Connecting seismic attributes with production performance at Camarupim Gas Field, Espirito Santo Basin, Brazil.

Alexandre Kolisnyk (Petrobras)*, Ricardo Castellani (Petrobras), Elita de Abreu (Petrobras), Luilson .T.L. e Sá (Petrobras), Anderson Pimentel (Petrobras), Carlos da Cunha (Petrobras), Viviane da Silva (Petrobras), Ronaldo Kraft (Petrobras), Carlos.Manuel.A. Silva (Petrobras) & Dione.C. Moraes (Petrobras)

Abstract

We describe an integrated approach that connects production performance with elastic and geometric seismic attributes to define the role of rock matrix and fractures/faults on gas production from Camarupim Field, offshore Brazil. Discovering, appraisal and development comprise three vertical and four horizontal wells, grossly 1000 meters long, showing very distinctly absolute open flows (AOFs) during tests.

Multi-scaled data, seismic, logs and lab-based supported elastic inversion feasibility analysis to understand and correlate band limited Poisson-Ratio (PR) and P-Impedance (Ip) cubes with rock properties. Positive PR and negative Ip values are associated with shales, while sands relate to negative PR and a wide range of positive and negative Ip values, the later ones assigning best sand quality.

Better facies detection was guided by combining PR and Ip cubes in a particular way, taking only negative values and zeroing the positive values of PR. Positive values in this product cube relates to better facies (Ip<0 and PR<0).

Product and discontinuity volumes were then integrated to connect changes in facies and/or fault/fracture or both with changes in production performance. Although facies related attributes allow reservoir quality discrimination, the well path direction across fractures/fault architecture plays the main role in field productivity.

Introduction

Camarupim gas field is located 37 kilometers (23 miles) offshore Brazil. Petrobras, with a 65% stake, operates this block in partnership with El Paso, which holds the remaining 35%. The field was discovered when the 1st exploration well (well A) encountered a gas column measuring 112 meters (367 feet) at 760 meters (2,493 feet) of water column. During 2007, two appraisal wells (B and C), further delineated the field to the north of the discovery, increasing expected recoverable reserves. Regarding reservoir quality, there is a slight difference among these wells, while in the 1st exploration well low and high impedance sandstones are present, in the appraisals high impedance sands dominate the pay zone. Impedance changes show good correlation with porosity changes.

More recently, four horizontal wells were drilled, AH following N-NE/S-SW direction and taking the discovering well A as a pilot and BH, CH and DH, following N-NW/S-SE direction in the north part of the field (see Figure 1). Electrical and acoustic image logs were performed in all horizontal wells, in order to analyze fracture presence and density along trajectories. Only in CH well the production logging test (PLT) was performed in order to determine which reservoir interval contributes the most to the total production. Production performance changes dramatically along the entire field. Comparative to BH, CH and DH wells, the southern horizontal well AH achieved the better result in terms of absolute open flow (AOF) potential (5-fold better). According with PLT analysis, CH production was tremendously concentrated in a small zone and the production tests of vertical B and associated horizontal BH (more than 1000 meters pay) provided AOFs very low and very similar, suggesting that the contribution for the horizontal well comes from a small zone, close to the vertical well.

According with Law and Curtis (2002), Camarupim can be classified as a tight gas field. Although sweet spots are present, field area is highly dominated by low permeability zones. Since impedance sands and natural fractures were detected only in the southern vertical and horizontal wells A&AH, it was not conclusive if the sweet spots are controlled by facies, by natural faults/fractures or both. In this paper a multi-scaled approach based on seismic, logs and lab-based data is followed to connect geometric and elastic seismic-attributes with field production performance.

Sedimentology and Stratigraphy

The base of the sandstone cycles were correlated where seismic resolution was high enough to allow the horizon to be tracked. In all seven intervals the dominant facies is coarse to very coarse grained sandstones. Reservoirs are classified as arkoses due to feldspar presence, poor sorting and massive texture. The wells show a cylindrical shape in gamma-ray logs, which implies that the sand grain size is not gradational.

Pay zone sandstones have the best permeability (values ranging from 1 to 10mD), which are interpreted to result from the diagenesis inhibition due to hydrocarbon emplacement in the reservoir. The extremely poor sorting of the grain size, the cylindrical shape of the gamma ray log and the channelized features observed in maps suggest that these sands were deposited in slope channels by hyper-concentrated density flows with very low efficiency. This could have occurred because the flow was not able to segregate the grain fractions, causing the grains to be instantaneously deposited as if there was a 'flow freezing' without sand bypass. It appears that there was a bathymetric barrier that hindered the flow evolution towards the downslope.

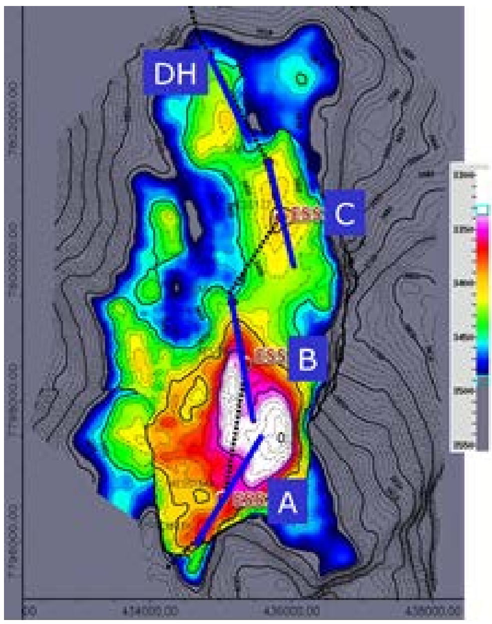


Figure 1: Structural contouring of Camarupim Field coloured above gas water contact, showing, from south to north, vertical and related horizontal wells A/AH, B/BH, C/CH and DH.

Elastic and Geometric Attributes

A routine described by Dillon et al. (2009) taking into account lab-based and logs from field and vicinities supported the feasibility studies. P-Impedance (Ip) and Poisson's ratio (PR) can be used to identify four different zone types: tight sands zone (low permeability and porosity), sandstones saturated with water (good permeability and porosity), sandstones saturated hydrocarbon (good permeability and porosity) and clay area. It is important to emphasize the impact of using the correct mineralogy, taking into account feldspar contribution, in the feasibility studies for tight sands, enabling better separation between gas and water saturated reservoirs. According with feasibility, cutoffs zones in attributes **Ip** and **PR** would allow the identification of highest porosity gas saturated reservoir. Seismic derived elastic attributes work very well to detect the presence of sands, reasonably to preview quality changes, but were not as clear as predicted to show the gas effect, since similar responses were not restricted to the region above gas/water contact.

Two different approaches based on spectral decomposition (Partyka et al. (1999)) were tested to generate geometric attributes related to the fault/fracture architecture. In the first approach we applied RGB colour blending technique (Henderson et al. (2007) and by McArdle and Ackers (2012)) using three frequency bands from Ip. In the second, colour blending technique was used taking three different attributes, the dip and two structural oriented (SO) cubes, SO-semblance and SO-discontinuity. The final discontinuity cube was then submitted to a technique for automatic faulting extraction called ant-tracking, described by Cox et al. (2007) and implemented in the Petrel software.

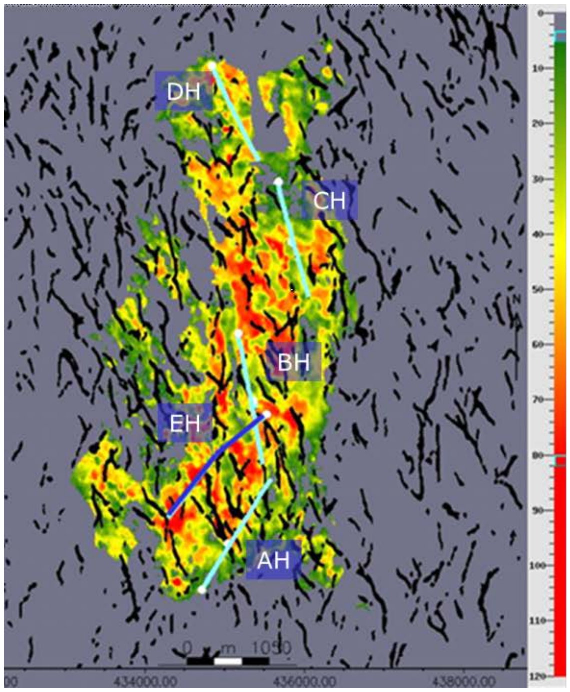
Methodology

Facies detection was performed using band-passed inversion cubes. From feasibility all sands are correlated with negative values of **PR** and porous sands with negative **Ip**, hence an approach was followed to generate product cube **PRneg x Ip**. First the generation of PRneg keeping only negative values and zeroing any other values. Then the generation of **PRneg x Ip** cube, where positive values correlate with better facies and negative values with worse facies.
In order to integrate facies and discontinuity, a sweet spot prediction volume was then generated by blending **PRneg x Ip** and ant-tracked cubes (Schlumberger), the last one designed to enhance natural fractures/faults visualization. Several maps were derived by slicing attribute cubes through the reservoir zone. The purpose was to capture features which can explain or give some clues about production performance differences and validate new well location.

It seems to be evident the connection between production field performance looking the composed map, best quality sand isopach over ant-tracked discontinuities, at Figure 2a. Horizontal well AH (associated with vertical well A) achieved the better production and is the only to cross perpendicularly NNW-SSE lineaments related to faults and/or fractures. The three other horizontal wells followed almost parallel directions to NNW-SSE lineaments.

Moreover, good facies distribution seems to be slightly thicker in the vicinities of AH well than in any other part of the field. Instead of assuming a network of fractures as the main hydrocarbon tank, production at AH is higher because is probably fed by the several blocks resulted from faulting/fracturing, while the remaining contribution from the other wells come from single blocks.

An even more straight relation between blended attributes and production field performance can be shown in Figure 2b, which presents blended sections in the same trajectory directions from production wells AH, BH and CH. In the well AH case it is possible to correlate fractures in seismic to natural fractures detected through image logs analysis. Observing the fracture/fault crossing in the same point vertical and horizontal wells (B and BH) is reasonable to explain the similarity between their productions. The only PLT ran in this field pointed out an extremely localized production at CH associated with the presence of fracture. Although not recognised through image logs analysis such fracture zone can be easily interpreted in the combined and ant-tracked discontinuity volume section.



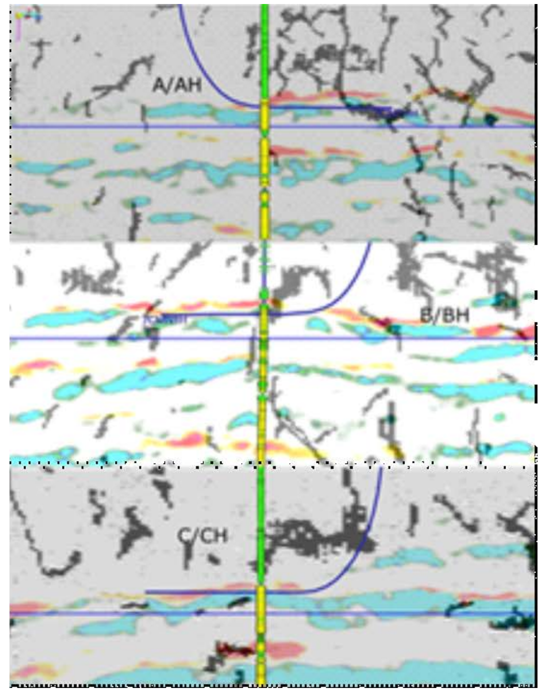


Figure 2a (Left): Surface slice at top reservoir level showing best sands thickness and ant-tracked discontinuities. Clearly southern horizontal well AH was drilled following orthogonal direction to natural fractures/faults while the others stayed almost parallel to main lineaments. Dark blue line shows the location for the future well. **Figure 2b (Right):** Sections over combined **PRneg x Ip** and ant-tracked discontinuity volumes along horizontal well trajectories. Better sands in red, worse in blue and dark blue line is the G/W contact. See text discussion.

Conclusions

Elastic and geometric attributes were blended to measure their connection with production performance along Camarupim gas field, which varies from reasonable down to tight sands numbers. Although inversion and derivatives allow mapping the presence of gas saturated sands and provide a kind of reservoir quality zoning, the most important mechanism for higher well productivity seems to be the relationship between well trajectory direction and the faults and/or fractures network.

References

Cox, T. and Seitz, K., 2007 Ant tracking seismic volumes for automated fault interpretation, *CSPG CSEG Convention*, Calgary, Alberta, Canada.

Dillon, L.D., Schwedersky, G., Nunes C.M.F., Justen J.C.R. and de Abreu E.S., 2009 Rock Physics Modeling as a Tool to Improve Interpretation from Tight Gas Sands Reservoirs, *AAPG International Conference and Exhibition*, Article #90100©2009, Rio de Janeiro, Brazil.

Henderson, J., Purves, S.J. and Leppard, C., 2007 Automated delineation of geological elements from 3D seismic data through analysis of multichannel, volumetric spectral decomposition data. *First Break*, 25(3), 87–93.

Law, B.E. and Curtis, J.B., 2002 Introduction to Unconventional Petroleum Systems, AAPG Bulletin, v.86, no. 11 p. 1851-1852.

McArdle, N.J. and Ackers, M.A., 2012 Understanding seismic thin-bed responses using frequency decomposition and RGB blending. *First Break,* 30(12), 57-65.

Partyka, G., Gridley, J. and Lopez, J. 1999, Interpretational applications of spectral decomposition in reservoir characterization. *The Leading Edge*, **18**, 353-360.

Acknowledgments

We thank Petrobras and El Paso for the authorization to present this work. Many colleagues helped the completion of this work. Among them, special thanks, Alcides Aggio Sobrinho, Juliana Alencar, Marcos Rachele, Rafael de Freitas, Ronaldo Freire, Fabio Rodamilans, Raul Damasceno, Paulo Denicol and Manoel Gontijo from Petrobrás, Romário Lima and Luis Gerardo Escalona from ffA-Geosciences..