Interpretation of hydrocarbon reservoir in the Campos Basin, using acoustic seismic inversion and well log data analysis and facies classification

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Abstract

Characterization of a turbiditic reservoir facies can become complex due to a high degree of heterogeneity that can be associated with these systems. Thus, interpretation depends heavily on the integration of all available information. In this study, we gather three different sources of information to delineate facies distribution of the field C, which are an interpreted geological model, well-logs and seismic data sets. Previous works provided a conceptual model for deposition and evolution of the sedimentary record, so we using this as background information. The well-log data were used to construct models electrofacies. Finally, we have inverted the seismic data for acoustic impedance, with the purpose of providing a better interpretation of the reservoir on the seismic scale.

Introduction

The deep-water turbiditic reservoirs still represent one of the most important reserves in the world, as it is the case with Tertiary and Cretaceous turbidites reservoirs of the Campos basin. These systems often constitute heterogeneous and complex deposits composed of layers of thicknesses below the seismic resolution.

A way to promote a better and more reliable characterization of a reservoir is through the integration of information, to construct a single model representing all available information about an area (BUITING & BACON, 1997). The generally available sources of information are, conceptual geologic models, seismic data, well-log and core data, among others.

One of the main advantages of integrating well data (typically with a high vertical resolution and small coverage or volume distribution) to seismic data (large coverage or volume distribution, but low vertical resolution) is that seismic data can be used to interpolate and extrapolate between and beyond the control of the well (COOKE ET.AL, 1999).

This study aims to delineate the facies distribution of a turbiditic reservoir in the Campos Basin, called field "C", through the integration of information emanating from geology, well data and seismic, originally with different scales and resolutions, focusing on two specific areas of this reservoir, here called the L and K.

Geological Context

The Campos Basin is located on the northern coast of Rio de Janeiro and south of Espírito Santo. With an approximate area of 100,000 km ^{2}, the Campos Basin is bounded on the north by the Arc of Victoria and south by the Arc of Cabo Frio. In almost four decades of oil exploration more than 2000 wells have been drilled.

The origin of the Campos basin, similar to other basins along the Brazilian coast, is related to the breakout of Gondwana (WINTER et.al, 2007). The target reservoir of this research study, called the Field "C" was discovered in 1984, approximately 80 km from shore, in water depth ranging between 300 and 700 m. Field C was formed in a passive margin regimen (drift phase), with its turbiditic sandstone reservoir belonging to the Carapebus formation, having ages ranging from Turonian to Campanian. The main geological elements that make up this area are normal faults controlled by halokinetic movements and a confining canyon.

According ALBERTÃO (2010), the canyon was incised in Turonian perpendicular to the direction of normal faults. These faults predate the canyon and are related to the movement of salt. Topographic lows were formed due to the activity of faults and were filled by sediments Conocinianos, who filled partially also the canyon. Thinner Santonian sediments have occupied the remnant canyon and spilled over to northeast rim towards the topographic lows. The Campanian sediments have a widespread distribution over the Field C, since the canyon and the topographic lows were almost completely filled by the Santonian sequence.

Database and Methodology

The suite of data used in this study consists of seismic and well data. The seismic data consist of a post-stack seismic cube in time with three regional mapped horizons, which are top and bottom of zone 2 and unconformity M. Acquisition of the seismic data occurred in 1999, covering approximately 46 km² of the Field C. The selected study area is about 30 km², with main regional horizons mapped over the entire study area. The acquisition was made using streamer towed by 10 cables, 4 km long. Acquisition bin size are 25 m by 25 m and the sampling interval is 4 ms. The maximum frequency is around 70 Hz, the dominant frequency around 35 Hz and the vertical resolution of data is approximately 22 m. Our target interval is 0.5 s, corresponding to a depth interval of approximately 1524 m. The available well-log data consist of Gama Ray (GR), Sonic (DT), Neutron (NPHI), Density (RHOB) and resistivity (ILD) from five wells located within the study area. We used the seismic inversion software from Jason (CGG). The wells used in the inversion are located in a region called in this paper K. Another region selected for blind testing is referred as region L.

The region L is composed of sediments deposited on a complex system of channels within a canyon incised in the Turonian. The region K, located northeast of the canyon is formed by sediments that have been spilled over from the canyon and deposited in topographic lows, caused by normal faults related to halokinesis. The electrofacies models were built using the software Interactive Petrophysics (IP) and data coming from 2 wells, one located in region L and another in region K.

Geological framework

The conceptual model of the reservoir is shown in Figure 1. The structural framework of the area has the shape of a canyon, which were deposited amalgamated channels. The reservoir is divided into two zones, 1 and 2, separated by a shale discontinuity. The area 1 corresponds to the oldest reservoir composite by sandstones deposited in turbiditic channels. These channels have coarse sediments at the base with thinning at the base to the top. Zone 2 corresponds to the reservoir youngest composed of turbidite sandstones, which have finer grains deposited in confined lobes.

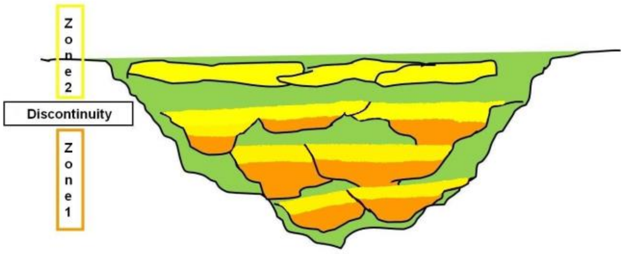

Figure 1: Conceptual model proposed for the Field C. The colors yellow and orange are related to grain size. The yellow color represents finner sandstones, predominant in the zone 2 and in the top of the channels. Orange represents the coarser sandstones, which appears at the basis of the channels.

Electrofacies Model

The electrofacies model was generated based on well logs, which have been analysed together to provide a class segmentation over the depth interval. The choice of logs can be made based on analyzes of cross-plots and histograms. The well logs used in building the electrofacies model were: density, sonic, clay volume and P-impedance. The models are shown in Figure 2. We found 4 lithologies, 2 reservoir and 2 non-reservoir. The reservoir facies were called sandstones 1 and 2 represented by the colors orange and yellow, respectively.

The sandstone 1 corresponds to coarser sandstone and should, according to the conceptual model, should occur at the base of the channels, whereas the finner sandstone 2 should lay at the channel top and within the reservoir zone 2. The intercalation of sandstones 1 and 2, in zone 1, may be an indication of channels. Based on this assertion, we mapped 10 possible channels with thicknesses ranging between 6 and 35 m. The non-reservoir facies were called NR1 and NR2 represented by light and dark green colors, respectively. It is important to say that most of these channels have thicknesses below the seismic resolution.
An strong impedance overlap between classes was observed as shown on the histograms of the Figure 3 computed from well C-L. We can observe this overlap especially between sandstones 1 and 2, and between the sandstone 1 and facies NR 2. This demonstrates the limitation of using impedance alone for facies discrimination. Consequently regional facies characterization of a reservoir strongly depends on the integration of geologic information, well logs and seismic data.

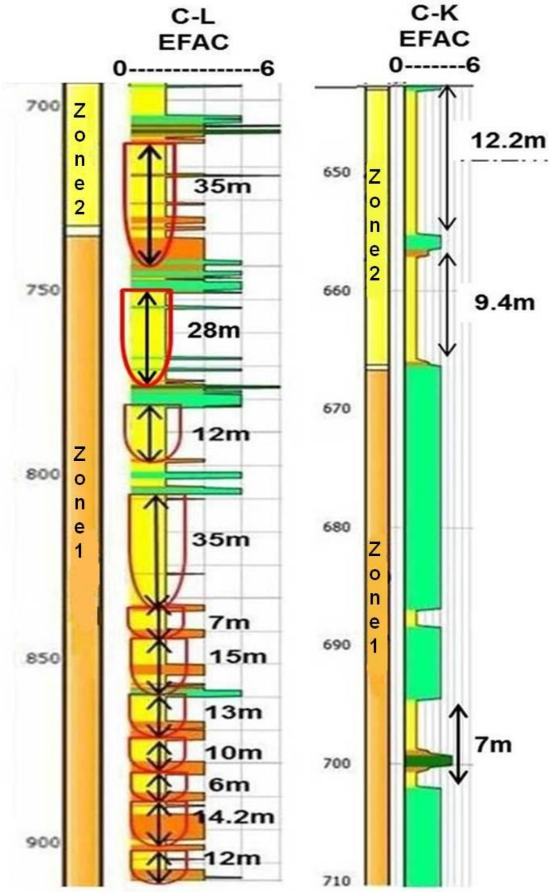

Figure 2: Electrofacies model constructed for the wells C-L and C-K (wich are located in the regions L and K, respectively). The red markers indicate possible channels.

Constrained sparse spike inversion (CSSI)

The post-stack inversion algorithm constrained sparse spike inversion (CSSI) requires the 3D seismic data volume and a background impedance model constructed from the integration of well logs and interpreted horizons used to guide interpolation of well information. The inversion generates a model of acoustic impedance with a resolution higher than the input data, since it removes the wavelet from seismic data. Consequently the end result has increased bandwidth to higher frequencies, which improves vertical resolution and minimizes tuning effects. Furthermore, the method CSSI allows to integrate lower frequencies through the background model. In this work, we decided to use relative P-impedance instead of absolute impedance, considering that the low frequency model, constructed from interpolation of well data, does not have sufficient reliability. The information available is too sparse since there were only three wells located in the region K. The use of absolute impedance can cause confusion and lead to interpretations which are not representative of real geology in areas with few wells. On the other hand, it is necessary to take certain precautions when using the relative P-impedance, because it can be affected by variations in the thickness of the reservoir. For example, two layers with similar lithologies but different thicknesses may have different dynamic ranges of relative impedance. This problem can be mitigated by using an integrated interpretation with different sources of information, how geology, and well logs data. (DEDDY HASANUSI et.al, 2007).

Results

The strong impedance overlap between classes derived from analysis of well-log data and the error associated with the effects of the thickness variations of the ranges of relative impedance can cause ambiguous interpretation. To minimize the effects of impedance overlap a filter was applied on whole area used in the inversion. The purpose of this filter is to remove the impedance ranges, with significant overlap with others, tohighlight the internal features of the reservoir. The main overlaps considered were between the sandstones 1 and 2, and between the sandstone 1 and the NR1 facies. The filter removed the ranges of impedance between -480000 and -500000 $\left({kg}/{m^3} * {m}/{s}\right)$ and over de 22000$\left({kg}/{m^3} * {m}/{s}\right)$.

We sought to delineate lobes and channel, since these features are related to the sandstone facies 1 and 2. The lobes are mainly present in zone 2 and in the K region, since the zone 2 is more representative in the low topography regions. The channels comprise the zone 1 in the L region of the reservoir.

Figure 4 shows an inline section through the C-K well. It is noted that reservoir levels of this region show spread geometry (characteristics of lobes), marked in black, with a predominance of facies sandstone 2, predicted by the conceptual and electrofacies models. An ambiguity occurs in this region. The area highlighted in white can be interpreted as a large reservoir in accordance with the acoustic impedance model; however, the well log information indicates a thin region, probably corresponding to the region of lowest impedance, marked in red. Figure 5 shows a crossline section through the well C-L. Black dashed lines represent interpreted channel system elements. Note the difficulty to individualize the channels due to amalgamation. It is also observed a large concentration of sandstone 2 facies on the northeast of the canyon, as reported by ALBERTÃO (2010).

Conclusions

The acoustic impedance inversion proved to be an useful tool for the regional facies characterization of a reservoir. Although the effects of the reservoir thickness to the dynamic range of relative P-impedance and the impedance overlap between classes are evident, the attribute of relative P-impedance allowed for interpretation of the facies distribution, as well as internal features of the reservoir, once associated with the geological models and well logs data.

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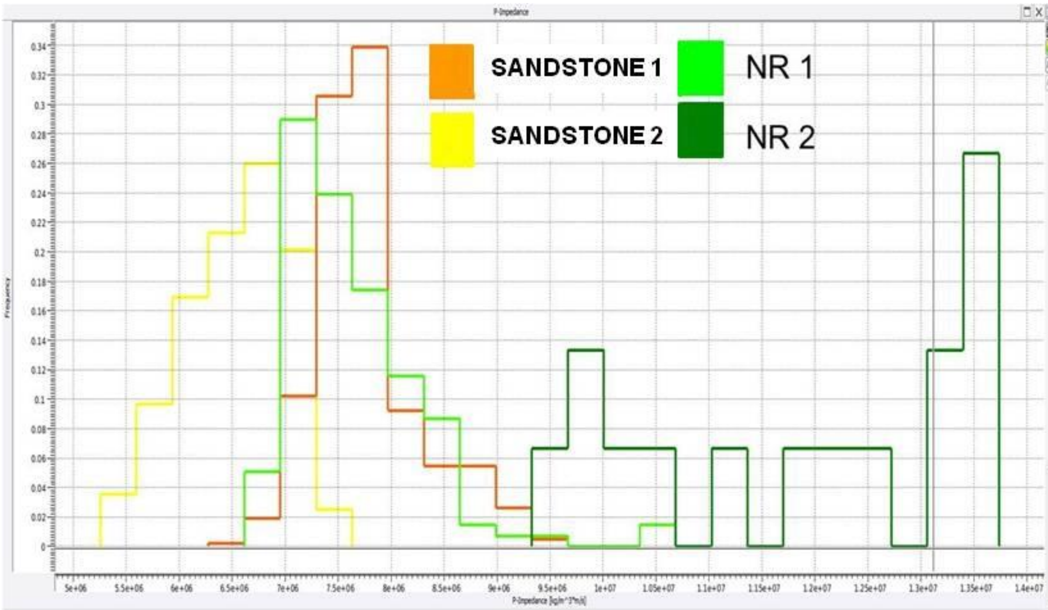

Figure 3: Histogram of the facies distribution based on the attribute impedance. The strong overlap in impedance between classes demonstrates the limitation of the impedance attribute to discriminate facies.

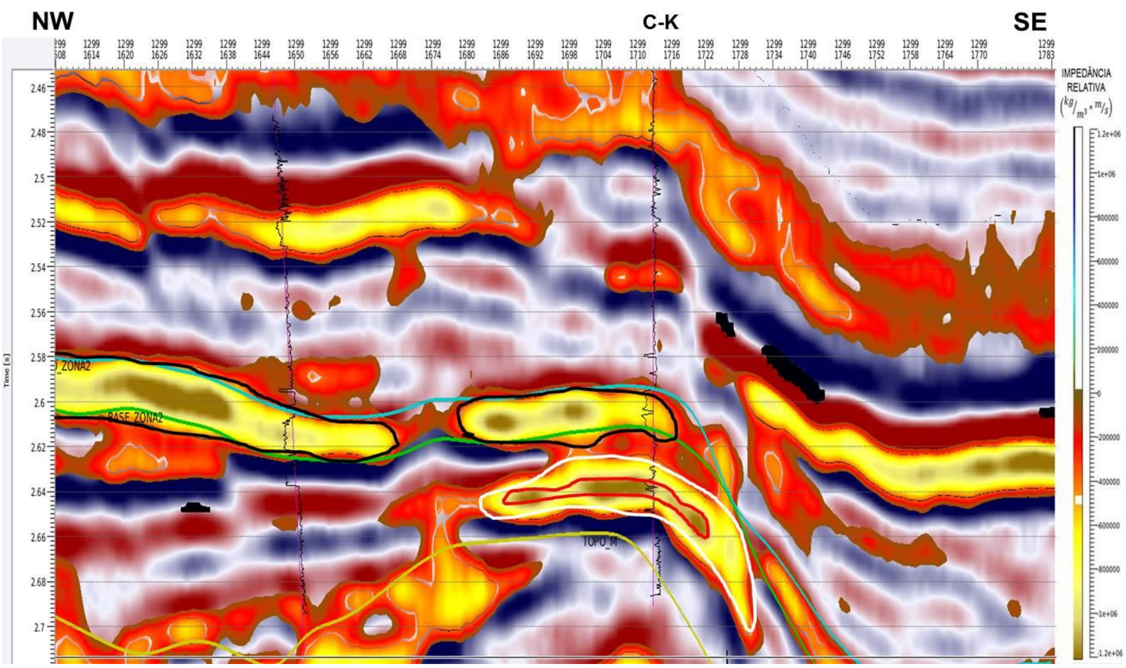

Figure 4: Inline section, perpendicular to faults, through the C-K well. Black lines indicate our interpretation of the reservoirs layers. White and red lines represent the ambiguity in interpretation. Interpreted seismic horizons are represented by blue, green and yellow lines.

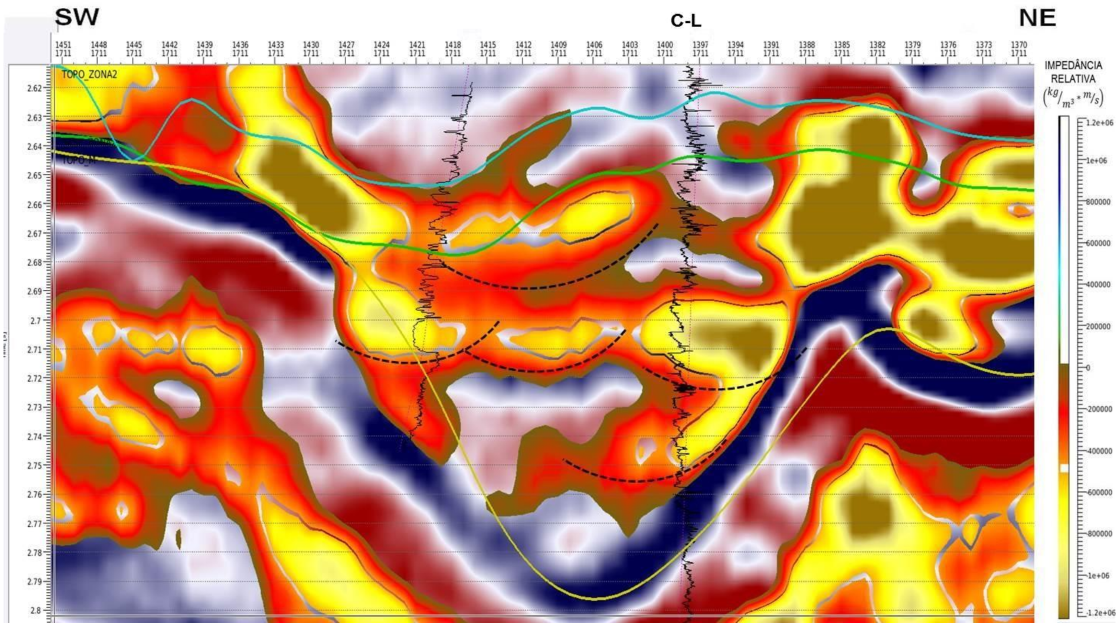

Figure 5: Crossline section, perpendicular to the canyon, through the well C-L. The lack lines (dashed) indicate interpreted channel system and geometry. Interpreted seismic horizons are represented by blue, green and yellow lines.