SBGf31299

Using old 2-D data with new technology for reservoir characterization

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Abstract

The 2-D geoinversion of land data is presented here as an application of new methodology to benefit of the available 2-D data in situations where one can´t count on 3-D data. This methodology is design to bring the seismic information close to the geology, enhance the amplitude spectrum as a whole accounting for improving seismic resolution and managing different sources of data. From the geological point of view, a knowledge of the depositional model is required in order to come up with a checking parameter for the characterization results. The integration of geological properties with seismic attributes counts on geostatistical tools.

Introduction

Reservoir characterization is increasingly gaining importance in helping the reservoir management and, therefore, the optimization of resources to develop a field. The new available tools have been used in order to achieve this target. In this sense, one can highlight the 3-D seismic acquisition as a minimum requirement today to get a properly image of the reservoir. But, how to deal with so many fields which remain being produced with the support of only 2-D data, by several reasons, such as economical, logistical? We propose a methodolgy here to address this subject.

Geological database

The log information and geological reports of 14 wells (Fig. 1) were used along with core descriptions of 6 wells. The geological integration leads to a interpretation of a deposition in an estuary environment filling an incised valley for the sandstone interval. The topography of the valley was controled by a previous compressional event which generated structures trending approximately N-S. A model (Fig. 2) combining the structural and stratigraphic controls using only well data can be built in order to provide a checking parameter for the characterization results. This model (Fig. 2) represents the incised valley paleotopography prior the transgression followed by the sandstone deposition.

Geophysical context: geoinversion applied to land data

The reservoir thickness in the area varies from 1 to 15 m. Even with the original good quality data available (band pass frequencies ranging from 10 to 40 hz) we are bellow the seismic resolution for the majority of the wells. In spite of that, besides the objective of bringing the seismic information close to the geology, broadening the spectrum will bring more confidence to the seismic interpretation specially for the sequence in which the sandstone is inserted.

The approach used in this paper is based on InterWell package (IFP-BEICIP/FRANLAB®). The model-based inversion improve the parametric inversion thecniques that have been developed since the early 80´s. The inversion theory parametric based was first proposed by Tarantola-Vallete (1982). The Tarantola´s *State of Information* theory has led to a new formulation of the Bayes Rule. The adaption of this theory to the seismic world was proposed by Lailly (*in* Johann, 1997) and by using known statistical distribution functions to the involved data ended to the objective function of geoinversion (Johann, 1997):

$$\mathrm{J}[I(x,t)] = [S_y(x,t) - S(x,t)]^2_{C_S^{-1}} + [I(x,t) - Ip(x,t)]^2_{C_{Ip}^{-1}} \qquad (1)$$

where,

$I(x,t)$ is the final target of this minimization, i.e., the Optimal Acoustic Impedance Model;

$I_p(x,t)$ is the *a priori* Acoustic Impedance Model which will come from well log;

$S(x,t)$ is the surface seismic amplitude information;

$S_y(x,t)$ is the synthetic seismic amplitude, i. e., the forward model and

C_s/C_{ip} are the uncertainties associated with the seismic and the acoustic impedance terms.

The forward model will be represented by the convolution of the reflectivity derived from I(x,t) obtained after each iteration with an integration operator. The flowchart to obtain this operator starts with a signal and noise spectrum estimation by trace-to-trace autocorrelation and crosscorrelation (Johann, 1997). The zero phase wavelet obtained to each 2-D seismic line in which a well is tied will be the input to the next phase (Rocha, 1998): the quantitative integration. Here, synthetics are built for each well, starting by its correspondent zero phase wavelet rotated by fixed angles convolved with the reflectivity series derived from the acoustic impedance curve. Each one of those tens of synthetics are correlated with seismic starting from the well position and moving away from it in both x and t domains. The best matches corresponds to a given rotation in degrees, a lateral translation in traces from the well position as well as a time shift. The first parameter to be considered is the phase rotation: the statistical analysis among all the wells indicated that a 50^0 phase rotation is the most representative for the area (Rocha, 1998). This fixed value is then reapplied in all the wells to search for the best positioning of the calibration. Now, one can choose among all the new operator generated

Sixth International Congress of the Brazilian Geophysical Society

the one that is the most statisticallly representative, based on its correlation coefficient obtained, the amount of shift, the amount of x,t shift, the amplitude spectrum and, mainly, the amplitude of the operator. The integration operator chosen was that for the P4 well (Fig. 1).

The next step is to derive an *a priori* impedance model. This will be done in two phases: first, key horizons are interpreted in each seismic line tied to wells. Then, seismostratigraphic surfaces are input into the model according to the expected stratigraphic relationships. These procedures generates the so called seismostratigraphic units (Johann, 1997). This means that both structural and stratigraphic settings are being taking into account while designing the model, from which comes the term *seismostratigraphic* for this kind of approach. Secondly, the acoustic impedance curves, now filtered out of frequencies over Nyquist (125 Hz) are repositioned in the best case quantitative calibration. Those curves are now propagated away from the this position according to the seismostratigraphic units defined previously, defining the *a priori* impedance model wanted. But how to deal with the seismic lines without any well calibrated on it? The solution adopted (Rocha, 1998) was to first invert all the lines with wells calibrated till the end and then, at each crossing of those lines with lines without wells derive a pseudo acoustic impedance curve and repeating all the calibration process with this newly obtained curve.

The inversion procedure can be then kicked off having the three basic ingredients to do so: the surface seismic, the *a priori* impedance model and the integration operator. The last parameters to be adressed (equation 1) are now the uncertainties associated to the seismic and impedance. They will come as a signal/noise for the seismic, estimated previously and uncertainties in the values and positioning in time of the *a priori* impedance model (Duijndam, 1988). By chossing properly those parameters one can balance the participation of the surface seismic and/or the *a priori* impedance model in the inversion. The first target, i.e., bringing the seismic information close to the geology, seemed to be acchieved, at least in qualitative stands, as it can be seen in the Optimal Acoustic Impedance Model (Fig. 3). The uniqueness is guaranteed by the acoustic impedance term but represent at the same time all the assumptions made (Duijndam, 1988): a) the so called observational errors related to all experimental results, such as the surface seismic itself, the interpretation that have been carried out during the process and the uncertainties estimate and b) the theoretical errors: all the basic assumptions in the theory, such as the use only of an acoustic approach to the forward model, the use of selected density curves to represent the a priori and the forward model, the fact of not taking into account multiples, coherent noise and other restrictions related to the main scope of the theory (tarantola, 1987).

The second objective, the specrtrum broadening (Fig. 4). Almost one additional octave was acchieved, from the surface seismic to the reflection coefficient sections (derivative of acoustic impedance). By increasing the relative amplitudes seismic bandpass, one can now interpret the key horizons more confortably. The attribute used can be the Optimal Acoustic Impedance section or its derivative reflection coefficients section. Considering the use of the second one and based on the fact that for the big majority of the wells the seismic resolution related to trough and peaks for the sandstone interval is not yet possible, one have to address the issue in a proper way: as showed by Widess (1973) a bed whose thickness is below 3λ/8 presents phase and amplitude distortions in its related response, making that the correct top and bottom picking will no longer correspond to traditional troughs and peaks. So, why not interpreting the shape of the signal by considering additional surfaces in between those peaks, troughs and zero-crossings? This work (Rocha, 1998) showed that this is an objective perfectly feasible, provide an enough well control is present. The main goal of that is a carefull tying by means of the synthetic built from the reflector coefficients section band pass.

And which seismic attributes to use? The literature and the practical basis has been shown that whenever the interpreter is not sure of which he/she wants, a huge number of seismic attributes is derived and some of them do have correlations with the reservoir properties but lacking any physical meaning (Hirsche, 1997). What do you want to characterize? Is it thickness? Well, is there any other direct seismic attribute to use than the correspondent time thickness? But, as some risk was involved in the seismic interpretation based on trace shape, it is also wise to think on other options. But, one can use the old Widess (1973) statement, by taking, the reflection coefficient of the sandstone base as a indication of thickness. An what about the sandstone porosity? Porosity variation affects directly the rock impedance. For that reason, the average sandstone impedance taken from the optimal models can be used. But, instead, the same reflection coefficient of the base of sandstone will be a valuable information about reservoir porosity. Porefoot will then be intimally related with the reflection coefficient of the base of sandstone. We think the recipe is: keep on as easy as possible always having in mind the required physical relationship between seismic attributes and reservoir properties to be characterized with the help of the first. Of course, one shall address at least to zero lag scatterplots to check if the correlations are good enough, in the case the number of wells don´t permit a complete structural analysis (variograms, crossvariograms, etc). The zero lag scatter plots shall account also to take the seismic information from the trace with better correlation with the synthetics (Rocha, 1998).

The external drift kriging can then be used to estimate reservoir properties from the seismic attributes. As we are working with 2-D data, the way we procceded was first to generate a regular grid of the seismic attribute by an ordinary kriging, after of course fitting a model for each experimental variogram. Then, using this newly image as a background variable to the external drift kriging with the seismic variogram model. This is the only model available in this such reduced number of wells and its use is fully supported by the strong physical relationship between the variables, meaning similar structural distribution. Taking the reservoir thickness as an example it can be said that the two images obtained are very similar in shape or while considering their correlograms/crosscorrelograms, validating both methods of obtaining this propertie (Rocha, 1998). Also, there is a good degree of similarity between the model obtained exclusively from wells (Fig. 2) and the seismic based model, except for the high frequency introduced by the seismic (Fig. 5). There, on can see the incised valley talvegue trending SW-NE with perpendicular ramifications, as well as the structural control prior to the erosion represented by the N-S structures.

Conclusions

The sucessful of the use of old land 2-D seismic data to characterize a thin bed reservoir with seismic 2-D geoinversion and high-resolution stratigraphic concepts provides a cost-effective approach to solve some challenges in situations where one can´t count on 3-D seismic data. In particular, we provide the characterization of the incised valley talvegue trending SW-NE and the structural control represented by the N-S structures.

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Acknowledgements

We wish to thank PETROBRAS and BRASPETRO for permission to publish this paper.

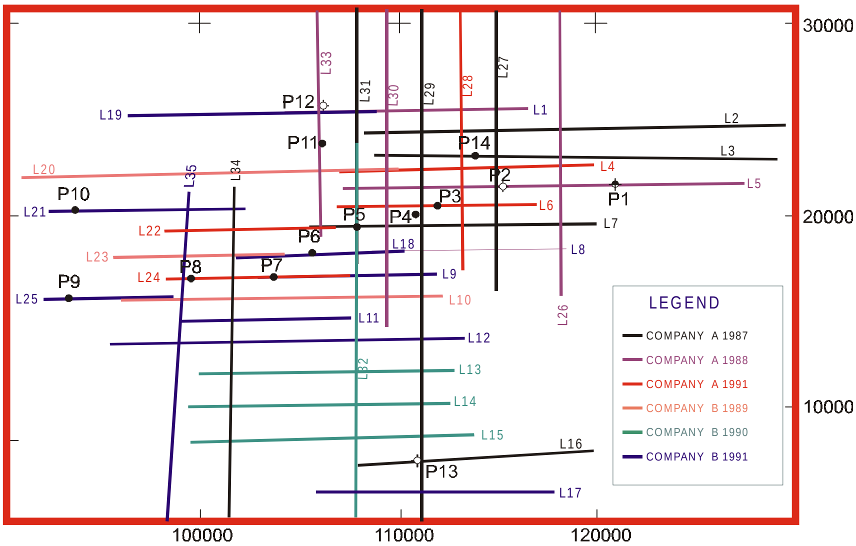

Fig. 1- Well and seismic base map.

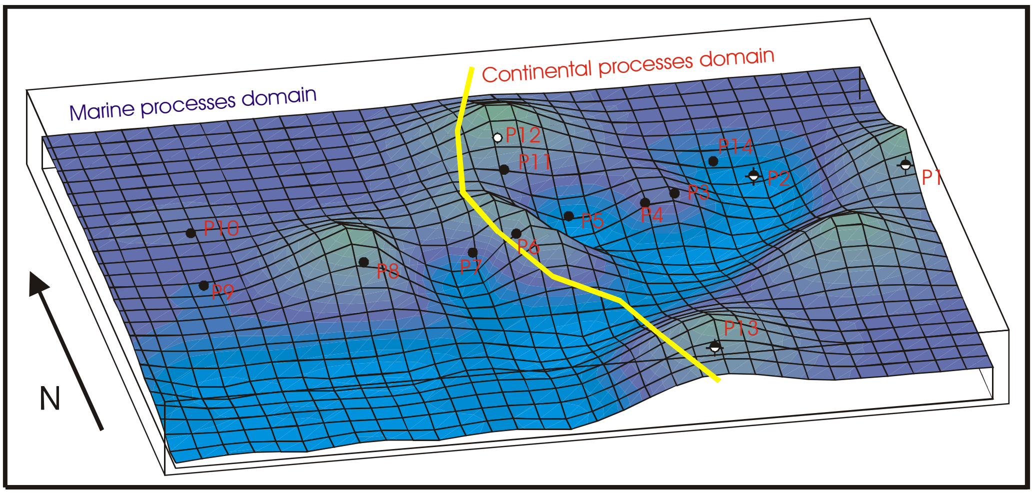

Fig. 2 – Incised valley paleotopography prior to sandstone deposition – based on wells.

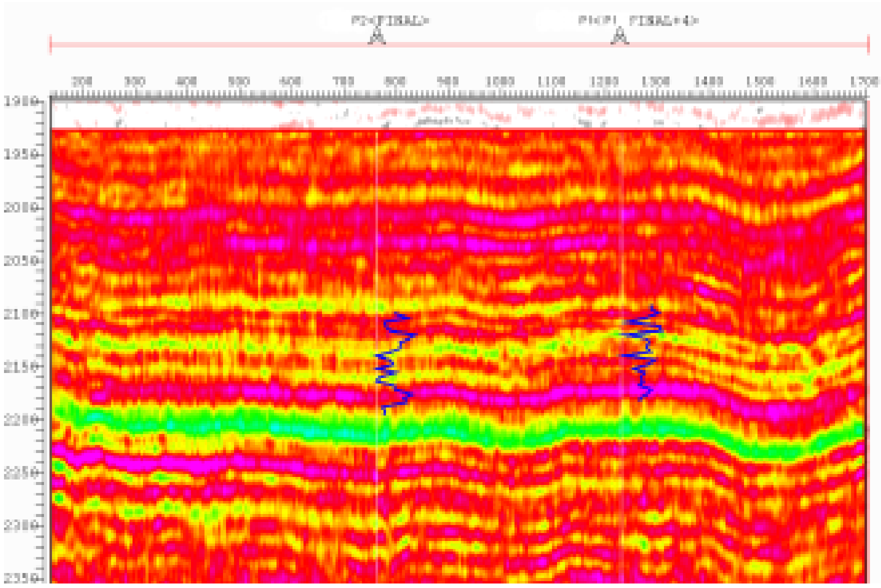

Fig. 3 - Optimal Acoustic Impedance Model.

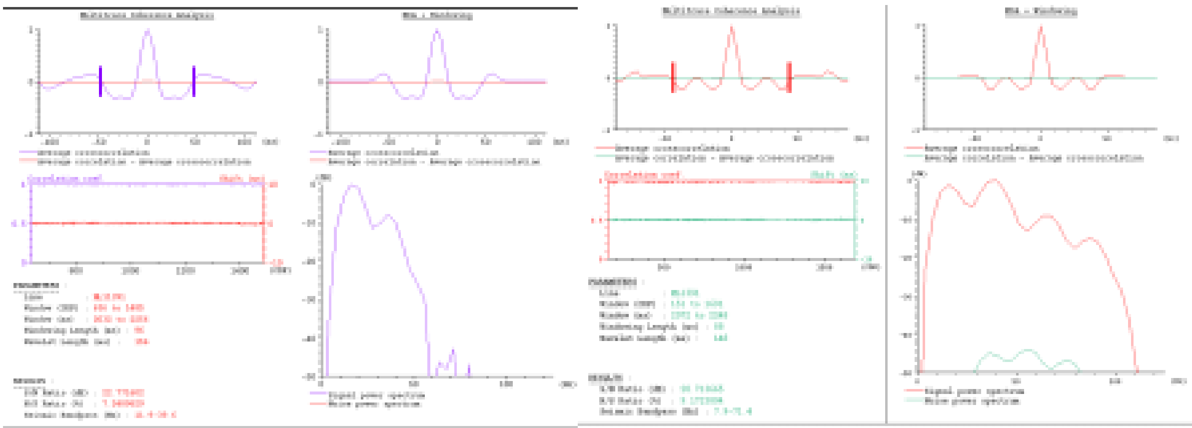

Fig. 4 – Amplitude spectrum, surface seismic (left), coefficient reflection section (right).

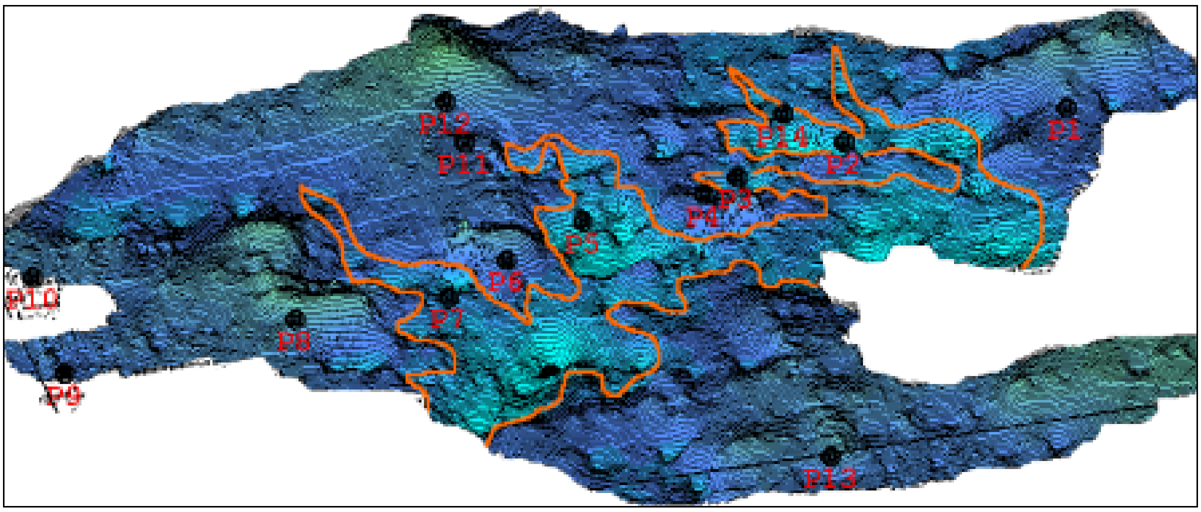

Fig. 5 - Incised valley paleotopography prior to sandstone deposition based on wells + seismic