



SPE 38666



Society of Petroleum Engineers

Predicting Fluid Production of Tuffaceous Sandstones in the San Jorge Basin With Array-Type Induction Logs

Alberto Khatchikian, SPE, Consultant, and Eduardo Breda, SPE, YPF S.A.

Copyright 1997, Society of Petroleum Engineers, Inc.

This paper was prepared for presentation at the 1997 SPE Annual Technical Conference and Exhibition held in San Antonio, Texas, 5-8 October 1997.

This paper was selected for presentation by an SPE Program Committee following review of information contained in an abstract submitted by the author(s). Contents of the paper, as presented, have not been reviewed by the Society of Petroleum Engineers and are subject to correction by the author(s). The material, as presented, does not necessarily reflect any position of the Society of Petroleum Engineers, its officers, or members. Papers presented at SPE meetings are subject to publication review by Editorial Committees of the Society of Petroleum Engineers. Electronic reproduction, distribution, or storage of any part of this paper for commercial purposes without the written consent of the Society of Petroleum Engineers is prohibited. Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgment of where and by whom the paper was presented. Write Librarian, SPE, P.O. Box 833836, Richardson, TX 75083-3836, U.S.A., fax 01-972-952-9435.

Abstract

Conventional log interpretation is a poor predictor of fluid production in the San Jorge basin in Southern Argentina. This was thought to be due to unpredictable variations of formation water resistivity. In this paper we show that the real reason is a combination of overestimation of the porosity and underestimation of the Archie exponent m in tuffaceous sandstones, and that a method based on the ratio of deep to shallow induction curves from array-type induction logs can be used to estimate fluid content as it is insensitive to those factors. This method was successfully used in more than 200 wells using Schlumberger's (AIT) and Western Atlas (HDIL) array-type induction tools with over 2000 zones that were perforated and tested.

Introduction

Formation evaluation in the San Jorge basin is difficult because of the thinness and lack of continuity of the reservoirs, which complicates well-to-well correlation, and the shaly-tuffaceous nature of the sandstones, which complicates the evaluation of porosity and water saturation¹. Because of this, historically the usual practice was to run a minimum logging program and decide which intervals to perforate on the basis of visual examination of the logs, sidewall cores and correlation. In order not to miss potentially productive zones, usually 10 to 20 sands are perforated and tested, of which only a few produce hydrocarbons. Many perforated intervals are dry, either because of poor permeability or formation damage².

Formation evaluation in the San Jorge basin

Porosity evaluation - Previous studies^{1,3} have shown that in tuffaceous sandstones the sonic log is less sensitive to variations in lithology than the density log. For this reason, sonic is the log of choice in the deeper wells. In shallow wells (1200 meters or less), density is the standard porosity log as it is difficult to match sonic velocity with porosity in unconsolidated sandstones, even when using the so called "empirical" relations. But due to the volcanic material content of many sandstones, grain density may vary from 2.4 to 2.7 g/cm³, introducing a large factor of uncertainty on the porosity. The example shown on Fig. 1 is a sandstone with an apparent density porosity of 30 % and relatively clean according the density-neutron response. However, the laboratory measurement of a rotary sidewall sample at 2185.8 meters indicates that the true porosity is 20.7 % and that the grain density is 2.45 g/cm³.

Water saturation - The quick-look method R_{wa} was, until recently, the standard fluid predictor in this basin. Unfortunately, this method is too optimistic in tuffaceous sandstones and pessimistic in shaly sands and therefore is not a reliable fluid predictor. Fig. 2 shows a water-producing, tuffaceous sand with an R_{wa} of about 4.0 ohm.m, i.e., roughly ten times the resistivity of the formation water. Note the anomalous SP caused by streaming potential, typical of low permeability tuffaceous sandstones.

R_{wa} is too high in tuffaceous sandstones because they tend to have lower permeability and higher values of m than quartz sandstones. Therefore, R_{wa} will be too high and computed water saturation too low if standard values of a and m are used. The example of Fig. 3 illustrates this effect. Using standard values for a and m ($a = 0.62$, $m = 2.15$), the average computed water saturation in the interval 1291-1299 meters is 60% (Fig. 3a). On the other hand, using $a = 1$, $m = 2.5$, which was estimated from a Pickett plot (Fig. 3c), the average water saturation reaches 100% (Fig. 3b). This is confirmed by a sidewall sample at 1298 meters which was described as a tuffaceous sandstone with no traces of hydrocarbons and the fact that S_{xo} computed from a

dielectric log is 100%.

On the other hand, in very shaly sands R_{wa} is too low because shaliness decreases the resistivity. In this basin, the effect of clay on the conductivity is important because of the low salinity formation water (average 10,000 ppm). For this reason very often low-resistivity, low- R_{wa} zones produce hydrocarbons, specially if the shale is laminated.

New method for fluid prediction

The introduction of array-type induction tools by Schlumberger and then Western Atlas in 1995 allowed us to revive the use of the old quick-look ratio method⁴ for fluid prediction. The method consists simply in comparing either R_{xo} or a shallow resistivity device to a deep resistivity. In fresh-water mud conditions, a large shallow-to-deep ratio is indicative of water or non-moveable hydrocarbons, while low ratios are indicative of oil production. The advantage of this method is that no porosity tool is required, and therefore it is insensitive to lithology. Its main limitation is that it is difficult to implement as an R_{xo} curve is not generally available. The alternative (albeit with a loss of dynamic range) is to use the spherically focused log (SFL) to deep induction ratio⁵, as conventional induction logs are available in every well. One of the problems of this approach is that the SFL and the deep induction have different vertical resolution, and therefore the ratio becomes meaningless in thin beds. But a more serious objection is that, even in thick beds, the SFL is not a shallow resistivity device, especially when $R_{xo} < R_t$, as will be shown later.

Schlumberger's array-type induction tool⁶ (AIT) presents five resolution-matched curves with 10", 20", 30", 60" and 90" radial depth of investigation and a vertical resolution of either one or two feet. Early in our study we found that the 2-feet vertical resolution curves are the best compromise between high definition and stable deconvolution (repeatability), as will be shown later. Western Atlas's tool⁷ (HDIL) presents six 2-ft resolution matched curves with 10", 20", 30", 60", 90" and 120" radial depth of investigation.

With any of these tools, a ratio of the 90"/10" or 120"/10" induction curves is computed at the well site and presented in a quick-look display. The ratio computed in this way is the reciprocal of the traditional shallow/deep ratio. We chose to do it this way because it was easier to interpret by the users (high ratio is hydrocarbons, low is water).

It was soon found that the ratio was a better fluid predictor than R_{wa} . The example of Fig. 4 shows two sands with almost identical values of R_{wa} (0.9-1.0 ohm.m) but very different values of the ratio. The oil-producing sand has a ratio of 0.9 while the water-producing sand has a ratio of 0.6.

Since array-type induction logs are not available in every well, we tried to see if the ratio derived from phasor-type, high-definition dual induction logs could be used for the same purpose. However, as the example of Fig. 5 shows, on the HDIL the 120" investigation curve (M2RX) reads way above the 10" curve (M2R1), indicating hydrocarbon production, but on the phasor induction the spherically focused log RSFL reads higher than the enhanced deep induction RERD. Note, however, that the enhanced medium induction RERM reads lower than RERD, indicating $R_t > R_{xo}$.

Pitfalls

R_{mf}/R_w variations - The values of the ratio that discriminate between water and hydrocarbons depend on shaliness and the R_{mf}/R_w ratio, which are supposed to be about constant along the well and for a group of wells drilled with the same type of mud. Unexpected variations of R_w will produce wrong predictions. The cut-off ratio should be adjusted for shaliness and R_{mf}/R_w using the SP, as shown on the chart of Fig. 6. However, it should be noted that for very fresh waters, the SP ceases to be an R_{mf}/R_w indicator. Fig. 7 is an example of very fresh ($R_w > R_{mf}$) water-bearing sandstone with a negative SP.

Horizontal temperature gradient effects - Although we have not implemented it, it seems that a correction factor should be applied to the 90"/10" ratio as a function of depth because of temperature effects. The reason is the following. In principle, all induction curves should read the same in shales regardless of their depth of investigation, since there should be no anisotropy nor borehole effects (since all curves are borehole-corrected). However, it can be observed that the 90"/10" ratio in shales at the bottom of the well is always in the order of 0.8 (Fig. 8), increases steadily uphole and reaches values above 1.0 close to surface (Fig. 9). This effect has been attributed to horizontal gradient effects: at the bottom of the well the formation is hotter than the mud, therefore the deeper investigation curves read lower, since shale conductivity decreases with temperature. Close to surface the reverse happens: the formation is cooler than the mud and therefore the deeper investigation curves read higher than the shallow ones. A temperature difference of 30 deg F close to surface, for example (a formation temperature of 80 deg F and a mud temperature of 110 deg F) would result in a ratio of counter-ion conductances⁸ B_{110}/B_{80} of 1.16 and therefore in a conductivity ratio of 1.16 in clays. In water sands, assuming the same thermal conductivity of shales and no invasion, the conductivity ratio due to the change in water resistivity with the same temperature gradient would be 1.34. In practice, however, close to surface the ratio in sands and shales seem to be similar.

Log quality - In some cases we have found it difficult to make a fluid production forecast because of variations of the

ratio along the sand. We have verified that these variations are in fact log anomalies, possibly due to deconvolution problems. On Fig. 10 we show an example of anomalous variations of the 90° curve, which in turn produces anomalies in the ratio.

The ratio can be inaccurate at high resistivities, as the repeatability of the one and two-foot resolution curves is not always within specifications because of limitations of the deconvolution. Fig. 11 is an example of poor AT90 repeatability at high resistivities, with the consequent uncertainty on the true value of the ratio. However, noise and poor repeatability at high resistivities is a price we are ready to pay for 2-ft resolution induction curves.

Conclusions

We have been able to successfully predict water or hydrocarbon production from the ratio of deep to shallow, 2-ft resolution-matched array-type induction curves. The hydrocarbons-water limit ratio had to be determined for each field, as it assumes that the formation water salinity is constant and that the properties of the drilling mud do not change from well to well. In shaly sands, the limit ratio needs to be adjusted for shaliness by comparing it with the SP.

Array-type induction tools are now being routinely run and the ratio method used to predict fluid production in different fields of the basin. It allows to identify the best zones in each well and to decrease well completion costs as it avoids unnecessarily perforating water zones.

Nomenclature

a = coefficient in the $F - \phi$ relationship
 B = counter-ion conductance, (mho/m)/(meq/cm³)
 F = formation factor
 m = Archie's porosity exponent in the $F - \phi$ relationship
 R_{mf} = mud filtrate resistivity, ohm.m
 R_t = non-invaded zone resistivity, ohm.m
 R_w = formation water resistivity, ohm.m
 R_{wa} = apparent water resistivity, ohm.m
 R_{xo} = flushed zone resistivity, ohm.m

SFL = spherically focused log, ohm.m
 SP = spontaneous potential, mV
 ϕ = effective porosity

Acknowledgments

The authors wish to thank YPF S.A. for the authorization to publish this paper.

References

1. Khatchikian, A. and Lesta, P.: "Log Evaluation of Tuffites and Tuffaceous Sandstones in Southern Argentina", SPWLA Annual Logging Symposium, 1973
2. Solanet, F., Khatchikian, A. and Breda, E. "NMR as Standard Porosity Tool in the San Jorge Basin: Log Responses and Applications", SPE 38735, SPE Annual Conference and Exhibition, 1997.
3. Colo, C., Donofrio, M., Crivaro, D. and Jauregui, J.M.: "Evaluación de pozos optimizada en la Cuenca del Golfo San Jorge". Boletín de Informaciones Petroleras YPF, June 1995
4. Poupon, A., Loy, M.E. and Tixier, M.P.: "A Contribution to Electrical Log Interpretation in Shaly Sands", JPT June 1954.
5. Tixier, M.P., Alger, R.P., Tanguy, D.R.: "New Developments in Induction and Sonic Logging", Technical Note 2059, JPT May 1960.
6. Barber, T.D. and Rosthal, R.A.: "Using a Multiarray Induction Tool To Achieve High-Resolution Logs With Minimum Environmental Effects", SPE 22725, presented at the 1991 SPE Annual Conference.
7. Beard, D., Zhou, Q. and Bigelow, E.: "Practical Applications of a New Multichannel and Fully Digital Spectrum Induction System", SPE 36504, SPE Annual Conference and Exhibition, 1996
8. Waxman, M.L. and Thomas, E.C.: "Electrical Conductivities of Oil-Bearing Shaly Sands - I. The Relation Between Hydrocarbon Saturation and Resistivity Index; II. The Temperature Coefficient of Electrical Conductivity", SPEJ (Feb. 1974) 213-25

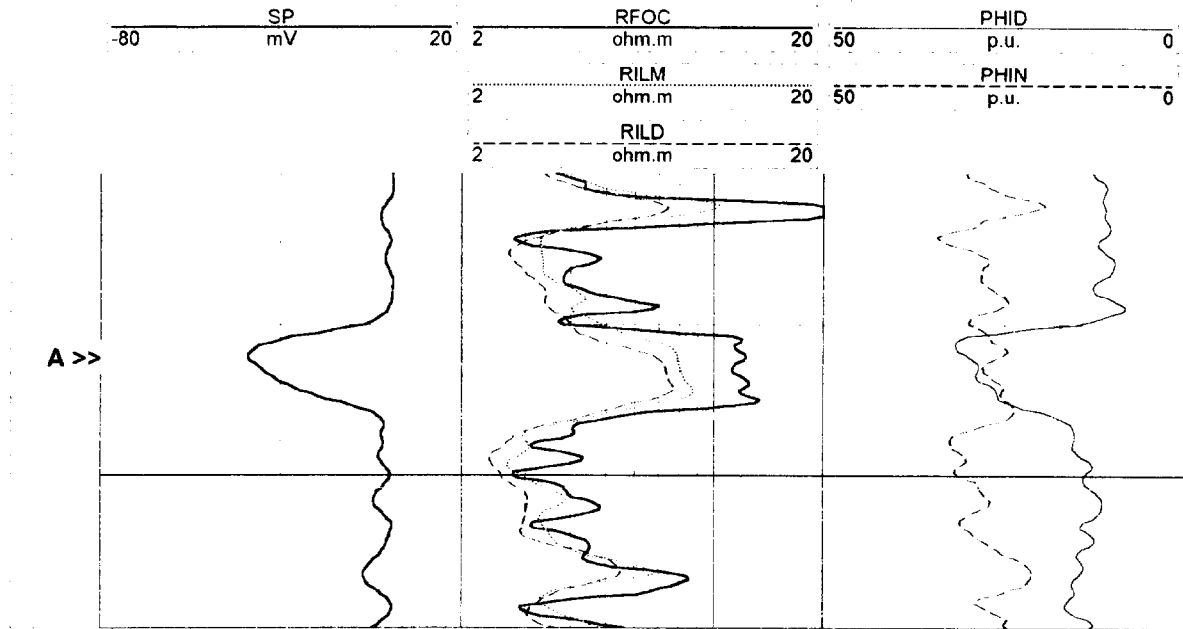


Fig. 1 -The density and neutron logs indicate that this is a clean sand with roughly 30 p.u. porosity. The porosity measured on a rotary sidewall core taken at point A was 20.7 p.u.

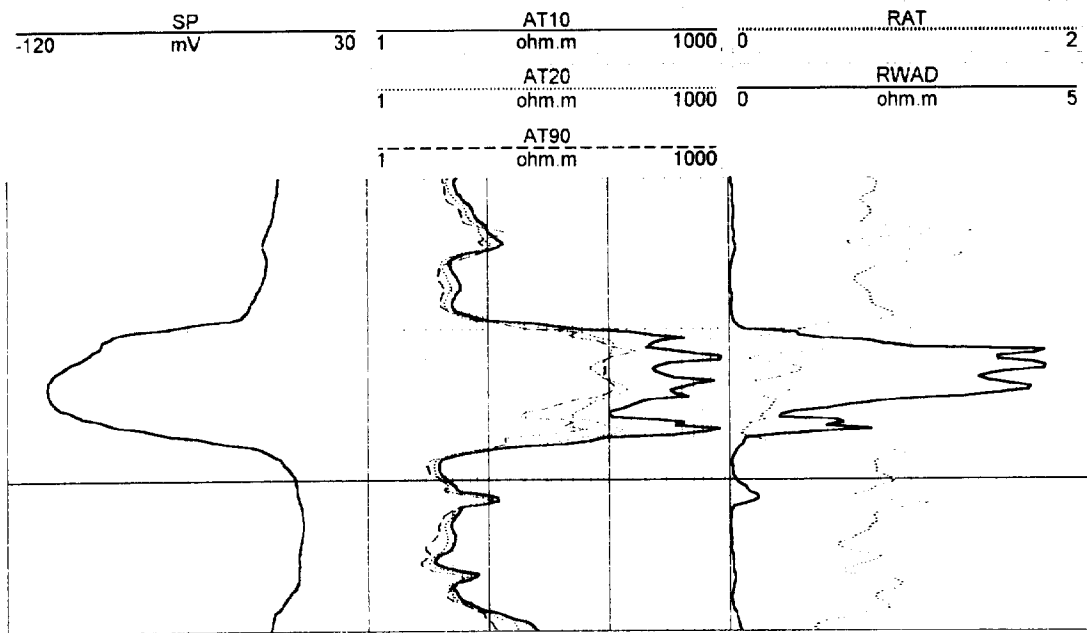


Fig. 2 -Example of sand with high Rwa that produced water

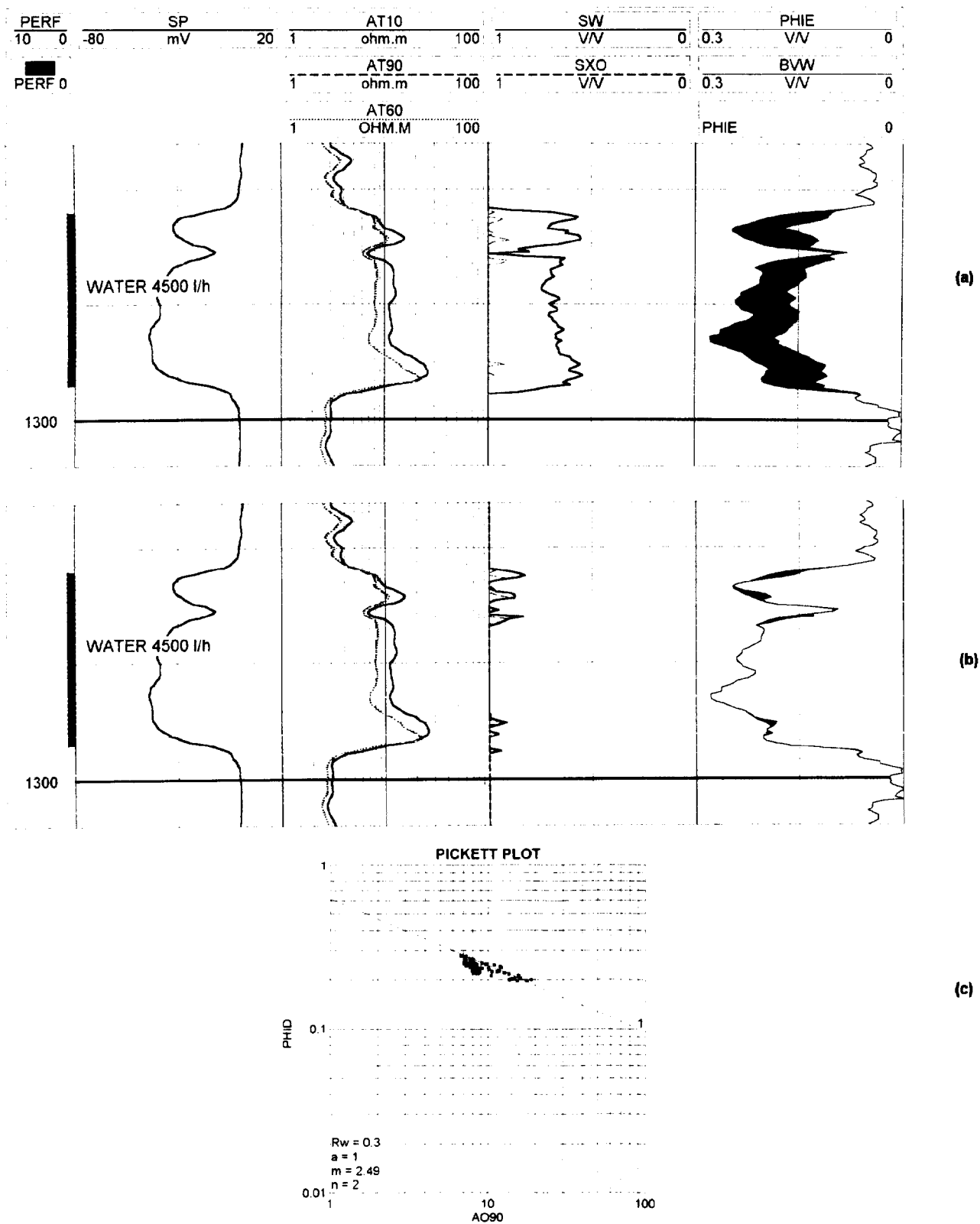


Fig. 3 - Example of a tuffaceous water sand with an apparent water saturation of 60% (a) if standard values of a and m are used. Computed S_w is 100% if $a = 1$, $m = 2.5$ are used (b). m was derived from the Pickett plot (c)

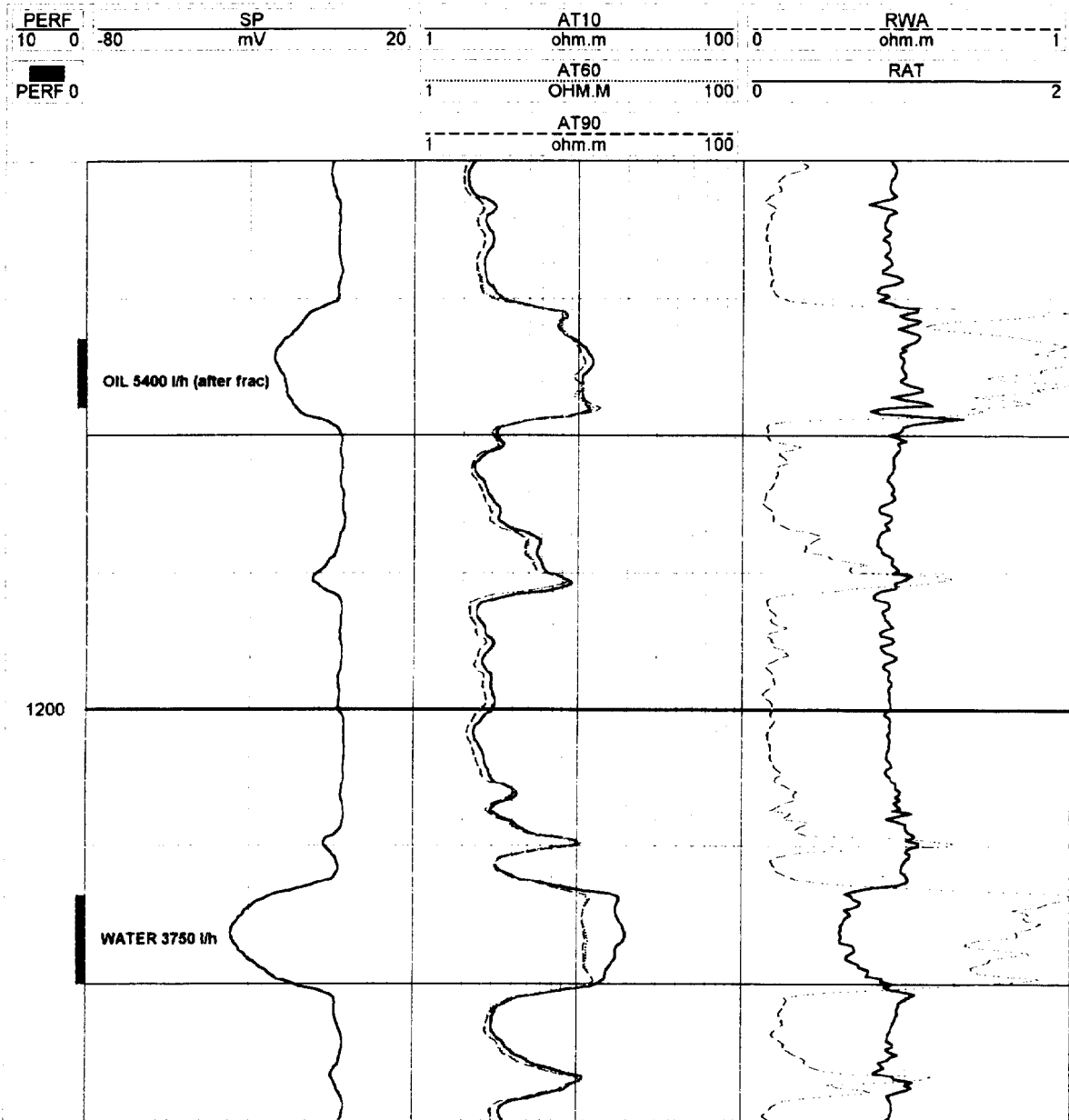


Fig. 4 - The ratio correctly predicts water and oil production in two sands with almost identical R_{wa} values

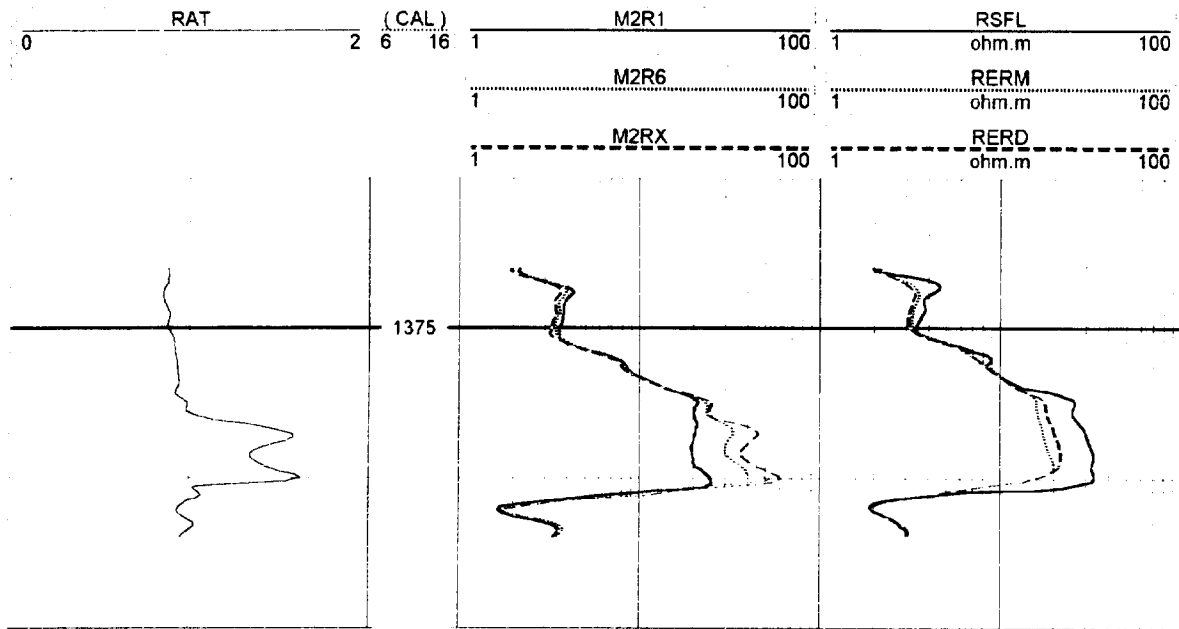


Fig. 6 - The 120" investigation induction curve M2RX reads higher than the 10" M2R1 since $R_t > R_{xo}$ in this oil sand. But on a conventional Dual Induction Log, the enhanced deep resistivity RERD reads lower than the spherically focused log RSFL

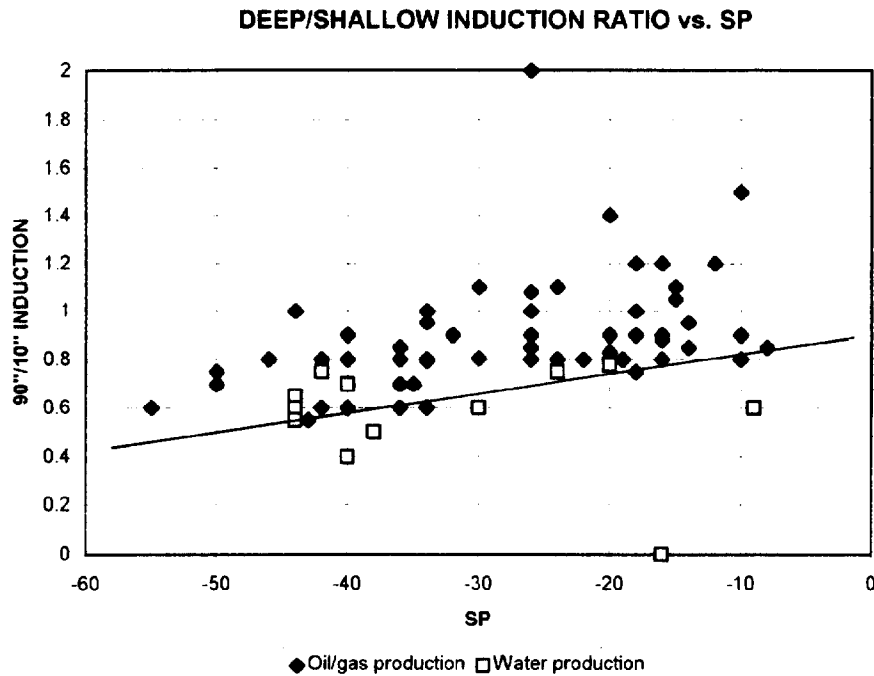


Fig. 6 - Plot of 90"/10" induction ratio vs. SP. The straight line shows the approximate limit between oil and water production.

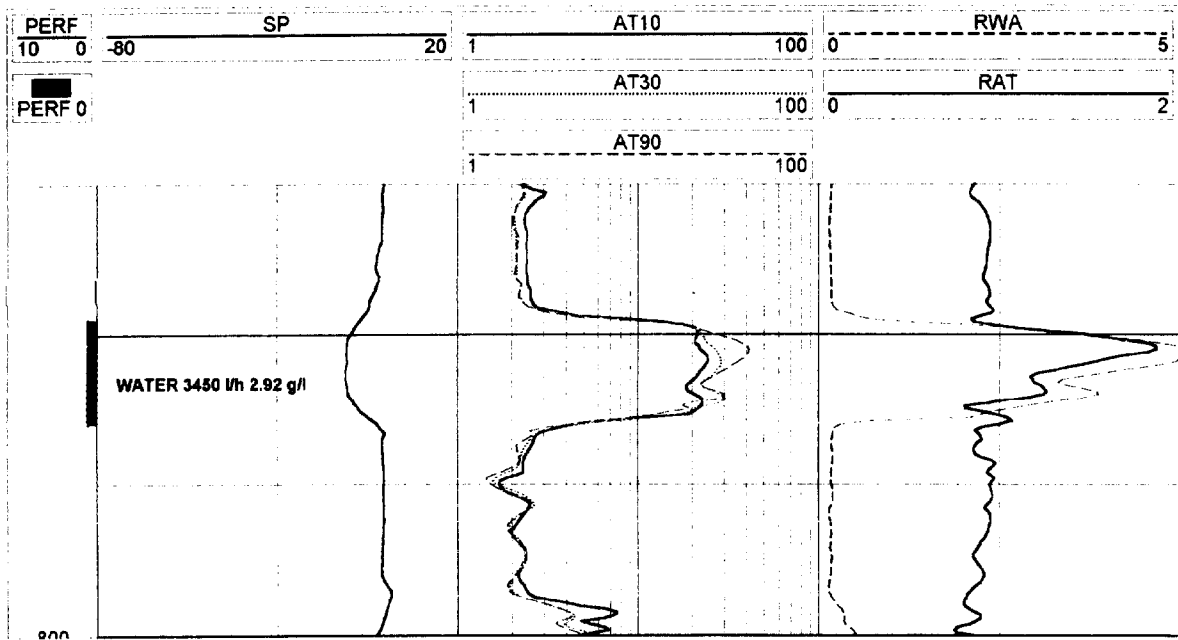


Fig. 7 - Example of fresh water sand (2.92 g/l of NaCl) with negative SP. The 90"/10" ratio is 1.8, about the same as the R_w/R_{mf} ratio

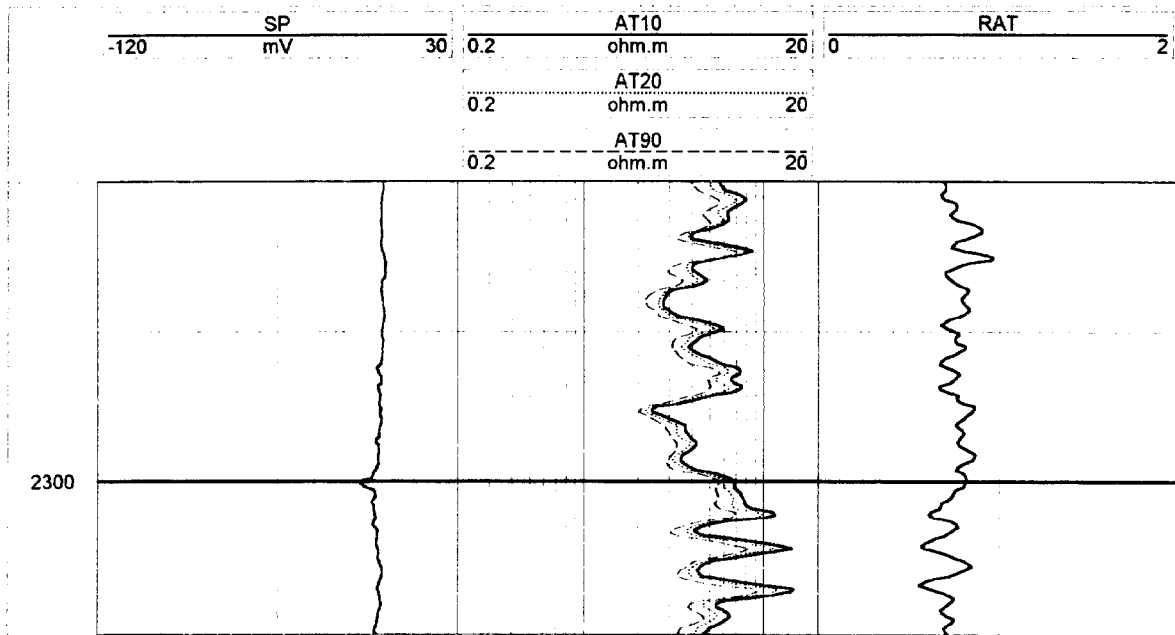


Fig. 8 - The 90"/10" ratio in shales at the bottom of the well is about 0.8

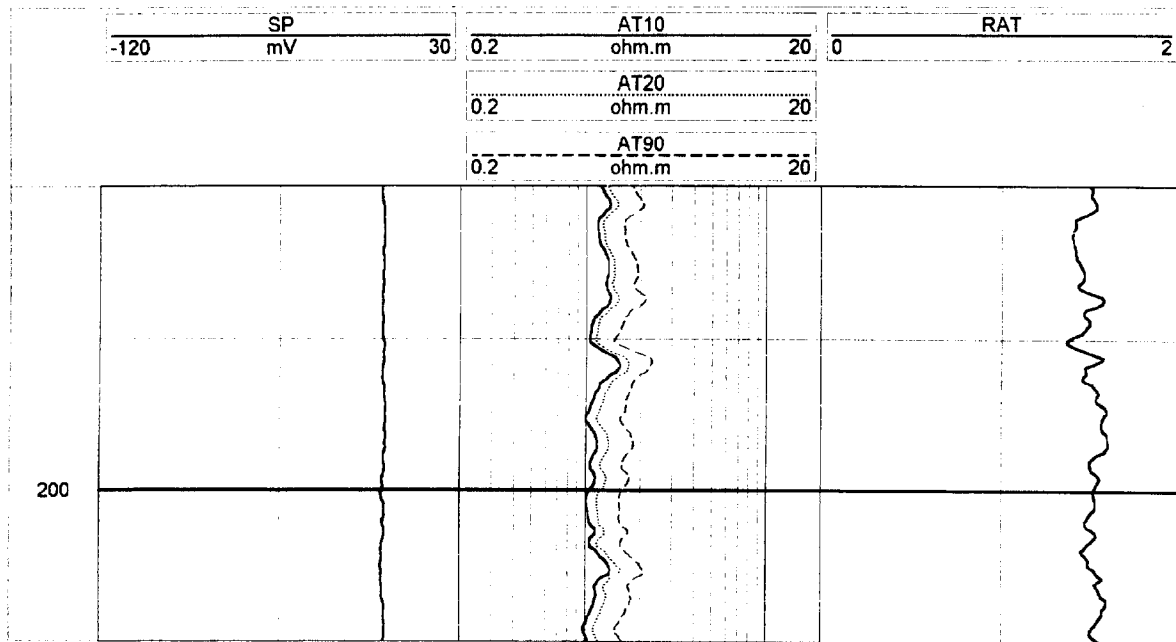


Fig.9 - The 90"10" ratio in shales close to surface is about 1.4

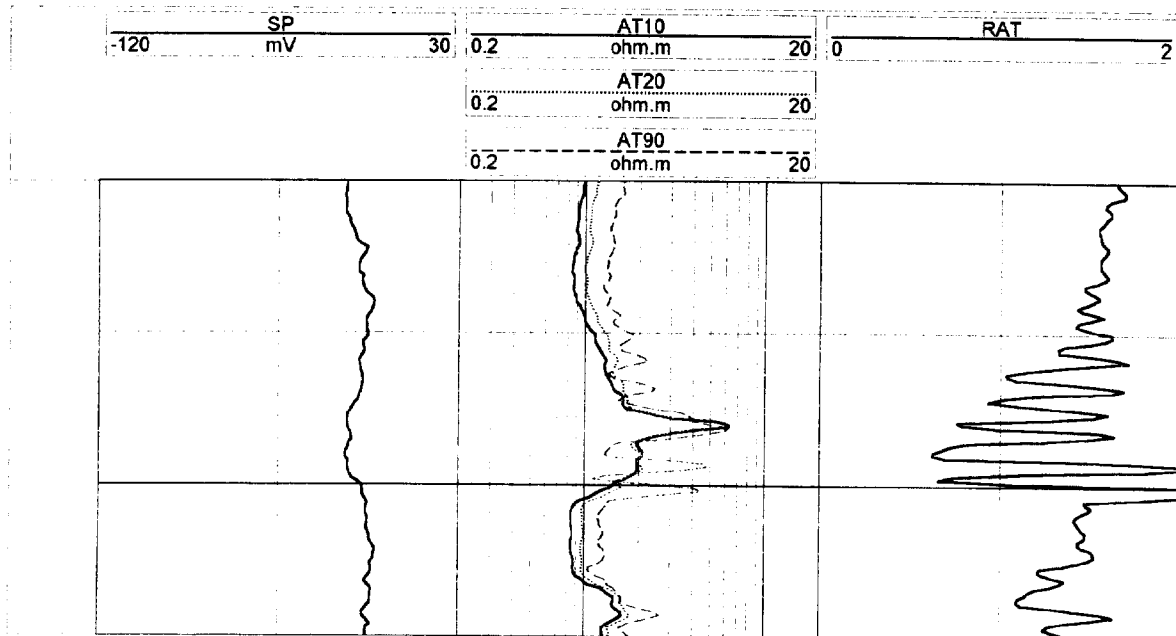


Fig. 10 - Anomalous variations of the AT90 curve which produces anomalies in the ratio

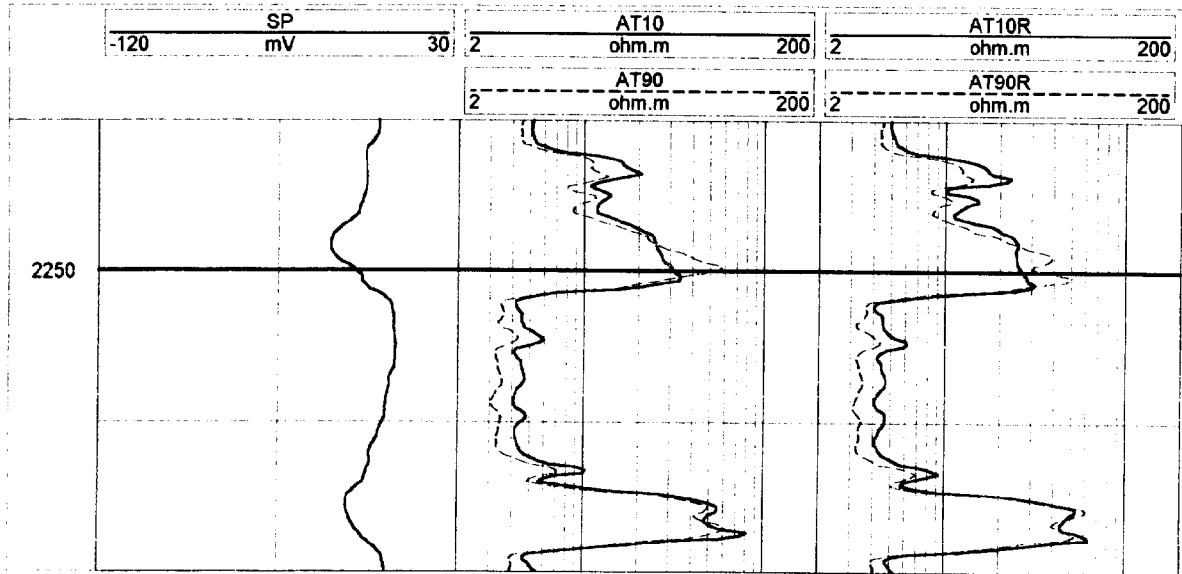


Fig. 11 - Example of poor repeatability of the 2-ft array induction curves at high resistivities