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Understanding the Pressure Gradients Improves Production From Oil/Water Transition Carbonate Zones

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Abstract

Worldwide, carbonate oil-water transition zones contain vast amounts of producible oil. Yet, traditional approaches to open-hole formation evaluation often fail to predict how much oil should flow from them, or even the location of the free water levels. A theory applying capillary pressure scanning curves shows how changing water saturations and variations in levels of mixed wettability systematically control the differences in the pressures of the invading mud filtrate and formation oil, to result in the following unusual yet often observed behavior: 1) negative pressure gradients, 2) water-like gradients significantly above the free water level, 3) significant shifts in the measured pressure potentials between the lower and upper part of the transition zone, 4) gradients implying an oil-density different to that which is expected. Supercharging effects are shown to be unimportant to the discussion. Both wells drilled with water based mud and oil based mud are considered. It is shown how it is usually possible to produce oil from a zone which has a water-like pressure gradient and low formation resistivity. The theory is supported by detailed analysis of examples from flow simulations, which recreate the well known field cases referred to above. Guidelines are presented on how to interpret traditional open hole pressure measurements in a carbonate oil-water transition zone to determine the free water level and the locations where oil should flow, and on how to improve on these interpretations by performing more advanced formation testing procedures, some of which are based upon new technology.

Introduction

Large, economically viable reserves of oil are widely thought to remain in the oil/water transition zones of limestone carbonate reservoirs around the world. Such zones can have vertical extents of significantly more than 100ft. This is perhaps not surprising given that the associated rock tends to have relatively low permeability (<20 mD). Typical open hole measurements for diagnosing such zones are pressure surveys by wireline formation testers (WFT), and formation resistivity logs, acquired in vertical and deviated wells. Typical SCAL measurements made on cores taken from such zones include characterization of the bounding imbibition and drainage capillary pressure and relative permeability curves (with associated end points). The answers being sought relate to questions such as:

1) Where are depths of the following contacts? Some use definitions borrowed from Desbrandes and Gualdron[1]. Free Water Level, FWL (location where there is zero capillary pressure between oil and water), OWC (as depth increases below the oil zone, the location at which oil saturation becomes irreducible), SOR (as depth increases below the oil zone, the location where oil ceases to be mobile), SWI (as depth increases below the oil zone, the location where water becomes mobile).

2) At any depth in the transition zone what is the oil saturation, Soil, what proportion (Sor_imb) of this is immobile under water imbibition, and what is the expected fractional flow of water, f_w, under production?

We share our experience from certain Middle East reservoirs, of the behavior to be typically expected from open hole pressure surveys which have been performed in such zones, and report that if supercharging and production/depletion effects are not major complications in the gradient interpretations, then there are two generic pressure gradients which can be observed in transition zones of homogeneous limestones. The profile of figure 1 is the most general and it is on this we focus our attention for the most of the paper. We present supporting evidence from flow simulation models that the kind of profile shown in figure 1 suggests that the transition zone is mixed wettable, with wettability decreasing from more oil wet at the top to pure water wet on or before reaching the FWL. The character is similar to the purely water-wet case described by Desbrandes and Gualdron (see figure 1 of [1] and/or figure 2 in this paper). But there are two significant variations between their case and the one of figure 1, and it is proposed that these differences relate to systematic changes in rock wettability vs depth.

Wells drilled with water based mud (WBM) are the main focus here. These occur with much higher higher frequency than wells drilled with Oil Based Mud (OBM). The latter are also considered, but only briefly. Using a commercially available finite difference numerical simulation computer program we built single well radial models which use scanning curves to model the effects of hysteresis between drainage and imbibition in the relative permeability and capillary pressure curves to reproduce key features related to the typical pressure profile (figure 1) observed in transition zones. The simulations helped to answer the questions listed above. The scanning curves use a technique developed by Killough [2], and take as input the bounding imbibition and drainage capillary pressure and relative permeability curves. It must also be noted that to properly simulate the observed pressure gradients it was also necessary to force the irreducible oil saturation, Sor_imb, to reduce linearly with depth (ie the rate of reduction with depth in Sor_imb by using just the approach in [2] was insufficient). Though it was considered that the simulations were sufficient to reproduce the key features of type A pressure gradients, it possible that the simulations could have been more accurate if other techniques (eg see [3],[9],[20]), or even direct experimental measurements, were used to generate the scanning curves. Users wishing for an overview of application of scanning curves in simulation models will find useful descriptions in [4],[20]. Apart from analyzing the generic curve of figure 1 we also consider a previously published example (figure 3) by Phelps et al [5],[6] in the context of our approach. This example was also addressed by Desbrandes and Gualdron [1].

It must be stated that extensive work has already been performed into characterizing oil/water transition zones and much of it has been excellent. For example see [7], [8], [9],[20]. This paper does not directly address these works. The intention here is just to present a generic field example of a pressure gradient in a limestone transition zone (based upon those often found in the Middle East), and then to pose an explanation for some of its distinctive characteristics through simple arguments related to wettability, and finally to suggest the outlines of a practical approach designed to answer the questions posed towards the beginning of the introduction. The arguments are supported by results of single well flow simulations which include the effects of gravity. The reader may query the need for including the vertical direction in the simulation when others (eg see [5] and [6]) have only included the horizontal direction. But, it will be shown that character of the gradient can be influenced by the Kz/Kx ratio. This is not considered to be a simple case of supercharging.

In this paper it is assumed that water is always the reference phase, no matter what rock wettability (water or mixed wet) condition is being discussed. Consequently, the capillary pressure is always given by $Pc = Poil - Pwater$.

Furthermore, unless otherwise stated, the WBM case is being discussed. The term “mixed wet” is frequently used in this paper. It is the same as that applied by Jackson et al [9] and references therein. On the imbibition capillary pressure curve it is manifested as a negative pressure (and hence a positive entry pressure for water to displace oil, Pthreshold_imb).

Oil/Water Carbonate Transition Zone Gradients – Generic Field Behavior

Excluding distortions related to supercharging, there appear to be at least 2 generic types of gradient behavior observed in oil/water transition zones of *homogeneous* unproduced limestone carbonates drilled with WBM. The assumption of homogeneity may seem restrictive, but it is often possible to extract sufficient numbers of pressure points which belong to approximately the same limestone rock type from many pressure gradient surveys.

Type A – The Most General Form Of Transition Zone Gradient

The gradient shown in figure 1 is the most general and most common in our experience, and is the main subject of this paper. It is only ever seen in transition zones. There maybe some variation in curvatures, slopes and lengths of various sections, with different wells and reservoirs. Sometimes it may not be recognized if the formation being logged is insufficiently thick. Additionally there is also the following type of gradient profile which is sometimes observed

Type B – The open hole pressures show a water gradient, yet the zone produces oil at low or zero water fraction.

In some cases there is uniformly low resistivity (eg see [11] or [12]). This type of resistivity behavior is suspected to occur *only* in transition zones.

In other cases the resistivity maybe high. The zones in which this is observed are generally thin (usually less than 20 feet) and have deep filtrate invasion. It is suspected that vertical slumping of WBM filtrate in the invasion zone does not occur properly in such instances. That is, gravity equalization between the WBM filtrate in the invasion zone, and the oil in the formation does not occur in a manner which allows the formation pressure to be directly inferred from the filtrate pressure. This type of gradient is not confined to transition zones.

Returning to type A, this type of gradient is commonly seen in homogeneous limestones with permeabilities in the range 2 mD to 20 mD in many Middle East reservoirs. At lower permeabilities it seems difficult to find sufficient number of good quality points to perform gradient interpretation. Homogeneous limestone formations with higher permeabilities are rarely encountered (and so we have insufficient experience of them). Type A is a variant of the water wet case described by Desbrandes and Gualdron (figure 1 of [1]). For example there is a negative gradient at the inflexion. For completeness in this paper, we have reported the key features of their case in figure 2. Strictly speaking the gradients they reported came from the oil phase pressure above the SOR and the water phase pressure below this. But, type A is just from *filtrate pressures in the near well bore region.*

The following distinctive features related to the gradient in figure 1 are to be noted:

F1: Firstly, between SWI and INFLEXION_UPPER, the gradient implies an oil which is significantly lighter than that which really exists.

F2: Secondly, for a significant depth below INFLEXION_LOWER (even below the top of where there is an apparent water gradient) significant amounts of oil can be produced. The open hole resistivity is often low enough to imply Sw = 1, when interpreted with standard Archie parameters (m=2, n=2).

F3: Thirdly, the curvature of the inflexion is much larger than would be expected for a purely water wet reservoir. This statement is consistent with the analysis of Desbrandes and Gualdron [1] who suggested that the measured filtrate pressure could sometimes be as depicted in figure 2 (long-dashed line), and so have little or no inflexion. They stated this based upon results from Phelps et al [5] and [6], who showed that capillary effects would be likely to cause Pfiltrate_s < Poil_s, at permeabilities above 1mD. Phelps et al stated that this effect would be severe for 10 mD. These statements broadly agree with single well flow simulations performed by us for purely water wet reservoirs (see Case1 below).

Phelps et al in [5] and [6], published a field example (figure 3) of RFT measurements made from a well drilled with WBM. In many key respects the profile appears to be similar to that of figure 1. Unfortunately, the underlying lithology of the reservoir is unknown. The focus of their analysis was on correcting supercharging, which they did very well. The reader is advised to read these papers since they contain many useful insights to the effects of an invasion zone on pressure measurements made with a formation tester.

The Simulation Models

Basic Assumptions and Parameters

A major objective of the single well simulation model was to match features F1, F2, F3 of figure 1, and so improve the understanding of the near well bore properties. Table 1 summarises the simulation cases performed. Regardless of the simulation case the following parameters were used, and the following assumptions were made.

1. A vertical well has been drilled through the oil, water and associated transition zones of a reservoir of homogeneous limestone lithology. With an initial over balance of 400 psi at the top of the 450 ft formation there has been 12 hours of dynamic filtration, followed by 2 days of static filtration (at 100^{th} the rate of the dynamic filtration) before the pressure survey and resistivity logging. The dynamic filtration rate was reduced in the manner described in [5] to simulate the buildup of mudcake. The basic parameters used for the simulations are shown in table 2. They are representative of many Middle East reservoirs. Though the permeability is 5 mD, it should be noted that similar simulated (and actual) gradient behavior is observed with permeabilities in the range 2 mD to 10 mD.
2. The oil migrated into the reservoir by accumulating at the top of the containing structure and invading downwards, and there has been no movement of the contacts after oil finished migrating.
3. The reservoir pressures have not been significantly affected by production/depletion effects, and that the reservoir fluids are in hydrostatic equilibrium
4. There are no significant pressure gauge or depth errors.
5. The pressure survey was completed within a few hours.

Case Name	Comment
Case1	Base Water Wet Case
Case2	Mixed Wettability, No Scanning Curves
Case3	Mixed Wettability, With Scanning Curves
Case3.1 Low Kz	Case3 With Kz=0.5 mD Globally
Case3.1 Baffle	Case3 With Kz=0.02 mD At The Inflexion
Case3.2	Case3 Well Drilled With OBM
Case1.1	Case1 With Kx=Kz=0.5 mD

Table 1 Simulation Cases

Table 2 Parameters For The Simulation Cases

The Invasion Schedule

1. Dynamic Filtration: 0.5 Days with No Mud Cake (400 psi over balance at the top of the open hole section of the well)
2. Static Filtration: 2 Days with a Leaking Mud Cake (The static filtration rate = dynamic filtration rate/100)
3. No Static Filtration for 1 day
4. Cased for 1 year

Other Parameters

- Mud hydrostatic gradient 0.5 psi/ft
- Well Drainage Radius = 3000 ft
- Connated Water Saturation = 0.2
- Residual Oil Saturation = 0.15 (above SWI)
- In-Situ Oil Density 0.62 g/cc, 0.269 psi/ft
- Formation Water is fairly fresh (~ 1 g/cc)
- Kx=Kz=5 mD
- Porosity = 25%
- Rock Compressibility = 3E-06
- Free Water Level – 9177ft (by definition)
- Oil Viscosity = Water Viscsosity = 0.4 cp

Case1 - Positive Imbibition Threshold Pressures

It was *impossible* for the simulator to reproduce the required inflexion (feature F3) or the "light oil effect" (feature F1) seen in figures 1, 2 (solid line) and 3, using imbibition capillary pressures with positive or zero threshold pressures. Figure 4 shows the results of simulation Case1. Remember that the filtrate pressure Pfiltrate_s at the wellbore to formation interface is being measured. Case1 is considered to representative of a water wet case. The relative permeability and capillary pressure curves used are shown in figure 5. The results (unreported) seemed to be fairly insensitive to sensible variations in these.

Case2 – Negative Imbibition Threshold Pressures/No Change In Sor_imb With Depth

As figure 7 shows, it was *possible* to reproduce feature F3, the inflexion of figure 1 (including the negative gradient) by using imbibition capillary pressure curves with a negative threshold pressure. But this case still could not reproduce the feature F1. The bounding imbibition and drainage capillary pressures and relative permeabilities are as shown in figure 6a.

The capillary pressure data (only) were similar to the 5 mD, core S17 of Masalmeh and Jing [13], who have done extensive, accurate SCAL measurements on limestone cores.

Case3 – Case2 + Scanning Curves – Match Achieved

We modified Case2 to make both the Pthreshold_imb (entry pressure for water to displace oil) and the irreducible oil saturation, Sor_imb, reduce with depth between SWI and FWL. This was implemented in the simulation by Killough[2] scanning capillary pressure curves (figure 6b). It was also necessary to force Sor_imb to reduce linearly with depth (ie the rate of reduction in Sor_imb from using just the Killough approach [2] was insufficient). *In this way we were able to reproduce feature F1.* See figure 7. We also found that this model could match feature F2. Recall that F2 is the ability to produce oil at relatively low water cuts, below the inflexion in the pressure gradient. This was not completely unexpected, because i) mobile oil exists till depths quite close to the FWL (in the simulation model at least), and ii) oil production is governed by drainage curves, which keep the water relative permeability comparatively low. See [9] and [10] for discussions on this subject. See figure 8 for the simulated productions at a location just above where gradient is truly water-like. We have encountered wells which in apparently a similar condition (ie no movement of the paleo FWL, post oil migration) have produced oil at a lower water cut than that shown in figure 8.

Case3.1 – Case3 with Kz/Kx Ratio Modified

The effects of variation in the Kz/Kx ratio were explored as follows:

A. The vertical permeability Kz, in Case3 was changed to 0.5 mD everywhere. That is, the Kz/Kx ratio was changed from 1 to 0.1. Figure 7 shows that with the exception of slightly increasing the level of supercharging there is no substantial difference in the character of the simulated pressure gradient. Thus, it seems that the character of the transition zone gradient is fairly insensitive to the overall Kz/Kx ratio.

B. The vertical permeability Kz (but *not* the horizontal permeability Kx), between INFLEXION_UPPER and INFLEXION_LOWER was reduced to 0.02, to simulate the effect of a baffle (eg styolitic) zone. This created a major difference in the inflexion region (figure 7). It is considered unlikely that this is a simple case of supercharging because Kz was also reduced in a similar manner in the oil and water zones at the respective depth intervals (8992ft,8902ft) and (9242ft,9252ft), and as can be seen from figure 7, this did not noticeably perturb the gradient. It conjectured (without any proof) that perhaps the baffle in the middle of the transition zone somehow interferes with the equilibration between the WBM filtrate and formation oil which normally occurs in the invasion zone. This issue requires further investigation.

Case3.2 – Oil Based Mud

Case3 was modified so as to simulate the effect of drilling with OBM. The OBM filtrate has the same properties as the formation oil. The behavior of the simulated gradient at selected times is shown in figure 9. It can see that after 2 days of static filtration even though there is significant supercharging everywhere, the water zone seems to have more of an over pressure than the oil zone. This is due to the entry pressure of oil filtrate having to displace formation water in the (water wet) water leg. This effect is well known and has been reported before (eg see [14]). Recall that pressure measurement after 2 days of static filtration is how all the other cases have been reported. There is no inflexion in the gradient (just a bump). Then after 1 further day, in which no static filtration is assumed to have occurred the gradient becomes close to the true one. But in the water zone there still is a slight shift of about 5 psi from the true pressure, which would cause inaccuracies for FWL interpretation using the method of intersecting lines. Note that even after 1 year a significant shift is still present, though towards the base of the reservoir it has diminished. This last effect is due to an increase in water saturation caused by gravity segregation. Unfortunately due to a lack of data we are not able to present a generic pressure gradient measured from wells drilled with OBM in limestone reservoirs. Readers may refer to example 1 in [15] for a field example of a pressure gradient measured from a well drilled with OBM in carbonates. This case does not show the inflexion seen in figure 1.

Case1.1 – Case1 with permeabilities divided by 10

The objective of this (the water wet) case was to explore whether the inflexion of figure 1 could be created at much lower permeabilities than those used in Case1. There was reason to believe based upon the work of Phelp et al in [5] and [6] that the capillary pressure gradient which in Case1 pulls water away from the well bore and hence causes the smearing of the inflexion, might have a negligible effect at much lower permeabilities. Note that the Case1 capillary pressure curve has been used in this case, so the effect a tighter lithology on the capillary pressure has not been modeled. Figure 4 shows that after 2 days of static filtration a large bulge in the gradient is produced (and no inflexion). Recall that measurement after 2 days of static filtration is how all the other cases have been reported. If the bulge is some how removed (perhaps by supercharging corrections) the required inflexion, feature F3, would still not appear. After 1 further day of no static filtration the bulge has disappeared. This result together with those from Case1 and Phelps et al [5] and [6] suggests that in water wet cases, that as long as the *filtrate pressure* is being measured the inflexion of figure 1 may be rarely observed.

Discussion Of Simulation Results

The simulations in Case1 and Case2 support the argument that all else being equal, the assumption of mixed wettability in the transition zone is the mechanism which ensures the high curvature of the inflexion in figure 1 (feature F3). A purely water wet formation is unlikely to allow this, because, as shown in the water wet case (Case1), the capillary pressure gradient is sufficiently large (above the OWC) to "pull" water filtrate away from the well bore faster than it leaks through the mud cake, thereby making Sw_s < 1-Sor_imb_ww. This in turn causes Pfiltrate_s < Poil_s.

This effect was observed by Phelps et al [5], [6] under similar conditions. They showed after 12 hours of dynamic filtration and then 12 hours of static filtration there could be significant mobile oil saturation at the wellbore to formation interface, and that this in turn would cause the filtrate pressure to be significantly less than the formation oil pressure. Desbrandes and Gualdron [1] stated that the effect of this would be to “smear” out the inflexion region and reduce the difference between the measured oil and water pressures (eg see figure 2). The mixed wettability assumption actually reverses the capillary gradient and has the effect of trapping water and hence keeping the oil saturation close to residual near the well bore. This is demonstrated by Case2.

Case3 shows that all else being equal, feature F1 in figure 1 (the reduction in the expected oil gradient in the transition zone between SWI and INFLEXION_UPPER) can be related to a systematic decrease with depth in the entry pressure for water to displace oil. This has been modeled by scanning curves using the technique in [2]. This approach also entails assuming that there is an accompanying reduction with depth in residual oil under imbibition, Sor_imb. This effect in turn contributes to the expectation of significant amounts of simulated oil production below INFLEXION_LOWER. This is feature F3 of figure 1. All of this implies a decrease in mixed wettability from SWI to the FWL. We do not know where exactly the formation becomes purely water wet, except that below the FWL it must be so. Such a wettability variation has been suggested and/or by others for limestone oil/water reservoirs. For example see [16].

It is interesting to note that the Case3 predicts that essentially dry oil can be produced for several years at locations in the transition zone between SWI and INFLEXION_UPPER (where the gradient is less than that expected from the true oil density). This is consistent with our experience from sampling jobs performed with wireline formation testers. These however, only investigate production for a few hours.

The overall matches on features F1 and F3 were fairly insensitive to sensible variations (unreported here) in capillary pressure and relative permeability relationships.

The example of Phelps et al [5], [6] presents a rare opportunity to examine a published field example of a pressure gradient taken from a well drilled with WBM across a substantial oil/water transition zone. This is done now from the perspective of considering whether the underlying formation is likely to be mixed wet or water wet The underlying lithology was not reported. Figure 3 shows the example. The pressures are those derived after Phelps et al applied their elegant supercharging corrections. The gradient profile is consistent with that of a limestone oil/water reservoir (ie having a depth gradient in mixed wettability rock), because it also shows the features F1 (reduction in apparent oil gradient above the inflexion) and F3 (a sharply curved inflexion). The gradient (0.39 psi/ft) through points A to B is larger than that (0.35 psi/ft) through points B to C. Based upon this analysis it is also speculated that the transition zone starts at approximately 300ft. The gradient is unlikely to be that of a strongly water wet reservoir if the associated parameters are similar to those used in our simulations.

Some major potential limitations in the simulations must be pointed out and accounted for. Firstly, secondary drainage curves have not been used to model the way in which WBM filtrate in the invasion zone is replaced by the formation oil. As has been shown by Masalmeh and Jing [13], the shape of the imbibition and secondary drainage Pc curves cannot be inferred from that of the primary drainage Pc curves. For example, Masalmeh and Ding showed for a set of limestone cores of widely varying permeability that even though the primary drainage and imbibition curves can be significantly different, the secondary drainage Pc curves tend to be similar between all the cores in the set, with some differences only found close to the connate water. They also showed evidence that the secondary drainage entry pressure tends to be much lower than that of the primary drainage in limestones. If this is also true for water wet situations then it might tend to reduce the importance of the capillary pressure gradient that moves water away from the well bore, which we discuss in relation to Case1, and which was first mentioned by Phelps et al [5],[6].

Secondly, the assumption that there has been no upward movement of the contacts after oil finished migrating into the reservoir is perhaps untrue of a large number of limestone fields in the Arabian Gulf and perhaps elsewhere. Hysteresis effects could cause the oil production from transition zones in such fields to be different from that associated with figure 1. The consequences of a movement in the paleo OWC have been examined in [9].

A Practical Methodology To Diagnose TZ’s

We return to the questions posed towards the beginning of this paper. These essentially relate to the following issues: where are the contacts in a transition zone, how much mobile oil and water are there in it, and how will these fluids flow? Provided sufficient data is available then such questions may be answered to a certain degree of accuracy and confidence through data acquisition, and can be improved after matching observed measurements in single well simulations. The necessary data can be acquired cost effectively and efficiently using the following approach which relies on industry standard technology.

It is assumed that an appraisal well is to be drilled into a limestone reservoir which is expected to contain a substantial oil/water transition zone. Operational decisions, such as where to drill a side track, may need to be rapidly made, perhaps even before the appraisal well is finished. The data must also help answer the longer term questions about the amount and distribution of transition zone oil reserves. There are negligible production depletion effects.

Step 1: Triple Combo logging

Resistivity logs will help identify whether there may be a transition zone and the possible locations of the contacts.

Density and neutron logging are used to derive porosity and to show similar locations of permeable lithology, which are then used to choose sites for the formation testing.

Step 2: Wireline Formation Test Survey

A wireline formation tester (WFT) is equipped to acquire in one logging descent the following measurements (and sample) in real time: open hole *filtrate* pressures (rapidly), formation mobility and Kz/Kx, oil/water fractional flow, downhole oil density measurement, open hole *formation fluid* pressures, fluid sampling. The WFT is equipped with probes such as a dual packer, which can handle the relatively low permeabilities associated with limestones. The WFT then makes the measurements as follows:

Step 2.1: Filtrate open hole pressure gradient . Note that the pressures must be all measured within a period of only a few hours if the survey is being done shortly after dynamic filtration has finished, because in such instances the level of supercharging may noticeably reduce over timescales on the order of a day. It is worthwhile trying to apply supercharging correction procedures such as those by Phelps et al [5],[6] to improve the gradient. Lithological variations across the points being used to make the gradient can often be simply minimised by looking at WFT pressure data from points with similar mobilities. If the (corrected) gradient has a similar profile to that in figure 1, then proceed to the following steps.

Step 2.2: Measure the oil density at the top of the zone. Samples are captured which can be used later to confirm this downhole measurement.

Step 2.3: Use the oil density, together with changes in slope of the pressure gradient, to detect an upper bound for SWI. This is approximately where the pressure gradient (above the inflexion) starts to reduce below that implied by the formation oil density.

Step 2.4: Measure the fractional oil/water flow versus depth downwards from the inflexion location. The place where only formation water flows marks an approximate upper bound of the FWL. A sample may be taken here to confirm the water density which will be inferred from the pressure gradient.

Step 2.5: Confirm that only oil flows at depths above the gradient inflexion.

Step 2.6: Measure the Kz/Kx ratio at the location of the inflexion.

Step 2.7: Measure the entry pressure for filtrate to displace formation oil at locations from SWI downto the Inflexion.

At this juncture urgently required operational decisions can be made (even before the WFT is out of the well), such as where and how to drill a side track well. Many steps of the above procedure have been successfully applied in several of the Arabian Gulf carbonates. The steps have only been very briefly outlined here and no references given for those wishing to find further details. These will be described in a forthcoming publication.

Step 3: Relative Permeability and Capillary Pressure Measurements.

Then to properly characterize and predict the behavior of the transition zone using flow simulations in the manner described in this paper, core measurements are also made to determine the bounding primary drainage and imbibition curves for relative permeability and capillary pressure (and Kz/Kx). Secondary drainage curves may also be measured to provide increased accuracy in the simulations. If the capillary pressure and relative permeability data cannot be acquired from core they can possibly be generated by correlations, such as those developed in [3].

Step 4: Single well simulations are built to honor the data acquired from the WFT and from core.

Provided that the assumptions that are mentioned in the section introducing the simulation modeling are reasonably accurate, final results of the simulation include trustworthy estimates of Sw(z), Sor_imb(z) and $f_w(z)$. These depth varying properties can be used to infer bounds on depths of contacts such as FWL and SWI. Consistency must be ensured as far as possible with equivalent saturation interpretations derived from resistivity.

Logging technology is advancing rapidly, and the following advanced (ie has just become commercially available) measurements may help in transition zone evaluation. **1)** Acquistion of pre-invasion formation fluid saturations. These are acquired whilst drilling. Techniques include neutron capture cross section measurements (eg see [17] and [18]), **2)** Advanced lithology characterization using Nuclear Magnetic Resonance and/or High Resolution Formation Images derived from resistivity measurements **3)** The presence of "paleo-oil" can be identified by NMR. These techniques are not referenced here, and will be dealt with in a future paper.

Concluding Remarks

Based up on our (Middle East) field experience with limestone reservoirs, we report that for wells drilled with WBM through oil/water transition zones there are two main types of gradient profile encountered, A and B, with type A being the most general. It occurs with some variation in curvatures, slopes and lengths of various sections, depending upon the well and reservoir. The arguments and simulations of this paper imply that Type A is expected in transition zones, but probably not if they are water wet and if the reservoir parameters are similar to those used in the simulations (table2, figures 5,6). Unfortunately, we not have sufficient field data to help substantiate this last assertion. Type A is essentially a variant of the water wet case reported in [1] (see figure 2). The mixed wettability condition just helps to ensure that the gradient inflexion exists (and is in fact accentuated) in the filtrate pressure.

We said that Type A gradient profiles are to be observed in zones of homogeneous limestone lithology, where differential supercharging and production/depletion effects can be ignored. But, even in non-homogeneous formations the gradient profiles can often be detected by looking at pressure points which are taken in similar lithology.

There are two distinctive features F1, F3 associated with Type A (figure 1) which can best be explained by assuming that Pthreshold_imb is significant at the top of the transition zone, decreases with the depth, and is accompanied by an associated decrease in Sor_imb. Using a commercially available finite difference numerical flow simulator[19] these features haves been matched (figure 7) in a single well radial model using scanning curves to model hysteresis in the relative permeability and capillary pressure curves (figure 6b). The simulation model can be used to predict the range in the quantity of mobile oil contained in the transition zone and how it will flow. It is concluded that the formation is less water wet at the top and that water wetness increases with depth until the formation becomes purely water wet on or before reaching the FWL.

Simulation sensitivities were performed to explore the effects on the gradient behavior of changes in vertical permeability and of drilling the well with OBM. The shape of the pressure gradient profile can be noticeably influenced if there is a tight (in Kz only) zone near or at the inflexion (figure 7). This is not a simple case of supercharging. If a well is drilled with OBM there is no inflexion in the pressure gradient. Instead there is a bump in the middle of the transition zone (figure 9) which disappears quite rapidly with time, and so may rarely be seen in actual data. A published OBM example [15] shows no inflexion (nor a noticeable bump). Nevertheless, the simulations agree with the suggestions of others (eg see [14]) that FWL determination will still be prone to capillary pressure effects related to OBM filtrate entering the (water wet) water zone.

The method for transition zone evaluation presented here pragmatically addresses field requirements. But, it needs much further development to be complete. For example, there is no proper discussion on how to deal with the difficult topics of supercharging, lithological variations and effects of secondary drainge curves on the pressure gradient. Nor is the method easy to apply, since it involves matching data by finite difference numerical simulation, which is usually a time consuming process. It might be better to derive an analytical model to match the transition zone data.

Nomenclature and Terminology

FWL – Free water level (where capillary pressure between oil and water is zero).
OWC - As depth increases below the oil zone, the location at which oil saturation becomes irreducible.
SOR - As depth increases below the oil zone, the location where oil ceases to be mobile.
SWI - As depth increases below the oil zone, the location where water becomes mobile.
WFT – Wireline formation tester.
Pfiltrate_s – Filtrate pressure in the formation near the well bore.
Pc – Capillary pressure.
Poil – Oil phase pressure.
Pwater – Water Phase Pressure.
Poil_s – Oil phase pressure in the formation near the well bore.
Pthreshold_imb – Entry pressure for water to displace oil (assumed positive in a non-water wet rock).
Sor_imb – Residual oil saturation under water imbibing.
Sw_s – Water saturation in the formation near the well bore.
Sor_imb_ww – Residual oil saturation under water imbibing (water wet conditions assumed).
Soil – Oil Saturation.
Sw - Water saturation
Swr – Residual water saturation
f_w – Fractional water flow
F1,F2,F3 – Critical features of the gradient in figure 1.
Kz – Vertical Permeability.
Kx – Horizontal Permeability.
OBM – Oil based mud.
WBM – Water based mud.

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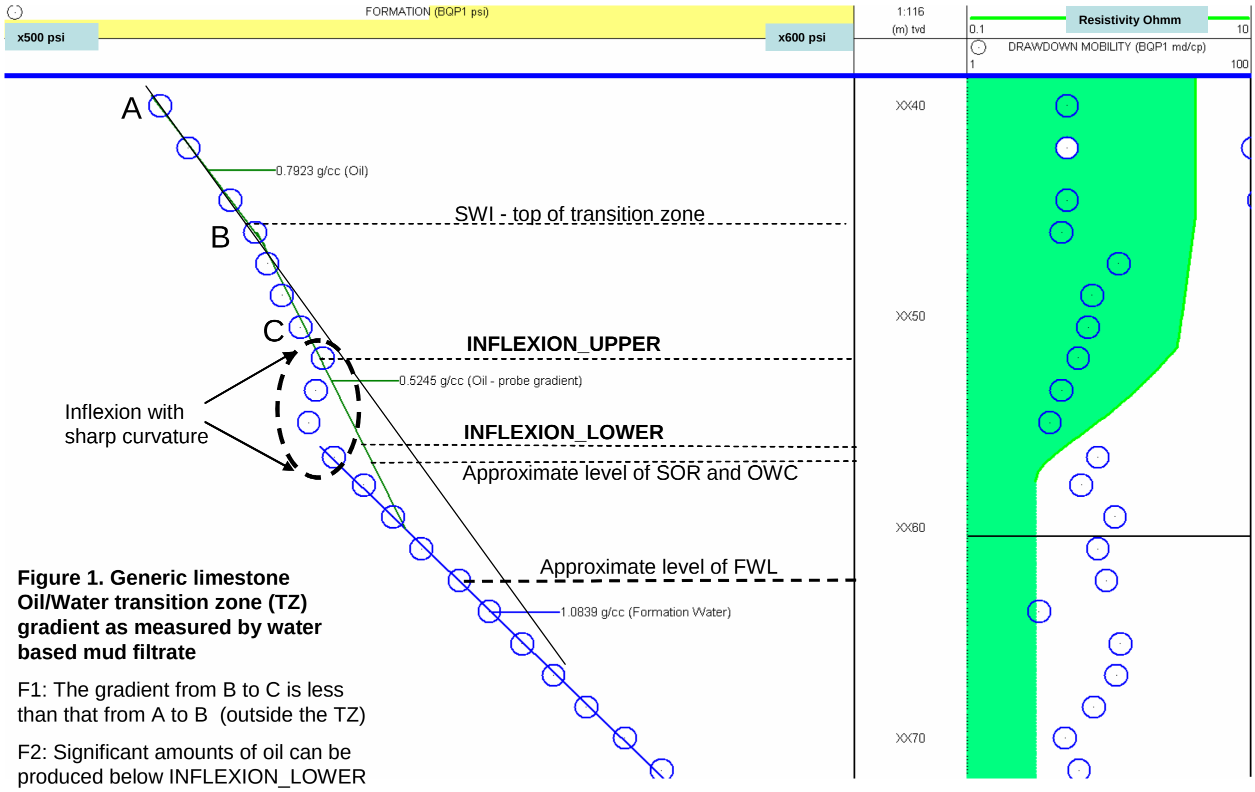


Figure 1. Generic limestone Oil/Water transition zone (TZ) gradient as measured by water based mud filtrate

F1: The gradient from B to C is less than that from A to B (outside the TZ)

F2: Significant amounts of oil can be produced below INFLEXION_LOWER

F3: The curvature of inflexion is large

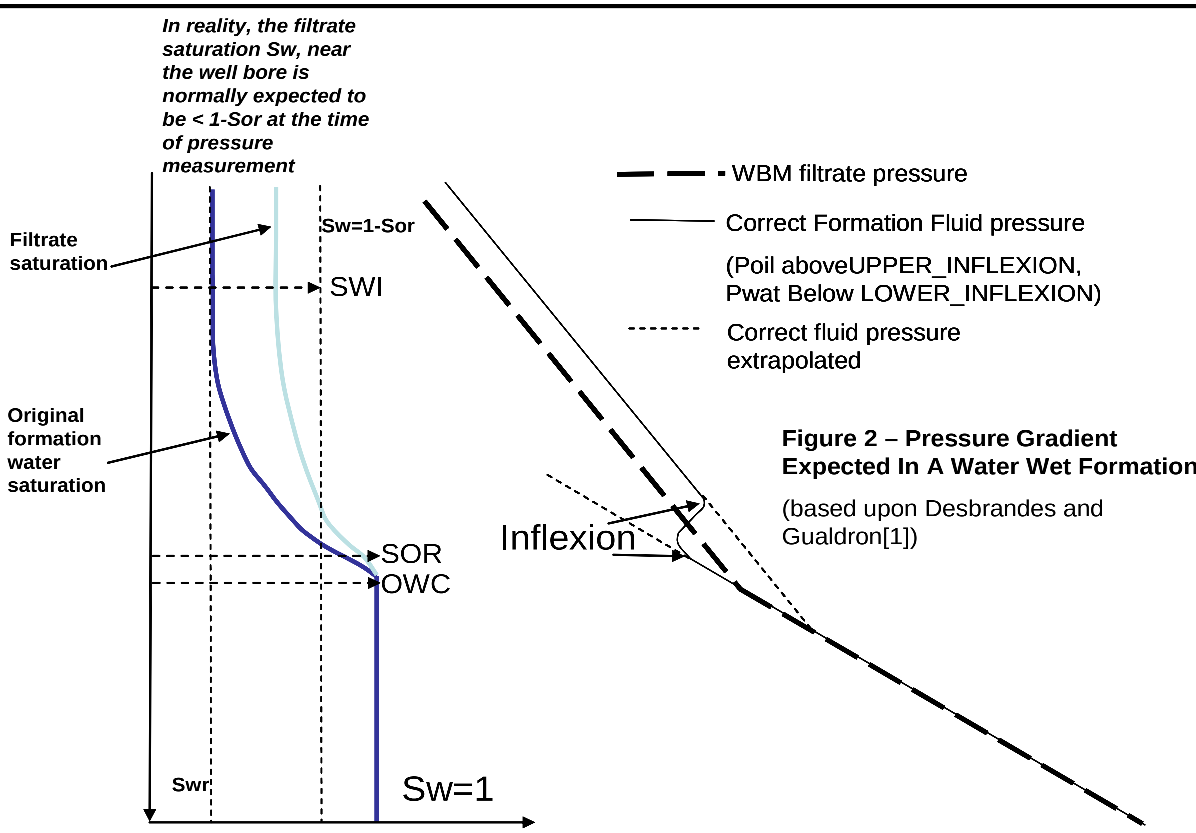
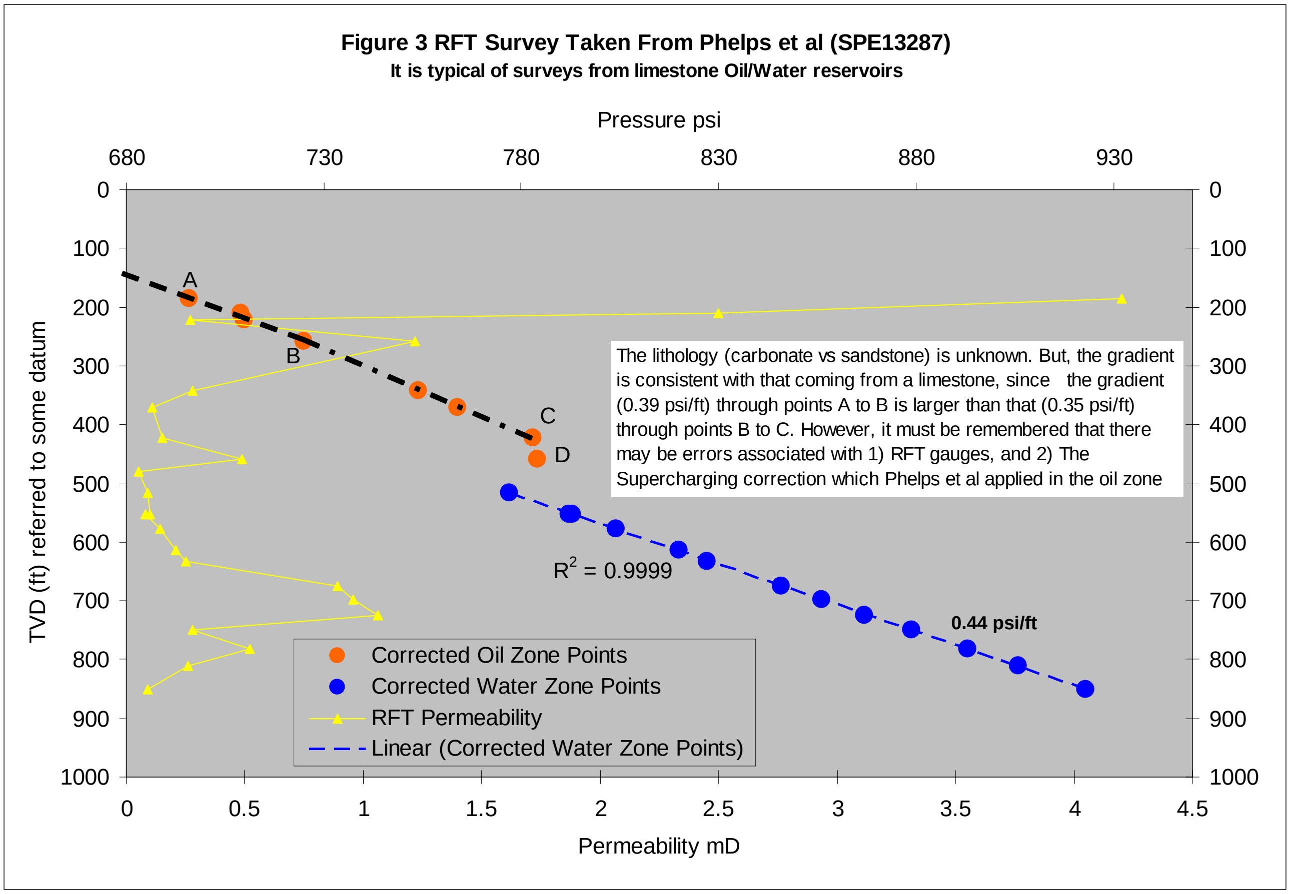


Figure 2 – Pressure Gradient Expected In A Water Wet Formation

(based upon Desbrandes and Gualdron[1])

Desbrandes and Gualdron [1] said that the correct formation fluid pressure should show a discontinuity for depths close to SOR. But, if the pressure is inferred by measuring the filtrate pressure (ie the normal way open hole pressure is measured), then the inflexion is liable to be smeared because the water saturation near the well is likely to be less than 1-Sor due to a capillary pressure gradient which pulls water away from the wellbore



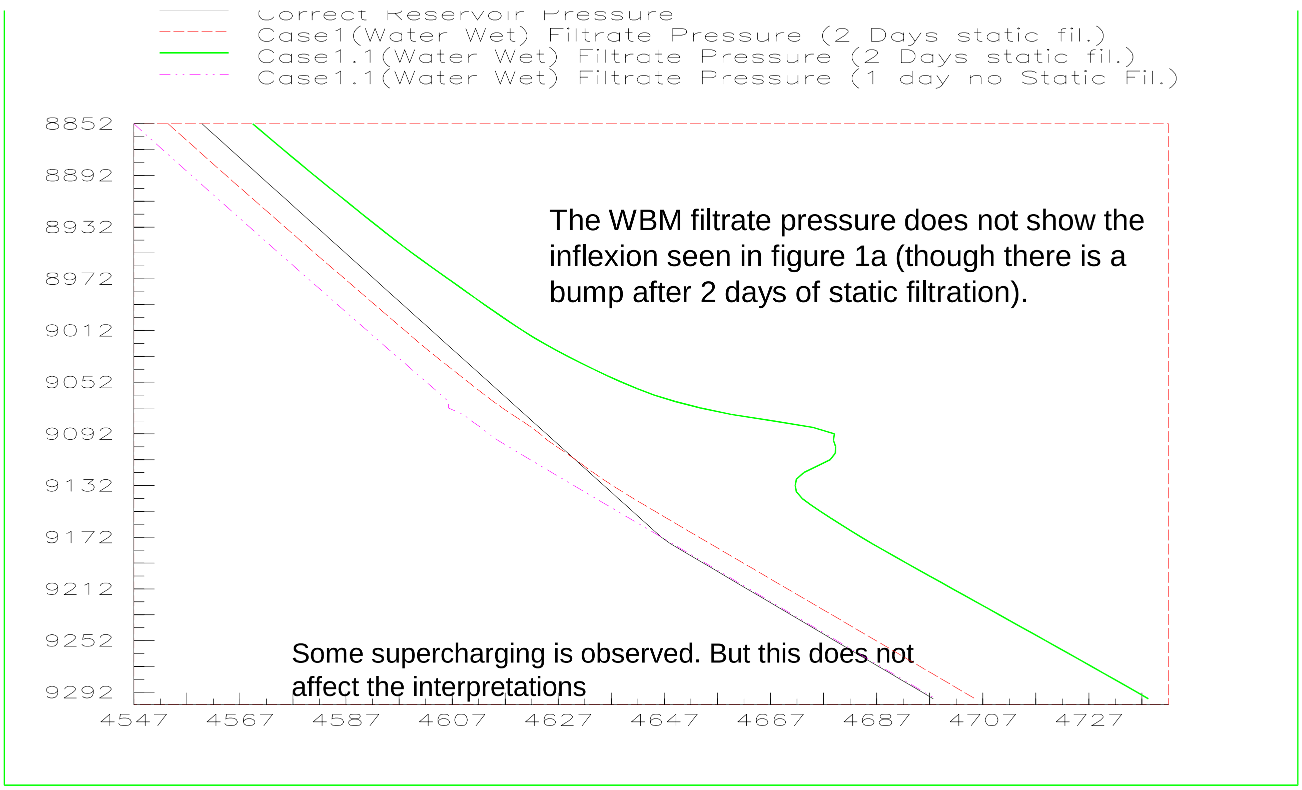


Figure 4 Case1 And Case1.1 (Water Wet)

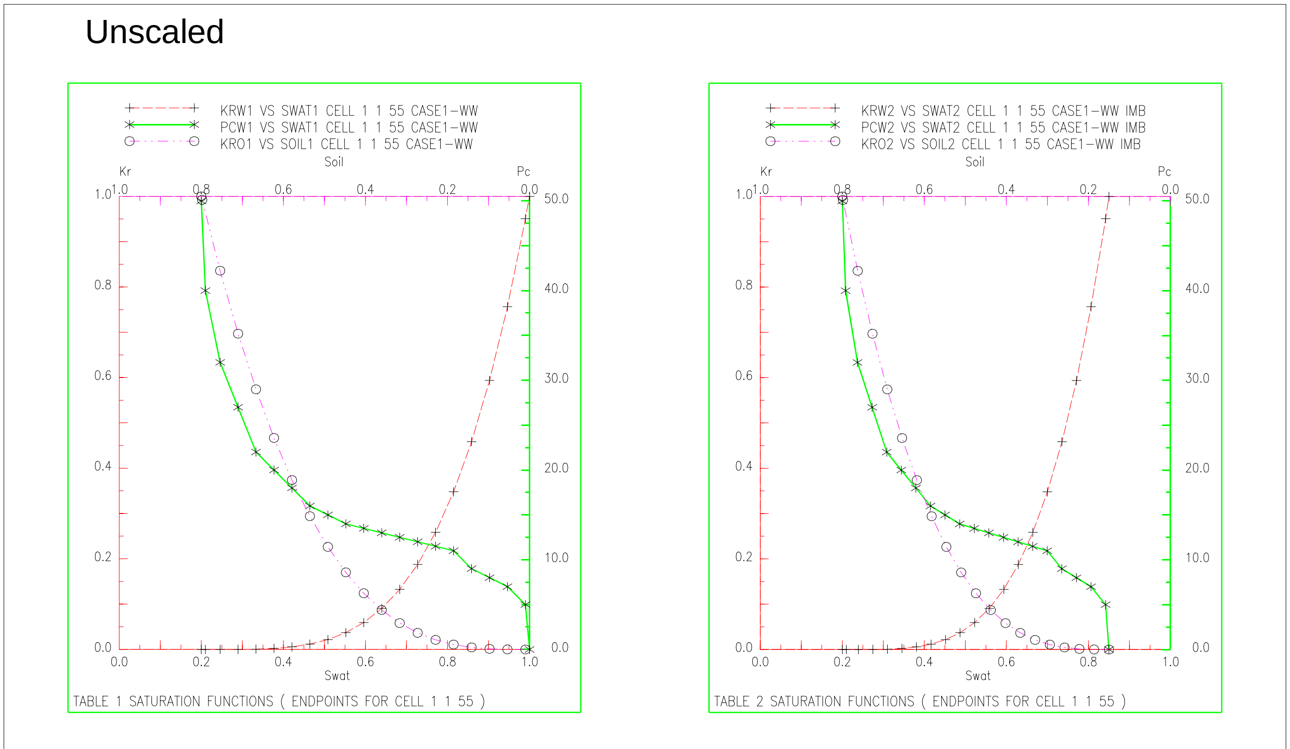
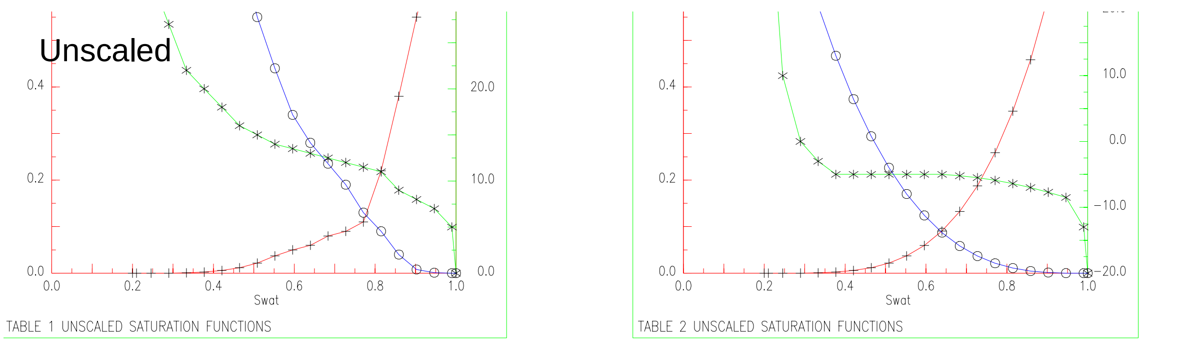


Figure 5 Case1 Relative Permeability and Capillary Pressure Data



ure 6a Case2 and Case3 Relative Permeability and Capillary Pressure D

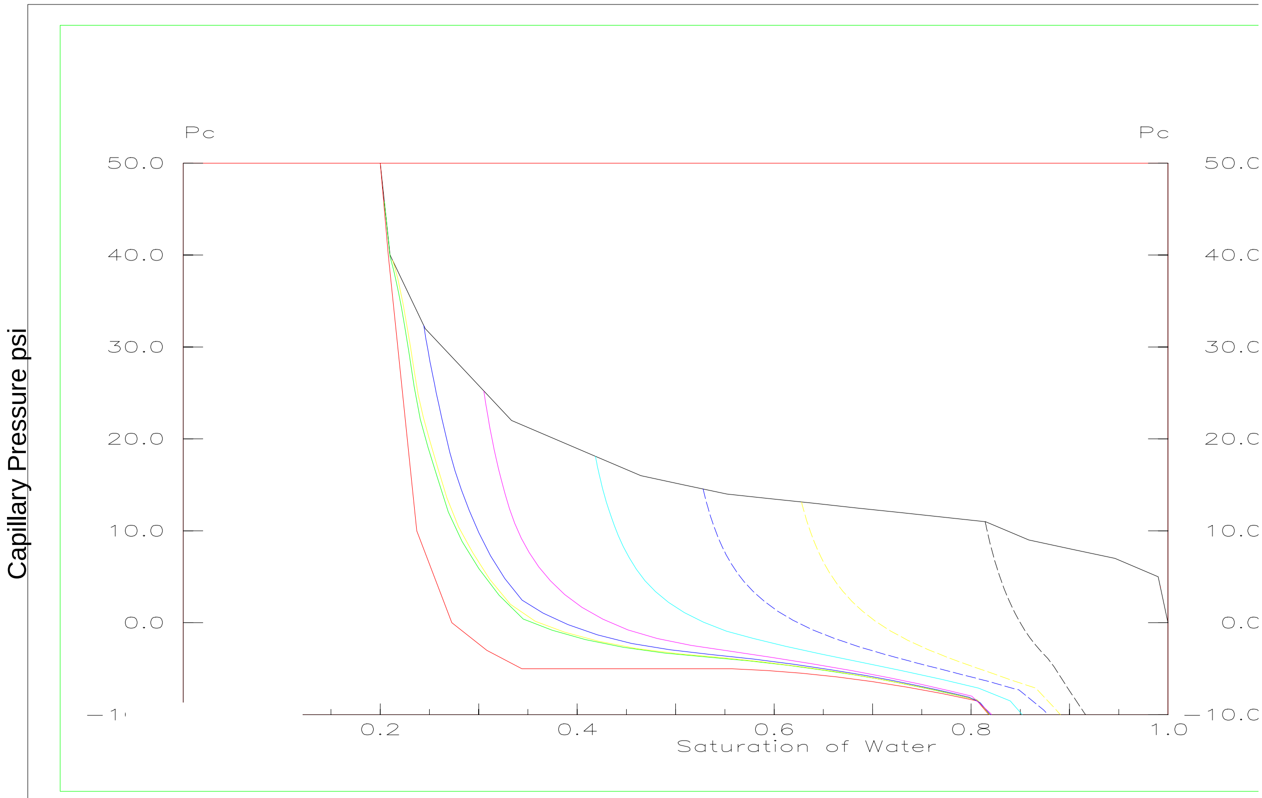
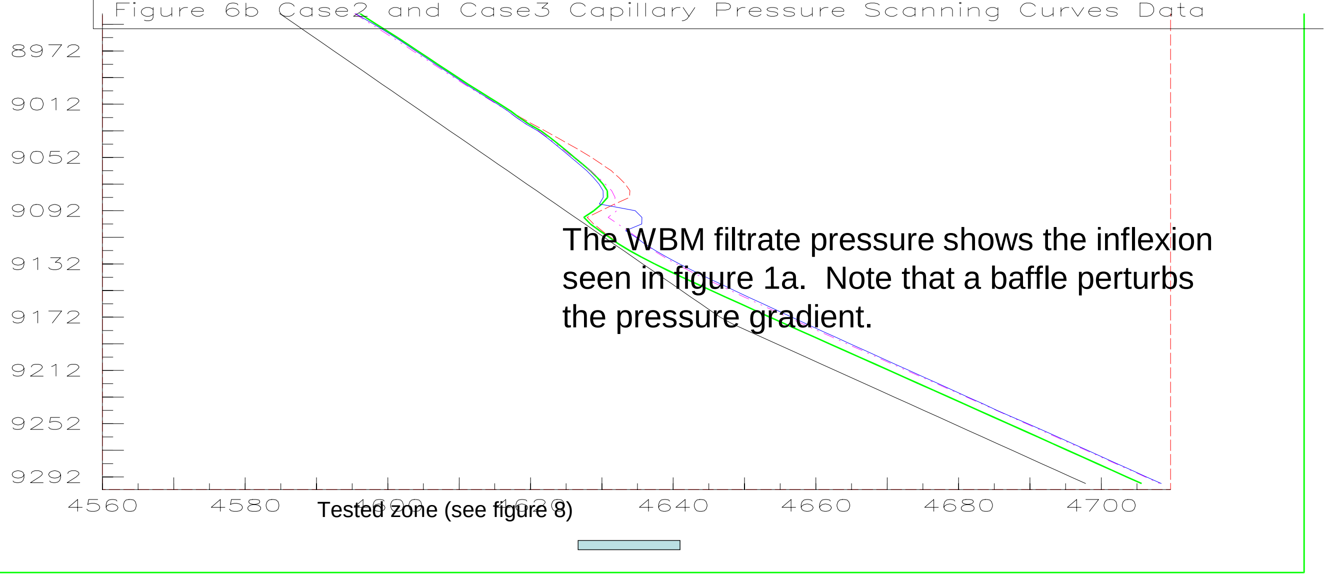


Figure 6b Case2 and Case3 Capillary Pressure Scanning Curves Data



gure 7 Case2,Case3,Case3.1 (Mixed Wet)

Some supercharging is observed. But this does not affect the interpretations

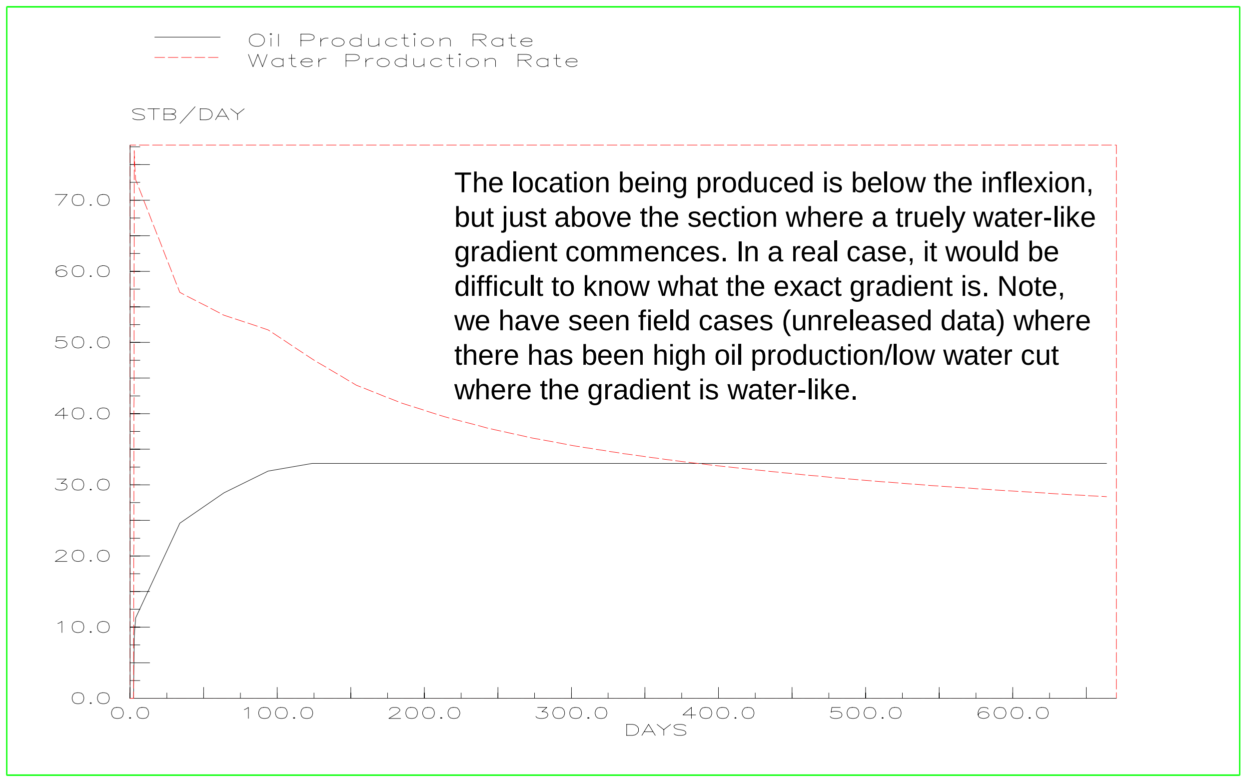
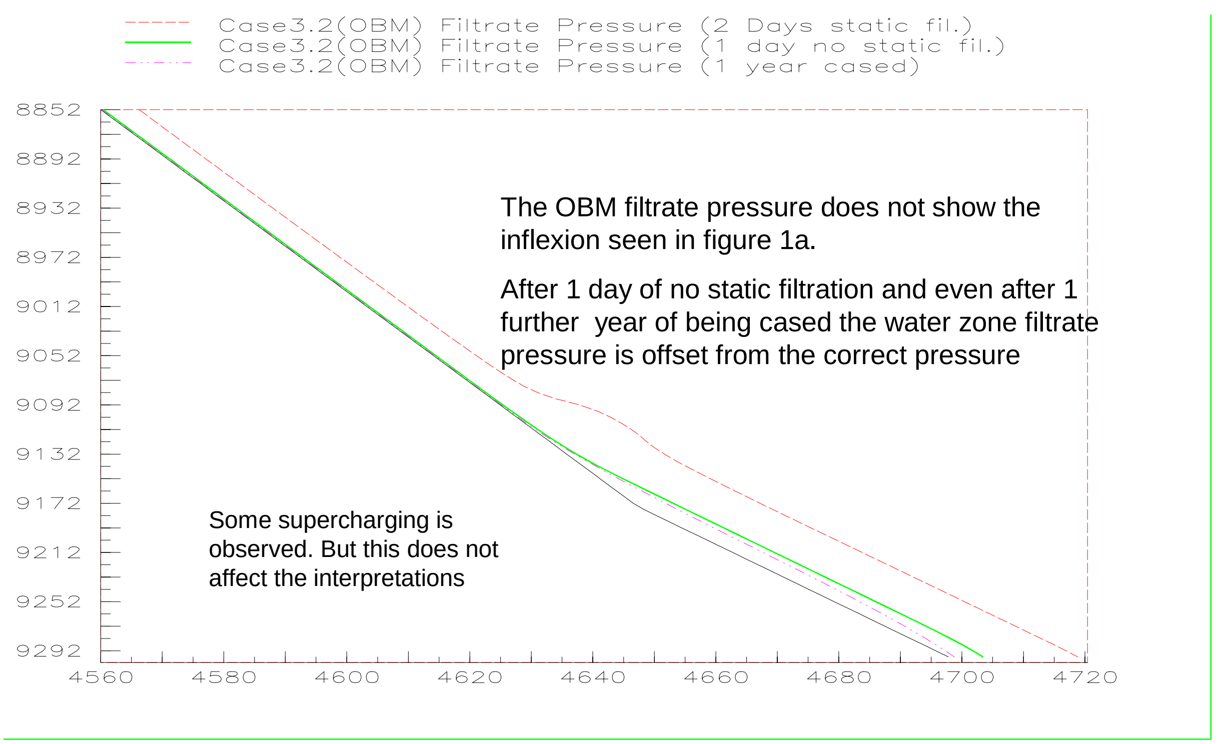


Figure 8 Case3 2 Year Production from 9115ft to 9120ft



ure 9 Case3.2 (OBM)