A PRACTICAL DETERMINATION OF ENDPOINT SATURATION FOR USE IN RESERVOIR SIMULATION

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Abstract: *Use of representative relative permeability curves is vital for a reliable dynamic reservoir simulation model. Determination of end point saturations and relative permeabilities is a critical step in any 3-D reservoir modeling studies. Especially the residual oil saturation (Sor) distribution will dictate the recoverable oil estimation and will influence the subsequent steps in dynamic modeling (history match and predictions). In this paper, a simple approach is presented to help select the appropriate endpoint saturations especially Sor from the actual displacement process and then using a set of known correlations to derive representative relative permeability and capillary pressure curves.*

Keywords*; relative permeability, End point and reservoir modeling*

Technical concern

The displacement of hydrocarbons - either oil or gas - in porous media is governed by the wetting/non-wetting phase interaction related to the wettability concept. Depending on the rock wettability, a displacement process is classified as drainage or imbibition. Drainage when the displacing fluid is the non-wetting phase and imbibition if the displacing phase is the wetting fluid. One of the common features of sandstone sediments is being water wet, but depending on the shale content or any other minerals it can be intermediate or mixed wet, and seldom oil wet. Also, most of the sandstone reservoirs are connected to strong or limited support aquifers. Therefore, one could conclude that in most of the cases, aquifer encroachment in sandstone rocks, will most likely be an imbibition displacement type of process. Similarly, if water is injected into the reservoir in order to enhance lateral sweep efficiency for example, then the process will be again an imbibition process. In the course of preparing the input data for performing reservoir simulation studies, the reservoir engineer must prepare a set of representative relative permeability curves that should adequately represent the actual displacement behavior and control phase movements. These curves are normally taken from core measurements and then may be correlated to different facies, rock types, members, core permeability ranges, etc. The technical concern arises from the fact that the use of either curve drainage or imbibition would have significant impact on reservoir model dynamics and consequently model quality and reliability.

In the literature, a strong emphasis is put on the care to selecting the function that actually represent the actual displacement process. For example:

"If oil is displaced by water (O/W interface and/or water injection), the "imbibition" curve must be used (at least for a water-wet medium). This also applies to gas reservoir with an active aquifer. By contrast, if oil is displaced by gas (G/O interface

and/or gas injection*), since the gas is non-*wetting in comparison with the oil, the "drainage" curve must be selected" [8].

"The displacement of oil by water in a water wet reservoir is, therefore, an imbibition process. As such, the capillary

pressure curve and relative permeability used in the description of the displacement must be measured under imbibition conditions. Conversely the displacement of oil by water in an oil wet reservoir would be a drainage process and require capillary pressure and relative permeability measured under drainage conditions" [6]. "In a water wet environment, you should equilibrate (initialize) using drainage data and then run the simulator using imbibition data"[7].

"The modeling team needs to realize that the relative permeability curves used in a flow model are most representative of the type of experiment that was used to measure the curves. Applying these curves to another type of displacement mechanism can introduce significant error"[5].These quotations clearly put strong emphasis on the use of the appropriate relative permeability and capillary pressure data.

Core test States

Cores are used to derive fundamental reservoir properties, because coring is the only means to approach the formation rock. Generally there are three different core tests: native state, cleaned-state, and restored-state.

Cores at **native state** are those obtained and stored at conditions preserve reservoir native wettability. Sometimes they are called fresh-cores.

Cores at **cleaned-state** are those cores subjected to cleaning by removing all reservoir fluids by solvents flow through the cores. The wettability of cleaned cores are usually exhibit water wetness characteristics. So the value of cleaned samples is when used for measuring non-wettability affected properties such as porosity and air permeability.

The **restored-state** cores refers to cores cleaned, then flooded by brine and crude oil and finally ageing the core at reservoir temperature usually for 40 days.

So, it is clear that the measured Sor form flood tests depends on the core state. Not only the Sor, but also other properties resulted from lithofacies, depositional and diagenetic processes including wettability, relative permeability capillary pressure any other two-phase flow related properties. However, the establishment of the in-situ wettability conditions is very important to properly duplicate or account for reservoir conditions [4].

Core data reliability

Special core analysis, SCAL, is the fundamental source of the relative permeability and capillary pressure measurements. The SCAL data are usually considered as solid data that many reservoir engineers tend to avoid modifying during the history matching process. However, other reservoir engineers argue that SCAL data are among the history matching parameters. The discussion of the reliability of SCAL data is important because the core sample is a very small piece of rock that it may not actually precisely represent the whole reservoir rock [5],[8] therefore the trend is to use the SCAL results as matching parameters for numerical models . Also, core extraction and handling in addition to conditioning the experiments adds more uncertainly to the lab measurements. For example, during the course of preparation, cores are cleaned with solvents to displace oil and samples are put in an oven to dry. This will definitely affect wettability characteristics of that small piece of rock. Most likely, the rock will be water-wet after cleaning and drying. That is probably why the residual saturations can be higher than those measured by open hole logs. In most laboratory tests, the viscous forces are designed to dominate capillary and gravity forces. This may not be true in the field [4]. Also, it is difficult to reproduce relative permeability measurements even with recent advanced techniques.

Endpoints determination

End point relative permeabilities along with saturation endpoints are important for phase movements and ultimately reserve calculations. The end-points relative permeability are also important for the mobility ratio calculation for water flood projects. The Mobility ratio is the mobility of the displacing phase to the mobility of the displaced phase. In case of water flood the mobility ratio is:

$$M = \frac{\lambda_D}{\lambda_d} = \frac{k_w}{k_o} \times \frac{\mu_o}{\mu_w}$$ where:

λ_D and λ_d are the displacing and displaced phase mobilities respectively and k_o and k_w are the endpoint effective permeabilities.

Generally speaking, core analysis and well logging (open-hole and cased-hole) are the two most widely used methods for measuring residual oil saturation. These two methods yield values that are considered averages of the vicinity of the near wellbore volume. A third method to measuring Sor is by use of a single-well tracer method. This method involves injection of trace chemicals dissolved in formation water. The Sor is measured in-situ for a much larger reservoir volume [3].

On the other hand, the Sor from the open-hole logging is calculated from the resistivity logging by the Archie equation as $1\text{-}S_{xo}$, where S_{xo} is water saturation in the invaded zone.

From the core analysis, capillary pressure measurements are usually used to determine the Sor. In the lab, the core is initially saturated with water. Then the oil is forces to inter the core constructing the drainage curve until water ceases to flow. The remaining water referred to as the irreducible water saturation. The oil phase pressure is slowly decreased allowing water to spontaneously displace the oil until oil ceases to flow, when capillary pressure becomes zero 0.

Fortunately, the Swc is mainly measured with accuracy. Swc or sometimes called irreducible water saturation and its relative permeabilities (i.e. Kro&Krw @Swc) from both drainage and imbibitions mechanisms are similar.

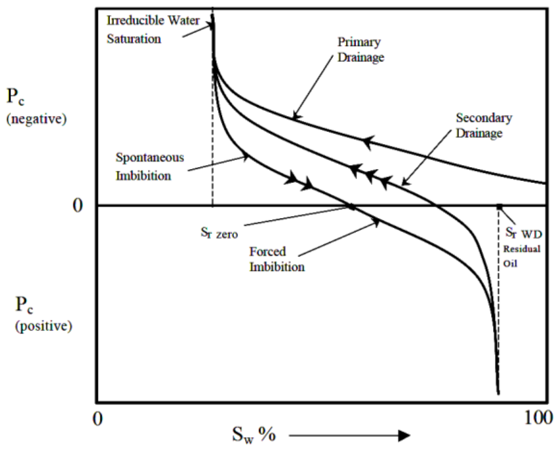

Figure 1: Typical capillary pressure curves

Figure 1 is an example of drainage and imbibition curves including forced imbibition and secondary drainage. $S_{r\ zero}$ is the oil saturation where the imbibition curve reaches capillary pressure of zero. $S_{r\ WD}$ is the oil saturation where oil recovery ceases after forced imbibition. (After Morrow 1990) 0.

The same concept applies to relative permeability curves Figure 2. The difference between drainage and imbibition is always at the right-hand side of the oil curve (i.e. Kro and krw at Sor).

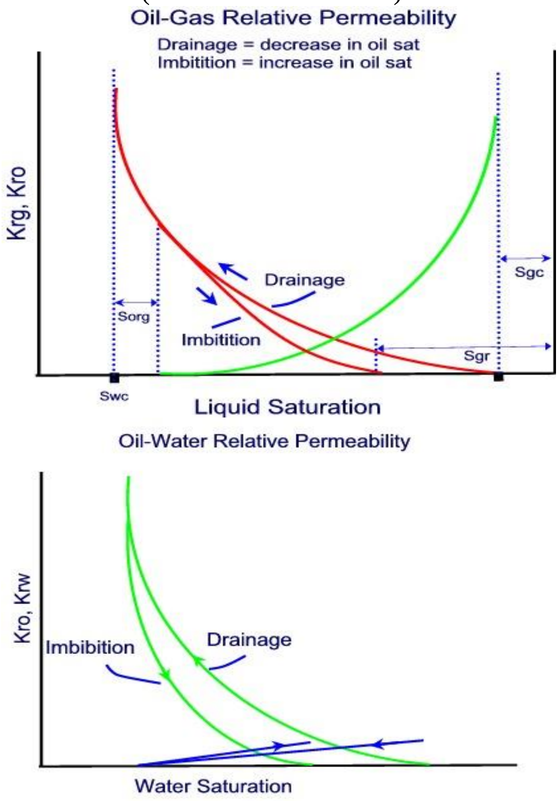

Figure 2: Typical relative permeability: imbibition and secondary drainage.

Log derived properties i.e., permeability, saturation

Open-hole logs and their petrophysical interpretations provide another source of basic reservoir rock properties like porosity, saturations, volume of clay etc. the saturations are mainly derived from resistivity logs. In the invaded zone the saturation is called Sxo. This Sxo is related to the oil saturation or in other words the residual oil saturation in the invaded zone. In a mature field a well that has both core and open-hole logs the Sor from SCAL and the 1-Sxo may not match and the difference may be intolerable. So which one is more reliable for initializing a dynamic model?. The author's opinion is to look at the cased-hole logs either resistivity based or neutron absorption based to derive a reasonable Sor in swept zones. Assuming well conditions and formation water salinity furnish reliable measurements.

Residual saturations: Sarir Field Case

Residual oil saturation is a very important parameter in reserve estimation. It is actually the target of secondary and especially tertiary recovery processes. The Sor measured by drainage is different from that measured by imbibitions process. So, it is clear that using either curve drainage/imbibition won't only affect the simulation model performance, particularly during history matching, but also it dictates future enhanced oil recovery, EOR, deveopment strategies. The source of Sor is basically the core measurements or petrophysical analysis, and therefore core derived data should be cross checked with log derived Sor especially in clean sands.

In mature field the petrophysical analysis consists of the open hole logs and the cased hole logs interpretations. Practically, a well that has saturation monitoring tools run frequently such as TDT, RST, RMT, CHFR can be used to determine Sor in swept zones. Oil saturation in swept zones represents Sor corresponding to the actual displacement process. Having Swc, Kro and Krw in addition to the Sor seen in the swept zone.

Sarir field is known as simply as a gaiant thich sandstone reservoir with different shale content. The reservoir is divided into five members from top to bottom: MBR5, MBR4, MBR3, MBR2, MBR1. MBR2 and 3 are considered part of theactive bottom aquifer. MBR3, 4, 5 are the oil bearing formations. MBR4 is the cleanest member;high porosity, high permeability, and very low clay content. Porosity averages 20%, permeability ranges from few hundred mD up to more than one Darcy.

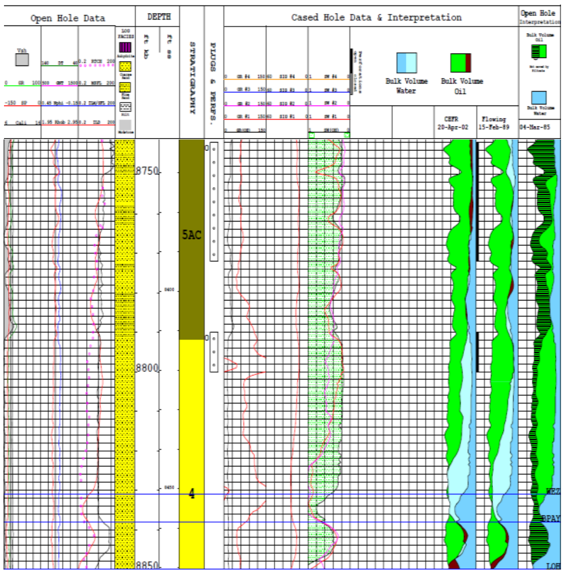

Figure 3: Saturation change monitored by cased-hole logs (TDT and CHFR)

In Figure 3, an example shows a comparison between the initial oil saturation measured by OH logs (right) and two saturation profiles measured by two saturation monitoring tools; TDT and CHFR [2]. The figure is composed of three sections, to the left the open hole logs. In the middle, the cased hole logs, and to the right is the comparison of the interpretations. In the interpretations the light blue area represents the connate/initial water saturation, the green area represents the mobile oil, and the dashed green area represents the immobile oil saturation derived from the open hole logs. The TDT was run four years after OH logs. It suggests about 15% Sor. The time lag between the OH logs and the CHFR is about 17 years. Against the clean sand CHFR indicated less than 5% Sor which is almost complete sweep. Of course CHFR in this case underestimated Sor, or in other worlds overestimates the sweep efficiency. The available SCAL data Figure 4, in the other hand, suggest an average value for Sor about 40%.

The log Sor is in fact a good representation of the actual displacement process whether drainage or imbibitions, with; gravity, capillary and viscous forces aswell as heterogeneity involvement. However, care related to logging and well conditions must be taken when considering log Sor. It is no surprise to achieve such a high recovery from Sarir MBR4.

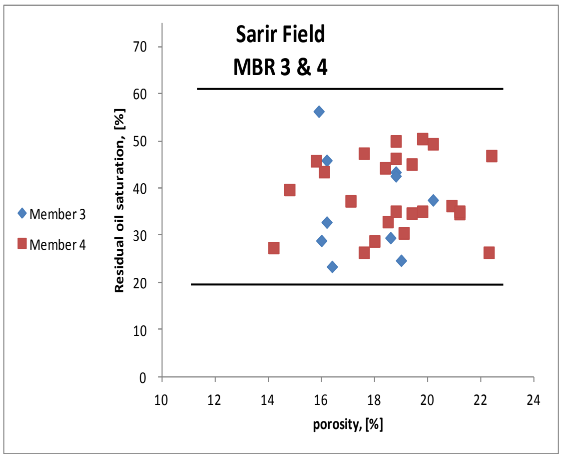

Figure 4: **Core measured residual oil saturation for MBR 4**

CONCLUSIONS

1. Residual oil saturation is only representative of the type of the experiments from which it was derived
2. Core derived Sor has to be taken with attention
3. Upscaling of core measurements to simulation grid cells is not fully correct
4. Availability of cased-hole logs over swept zones help reduce Sor uncertainty for mature fields
5. Log derived Sor is qualitatively and quantitatively reliable
6. An approach is proposed to better estimate Sor in sept zones and applied that Sor to the remaining unswept layers assuming continuity of similar rock quatilty. This approach is effective in case of mature clastic reservoirs with good reservoir rock quality in swept zones
7.The presented approach helps the reservoir engineer to select the adequate saturation functions for a dynamic simulation modeling.

Nomenclature

CHFR® = Cased-hole formation resistivity log
EOR =Enhanced oil recovery
Ko, Kw = Effective oil and water relative permeabilities
Kr = relative permeability
M = Mobility ratio
RMT® = Reservoir monitoring tool
RST® = Reservoir saturation tool
SCAL = special core analysis
Sor = residual oil saturation
$S_{r\text{-}WD}$ = Sor from forced imbibition
$S_{r\text{-}zero}$ = Sor from spontaneous imbibition
Swc = critical water saturation
Sxo = Invade zone saturation
TDT® =Thermal decay time log
λ_D & λd = Mobility of the displacing and displaced fluids
μ_o , μ_w = Oil and water viscosities

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