SEISMIC MODELING AND BASIN MODELING – COMPLEMENTARY TOOLS

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Introduction

Physical processes that takes place in basin evolution can be simulated in basin modeling or basin simulator software. Indeed the software solves heat transfer and fluid flow differential equations whose input parameters are: model geometry (layer geometries) and properties (compaction curve, porosity-permeability relation, heat capacity, thermal conductivity, capillary pressure etc.), followed by boundary conditions definition. The outputs of the simulator, among other results, are rock properties and fluid contents. Calculated properties should be cross-checked with known real properties from wells in order to validate the simulation. As the difference between real values and calculated ones get smaller, the more accurate the interpretation is.

The objective of this work is to propose a procedure on applying seismic modeling with basin simulator outputs in order to cross-check synthetic seismics with the real one. Interpretation revision aims to minimize differences from real and synthetic seismic. In order to illustrate the suggested procedure, basin model outputs from an onshore basin were used to estimate P velocity field in a small region. After that, a 2D acoustic seismic model was performed and the obtained synthetic seismogram was compared to the real seismic section on the same location.

Basin modeling was built and run in Petromod IES package. Synthetic seismograms were calculated with an acoustic model routine - developed in Petrobras Research Center (CENPES), which solves acoustic wave equation through the finite difference method with a second order approximation. Synthetic seismic section (figure 3) was made with ximage resource of Seismic Unix package.

Methodology

The suggested workflow embodying data integration, basin modeling and seismic modeling is illustrated in figure 2. Indeed it is a continuous process aiming to minimize the error among real and calculated (or modeled) parameters (Santos et al., 2003). The steps are as follows: 1) Data acquisition. Geophysical and geological data mainly from seismic surveys, well logs and cores; 2) Data interpretation embodying well log correlations, seismic interpretation, seismic and well correlation and building of geological model. During this step the comprehension about the petroleum system begins; 3) Run basin simulator with estimated lithologies properties; 4) Export of properties files according to the chosen method to estimate P velocity: Among calculated properties, for instance porosity, permeability, density, fluid saturation, fluid density etc., we have to choose the most suitable ones to estimate P velocity (Willie, modified Willie, Gardner etc.). Indeed, from Petromod-IES, we can export files containing the top or bottom of a layer and its corresponding property; 5) Choice of suitable mesh dimension for finite difference grid; 6) Top or bottom surface interpolation: as basin modeling mesh is coarser than the one in the seismic model, we should interpolate the surfaces; 7) Apply the method to estimate P velocity corresponding to each layer; 8) Fill the interval between each surface with the proper P velocity; 9) Run acoustic seismic model: with the estimated velocity field we perform an acoustic seismic model firstly shooting all the sources together –a zero-offset survey; 10) Compare synthetic and real seismic on common locations; 11) Review model interpretation until synthetic and real seismic converge: in practice, as we are dealing with an extremely coarse basin model grid and a highly noisy seismic, it is not possible to reach compatibility of real and calculated amplitudes. Indeed, nowadays we should aim structural compatibility.

Geological model

Data integration and interpretation of the study area have shown fifteen sequences individualized as layers during geological model building in the Petromod program. From those fifteen layers, only six are found in the region selected to perform seismic modeling – Figure 1.

Layer 1 is represented by alluvial fans and fluvial deposits mainly composed by conglomerates and coarse sandstones, sometimes unconsolidated. They were deposited from 3,0 million years to the present. Layer 2, a continental sequence, mainly represented by mudstones with minor sandstones, was deposited from 14,8 million years to 5,3 million years, and it was eroded from 5,3 to 4,0 million years. There is, then, a paraconformity between layer 1 and layer 2.Layer 3 is also a continental sequence, but coarser than layer 2. It was deposited from 16,4 to 14,8 million years with no evident erosion period. Layer 4 is a continental sequence composed of equal amounts of shaly and sandstones deposited from 37,0 to 18,0 million years. From 18,0 to 16,4 million years erosion took place removing layer 4 and even older layers. In the study area (figure 1) such erosion removed part of layer 4 and layer 5 and it represents a regional unconformity (green line in figure 1). Layer 5 is a Cretaceous sequence composed of marine carbonatic and clastic sediments deposited from 105,0 to 83,0 million years. Layer 6 is a clastic sequence mainly composed by near shore sandstones, fluvial sandstones and minor shales deposited between 124,0 and 105,0 million years.

The section selected to perform this study exhibits gentle structures. Over the unconformity (green line in figure 1) layers are almost parallel and horizontal. Below the cited unconformity, layers are gently folded (figure 1).

Seismic modeling

After running basin simulation, was extracted a 2D section (figure 1) that coincides with a 2D seismic line (figure 4). Over the 2D section containing model properties, a 2D acoustic seismic simulation was performed.

ASCII files containing the top and average density of each layer (1, 2, 3, 4, 5, 6 respectively 2171,37 kg/m3, 2381,28 kg/m3, 2485,54 kg/m^3, 2568,91 , 2610,65 kg/m^3 and 2617,23 kg/m^3) was exported from Petromod and re-sampled from a 750m grid spacing to 3m. Then Gardner Equation ($V = (\rho / G)^4$, with G (Gardner constant) equal to 0,3365) (Gardner et al, 1974), was applied to estimate P velocity (1, 2, 3, 4, 5, 6 respectively 1733,78 m/s, 2507,87 m/s, 2976,74 m/s, 3396,66 m/s, 3622,87 m/s and 3659,51 m/s). Acoustic model was performed by shooting all sources together on model top. The following acquisition parameters were used: the source is the second derivative of Gaussian wavelet (Cunha, 1997); maximum frequency of 60 Hz.

Steps 10 and 11 cited in the methodology topic are discussed below.

Synthetic results and comparison with real seismic

The synthetic seismogram has shown 12 events – figure 3. Event **a** represents the contact between layer 1 and layer 2. In the real seismic section (figure 4) that contact is at any time between 0,0 and 0,4 seconds, where the traces are muted during the seismic line processing. As it was initially reported in the geological model topic, layer 1 contains unconsolidated fluvial deposits, a characteristic that imposes low velocity. Differing from layer 1, layer 2 was deposited (from 14,8 to 5,3 million years), consolidated, compacted and eroded (from 5,3 to 4,0 million years). Compaction is not exactly elastic, therefore, the porosity of layer 2 was not completely recovered after sedimentary pile removing from above. As a consequence, layer 2 has lower porosities and higher P velocities than it would have in such level - immediately under a paraconformity. As the velocity contrast between both layers is very high (layer 1 with 1733,78 m/s; layer 2 with 2507,87 m/s), short period multiples were formed. Such multiples correspond to events **a1** to **a6** that appear under the other contacts. It suggests that the quantity of events between 0,5 s and 1,8 s in figure 4 (real seismic section) is not only due to geologic characteristics of the medium, but also to the high impedance contrast between shallower layers which caused short period multiples superimposed along the section.

Event **b** marks the contact between layer 2 and layer 3. In the synthetic seismic, reflector **b** appears near time 0,8s. In the real seismic, event **b** stays in the interval between 0,5 and 1,8s which is rich in horizontal events - most of them short period multiples. It was not possible to point out which event or group of events represent reflector **b**.

In the synthetic seismogram (figure 3) event **c**, the angular unconformity, occurs near time 1,45 s. In figure 4, such event appears near time 1,86 s which shows an error in P velocity estimation. The empirical Gardner formula, in this case, could not be a good velocity estimator. Alternative ways to estimate velocities embodies the use of other methods or the use of Gardner's formula with another constant (other than 0,3365). As layers 1, 2 and 3 are horizontal, layer thicknesses are known, and two way time of event **c** in real seismic is also known, 1,86 s, the suitable constant that puts event **c** on correct time is 0,359.

Event **d** in figure 3, represents the diffraction caused by the corner formed by layers 3, 4 and 5 on both sides of the model. It is not, as it could be misinterpreted, the contact between the dipping flanks of layers 4 and 5. The almost horizontal contact of layers 4 and 5 is represented by event **e** on both sides of the synthetic seismogram.

Events **f** are undesired edge effect caused by the first and last source diffractions on each side of the section. To avoid events **f**, the shot line should extrapolate the interest area.

Small diffractions along event **a** are caused by little corners in the contact between layers 1 and 2, and by its extremely high velocity contrast. If the section were migrated those diffractions and event **d** would disappear.

Conclusion

In this job, synthetic seismogram has shown that most of the shallow events in real seismic are multiples caused not by layer 2 properties but the high velocity contrast of layer 1 and 2 due to paraconformity.

In this work Gardner's formula was chosen to calculate velocity, but it would work better if we use suitable constant G (equation 1) for study area. The constant G that provides the best fit between synthetic and real seismic is 0,359.

Finally, it is clear that real seismic is much richer in events than synthetic one. Nowadays, basin simulation demands an up-scaling level, due to computer limitations, that reduces the details of geological media. Each layer in a basin model is an entity whose properties are averages of many other small layers. Indeed, in that process, we are applying a low pass filter over the reflectivity function. It is, indeed, the main cause that synthetic seismogram is poorer in events when compared to real ones. As computational resources increase and geologic details are incorporated in basin models, it will be possible to obtain synthetic seismograms closer and closer to real ones.

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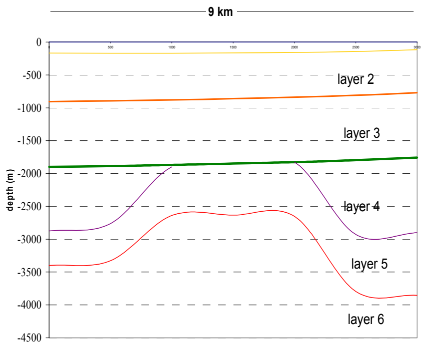

Figure 1: Geological model used to simulate acoustic modeling. Layer 1 is between the blue line and yellow line.

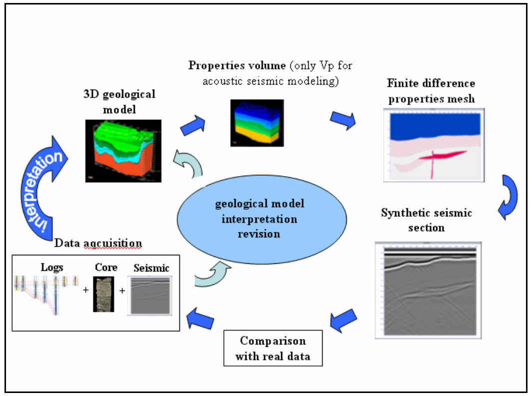

Figure 2: Modeling workflow in exploration cycle.

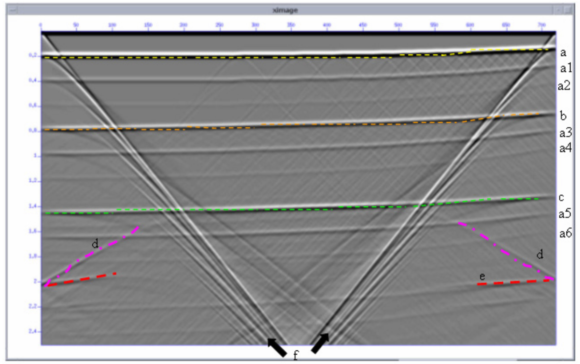

Figure 3: Synthetic seismogram of the model shown in figure 1. Event a corresponds to the contact between layer 1 and layer 2. Events ai (a1 to a6) are short period multiples caused by the high velocity contrast between layer 1 and layer 2 (layer 1 with 1733,78 m/s; layer 2 with 2507,87 m/s). Event b represents the contact between layer 2 and layer 3. Event c corresponds to the unconformity. Events d correspond to diffraction caused by the triple point corner formed by layers 3, 4 and 5 on both sides of the model. Event e corresponds to the almost horizontal contact between layers 4 and 5. Events f are undesired edge effect caused by the first and last source on each side of the section. To avoid events f we need to shoot the source line extrapolating the interest area.

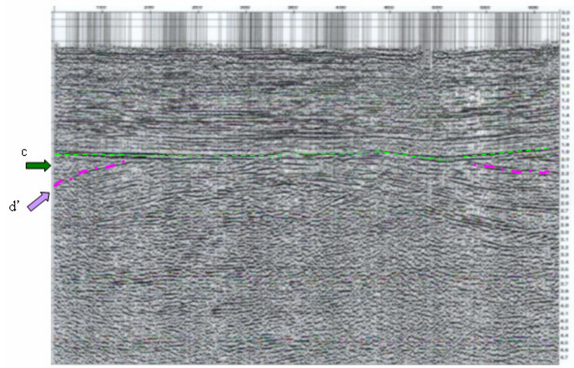

Figure 4: Seismic section of the modeled area. Only events c, the unconformity, and d’, the flank of layer 4 and 5 contact, are exposed.