Time-Lapse Feasibility Analysis for a Brazilian Offshore Field: Target on Saturation and Pressure Changes Interpretation

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Abstract

Time-lapse feasibility study is not only the first step to validate a 4D campaign; it is also an essential tool for the interpretation of the acquired seismic volumes. In this paper we present a practical example of feasibility study for a Brazilian offshore reservoir to illustrate the main issues and benefits of feasibility analysis. Our goal is to emphasize which information may be accessed with the feasibility analysis, as well as the uncertainties and non-uniqueness in time-lapse feasibility and interpretation.

Introduction

Any seismic interpretation is subjected to uncertainties and may be questionable at some extend. Particularly, time-lapse interpretation is a highly non-unique process, and must be guided by rock physics and seismic modeling. The feasibility analysis, usually done to give a technical validation for a time-lapse seismic survey, is crucial for a consistent interpretation of the different vintages of seismic data. Reservoir simulator output may also be integrated with rock physics relations and seismic modeling tools to aid on time-lapse feasibility and interpretation studies.

The first step on feasibility analysis relies on available core data, which ideally may include not only measurements of elastic properties on rock samples, but also on fluid samples. The models based on cores may be classified as a "0-D" modeling. Then, usually in parallel, the next step is to construct some synthetic seismic in one and "one and a half" dimensions, that is, both acoustic seismograms as AVO synthetics. Two and three dimensional synthetic seismic modeling are natural evolutions of the feasibility analysis.

Although there are some commercial software to integrate reservoir simulator output to seismic rock properties, Petrobras developed proprietary software that enable the translation from reservoir geo-engineering information's to seismic properties and synthetics. The purpose is not to compete with other software's, but to have a tool oriented to our needs and our beliefs. For instance, the parameterization of the elastic behavior of a reservoir may be done in a number of different manners; each one will have its assets and drawbacks. With a proprietary and flexible "translator", we can access the impact of each formulation and assumption on our analysis.

Usually, Gassmann relations are used to estimate saturation changes effects. This requires the inputs of fluid and rock elastic properties. The reservoir pressure variation may affect fluid properties as well as rock frame elastic parameters. This pressure behavior of the rock may be accessed though laboratory measurements.

Single phase fluid properties can be estimated with the relations published by Batzle and Wang (1992) or with the recent refinements by Han and Batzle, developed on their DHI Project, at Houston University and Colorado School of Mines. The mixing of fluids is a matter of discussion. It can be done through Wood's equation, for a uniform fluid mixing. In the case of patchy saturation, one may consider that the fluid modulus value will lie somewhere in between the uniform and the completely patchy predictions (Cadoret *et al*., 1993; Mavko and Mukerji, 1998). Brie (1995) had proposed an empirical formula to estimate the bulk modulus of fluid mixtures with and additional parameter. We had verified that the Brie approximation can violate the Voigt and Reuss bounds under certain conditions, so it may bring physically incorrect estimations.

The construction of synthetics under various possible (and even unusual) scenarios can help in a better qualitative or even semi-quantitative time-lapse interpretation. In fact, some authors refer to quantitative time-lapse analysis, but it may be a too ambitious noun for these studies, since there are too much uncertainties involved in each step we make on this field.

In this article we describe some of our efforts on the feasibility analysis for seismic monitoring on a Brazilian offshore field. In spite of the sand quality, that is very sensitive to fluid replacement, this reservoir presents some issues to 4D seismic. Particularly, its reduced thickness and the relatively low API of reservoir oil. Our emphasis is on pressure and saturation changes effects on the seismic behavior of the sands.

Feasibility Based on Core Measurements

One important issue on pressure and saturation inversion of time-lapse data lies on the intrinsic coupling between the effects of these two parameters on the elastic behavior of rocks. For instance, as pore pressure increases, the modulus of the saturating fluid may increase, but the rock frame bulk modulus may decrease. If water is injected on a reservoir, the increase in water saturation may cause an increase in velocity, but if this injection causes a substantial increase in pore pressure, the velocity may even decrease, depending on the amount of saturation and pore pressure changes. The pressure sensitivity of rocks is being discussed by several authors (e.g., MacBeth, 2004; Vasquez *et al*., 2005), and may be accessed though laboratory measurements.

We had a data set with velocity and petrophysical information involving 69 samples from the target field. Although these data was collected for other purposes, it was very useful to our study. We observed a clear correlation between the bulk and shear moduli of the dry reservoir rocks with pressure and porosity. In figure 1 the data for bulk modulus as a function of pressure and porosity is shown along with a surface that represents the regression obtained, of the type:

$$K_{dry} = (a_K + a_{Kf}\, f) + (b_K + b_{Kf}\, f)\, ln(P)$$

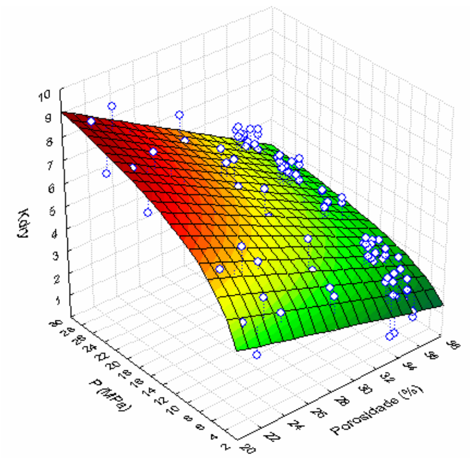

Figure 1 – Behavior of the reservoir samples with pressure and porosity variation.

where K_{dry} is the dry rock bulk modulus, f the porosity, P the pressure and a and b the regression parameters.

We had observed also that the velocities and impedances of the samples do present good correlation with the water saturation. The most accurate and simultaneously simplest relation obtained between elastic properties and water saturation was a second degree polynomial function, in the case of homogeneous distributed fluid saturation. For increasingly patchy distributions this function approaches a simple linear form.

These second degree polynomial functions are exemplified for a single reservoir sample on figure 2. It is shown the acoustic impedance, shear impedance and Poisson's ratio at four different effective pressures. In fact, the shear impedance is rather a linear function of water saturation. We note also that the pressure behavior of Poisson's ratio is opposite of that of the acoustic impedance: while the acoustic impedance decreases with increasing pressure for constant water saturation, the Poisson's ratio increases. The lines on these figures represent the obtained regressions of the elastic property as a function of water saturation.

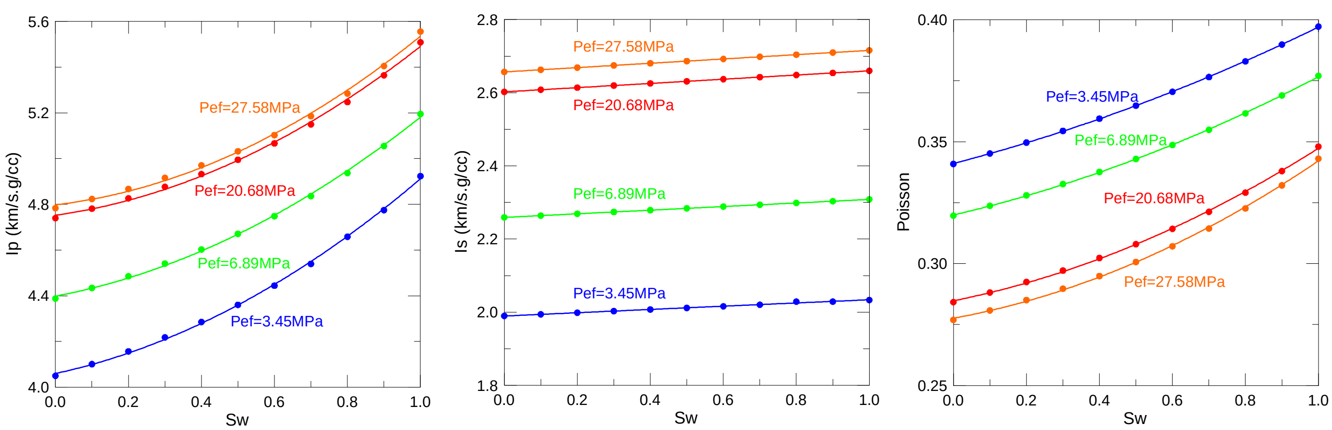

Figure 2 – Example of single variable regression for acoustic and shear impedances and Poisson's ratio of a particular rock sample as a function of water saturation at different effective pressures. The solid lines represents the polynomial functions of the properties with water saturation.

We were able to include the pressure dependence of the elastic properties simultaneously with the saturation influence by combining the polynomial function of saturation with a logarithm function of pressure. Figures 3 and 4 represent this kind of function for the acoustic impedance and for the Poisson's ratio of another particular sample from the target field.

All samples exhibit regression coefficients higher than 0.96 when we adjust the pressure-saturation dependence of the elastic property by a function of the form:

$$\text{Property} = \text{a} + \text{b}\, ln(P) + \text{c}\, S_W + \text{d}\, S_W^2$$

where S_W is the water saturation, P the pressure and Property may be acoustic impedance, Poisson's ratio, velocity, etc. For the shear impedance and velocity the function is simply linear on water saturation. Figure 5 shows the predicted versus observed values of the acoustic impedance for a rock sample with the 95% confidence limit ellipse.

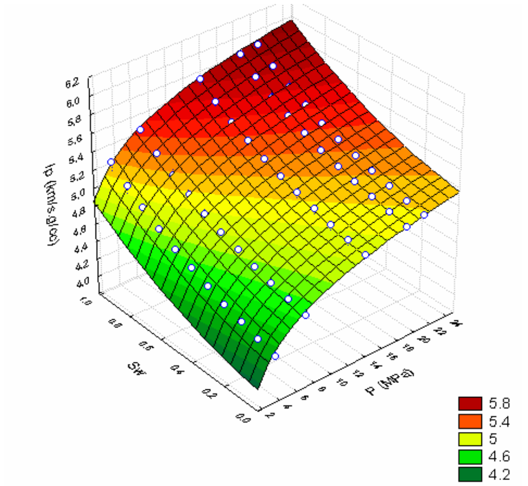

Figure 3 – Acoustic impedance of a particular sample as a function of water saturation and pressure.

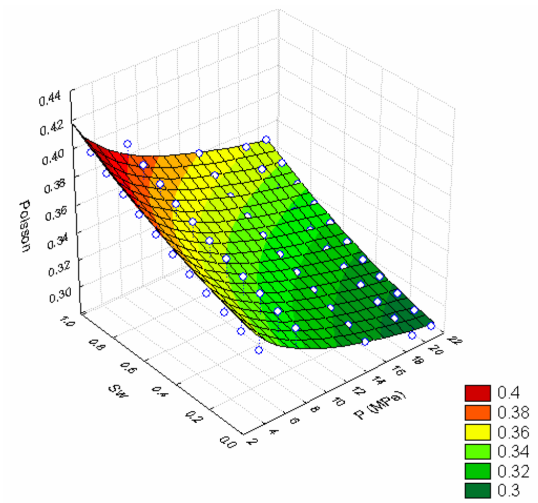

Figure 4 – Poisson ratio of a particular sample as a function of water saturation and pressure.

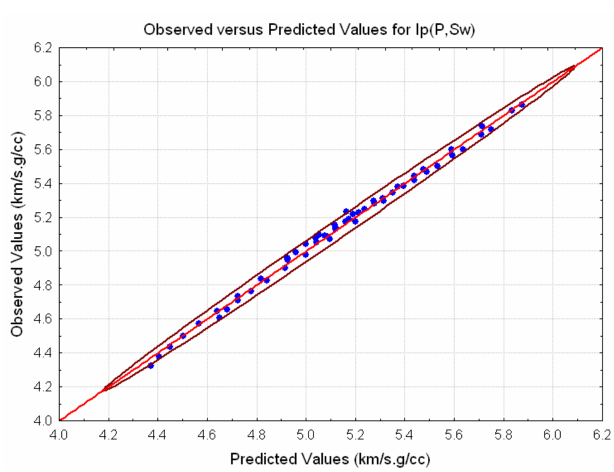

Figure 5 – Observed versus predicted values for the acoustic impedance of a rock sample with the 95% confidence limit ellipse.

For the data set as a whole, we had obtained relations between the elastic properties, porosity f, pressure P and water saturation S_W of the form:

$$\text{Property} = a + b\ f + (a_P + b_P\ f) \times ln(P) + \ c \times S_W + d \times S_W^2\ ;$$

where Property may be any elastic property of the reservoir. As one example, the relations obtained for I_P and I_S were:

$$I_P = 7.80 - 12.27\,f + (0.70 - 1.10\,f)\,ln(P) + \\ + 0.27\,S_W + 0.52\,S_W^2$$

and

$$I_S = 3.80 - 6.77\,f + (0.70 - 1.14\,f)\,ln(P) + \ 0.05\,S_W$$

With these laws for the elastic properties we can map the pressure and saturation changes in terms of elastic properties or vice-versa. As can be noted, we must have at least two elastic properties for decouple the pressure and saturation effects. We may also write the variation of elastic properties in terms of variations of pressure and water saturation thought partial derivatives.

One of the main issues regarding these analysis based on core samples is if the samples are representative of the reservoir properties or not. Usually, feasibility based on cores is slightly pessimist when compared to well log analysis, maybe due to the bias on sample recovering. In the case of unconsolidated reservoir, we may recover only the more competent rocks. Other important issue refers to the scaling.

Time Lapse Modeling for Different Scenarios

Based on well and sample information, we made a series of simulations of different scenarios to get insights on the possible acoustic and AVO (Amplitude versus Offset) behavior variation due to the production. Figure 6 shows an example of the variation of AVO response due to water saturation as the pressure is held constant at 18.62MPa, while figure 7 shows the variation of reflection coefficient as the pressure changes and the water saturation is maintained at 20%.

We had noticed that, for very large pressure variations, the AVO behavior may deviate from the linearity on $\sin^2\theta$ and also that we may have, in some cases, the dimming of amplitudes with angle due to the reduction of the sand Poisson's ratio.

Figure 8 shows the reflection coefficient as a function of angle for two possible scenarios, and table 1 lists the AVO attributes intercept A and gradient B for these four situations. It can be noticed that the pressure and saturation changing simultaneously may lead to a kind of puzzle, were its effects compete both on zero offset as on far offsets or AVO gradient. The maximum changes in AVO gradient and intercept for this particular simulation are about 22%.

Although these reflection coefficient modeling are useful, it is far away for completeness. It is necessary, also, to access information about seismic resolution. A series of synthetic seismic modeling was done, considering both water saturation changes and pressure variation. Figure 9 illustrates an example of AVO synthetic modeling for a particular well.

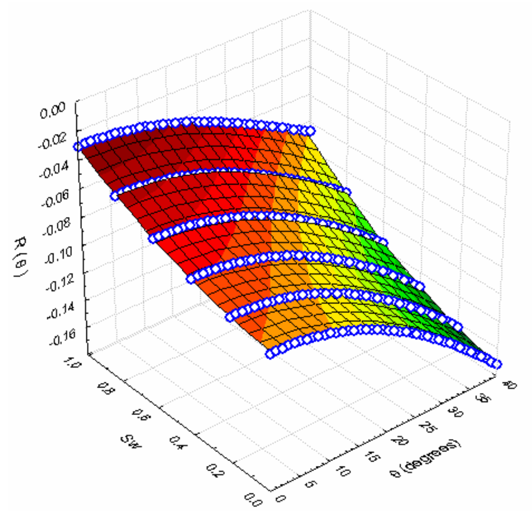

Figure 6 – Variation of the reflection coefficient with angle and water saturation for constant reservoir pressure of 18.62MPa.

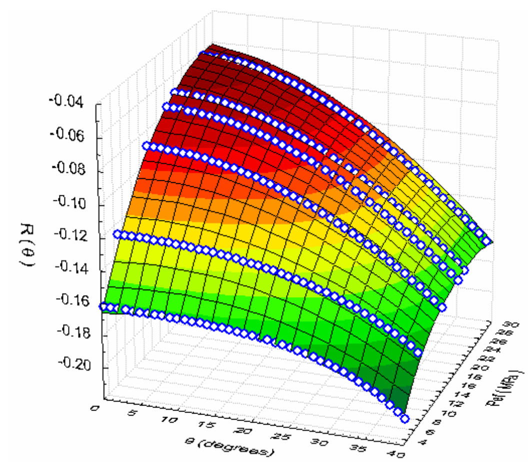

Figure 7 – Reflection coefficient variation with angle as pressure changes.

Table 1 – Two term AVO approximation parameters A and B (intercept and gradient) for a hypothetical situation.

S_W (%), P(MPa)	A	B
20, 13.8	- 0.089	- 0.180
20, 18.6	- 0.076	- 0.205
60, 13.8	- 0.071	- 0.159
60, 18.6	- 0.059	- 0.184

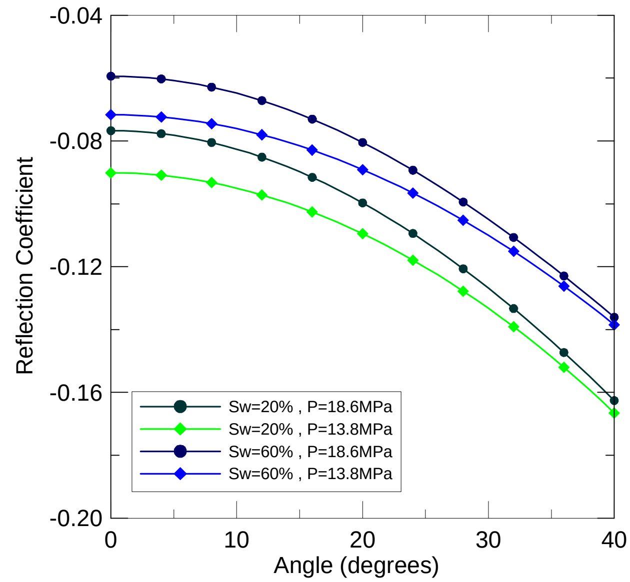

Figure 8 – A simple modeling example of the reflection coefficients for different water saturation and pressure.

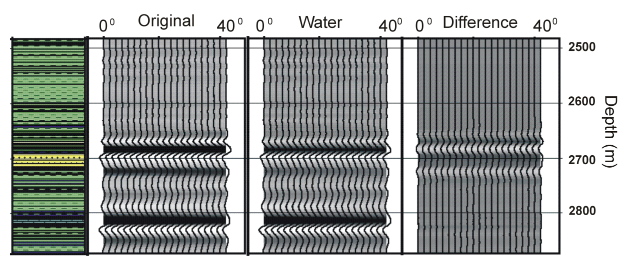

Figure 9 – Model of AVO changes due to water saturation increase.

One important issue regarding the target field is related to the seismic resolution. The reservoir thickness may be somewhere between few meters up to 35 or 40 meters. Since a large area of the reservoir is composed of low thickness sands, one question may arise regarding the influence of tuning effects on the time-lapse differences.

To maintain reservoir and cap rock properties and vary reservoir thickness with a realistic model, we took an actual well and had “cut” and “append” reservoir sections with the real elastic logs, and then “constructed” our typical well for reservoir thickness from 5 up to 45 meters. Also, we used fluid substitution to change the water saturation from real reservoir saturation (about 20%) up to 100%. The combination of tuning and water saturation variation introduces peculiar features on the seismic signature. In figure 10 is shown some difference traces for water saturations of 80, 60 and 40% related to the original synthetic trace. On figure 11 we plot the amplitude difference for the top of reservoir for different thickness and water saturations. The amplitude versus thickness curves resembles the classic tuning curve but, as water saturation decreases, the curve seems smoothed and distorted. The wavelet used on these simulations was a Ricker zero phase pulse with central frequency of 30Hz.

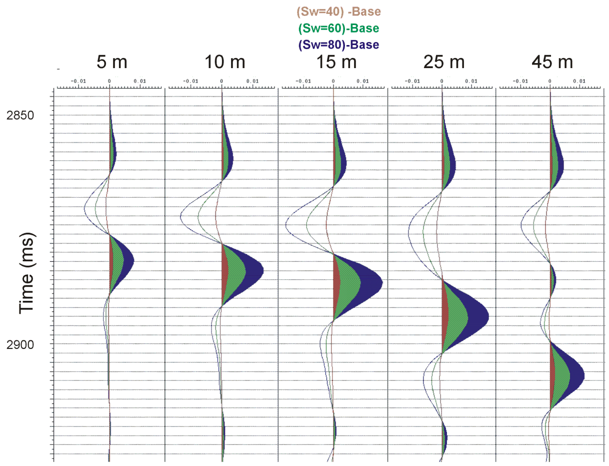

Figure 10 – Synthetic difference traces for different reservoir thickness and different water saturations. Brown, green and blue traces refers to the differences between 40%, 60% and 80% water saturation and in situ synthethic trace.

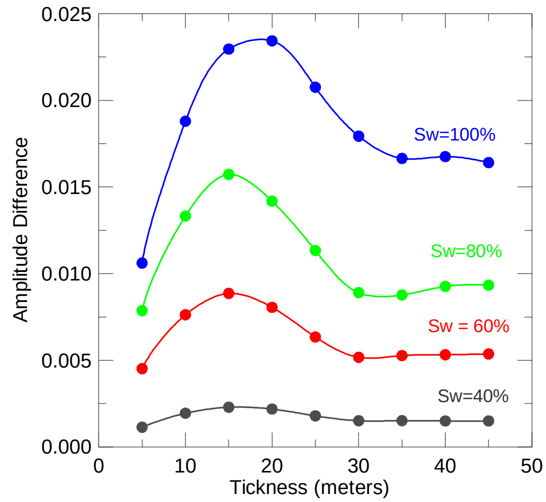

Figure 11– Top reservoir amplitude difference as a function of reservoir tickness for different water saturations (Base water saturation is 20%).

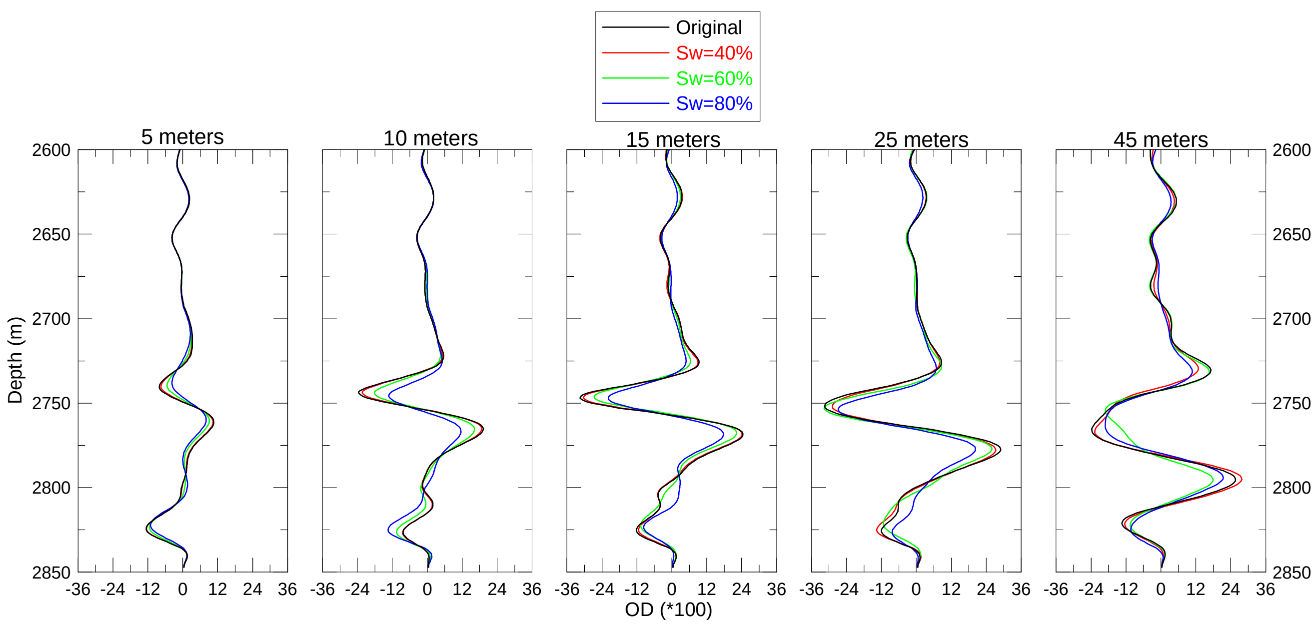

Figure 12 –Orthogonal Deviation from Background (or Pseudo-Fluid Factor) for different reservoir thickness and water saturation scenarios. (Top of reservoir on 2740m.) Black trace: in situ, red, green and blue: SW=40%,60% and 80%, respectively.

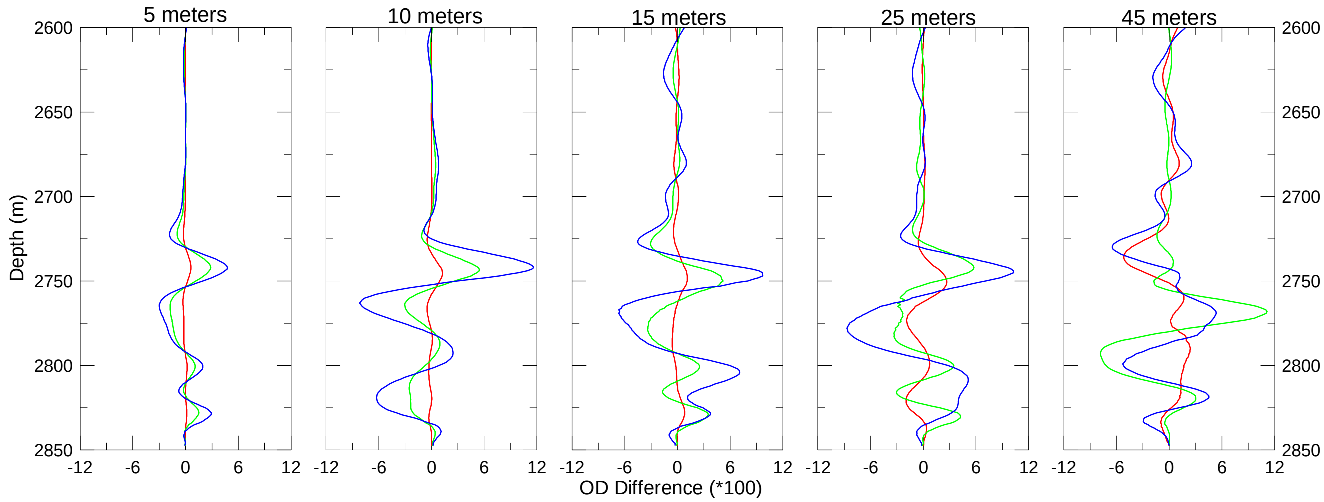

Figure 13 – Difference in Orthogonal Deviation from Background (or Pseudo-Fluid Factor) for different reservoir thickness and water saturation scenarios. (Top of reservoir on 2740m.) .) Black trace: in situ, red, green and blue: SW=40%,60% and 80%, respectively

In figure 12 the orthogonal deviation from background traces (or pseudo fluid factor traces) are shown for different reservoir thickness and water saturations. The differences in pseudo fluid factor for these different scenarios are shown on figure 13. The use of real elastic logs had introduced some strange artifacts on the synthetics, related to the presence of thin shale layers inside the reservoir.

Modeling of synthetics for possible pressure variation scenarios reveals that, although the expected pressure changes are not too high, some variation on seismic signature may be present.

The time-lapse seismic data for this reservoir is just being acquired, and the reservoir simulator output is being integrated in our 4D modeling software to bring up more insights on the expected seismic changes in area an volumetric extend.

Conclusions

A concise time lapse feasibility analysis was presented and some of its drawbacks discussed. These studies are strongly interpretation oriented, especially regarding the pressure and saturation effects on the seismic signature changes.

Our modeling reveals that this case study will push time-lapse techniques to its limits. The changes in elastic behavior, rather than only acoustic impedance, may help on the data analysis.

Acknowledgments

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