Journal of Energy Research and Reviews

Volume 13, Issue 4, Page 31-41, 2023; Article no.JENRR.98480
ISSN: 2581-8368

Transition Zone Analysis in Oil Reservoirs with Mixed or Preferential Water Wettability

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Authors' contributions

This work was carried out in collaboration among all authors. All authors read and approved the final manuscript.

Article Information

DOI: 10.9734/JENRR/2023/v13i4269

Open Peer Review History:
This journal follows the Advanced Open Peer Review policy. Identity of the Reviewers, Editor(s) and additional Reviewers, peer review comments, different versions of the manuscript, comments of the editors, etc are available here: https://www.sdiarticle5.com/review-history/98480

Review Article

Received: 02/02/2023
Accepted: 05/04/2023
Published: 10/04/2023

ABSTRACT

Defining the transition zone in clastic oil formations with mixed or water-preferential wettability is useful in estimating the initial oil resource, locating production and injection wells, choosing drilling intervals, predicting water intrusion into production wells, and modeling the reservoir for simulation purposes.

The purpose of this article is to define the initial distribution of water in oil reservoirs and especially the knowledge of the transition zone, presenting theoretical concepts and practical methods for planning the necessary experiments and interpreting the data collected to define this part of the oil structure. The article presents the theoretical elements of the methods of obtaining and using capillary pressure curves, data on interfacial tension and contact angle. The dynamics of the saturation state during oil reservoir formation and the most optimal method for determining fluid contacts and free water levels are also described.

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Keywords: Transition zone; oil field; water saturation curve; free water level; capillary pressure.

1. INTRODUCTION

Rock pores are the spaces where petroleum fluids are stored, the percentage occupied by the pores being an indicator of the storage capacity of the petroleum structure.

Pores are not uniform in size, due to the nature of geological processes. The main factors that affect porosity are the grain packing type, size of the grain, shape of grain and cementing material. In the end all this guide how many pores are interconnected and how easy the fluid can flow through them, defined as rock permeability. The before mentioned factors and their variation led to heterogeneity in permeability. This is the main reason for the existence of transition zones in reservoirs [1].

This is precisely why a good understanding of the pore size distribution (the abundance of each pore size in a given rock volume analyzed) provides a method for quantifying heterogeneity and a solid basis for making a sucessful reservoir development plan.

Pore size distribution is considered one of the most important variables controlling displacement efficiency in oil reservoirs [2,3].

Pore size is usually described using the pore or constriction radius. Alternatively can be used the cross-sectional area of a pore and the hydraulic radius (defined as the ratio of cross-sectional area to circumference), or the ratio of volume to specific area [4].

There are multiple works [5,6,7] in which different experiments are discussed and compared to determine the capillary pressure difference curves with the help of which the transition zone is described. Most commonly the data used to describe the transition zone comes from the sources listed in Table 1.

In any system the constinuent elements are interacting. Fluid-fluid interaction is the result of the intermolecular forces of each fluid. In the case of a water-oil system, two imiscible fluids, one separation surface appears with distinct properties. This is characterised by the phisical property called interfacial tension denoted σ [8].

This state of tension in the membrane that shapes the interface phase can be expressed as the energy required (*dw*) to increase the interface area (*dA*) by one unit [8].

$$\sigma = \frac{dw}{dA} \qquad (1)$$

The increase in interfacial tension implies a transfer of molecules from the volumic phases to the interface phase.

The surface energy is minimum when the area is minimum, which is reflected in the spontaneous tendency of the interface to be spherical [9-11].

The deviation from the spherical shape is due to the potential energy and depending on the conditions, the frictional force acting on the unit volume (Figs. 1 and 2) [12].

Table 1. Industry standard data sources for defining transition zone

Technique	Benefits	Disadvantages
Mercury injection	Possible on any shape of core Good for classifying rocks Fast and affordable	Too optimistic results in terms of oil recovery The drainage curve is not ideal for use in simulators Occupational safety and health issues The core cannot be used afterwards
Special core analysis	The rapid centrifuge method uses reservoir fluids The porous plate method has simple equipment and uses reservoir fluids.	It requires regularly shaped cores The centrifugation method has high operating costs
Analysis of data from wellbore investigations	The data represents the reservoir fluids and has a rich basis to analyze	The reservoir zone must not be invaded by water from injection
Nuclear magnetic resonance	Continuous data Sometimes covers all needs	High costs Sensible to borehole condition

The connection angle of the interface with the solid surface is called the contact angle. It is defined as the plane angle of the dihedral angle between the plane tangent to the solid surface and the plane tangent to the fluid-fluid interface taken at a three-phase contact point, measured in the reference phase [8].

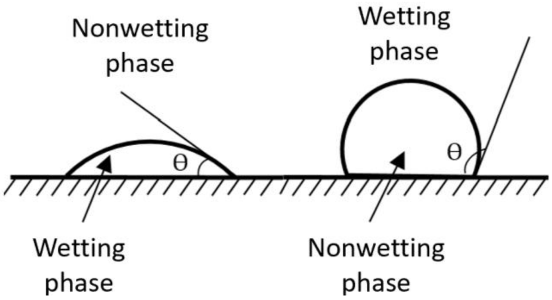

Fig. 1. Contact angle ilustration based on phase type [8]

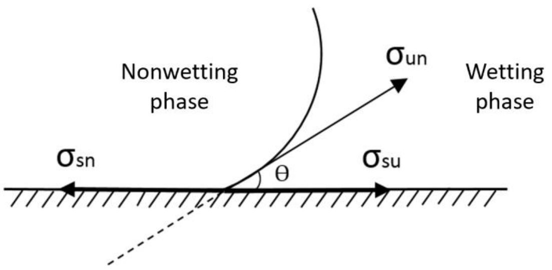

Fig. 2. The contact angle of the oil to solid surface [8]

$$\sigma_{sn} > \sigma_{su} \tag{2}$$

$$\sigma_{sn} - \sigma_{su} = \sigma \cos \Theta \tag{3}$$

$$\sigma \cos \Theta = \frac{\sigma_{sn} - \sigma_{su}}{\sigma} \tag{4}$$

σ_{sn} is interfacial tension solid-nonwetting phase
σ_{su} is interfacial tension solid-wetting phase
σ_{un} is interfacial tension wetting-nonwetting phase

The phase that tends to occupy a more even surface area on the solid surface is called the wetting phase.

Based on the wetting phase distribution can be concluded that it`s force field is more similar to the force field of the solid phase. The interface arranges until Young's law is satisfied [8].

A consequence of the existence of the interfacial tension σ, is capillary rise. The interface tends to move spontaneously in the direction in which σ acts. As it moves, a back pressure occurs.

This phenomenon and its implications in hydrocarbon reservoirs are the study objects of the paper.

2. CAPILLARY PRESSURE DIFFERENCE. THE DYNAMICS OF THE STATE OF SATURATION DURING THE FORMATION OF THE RESERVOIR

For any type of rock, when the reservoir is formed (primary drainage), oil first occupies the largest pores, where the capillary pressure difference is the lowest.

As can be seen in Fig. 3, the oil migrated at time t_1 occupies the largest pores in zone 1 (class 1).

As the size of the oil column increases, pore class 2 also saturates in zone 1 and pore class 1 saturates in zone 2.

Further saturation occurs in a similar manner until the maximum size of the oil column is reached that it can be supported by the protective rock, or a "spill point" is reached or the source of hydrocarbons is lost/exhausted. Irreducible saturation is first reached in the upper zone, when the displacement force can no longer overcome the capillary pressure difference in the finest pores [13].

The consequence of this process is the variation of the saturation state with depth. This is reflected by the capillary pressure difference curve for drainage [6,7,12].

3. ANALYSIS OF LABORATORY TECHNIQUES FOR DETERMINING THE CAPILLARY PRESSURE DIFFERENCE

3.1 Mercury Injection

In the case of the mercury injection experiment, the capillary pressure difference (ΔCp) is calculated as a function of the constriction radius, wettability and contact angle, with the Young-Laplace formula [8]:

$$\Delta c_p = \frac{2\sigma \cos\Theta}{r} \tag{5}$$

Because of the different nature of the phases higher injection pressures are used than for the oil/water system.

For this reason the conversion to the pore pressure specific to the oil/water system must be performed (T is oil and A is water).

$$\Delta c_{p\left(\frac{Hg}{Air}\right)} = \frac{(2\sigma \cos\Theta)_{(Hg/Air)}}{r} \quad (6)$$

$$\Delta c_{p\left(\frac{T}{A}\right)} = \frac{(2\sigma \cos\Theta)_{(T/A)}}{r} \quad (7)$$

$$\Delta c_{p\left(\frac{T}{A}\right)} = \Delta Cp_{\left(\frac{Hg}{Air}\right)} \frac{(\sigma \cos\Theta)_{\left(\frac{T}{A}\right)}}{(\sigma \cos\Theta)_{\left(\frac{Hg}{Air}\right)}} \quad (8)$$

All the unknowns needed in the calculation can be determined in the laboratory, and based on them, the capillary pressure difference curve is built according to the water saturation.

Another variant of defining the capillary pressure difference is as the difference between the pressure of the non-wetting phase (p_n) and the pressure of the wetting phase (p_u).

$$\Delta c_p = p_n - p_u \quad (9)$$

The paper discusses the particular case where water is the wetting phase and oil is the non-wetting phase, a situation frequently encountered in the case of clastic rocks.

By definition, the free water level (FWL) is identified at the intersection of fluid gradients, defined as the point where the capillary pressure difference is zero (Fig.4) [13-15].

$$\Delta c_p = p_t - p_a \quad (10)$$

If we consider the pressure at FWL as p_i, using the hydrostatic pressure equation we can define:

$$p_a = p_i - \rho_a gh \quad (11)$$

$$p_t = p_i - \rho_t gh \quad (12)$$

by substitution,

$$\Delta c_p = p_t - p_a = (\rho_a - \rho_t)gh \quad (13)$$

$$\Delta c_p = \Delta\rho\, gh \quad (14)$$

Where:

p_a is water phase pressure,
p_t is oil phase pressure,
g is gravitational acceleration,
ρ is density (oil and water) ρ_a , ρ_t
p_i is pressure at free water level,
h is level of measurements (depth wellbore).

The following table (Table 2) summarizes the methods for determining fluid contacts and free water level.

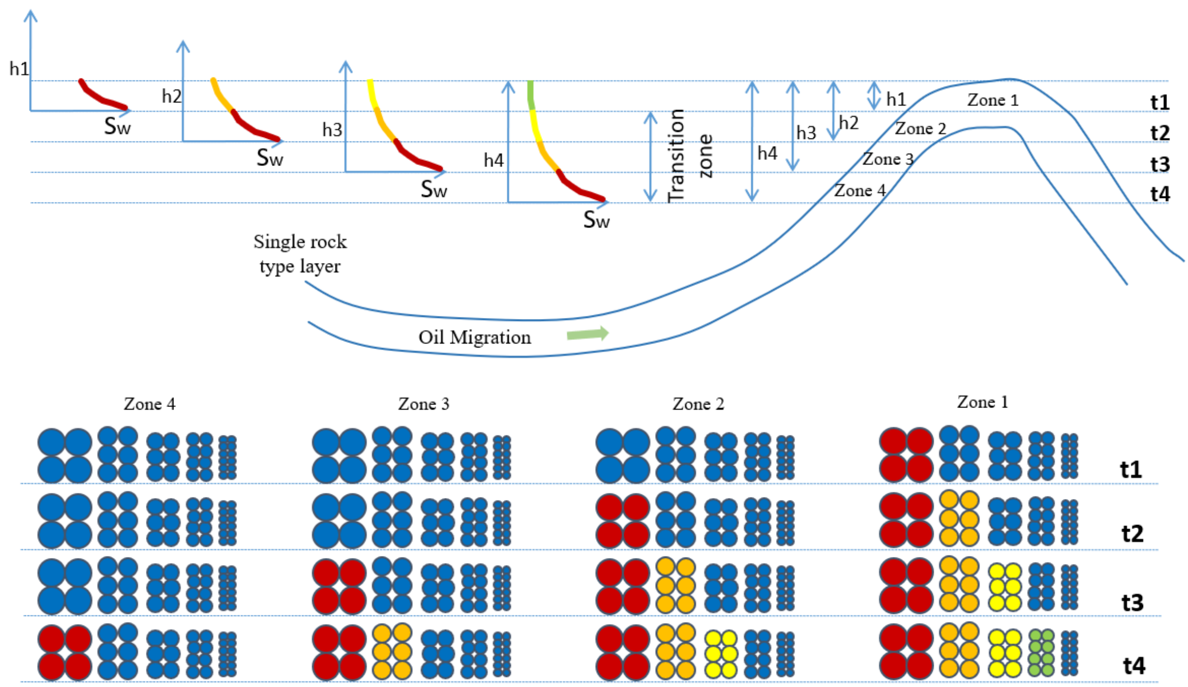

Fig. 3.Timelapse of oil saturated pore classes depending on structural position/zone [13]

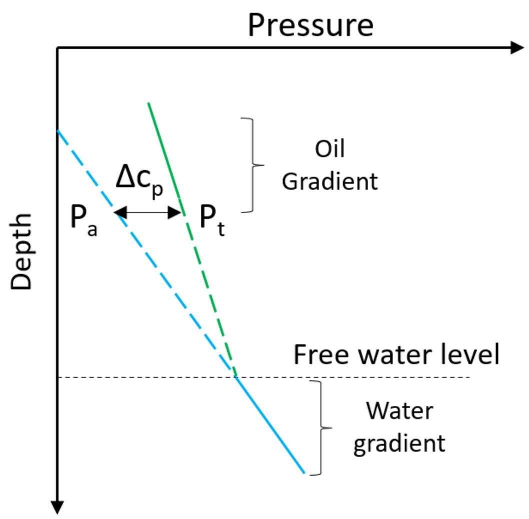

Fig. 4. Plot of intersection of fluid gradients [8]

All methods of estimating the lower limit of the reservoirs involve the existence of capillary pressure difference data, porosity derived from cores or petrophysical investigations, water saturation and permeability. In the absence of these data, in the situation where there are wells that in the initial period of exploitation also produced water, these production data can be used to estimate the fluid/fluid contact and to establish the positions of the next wells.

The capillary pressure difference data can be used to obtain the water saturation distribution in the reservoir.

The data are obtained by carrying out experiments on cores with dimensions of the order of centimeters, though being relevant in the reservoir for meters or tens of meters. The usual method of making this conversion is to use the notion of "height above the free water level", h. In equilibrium conditions, h can be obtained from relation 8 [14]:

$$h = \Delta c_p / \Delta \rho \, g \qquad (15)$$

Based on this formula (15), the saturation-height dependence is obtained.

The height *h*, is equal to zero at the FWL where Δc_p=0, so the starting point of the representative curve for the reservoir scale will be the depth of the FWL.

Capillary pressure curves show the distance between the oil/water (T/A) contact and the FWL, but cannot indicate the depth of the FWL.

Table 2. Used techniques for determining the fluid contacts and free water level

Technique	Benefits	Disadvantages
Fluid samples can be obtained from production tests DST (drill stem test) or RFT (repeat formation test)	Direct determination of contracts based on the type of recovered fluid	Sampling is not made at frequent enough intervals, requiring data extrapolation. The drilling fluid filtrate also contaminates the samples
Determination of saturation by geophysical methods. Changes in saturation in the well can indicate the contact value of the fluids	It is a fast and relatively low-cost method, being useful for simple lithologies	Saturation must be calibrated with production
Determination of saturation from core	Simple and useful method for complex lithologies, the saturation being interconnected with the petrophysical properties	Deficient in the case of the lack of continuous cores
Pressure profiles (XPT)	It indicates the water level when the slope of the pressure gradient changes, being useful in the case of large columns of oil	Requires continuous pressure monitoring
Production profiles (pressure and flow tests)	Estimates the water level from pressure data and fluid densities data	Requires measurements in both fluid zones. Requires corrections.

According to Fig. 4, FWL can be determined from pressure measurements by establishing fluid distribution. It is at the intersection of the hydrocarbon gradient with the water gradient (gas, oil and water have different densities and therefore different gradients).

The well must be drilled in a structural position that favors the capture of this data.

After determining the free water level (FWL) by the gradient method and after expressing the capillary pressure data as "height above the free water level", the water saturation at any point in the reservoir can be calculated according to the scheme in Fig. 5.

If this value is consistent with the values obtained from the petrophysical investigations and with those obtained on the cores, then the values obtained from the investigations can be used with confidence also for the uncored intervals of other wells in the same reservoir. With the help of the aforementioned input data, the graph c in Fig. 5 can be constructed to calculate the water saturation at a certain depth value [16].

3.2 Characteristics of Capillary Pressure Difference Curves

The transition zone is characterized by a lower boundary called the oil/water (T/A) contact and an upper boundary above which water is immobile.

The process of decreasing saturation in the wetting phase (water) is called drainage and describes the reservoir formation process.

In the Mercury injection capilary pressure (MICP) experiment the capillary pressure difference increases at the start of the injection without influencing the saturation (Fig. 6), until the moment when the pore entry pressure threshold is exceeded.

At this value of the capillary pressure difference, the oil/water contact is defined.

Moving above the oil/water contact, water saturation decreases, until irreducible water saturation is reached.

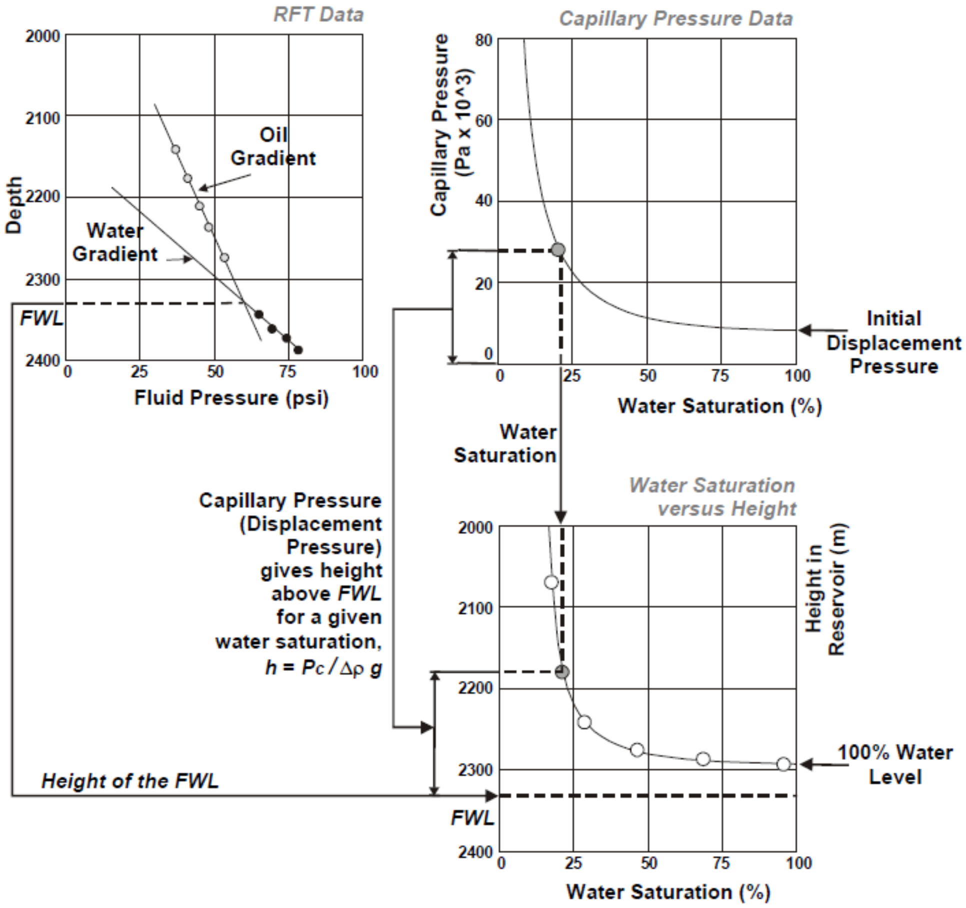

Fig. 5. Method for obtaining the saturation-height function above the FWL [16]

The occurrence of the oil phase in the reservoir/core does not imply that the oil is also mobile.

There is a portion of the transition zone where the saturation in oil varies from infinitesimally small to a value at which it becomes mobile.

To determine the value at which the oil begins to flow, the experiment of tracing the imibibition curve (increase of saturation in the wetting phase) is necessary.

On this direction of variation of the water saturation (S_a), the saturation in the residual oil is obtained(S_{tr}). From this point a vertical line is drawn and where it intersects the drainage curve we define the lower limit of the area from which oil will be produced in a drainage process. (Fig. 6) [5].

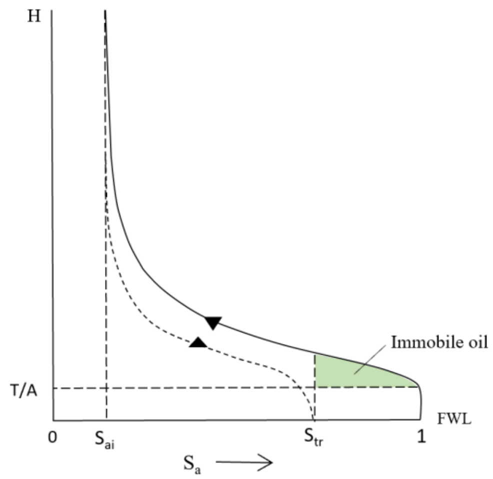

Fig. 6. Capillary pressure difference curves [5]

The free water level (FWL) can also be defined as the level at which the capillary pressure difference is zero.

The above figure is valid for the case where the rock is preferentially wetted by water.

For preferential watering by oil, the oil/water T/A contact is below FWL.

It has been shown in numerous books and papers that preferentially water-wetted or mixed-wetted reservoir rocks have extremely different capillary pressure difference characteristics compared to rocks in which oil is the wetting phase.

3.3 Influence of Rock Properties on Capillary Pressure Difference

The capillary pressure difference expressed as the difference between phase pressures (rel. 9) reflects only the effect of buoyancy forces, so it is not influenced by pore size or pore constrictions.

The capillary pressure difference (Young-Laplace) (rel. 1) is proportional to the height above the FWL, but is also affected by the rock properties, *(k, Ø)* and their distribution, so it does not depend only on the height value of the point of interest referenced to the free water level.

The cases discussed in Fig. 5 and Fig. 6 are valid for a known wettability value, porosity and pore constriction size.

The narrower the pore size distribution, the narrower the transition zone will be.

If the reservoir rock has larger pores, or there is a preferential wettability for the oil, there may be a case where the oil/water (T/A) contact coincides with the FWL.

In the case of a clastic rock, considered preferentially wettable for water, with a significant pore size distribution, the oil/water T/A contact will be much higher than the FWL.

Fig. 7 illustrates four sand layers that have different pore size distributions, different porosities and permeabilities.

Each layer has a characteristic capillary pressure difference curve.

Well 1 will intercept sand 1 only in the oil zone, from sand 2 and 3 the oil/water contact value can be estimated and in sand 4 the oil zone is missed.

In sand 1 the well does not intercept the oil/water contact, but based on the FWL and the capillary pressure curve its value can be found.

Due to the very good properties of the layer, it coincides with the FWL.

For sands 2 and 3 there is the possibility of verifying the oil/water T/A contacts estimated on the basis of capillary pressure data with those indicated by petrophysical investigations [15,17].

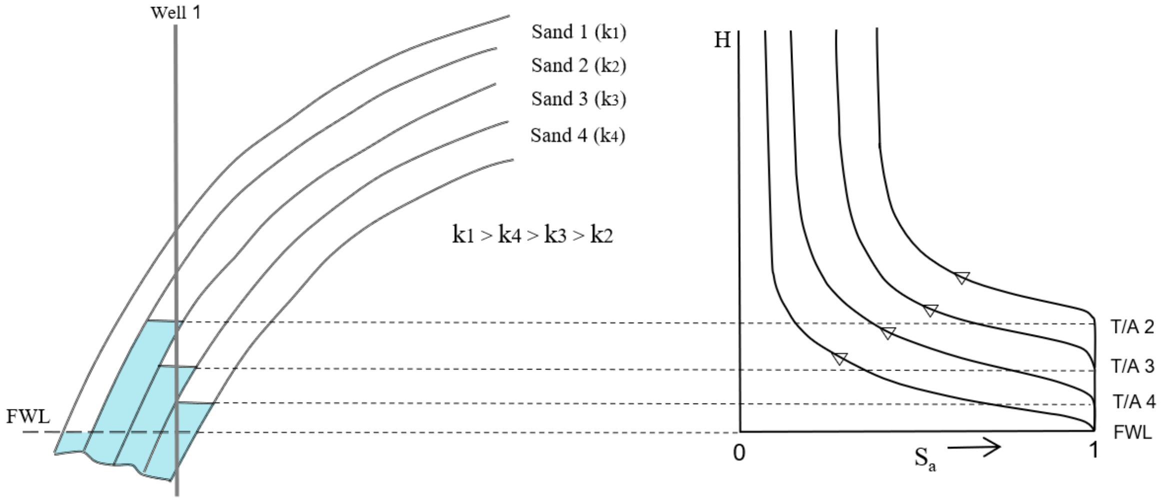

Fig. 7. Sketch of characteristic curves of Δc_p (capillarity pressure difference) for sands with different properties

3.4 Generating a Water Saturation Profile for a Well Based on Δc_p Data

One method of obtaining the saturation profile in a well requires FWL and capillary pressure data available for each rock type intercepted, expressed as depth above FWL function of saturation.

Based on the FWL, the depth point from which the Δcp curves start is identified.

From these curves, now calibrated for depth, the saturation values corresponding to each type of rock are extracted.

Thus, the saturation profile will be made up of fragments of the capillary pressure curves chosen according to the depth and the type of rock intercepted.

The process is illustrated in the following Fig. 8.

Five rock types have been identified for the sketched example, with capillary pressure data available for each. FWL is at 1615m (5300 feet). The saturation profile is built based on the lithology indicated for each depth value and the corresponding Δc_p curves. Two oil/water T/A contacts can be defined, one for the lower zone, consisting of rocks with better properties oil/water T/A 1=1615m (5300 feet) =FWL and one for the zone of rocks with poorer properties, oil/water T/A 2 = 1570m (5150 feet).

This saturation-height dependence was derived for modeling saturation in water.

It must be confirmed with the petrophysical investigations carried out in the borehole [15,17].

3.5 Representativeness of Experiments (Quality Check)

In addition to all aspects of core collection, transport and storage, a very important factor in the design and conduct of experiments is the use of injection pressures or centrifuge speeds that closely reflect the true capillary forces existing in the reservoir before production begins.

Centrifuge tests have become the preferred method in the industry for measuring the capillary pressure difference on cores.

The maximum centrifuge speed should vary from reservoir to reservoir and be based on the degree of closure of the reservoir (the height of the oil column).

To determine this rate, three parameters are required: reservoir closure and reservoir density of water and oil.

As previously mentioned, the term reservoir closure is defined as the difference between the depth of the upper boundary and the depth of the lower boundary of the oil zone.

For a oil - water system, the maximum capillary pressure difference corresponding to the maximum velocity can be calculated as follows: we assume the water gradient is 0.1 bar/m ($grad_a$) and the oil is 0,067 bar/m ($grad_t$).

If the total reservoir closure (height above the oil – water contact) is 120 m, the maximum capillary pressure difference is approximately 4 bar, [(0,1-0,067)x120].

Thus, in this example, the maximum centrifugation speed should correspond to a capillary pressure difference of 4bar [15,17].

The usual practice is to operate the centrifuge test until the speed at which no more water will be produced or until we reach 4 bar.

This 4 bar limit is a relatively arbitrary limit and based on previous calculations. It only applies to reservoirs with a closure of less than 120 m (for densities above).

For major reservoirs, which most likely have closures greater than 120 m, this limit is not valid. If this reservoir had a closure of 240 m, then the capillary pressure difference would be 8 bar.

The water saturation above the transition zone is generally considered to be constant.

Thus, even if we increase the spin speed, the irreducible water saturation measured will be essentially the same.

This perception is not valid for all practical cases, in some situations the capillary pressure curve does not reach a minimum in water saturation; rather, it asymptotically approaches a lower value of saturation in water.

4. DATA CONVERSION AND THE IMPORTANCE OF PROTECTIVE ROCK PROPERTIES

There are cases where the entry pressure for the protective rock is exceeded and thus the reservoir will not be saturated down to the inferior limit of the structure.

The fluid column will stabilize at a certain value h, which provides a buoyancy of the oil equal to the entry pressure of the protective rock.

In a reservoir for which the protective rock entry pressure, contact angles, interfacial tensions for both systems (Hg/air, oil/water) and fluid densities are known, the maximum size of the oil column that the protective rock can support can be calculated.

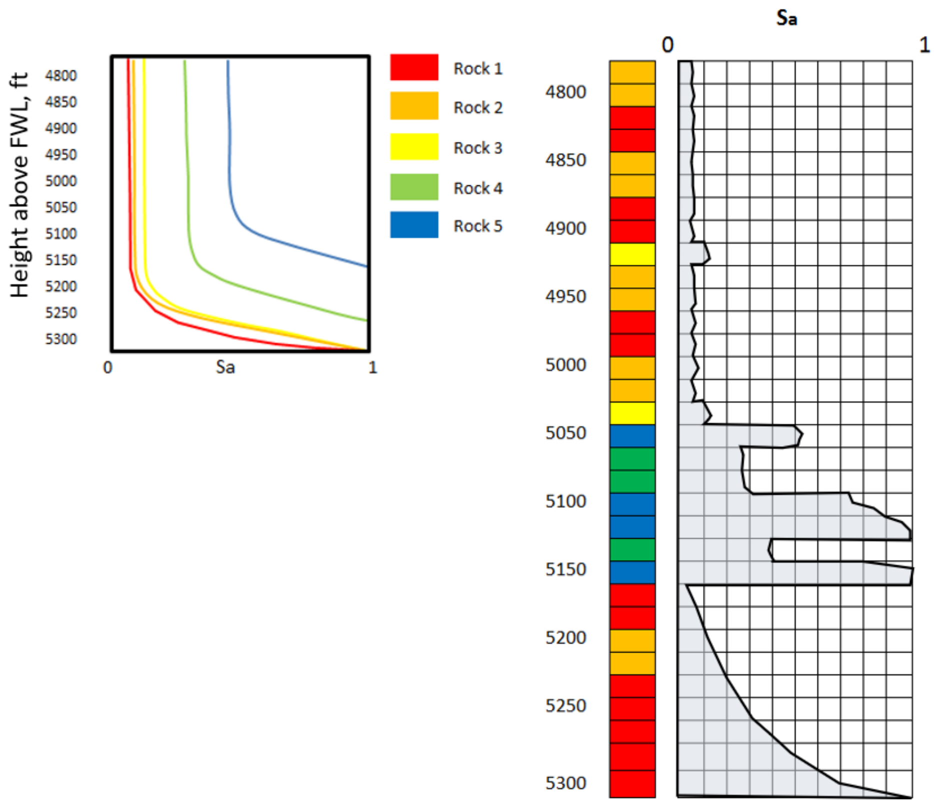

Fig. 8. Water saturation profile for a well based on ∆cp data. HOT - reservoir characterization

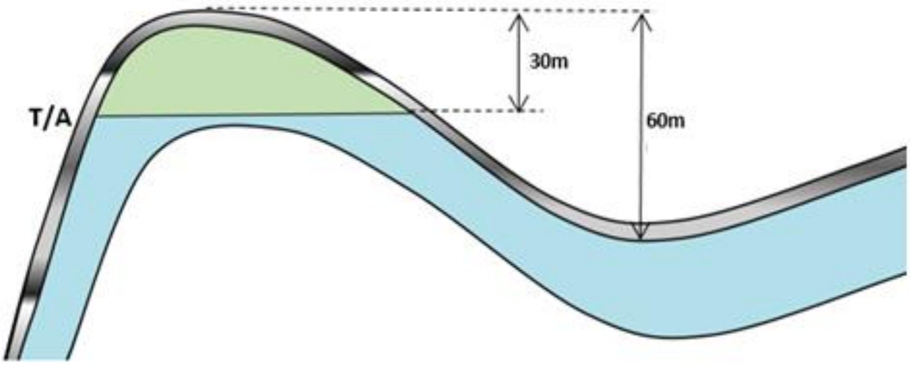

Fig. 9. Oil column and reservoir closure in cross-section

In the following example, consider:

- The entry pressure *(ΔC_p)* of the protective rock is 10 bar, measured in the laboratory by mercury Injection
- Relative density (ρ_{rel}) of water 1,03 and oil 0,8
- Interfacial tension (σ) Hg/air of 480 mN/m, σ O/W of 25 mN/m
- Contact angle (Θ) Hg/air of 140^0 and O/W of 0^0

To calculate the maximum column of oil for which the protective rock has sealing capacity, the first step is to perform a conversion.

In the case of the mercury injection experiment (MICP) higher pressures are used than for the oil/water system.

For this reason we need to calculate the inlet pressure for the oil/water system.

$$\Delta Cp_{\left(\frac{O}{W}\right)} = \frac{2\sigma_{(O/W)} cos\Theta_{(O/W)}}{r}$$

$$\Delta Cp_{\left(\frac{Hg}{Air}\right)} = \frac{2\sigma_{(Hg/Air)} cos\Theta_{(Hg/Air)}}{r}$$

$$\Delta Cp_{\left(\frac{O}{W}\right)} = \Delta Cp_{\left(\frac{Hg}{Air}\right)} \frac{\sigma_{(O/W)} cos\Theta_{(O/W)}}{\sigma_{(Hg/Air)} cos\Theta_{(Hg/Air)}}$$

$$\Delta Cp_{\left(\frac{O}{W}\right)} = Pc_{\left(\frac{Hg}{Air}\right)}\, x\, 0{,}068$$

$$\Delta Cp_{\left(\frac{O}{W}\right)} = 10\, x\, 0{,}068 = 0{,}68\, barg$$

$$\Delta Cp_{entry\left(\left(\frac{O}{W}\right)\right.} = 0{,}098\, (\rho_{rel\ water} - \rho_{rel\ oil})h$$

Equating the last two formulas results in a maximum height for these conditions of approximately 30 meters (Fig. 9).

5. CONCLUSION

1. The interpretation of the laboratory data needed to define the transition zone is a complex process that requires a conversion of the data according to the experiments performed.
2. Based on the capillary pressure difference information, the transition zone is defined.
3. This has an important role in the correct estimation of the initial oil resource and in the optimal placement of the wells.
4. A suitable set of capillary pressure difference data can be used to create the saturation profile for the sampled well.
5. The obtained saturation values can be used to calibrate information from geophysical well investigations and validate them for areas where the wells do not have cores collected.
6. In certain situations, especially in cases of exploration, it is possible and useful to estimate the height of the oil column without the structure being completely defined by wells, by analyzing the protective rock properties.

COMPETING INTERESTS

Authors have declared that no competing interests exist.

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