Preliminary analysis of petrophysical data set of a carbonate reservoir from Field A in Campos Basin

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Abstract

In this work, we made a preliminary analysis of petrophysical data set for two wells to assess a carbonate reservoir of Field A in Campos Basin - Southeastern Brazil. Petrophysical data refer to thin sheet images and sonic (DT), density (RHOB), neutronic porosity (NPHI), natural gamma ray (GR), shallow (R_{XO}) and deep (R_t) resistivities logs. As is usual in the interpretation of logs, the first results of this study allowed us to locate seal and reservoir rocks, calculate the volume of clay (V_{sh}), situate the depth of the oil - water contact, compare the presence of porosity viewed in thin sheet images and check V_{sh} and corrected porosity in NPHI - RHOB crossplot. We consider this initial study as the first steps in a complete petrophysical characterization of this reservoir in the future.

Introduction

This preliminary petrophysical study was conducted in a carbonate reservoir in Field A of Campos Basin, which is located along the continental shelf of Rio de Janeiro State (Figure 1), Southeastern Brazil (Rangel et al., 1994). The basin covers an area of approximately 100.000 km^2 (Milani et al., 2000), corresponds to the main oil province of Brazil, comprising approximately 80% of the country's oil reserves (Bruhn, 1998).

Campos Basin is a typical passive margin basin that started with basaltic extrusion during the Lower Cretaceous above Precambrian crystalline rocks. It evolved tectonically into a rift environment with predominant shallow lacustrine sedimentation, followed by a siliciclastic and evaporitic transitional phase that was related to the Southern Atlantic Ocean opening. This tectonic-sedimentary phase persisted until the beginning of middle Cretaceous (Figure 2). An open marine environment developed about 112 million years ago (Early Albian) and still persists today. It started with shallow water carbonate deposition followed by predominantly deep-water siliciclastics (Schlumberger, 1998).

The origin and evolution of Campos Basin is associated with disruption of Gondwana and subsequent opening of the South Atlantic. Hydrocarbon reservoirs occur throughout almost the entire stratigraphic column of this basin, being that the main sequences comprise fractured basalts, coquinas, turbidites, and carbonate rocks. The reservoirs of interest in this work were formed during the Albian, when marine conditions prevailed in giving rise to a carbonate platform of restricted marine basin phase, yielding the Macae Group (Figure 3). This group comprises carbonate ramp deposits, comprising rocks of various textures such as porous grainstones and packstones, and mudstones of outer platform (Souza Cruz, 1995).

Among the many physical parameters of an oil and gas reservoir, porosity and permeability are the main factors that determine its storage capacity. However, a very heterogeneous porosity usually occurs within carbonate reservoirs at various scales, from large vugs to small interparticles, making complex the construction of geological models (Hartmann & Beaumont, 1999). These porosity distributions become more intricate even when dissolution and diagenesis processes create secondary porosity. However, high porosity of carbonates allows high capacity hydrocarbon accumulations in these types of reservoirs, which results in high oil production around the world. There is therefore great interest in studying carbonate reservoirs (Lucia, 1999).

An important factor to be considered in our work is the calculation of the shaliness volume (V_{sh}), as proposed by Larionov (1969), which begins calculating the Index of Gamma Ray – IGR (Equation 9) and selecting type of rock, to evaluate V_{sh} (Equation 10):

$$I_{GR} = \frac{GR_{\log} - GR_{\min}}{Gr_{\max} - Gr_{\min}}, \quad (1)$$

$$V_{sh} = \frac{I_{GR}}{A_{GR} - (1 - A_{GR}).I_{GR}}, \quad (2)$$

where GR_{log} is gamma ray log (ºAPI); GR_{min} and GR_{max} are, minimum and maximum values for GR log, respectively; AGR = 1 to Tertiary rocks, 2 for pre-Tertiary rocks and 3 for post-Tertiary rocks. Although carbonate rocks generally present low V_{sh}, in our study we use it to target better the reservoir zone.

In the studied oilfield, petrophysical data set is composed by well DT, RHOB, NPHI, GR, R_{xo} and R_t logs (Rider, 2002), basic laboratory permeability and porosity with expansion of helium gas, porosity with mercury injection and irreducible water saturation with retort, centrifuge and membrane. In this work, however, we are only presenting an initial qualitative study of these data considering basically well logs and thin sheets, getting forward the incorporation of more geological and petrophysical data in our study.

Methodology

To perform this study, we used data from two wells of a carbonate reservoir in Campos Basin (Figure 1). Oilfield A has 27 drilled wells, but only boreholes A3 and A10 have a more complete data set, including laboratory petrophysical data (retort, centrifuge and membrane saturations, capillary pressure by mercury injection, porosity, permeability, etc.), geological interpretation (lithofacies, stratigraphy, etc.), and measured well logs (DT, RHOB, NPHI, GR, R_{xo} and R_t). Of these two studied wells, well A3 was considered as a reference and well A10 as a blind test of the methodology proposed along this study.

Initially, we plot the available logs to observe main features in them (Luthi, 2001). Next, we combine these results with thin sheet images for a more reliable and accurate qualitative interpretation of porosity. With this, we plan to conduct preliminary studies for the subsequent completion of the petrophysical characterization of this reservoir in future steps.

Results

All results of this study were generated using the software Interactive Petrophysics (IP) versão 4.0 (IP, 2014) and Matlab (2014) for mathematical computations.

Firstly, we analyze GR, DT, Rt, Rxo, NPHI and RHOB of borehole A3 to localize the reservoir (dash green rectangle) and the seal (dash red rectangle) rock, what it is shown in Figure 4. Basically, it was made a separation of high (shale, seal rock) and low (carbonate, reservoir rock) values. Inside the reservoir, high resistivities show presence of oil and low values denote brine. In the same figure, we can observe that the reservoir presents around 20% of porosity (NPHI), 2.4 gr/cm^3 of density (RHOB) and 80 µsec/feet of transient time (DT).

Next, we used the approach of Larionov (1969) and GR log to estimate V_{sh} in well A3, which it is shown in Figure 5. Clearly it is observed that GR and V_{sh} have high correlation relationship, meaning that high/low values of V_{sh} are found where high/low content of clay are, meaning high/low values of GR log. Also, analysis of V_{sh} was made together with NPHI and RHOB in Figure 6, showing V_{sh} in 5th track and join NPHI – RHOB plot in the 6th track, with the arrows showing possible presence of hydrocarbons.

To assist the detection in depth of the water – oil contact, we show all logs in Figure 7, what was derived from the interpretation of them, supported mainly by the abrupt change in the value of resistivity cause by contact between resistive oil with conductive brine.

In Figure 8, on the other hand, logs from borehole A3 are shown together with V_{sh} (track 3), highlighting the zone where carbonate reservoir is**,** beside thin sheet images (on the right) refered of samples of grainstones and packstones of this well with porosity shown in blue.

Finally, we show a NPHI - RHOB crossplot together with V_{sh} in Figure 9. In this graphic it is possible to identify a carbonate reservoir with V_{sh} close to 0% and a corrected porosity around 20%. In the same plot, GR log shows mainly values in the ranges of 0 – 30 and 30 – 60 GAPI.

Conclusions

In this work, we analyze mainly geophysical well logs corresponding to two wells of Field A of Campos Basin, which traverse a carbonate reservoir. The qualitative interpretation of the data showed that the integration of different data helps to better understand the distribution of the properties of reservoirs. First results of this study allowed us to locate seal and reservoir rocks, calculate V_{sh}, situate the depth of the contact oil - water, compare the presence of porosity viewed in thin sheet images and check V_{sh} and corrected porosity in NPHI - RHOB crossplot. We consider this initial study as the first steps in a complete posterior petrophysical characterization of this reservoir.

Acknowledgments

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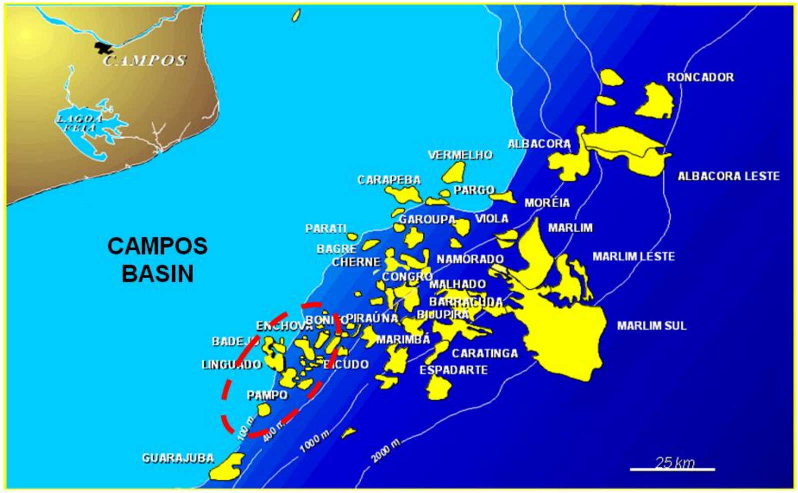

Figure 1. Campos Basin and main oilfields (Rangel et al., 1994), highlighting oilfields with Albian reservoirs used in this study.

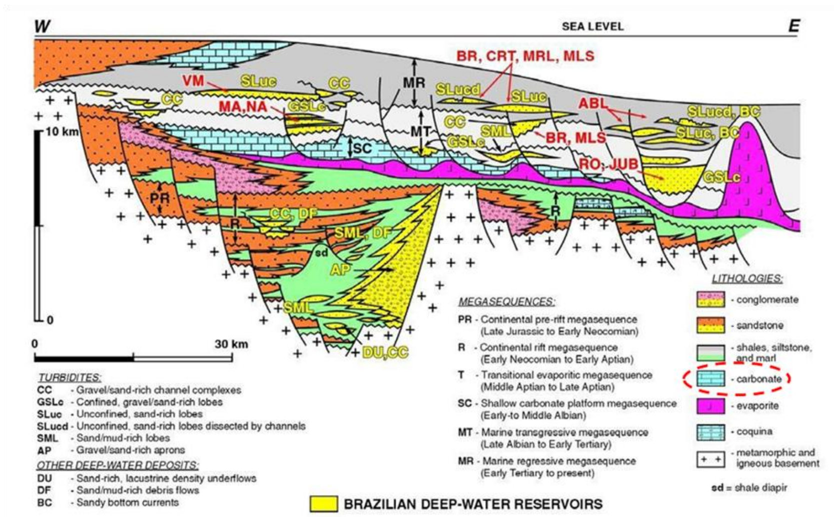

Figure 2. Main reservoirs of Campos Basin. Carbonate reservoirs above salt (evaporites) are the reservoirs studied in this work (modified from Bruhn, 1998).

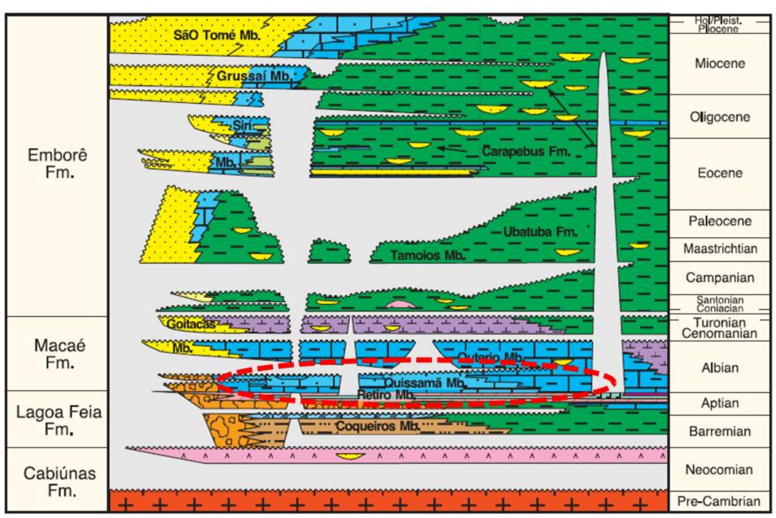

Figure 3. Stratigraphic chart of Campos Basin highlighting Quissamã Formation of Macaé Group (Schlumberger, 1998),

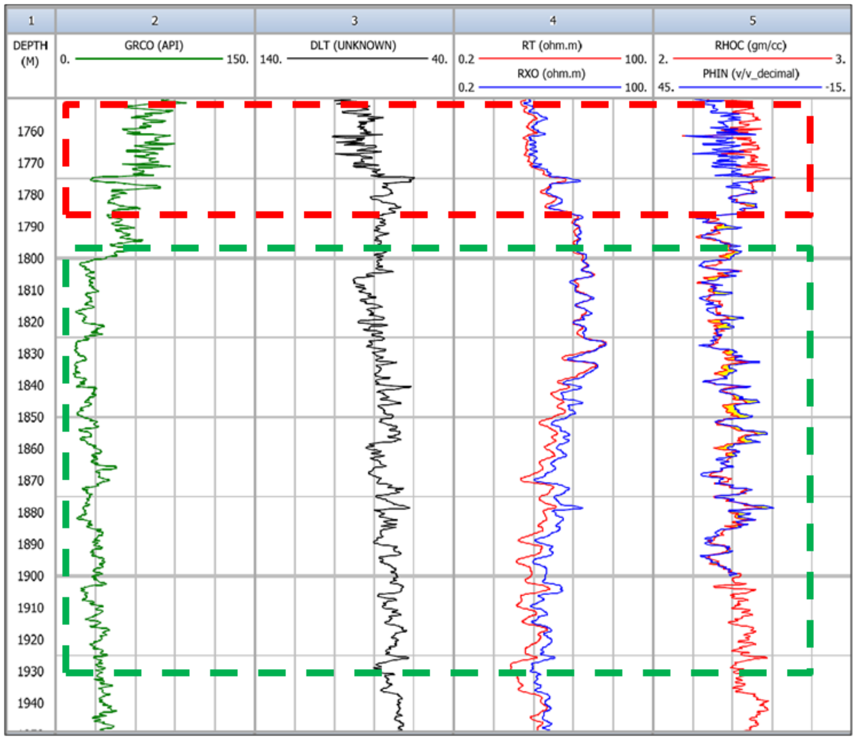

Figure 4. Well logs and separation of seal (red dash rectangle) and reservoir rocks (green dash rectangle).

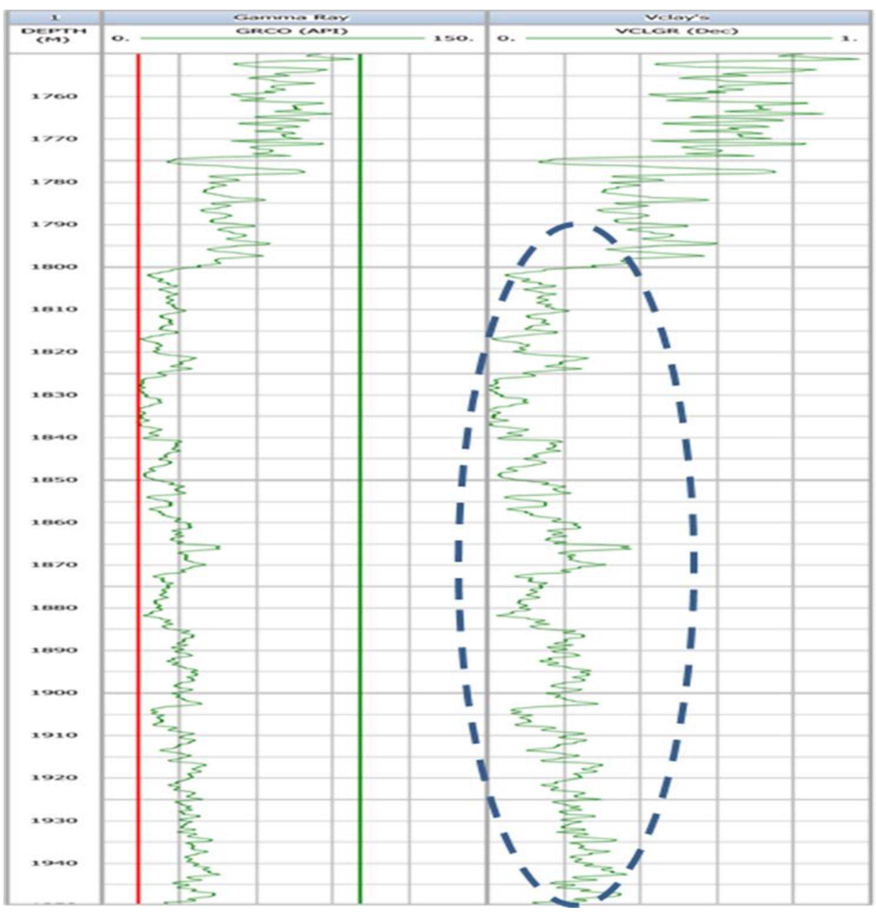

Figure 5. GR log and V_{sh} for well A3, highlighting reservoir zone with low values of *Vsh*.

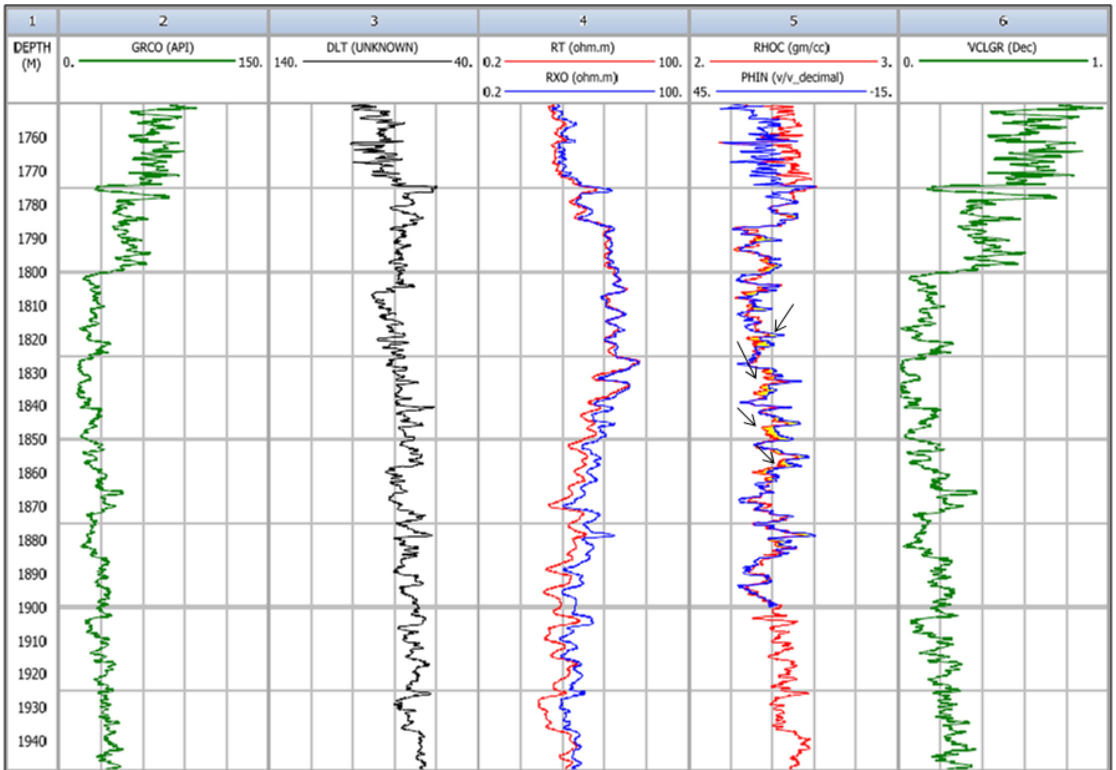

Figure 6. Well logs of borehole A3, showing V_{sh} in 6^{th} track and join NPHI – RHOB plot in the 5^{th} track, with the arrows showing possible presence of gas.

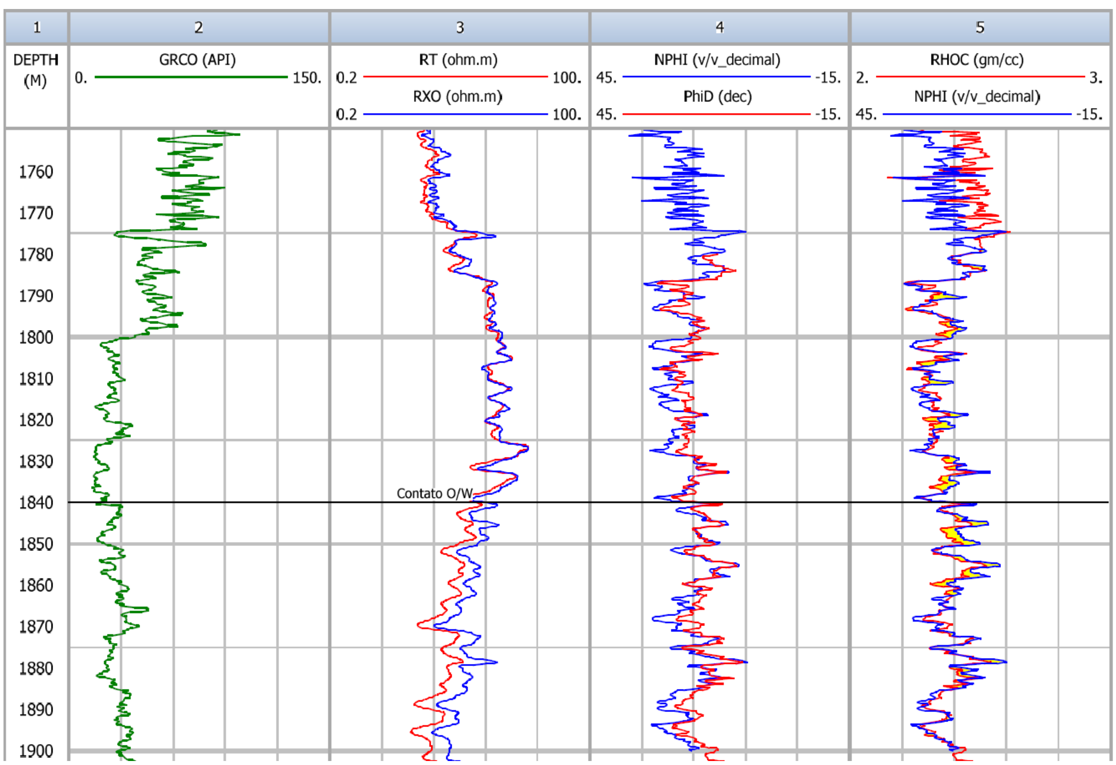

Figure 7. Well logs of borehole A3, showing the contact oil - water derived from the interpretation of logs.

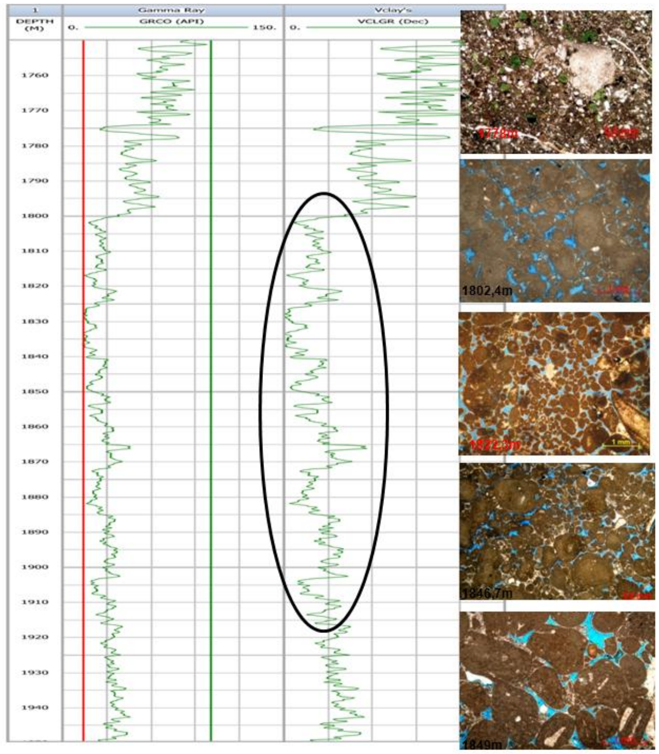

Figure 8. Well logs of borehole A3, showing reservoir zone of carbonates with thin sheets at the right of grainstones and packstones with porosity in blue.

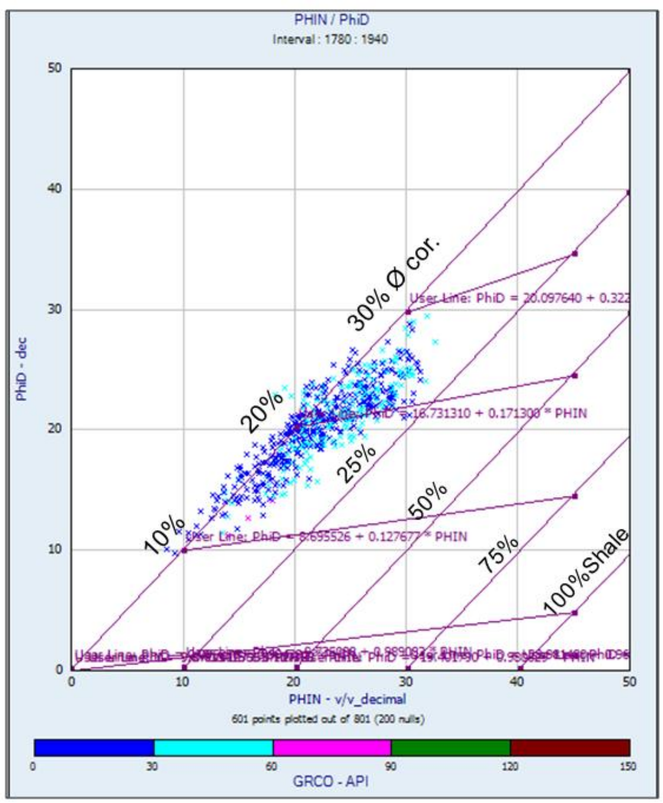

Figure 9. Crossplot of NPHI - RHOB porosities, showing also V_{sh}, corrected porosity and GR log values.