# Carbonate reservoir characterization in Campos Basin - Southeast Brazil

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**Summary**

Reservoir characterization process describes productive zones more reliably through the integration of disciplines, technology and data, having as essential components the identification of their most significant heterogeneities, which become in the main input parameters in geological and flow models. In this work, geological and petrophysical data from three wells crossing a carbonate reservoir of Campos Basin, Southeast Brazil, were analyzed in order to determine formation properties, make reservoir classification and rock typing study. Thus, combination of geological analysis, lithofacies description, analysis of petrophysical data and interpretation of well logs reveal a vertical sequence of three petrofacies and lithofacies (packstone, grainstone and cemented grainstone), four reservoir rock types, eight flow units and zones, and, three productive flow units. To verify the reservoir flow units model, a test was performed to compare it with production log, where a good analogy and a high correlation between the two curves was found. Finally, this methodology has proved convenient in showing several parameters in the studied reservoirs, as well as, compliance with the production log shows that such interpretations can be integrated with the results from other areas like formation test.

**Introduction**

Intense geological processes cause carbonate rocks to develop wide variations in pore types, such as interparticle, intercrystal, moldic, vuggy, intraframe and microcracks. This heterogeneous nature of carbonate reservoirs presents challenges for its characterization, the main one is the evaluation of their rock properties Archie (1952).

Thus, reservoir characterization encompasses the understanding and methods to characterize this reservoir heterogeneity. It can be defined as the construction of realistic interpretations of petrophysical properties used to predict reservoir performance, and its multidisciplinary integrated task involving expertise in reservoir geology, geophysics, petrophysics, well logging and reservoir engineering Lucia (1999).

**Method**

In this work, we made use of several theoretical concepts actually used in reservoir characterization as PetroFacies (PF), Lithofacies (LF), Reservoir Rock Type (RT), Winland - Pittman plots, Flow Zone Indicate (FZI), Modified Lorenz Plots (MLP), Stratigraphic Modified Lorenz Plots (SMLP) and Timur - Coates NMR permeability equation. These concepts can be found in publications of Winland (1972), Pittman (1992), Amaefule et al. (1993), Gunter et al (1997), Porras et al. (2001), Romero & Gómez (2004) and Betancourt (2012).

All these theoretical concepts were applied in the study of a reservoir that belongs to a carbonate platform, with an extension of more than 1.500 km along the coast of Southeast Brazil, in Campos and Santos Basins (Figure 1). The sedimentary evolution of this platform was conditioned by the pre - Albian structures section. The geometry and the distribution of lithological facies are controlled by evaporites movement (influenced by sedimentary weight), substrate tilt and fault reactivations. To develop our work, initially, we collected previous data of the reservoir, mainly geological analysis, lithofacies description and petrophysical data from core plug. The detailed core analysis data included core description, capillary pressure by mercury injection, core porosity, core permeability and Nuclear Magnetic Resonance (NMR) measurements. After this initiative, we interpret the existent well logs and combine it with geological information. With these interpretations in hands, we determine the RRT, model the RFU along the reservoir, and, finally, test RFU model considering the production log. To complete all these tasks, we use the IP - Interactive Petrophysics software (Senergy, 2013), which has modules to calculate the different steps.

**Results**

The analysis of core plugs obtained in three wells that cross a same carbonate platform in Campos Basin, allowed us to identify, according to simplified textures, three different lithofacies (LF), which are described in Table 1.

Advancing at work, static petrophysical rock typing models were based on these lithofacies descriptions, however, taking into account well log data calibrated with core data. Figure 1 show this information along the region of interest, into one of the studied wells. The three first tracks show the conventional logs of gamma ray (GR), caliper (CALI), shallow and deep resistivities (P22H and P40H), density (RHOB), neutron porosity (NPOR1) and transit time (DTCO). The next two tracks present the porosity (POROS) and permeability (PERME_h) measured in plugs, while in the last track, we have the NMR $T_2$ distribution measured along one of the wells. Thus, looking to plugs measurements and the logs, we can easily observe the presence of a reservoir between 10 to 50 metros of depth, surrounded by two less interesting formations for oil exploration above and below. Besides this zone analyzed in this well, three interesting petrofacies (PF1, PF2 PF3) were identified, which are shown in Table 2, corresponding to packstone, grainstone and cemented grainstone with basic textures, respectively. On the other hand, for one of the wells, Figures 2 show pictures of cores and thin sections, besides pore throat distributions for PF2, and the petrophysical data obtained from core plug measurements together with the NMR T2 distribution of each petrofacies. In addition, Figure 3 shows a cross plot between porosity and permeability of the core, as can be seen, the PF2 has the best petrophysical properties and it shows the best potentialities as reservoir, with high porosity (21 %) end permeability (364,5 md).

Facies, as defined by lithology, can normally be identified through permeability - porosity crossplot measured in plugs, which is shown in Figure 5. In this figure, the reservoir is shown in green color, corresponding to petrofacies PF2, with high values of permeability and porosity. This plot established a relationship between petrophysical units and petrofacies within the analyzed section of the well. Each unit retains a geologic significance and emphasizes its immediate link with petrophysics. Once PF are identified, we used log data of three boreholes to perform a multiple well petrofacies correlation between them. To assist in sedimentological and stratigraphic interpretation, Figure 6 shows the distribution of PF in three wells and how these are can be correlated according to the signatures of conventional logs. Although logs have the ability to help identify PF zones, they have limitations to identify facies (typically carbonate facies) and define lithology, so, the choice of facies used to construct a refined geologic model becomes a problem. To better recognize petrophysical properties of small regions within a same petrofacies, is necessary to deepen the RT characterization.

Figure 7 shows different RT for plugs using the Winland R35 plot. Four rock types were identified, where RT4, having the highest permeability (higher than 100 mD), and RT3, having moderate permeability (between 50 and 100 mD), are reservoirs. RT1 and RT2 are not reservoir rocks, because have very low permeabilities, less than 20 mD.

Based on porosity and permeability crossplot, it was possible to find eight flow zones obtained by linear regression (Figure 8). For each ZF there is a representative ZF equation relating porosity and permeability, where these equations can be strong allies in petrophysical data extrapolation. In the plot, between ZF8 to ZF3 we have flow zones that can indicate a reservoir characteristics.

Following Gunter et al. (1997) methodology, Figure 9(A) show flow capacity (*K*H) plotted versus storage capacity ($\phi$H), where H is the thickness of the layer. This plot has segments with high slopes, which representing high productive units of flow (UF4, UF6 and UF8), and flat segments representing units low flow (UF1 and UF9). Figure 9(B) shows the SMLP plot, where the best productive zones, with higher slopes, are located at bottom (UF6), and the poorest rock types are located at top (UF9).

A summary of petrophysical characteristics for each UF is shown in Table 4, where $\phi$ (%) and $K$ (mD) were determined in laboratory, $\phi_{FFI}$ (%) is the NMR porosity also determined in laboratoty, and $R_{35}$ is the Winland measure. Note that UF6 UF8, UF7 and UF present the best characteristics as reservoir**.** At the same time, Figure 10 presents a summary of all results obtained in this work. From left to right, the first track shows the lithofacies (LF), followed by petrofacies (PF), flow zones (FZI), reservoir rock types (RT), and flow units (UF). In these graphs we can see clearly that there are many concordances between the different results, especially among the LF, the FZI and RT. In the center track, we plot the log of production (blue) against the flow capacity - *K*H (red), where observed very similar inflections between the two curves, may find it a coincidence if a normalization is done. The petrophysical flow static models based on porosity and permeability data were correlated with production log curve in an attempt to evaluate the potential of these to predict the flow well distribution. Finally, in the last two tracks, log porosity (Phie Log (%)) is compared with porosity measured in laboratory (Petro: Phi (%)), and NMR permeability measured in laboratory (NMR permeability (mD)) is compared with permeability measured in laboratory (Petro:K_h (mD)). In both cases, it exists a good fit between the data and the continuous curve.

**Conclusions**

Logs were very useful tool in identify three petrophysical zones, called PF1, PF2 and PF3, with strong stratigraphic control, which were easily identified studying three wells of Campos Basin. PF2, the intermediate zone, has the best petrophysical properties, being, in this form, the reservoir. Rock Type approach, on the other hand, reveals that even being a potentially productive sector, PF2 has different flow units inside it, as UF3, UF5 and UF7, which have low production capacity. According to Winland plot, these zones have a RT values (RT1 and RT2), i.e. zones with pore throat lesser than 2 µm, which is reflected in low flow capacity. Moreover, UF4, UF6 and UF8 have high RT values (RT3 and RT4), with pore throats near 10 mm, which means a good flow capacity. Although, depositional environment zones may not necessary coincide with static petrophysical rock type zones and not necessarily coincide with flow zones. However in this case was observed that the production log and the flow capacity curve are similar, which shows that flow petrophysical models have a good applicability.

# Carbonate reservoir characterization in Campos Basin

Table 1. Lithofacies classifications based in thin section descriptions.

| Lithofacies | Texture | Description |
|---|---|---|
| LF1 | Packstone oolitic/oncolitic, peloids and bioclastics | Intergranular and vugular porosity type |
| LF2 | Grainstone oolitic/microoncolitic, with rare bioclasts and peloids | Intergranular, intercrystalline, vugular and intragranular porosity type with grains dissolution. Represents facies of high energy with lower permeability |
| LF3 | Grainstone oolitic-microoncolitic / Rudstone oncolitic, with fine peloids | Intergranular and vugular porosity type. Represents facies of high energy with higher permeabilities |

Table 2: Petrofacies classifications based in lithofacies descriptions and petrophysical propriety.

| Petrofacies | Lithofacies | Basic Texture | Description |
|---|---|---|---|
| PF1 | LF1 | Packstone | - Low porosity and permeability<br>- Unimodal pore throat system<br>- Porosity: 18,3%<br>- Porosity (FFI): 11,6%<br>- Permeability: 1,1 mD |
| PF2 | LF2 / LF3 /LF4 | Grainstone | - Higher porosity and permeability<br>- Bimodal pore throat system<br>- Porosity: 26,2%<br>- Porosity (FFI): 21,0%<br>- Permeability: 364,5 mD<br>- T2 cutoff 40ms<br>- Reservoir Zone |
| PF3 | LF2 | Cemented Grainstone | - Strongly Cemented<br>- Low porosity and permeability<br>- Unimodal pore throat system<br>- Porosity: 20,9%<br>- Porosity (FFI): 15,23%<br>- Permeability: 1,04 mD<br>- T2 cutoff 110ms |

Table 3. Summary of petrophysical characteristics for each UF.

| Units of Flow | Petrophysical Characteristics | | | |
|---|---|---|---|---|
| | $\phi$ (%) | $\phi_{FFI}$ (% | $K$ (mD) | $R_{35}$ |
| UF2 | 21,3 | 15,0 | 153,6 | 4-10 |
| UF3 | 24,9 | 20,7 | 122,8 | 2-4 |
| UF4 | 20,1 | 17,0 | 381,8 | 10-20 |
| UF5 | 22,0 | 16,6 | 184,8 | 2-4 |
| UF6 | 24,2 | 18,6 | 486,8 | 10-20 |
| UF7 | 25,0 | 17,3 | 221,3 | 4-10 |
| UF8 | 25,0 | 21,0 | 196,0 | 10-20 |

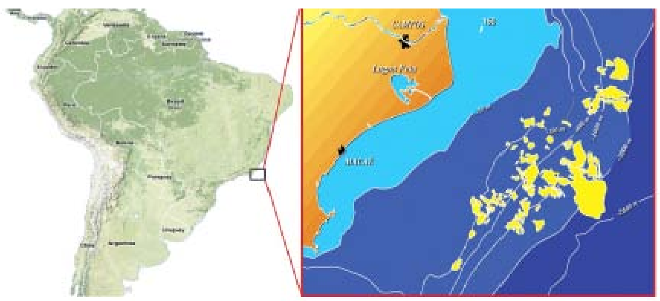

Figure 1. Location of Campos Basin in Southeast Brazil (modified from Matos et al., 2008).

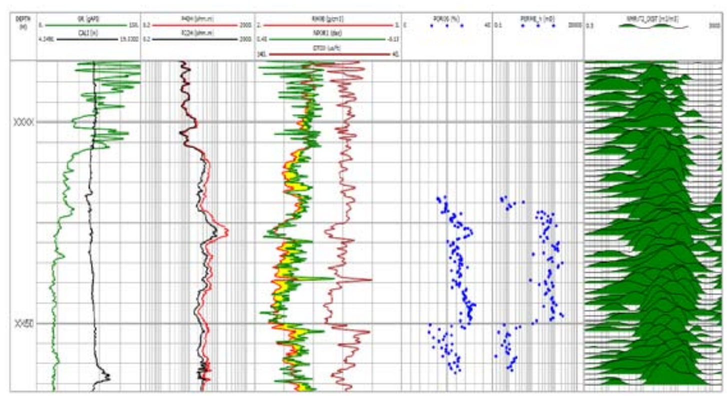

Figure 2. Well log and core plug data.

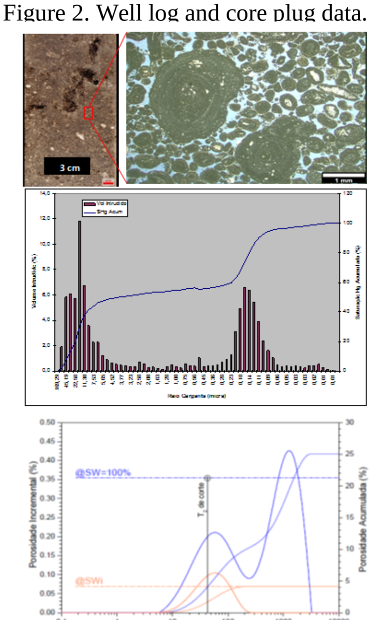

Figure 4. Core, thin section, pore throat distribution and NMR T2 distribution representing of petrofacies PF2.

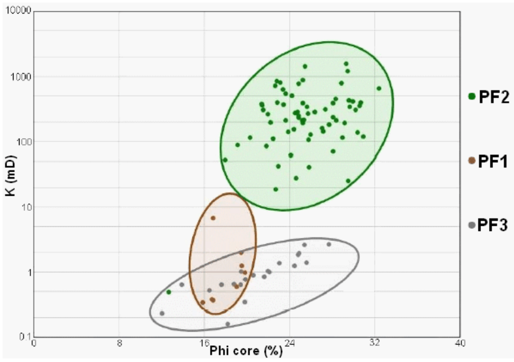


Figure 5. Porosity vs permeability plot of the studied carbonate rock and the petrofacies distinction.

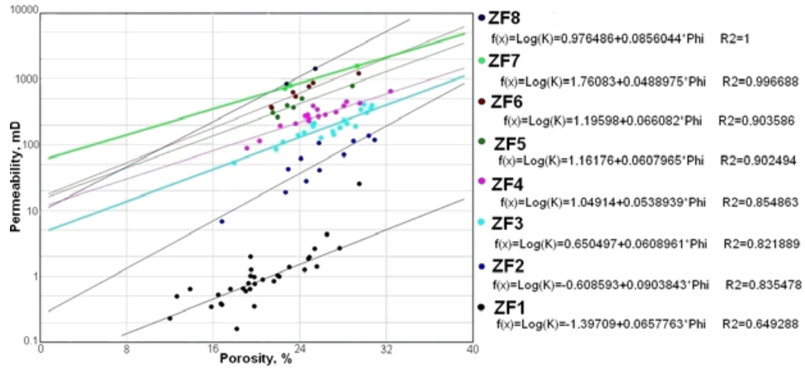


Figure 8. ZF determined by FZI and equation FZ obtained by linear regression.

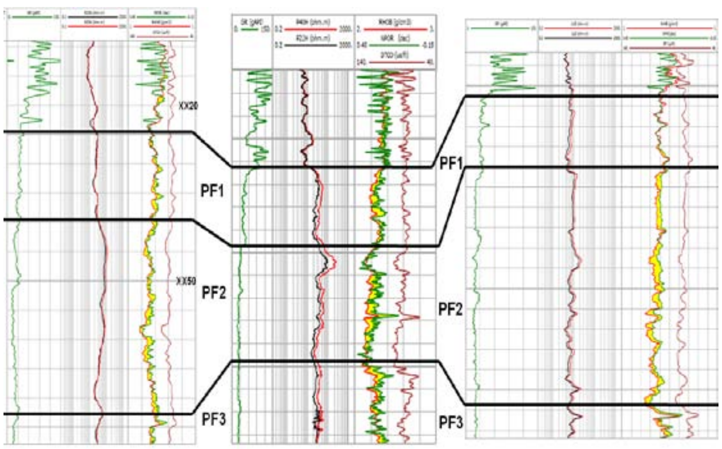


Figura 6. Multiple wells signature correlation.

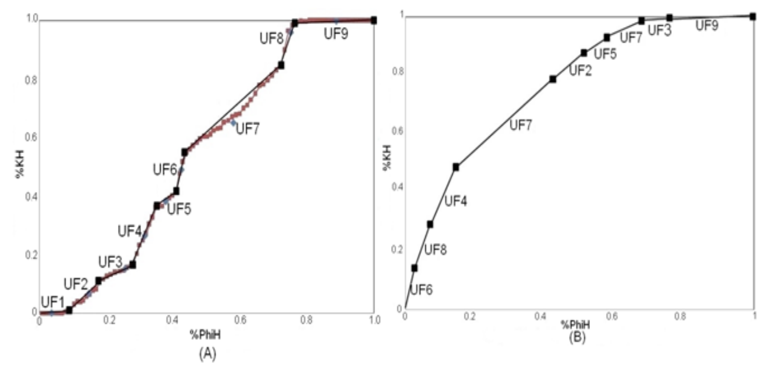


Figure 9. Modified Lorenz (A) and Stratigraphic Modified Lorenz Plots (B).

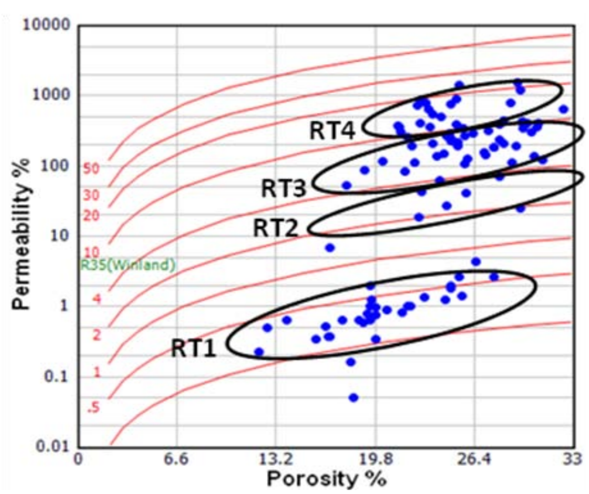


Figure 7: Winland R35 plot for the core data.

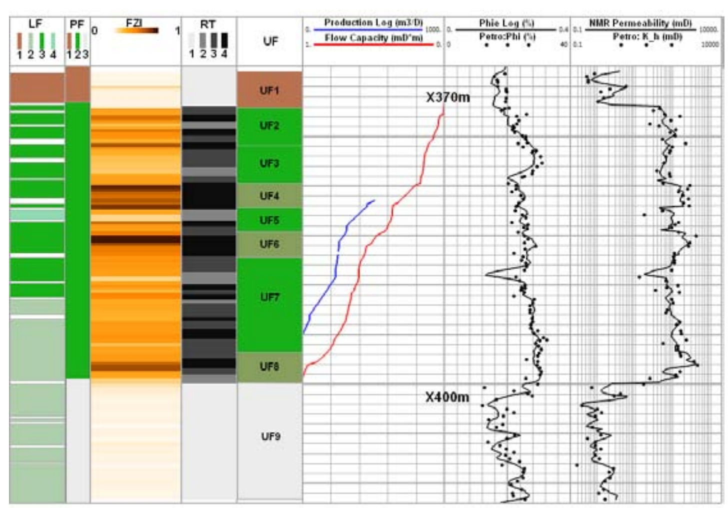


Figure 10. Stratigraphy flow log.