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Capillary Pressure and Rock Wettability Effects on Wireline Formation Tester Measurements

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Abstract

Wireline formation testers such as the well established Repeat Formation Tester (RFT™) and the more recent Modular Dynamics Tool (MDT™) measure the pressure of the continuous phase present in the invaded region, which is typically drilling fluid filtrate. Conventional interpretation techniques have often assumed this pressure identical to the pressure of the continuous phase in the virgin region of the formation, i.e., formation fluid pressure. As such, a series of pressure measurements at different depths would be expected to consistently yield a pressure gradient corresponding to the density of the formation fluid. More recent work has pointed out that this assumption cannot be entirely correct, otherwise it would appear that most formation tester surveys are anomalous.

In reality, because the concepts of free fluid level, fluid contacts, rock wettability, and pore fluid pressures are so intimately related, the measured tester pressure cannot be simply identical to formation pressure. Rather, it is different from the formation fluid pressure by the amount of capillary pressure, which is itself mainly a function of the wetting phase saturation. The effects of rock wettability and capillary pressure on wireline formation tester measurements are often manifested in one or both of two ways:

1) Fluid level changes, which affect the position of the free water level with respect to the fluid contacts determined from other openhole logs.
2) Gradient changes, which affect the slope and scatter of the gradient lines.

This paper explores the effects of capillary pressure and formation wettability on wireline formation tester measurements and investigates ways of correcting or compensating for these effects.

Introduction

Wireline formation testers measure the pressure of drilling fluid filtrate, the continuous phase present in the invaded region. According to conventional assumptions, this pressure is identical to the pressure of the formation fluid, implying that the wireline tester measurement is unaffected by the invasion process. Recent work has shown that many formation tester surveys cannot be explained if these assumptions were true. In reality, the concepts of free fluid level, fluid contacts, rock wettability, and pore fluid pressures are so intimately related that the measured tester pressure cannot be simply identical to formation pressure. This paper explores the effects of capillary pressure and formation wettability on formation tester measurements, as manifested in fluid level and/or gradient changes, and investigates ways of attempting to correct for these effects.

Uses of formation pressure measurements

Formation pressure measurements in a virgin reservoir provide a wealth of information about that reservoir. They are important in supplementing data unattainable from seismic surveys, cores, conventional logs, and geological studies, hence helping to develop a static model of the reservoir. The distribution of formation pressure across a hydrocarbon reservoir and across its associated sedimentary basin provides invaluable insights into their history, structure, as well as formation and fluid characteristics. Pressure gradients identify producible fluid by determining fluid densities and locating fluid contacts.

Fluid density controls to a large extent the distribution of fluids in the reservoir. This allows the use of pressure gradient measurements for fluid identification and for the location of reservoir fluid contacts. In thick reservoirs, density variations may be discernable within the same reservoir. This may occur for light crudes, which are often near-critical temperatures and pressures, or for heavy crudes, which have high wax and asphaltene content. The lack of chemical equilibrium in reservoirs affected by recent fluid migration can also lead to pressure profile alterations. When barriers to vertical flow exist, the vertical pressure gradients will exhibit step-wise changes, and when virgin pressures change radically between two nearby wells, these two wells are likely situated in different reservoir compartments. If, on the other hand, virgin reservoir pressures show fluid pressures that are abnormally high or low, one can conclude that past uplift or erosion must have occurred.

In the more complex case of a developed reservoir, formation pressures can also yield a lot of information. The reservoir-pressure distribution changes after some oil has been withdrawn. The fluid production causes a pressure drop around the wellbore and a gradual decrease of pressure throughout the reservoir. The pressure disturbance propagates faster through the thinner, more permeable layers stopping when it reaches impermeable faults or boundaries. As such, this pressure drop can be used to further our understanding of the reservoir's structure by providing a way of zoning the reservoir into different layers. Since pressure is, in essence, a measure of the potential energy used to drive fluid movements in the reservoir, reservoir pressure measurements can provide an estimate of aquifer or gas cap support. Moreover, because pressure differences are enhanced by production, reservoir heterogeneities not detected by virgin formation pressure measurements may be clearly revealed by post-production pressure measurements. Such is the case for alternating layers of high and low permeability, which should exhibit differential depletion rates.

Definitions

In an oil reservoir, water will normally compete with oil and gas for pore space. This is because water was present in the pores before oil migrated into the reservoir. Thus, at the same depth in a formation, pressures will be different depending on whether oil or water is filling the pores. The amount of pressure difference between the two fluids is largely controlled by pore geometry, rock wettability and the interplay of interfacial tensions between rocks and fluids.

Before proceeding on to a more detailed discussion of the effects of wettability and capillary pressure on formation pressure measurements, some definitions may be handy.

Wettability is the preferential affinity of the solid matrix for either the aqueous or oil phases. It can also be defined as the tendency for one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids. It is normally quantified by the value of the contact angle, such that a value less than 90 degrees indicates a water-wet system, and a value greater than 90 degrees indicates an oil-wet system. Wettability is an important petrophysical parameter, which affects saturation and recovery. **Fig.1** shows the situation that would occur if the rock had a preference for being water-wet, wherein an isolated droplet of oil is being squeezed from all directions by water. As a result, the pressure of the oil becomes higher than that of the surrounding water by an excess amount termed capillary pressure. On the other hand, if a rock is preferentially oil-wet, the reverse occurs, with the oil being the continuous phase and the pressure being higher in the water. **Fig.2** shows how the surrounding oil in an oil-wet rock squeezes the water droplets from all directions.

Capillary pressure (P_c) is the excess pressure seen by the non-wetting phase. It is defined the following equation:

$$P_c = P_{\text{nonwetting phase}} - P_{\text{wetting phase}} \qquad (1)$$

The value of capillary pressure is dependent on the saturation of each phase, on which phase is the continuous phase, and on the shape and size of the pores and pore throats.

Displacement pressure (P_D) is the threshold or entry capillary pressure needed for the non-wetting phase to displace the wetting phase from the largest pores.

Drainage is a process in which the wetting phase saturation decreases and the non-wetting phase saturation increases.

Imbibition is process in which the wetting phase saturation increases and the non-wetting phase saturation decreases.

The Free water level (FWL) in a reservoir is the level at which the oil-water capillary pressure vanishes. It is the oil-water interface that would exist at equilibrium in an observation borehole, free of capillary effects, if it were to be drilled in the porous medium and filled with oil and water.

The Oil-water contact (OWC) is the level at which the hydrocarbon saturation starts to increase from some minimum saturation. In a water-wet rock, that minimum saturation is essentially zero.

The residual oil saturation (Sor) is the oil saturation level above which the oil starts to be moveable.

The connate or irreducible water saturation (Swc) is the water saturation level below which the water becomes immovable.

Supercharging is a phenomenon that leads to measurement of a formation pressure that is higher than actual, leading to scattered pressure profiles or to altered gradients. The degree of supercharging is generally inversely related to permeability.

Wettability of a porous medium

One of the fundamental pieces of information required for efficient design of oil recovery processes is the reservoir wettability. Wettability has been the subject of much research for the last 60 years for its effects on capillary pressure, relative permeability, electrical properties, water cut production, waterflood behavior, and enhanced recovery. This is because wettability determines the fluid distribution in a porous medium. The wetting fluid coats the surface of the solid grains, occupies the corners of grain contacts and resides in the smaller pores. In order to minimize the system's specific surface free energy, the wetting phase occupies the small pores, which have high specific surface area. On the other hand, the non-wetting phase is stays in the center of the pores and is concentrated in the larger pores.

Oil-wet and mixed-wet reservoirs, once considered a rarity, have been found by several researchers to form half or more of all reservoirs (Chiligarian and Chen, 1983). In their natural state, rocks may be either water-wet or oil-wet according to the atoms exposed in the grain or pore surface. Naturally water-wet rocks include quartz, calcite, and dolomite, while naturally oil-wet rocks include coal, sulfur, and some silicates. In the case of rocks, which tend to be water-wet, they become thus when the oxygen atoms exposed at their surfaces attract hydrophilic hydrogen from the water molecules. If polar impurities such as resins or asphaltenes can reach the surface, they will substitute lipophilic radicals for the H or OH, rendering the surfaces oil-wet. Note that while only basic impurities will attach to quartz, both basic and acidic impurities can attach to calcite. This might explain the large percentage of carbonate reservoirs found by several researchers to be oil-wet (Treibel et al, 1972). In their study of 155 carbonate reservoirs worldwide, Chillinger et al found that 65% are moderately to strongly oil-wet (contact angles 100-160). Oil wettability can be artificially induced by treating the surface of the pores with substances that bond to the surfaces and render them oil-wet, such as chlorosilane compounds.

Increased surface roughness tends to make the water-wet rocks even more water-wet, while making the oil-wet rocks still more oil-wet. As most rock surfaces are rugose, few formations are neutrally wet, but some researchers have reported fractional wettability conditions, in which some portions of the rock are strongly oil-wet and others strongly water-wet (Brown et al, 1956). Salathiel, in his landmark 1972 work, identified mixed wettability reservoirs in which the polar impurities reach the larger but not the smaller pores, resulting in a case wherein the larger pores (higher porosity) become oil-wet, the smaller pores (lower porosity) remain water-wet, and both remain continuously connected. As shown in his core flood experiments, mixed-wet rock exhibited a very low residual oil saturation but slow oil production rates at these low saturation.

Consistent with Salathiel's vision of continuous oil and water phases, Hiekal et al. have hypothesized that configurations of oil in pores involve either direct contact between oil and rock in the larger grains and pores (**Fig.3)**; or separation of the oil phase from the solid by aqueous films in the smaller grains and pores (**Fig.4)**. In the larger grains and pores, the oil saturation is highest. When a critical capillary pressure is exceeded, water films destabilize and rupture to an adsorbed molecular film of up to several water mono-layers. Crude oil now contacts rock directly, allowing the polar oil species to adsorb and/or deposit onto the rock. It is this process that locally reverses the wettability of certain sections of the rock from water-wet to oil-wet (Morrow, 1991).

Wettability effects on saturation in a mixed-wet reservoir-Example of a mixed-wet reservoir

The Nubian Sandstone reservoir in the Zeit Bay field, located offshore the Gulf of Suez, Egypt is a vivid example of mixed-wet reservoirs, which was used in this work to investigate the effects of wettability and capillarity on formation pressure measurements. It is a fine to coarse-grained sandstone reservoir deposited on the lapping wedge of a tilted eroded basement block. Ranging in thickness from nil to 600 ft-TVT, the Nubian Sandstone is a highly productive reservoir with average porosity and connate water saturation of 19% and 13%, respectively. Exhibiting high average horizontal permeability is 400md and a Kv/Kh ratio close to unity, the reservoir has been proven to be in complete hydraulic communication, showing the same pressure trends all across. (Hiekal et al., 1998).

The mixed wettability condition was deemed consistent with reservoir features found in the Nubian Sandstone reservoir of the Zeit Bay field. The high oil saturations (up to 30%) found below the OOWC in wells A1, C3 and L7 (**Fig.5**), and the very low connate water saturation level (less than 6%) found in some rock types suggest that some of the pore system is oil-wet. Another phenomenon that supports this hypothesis is that significant oil saturations were found at depths below the original OWC (OOWC) in high porosity intervals. Although this oil may represent a paleo-residual zone formed by leakage of oil prior to discovery of the field, there are no oil seeps at the surface above the oil accumulation to support this view. On the other hand, water saturation versus depth profiles for low and moderate porosity intervals do not show any moveable oil below the OOWC, contrary to what would be expected if oil seepage were the source of this residual oil. For example, moveable oil was detected at a depth of 5,100 ft-TVDss in well L7, which is 265 ft-TVT below the OOWC (**Fig.6**). In fact, wherever the porosity is greater than 19% (between the depths of 4,835 ft-TVDss and 5,100 ft-TVDss), oil is found indicating oil-wet rock. In contrast, wherever porosity is less than 19% (depths below 5,100 ft-TVDss), very little oil can be found indicating water-wet rock. (Hiekal, 1998).

A mixed wettability condition would explain the foregoing observations. As oil accumulated in the reservoir, water present in the initially water-wet rock was displaced from the larger pores while capillary forces retained water in smaller capillaries and at grain contacts. After extended periods of exposure to this fluid distribution, the required conditions for mixed-wettability developed. As the oil saturation in the larger pore increased, the capillary pressure rose, and when a critical capillary pressure was exceeded, the water films destabilized and ruptured to adsorbed molecular films of up to several water mono-layers, allowing crude oil to contact the rock directly. This, in turn, allowed the organic surface-active agents to adsorb and/or deposit onto the rock surfaces in the larger pores, thus reversing the native wettability of the higher porosity rock from water-wet to oil-wet. On the basis of this model, the high porosity system within the Nubian Sandstone can be considered to be oil-wet while the lower porosity system can be considered to be water-wet (Hiekal et al., 1998).

The water connate water saturation, measured 100 ft-TVD above the OOWC (i.e., above the transition zone), was taken as another indication of wettability. The relationship between porosity and connate water saturation was based on multiple well log data. **Fig. 7** shows that two distinct systems exist; with the high porosity system having a very low connate water saturation (as low as 4%) as would be expected in an oil-wet system; and the low porosity system having a higher connate water saturation of up to 25% as would be expected in a water-wet system. This again confirms that the low porosity system in the Nubian Sandstone is preferentially water-wet while the high porosity system is preferentially oil-wet (Hiekal et al., 1998).

Capillary pressure in a porous medium

The combined effects of wettability and interfacial tension cause the wetting fluid to be simultaneously imbibed into a capillary tube. This phenomenon is known as capillarity and is significant in a porous medium saturated with two or more immiscible fluids since the interconnected pores of the medium are of capillary dimensions. As defined earlier, capillary pressure represents the pressure differential that must be applied to the nonwetting fluid in order to displace a wetting fluid. For the capillary tube, an often used yet admittedly simplistic representation of a pore throat, capillary pressure can be expressed as:

$$P_c = P_{nw} - P_w = 2\sigma \cos\theta / r = (\rho_w - \rho_{nw})gh \quad \text{......(2)}$$

Where σ is the interfacial tension between the two fluids, θ represents the wettability of the capillary tube, r is the radius of the capillary tube, P_w, Pn_w are the pressures of the wetting and non-wetting phases, respectively, and ρ_w and ρ_{nw} are the wetting and non-wetting phase densities, respectively.

For a pendular ring at the contacts of two spherical sand grains in an idealized porous medium consisting of a cubic pack of uniform spheres (**Fig. 8**), the capillary pressure in general, can be expressed by the Laplace equation (Eq.3). This is a more general expression for the pressure difference across the curved interface between two immiscible fluids, with the pressure on the concave side greater than that on the convex side. In fact the capillary tube expression is a special case of the Laplace equation, which can be expressed as follows:

$$P_c = \sigma\,(1/r_1 + 1/r_2) \quad \text{......(3)}$$

Where r_1 and r_2 are the two principal radii of curvatures of the interface in two perpendicular planes as shown on **Fig 8**. According to the figure and the Laplace equation, as the wetting fluid saturation in the pendular ring is increased, the radii of curvature will be increased, and the capillary pressure will decrease. Vice versa, as the wetting fluid saturation in the pendular ring is reduced, the radii of curvature will be reduced and the capillary pressure will increase. Of course, for an actual porous medium, the complexity of the pore structure and the fluid interface arrangements therein precludes the use of the above equation directly to calculate the capillary pressure. Instead, the capillary pressure is measured experimentally as a function of the wetting fluid saturation. Still, in general, the mean radius of curvature and the capillary pressure increase as the wetting phase saturation decreases. This can be expressed in the general form below:

$$P_c = fn(Sw) \propto \sigma / r_m \quad \text{......(4)}$$

Where r_m represents the mean radius of curvature.

The capillary pressure curve of a porous medium

The capillary pressure curve for a porous medium is a function of pore size, pore size distribution, pore geometry, fluid saturation, fluid saturation history or hysterisis, wettability, and interfacial tension. **Fig.9** shows drainage and imbibition capillary pressure curves. The drainage capillary pressure curve describes the displacement of the wetting phase from the porous medium by a non-wetting phase, as is relevant for the initial fluid distribution in a water-wet reservoir as well as for the water front advance in an oil-wet reservoir. The imbibition capillary pressure curve, on the other hand, describes the displacement of a non-wetting phase by the wetting phase, as is relevant for water front advance in a water-wet reservoir. In both cases, the capillary pressure is equal to the non-wetting phase pressure minus the wetting phase pressure as given by Eq.2.

The capillary pressure curve has several characteristic features. Focusing on the drainage curve and describing it in more detail, one finds that the minimum threshold pressure is the displacement pressure that must be applied to the wetting phase in order to displace the non-wetting phase from the largest pore connected to the surface of the medium such that:

$$P_{c)Displacemnet} = (P_{nw} - P_w)_{displacement} = 2\sigma \cos\theta / r_{Largest\ pore} \quad \text{......(5)}$$

A lower displacement pressure indicates larger pores connected to the surface, which generally implies higher permeability. As the pressure of the non-wetting phase is increased, increasingly smaller pores are invaded corresponding to the flat section of the curve. A lower capillary flat section indicates larger pores, and consequently higher permeability. A capillary pressure curve that remains essentially flat over its middle section indicates that many pores are being invaded by the non-wetting fluid at the same time, implying that the grains are well sorted and the rock is fairly homogeneous. Inversely, the higher the slope of the middle section of the capillary pressure curve, the worse the sorting and the wider the grain and pore size distributions. Such a rock has lower porosity and generally lower permeability as well. A very steep capillary pressure curve that is nearly vertical over its middle section implies poor reservoir rock with extremely fine grains, very poor sorting, low porosity, and low permeability. Eventually, when the irreducible wetting fluid saturation is reached, the capillary pressure curve becomes nearly vertical. At this stage, the wetting phase becomes discontinuous and can no longer be displaced from the porous medium simply by increasing the non-wetting phase pressure. A lower wetting phase irreducible saturation is generally indicative of relatively larger grains and pores. Generally speaking, therefore, a higher capillary pressure curve describes poorer reservoir quality compared to a lower curve.

The capillary pressure curves for rock samples from the same reservoir having different permeabilities will be different. It is often necessary to average the capillary pressure data for cores from the same reservoir to obtain one capillary pressure curve representative of the whole reservoir. This can be done through use of a dimensionless capillary pressure relation called the Leverett J-function. In this function, Leverett (1941) used a characteristic pore dimension equal to the square root of the ratio of the permeability and porosity of the medium as an equivalent for the capillary tube radius in the capillary rise expression. In oilfield units, the Leverett-J function is given by:

$$J(Sw) = (6.848\ Pc \sqrt{k/\phi}) / (\sigma \cos\theta) \quad \text{.......(6)}$$

Where σ is the interfacial tension in dyne/cm, k is the permeability in darcy, and Pc is the capillary pressure in psi.

Comparing the above definition to the capillary rise expression tells shows that the equivalent J-function for a capillary tube is a fixed value of 2. It has been confirmed by many researchers that different capillary pressures for cores from the same reservoir rock will yield the same J-function (Leverett, 1941 and Bear, 1951). On the other hand, the Leverett J-function for different rock types will be different. The concept of a dimensionless characteristic capillary pressure curve for the reservoir provides the flexibility of making laboratory capillary pressure measurements with more convenient fluids than reservoir fluids. This enables the conversion of core capillary pressure data measured in the laboratory to reservoir conditions even if the fluid combination used in the lab is completely different than the one encountered in the reservoir.

Wettability and capillary pressure effects on a reservoir's static pressure gradient

All petroleum reservoirs were initially saturated with water before oil migrated into the reservoir, displacing the water. The resulting fluid distribution is governed by the equilibrium between gravitational and capillary forces. In the case of a water-wet reservoir, this distribution is simulated by a drainage capillary pressure curve. Using the FWL as the reference datum, The water and oil phase pressure at a distance z above the FWL datum are given by the following two expressions:

$$P_w(z) = P_{FWL} - \rho_w g z \quad \text{.......(7)}$$
$$P_o(z) = P_{FWL} - \rho_o g z \quad \text{.......(8)}$$

Subtracting the two equation and using oilfield units yields an expression for the capillary pressure provided the two phases are continuous:

$$P_c(z) = (\rho_w g z - \rho_o g z)/144 = \Delta\rho g z/144 \quad \text{.......(9)}$$

where P_c is in psi, $\Delta\rho$ is in lbm/cu.ft, and z is in ft.

The FWL is generally not coincident with the OWC but, instead, differs by an amount related to the displacement pressure. In a water-wet reservoir, the FWL occurs at a depth d_o below the oil-water contact given by:

$$d_o = (P_D/\Delta\rho g) \times 144 \quad \text{.......(10)}$$

where P_D is the displacement pressure (oil displacing water) in psi, $\Delta\rho$ is in lbm/cu.ft, and z is in ft. It is determined by largest pore of the pore size distribution

The capillary transition zone is the region above the OWC where the water saturation decreases from its maximum value (100% in a water-wet rock) to the irreducible water saturation. The height of the transition zone is a function of wettability, the fluid density contrast, and the oil-water interfacial tension. In addition to these factors, and just like for a capillary pressure curve, the shape of this transition zone is dependent on several other factors, including pore size, pore size distribution, pore geometry, fluid saturation, and fluid saturation history. This is demonstrated graphically in **Fig.13**. The elevation (h) above the OWC of any particular saturation within the transition zone is given by:

$$h(S_w) = (P_c(S_w) - P_D)/\Delta\rho g \times 144 \quad \text{.......(11)}$$

In a layered reservoir, in which layers have different capillary pressure curves, the layers must remain in capillary pressure equilibrium on either side of layer boundaries. As a result, saturation discontinuities will occur, but there will be only one FWL.

In an oil-wet reservoir (**Fig.14**), the situation described above is slightly different. In this case, it is the water that is the non-wetting phase, and hence, its pressure is higher than it would be in a water-wet medium. Even though the reservoir was initially saturated with water before oil migrated into the reservoir and displaced the oil, an imbibition capillary pressure curve, rather than a drainage curve better describes the situation once the reservoir has become preferentially oil-wet reservoir. As an imbibition curve would predict, the minimum oil saturation encountered below the zero capillary pressure line is not zero, but rather a residual value, S_{or}. Since it is easier to displace water than oil in this case, the portion of the capillary pressure curve below the zero line (corresponding to the FWL) is larger than the part above. Consequently, he OWC in this case is the lowest level that the oil will reach (at which the oil saturation will start to increase from its minimum value). The FWL is located above the OWC by a distance d_o given by:

$d_o = (P_D/\Delta\rho g) \times 144$……………………………………(12)

which is generally larger than the equivalent distance in a water-wet rock. Also unlike for a water-wet reservoir, this distance is determined by the smallest-rather than the largest-pore of the pore size distribution.

Wettability and capillary pressure effects on tester gradient measurements

From the foregoing discussion, it is clear that a capillary pressure difference will exist between the oil and water in the capillary transition zone by virtue of the very existence of that transition zone. Despite this, and despite the fact that the tool actually draws mud filtrate into its small test chamber(s), conventional formation tester interpretation methods assume that the tool measures the true formation pressure of the continuous mobile formation fluid in the virgin zone. The fallacy of this assumption is made clear by examining **Fig.10 (a to h)**, which details the saturation profile for various wetting fluid-drilling mud-formation fluid combinations, **Fig.11(a to h)**, which details the capillary pressure distribution corresponding to each combination, and **Fig.12(a and b)**, which details the effect of these combinations on the wireline pressure tester gradient measurements.

For a well drilled with water-based mud in a water-wet formation, the oil in the flushed zone of an oil-bearing interval (**Fig.10-c**) is close to residual saturation so that the capillary pressure in the invaded zone becomes small (**Fig.11-c**). The result is that the water-phase pressure actually measured is only marginally lower than the oil phase pressure that we desire to measure, shifting the oil gradient slightly to the left (top of left plot of (**Fig.12-a**)). In the water-bearing interval (**Fig.11-a**), there will be no capillary pressure difference between the mud filtrate and the formation water, and the tool measures the true formation pressure (**Fig.11-a**) and (bottom of left plot of (**Fig.12-a**)).

For a well drilled with oil-based mud in a water-wet formation, there is no capillary pressure difference between the mud filtrate and the formation oil in an oil-bearing interval, so the tool measures the actual formation gradient (**Fig.10-d**), (**Fig.11-d**) and by The formation tester over-estimates the value of the true formation gradient by In the water-bearing zone (**Fig.10-b**), the water saturation in the invaded zone is close to connate or irreducible, and the capillary pressure is large (**Fig.11-b**). The value of the oil pressure actually measured is thus higher than the water pressure that is desired by P_c(Swc). The measured water gradient is thus shifted to the right (bottom of right plot of (**Fig.12-a**)). In a gas reservoir drilled with oil-based mud, the pressure measured in the water zone is similarly boosted by an amount equal to the capillary pressure. The situation is further complicated by the existence of three phases but can be simplified by treating the water and oil as a single wetting phase and the gas as the non-wetting phase which controls the capillary pressure. In the invaded zone, however, gas saturations are normally close to residual levels, and the capillary pressure is nearly nil, so the capillary effect on the pressure measurement can be safely neglected.

For a well drilled with water-based mud in an oil-wet formation, the oil in the flushed zone of an oil-bearing interval is close to residual saturation (**Fig.10-g**), and the capillary pressure is maximum (**Fig.11-g**). The measured water phase pressure is higher than the oil phase pressure by the amount of P_c(Sor). The formation tester thus over-estimates the value of the true formation pressure, shifting the oil gradient line to the right (top of left plot of (**Fig.12-b**)). In the water-bearing interval, there will be no capillary pressure difference between the mud filtrate and the water, and the tool measures the true formation gradient (**Fig.10-e**, **Fig.11-e** and bottom of left plot of (**Fig.12-b**)).

For a well drilled with oil-based mud in an oil-wet formation, there is no capillary pressure difference between the mud filtrate and the formation oil in an oil-bearing interval, so the tool measures the actual formation gradient (**Fig.10-h**, **Fig.11-h** and top of right plot of (**Fig.12-b**)). In the water-bearing zone, the water saturation in the invaded zone is close to irreducible, and the capillary pressure is a small value (**Fig.10-f** and **Fig.11-f**). The result is that the measured oil pressure is slightly lower than the desired water pressure. Thus, the measured water gradient is slightly shifted to the left (bottom of left plot of (**Fig.12-b**)).

When one of the two phases becomes discontinuous at low saturation, its pressure follows the gradient of the other (continuous) phase. The pressure of a discontinuous phase is unobservable except under lab conditions and is of no practical importance. In silty sandstone reservoirs, the irreducible water saturation corresponding to the top of the capillary transition zone may be quite high yet the oil phase is continuous and the well produces oil. A magnetic resonance log would be able to differentiate moveable from bound fluid, but if only conventional logs are available, potential recoverable oil will probably be missed. In such a case, formation tester gradients can be used to distinguish between moveable oil, which appears as a continuous oil gradient on the pressure measurements despite the high water saturation, and residual oil, which appears as a continuous water gradient. The importance of this for reserve estimation is obvious.

Wettability and capillary pressure effects on tester fluid level measurements

The effects of wettability and capillary pressure on the wireline formation tester's fluid level measurement are closely linked to their effects on gradient measurements. Ordinarily, the intersection of the continuous phase pressure lines on a depth-pressure diagram occurs at the FWL as shown in **Fig.13** and **Fig.14** for water-wet and oil-wet reservoirs, respectively. The intersection of the water and hydrocarbon continuous phase pressure lines as measured by the wireline formation tester is an indication of the FWL. In general, however, this intersection will differ from the FWL in a direction that reflects the rock wettability and by an amount that is dependent on the degree of wettability, the magnitude of capillary pressure, and the type of drilling mud used (**Fig.12a and b**).

In a water-wet medium, the capillary pressures in the oil-filled pores are higher than in the water-filled ones, and the FWL is located below the OWC by a distance determined by the capillary threshold or displacement pressure (**Fig.13**). As shown in **Fig.12-a**, the actual intersection of the oil and water gradients from the wireline formation will be generally higher than the true FWL. This is true for wells drilled with either water and oil-based muds. As explained in the previous section, with a water-based mud (WBM) in the oil zone, the measured pressure will be the water phase pressure, which will be lower than the oil phase pressure we are aiming to measure. Therefore, the measured oil line will be shifted to the left of the true formation oil pressure line, making the intersection higher than the actual FWL (left plot of **Fig.12a**). On the other hand, with an oil-based mud (OBM) in the water zone, the measured pressure is the oil filtrate pressure, which will be greater than the water phase pressure. Thus, the measured water line will be shifted to the right of the true formation water pressure line, making the intersection again higher than the actual FWL (right plot of **Fig.12a**).

In an oil-wet medium, the capillary pressures in the water-filled pores are higher than in the oil-filled pores, and the FWL is located above the OWC by a distance again determined by the capillary threshold or displacement pressure (**Fig.14**).. The actual intersection of the oil and water gradients from the wireline formation tester will be generally lower than the true FWL as shown by **Fig.12b**. This is true for wells drilled with either water and oil-based muds. As discussed in the previous section, with a WBM in the oil zone, the measured pressure will be the water phase pressure, which will be higher than the oil phase pressure we are aiming to measure. Therefore, the measured oil line will be shifted to the right of the true formation oil pressure line, making the intersection lower than the actual FWL (left plot of **Fig.12b**). On the other hand, with OBM in the water zone, the measured pressure is the oil filtrate pressure, which will be lower than the water phase pressure. Thus, the measured water line will be shifted to the left of the true formation water pressure line, making the intersection again lower than the actual FWL (right plot of **Fig.12a**)..

Fig. 15 and **Fig.16** show how rock wettability was detected in-situ in the mixed-wet Nubian Sandstone by its effect on the wireline formation pressure measurements (Hiekal at al., 1998). **Fig.15** shows the OWC at a depth of 4835 ft-TVDss, 20 ft-TVD below the FWL at 4815 ft-TVDss in the high porosity system of the reservoir with strong preference to be oil wet (example from well L7). On the other hand, **Fig.16** shows the OWC at a depth of 4835 ft-TVDss, 35 ft-TVD above the FWL at 4870 ft-TVDss in the low porosity system reservoir which has a strong affinity to be water-wet (example from well A1).

The three fluid column model

It should now be clear that it is not really accurate to assume that the formation tester can, in all cases, see through the invaded zone into the virgin zone. But how can one explain that even when the measured gradient is shifted or scattered, it still in many cases reflects the true formation fluid gradient? To be able to answer this question, it is best to think of a system made up of three columns in partial communication with one another, with each having its own pressure gradient. These are the mud column, the invaded zone column, and the formation fluid column.

The mud column normally contains the highest density fluid and is partially isolated by the mud cake from the annular flushed zone column, which is primarily composed of filtrate. The effectiveness of the mud-cake isolation varies with time, depth, and the amount of overbalance. A stable mud column can be considered to be a pressure sink whose gradient cannot be altered by flows into or out of the formation. At its outer boundary, the mud column is contact with the invaded zone column. This invaded zone column contains primarily filtrate, which is less dense than mud, in addition to formation fluids at residual or irreducible saturations. The static hydrostatic gradient of this column is, therefore, that of the mud filtrate. At its outer boundary, the flushed zone column is in contact with the formation fluid column. There is normally no sharp barrier between the invaded zone and the formation, so the interface between the two depends on the balance of viscous and capillary forces. The viscous forces depend on the rate of filtration through the mud-cake, while the capillary forces are controlled by, and in turn control, the saturations across the interface. Like the mud column, the reservoir fluid column is a pressure sink, and the invasion process does not affect its hydrostatic gradient.

Since the invaded zone column is in continuous contact with the mud and the formation fluid, it clearly cannot be at hydrostatic equilibrium. If the mud-cake is an effective seal, the invaded zone must come to equilibrium with the reservoir after some time. In the case of oil-based mud invading a water zone, the gradient of the water is impressed upon the filtrate so that it is forced to float upwards as far as vertical permeability allows. The extra viscous pressure drop from this vertical movement is superimposed onto the hydrostatic gradient of the filtrate so as to yield the hydrostatic gradient of the formation fluid in the invaded zone. In some cases, the mud-cake may not fully control the filtration process, leading to high rates of filtration, deep invasion, and Buckley-Leverett-type shock-front displacement in the invaded zone. Viscous forces would predominate over capillary forces, and some isolation between the invaded and reservoir columns may result. In this case, the filtrate floats upwards, whilst trying to equilibrate with the mud column. There would still be some pressure drop across the mud-cake, however, so the measured formation pressure would be lower than the mud pressure, often resulting in a gradient that is somewhere between formation and mud gradients. This helps explain one of the most commonly encountered formation pressure gradient anomalies, wherein the gradient in the oil zone is steeper than normal.

A less commonly observed gradient anomaly is one in which the gradient across an oil-bearing zone of a water-wet reservoir drilled with water-based mud is steeper than normal. This may be related to capillary hysterisis effects since the invasion of the water-based mud filtrate into the oil zone is an imbibition process. Since it is possible for the imbibition capillary curve to become negative as the oil saturation approaches residual, the water phase pressure can be higher than that of the oil phase, producing a gradient that is too steep.

Supercharging

As a consequence of mud filtrate invasion in the immediate vicinity of the wellbore, the formation may exhibit pressures higher than the actual formation pressure. This over-pressure tends to dissipate when a mud cake is established and further invasion becomes negligible. Even if a mud cake is built, however, this overpressure may still exist at the time of the pressure measurement. This effect is called supercharging and should not be confused with capillary or intrinsic formation over-pressures. Such confusion is common since supercharging is similar to capillary over-pressure effects in the sense that both are inversely related to effective permeability. As a consequence of supercharging, all permeable zones are locally, and often temporarily, over-pressured by the invading filtrate. Levels affected by supercharging in either the oil or the water zones will appear to the right of the expected formation pressure line, with gradients tending to be more scattered as the mobility of the measured phase decreases. In capillary transition zones, where often both oil and water phases are mobile, the total mobility is reduced, leading to an increase in the possibility of supercharging. As the pressure difference between the mud column and the formation increases with depth, and with everything else being equal, supercharging could possibly lead to an apparent increase in gradient.

The primary factors affecting supercharging are the degree of pressure differential across the sand-face, the extent of mud cake build-up and its effectiveness in preventing filtrate-fluid loss into the formation, and the total mobility of the formation. Fergusson and Koltz (1954) defined three stages of mud filtrate invasion. These are the initial spurt loss leading to a rapid buildup of mud cake; the dynamic filtration, which occurs when the mud cake attains an equilibrium thickness and while mud is still circulated; and the static filtration which takes place after circulation of the mud has ceased. Halford (1983) reviewed the processes of mud filtrate invasion and made some conclusions, which can be summarized as follows. Firstly, if filtration is governed by the mud cake, which is the case except in very low permeability formations, then after several hours, the dynamic rate converges to a constant rate equilibrium rate. Secondly, after about fifteen hours of static filtration, which is typical of the condition wherein formation tester surveys are run, that static loss rate may be considered constant. Thirdly, oil-based muds show lower dynamic and static loss rates compared to water-based muds. Despite this latter conclusion, oil-based muds do not always form mud cakes, and dynamic filtrate invasion continues even during the wireline formation tester survey. In extreme cases, even moderately high permeability zones may appear supercharged at the time of the survey.

Correcting for wettability, capillary pressure, and supercharging effects on the formation tester

One possible method of correcting for wettability and capillary pressure effects on wireline formation tester pressures is to construct the Leverett J-function for the reservoir from core samples and transform it to reservoir fluid conditions. This is possible because by definition of the leverett J-function,

$$J(Sw) = (6.848\ Pc\ \sqrt{(k/\phi)_{lab}})/(\sigma \cos\theta)_{lab}$$
$$= (6.848\ Pc\ \sqrt{(k/\phi)_{res}})/(\sigma \cos\theta)_{res} \quad \text{.......................................}(13)$$

The lab (core) capillary pressure data can thus be used to translated to reservoir conditions as follows:

$$Pc)_{res} = Pc)_{lab}\sqrt{((\phi_{res}\ k_{lab})/(\phi_{lab}\ k_{resevoir}))}\ x((\sigma\cos\theta)_{res}/(\sigma\ \cos\theta)_{lab}) \quad ....(14)$$

By knowing the invaded zone saturation, the amount capillary pressure can then be computed. Thus, it is possible to correct the measured formation pressure at each point by adding (or subtracting) the capillary pressure corresponding to the value of invaded zone saturation (S_{xo}) measured at that point (Awad, 1982) such that

$$P_{corrected} = P_{measured} + P_c(S_{xo}) \quad ....(15)$$

Better still, if a nuclear magnetic resonance (NMR) log is available, then the downhole capillary pressure correction can be computed directly. Unfortunately, there are many cases in which neither core data nor NMR data is available. In these cases, it is possible to derive drainage capillary curves by plotting the height above the OWC in the transition zone vs. the water saturation as computed from the openhole logs. This type of correction generally results in adjustment of the gradient towards the correct direction but may result in large scatter. This is due to the simplicity of this type of correction, which fails to take into account the vertical flow occurring within the invaded zone as detailed earlier. It is important to realize that without correction, the intersection of the hydrostatic gradients in a well drilled with OBM in a water-wet reservoir will indicate the top of the transition zone rather than the actual FWL. This is a potentially very useful measurement in its own right as it indicates the highest producible water level.

Amongst other things, the state of the art Modular Dynamics Tester MDT™ offers convenient solutions to overcome the anomalies described earlier. For instance, the ability to “pump out” mud filtrate enables the measurement of formation pressure before and after capillary pressure effect removal, and hence allows the estimation of the amount of capillary pressure. The same facility also minimizes supercharging and reduces its disturbing effect on the measured gradients. On the other hand, the flow identification abilities of the MDT such as the flow line resistivity and the optical fluid density can indicate the type and quantity of mud filtrate as well as the moveable reservoir fluid, which would help establish and confirm and correct the measured pressure gradient.

To reduce the effects of supercharging, the formation tester survey should be run as late as possible after a circulation of the well in order to maximize the time-dependent decay of the relatively large dynamic filtrate loss-rate. In fact, the usefulness of the widely used practice of routinely running wiper trips prior to wireline formation tester surveys is rather dubious, since these trips often only serve to stir up the mud column and scrape off the mud cake, leading to increased filtration rates, increased supercharging effects, and greater chances of getting differentially stuck. The true formation pressure can be obtained by applying a correction technique to correct the effects of supercharging in low permeability formation. This method can be applied by measuring P_{bh} “wireline borehole pressure” and P_{wf} “wireline formation pressure” more than two times at the same point. By plotting P_{wf} versus P_{bh}, the true formation pressure is obtained at the point where a line drawn through the data crosses a 45^o line with $P_{bh} = P_{wf}$ as shown in **Fig.17**. This technique was applied to correct the effect of supercharging in a low-permeability formation. **Fig.18** shows the pressure profile obtained with the formation tester tool. Two pretest points were identified as supercharged. The pretests were repeated after applying 300 at the mud column. The measured pressures changed at both depths, and the correction was computed according to the technique described above.

Conclusions

1. Wireline formation testers measure the pressure of the continuous phase present in the invaded region.
2. Conventional interpretation techniques assume that this pressure is identical to the pressure of the formation fluid, implying that the wireline tester measurement is unaffected by the invasion process. This in not true as proven by many field examples, particularly in OBM.
3. The concepts of free fluid level, fluid contacts, rock wettability, and pore fluid pressures are intimately related.
4. The effect of wettability and capillary pressure will make the measured formation pressure either too high or too low depending on the specific wetting fluid-drilling mud-formation fluid combination. This will result in shifted gradient lines, altered gradient slopes, or greater scatter.
5. In a water-wet medium, the FWL is expected to occur below the OWC, while in an-oil wet medium, the FWL is expected to occur above the OWC.
6. Capillary pressure effects can be corrected for, provided core and intermediate zone saturation data are available. NMR data may supplement or replace these sources.
7. The formation tester contact will generally be off from the actual FWL. In a water-wet medium, the contact will generally appear too high compared to the FWL, while in an oil-wet medium, it will generally appear too low compared to the FWL. In the latter case, the measured contact will indicate the highest producible water level.
8. The new MDT offers several features that reduce the uncertainties arising from capillary and supercharging effects. In addition to its fluid-identification features, these include the ability to pump out mud filtrate and formation fluid.

Nomenclature

CMRä: Continuous Magnetic Resonance Tool
c.u.: Capture Unit
FWL: Free Water Level
GOC: Gas Oil Contact
J(Sw): Leverett J-function
K: Permeability
MDTä: Modular Dynamics Tool
OBM: Oil-based mud
OOWC: Original Oil Water Contact
OWC: Oil Water Contact
P_c: *Capillary pressure*
P_{nw}: *Non-wetting phase pressure*
P_D: *Displacement Pressure*
P_w: *Wetting phase pressure*
p.u.: Porosity Unit
r: radius of curvature
RFTä: Repeat Formation Tester
ROS: Remaining Oil Saturation
S_{or}: *Residual Oil Saturation*
SOWC: Secondary Oil Water Contact
s.u.: Saturation Unit
S_w: *Water Saturation*
S_{wc}: *Connate Water Saturation*
S_{xo}: *Water Saturation in the flushed (invaded) zone*
WBM: Water-based mud
r: Fluid density
s: Interfacial tension
f: Porosity
q: Angle of contact

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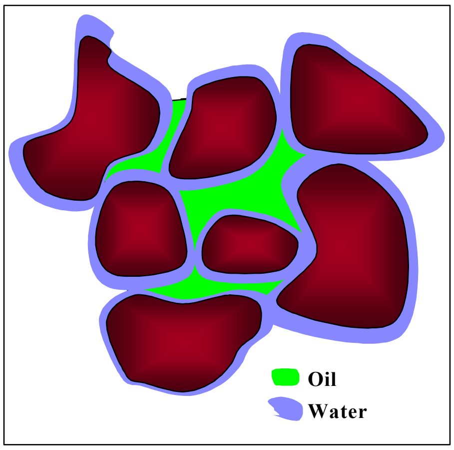

Fig.1-Schematic of Pore Cross-section in a water-wet porous media, (grains rock are surrounded by thin film of brine and are not contacted by oil).

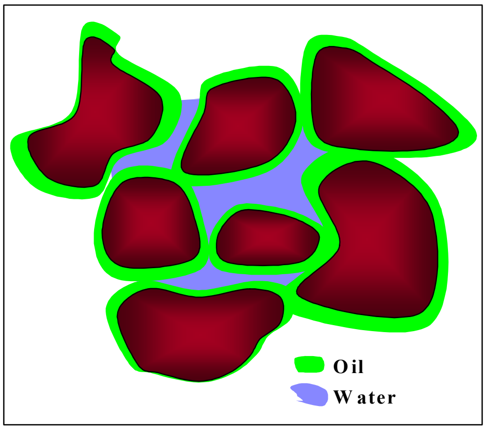

Fig.2-Schematic of Pore Cross-section in an oil-wet porous media, (grains are surrounded by thin film of oil and are not contacted by water).

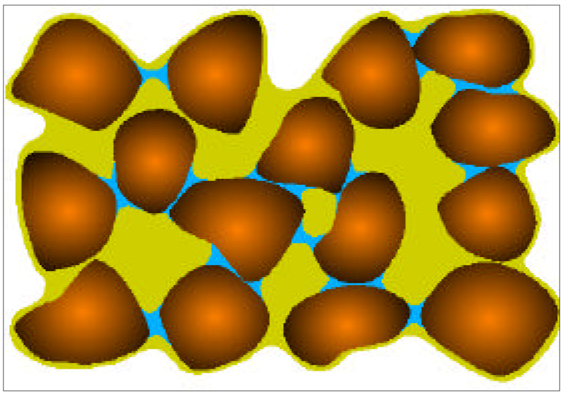

Fig.3-In larger grains/pores, the water film ruptures, and oil and rock in direct contact, locally altering wettability to preferentially oil-wet.

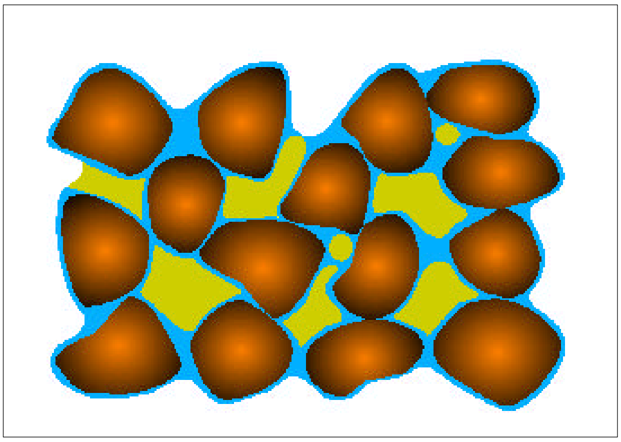

Fig.4:-In smaller grains/pores, the water film covers the grain surfaces completely, thus maintaining those grains water-wet.

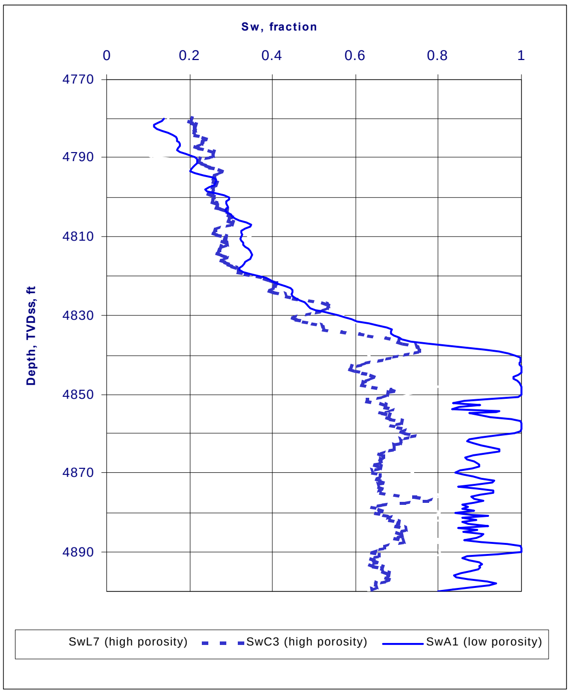

Fig.5-Water saturation versus depth profile for low porosity (water-wet) and high porosity (oil-wet) Nubian Sandstone rocks (after Hiekal et al., 1998).

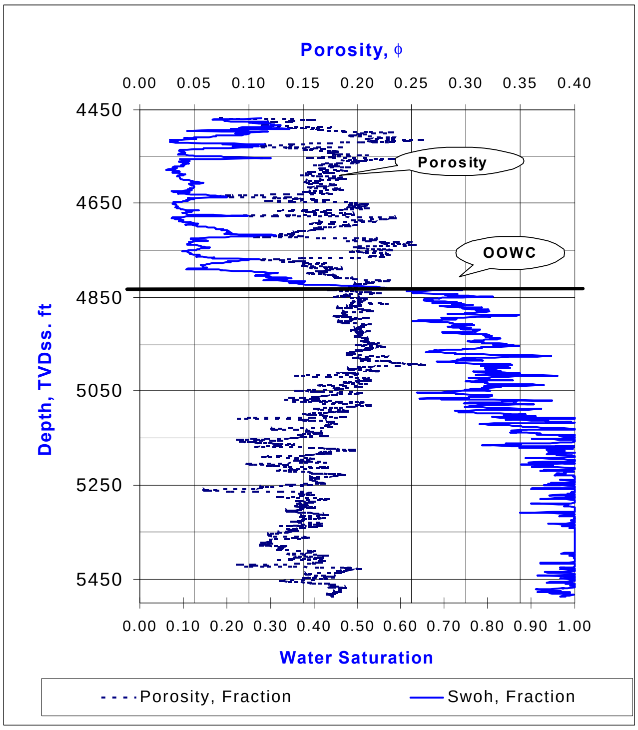

Fig.6-Mixed-wettability example: Porosity & water saturation versus depth profiles for well L-7 (after Hiekal et al 1998).

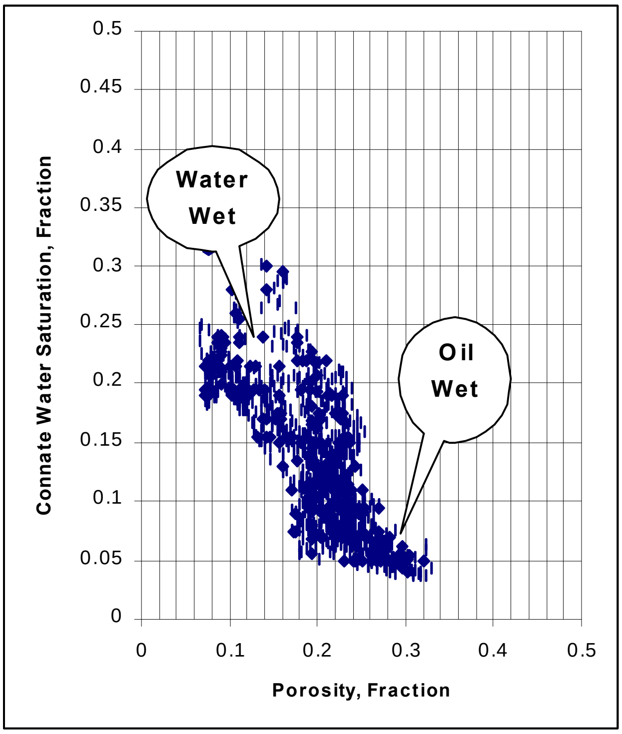

Fig.7-Connate water saturation versus porosity profile (Multiple wells CPI log data 100 ft above OOWC in Nubian Sandstone)

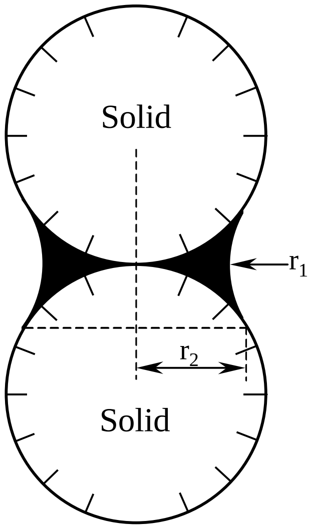

Fig.8-Radii of curvatures for pendular rings around a spherical sand grain junction.

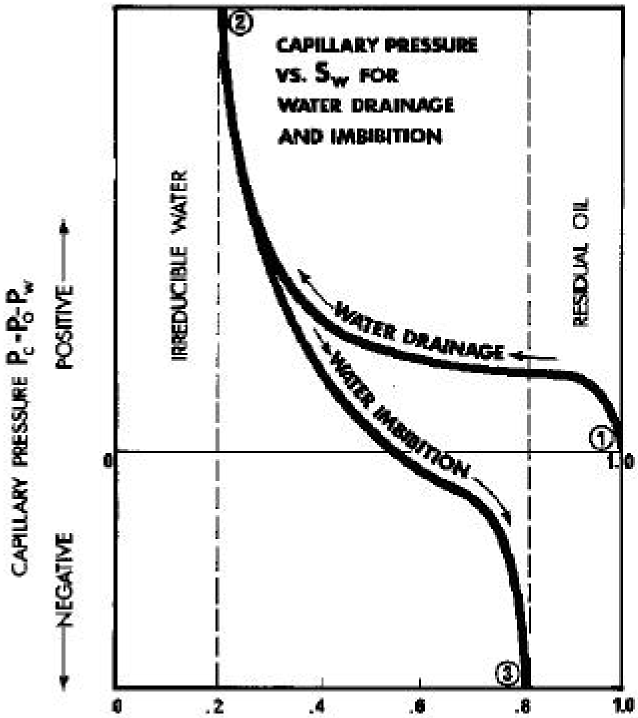

Fig.9-Drainage and imbibition capillary pressure curves for a water-wet system.

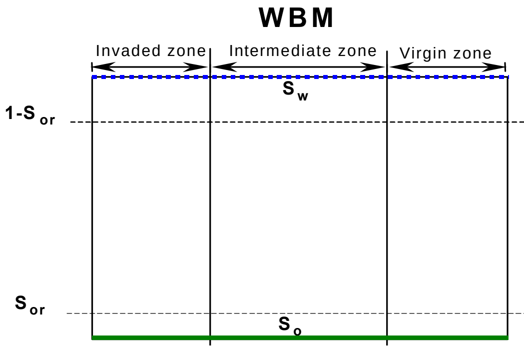

Fig.10-a: Saturation Profile, Water Zone & Water Wet

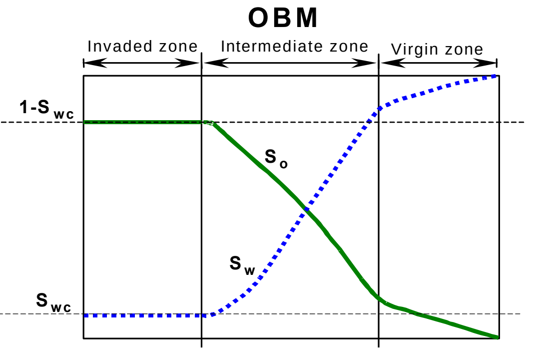

Fig.10-b: Saturation Profile, Water Zone & Water Wet

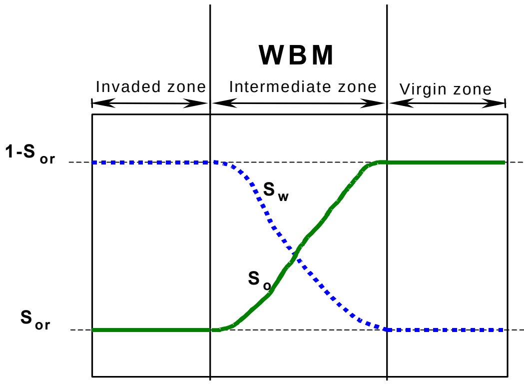

Fig.10-c: Saturation Profile, Oil Zone & Water Wet

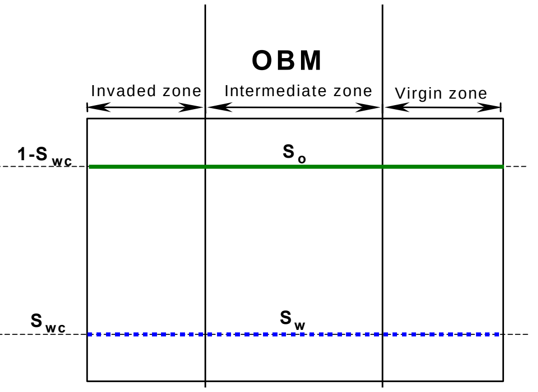

Fig.10-d: Saturation Profile, Oil Zone & Water Wet

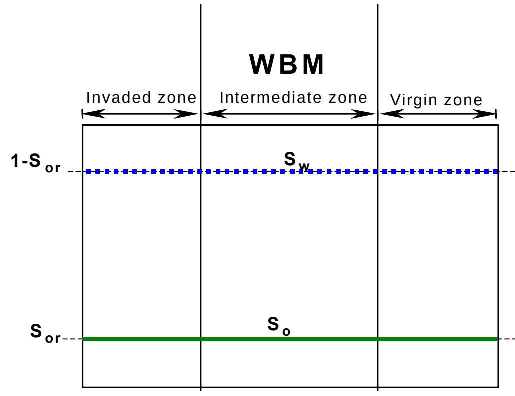

Fig.10-e: Saturation Profile, Water Zone & Oil Wet.

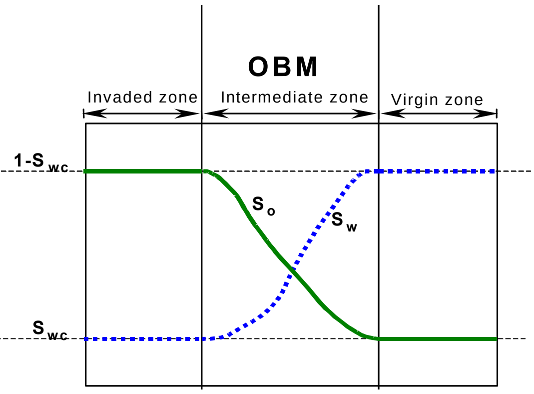

Fig.10-f: Saturation Profile, Water Zone & Oil Wet.

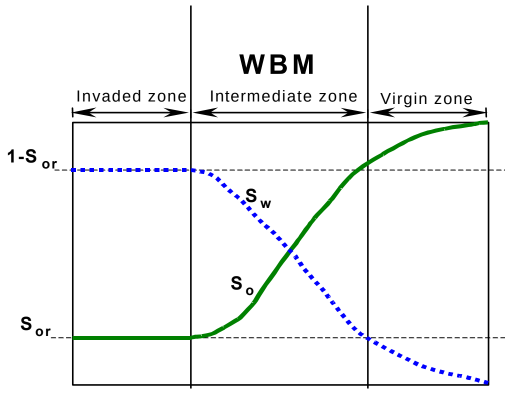

Fig.10-g: Saturation Profile, Oil Zone & Oil Wet.

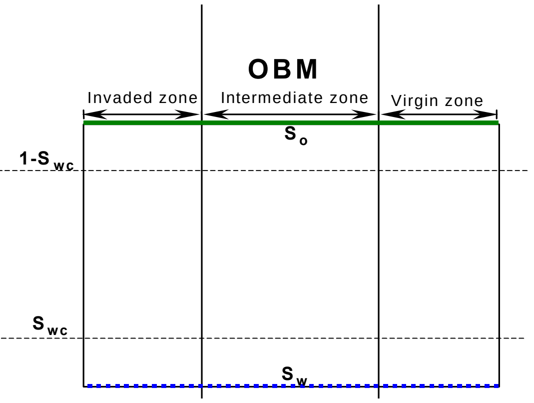

Fig.10-h: Saturation Profile, Oil Zone & Oil Wet

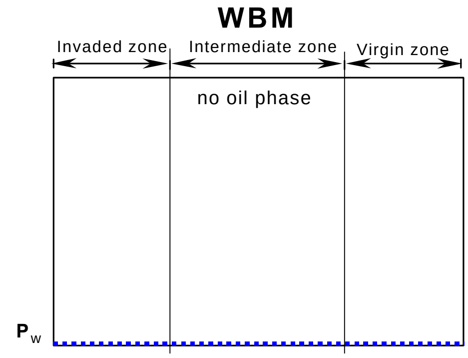

Fig.11-a: Capllary Pressure Profile, Water Zone & Water Wet

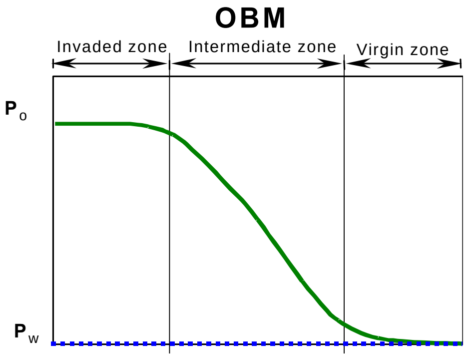

Fig.11-b: Capllary Pressure Profile, Water Zone & Water Wet

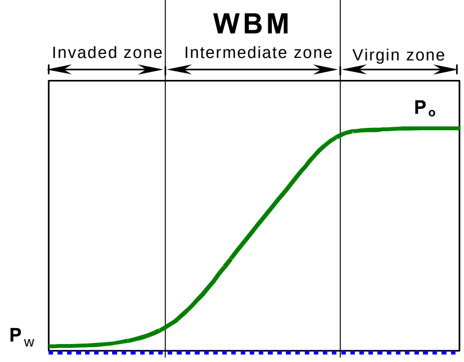

Fig.11-c: Capllary Pressure Profile, Oil Zone & Water Wet

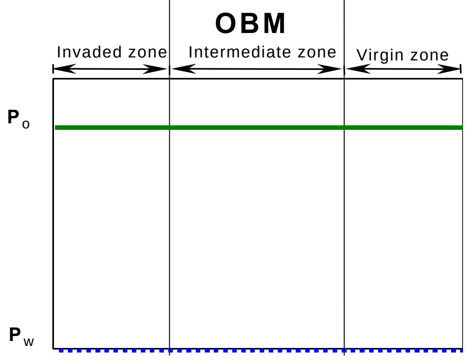

Fig.11-d: Capllary Pressure Profile, Oil Zone & Water Wet

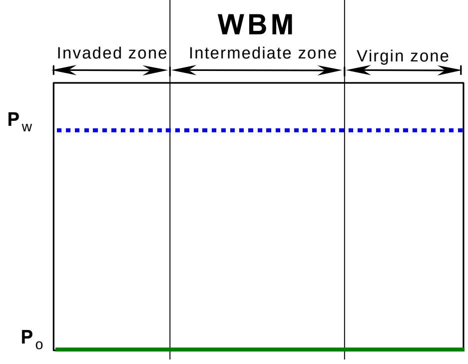

Fig.11-e: Capllary Pressure Profile, Water Zone & Oil Wet

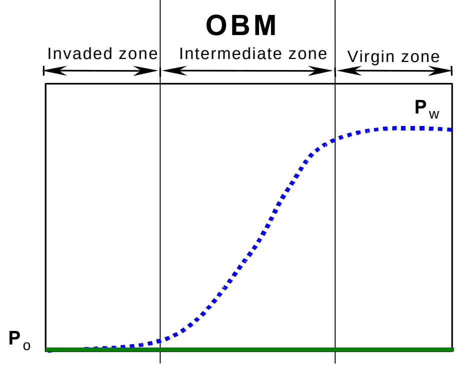

Fig.11-f: Capllary Pressure Profile, Water Zone & Oil Wet

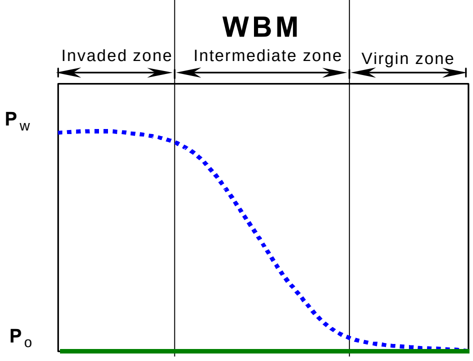

Fig.11-g: Capllary Pressure Profile, Oil Zone & Oil Wet

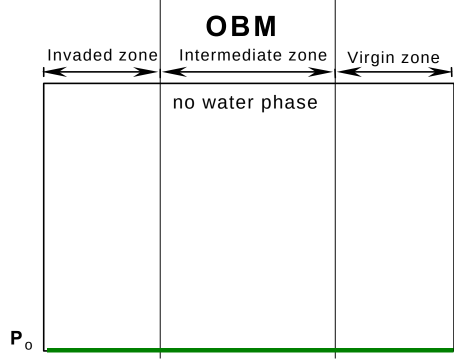

Fig.11-h: Capllary Pressure Profile, Oil Zone & Oil Wet

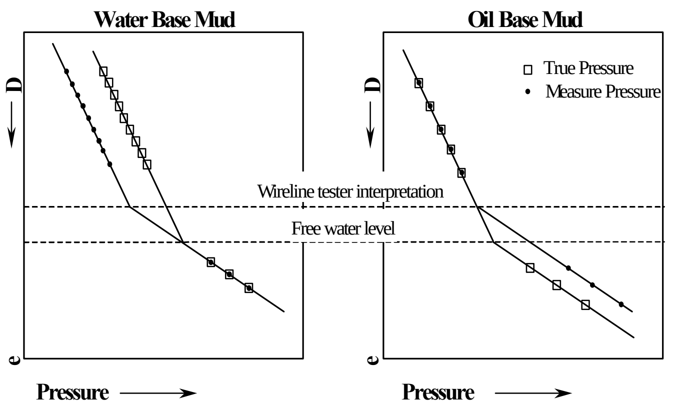

Fig.12-a: Capillary pressure effects on pressure measurement in a water wet system

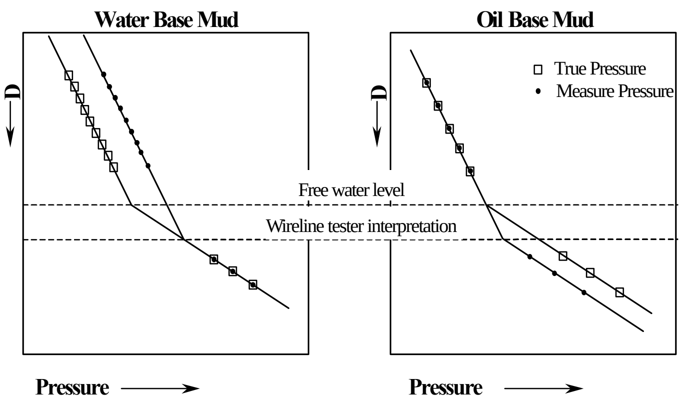

Fig.12-b: Capillary pressure effects on pressure measurement in an oil wet system

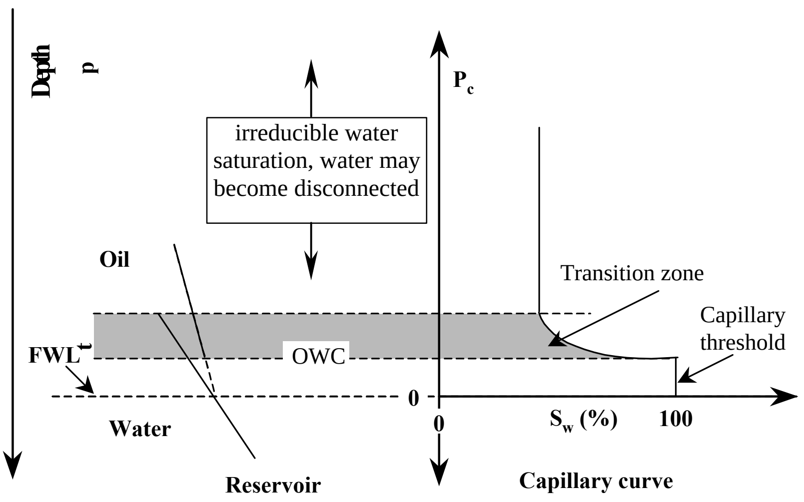

Fig.13-Fluid pressure, capillary pressure, and saturation distribution a water-wet reservoir

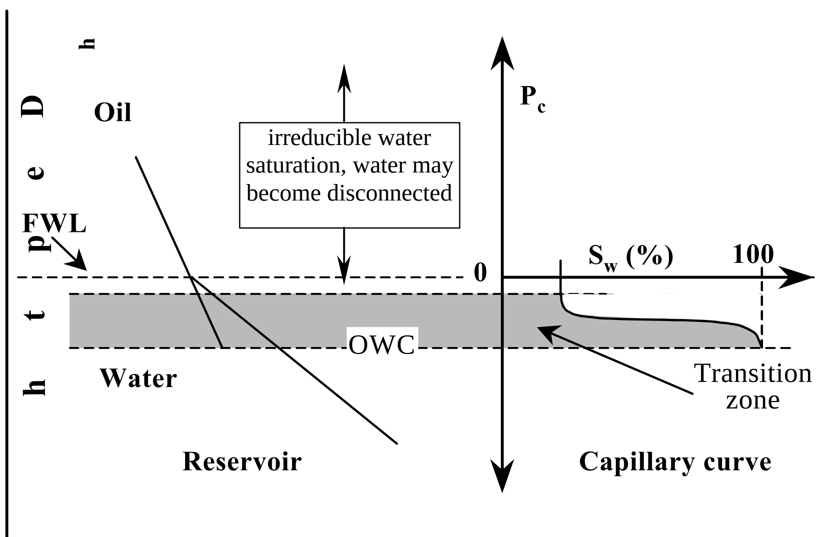

Fig.14-Fluid pressure, capillary pressure, and saturation distribution an oil-wet reservoir

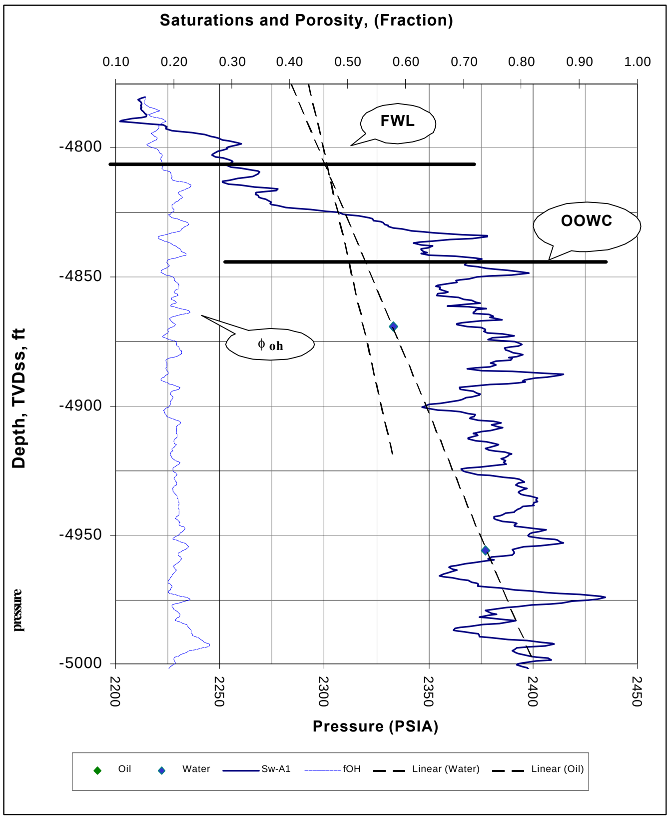

Fig.15-Example of pressure behavior in oil-wet Nubian Sandstone rocks from well L7.

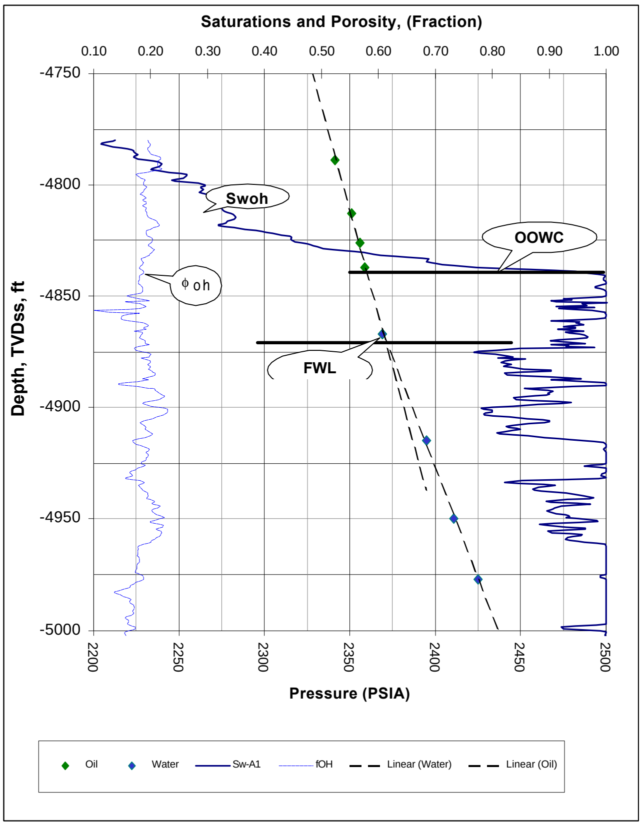

Fig.16-Example of pressure behavior in water-wet Nubian Sandstone rocks from well A1.

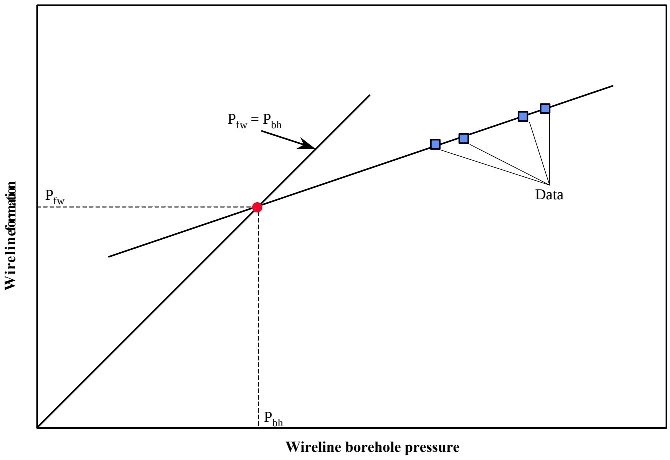

Fig.17: Wireline formation pressure plotted against wellbore pressure.

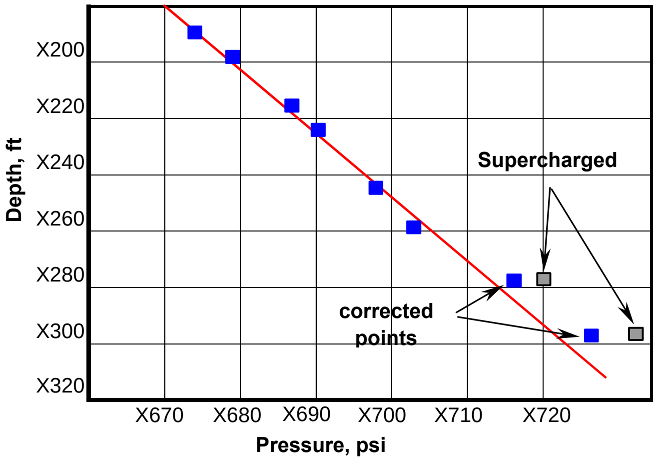

Fig.18: Pressure profile showing how two supercharged points fall into the formation gradient line after correction.