Petrophysical Characterization of Carbonates of Campos Basin in Southeastern Brazil*

Antonio Carrasquilla

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Abstract

In our studies, we analyzed geological, geophysical, and petrophysical data sets (DS) from different wells and in oil fields of Campos Basin, Southeastern Brazil, to assess the carbonate reservoirs’ physical properties. Beside this, we examine the ability of artificial intelligence techniques (AIT) in deriving petrophysical parameters as porosity and permeability of these reservoirs starting from conventional logs. The purpose of these studies is to test our hypothesis that it is possible to achieve a more accurate profile of the distribution of the properties of reservoirs through a qualitative and quantitative analysis of integrated DS and AIT. Our results show that the integration of both DS and AIT to greatly enhance the petrophysical evaluation, indicating that the studies in reference wells can be extended to the rest of the wells of the oil fields, to have a more complete view of the carbonate reservoirs.

References Cited


Petrophysical Characterization of Carbonates of Campos Basin in Southeastern Brazil

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Outline

- Introduction
- Geological context
- Available information
  - 1\textsuperscript{st} oilfield
  - 2\textsuperscript{nd} oilfield
- Case studies
  - MSc. thesis - 1\textsuperscript{st} oilfield
    - Nocchi
    - Torres
    - Briones
  - Research project - 2\textsuperscript{nd} oilfield
- Conclusions
- Acknowledgements
Post-Salt Carbonates

TURBIDITES:
- CC: Gravel/sand-rich channel complexes
- GSLc: Confined, gravel/sand-rich lobes
- SLuc: Unconfined, sand-rich lobes
- SLucd: Unconfined, sand-rich lobes dissected by channels
- SML: Sand/mud-rich lobes
- AP: Gravel/sand-rich aprons

OTHER DEEP-WATER DEPOSITS:
- DU: Sand-rich, lacustrine density underflows
- DF: Sand/mud-rich debris flows
- BC: Sandy bottom currents

MEGASEQUENCES:
- PR: Continental pre-rift megasequence (Late Jurassic to Early Neocomian)
- R: Continental rift megasequence (Early Neocomian to Early Aptian)
- T: Transitional evaporitic megasequence (Middle Aptian to Late Aptian)
- SC: Shallow carbonate platform megasequence (Early to Middle Albian)
- MT: Marine transgressive megasequence (Late Albian to Early Tertiary)
- MR: Marine regressive megasequence (Early Tertiary to present)

LITHOLOGIES:
- conglomerate
- sandstone
- shales, siltstone, and marl
- carbonate
- evaporite
- coquina
- metamorphic and igneous basement
- shale diapir

BRAZILIAN DEEP-WATER RESERVOIRS
Geological context

Depositional model of Quissamã Member

Basement
Depressions
Salt
Sandy carbonate banks

Ramp Platform

Geological Time Scale

Campos Basin

1cm
Available information 1st Oilfield (3 wells)

- Packstones Section
  - Phim = 18.3%
  - Km = 1.1 mD

- Grainstone Section
  - Phim = 26.2%
  - Km = 264.5 mD

- Cemented Section
  - Phim = 20.9%
  - Km = 0.9 mD
Available information 1st Oilfield (3 wells)

Grainstones Porous oolitic/microoncolitic. Optimal intergranular porosity, partly enlarged by dissolution.

Oncolitic/peloidal grainstone with intergranular and vugular porosity (25%).

Oolitic grainstone with aggregates. Intergranular porosity (25 - 30%). Presence of open subvertical fractures stained with oil.

Micro oncolitic/oncolitic grainstone, rare ooliths and peloids. Intergranular and vugular porosity (25%).
Available information 2\textsuperscript{nd} Oilfield

- Well logs of 27 boreholes;
- Lithofacies information for all wells;
- Basic petrophysics core data for 3 wells.
Work flow 1 - 1st oilfield

Reservoir identification

Petrophysical data: reference well
(Conventional logs, NMR & images logs, Laboratory tests (NMR, PCHg, Retort, etc.) & Formation tests)

Reservoir zoning: reference well

Calibration between NMR data: laboratory and log

Correlation with other wells (blind tests)

Finish

Not good

Good
Comparação dos modelos vistos

Grainstone
Packstone
Cemented Grainstone

Lithofacies and Petrophysical Units

Flux Units

Unit 8
\[ f(x) = \log(K) = 0.976486 + 0.0855044 \Phi \]
\[ R^2 = 1 \]

Unit 7
\[ f(x) = \log(K) = 1.76033 + 0.0485975 \Phi \]
\[ R^2 = 0.998688 \]

Unit 6
\[ f(x) = \log(K) = 1.19598 + 0.066082 \Phi \]
\[ R^2 = 0.903566 \]

Unit 5
\[ f(x) = \log(K) = 1.16176 + 0.0607468 \Phi \]
\[ R^2 = 0.902494 \]

Unit 4
\[ f(x) = \log(K) = 1.04514 + 0.0538939 \Phi \]
\[ R^2 = 0.854863 \]

Unit 3
\[ f(x) = \log(K) = 0.650497 + 0.0608961 \Phi \]
\[ R^2 = 0.821889 \]

Unit 2
\[ f(x) = \log(K) = 0.986593 + 0.0903943 \Phi \]
\[ R^2 = 0.835478 \]

Unit 1
\[ f(x) = \log(K) = 1.36790 + 0.0657763 \Phi \]
\[ R^2 = 0.649288 \]
Porosity

<table>
<thead>
<tr>
<th>FZ</th>
<th>( \phi_{\text{minimo}} )</th>
<th>( \phi_{\text{ máximo}} )</th>
<th>Standard Deviation</th>
<th>( \phi_{\text{medio}} )</th>
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<tbody>
<tr>
<td>1</td>
<td>0.15354</td>
<td>0.19182</td>
<td>0.0096669</td>
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<tr>
<td>2</td>
<td>0.18379</td>
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<td>0.21296</td>
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<tr>
<td>3</td>
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<td>0.28587</td>
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<td>0.1769</td>
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<tr>
<td>8</td>
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<td>0.2625</td>
<td>0.0664759</td>
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<tr>
<td>9</td>
<td>0.13312</td>
<td>0.27508</td>
<td>0.037924</td>
<td>0.19747</td>
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</table>

Total Porosity

<table>
<thead>
<tr>
<th>FZ</th>
<th>( \phi_{\text{minimo}} )</th>
<th>( \phi_{\text{ máximo}} )</th>
<th>Standard Deviation</th>
<th>( \phi_{\text{medio}} )</th>
</tr>
</thead>
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<td>0.12665</td>
<td>0.17641</td>
<td>0.015011</td>
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<tr>
<td>3</td>
<td>0.13099</td>
<td>0.24443</td>
<td>0.033826</td>
<td>0.20652</td>
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<tr>
<td>4</td>
<td>0.14468</td>
<td>0.18201</td>
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<tr>
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<td>0.16536</td>
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<tr>
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<td>0.17342</td>
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<td>8</td>
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<td>0.22278</td>
<td>0.0665258</td>
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<tr>
<td>9</td>
<td>0.096589</td>
<td>0.19783</td>
<td>0.022167</td>
<td>0.15296</td>
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</tbody>
</table>

Porosity associated to FFI
Permeability

Flux Zones

1
2
3
4
5
6
7
8
9

Scale: 1:250

P2

DEPTH (M)

K_RockType (mD)

nPermpopo (mD)

KDR1 (mD)

NRI_T2_DIST (m3/m3)

T2cutoffpopo (ms)

T2LM1 (ms)

10000
10000
10000
3000
3000

Comparison between petrophysical model and formation test

<table>
<thead>
<tr>
<th>DEPTH (M)</th>
<th>ZP</th>
<th>Lithofacies</th>
<th>Flux Zones</th>
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<tbody>
<tr>
<td>X370</td>
<td></td>
<td>Packstone 5</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Grainstone 4</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Grainstone 4</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Grainstone 4</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Grainstone 4</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Limestone/Granite 4</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Grainstone 4</td>
<td>7</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Grainstone 4</td>
<td>8</td>
</tr>
</tbody>
</table>

- **P2**
  - Qc (m³/D)
  - 1000.0
  - 0
  - 0.1
  - POROS (%)
  - 40
  - 0.1
  - PERME (mD)
  - 10000
Irreducible water saturation

\[ S_{wir} = \frac{BFT}{\phi} \]
The methodology could be simplified in just two steps:
1. Obtain electrofacies models using conventional logs, image logs (textures), NMR logs (pore-size distribution)
2. Apply the electrofacies models previously generated to improve the estimation of permeability in the reservoirs.

MRGC = Multi Resolution Graph Clustering
Texture estimation from image logs

- A statistical texture model proposed by Gagalowiczz (1983) was used which is defined by the moments of the first and second orders of the image, i.e., histogram (H) and auto covariance function (M2).

- The histogram allows the contrast of the texture to be kept, and the auto covariance function supplies information in orientation and size of texture primitives (Rabiller et al., 2001).

**Histogram (H):**

\[
H(l) = \frac{1}{N} \sum_{i}^{N} \delta(x_i - l)
\]

**Auto covariance (M2):**

\[
M_2(\Delta) = \frac{1}{N} \sum_{i}^{N} \frac{(X_i - \mu)(X_{i+\Delta} - \mu)}{\sigma^2}
\]

Where:

**Mean:** \[\mu = \frac{1}{N} \sum_{i}^{N} X_i\]

**Variance:** \[\sigma^2 = \frac{1}{N} \sum_{i}^{N} (X_i - \mu)^2\]
Based on the shape and appearance of the texture feature log, a descriptive analysis was carried out, showing that:

**Homogeneous textures** have an appearance dominated by the high frequency spectrum of the feature log.

**Heterogeneous textures** show just the opposite; they are represented by the low frequency marked on the feature log.
Texture features classification

MRGC Autotexture Map

Interval: Core

<table>
<thead>
<tr>
<th>Kernels</th>
<th>KRI</th>
<th>DELTA_KRI</th>
</tr>
</thead>
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<tr>
<td>1</td>
<td>1.000000-</td>
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<tr>
<td>2</td>
<td>0.190714 0.809286</td>
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<td>10</td>
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<tr>
<td>11</td>
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<tr>
<td>12</td>
<td>0.015690 0.004060</td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>0.012811 0.002888</td>
<td></td>
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</tbody>
</table>

70 = 4653
Color: FREQUENCY

MRGC = Multi Resolution Graph Clustering
Extrapolation of permeability texture model of Well P1 to Well P2

The light-blue textures represent the cemented levels which are very well characterized by resistive events as seen on the image logs from Well P2
The pore-size distribution was estimated using the NMR log, from which a histogram upscaling of the T2Dist (30 bins) was created. For this process, a window size with step length equal to the vertical resolution of the NMR log was used. The histogram was calculated using the maximum and minimum limits of the entire log.
Permeability with pore-size distribution

Well P1

Well P2
Work flow 3 – 1st Oilfield

Conventional logs

Genetic Algorithm or Average

Artificial intelligent techniques

Fuzzy Logic

$W_1$

$k_{FUZZY}$

$\phi_{FUZZY}$

$W_2$

$k_{NN}$

$\phi_{NN}$

Optimization

Genetic Algorithm or Average

Parameters NMR log

$k_{SDR}$ or $\phi_{CMFF}$

Conventional logs

$GR$

$R_t$

$RHOB$

$NPHI$

$DT$

Artificial intelligent techniques

Fuzzy Logic

Neural Network

Optimization

Genetic Algorithm or Average

Parameters NMR log

$k_{SDR}$ or $\phi_{CMFF}$
Porosity Well P1
Porosity Well P2
Permeability Well P1
Permeability Well P2
## Comparison of simulations

<table>
<thead>
<tr>
<th>System</th>
<th>Reference well (Well P1)</th>
<th>Blind test (Well P2)</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>MSE (pu²)</td>
<td>Rating</td>
</tr>
<tr>
<td><strong>POROSITY</strong></td>
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<td>Fuzzy</td>
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<tr>
<td>Neural network</td>
<td>0.00017897</td>
<td>2º</td>
</tr>
<tr>
<td>Average</td>
<td>0.00020668</td>
<td>3º</td>
</tr>
<tr>
<td>Genetic algorithm</td>
<td>0.00017390</td>
<td>1º</td>
</tr>
</tbody>
</table>

| **PERMEABILITY**        |                          |                      |           |                      |
| Fuzzy                   | 715519.9231              | 4º                   | 2999840   | 4º                   |
| Neural network          | 488169.7611              | 2º                   | 254018    | 1º                   |
| Average                 | 528990.8120              | 3º                   | 1108540   | 3º                   |
| Genetic algorithm       | 385011.4734              | 1º                   | 300658    | 2º                   |
Work flow - 2nd Oilfield

\[ RQI = 0.0314 \sqrt{\frac{K}{\phi}} \]

\[ \log S_w = \left( \frac{1}{n} \right) \left( \log a + \log R_w - \log R_t - m \log \phi \right), \]

\[ x = \left( A^T A + \delta I \right) A^T y, \]

Reference well

Finish

Good

Blind test

Not good

Plot data and reservoir evaluation

Archie linearization

Archie parameters calculation \((a, m, n \in R_w)\)
Well A3

Energy: +high, −high, medium, −low, +low
Well A10

Energy

- +high
- -high
medium
- -low
+ +low
Well A10

Swirr

Shallower
\[ a = 1.0098; m = 2.1000; n = 2.1000; R_w = 0.0437 \]

\[ a = 1; \quad m = 2; \quad n = 2; \quad R_w = 0.02 \]
Conclusions

- In the two oilfields of Campos Basin, the integrated methodology shows that the resulting interpretation is much more reliable.

- In the first oilfield, we reached similar models to permeability and porosity through different approaches - flux zones and statistics with images logs.

- Also in this oilfield, the flux zone results obtained from static NMR measurements are similar to results of dynamic formation tests.

- For the second oilfield, the carbonates reservoir is shown as an Archie reservoir, that is, with characteristics of a sandstone reservoir, as shown by the values of Archie equation coefficients.
ACKNOWLEDGEMENTS

Thanks!