PS Identification of High-Resolution Features on Formation Pressure Gradients: A Case Study in a Heavy Oil Accumulation of the Campos Basin, Offshore Brazil*

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Abstract

Important features in hydrocarbon reservoirs can be identified from the analysis and interpretation of formation pressure data. When the original pressures are still preserved, one can identify changes of fluid gradients, fluid contacts, discontinuities related to vertical permeability barriers, or even the reservoir structural compartmentalization. This analysis can become more complex due to capillary, wettability and compositional variation effects of the hydrocarbons.

The interpretation technique most commonly used is the conventional pressure-depth plots, which sometimes becomes a very complicated task due the difficult to express small pressure variations and when there is no enough density contrast between fluids, especially in the presence of reservoirs containing heavy oil.

For over 10 years, Petrobras has been developing special techniques to highlight small and subtle pressure differences caused by variations in oil composition and permeability barriers. The ratio of static pressures to their true vertical depths plotted against the vertical depth helps to distinguish fluid pressure gradients, thus making it easier the reservoir fluid typing and their contacts definition. This technique is also used in regional studies. The analysis should be preceded by careful planning and quality control of data. The pressure data analysis in combination with other data sources should be evaluated qualitatively and relevant information should be treated statistically in order to provide a sensitivity analysis.

Cretaceous sandstones were investigated regarding the facies description and petrophysical-structural aspects aiming to provide expertise to the analysis and understanding of some anomalies observed in the pressure gradient analysis. Some considerations were made about the oil column composition variations, the presence of effective barriers to vertical flow and connectivity between the reservoirs, and their structural and hydraulic compartmentalization. Different types of aquifers associated with accumulations were also identified.

Identification of High-Resolution Features on Formation Pressure Gradients: A Case Study in a Heavy Oil Accumulation in the Campos Basin, Offshore Brazil

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ABSTRACT

Formation pressure data obtained with wireline formation tester tools (WFT) are useful for integrated studies aimed at understanding the different characteristics of reservoirs, fluids and their relationships. Several sources of uncertainty have proved that this procedure is not a simple task and does not rely on the result analysis alone. Therefore, the operation should be preceded by careful planning and data quality control. The pressure data and its final integration with other data sources should be evaluated qualitatively and relevant information must be treated statistically in order to provide a sensitivity analysis.

Important features in hydrocarbons reservoirs can be identified from the analysis and interpretation of formation pressure data. If the original pressures have been preserved it is possible to identify changes of fluid gradients, fluid contacts, discontinuities related to vertical permeability barriers, or even the reservoir structural compartmentalization. The analysis can become more complex due to capillary, wettability and compositional variation effects of the hydrocarbons.

Conventional pressure-depth plot is the interpretation technique that has been most commonly used, but sometimes it becomes a very complicated task due to the difficulty to express small pressure variations and also in situations where there is not enough density contrast between fluids, mainly in reservoirs containing heavy oil. For over 10 years, Petrobras has developed a technique to highlight small and subtle pressure differences caused by variations in oil composition and permeability barriers.

Cretaceous sandstones in the study area have been investigated regarding the facies descriptions and the petrophysical-structural aspects aiming to provide expertise to the analysis and understand some anomalies observed in the pressure gradient analysis. Some considerations were made about the oil column composition variations, the presence of effective barriers to vertical flow and connectivity between the reservoirs and their structural and hydraulic compartmentalization. Different types of aquifers associated with accumulations were also identified.

CAMPOS BASIN

Campos Basin is located in southeastern Brazil, mostly offshore from the states of Rio de Janeiro and Espírito Santo (Figure 1), occupying an area of 115,000 km^2 (44,402 mi^2), of which only 500 km^2 (193 mi^2) onshore (Bruhn *et al.*, 2003). The first offshore well was drilled in 1971 and the first oil discovery dates back from 1974, when the ninth well found Albian carbonate reservoirs (Garoupa Field) at a water depth of 120 m (394 ft).

Campos Basin is one of the twelve eastern Brazilian marginal basins that lie beneath the coastal plain, continental shelf and slope of the western portion of the South Atlantic Ocean. Their tectonic and sedimentary evolution is linked to the Neocomian breakup of Gondwana, and the subsequent opening of the South Atlantic Ocean (Bruhn *et al.*, op. cit.).

The stratigraphic record from Late Jurassic to Recent of the Campos Basin can be subdivided in three tectono-sedimentary megasequences (Figure 2; Rangel *et al.*, 1994; Winter *et al.*, 2007): (1) Rift Megasequence; (2) Post-Rift or Transitional Megasequence and (3) Drift or Passive Margin Megasequence.

During the evolution history of the basin, faults reactivation and differential subsidence processes, beyond intense salt tectonics, led to the development of efficient structural styles active in the secondary migration process and trapping of giant hydrocarbon accumulations.

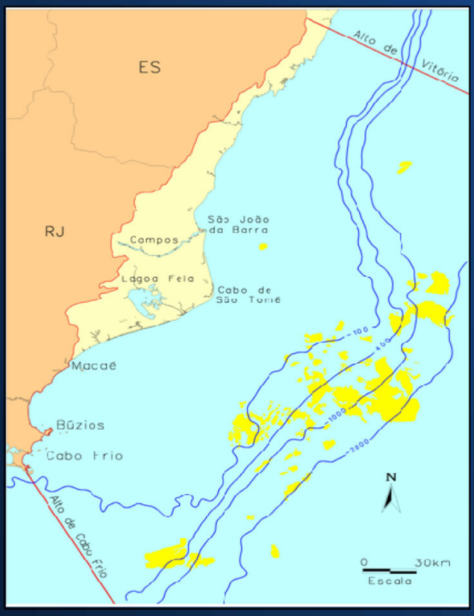


Figure 1. General location map of the Campos Basin.

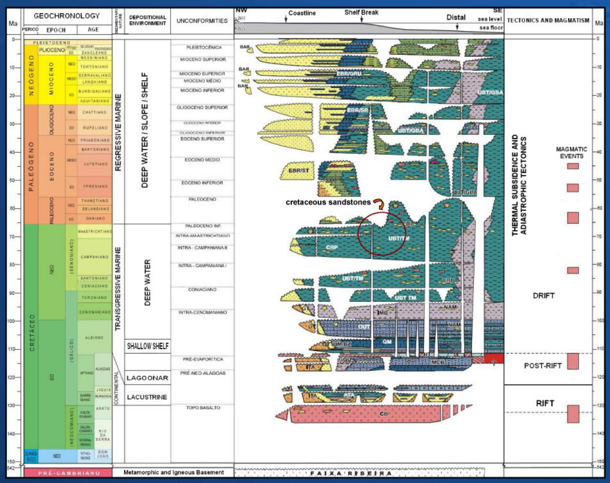


Figure 2. Stratigraphic chart of the Campos Basin (Adapted from Winter *et al.*, 2007).

THE OILFIELD

The study area (Figure 3) is situated in the Campos Basin under water depths from 350 to 1,650 m (1,150 to 5,415 ft). In the wake of partnership agreements between Petrobras and another oil company significant results were obtained from a drilling performed in 2003, resulting in the discovery of a new oilfield. After drilling and evaluation of five more wells, the commercial viability of the oilfield has been declared since 2005.

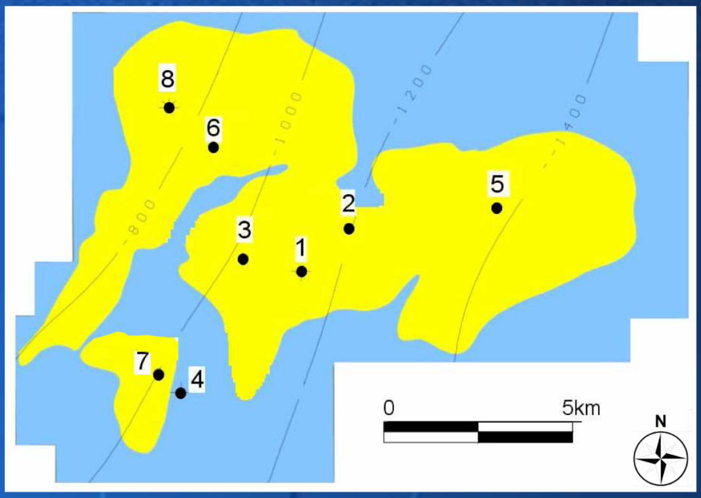


Figure 3. The current boundaries of the oilfield studied. Up to 2011, eight wells have been drilled.

Important structural features had a direct influence on facies distribution, sedimentary deposits geometry and preservation, geometric arrangement of faults which acted as significant conduits for hydrocarbon flow and on trapping of oil-bearing sandstones.

A positive structural feature identified in the structure contour, magnetic and gravimetric maps takes place in the central portion of the oilfield. Figure 4 shows the clear presence of this structural high in the Upper Cretaceous. It is interesting to note that the structural high proved to be persistent in geological time, being mapped from the rift sedimentation to, at least, the K-T boundary. This indicates the presence of a large regional paleostructure, probably inherited from crystalline basement structures.

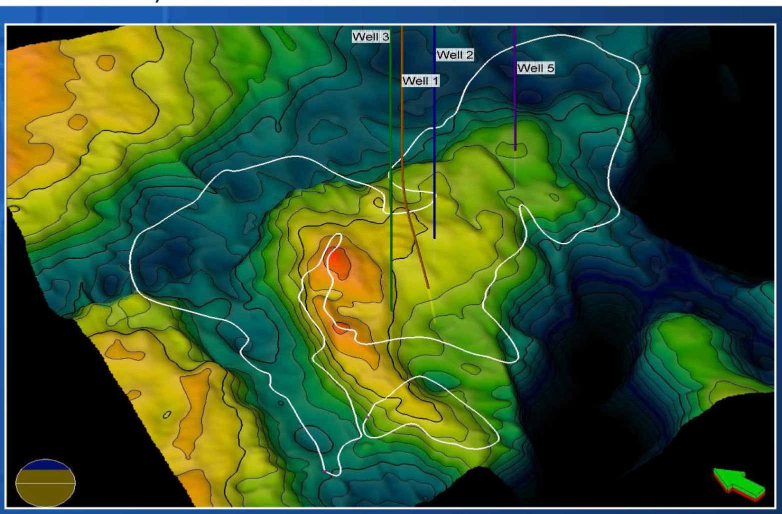


Figure 4. Structure contour map of the Upper Cretaceous (K-T boundary) highlighting the presence of the positive structural feature in the central portion of the field.

THE RESERVOIRS

The stratigraphic position of the sandstone reservoirs is illustrated in figure 2. In previous works, Petrobras geologists have identified from the macroscopic core description the following facies: (1) parallel laminated fine to medium-grained sandstones with rare shale and volcanic fragments, and interlaminated shales and sandstones. These facies were generated by tractive flow in final stages of deposition and by bottom currents reworking; (2) fine to medium-grained sandstones, locally intraclastic and with injection and convoluted structures; facies formed by erosional flows and slumps; (3) dark grey/green bioturbated shales deposited in the final stages of gravity flows of low-density and by suspended load deposition.

Three depositional sequences (Figure 5) have been identified based on seismic sections, well logs and biostratigraphic zoning (Petrobras, 2005), which were formed during a relative sea-level fall. At the top of the sequences shales and siltstones deposited during sea level rises occur. The sequences consist mostly of medium to coarse-grained sandstones at the base and fine to medium-grained toward the top. The porosity is predominantly intergranular, ranging from about 18 to 30%. Petrographic analyses indicate an arcosean composition to the sandstones, which contain quartz, potassic feldspar, plagioclase, biotite, muscovite and lithic fragments.

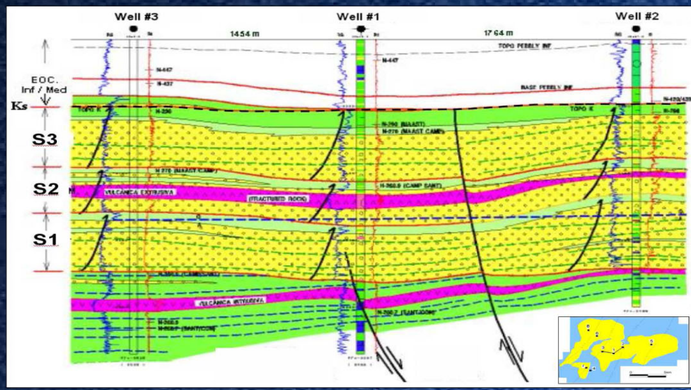


Figure 5. Stratigraphic cross section showing the S1, S2 and S3 depositional sequences distribution in the central part of the oilfield. The bodies in purple color correspond to volcanic rocks (Petrobras, 2005).

Based on the stratigraphic subdivision adopted, a lithofacies zoning has been performed for each of the wells, based on gamma ray, sonic and density logs. An example is illustrated in figure 6.

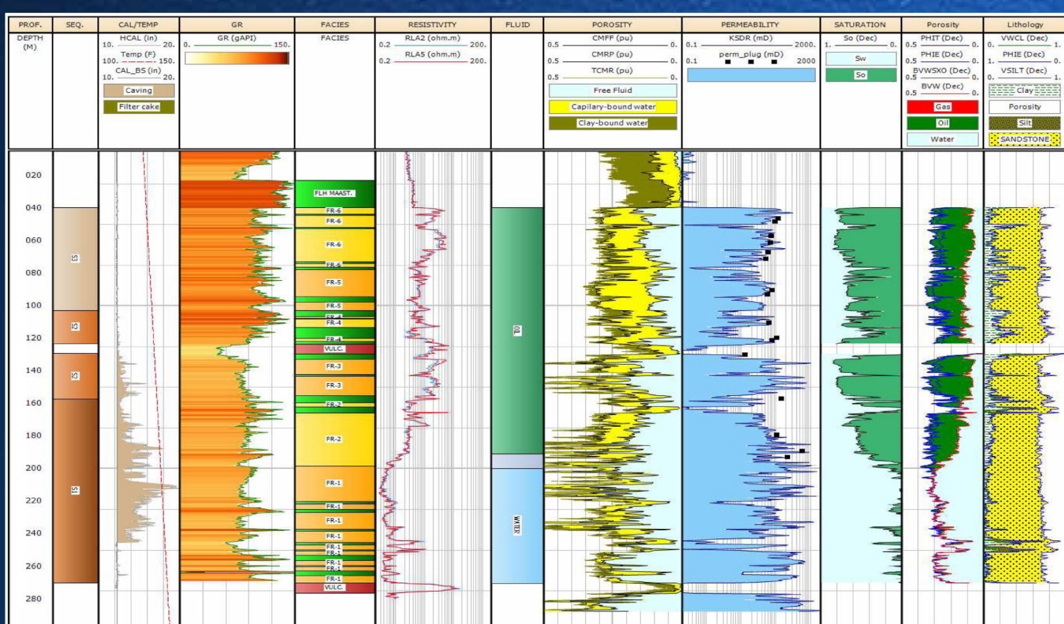


Figure 6. Composite well logs (Well 2) showing the depositional sequences S1, S2 and S3 and the six reservoir facies recognized (FR-1 to FR-6). *The true depth values have been changed.*

PRESSURE ANALYSIS TECHNIQUE

For over 30 years, the most commonly used pressure interpretation technique has been the conventional pressure-depth plots which shows the distribution of static formation pressures against true vertical depths. The analysis of these plots aims to evaluate variations in the pressure patterns (compositional gradients and barriers), fluid contacts and possible inter-reservoir connectivity and compartmentalization.

However, the task becomes more complicated in studies involving high-resolution analysis of pressure data, due to the difficulty to express small pressure variations and when there is not enough density contrast between fluids, especially in the presence of reservoirs containing heavy oil.

Stumpf & De Gasperi (2000) had developed a special technique to highlight small and subtle pressure differences caused by variations in oil composition and permeability barriers. The ratio of static formation pressures to their true vertical depths plotted against the vertical depth allows to distinguish more clearly the trends of the fluids, making it easier for log analysts to identify reservoir fluid type and fluid contacts (Figure 7). Another technique, called excess-pressure, had been proposed by Brown (2003), but in this case the plots must be constructed by using an arbitrary fluid density. However, it would be necessary to define its pressure trend (datum) for calculations.

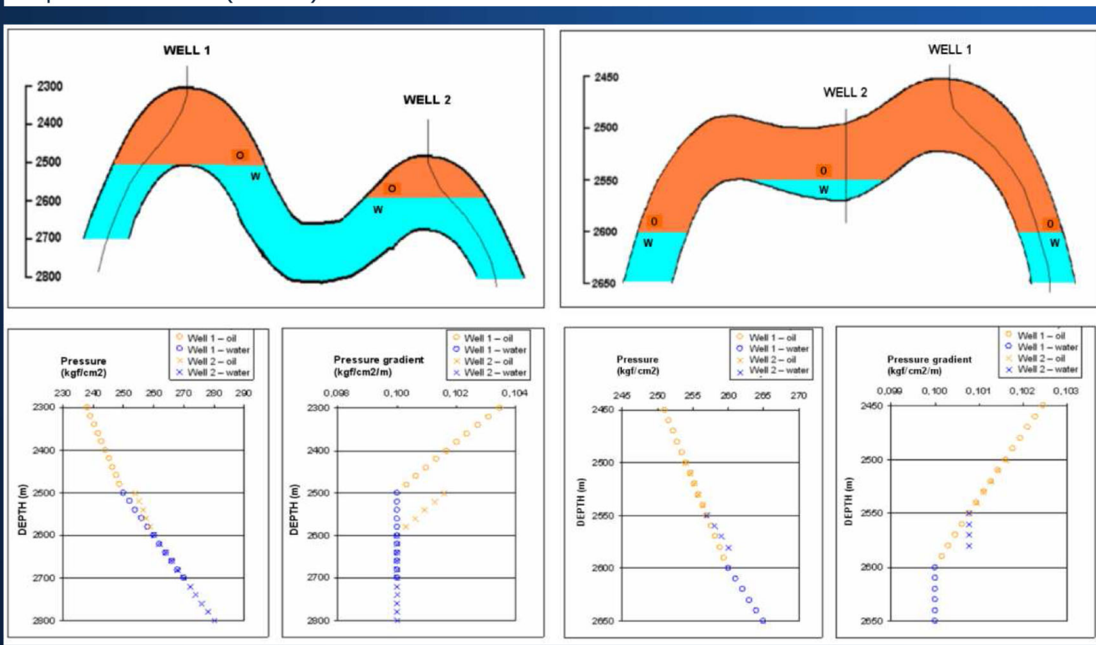


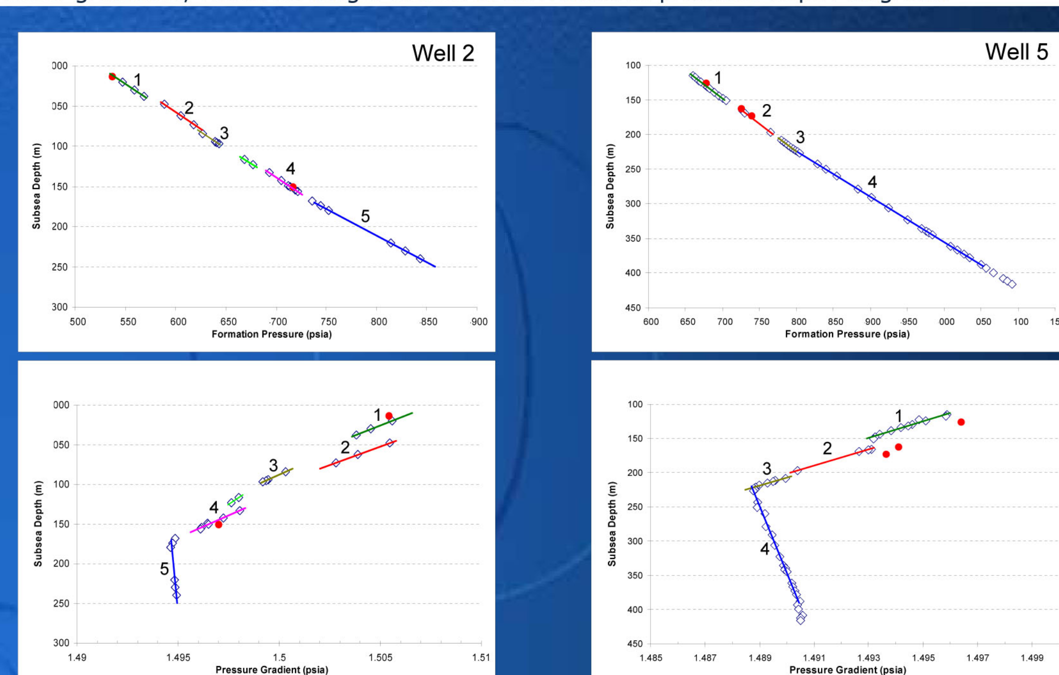
Figure 7. Schematic geological models showing different behaviors of the pressure gradients. On the left, a model with two distinct accumulations and just a single aquifer; on the right, another with only one accumulation and two aquifer systems (adapted from Stumpf & De Gasperi, 2000).

The resulting depth versus pressure gradient graph illustrates the overpressure in the hydrocarbon phase caused by hydrocarbon buoyancy effect, that is, a pressure differential that exists between formation water and petroleum in an accumulation. The amount of overpressure within the hydrocarbon accumulation is a function of the pressure gradients of oil, gas and water and the height of the hydrocarbon column (Swarbrick and Osborne, 1998).

Besides the easy hydrocarbon column visualization, there is another important piece of information provided by the graph, which is the angle between the hydrocarbon and aquifer trends. This angle reflects the oil and/or gas buoyancy at reservoir conditions. The greater the angle, the lighter the hydrocarbon. The angle is also directly proportional to the gas/oil ratio (GOR).

It is very important to emphasize that many pressure measurement errors and uncertainties have been recognized in data sets, which often compromises the quality of interpretations. This demonstrates that the operation should be preceded by careful planning and data quality control. Dewan (1983), Brown (2003), Chen (2003), Jackson *et al.* (2007), among other well log analysts, give special emphasis to this topic. The pressure data and its final integration with other data sources should be evaluated qualitatively and relevant information must be treated statistically in order to provide a sensitivity analysis.

Figure 8 shows pressure gradient-depth distributions and statistics analysis of two wells analyzed in this study. The technique demonstrates how easy it is to identify the oil and water gradients, which no longer occurs in conventional pressure-depth diagram.



	1	2	3	4	5
Density (g/cm3)	0,846	0,825	0,866	0,851	1,058
Pressure Gradient (psi/m)	1,20	1,17	1,23	1,21	1,51
Gradient Standard error (psi/m)	0,013	0,012	0,005	0,011	0,003
95% Confidence Interval	1,03 / 1,37	1,02 / 1,33	1,21 / 1,26	1,18 / 1,24	1,50 / 1,51
R-squared	0,9998	0,9998	0,9999	0,9995	0,9999
Residuals Standard error (psi)	0,17	0,21	0,055	0,31	0,17
Total pressures used	3	3	4	7	5

	1	2	3	4
Density (g/cm3)	0,869	0,857	0,856	1,070
Pressure Gradient (psi/m)	1,24	1,22	1,22	1,52
Gradient Standard error (psi/m)	0,015	0,014	0,017	0
95% Confidence Interval	1,20 / 1,27	1,16 / 1,28	1,17 / 1,27	1,52 / 1,53
R-squared	0,9988	0,9997	0,9992	0,9999
Residuals Standard error (psi)	0,49	0,35	0,18	0,15
Total pressures used	10	4	6	19

Figure 8. Conventional and pressure gradient-depth diagrams. Statistics analysis of the pressure gradient data sets is shown in the tables. The outliers and not used data are marked in red. *The true depth and pressure values have been changed.*

RESERVOIR PRESSURE REGIME

Cretaceous sandstones were investigated regarding the facies descriptions and the petrophysical-structural aspects aiming to provide expertise to the analysis and understand some anomalies observed in the pressure gradient analysis. Some considerations were made about: (1) variations in composition along the hydrocarbon column, (2) the presence of effective barriers to vertical flow and connectivity between the reservoirs, (3) the occurrence of different types of aquifers associated with accumulations and (4) some preliminary notions of the structural and hydraulic compartmentalization of the oilfield.

Pressure Barriers and Compositional Gradients

Jackson *et al.* (2007) point out that in routine practice of pressure-depth plots interpretation it has been very common to fit straight lines to as much of the data as possible, and so often ignore complexity in the pressure data. Subtle changes in pressure behavior can be characterized by slight drifts in pressure-depth trends due to compositional gradients, permeability barriers or reservoir compartmentalization. When there is some evidence of the presence of the features mentioned above, then a linear relationship can be inadequate to explain the phenomenon.

Due to sensitivity provided by the pressure gradient-depth plots, the barriers are characterized by discontinuities in the pressure trends, which show a sudden displacement of the values (15-20 psi) below the barriers, lithologically represented by shales (1-4 m thick; Figure 9). On conventional pressure-depth plots these features are very hard to recognize. The main pressure barrier separates FR-5 and FR-6 facies and has been described as bioturbated shales, slightly carbonatic.

The presence of compositional gradients had also been identified in the pressure trends (Figure 9). It is observed that the pressure gradient values do not obviously fit on a straight trend, but rather show a curvilinear behavior, possibly indicating oil compositional variations. Some supporting data, such as API gravity and drawdown mobility decreasing towards the reservoir base, reinforce this assumption. Geochemical analysis indicate that resins and asphaltenes represent around 40 to 50% of the total oil composition and the deepest oil samples show evidence of higher biodegradation. Probably, the oil compositional stratification is related to thermodynamic and gravitational equilibrium processes acting within each sandstone body, resulting in the accumulation of heavy fractions in the lower parts of the bodies with formation of tar mats.

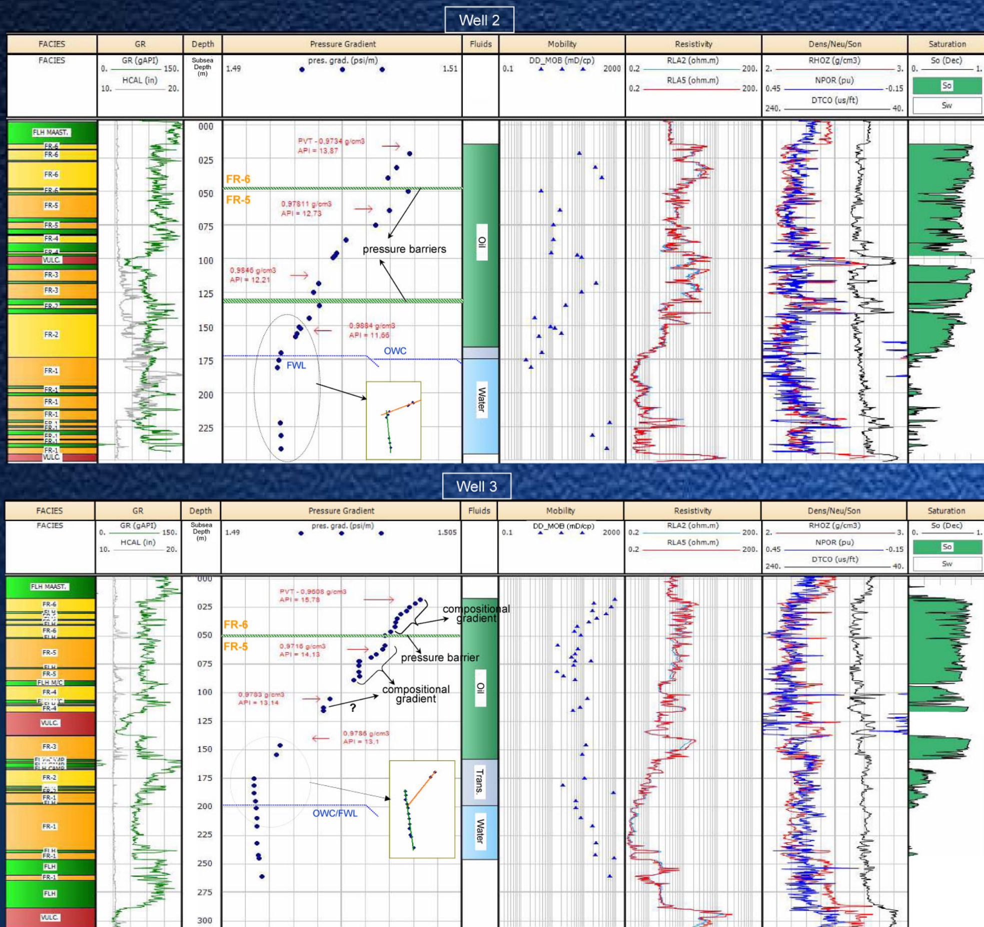


Figure 9. Composite well logs showing features indicative of the presence of flow barriers and oil compositional variations. Note that API gravity data indicate oil with poorer quality towards the reservoir base. *The true depth values have been changed.*

Fluid Contacts Identification

The pressure gradient-depth plots allow quick and easy identification of fluid contacts from the interception of gradient lines, as seen in figures 8, 9 and 10. However, it is very important to be alert to the fact that, in some cases, the intersection between oil and water gradients will differ from the true FWL (Free Water Level) due to the wettability, capillary pressure and mud filtrate invasion effects in transition zones. Likewise, the OWC (Oil-Water Contact) position derived from open hole log interpretations may also be very different from the contact observed in the interception of gradient lines. Elshahawi *et al.* (1999) and Jackson *et al.* (2007) place a lot of emphasis on this issue.

Aquifer Characterization

Two types of aquifers have been identified in the study area, which are well characterized in the pressure gradient-depth graph in figure 10. The first, including the area of wells 1,2 and 3, is defined as a non-connected type aquifer. The second, called interconnected aquifer, has been identified only in Well 5, showing OWC approximately 55m (~180ft) below in relation to the non-connected aquifer. The non-connected aquifer shows higher pressure regime in comparison with that of the interconnected due to the transmission of the hydrocarbon column pressure to water zone (Stumpf & De Gasperi, 2000) which has probably been confined since the oil accumulation formation process. In exploited areas the pressure of the non-connected type aquifer will not be replaced, such as it happens in the interconnected aquifers.

When it comes to spatial compartmentalization we can better understand the characterization of the accumulations and its aquifers from the analysis of structure contour map of the beginning of the sandy sequences sedimentation, which highlight the restricted geometry of the depositional substrate in the area of wells 1,2 and 3 and, possibly, detached from the area of Well 5. This geometry is still preserved, as illustrated in seismic section in figure 11. It is observed a slightly concave up shape of the Cretaceous Sequence in the area of wells 1,2 and 3, which probably have caused the imprisonment and isolation of the non-connected aquifer during the period of accumulation.

The fault that currently delimits to the east the main structural high shows strictly syndepositional behavior and, based on the results of figure 10, does not represent an effective barrier to transmissibility and lateral connectivity among the oil-bearing reservoirs situated to the east and west from it.

The stretch between wells 2 and 5 has not been drilled yet, but it must have a non-connected type of aquifer different from those already recognized in the oilfield or still be part of the interconnected aquifer.

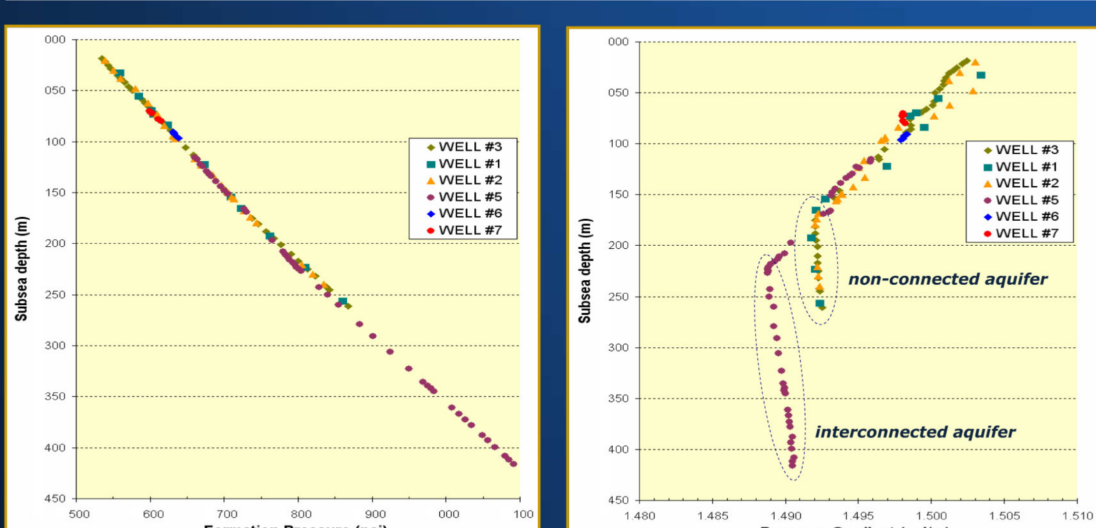
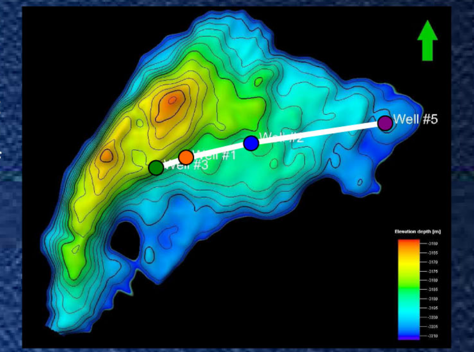
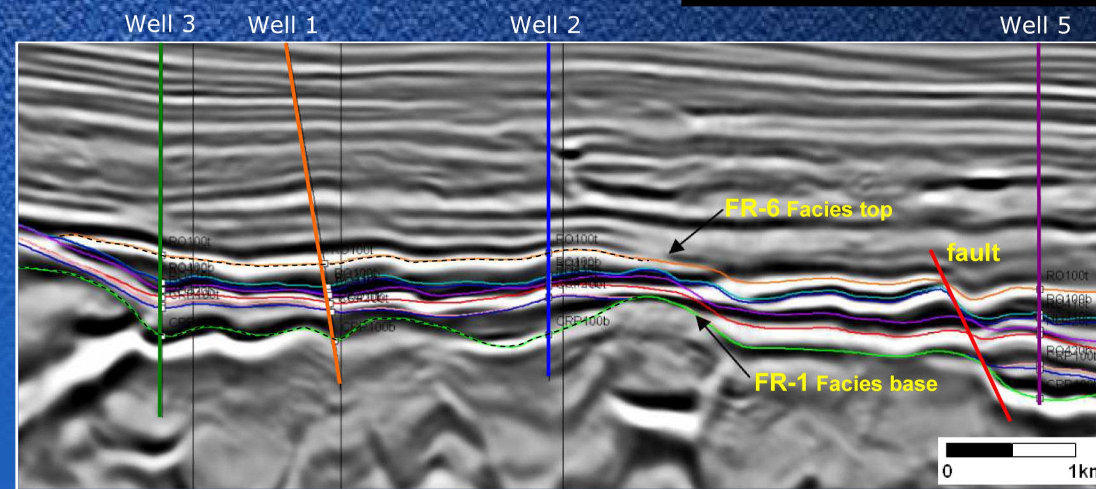


Figure 10. Conventional and pressure gradient-depth diagrams. Observe a clear compartmentalization of the aquifers. *The true depth and pressure values have been changed.*

Figure 11. Seismic reflection cross-section showing a slightly concave shape of the sandy sequence crossed by wells 3, 1 and 2. This block is structurally higher than the block of well 5. The fault that separates them is responsible for the structural compartmentalization of the oilfield and formation of two separate and distinct aquifers.





CONCLUSIONS

The following conclusions can be drawn from the presented study:

❑ The lithofacies zoning and the petrophysical characterization of the neocretaceous reservoirs made it possible to recognize different compositional patterns and permo-porous features.

❑ The technique developed by Stumpf & De Gasperi (2000) highlights small and subtle pressure differences caused by variations in oil composition and permeability barriers. The ratio of static formation pressures to their true vertical depths plotted against the vertical depth allows to distinguish more clearly the trends of the fluids, making it easier for log analysts to identify reservoir fluid type and fluid contacts.

❑ The quality control of the pressure data, followed by statistics analysis and uncertainty quantification of the gradients shed more light to the interpretations.

❑ High-resolution features have been identified in the study area: pressure barriers and oil compositional stratification (asphaltenes precipitation and tar mats formation?).

❑ The distribution of the pressure gradients shows that the oil-bearing reservoirs are under the same pressure regime indicating an occurrence of only one accumulation.

❑ Two types of aquifers are recognized: non-connected and interconnected.

❑ The fault that delimits the footwall block to the west (wells 1,2 and 3) and the hanging wall block of Well 5 has a strictly syndepositional behavior and was decisive to the hydraulic disruption of the original aquifer.

❑ The faults which had been mapped in the oilfield do not represent effective barriers to transmissibility and lateral connectivity between oil-bearing reservoirs.

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