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An Approach to Water Saturation Estimation using NMR Data in Water-Wet Rocks: A Case Study

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Summary

The present study demonstrates a methodology of computing water saturation in virgin zone using NMR data in conjunction with nuclear logs only. Water saturation for case of virgin saturations restored near sand-face, and when the case it is not so, has been computed, to aid realistic water saturation modeling. The paper demonstrates viability of technique using actual well data as a case study from East Coast deep water well in India. The technique has potential for obtaining , likely free water level even when the same is not penetrated by a well, when petrophysical data from regular suite of logs is integrated with NMR analysis results in detail in the paper.

Introduction

The present case study concerns an examination of an improved method of estimation of water saturation in virgin zone using NMR data. The candidate well selected is an offshore well in East Coast deep-water, India. The reservoir analyzed is a gas bearing reservoir with no Gas-Water-Contact (GWC) penetrated in the well. The lithofacies of the section analyzed is blocky and partially finely laminated sandstone with interlaminations being silty sandstone, clayey silt and shale.

Conventional approaches to water saturation estimation using NMR data are limited to techniques in which dual wait-time and dual echospacing CPMG echo trends are inverted to hydrocarbon volumes in the zone of investigation of NMR tools and therefore do not necessarily give water saturation in virgin zone.

Another approach involves obtaining the upper most transverse relaxation time (T_2), upto which, cumulative porosity summed from a minimum T_2 of 0.3 ms would yield the total volume of water, in a rock under initial drainage saturation condition level by level and therefore lead to water saturation in virgin zone (Ramamoorthy et. al., 2000).

The current work starts from this perspective and describes a method of computing reliable water saturation in virgin zone, by integrating NMR with other measurements and demonstrates viability with an actual case study.

Theory and Methodology

A water-wet rock is considered under initial drainage saturation condition, containing gas as the hydrocarbon fluid phase.

Let h is the height of a level above free water level (FWL), Υ_{throat} represents the maximum throat radius of the pore system un-drained by gas. Let τ stands for gas-water interfacial tension and θ stands for angle of contact, relevant to water-gas interface in a gas water quartz system. We then have,

$$\gamma_{throat} = 2\tau \cos\theta / P_c(h) \qquad \text{.... (1)}$$

Where $P_c(h)$ stands for capillary pressure at height h. Above free water level

$$P_c(h) = (\mu_w - \mu_g)\, hg \qquad \text{.... (2)}$$

where μ_w and μ_g stand for density of water and gas respectively under condition of formation temperature and pressure. θ is non-zero for a gas quartz water system and is so assumed. We would then have from equation 1 and 2,

$$\gamma_{throat} = 2\tau / (\mu_w - \mu_g)\, hg \qquad \text{…. (3)}$$

by assuming cosθ is equal to 1

Let α stand for the representative pore size to pore throat ratio for the un-drained pore system and ß stands for a shape factor which connects the specific area of a pore, designated by the symbol Sp_v Half the pore diameter (defined as diameter of cylinder for cylindrical pores, maximum diameter of a section orthogonal to long axis incase of ellipsoid pores and diameter of the sphere in case of spherical pores) is having the relation

$$Sp_v = \beta / \text{half diameter of pore} \qquad \text{…. (4)}$$

It is easy to see that the diameter is nothing but α. Υ_{throat} making the relation

$$Sp_{v\,undrained\,pores} = \beta / \alpha * ((\mu_w - \mu_g)\, hg) / 2\tau \qquad \text{…. (5)}$$

We now consider the volume of Sp_v of the water in drained pores. If Υ_{min} stands for the minimum radius of curvature of the water-gas interface (miniscus) in a drained pore at a level of height h above FWL, then Υ_{min} can be written as

$$\gamma_{min} = 2\tau / (\mu_w - \mu_g)\, hg \qquad \text{…. (6)}$$

with an assumption of cosθ is equal to 1.

The volume of pore water for such a level, for drained pore system only, can be approximated to wetted surface area of drained pore system multiplied with Υ_{min}. This makes Sp_v of water in drained pores equals to surface area of the waterwet grains in drained pore system divided by wetted surface area of drained pore system times Υ_{min} (since surface area of water wetting grains in drained pore systems can be approximated to be equal to wetted surface area of the grains wetted, in the drained pore system). This leads to the following relationship

$$Sp_{v\,drained\,pores} = 1/\gamma_{min} = (\mu_w - \mu_g)\, hg / 2\tau \qquad \text{…. (7)}$$

Now, surface relaxivity of the grains (assumed to be made of quartz in this case) can be denoted as ρ and transverse surface relaxation as T_2. Then equation 5 and 7 can be rearranged as

$$T_{2\,undrained\,pores} = (1/\rho) * (\beta/\alpha) * ((\mu_w - \mu_g)\, hg) / 2\tau \qquad \text{…. (8)}$$

and

$$T_{2\,drained\,pores} = (1/\rho) * (\mu_w - \mu_g)\, hg / 2\tau \qquad \text{…. (9)}$$

because $T_2 = (1/\rho * Sp_v)$. For elongated pores (which are nearest approximate to cylindrical pore geometry) the value of α is close to 1.0 and the value of ß is close to 2, whereas in case of rounded pore α is close to 1.5 - 2 and ß is close to 3. For elliptical pores α is close to 1 – 1.5 and ß is in range of 2-3. The value of ß/α has a week dependence on pore size or shape.

Consequently it is reasonable to assume that, in general, in a permeable sandstone reservoir (which is usually having higher degree of textural maturity) the value of (α/ ß) is in excess of 1.0.

Hence, if a NMR T_2 distribution is acquired, hypothetically, in a reservoir, at initial drainage saturation condition, and the same condition apply even in the zone of investigation of NMR tool, then, the summation of cumulative volumes in different T_2 classes of a T_2 distribution from $T_{2\,min}$ to $T_{2\,undrained\,pore}$ water would correctly estimate the volume of water in un-drained pores plus volume of water in drained pores at any level h above the FWL. In other words,

$$T_{2\,threshold}(h) = T_{2undrained\,pore} = (1/\rho) * (\beta/\alpha) * ((\mu_w - \mu_g)\, hg) / 2\tau \qquad \text{…. (10)}$$

Hence, the saturation of water at a level h above FWL can be given by

$$S'_{wT} = \frac{1}{\phi_t} * \sum_{T_2 = 0.3ms}^{T_2 = T_{threshold}(h)} \phi(T_2) \qquad \text{…. (11)}$$

It is important to note that the above result would yield accurate results only if initial drainage saturation of gas is restored near sand-face postmud-cake formation, at the time of logging. In reality when a well is drilled, the near sand-face saturation of gas decreased owing to invasion initially. As time progresses, the mud-cake formation isolates the borehole pressure from near sand-face pressure allowing gas in virgin zone to come back to near the sand-face equilibrium. Conditions may or may not generate full restoration of virgin saturation in the zone of investigation of NMR tool. This, however, can happen when vertical permeability as well as horizontal permeability is sufficiently high at any given level (Fig. 1).

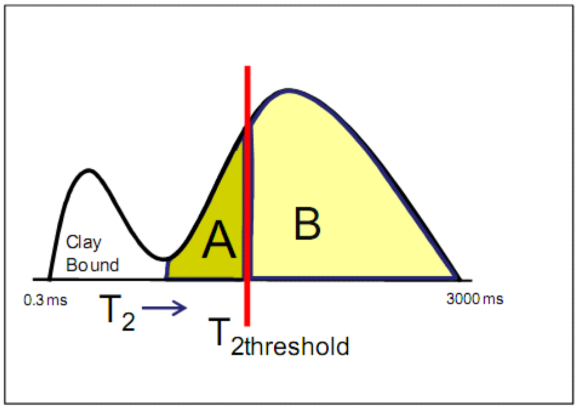

Figure 1: A schematic representation of NMR T_2 distribution of a level above the free water level. Zone A shows the water of drained pores plus water of un-drained pores if near sand-face saturation is restored to virgin saturation. On the other hand zone A has un-drained pore water plus part of no drained pore water if near sand-face saturation is not fully restored to virgin saturation.

In extreme cases, the saturation of water at a given level is given by

$$S^2_{wT} = \frac{1}{\phi_t} * \sum_{T_2=0.3ms}^{T_2=T_{threshold(h)}} \phi(T_2) + \frac{1}{\phi_t} * \sum_{T_2=T_{threshold(h)}}^{T_2=T_{2MAX}} \frac{\phi(T_2)}{\rho * T_2} * \gamma_{min}$$

Or,

$$S^2_{wT} = \frac{1}{\phi_t} * \sum_{T_2=0.3ms}^{T_2=T_{threshold(h)}} \phi(T_2) + \frac{1}{\phi_t} * \sum_{T_2=T_{threshold(h)}}^{T_2=T_{2MAX}} \frac{\phi(T_2)}{\rho * T_{2H}} * \frac{2\tau}{h*(\mu_w - \mu_g)*g}$$

…. (12)

Where specific area associated with a pore class is denoted as ($1/\rho * T_{2H}$) in which T_{2H} stands for mean T_2 of the class. In addition, Φ (T_2) represents the area under the entire T_2 distribution.

Results and Discussion

In the present case study a total porosity was computed using NMR-density combination. Polarization correction with a polarization factor for T_1/T_2 of gas has been applied on T_2 porosity bias to remove the gas effects in NMR data. The total porosity obtained has been compared with total porosity estimated using NMR-density combination at every level and has been confirmed that the two agree with in 1-1.5 p.u.

The gas corrected NMR total porosity has been used as Φ_t. The data acquisition was with echo spacing of 200 ms. For the field gradient of the tool magnets in the zone of investigation of the NMR tool used diffusion induced spin de-phasing effects are minimal and have been ignored.

The boosted T_2 distribution obtained after applying polarization correction has been used as the T_2 distribution.

Formation tester derived formation pressure data has been compared with similar data of offset wells which penetrates FWL and has been confirmed that the pressure regimes were identical. The FWL confirmed on formation pressure versus depth plots of offset wells has been used to compute h of equations given in the foregoing.

Interfacial tensions between gas and water phases, density of water and density of gas have been obtained from standard correlations. Known water salinity has been used as salinity input and in-situ gas density from formation pressure-depth plot from formation tester data has been used while computing gas density.

Finally, in the current work a value 2 has been used for ß/a.

Two formation water saturation sets can be derived as S^1_{wT} and S^2_{wT} respectively from equations 11 and 12.

A regular multi-mineral petrophysical model has been used for processing well-log data consisting of resistivity, porosity, natural gamma-ray spectroscopy and photoelectric factors apart from NMR data. A simultaneous volumes optimization minimizing total error with respect to theoretical values of log measurements from a robust forward model has been implemented as commercially available software.

The results of total porosity and volume of water have been overlaid against water volumes computed employing the techniques elaborated in the foregoing. Also, water saturation from petrophysical processing in respect of un-invaded zone has been overlaid against S^1_{wT} since the permeability of the formations lie in the range 100-1000 mD.

The match between the results of the technique presented and from conventional processing is excellent as can be seen from (Fig. 2 and Fig. 3).

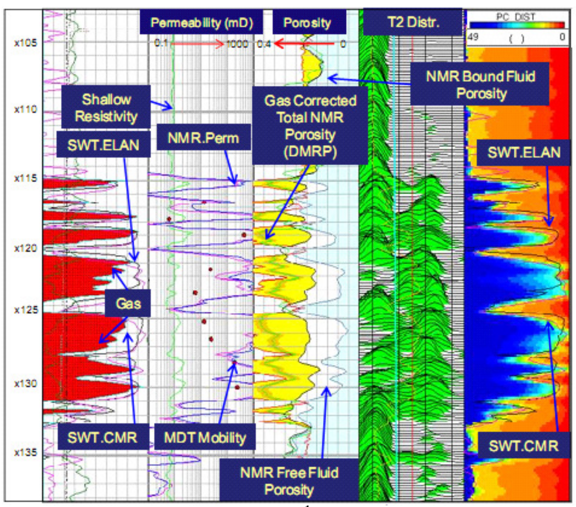

Figure 2: Water saturation result (S^1_{wT} or SWT.CMR) using present technique compared with the conventional petrophysical analysis (SWT.ELAN)

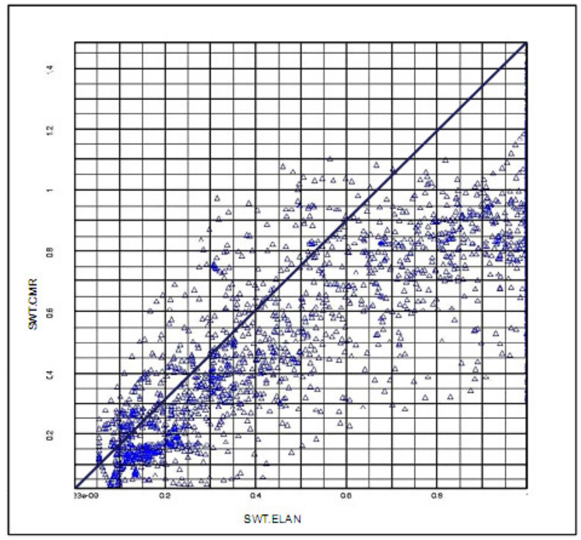

Figure 3: An excellent match of the technique presented and from conventional processing

Conclusions:

The viability of the techniques described in computing the water saturation in the virgin zone is demonstrated.

S^1_{wT} can be relied upon where formation permeability exceeds 1000 mD as has been demonstrated. On the other hand for formations having permeability below 100 mD the S_w can lie between S^1_{wT} and S^2_{wT}. It is possible to generate the most likely S_w as a weighted average between S^1_{wT} and S^2_{wT}, with $\sqrt{\frac{K}{\phi}}$ controlling the relative weight factors for S^1_{wT} and S^2_{wT}. The output can be made to be S^1_{wT} when K exceeds 100 mD.

This technique has potential for being a viable technique for gas detection in shally zones because of the advantages of being able to account for clay in a very simple manner in case of NMR.

Wherever, lamination with shale or other factors make S_w from conventional Petrophysics to be pessimistic, the method presented offers as an alternative for realistic hydrocarbon volumetrics.

When the FWL is not penetrated in a well it is possible to obtain the best $T_{2threshold}$ at every level in a well section. That result in best match of water saturation from the T_2 distribution with water saturation computed from conventional petrophysical analysis. The $T_{2threshold}$ versus depth data can be inverted into most likely H, where H stands for the vertical distance between the bottom most depth of hydrocarbon bearing reservoirs and free water level, and thereby enabling estimation of the FWL depth.

The technique discussed in this paper works best in clastic environment.

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