fluid is the same. Therefore, the interface between the immiscible fluids is straight across (-90") and the capillary pressure is equal to zero. If the pressure in the water is greater than in the oil, the curvature of the interface is directed into the oil and the capillary pressure is positive (Figure I.16).

The radii of curvature between water and oil in the pores of the rock are functions of wettability, saturations of water and oil, pore geometry, mineralogy of the pore walls, and the saturation history of the system.

Therefore, the radii of curvature and contact angle vary from one pore to another, and the average macroscopic properties of the rock sample apply

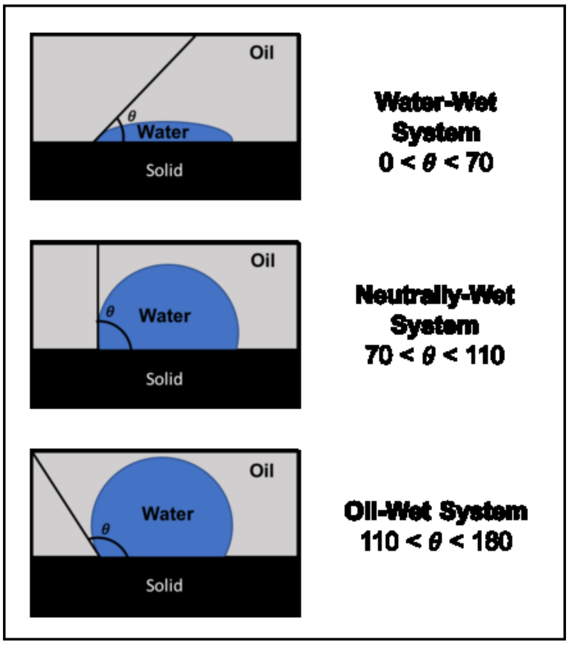


Figure (II-11): Various wetting conditions that may exist for water and oil in contact in a capillary, using the contact angle method.

Due to interfacial tension (IFT), the fluid experiences the force Capillary Pressure through the narrow capillaries of a porous medium and rises up or down from the free fluid level. In Figure I.17, the left side of figure shows water rising above the Free Water Level (FWL) differently in capillary tubes of different diameters, whereas the right side of the figure shows the same phenomena in a porous medium with different pore sizes. **[41**

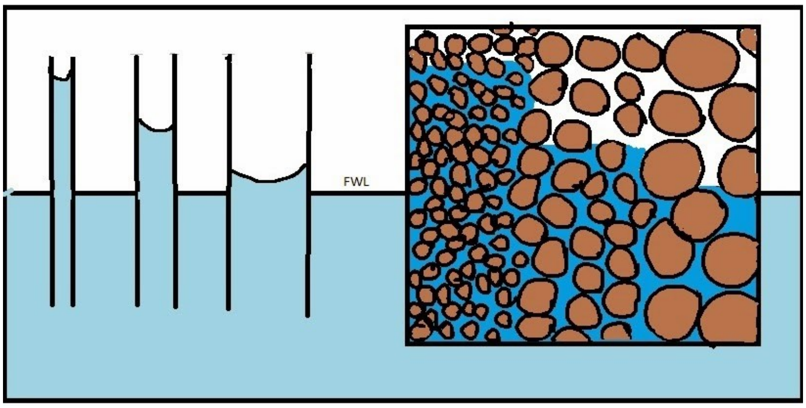


Figure (II-12): Schematic structure of Capillary Pressure in the narrow capillaries of a porous medium **[41]**

Capillary Pressure is often observed in oil-water hydrocarbon system with a varied thickness of a "Transition Zone". In some situations, the entire reserve may be within the "Transition Zone". **[41]**

Capillary pressure equation: [37]

With Laplace's equation, the capillary pressure Pcow between adjacent oil and water phases can be related to the principal radii of curvature R1 and R2 of the shared interface and the interfacial tension σow for the oil/water interface:

$$P_{cow} = p_o - p_w = \sigma_{ow}\left(\frac{1}{R_1} + \frac{1}{R_2}\right). \qquad \text{(I-8)}$$

c) **Wettability:**

Understanding formation wettability is crucial for optimizing oil recovery. The oil versus-water wetting preference influences many aspects of reservoir performance, particularly in water flooding and enhanced oil recovery techniques. Making the assumption that a reservoir is water-wet, when it is not, can lead to irreversible reservoir damage.

Definition:

Wettability is defined as the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids. The concept of wettability is illustrated in Figure I-18. Small drops of three liquids— mercury, oil, and water—are placed on a clean glass plate. The three droplets are then observed from one side as illustrated in Figure I-18.

It is noted that the mercury retains a spherical shape, the oil droplet develops an approximately hemispherical shape, but the water tends to spread over the glass surface.

The tendency of a liquid to spread over the surface of a solid is an indication of the wetting characteristics of the liquid for the solid. This spreading tendency can be expressed more conveniently by measuring the angle of contact at the liquid-solid surface. This angle, which is always measured through the liquid to the solid, is called the contact angle θ

The contact angle θ has achieved significance as a measure of wettability.

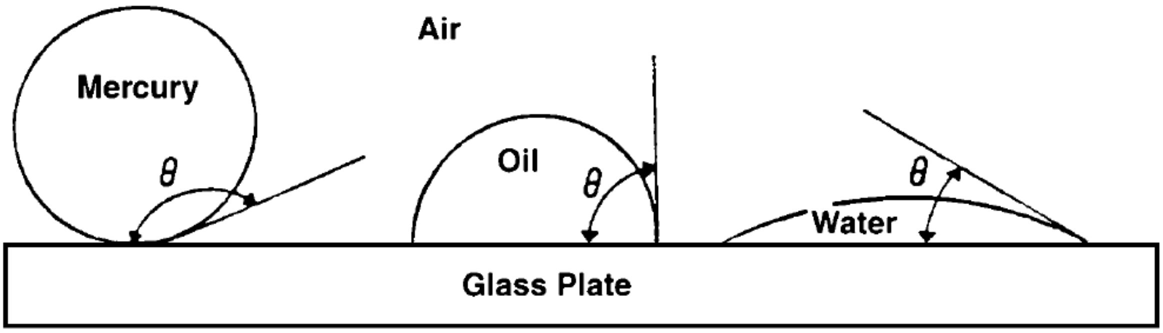


Figure (II-13): Illustration of wettability **[32]**

As shown in Figure I-18, as the contact angle decreases, the wetting characteristics of the liquid increase. Complete wettability would be evidenced by a zero contact angle, and complete non-wetting would be evidenced by a contact angle of 180°. There have been various definitions of intermediate wettability but, in much of the published literature, contact angles of 60° to 90° will tend to repel the liquid.

The wettability of reservoir rocks to the fluids is important in that the distribution of the fluids in the porous media is a function of wettability.

Because of the attractive forces, the wetting phase tends to occupy the smaller pores of the rock and the nonwetting phase occupies the more open channels.

Imbibition and drainage [42]

Imbibition: is a fluid flow process in which the saturation of the wetting phase increases and the nonwetting phase saturation decreases. (e.g., waterflood of an oil reservoir that is water-wet). Mobility of wetting phase increases as wetting phase saturation increases. Mobility is the fraction of total flow capacity for a particular phase

If a water-wet rock saturated with oil is placed in water, it will imbibe water into the smallest pores, displacing oil. If an oil-wet rock saturated with water is placed in oil, it will imbibe oil into the smallest pores, displacing water.

Drainage: is a fluid flow process in which the saturation of the nonwetting phase increases. Mobility of nonwetting fluid phase increases as nonwetting phase saturation increases e.g., waterflood of an oil reservoir that is oil wet Gas injection in an oil or water wet reservoir. Pressure maintenance or gas cycling by gas injection in a retrograde condensate reservoir. A water-wet reservoir that accumulation of oil or gas in a trap does so by drainage.

Primary and waterflood oil recovery is affected by the wettability of the system. A water-wet system will exhibit greater primary oil recovery.

II.3.2 The wettability of the reservoir rock:

II.3.2.1 Types:

Wettability is classified by its variations: **[42]**

1) Strongly oil or water wetting. (See figure I.19)

2) Neutral wettability – no preferential wettability to either water or oil in the pores.

3) Fractional wettability – reservoir that has local areas that are strongly oil-wet, whereas most of the reservoir is strongly water-wet - occurs where reservoir rock has variable mineral composition and surface chemistry.

4) Mixed wettability – smaller pores are water wet and filled with water, whereas larger pores are oil wet and filled with oil. Residual oil saturation is low - occurs where oil with polar organic compounds invades a water-wet rock saturated with brine.

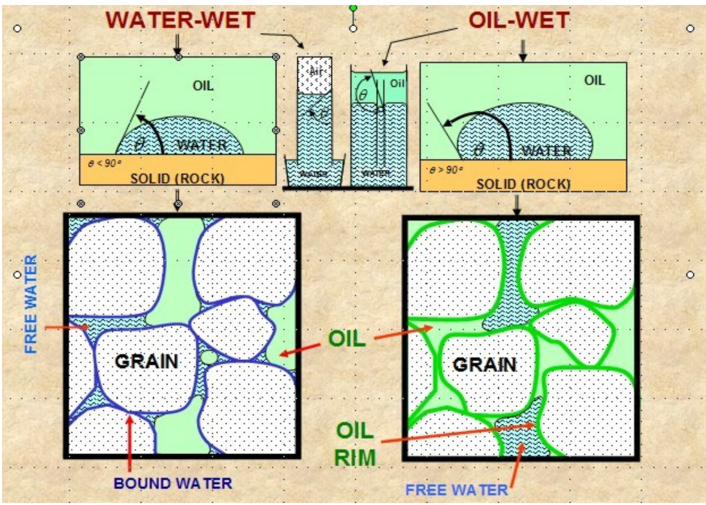


Figure (II-14): Comparison of water wet and oil wet rocks **[42]**

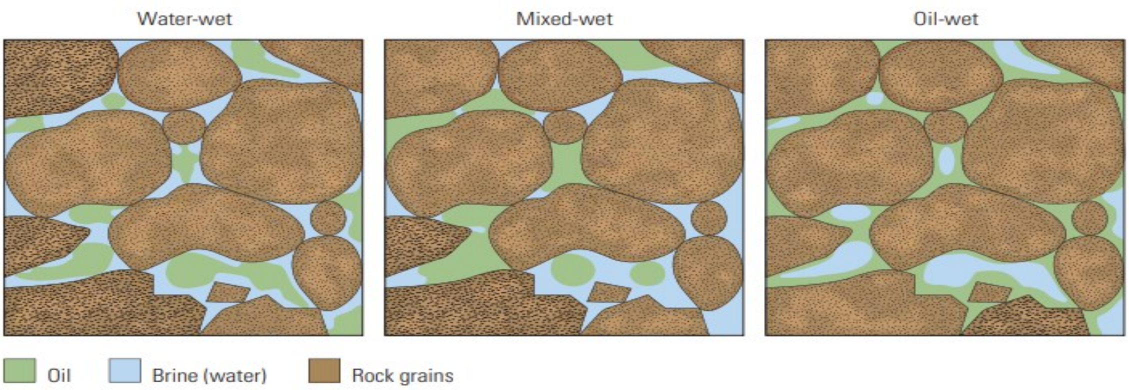


Figure (II-15): Characterization of the wettability of a solid surface **[43]**

Note: wetting in pores. In a water-wet case (left), oil remains in the center of the pores. The reverse condition holds if all surfaces are oil-wet (right). In the mixed-wet case, oil has displaced water from some of the surfaces, but is still in the centers of water-wet pores (middle). The three conditions shown have similar saturations of water and oil. **[43]**

II.3.2.2 Wettability alteration: [31, 44]

Reservoir rocks are originally highly wettable to water however their wettability gets altered during the migration of hydrocarbons and their aging. The degree of this alteration will depend on:

a) Crude oil and its polar components:

Crude oil is consists of four families of components: saturated hydrocarbons, aromatics, resins and asphaltenes. Asphaltenes constitute the most polar and heaviest fraction of crudes. They are responsible for the wettability alteration in petroleum reservoirs, due to their ability to flocculate and to be adsorbed on mineral surfaces.

b) The mineralogy of the solid surface:

The mineralogical composition of the solid surfaces of the porous medium is of a crucial importance in the process of ionic exchange and absorption of fluids on them.

All limestone rocks show a very wettable character in oil after alteration of crude oil wettability, while sandstones of reservoirs are more or less than intermediate wettability under the same alteration conditions.

c) Temperature and pressure conditions:

The pressure plays an important role on the stability of the aqueous films, these last are controlled by the pressure at the oil / brine and brine / mineral interfaces. The continuity of the aqueous film therefore depends on this pressure and can be broken thus allowing the compounds of the crude oil to come into direct contact with the surface of the pore and also to adsorb more easily and to alter the wettability.

Several studies have shown that the solubility of asphaltenes increases with temperature. It plays a role in the kinetics of adsorption of asphaltenes to minerals. Other studies have shown that increasing the temperature promotes wettability alteration towards oil wettability.

d) Aging time of fluids in the reservoir:

Morrow et al. (1998) demonstrated the evolution of the wettability alteration as function of time. The authors observed a recovery of oil from spontaneous brine imbibition which decreased with longer aging times. Therefor the displacement of crude oil by capillary action becomes less important due to the adsorption of its components to solid surfaces.

II.3.3.Measurement Methods of wettability

Wettability is determined in three ways:

- Measurement of the contact angle, or the product of the contact angle and the interfacial tension (the last term in Young's equation)
- Measurement of the relative amounts of oil and water displaced under similar conditions
- Observations of displacement or surface phenomena associated with the water or oil phase

The first method is the most difficult, while the second is the most common. The third is the most varied in terms of methods and results. **[12]**

II.3.3.1 Contact Angle (sessile drop method)

This method works best with pure fluids and well-prepared surfaces limiting its application when used with reservoir rocks and oil. The complex geometries and heterogeneities of reservoir rocks with organic coatings and organic particles will greatly complicate. The measurement of contact angle hysteresis can be used to measure adhesion. The measurements can be made at elevated temperature and pressure requiring high pressure high temperature (HPHT) equipment that significantly increases cost.

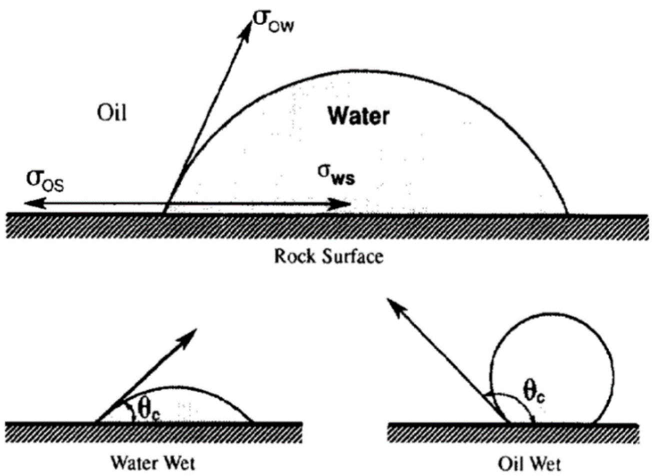


Figure (II-16): Wettability of oil, water, and rock system **[12]**

II.3.3.2 Amo*tt*-Harvey

This method uses spontaneous imbibition of water into an oil saturated core over a period of time. The procedure takes place inside a water-filled tube. This is followed by coreflooding of the sample to reach residual oil saturation and then imbibition of oil back into the core inside an oil filled tube and another coreflood with oil. The data is used to calculate the water and oil indices which produce the wettability index value ranging from -1 to +1, -1 for oil-wet to +1 for water-wet. The equipment is specialized, but relatively inexpensive. The experiments can be conducted at elevated temperature, but not elevated pressure. **[45]**

II.3.3.3 USBM

The US Bureau of Mines test employs a centrifuge to force fluids into the core samples, again within water-filled or oil-filled containers. The use of a centrifuge allows precise application of gravitational forces and greatly speeds the experiment. The data are used in a fashion similar to the Amott-Harvey method and generates a wettability index with values that can range to infinite negative to positive values, but usually range between -1 and +1. The measurements are normally made at room temperature and pressure on samples that have been subjected to reservoir conditions. **[45]**

Comparison of Amott and USBM methods

Both the Amott and the USBM test are commonly used in the oil industry, but direct comparisons of the two techniques show only minimal correlation.The most significant deviations occur near the neutral wettability region. The Amott method is more sensitive in this area and may be a better indicator. The Amott method can also be used to indicate mixed wettability if a sample spontaneously imbibes both oil and water. **[12]**

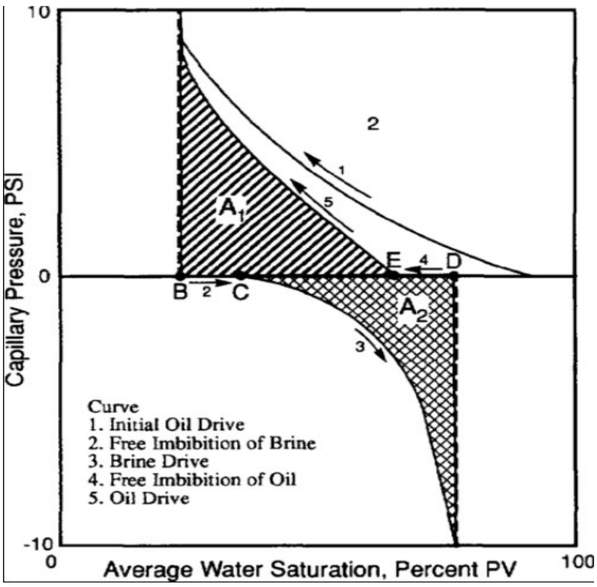


Figure (II-17): Combined Amott and USBM method. **[12]**

II.3.3.4 Additional techniques

Several techniques are described in the literature for determining wettability. Some are modifications of the Amott or the USBM methods, while others represent significant departures from the standard techniques. These vary from microscopic examination of imbibed fluids to measurement of nuclear magnetic resonance (NMR) longitudinal relaxation. Tableau II.1lists some of these techniques and their observed variables. **[12]**

Method	**Observation**
Microscopic examination	Visual examination of the fluid surrounding grains
Flotation method	Distribution of grains at water/oil interface or air/water interface
Glass slide method	Displacement of the nonwetting fluid from a glass slide
Relative permeability method	Location and relative magnitudes of k_{ro} and k_{rw} curves
Reservoir logs	Resistivity logs before and after injection of a reverse wetting agent
Nuclear magnetic resonance	Changes in the longitudinal relaxation time
Dye adsorption	Adsorption of a water soluble dye

Table II.1: Alternative wettability measurement techniques **[12]**

II.3.4 Influence of wettability on flows in porous media:

II.3.4.1 Effect of wettability on phases' distribution in a two-phase flow:

Different studies reported by [Elmkies, 2001] show the influence of wettability on phase trapping during immiscible two-phase flow. While draining oil in a water-wettable medium, the trapped water occupies the smaller pores because oil cannot access these pores. When imbibing on the same medium, residual oil resides in the larger pores

In the case of oil wettability, the oil and water distributions are reversed. In the case of a medium of intermediate wettability, irreducible water and residual oil occupy a set of pores of different sizes.

In the case of oil wettability, the oil and water distributions are reversed.

In the case of an intermediate wettability medium, irreducible water and residual oil occupy a set of pores of different sizes. If the wettability is mixed, oil and water are present simultaneously in all the pores, and in particular limit saturations. If the wettability is fractional, the irreducible water resides in the smallest pores of the water-wettable network and the largest of the wettable network the oil. Conversely, the residual oil will be found in the largest pores of the water- wettable network and in the smallest pores of the oil-wettable network **[46].**

II.3.4.2 Influence of wettability on relative permeability:

Relative permeability is a direct measure of the ability of the porous medium to leave a fluid flow through its network of pores. This property is controlled by the spatial distribution of the phases, therefore the wettability will have an effect on the relative permeabilities. Multiple studies have evoked a same evolution of the behavior of relative permeabilities with wettability. When changing from a water-free wettability medium to an oil wettability medium, the relative permeability to oil decreases for the same saturation while the one of water increases.(The non-wetting phase moves more easily in the center of the pores and when it becomes wetting, its flow becomes more difficult) **[31]**.

CH III:
Damage of the porous medium.

CH III Damage of the porous medium.

III.1. Introduction

Formation damage is the impairment of petroleum bearing formations by various adverse processes. Formation damage is one of the major problems in oil industry and still a fresh subject to search about.

Formation damage is undesirable operational and economical problem that can occur during the various phases of oil and gas recovery from subsurface reservoirs including drilling, production, hydraulic fracturing, and workover operations **[47]**

It is a zone of reduced permeability within the vicinity of the wellbore (skin) as a result of foreign-fluid invasion into the reservoir rock.

The four main categories of formation damage mechanisms are

(1) Mechanical (fines migration – external solids - phase trapping and blocking – perforation damage).

(2) Chemical (clay swelling – clay deflocculating – wettability alteration).

(3) Biological (plugging – corrosion – toxicity).

(4) Thermal (thermal degradation – mineral transformation).

These processes are triggered during the drilling, production, workover, and hydraulic fracturing operations.

Formation damage indicators include permeability impairment, skin damage, and decrease of well performance. Formation damage is not necessarily reversible and what gets into porous media does not necessarily come out.

Therefore, avoiding formation damage is much better than to try restoring it because restoring formation damage may result in additional damage to the formation. Formation damage is possible to occur during any field operation that involve the producing formation.

The consequences of formation damage are the reduction of the oil and gas productivity of reservoirs and noneconomic operation. If the productivity of a well is determined to be lower than the expected, there is high probability that the source of the reduction is caused by formation damage. The main indicators of formation damage are permeability impairment, skin damage, and decrease of well performance. Specialized formation damage analysis can be performed in reservoir rock samples after cores have been extracted from formation.

Formation damage is an exciting, challenging, and evolving field of research. Eventually, the research efforts will lead to a better understanding and simulation tools that can be used for model-assisted analysis of rock, fluid, and particle interactions and the processes caused by rock deformation and scientific guidance for development of production strategies for formation damage control in petroleum reservoirs.

The ability to produce fluids from a reservoir is strongly affected by near wellbore permeability. Thus formation damage is a crucial problem that thunders the productivity of the well. Drilling, completion and production operations should be executed with optimal efficiency and economic viability.

It is very important to have a fundamental knowledge of the formation damage causes and the ability to predict the possible problems in advance and minimize them. This challenge for petroleum industry requires a vast understanding and multidisplinary teams of engineers, chemists, geologists biologists and others working together to provide better diagnosis and treatments.

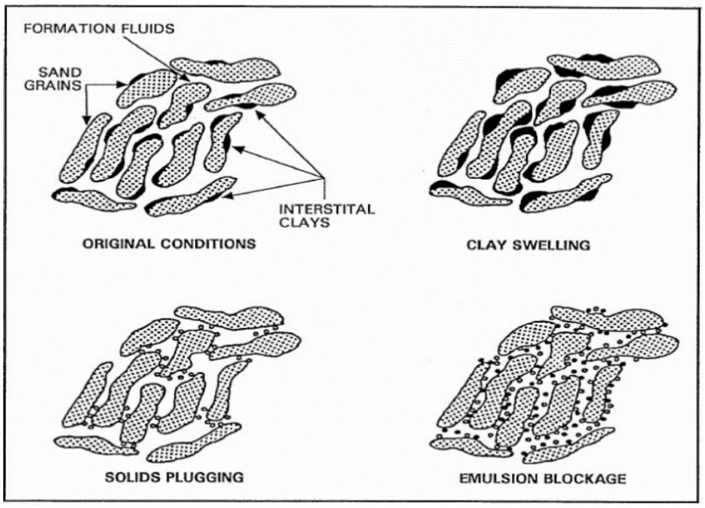


Figure (III-1): Illustration of various types of reservoir damage **[48]**

III.2. Formation damage indicators

Formation damage indicators include permeability impairment, skin damage and decrease of well performance. When the productivity of the well starts to get lower than the expected ratio, there is a big chance of formation damage occurrence.

III.2.1 Permeability Impairment

Permeability impairment is the reduction of formation permeability due to the capture and deposition of fine particles in tortuous paths of porous matrixes. These particles close the pathways of fluid by different mechanisms like bridging, plugging pore throats or even forming cakes.

III.2.2 Skin Damage

Skin is another indicator of formation damage. The concept of skin factor was introduced to petroleum industry and researchers realized that if the measurement of bottom hole pressure for a specific flow rate is less that the theoretical value, it means there is additional pressure drop which is time independent.

This skin pressure drop is related to a damaged zone shown in **Figure III-2** near the wellbore called skin zone. Permeability in this zone is reduced by foreign particles or due to mud contamination of the reservoir. Moreover, it is caused by the invasion of drilling fluids to the area around the wellbore.

Pressure drop by skin is illustrated mathematically by the following equation **[49]**.

$$s = \left(\frac{k}{k_s} - 1\right)\left(ln\,\frac{r_s}{r_w}\right) \qquad \text{(III-1)}$$

Where:

K: Reservoir permeability, md

k_s: Permeability of altered zone, md

r_s: Outer radius of altered zone, ft

r_w: Wellbore radius, ft

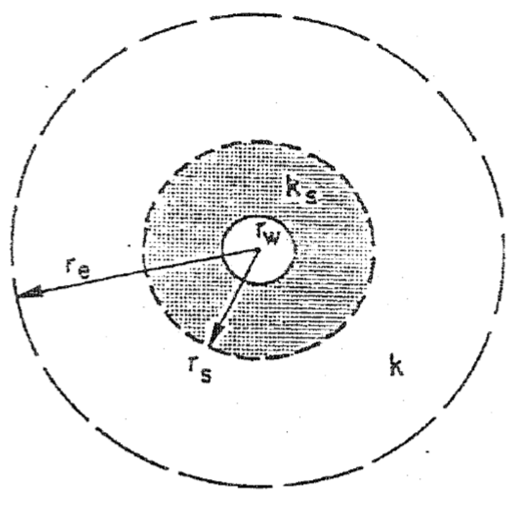


Figure (III-1): Schematic of a well with skin damage **[50]**

Skin factor is a dimensionless number and if the permeability of altered zone is smaller than reservoir permeability, the reservoir is damaged and the value of skin will be greater than zero (s>0).

In this case, the skin factor is an additional dimensionless pressure drop needed to produce at the specified rate because of the decrease in permeability in the skin zone.
Permeability decrease near the wellbore results in pressure drop at the damaged zone. In this situation the permeability is altered to the permeability of skin zone (ks). Therefore, skin effect will result in pressure drop (Δps).
If the permeability of near wellbore is the same as reservoir permeability, then no damage is taking place and a steady state pressure drop will dominate the situation.
The situation is illustrated in **Figure III-3**, in which pressure lines have different values near the wellbore. In the figure, $pwf, ideal$ the pressure drop with no damage (skin) effect is shown. On the other hand, $pwf, real$ shows pressure drop in damaged wells.

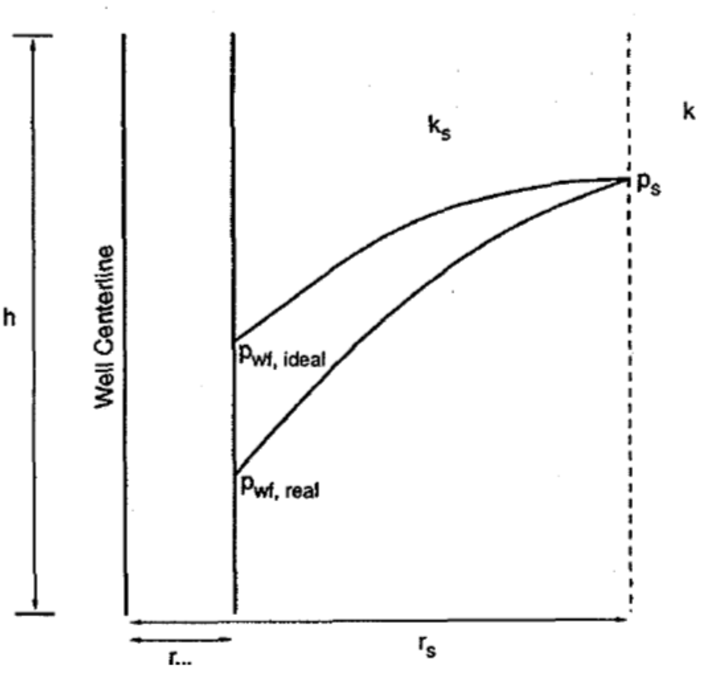


Figure (III-3): Near wellbore zone. Ideal and real bottomhole pressures **[49]**

III.2.3 Decrease of Well Performance

Decrease of well performance is another indicator of formation damage. Well performance is understood from productivity index measurements. When the productivity index shows less values, there is high probability that formation damage is a main cause for the reduction of fluids produced. Productivity index is defined as the rate obtained by unit pressure drop in the reservoir.

$$PI = \frac{q_{sc}}{p_e - p_{wf}} \qquad \text{(III-2)}$$

Where:

PI =Productivity Index, STB/day/psi

qsc =Surface flow rate at standard conditions, STB/D

pe= External boundary radius pressure, psi

pwf =Well sand face Pressure, psi

For steady state radial flow, productivity index is illustrated as the following:

$$\mathrm{PI} = \frac{\mathrm{kh}}{141.2\ \mathrm{B}\mu\left(\ln\left(\frac{r_e}{r_w}\right)+s\right)} \qquad \text{(III-3)}$$

Where:

k=Permeability, md

h =Net thickness, ft

μ =Fluid viscosity, cp

B =Formation volume factor, rb/STB

re = External boundary radius, ft

rw = Wellbore radius, ft

s = Skin

According to equation above, productivity depends on skin factor effect. Productivity is increased if skin factor is decreased and vice versa.

III.3. Formation damage problems during various well operations [51]

Formation damage is defined as any type of process which results in flow reduction of the flow capacity of oil, water or gas bearing formation. Formation damage has long been recognized as a source of serious productivity reductions in many oil and gas reservoirs and as a cause of water injection problems in many operations. In the literature, most types of operation which result in decline of well performance, permeability decrease are referred to as formation damage. In fact, most of field operations are a potential source for formation damage. This problem may occur during drilling, cement job, completion, simulation, injection and many other operations. However, casing operations and fluid injection contributes the most to formation damage.

During perforation operation, the rocks are penetrated by high pressure explosives. The matrix of the rock is destroyed. As a result, an absolute damage is made during perforation process. The fines due to perforation closes the tortuous paths of fluids and decrease the permeability near the wellbore.

Formation damage is recognized to be a cause for water injection. However, when water injection is performed for recovery purposes, the water itself causes a formation damage and the problem continues.

III.3.1. Drilling

a) Mud solids and particle invasion

- Pore throat plugging
- Particle movement

b) Mud filtrate invasion

- Clay swelling, flocculation dispersion and migration
- Fines movement and plugging of pore throats
- Adverse fluid-fluid interaction resulting in either emulsion/water block or inorganic scaling

III.3.2 Casing and cementing

Blockage of pore channels by cement or mud solids pushed ahead of the cement.

- Adverse interaction between chemicals (spacers) pumped ahead of cement and reservoir mineral fluids.
- Cement filtrate invasion with resultant scaling, clay slaking, fines migration and silica dissolution.

III.3.3. Completion

- Excessive hydrostatic pressure can force both solids and fluids into the formation.
- Incompatibility between circulating fluids and formation with resultant pore plugging.
- Invasion of perforating fluid solids and explosives debris into the formation with resultant pore plugging.
- Wettability alteration from completion fluid additives.

III.3.4. Well stimulation

- Potential plugging of perforations, formation pores and fractures from solids in the well kill fluid.
- Invasion of circulating fluid filtrate into the formation with resultant adverse interaction.
- Precipitation of hydrofluoric acid reaction by-products

during acidizing.

- Precipitation of iron reaction products.
- Potential release of fines and collapse of the formation

during acidizing.

III.3.5. Production

- Initiation of fines movement during initial DST by using excessive draw-down pressure.
- Inorganic/organic scaling through abrupt shift in thermodynamic conditions.
- Sand production in unconsolidated formations triggered by water encroachment into production zones.

III.3.6. Secondary recovery operations – Injection wells

Formation wettability alteration from surface-active contaminants in the injection water.

- Formation plugging by iron corrosion products.
- Inorganic scaling due to incompatibility of injected water and formation water.
- Fines movement due to hydrodynamic conditions of velocity and viscosity during water injection projects.
- Potential emulsion formation during CO2 wag process

III.4 Most common formation damage in the Hassi Messaoud field [52]

III.4.1. Salt Deposition

The changes in temperature and pressure associated with the production enhances the precipitation of salt from salt rich formation fluids. In addition the cooling effect from continuous injection of water will help the precipitation process. Such salt precipitation results in severe plugging of the slotted liners, the perforations and in some cases the formation matrix.

III.4.2. Scales Deposition

They are formed due to the incompatibility between the formation waters and the desalination and injection waters. They plug liners, production tubular and

openholes The most common types of scales are $BaSO_4$,

$CaSO_4$. Also $CaCO_3$ and $FeCO_3$ may be found. The occurrence of these scales is predictable as the comparison between the composition of the different waters show the possible chemical reactions, hence the type of scale.

III.4.3 Asphaltenes Deposition [53]

Asphaltenes deposition intensity decreases in the west - east direction. It is very common in zones 1A, 1B, 1C, 2 and 4. Asphaltenes typically deposit in the tubing, on slotted liners, perforations and in the formation. It is usually caused by:

- Change in temperature or/and pressure, in particular when the pressure is below the bubble point of the crude produced.
- The oil movement within the rock matrix during production can produce an electric field depending on its flow rate. Such an electric field could enhance the flocculation of asphaltenes.
- The low pH of the Cambrian together with the heavy metals found in the formation waters, could cause precipitation.

III.4.4 Clays and Fines Migration

Kaolinite exists in abundance in the formation rocks as pore filling material. Also some illite exists as pore lining material. Kaolinite has the tendency to break up from the host grain in large size particles plugging the pore throats. Illite on the other hand retains water thus creating large volume of microporosity causing water blocking. In addition it can break, migrate to the pore throats and act as a check valve. Damage due to clays and fines is located in the near wellbore area within a three to four feet radius.

III.4.5 Reservoir Pressure Evolution*:*

- The decline in reservoir pressure will aggravate some types of damage. The case get worse if pressure drops below the bubble point pressure
- Gas breakthrough may be induced from gas injection and water cut may be increased from water injection indicating that there might be conformance problems

III.4.6. Perforations*:*

Currently Sonatrach is conducting a campaign of recompleting the wells with cemented and perforated liners.

Crushed zone, charges debris and filter cake from completion or workover fluids may plug some of the perforations tunnels causing a severe skin and pressure drop in the near wellbore.

III.4.7. Emulsion, wettability change and water block

These are basically induced from invading the formation with drilling and fluids, whether oil or water based mud, cement filtrate and completion brines. And other fluids associated with workover, re-completion and snubbing operations. These types of damage reduce the effective and the relative permeabilities to hydrocarbons and extend within the formation critical matrix.Fig. III.5 illustrates the most common formation damage in the Hassi Messaoud field.

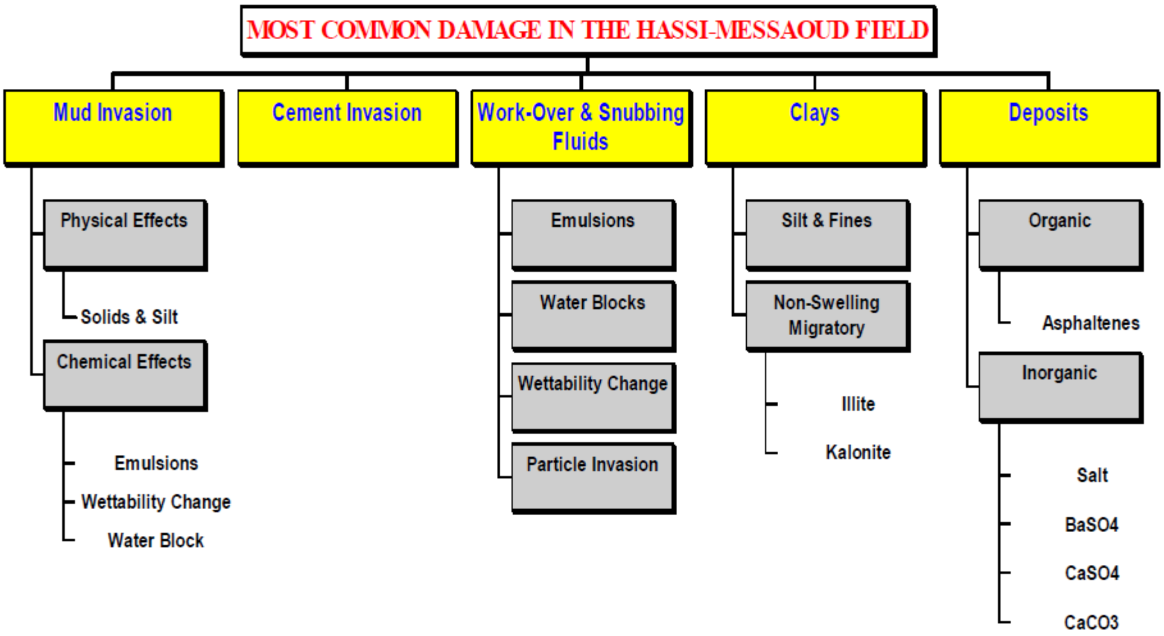


Figure (III-4): The most common damage in the Hassi Messaoud field **[52]**

III.5 Chemical mechanisms of formation damage

The formation can be damaged by the reaction between the filtrate ad pore contents and/or matrix materials. Chemical causes for formation damage are essentially swelling or dispersion of clays, precipitation by reactions between mud filtrate and pore contents as well as solution of salts and materials from matrix.

III.5.1 Fluid-Fluid Interactions

Interactions between fluids is a chemical mechanism causing formation damage in reservoirs. For example, fluid-fluid incompatibilities like emulsions generated between invading oil based mud filtrate and formation water is a main mechanism of formation damage. The driving force for particle transfer between two fluid phases is the wettability of the fluid phases relative to the wettability of the particles **[47]**

The fluid-fluid interactions include:

1. Emulsion blocking
2. Inorganic deposition
3. Organic deposition
4. Asphaltene Deposition

III.5.2 Rock-Fluid Interactions

Rock-fluid incompatibilities, for example contact of potentially swelling clay or deflocculatable kaolinite clay by no equilibrium water based fluids with the potential to severely reduce near wellbore permeability.

The fluid-rock interactions include:

1. Mobilization, migration and deposition of in-situ fine particles.
2. Invasion, migration and deposition of externally introduced fine particles.
3. Alteration of particle and porous media properties by surface processes such as adsorption, wettability change, swelling.
4. Damage by other processes.

III.6 Formation Damage during Drilling

III.6.1 Introduction:

Formation damage is a serious problem which starts from the very early life of the well. Drilling operation itself is potential source of formation damage. Invasion of mud solids into the reservoir rocks and the drilling fluid rock interactions result in formation damage.

Bit-rock interaction while drilling produces fines. These small pieces of the rock are supposed to get out of the borehole by the drilling fluid. But under overbalanced drilling operations, fines stays inside the well and get trapped near the wellbore and become a main source for formation damage. To understand the effect of fines on the formation, an accurate definition of fines is required. As stated by Byrne, fines are any part of the rock that can move through or within the pores of the rock **[47].**

Solids and fines mixed with drilling mud are trapped inside the reservoir tortious paths inside the rock matrix. As a result, drilling fluid invasion into the reservoir damages the formation by blocking the pores or by contamination near the wellbore.

Fine particles are trapped inside the pores during filtration process. Such accumulation results in porosity decrease as well as permeability. As shown in Figure III.4 the particle/pore size ratio is very important parameter in filtration operations because the larger the ratio is the higher tendency for damage to happen for the formation near the wellbore.

Solid and liquid particles dispersed in the drilling fluid (mud) are trapped by the rock (porous medium) and permeability decline takes place during drilling fluid invasion into reservoir resulting in formation damage. The formation damage due to mud filtration is explained by erosion of external filter cake.

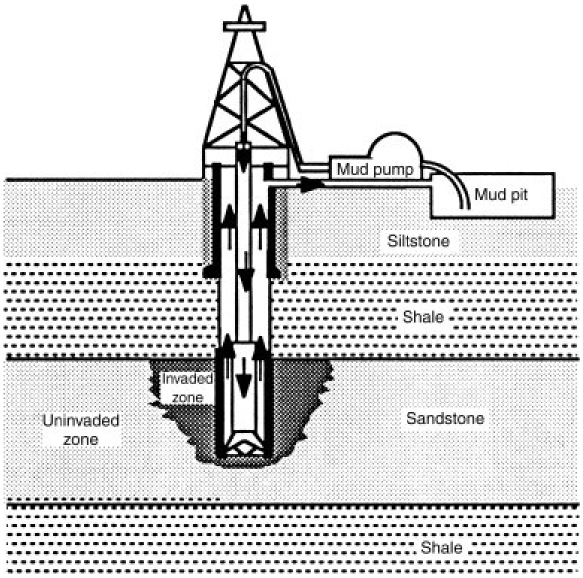


Figure (III-5): Mud filtrate invasion in the near-wellbore formation **[54].**

The challenge is that if any foreign particle reaches the porous media of the reservoir, it is a challenging issue to get it out. Migrated particles to the porous rock does not necessarily get out.

III.6.2 Mechanisms of formation damage during drilling:

The damage is caused by different phenomena namely [11, 47, 55, 56, 57, 58, 59]:

III.6.2.1 Mechanical damage:

The mechanisms of mechanical damage are direct with no chemical interactions between the equipment and the fluid used to complete the drilling, completion or stimulation work. Among these effects we can name:

a) Grinding of the reservoir rock:

This purely mechanical action is likely to block certain reservoirs. Indeed, the spraying of many particles allows them to clog the pores while the compacting effect is added to achieve the blocking.

***b) Fines migration*:**

This is the movement of natural particles existing in the porous system as a result of the considerably high shear forces applied by the filtrate of the drilling fluids.

During drilling, cementing, completion or work-over, the drilling fluid is in continuous contact with the reservoir rock for a long period and at a pressure greater than the pressure of the fluid contained in this rock.

As the medium is porous, the liquid phase of the mud infiltrates this rock while the solid phase forms an external cake on the walls of the well and an internal cake made up of fine solid particles.
This invasion of the filtrate in the matrix causes an imbalance of the system which affects both the clay cement of the rock, and the fluid contained in the pores. The solid particles which originally occupy the walls of porous pipes without affecting the permeability of the reservoir, can be entrained by the fluid. These particles can also migrate with the effluent during the normal production of the well and thus block the surroundings of the latter, leading to a decrease in the useful porosity and subsequently that of the permeability, which is translated by resistance to flow of oil or gas. A significant reduction in the expected productivity of the well is then observed.

c) Entrance of external solids***:***

This phenomenon is linked to the invasion of particles that are suspended in drilling fluids or other fluids that may be injected or exposed to the matrix of rocks around the well. These particles can be either weighting agents, filtrate reducing agents or solids generated by the drilled debris.

The invasion of the formation can be represented schematically by several zones away from the well axis as shown in the figure

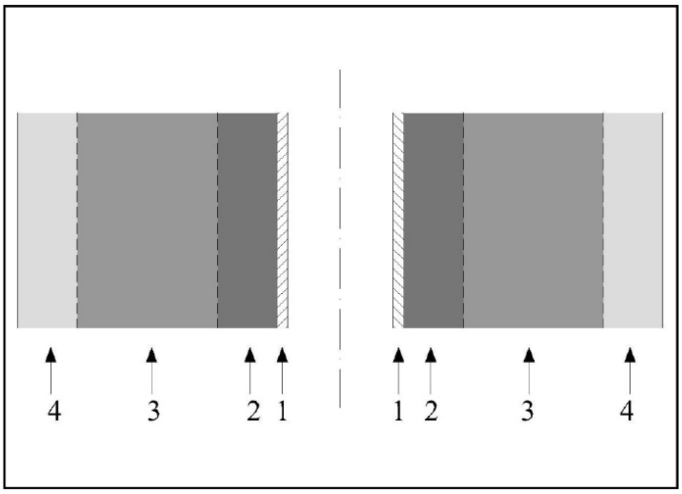


Figure (III-6): Schematic representation of the invasion of reservoir by drilling fluid when crossing it.

Zone 1: “external” cake lining the walls of the well

Zone 2: “internal” cake: solids having penetrated into the porous medium

Zone 3: zone invaded by the filtrate

Zone 4: virgin area where permeability is not affected

- External cake (zone 1): The external cake is formed from solid mineral particles or organic deposited during drilling on the wall of the hole (to consolidate the walls of the well and reduce the infiltration of mud into the formation).

Its elimination is done mechanically by scraping or chemically by washing with solvents. Or acids.

- The internal cake (zone 2): The internal cake is made up of fine solid particles originating from mud, cement and completion fluids, is located in a very thin crowns in the immediate vicinity of the well and block the pores, making the medium less permeable
- The invaded zone (zone 3): Beyond the internal cake is the zone invaded by filtrates of mud and cement, its depth, variable, can reach up to several meters in cases of deep invasion. Which will modify the natural environment of the porous medium. We can thus observe:
  - Change in wettability;
  - Formation of emulsions;
  - Swelling and / or disintegration of clays.

Various precipitations (mineral and sometimes organic) in case of incompatibility of a filtrate with fluids in place.

The penetration of the filtrate, and to some extent of the solids it entrains, is a function of several cumulative factors. Those are:

- The overpressure exerted on the tank,
- The permeability of the formation,
- The mud flow rate,
- Mud-ground contact time during drilling.

III.6.2.2 Chemical damage:

This damage is linked either to the interaction between the external fluids and the formation, or to the interaction between the formation fluids and the external ones. Among these effects, we can mention:

a) Swelling of clays

It is a classic mechanism of formation damage that involves the interaction and hydration of hydrophilic materials (eg bentonite) by fresh water or low salinity water. The expansion of these clays can lead to a severe reduction in permeability.

b) Deflocculation of clays

The deflocculation of clays is driven by the forces of electrostatic repulsion. A shock of rapid salinity or a rapid pH transition can cause deflocculation.

c) Chemical adsorption

Polymers or weighting materials present in fluids can adsorb on the surface of the matrix formation and on clays and, due to their large size, lead to a decrease in the size of the flow channels, hence the permeability.

***d) Formation of emulsions*:**

Emulsions can be formed during drilling operations. It is the result of an intimate mixture between two immiscible fluids, namely here:

- The filtrate water with the crude from the reservoir;
- Crude filtrate from an oil-based mud with formation water.

The main characteristic of an emulsion is its high viscosity, which makes it able to drastically reduce the productivity of the wells, which is inversely proportional to it.

***e) Water block*:**

The water block phenomenon can be defined as an obstacle to the flow of reservoir fluids caused by capillary forces in the pores of the rock and the presence of high water saturation which reduces the relative permeability to hydrocarbons.

f) Poor wettability: action of surfactants

Several additives in drilling fluids, in particular surfactants, have a tendency to adsorb to rock, making it wettable by oil in the region of the reservoir where they infiltrate, resulting in a decrease in relative permeability with oil therefore a decrease in productivity

III.7 Matrix acidizing

Matrix acidizing refers to one of two stimulation processes in which acid is injected into the well penetrating the rock pores at pressures below fracture pressure. Acidizing is used to either stimulate a well to improve flow or to remove damage. During matrix acidizing the acids dissolve the sediments and mud solids within the pores that are inhibiting the permeability of the rock. This process enlarges the natural pores of the reservoir which stimulates the flow of hydrocarbons. Effective acidizing is guided by practical limits in volumes and types of acid and procedures so as to achieve an optimum removal of the formation damage around the wellbore. **[60]**

III.7.1 Acidizing to remove damage

A matrix treatment restores permeability by removing damage around the wellbore, thus improving productivity in both sandstone and carbonate wells. Although the acid systems used in sandstone and carbonate differ, the same practices apply to both. In the absence of damage, the large volume of acid that is required to improve the formation permeability in the vicinity of the wellbore may not justify the small incremental increase in production, especially in sandstone. In carbonate rock, hydrochloric acid enlarges the wellbore or tends to bypass damage by forming wormholes. The permeability increase is much larger in carbonate than in sandstone. The effect of damage on well productivity and flow is illustrated in Figure III-7 & 8 Severe damage (k_D/k less than 0.2) is usually close to the wellbore, within 12 in., as in Figure III-7. More moderate damage (k_D/k greater than 0.2) may occur much deeper (3 ft from the wellbore or more), as described in Figure III-8. Oilwell flow behavior is greatly affected by the geometry of radial flow into the wellbore; 25% of the pressure drop takes place within 3 ft of the wellbore if no damage is present, as shown in Figure III-9 Because of the small flow area, any damage to the formation at that point may account for most of the total pressure drop (drawdown) during production and, thereby, dominate well performance. **[60]**

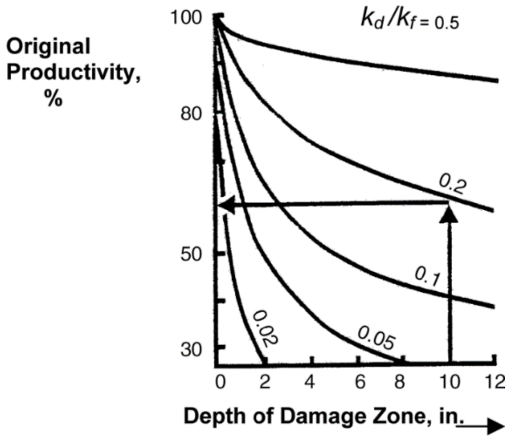


Figure (III-7): Effect of damage on well productivity-shallow damage **[60]**

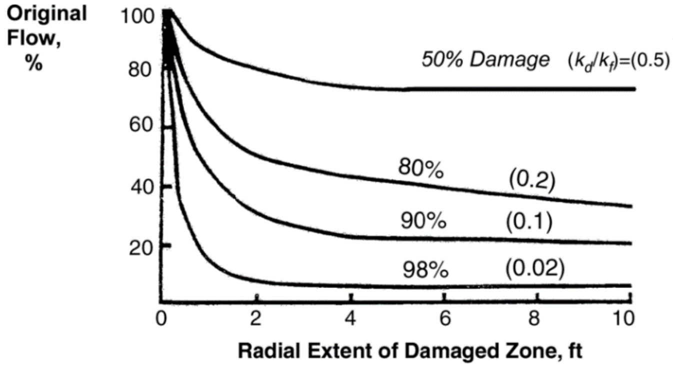


Figure (III-8): Effect of damage zone on flow-deep damage. **[60]**

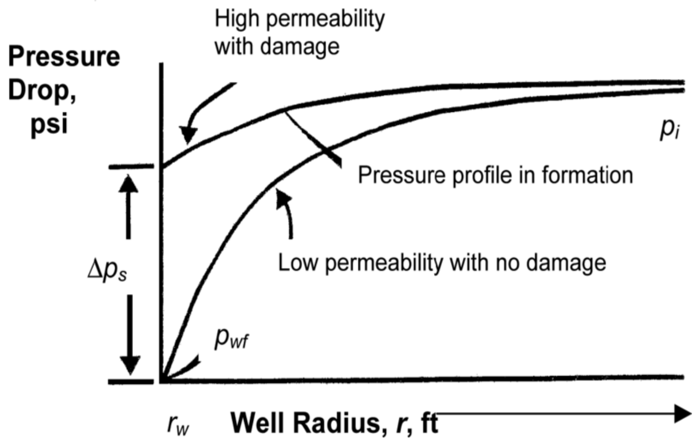


Figure (III-9): Pressure distribution around a well. **[61]**

III.7.2 Minimize formation damage

Drilling operations expose the producing formation to the drilling fluid, and any solids and chemicals contained in that fluid. Some invasion of fluid filtrate and/or fine solids into the formation is inevitable. However, this invasion, and the potential for damage to the formation, can be minimized with careful fluid design that is based on testing performed with cored

Experimental future project:

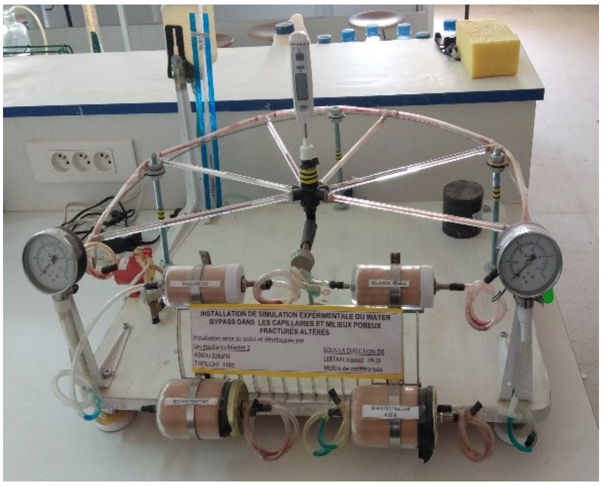
Experimental part:

Core sample tests take a long time and charge high expenses, therefore using a Micro-model installation will help us to obtain the results in a short period and free of charge, while we can replace the core samples with:

- Glass particles
- Sand.
- Cuttings.
- Crunched core sample.

The models below represent an example of installations that we can use for the tests.

Exploitation simulation micro-model of horizontal and vertical wells with circular radial flow



Experimental simulation Installation of Water Bypass in capillaries

We intend to add:

- A customized stimulation method for this specific type of damage through experimental work of lab tests and a previously built Micro-Model Installation.
- Software simulation through licensed SLB softwares and data sciences with the use of Matlab and Python programming language.
- Review of the new stimulation technologies such as Schlumberger Naki-Clean and One Step Acid.
- Investigate the most optimized stimulation method in term of efficiency in treatment and cost.
- A study of Mud damage in horizontal wells.
- Damage evaluation comparison between Horizontal wells & Vertical wells.
- Closed well development (case of unsuccessful treatment).
- Selection criteria: Work-Over + Open hole + DST after = the best candidate for study
- A detailed study of candidate wells.
- Study the mitigation – prevention – of mud damage during drilling or work-over through Nano particles mud and other innovative technologies.
- Application of Nano particles as filtration control additive to reduce formation damage.

Conclusion

Conclusion

To meet the specific needs of different drilling conditions and so as not to damage the reservoir, oil-based drilling fluids are used which combine a very large number of components, in particular surfactants which can alter the wettability of reservoir rocks causing a loss of productivity.

Water Based Mud Contamination

In high permeability reservoir rock

- Mud contaminations can be difficult to remove, especially particles
- Cleaned reservoir rock water-wet, but clay particle invasion may affect established wettability

Oil Based Mud Contamination

- Slow release of emulsifiers during STO injection, and core plugs exposed to OBM filtrate less water-wet

A Micro-model Installation was previously built to facilitate the performance study which will be conducted on different acids for a purpose to determine the problem and remedy - solve - the well assumed to clogging phenomenon due to the drilling mud.

Recommendations:

Based on our study, the following points are recommended:

1. Perform compatibility tests of the surfactants with the reservoir rock before starting the drilling.
2. Proceed with the preliminary test by this new device through AMOTT by using drill cuttings from the producing layer.
3. Drill underbalance if possible.
4. Limit the contact times between drilling fluid and rock by speeding up the work.
5. Complete the study under different temperatures close to those of the deposit and with drill cuttings from the producing layer.
6. If the reservoir rock contains carbonates, use substances based on Zinc and aluminum to activate the emulsifier.
7. In the event of a deterioration of the wettability, allow the deposit water to flow for a determined time allowing the release of the surfactants and the restoration of the initial wettability.

8- Study of wettability at different concentrations of products entering into the formulation sludge for optimization.

9- Investigate the performance of the wetting agent (quality / concentration).

10- Optimize the size of the $CaCO_3$ grains as a function of the pore diameter.

11- For the sample clogged with sludge, acidification is necessary to restore its permeability.

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