Seismic fracture characterization workflow and support for the geological model: Albian carbonate reservoir, Campos Basin, Brazil

Klédson Tomaso*, Pedro Benac, Jorge Sarturi, PETROBRAS, Gerardo González, and Bruno de Ribet, PARADIGM

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Abstract

Seismic data from an Albian carbonate field located in the Campos Basin (offshore Brazil) reveal, through conventional interpretation and characterization studies, differential zones of more complex structures. Geometric attributes extraction and multi-attributes patterns recognition analysis on a time migrated amplitude volume highlight features that could be related to fracture zones in the carbonate reservoir rock.

Based on a fractal theory, a seismic structural characterization workflow can be adapted as a fracture characterization approach in order to identify fracture sets and estimate a fracture intensity property. From the generation of an Eigen structure-based coherence cube, several algorithms and Laplacian filters are applied to extract seismic discontinuities and produce new seismic attributes.

The generation of fracture intensity properties for every reservoir unit on the static model grid, in addition with the identification of principal fracture orientations and fracture apertures, drives the construction of Discrete Fracture Networks (DFNs) and their associated properties. Resultant properties as porosity, permeability and fracture effective area can be exported to dual-porosity/permeability flow simulators for improving the history matching and establish new predictions with more confidence.

Introduction

Carbonate reservoir characterization is still a multidisciplinary challenge that runs into some obstacles, like the seismic resolution for fracture detection, the heterogeneity and drastic facies changes of carbonate rocks and the incorporation of dual-porosity/permeability flow simulators.

The study area is an Albian carbonate reservoir composed by an association of calcarenites, calcilutites and calsilitites. From previous studies, the reservoir has been separated into two main zones according to their fracture degree; this leads directly to a close relation between oil production and fractures presence. For such reason, it is crucial to characterize the different fractured regions in the reservoir. This paper demonstrates a workflow, starting with seismic processing data and running through the incorporation of the seismic products in the geologic model. Seismic attributes, well logs and core data are used to generate properties associated with fractured zones.

Geological Characteristics of the Reservoir

The carbonate from Albian reservoir of the Campos Basin are composed by an association of calcarenites, calcilutites and calsilitites deposited in an environment characterized as shallow and with high-energy. At the end of the cycle of carbonates sedimentation, gradually became drowned. The diagenetic history of these deposits, however, has evolved to cement the pore spaces of rocks, resulting in low porosity (<22%) and permeability (<15 mD). Despite this low permeability, the presence of a faults system, reactivated after the carbonates diagenesis, helped to create a fracture network that produces a secondary permo-porosity in the reservoirs. This effect is very significant in the southern part of the field; there, wells were capable of producing over 130 thousand m3 oil / year / well, in the fractured area. On the other hand, wells in the non-fractured region showed flows under than 30 thousand m3 oil / year / well.

Proposed Seismic Characterization Workflow

The workflow proposed is: 1) Generate unconventional geometric seismic attributes and products from an automatic fault extraction process: Fault Enhanced and Vector Azimuth volumes; combined with trace complex, spectral decomposition and elastic seismic inversion attributes. 2) Principal components analysis in a multi-attribute approach as input to a seismic pattern recognition process with artificial neural networks and cluster algorithms. 3) Seismic facies classification for the geometric characterization of the carbonate bodies, structural complexity determination, anisotropy directions, generation of probabilistic scenarios for lithofacies distribution and quality control of the structures considered in the geological model. 4) Adaptation of a seismic structural workflow to a seismic fracture characterization approach to identify sets and fracture density. 5) Fracture intensity property estimation for each fracture set in the geological grid cells, in order to reduce uncertainties in the fracture modeling parameterization. 6) With the identification of the principal directions of fracturing, seismic fracture intensity attributes and fracture aperture from the core well data and FMI logs in the reservoir level, it is possible to construct discrete fracture networks (DFN) and the properties associated that can be exported to the dual-porosity/permeability simulators.

Unconventional Seismic Attributes

Extraction and analysis of conventional seismic attributes from the initial amplitude volume do not support the different behavior of the wells production history. From the new hypotheses of the sedimentological model, there is no clear differentiation in the carbonate sequence, but there is a structural component that controls the production.

Several geometric attributes were tested and evaluated like the most negative curvature in a 3x3x5 window. The curvature, as geometric attribute, takes into account the shape dimension, allowing a better faults definition with a polygonal appearance, discriminating faults of other linear features on the surface (Robert et al 2001). The response of this attribute is important for the quality control of the extent and orientation of faults embedded in the geological model, as well as the identification of minor faults, chaotic seismic areas and artifacts present in the amplitude volume. In the south part of the carbonate reservoir, it is possible to identify a more chaotic response from the most negative curvature on surfaces, coincident with a structural high and directly interpreted as a zone with a higher incidence of fractures.

On the other hand, an automatic fault extraction workflow was performed on the time migrated amplitude volume from the OBC acquisition, the purpose was taking advantage of the seismic products involved. Filters were implemented into the workflow using a high resolution coherence volume, calculated with Eigen-structured algorithm completely parameterized as input (figure 1a). One of the products in the steps of extracting fault is the Fault Enhancement volume (figure 1b). This attribute uses a window defined by dip and number of vertical samples to emphasize the discontinuities on the filtered coherence cube, which is useful to the differentiation of areas with higher or lower incidence of fractures (Fractures in this topic are interpreted within a fractal connotation).

Vector Azimuth (figure 1c) is another attribute and represents the fault vectors extracted on each slice from the Fault Enhancement attribute. Planar clustering (figure 1d) helps to determine azimuth families and fractures orientation.

Two important statements are derived from the first approach: 1) Unconventional geometric attributes highly contribute to the definition of the structural framework for understanding orientation, geometry and fault network, reservoir compartmentalization and delineation of fractured zones. 2) Their contribution in a multi-attribute seismic pattern recognition and in a seismic fractures characterization study.

Multi-attribute Studies and Dimension Reduction of the Seismic Space (PCA)

The goal of the multi-attributes classification process is to describe the variability of seismic response, within an interval of interest, in order to reveal details of the reservoir geological characteristics. Low and high vertical variability attributes were selected to characterize the carbonate reservoir. Elastic seismic inversion products, complex trace, spectral decomposition and unconventional geometric attributes are combined in this approach to delimit geobodies, determine the structural complexity, reservoir quality and anisotropy directions.

A combination of seismic attributes and the subsequent data reduction (Principal Component Analysis) are used to apply for seismic pattern recognition, generating seismic facies maps and cubes. The results of the classification are validated against wells logs and can be used as trend to create probabilistic scenarios for facies distribution, determine anisotropy directions, lateral and vertical continuity, internal structures, interconnectivity.

The figure 2a shows the results of a principal component analysis on a constant interval 8ms above and 40ms below the top of the porous Albian reservoir. An analysis for map generation is performed from a combination of seismic attributes with a more geometrical focus: signal envelope, most negative curvature and Fault Enhanced. The principal component analysis suggests working with the first four components accounting for 86% of the accumulated inertia.

Figure 2b represents the first principal component, which has a contribution of approximately 40% for restituting the total information, captured by all the seismic attributes. It shows the continuity of the main faults, a chaotic response area in the south, and a contribution to define the size and continuity of carbonate bodies.

The result of the classification workflow, based on artificial neural network technology, is a seismic facies map. The map (figure 2c) displays a distinctive seismic pattern in the porous reservoir. Yellow and red facies in the north part delimit continuous bodies, while the southern regions, expected to have a higher incidence of fractures, are classified with blue facies. This different facies response is useful to explain the unequal behavior of production observed in the wells and define anisotropy directions for the variograms in the geologic model properties distribution.

Seismic Fracture Characterization Workflow

The results of the multi-attribute study revealed more structurally complex zones in the south of the Albian reservoir, compared to more continuous bodies northward.

Understanding the structural behavior of carbonate reservoirs as a fractal, a 3D seismic structural characterization workflow can be adapted to a seismic fracture characterization process. Fault Enhanced and Vector Azimuth attributes, generated in the filtering treatment of an Eigen-structured coherence cube, provide important information about the orientation of the fractures in the whole area, the fracture families identification (sets) and occurrence studies (zones of greater fracture intensity).

The Vector Azimuth analysis as point cloud (figure 3a), offers a higher faults occurrence detected below the top of the reservoir porous from Albian, this represents the entry of the carbonate section in the field. From the response of this attribute, it is possible to study the intensity and orientation of fracture families in the reservoir. The interpretation of the azimuth attribute histogram enables the separation of families in two azimuth orientation sets: 85º-120º and 120º-160º (figure 3b). A fracture intensity property for each azimuth family is generated with the relationship between the occurrence of discrete seismic attributes and the cells volume of the geological grid. Fracture main directions, intensity properties and aperture (obtained from core studies), represent important information for reducing uncertainties in the characterization of naturally fractured reservoir in this Campos Basin field.

Discrete Fracture Networks and Associated Properties

The fracture intensity properties calculated from seismic attributes enter in a fracture modeling workflow. The goal is to create a fracture model by calculating discrete fracture networks (DFN) and reservoir properties associated that can be exported to dual porosity/permeability flow simulators.

The DFNs are useful to evaluate the fractures impact on the reservoir model and production response. At the time of building a fractured reservoir model, it is important to know the fractures impact on the reservoir permeability and they may result in additional porosity. They also provide paths for fluid flow in a rock matrix with very low porosity. The contribution of the fracture network to the permeability behavior of the reservoir is determined by the geometry, which is defined by the spatial distribution of fractures orientation, sizes and apertures.

An important limitation of subsurface data is the lack of information about the fractures aspect. Orientation data are obtained from FMI logs, allowing the definition of fractures sets and azimuths. However, the fracture length is limited to the well diameter. The fracture aperture is also a difficult parameter to quantify because FMI logs and cores are not always available. Moreover, a significant uncertainty remains in the fracture network character as the distance from the well increases.

In this field, only one well in the fractured reservoir has core information for the fracture aperture measurement. From the available data, two DFNs were generated for each azimuth family and their combination produced fracture properties in the geological mesh. The DFNs orientation was estimated from the seismic analysis and was used a Fisher distribution with a dispersion k-parameter, a power law distribution for the fractures length and 2:1 aspect ratio between length and height. The figure 4a shows the DFNs superimposed on the geological model and the permeability tensors calculated from both directions, area, and fracture aperture that intersect each cells.

Finally, these properties were generated and evaluated in the grid: 1) fracture porosity calculated in each cell 2) 3D and 2D anisotropy, as function of the minimum and maximum values of permeability (figure 4b and 4c). All of them can be exported to the scaled model and will be the input in a dual porosity/permeability flow simulator.

Conclusions

The study of fractured reservoir remains a huge multidisciplinary challenge that runs from the seismic resolution for fracture detection, through the anisotropy characteristic of carbonate rocks until the evaluations in a dual porosity/permeability flow simulator. This study offers an easy-to-use methodology for this type of reservoir, which can be still improved.

It is proposed a generation of a seismic attribute workflow for noise suppression, reduction of structural uncertainties and parameterization for fracture models. Petrophysical properties from this fracture analysis, used as input for a dual- porosity /permeability model, could help for production prediction and history matching.

The next step would be the application of this methodology to other fractured fields, preferably with greater numbers of wells, cores and image logs and the possible incorporation in the simulation model of simple porosity.

Reference

Roberts, A., 2001. Curvature attributes and their application to 3D interpreted horizons: Technical article. First Break, 19.2.

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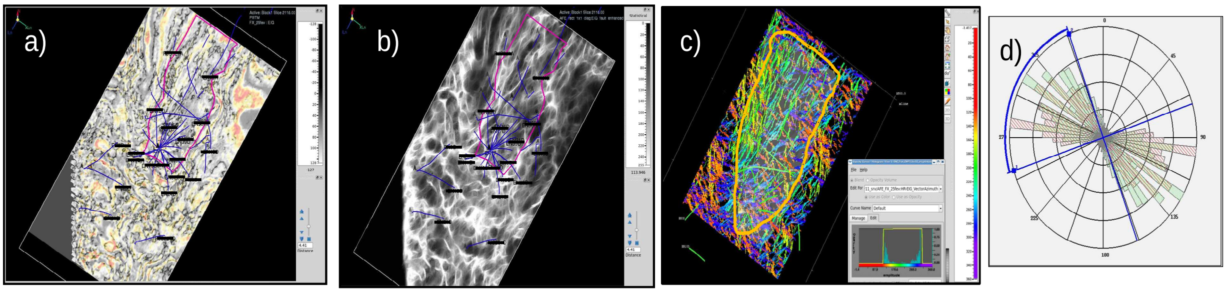
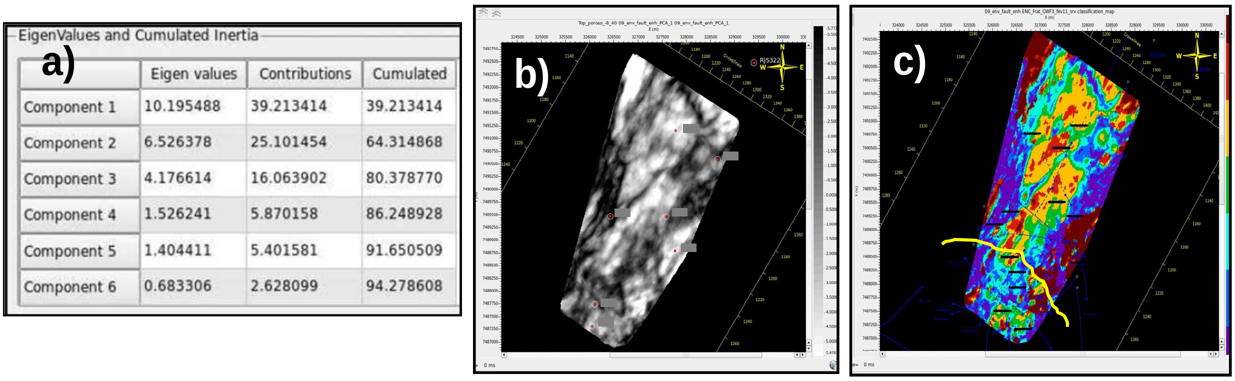


Figure 1: a) Eigen-structured coherence attribute. b) Fault Enhanced brick. c) Vector Azimuth brick and opacity. d) Rose diagram showing the two family sets.



EigenValues and Cumulated Inertia

	Eigen values	Contributions	Cumulated
Component 1	10.195488	39.213414	39.213414
Component 2	6.526378	25.101454	64.314868
Component 3	4.176614	16.063902	80.378770
Component 4	1.526241	5.870158	86.248928
Component 5	1.404411	5.401581	91.650509
Component 6	0.683306	2.628099	94.278608

Figure 2: a) PCA table results. b) First component map from the combination of signal envelope, Fault enhanced and most negative curvature. c) Facies classification map.

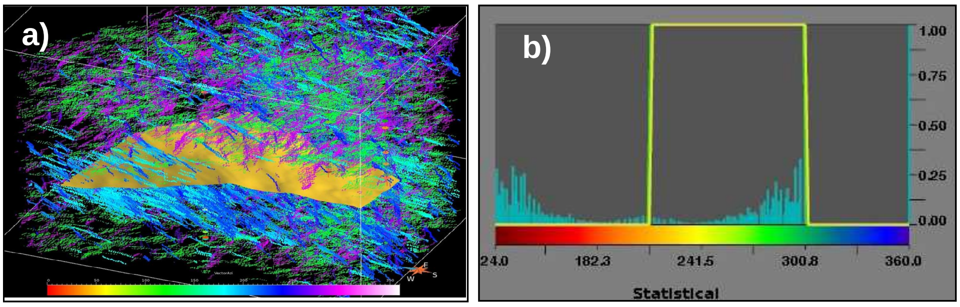


Figure 3: a) Vector azimuth attribute as points cloud. b) azimuth attribute histogram showing the separation of families in two azimuth orientation sets: 85º-120º and 120º-160º.

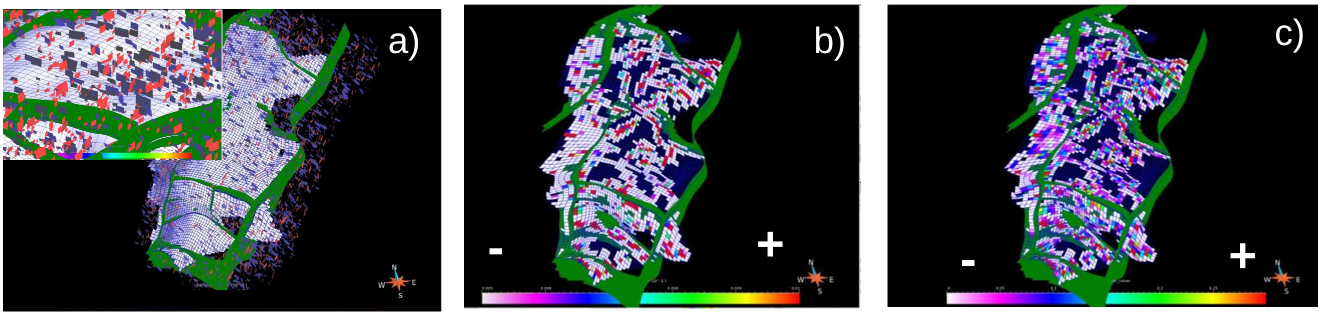


Figure 4: a) DFNs. b) Fracture porosity. c) Fracture permeability.