First 4D Seismic Results for Tupi Field, Santos Basin

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Abstract

The oil and gas industry has already established 4D seismic as a key tool to maximize oil recovery and ensure operational safety in siliciclastic reservoirs and low stiffness carbonates. Very recently, the Tupi field was the stage for a pioneering 4D seismic project to monitor production and water-alternating-gas (WAG) injection in the Brazilian Pre-Salt reservoirs. As the project used ocean-bottom-nodes technology (OBN) for the first time in the ultra-deep waters of the Santos basin, the project is known as the Tupi Nodes Pilot project. The project started with technical feasibility studies to forecast the Pre-Salt carbonates 4D seismic response and two OBN seismic acquisitions were carried out, approximately two years apart. Time-lapse processing included the application of top-of-the-line seismic processing tools. The resulting 4D seismic images, demonstrating a good signal-to-noise ratio, supply static and dynamic interpretations that are quite compatible with the injection and production histories, given new insights about preferential flow paths and signaling or confirming areas of reservoir quality degradation. Particularly for the Tupi field, but with the promise of serving as a field test for the entire Pre-Salt section, these 4D OBN seismic surveys and studies will hopefully assist to identify oil-bypassed targets for infill wells, optimize the use of intelligent completion valves to improve the reservoir overall sweep and calibrate the WAG injection cycles to increase the oil recovery.

Introduction

4D seismic primarily responds to variations in reservoir saturation and pressure. Different combinations of these parameters' changes imply acoustic impedance responses regularly classified as *hardening* (impedance increases from Baseline to Monitor) and *softening* (impedance decreases from Baseline to Monitor). For Tupi, the technical feasibility studies for predicting the 4D seismic response reported impedance variation values exceptionally close to the detection limit of 4D seismic acquisition and processing methods former applied in the oil industry.

The reservoir elastic response to effective pressure variation, for example, reported acoustic impedance variations around 1%. For modeled fluid replacement scenarios, where combined transformations of pressure, temperature and fluid saturations were considered, the recorded variations were more promising, but still, around 2%, for most studied cases (Costa *et al.*, 2019).

4D Pilot Location

Tupi field is located at the central part of the São Paulo plateau, which corresponds to the distal portion of the Santos basin, approximately 280 km off the coast of Rio de Janeiro (Moreira *et al.*, 2007).

The field was discovered in July 2006 and the first oil occurred in April 2009. In October 2010, the Cidade de Angra dos Reis, a Floating Production Storage and Offloading (FPSO) unit, started the operation in Tupi Pilot production module, the chosen place for the Tupi Nodes Pilot project.

The regional location of Tupi field in the Santos basin and the representative polygons of the Baseline and Monitor seismic surveys are exhibited over the *Reservoir top* structural map of Figure 1. The area with the highest seismic quality is of approximately 30 km^2, containing three producers (P1, P2 and P3) and two water-alternating-gas (WAG) injectors (WAG1 and WAG2). The processed data quality starts to deteriorate towards the edges of the survey, but it is still quite interpretable in most of the nodes carpet. Therefore, allowing to evaluate the performance of nine extra neighboring wells. The seismic acquisition was executed by Seabed Geosolutions™ under PETROBRAS supervision and advisement.

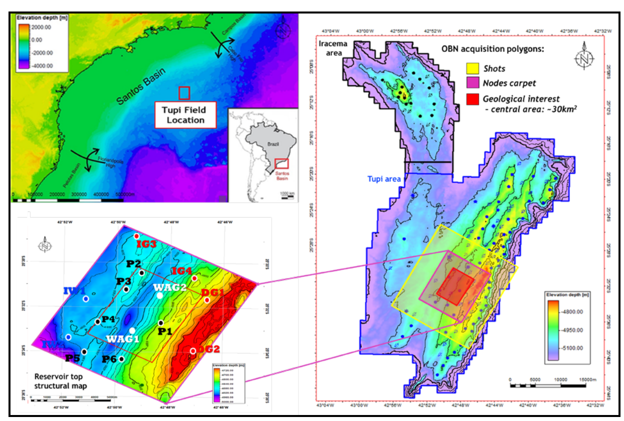

Figure 1 *– Location of Tupi field in the Santos basin and the representative polygons of the Baseline and Monitor seismic acquisitions.*

Geological Setting

The Santos basin stratigraphic chart subdivides the sedimentary record of the area into supersequences, limited by regional unconformities, related to the main phases of tectonic evolution: rift, post-rift and drift. The reservoirs of Tupi field are distributed within the Guaratiba Group, which comprises the deposits of rift and post-rift phases (Moreira *et al.*, 2007). In the post-rift phase, in a predominantly thermal subsidence domain, are the Barra Velha Formation carbonates, the main hydrocarbon-bearing rocks inside the area of geological interest of the Tupi Nodes Pilot project. These carbonate rocks present a strong structural control in their deposition. Structurally high portions are prone to deposition of lithologies associated with higher energy environments and therefore presenting better reservoir characteristics. The reservoir degradation tends to occur towards the structural lows and in depositional-related regions of lower energy environments (Faria *et al.*, 2017; Teixeira *et al.*, 2017; Artagão, 2018).

Tupi field contains light oil, with API gravity from 28º to 30º and gas-oil ratio (GOR) varying from 200 to 300 m3/m3, with different CO_2 contents in the gas phase. The Tupi Pilot development plan positioned six producing wells at the structural highs (P1, P2, P3, P4, P5 and P6) and six water and/or gas injectors on the flanks (IW1, IW2, IG3, IG4, WAG1 and WAG2). Wells DG1 and DG2 are used for gas disposal. All Pilot module injection takes place in the oil zone, except for wells DG1 and DG2 that inject into the supercritical fluid region ("pseudo gas cap"). In the oil zone, the reservoir has an average effective porosity of approximately 9%, varying from 6% ("cutoff") to approximately 24%. The average permeability is approximately 200mD and can vary significantly depending on rock type.

The elastic properties of rocks are affected by several factors, such as variations in fluid saturation, porosity, mineralogy, pore shape, pressure and lithology (Xu & Payne., 2009; Mavko *et al.*, 2009; Eberli *et al.*, 2013). Elastic properties changes can be translated into variations of seismic signal amplitude once acquisition and processing effects are compensated. Regarding the 4D signal, feasibility studies indicated that rock types, fluid saturation and rock-fluid interaction (rock dissolution and/or mineral precipitation) exercise major influence in the variation of elastic properties.

The schematic graph in Figure 2 shows the relationship between lithology, facies and porosity in the 4D seismic response for three different types of rocks: analogous to the injectors and producers of Tupi Pilot area and analogous to classical reservoirs such as Campos basin turbidites. The experiment represented by the graph simulated the replacement of oil by water (*hardening* effect) and the results are displayed in terms of delta acoustic impedance changes and rock stiffness (from lab). We observe that Tupi's carbonates are stiff rocks, presenting small 4D seismic responses when compared to the turbidite reservoirs. Impedance variations are often less than 2%, a value that was initially considered to be a threshold for 4D success when applying high repeatability methodologies of seismic acquisition.

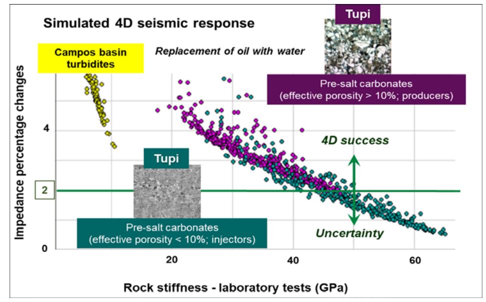

Figure 2 *– Relationship between lithology, facies and porosity in the 4D seismic response.*

Dynamic Data

Knowledge of the pressure and fluid dynamics of the target, especially in the period between Baseline and Monitor surveys, is crucial for performing accurate 4D seismic interpretation in a qualitative or quantitative manner. Figures 3 and 4 schematically show the water and gas injection history and breakthrough schematics for key wells inside the Tupi Pilot region.

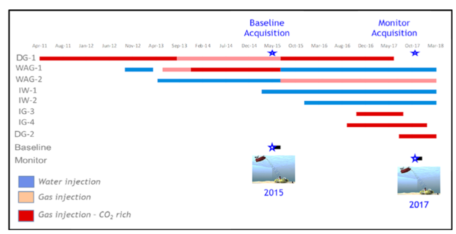

Figure 3 *– History of water and gas injection for key wells inside the Tupi Pilot region.*

Between May 2015 (start of the Baseline acquisition) and October 2017 (start of the Monitor acquisition) two new injectors started operating in the west flank of Tupi Pilot production module: wells IW2 (injecting water) and IG3 (injecting gas with high CO_2 content). During this same period, we also observed a considerable increase in the water volume injected into well IW1 and, for the eastern edge, we had the gas disposal DG1 alternating from low CO_2 to high CO_2 gas. Additionally, wells IG4 and DG2 started with high CO_2 gas injection.

Gas considered to be high in CO_2 has contents of this component in the order of 80% while gas low in CO_2 has contents of about 5%. Importantly, the higher the CO_2 content, the higher the gas density and the lower the acoustic impedance contrast to water or oil. On the other hand, if water and CO_2 are mixed, the higher CO_2 content may result in a greater intensity of rock-fluids interaction (reservoir rock dissolution for example). Both situations may impact the observed 4D signal according to petroelastic modelling (PEM).

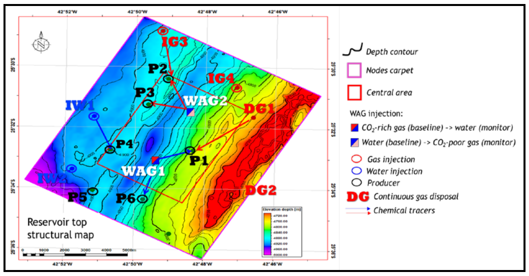

Figure 4 *– Representation of water and gas tracer's breakthrough for key wells inside the Tupi Pilot region.*

PEM is a workflow that relates pressure, saturation, porosity and clay content to impedances and velocities for the different survey times. The next step is to compute the corresponding synthetic seismic data for each survey, which can be done by using a convolution model. The 4D synthetics represent the seismic signature of the geomodel and of the fluid movements predicted by the flow simulator (Doyen, 2007). The performed 4D seismic viability studies for Tupi (PEM and synthetics) indicated that the alternation of water and gas injection between Baseline and Monitor acquisitions, combined with the effects of rock-fluids interaction in presence of CO_2 (acidification, dissolution) tended to return 4D seismic signatures at higher amplitudes and therefore increase the chances of a first 4D seismic signal detection (Figure 5). With that in mind, the implantation of the Tupi Nodes Pilot project was made in sync with the WAG injection schedule. Thus, during the Baseline survey, well WAG1 injected gas and well WAG2 injected water. For the Monitor survey, in turn, the fluids were alternated prior to seismic shooting start.

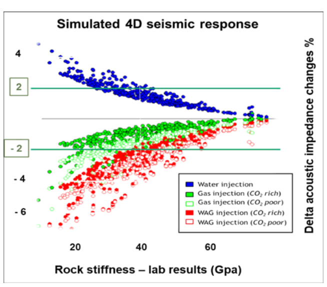

Figure 5 – *Comparison of simulated 4D signal for water, gas and WAG injection (with different CO_2 contents).*

In Figure 4, the bold arrows represent the paths of injected fluids, mapped through chemical tracer analysis. All data is filtered for the period in between the Baseline and Monitor seismic surveys. We observed water saturation increase (BSW - *basic sediments and water*) on producers P4 and P1, by 14% and 35% in relation to the Baseline period. For well P4 our interpretation is that it is water injected into the neighboring wells IW2 and IW1. Most recently, IW1 water tracer has been identified in the P4. For producer P1 the chemical tracer examination points to the arrival of water from the injection of WAG1.

To sum up, in producers P3 and P2 we noticed the gas/oil ratio increase (deltas GOR of 240 and 160 respectively) interpreted as resulting from gas injection in well WAG2. Recent information, right after the period between the Baseline and Monitor acquisitions, also points to the arrival of injected gas from well IG3 at producer P2 (gas tracer spotted).

Seismic Data

The feasibility studies (PEM, synthetics, survey modeling) indicated that the success of 4D seismic as a production monitoring tool for Brazilian Pre-Salt reservoirs would involve the use of seismic acquisition techniques able to ensure maximum repeatability and high signal-to-noise ratio (better than conventional streamer surveys), azimuthal richness and enough vertical resolution to individualize geological features of a few dozen meters. Taking all these factors into account and adding to the fact that Tupi already had many subsea operational obstructions present in the area, the chosen technology was OBN.

To ensure high azimuth coverage with long offset, prior to seismic shooting, all Nodes were installed and turned on at the seabed, thus employing the OBN acquisition technique known as "all live" where all seismic node-type receivers are active during shot period. The OBN acquisition included 954 stations over 36 lines, covering an area of 111 km^2. The Baseline acquisition took place in 2015 and the Monitor in 2017; the seismic processing methodologies adopted, wich included IMA and LSM are described by Cypriano *et al.* (2019) and Pereira *et al.* (2019). Data processing was mainly carried out by CGG™ under PETROBRAS supervision and advisement.

The seismic processing methodologies adopted were efficient in providing 3D and 4D seismic images capable of portraying subtle geological features and fluid exchange dynamics, not only for the central area of interest, but also for most of the nodes carpet. The images have a good signal-to-noise ratio, despite the thick and irregular salt layer that covers the reservoirs and the observed 4D responses have amplitudes greater than background noise. The main remaining 4D noises are interpreted to be related to the presence of residual interbed multiples and the non-perfect repeatability of Baseline and Monitor seismic acquisition conditions (mainly variations in water layer velocity and the *bubble effect*, even after all steps to mitigate these undesirable seismic signal problems have been taken).

4D seismic repeatability depends mainly on seismic acquisition parameters such as source and receiver post-plot positions, environmental conditions, and subsequently, the effectiveness of the processing techniques implemented. Seismic repeatability can be measured by the normalized root mean square (NRMS) attribute (Kragh and Christie, 2001) where NRMS is a measure of the difference between two traces. It is defined as the RMS amplitude of the trace difference divided by the average RMS of each trace and can range from 0 to 2 (or from 0 to 200%). A value of zero indicates perfect repeatability, while a value of 200% indicates that the traces are exactly opposite. Tupi Pilot 4D seismic amplitude data displays an average NRMS value of approximately 3% for standard 4D seismic processing methods, which already indicates an excellent repeatability. The use of more advanced techniques such as Interbed Multiples Attenuation (IMA) and Least-squares Migration (LSM) returned even lower NRMS values of around 2% at the Pre-Salt level (Cypriano *et al.*, 2019). Although 2% can be considered excellent, the residual non-repeatability still causes low frequency noise to emerge as alternating stripes of positive and negative amplitudes, representing, together with the residual interbed multiples, the main background noise disturbing 4D seismic interpretation.

4D Seismic Interpretation

The present paper portrays time-lapse seismic interpretations performed mainly on 4D amplitude volumes, differences between Baseline and Monitor amplitude data (Monitor *minus* Baseline). The analysis is focused on the main oil-bearing reservoir interval of the Tupi area, upper portion of the Barra Velha Formation (Figure 6 - B).

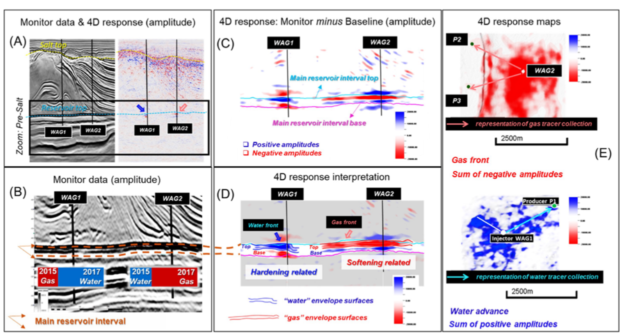

Figure 6 *– First 4D seismic images interpreted around wells WAG1 and WAG2, depicting the water and gas advancing fronts in the reservoir. In the 4D seismic amplitude, we identified the water and gas fronts as pairs of positive and negative reflectors (C). The positive top (blue) indicates the water advance and the negative top (red) the gas front (D). Through mapping of enveloping surfaces, we separated the tops of the referred anomalies (D) and calculated the seismic attribute maps "sum of positive amplitudes" and "sum of negative amplitudes" (E). The interpretations are focused on the main oil-bearing reservoir interval (B).*

The first 4D seismic images for the Santos Pre-Salt, interpreted around wells WAG1 and WAG2 (Figure 6) correctly portray the water and gas fronts at the reservoir. In this type of seismic amplitude section, 4D seismic anomalies commonly appear as pairs of positive and negative signals, provided the data is of enough vertical seismic resolution to represent the top and the bottom of the layer in question. For this case, the positive top reflection (blue) indicates the waterfront, and the negative top reflection (red) indicates the gas front. Through manual mapping of envelope surfaces we separated the tops of the 4D anomalies and calculated the maps of the attributes "sum of positive amplitudes" and "sum of negative amplitudes" (Figure 6-E). In the vicinity of the WAG-injector-1, towards producer P1, an elongated 4D *hardening* anomaly is observed, as the resulting increase in impedance between Baseline and Monitor acquisitions, mainly related to BSW escalation measured in P1.

Information from chemical tracers confirmed that the water injected into well WAG1 has reached producer P1. In addition to the effects of increased water saturation in the region, the effects of rock-fluid interactions and depletion were also investigated. This investigation was done by comparing the actual seismic response measured (Baseline and Monitor amplitude volumes) with the synthetic petroelastic response calculated from well profile data and flow models adjusted to the production and injection histories (Costa *et al.*, 2019). Figure 7 illustrates that the synthetic response considering only saturation effects has stronger amplitudes than the recorded 4D response. Subsequently, by analyzing the synthetic trace of well WAG1, we confirm that in view of only saturation effects, 4D amplitudes and impedances are overestimated. A scenario combining saturation plus rock-fluid interaction effects (acidification) and pore pressure variation gives the best synthetic to real data fit.

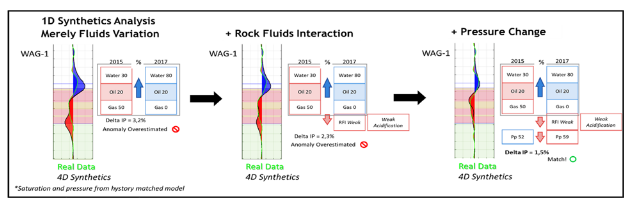

Figure 7 ***–*** *4D synthetic response considering only saturation effects and a scenario combining saturation plus rock-fluid interaction effects (acidification) and pore pressure variation.*

Of utmost importance to emphasize in Figure 7 the value of acoustic impedance variation recorded around WAG1: less than the 2% "cutoff" initially considered for Pre-Salt 4D seismic success. Taking Tupi's 4D data as a reference, in the pre-salt context, the detectability limit using OBN technology is currently considered to be approximately 1.5% for acoustic impedance variations.

For well WAG2 surroundings (Figure 6 - E), we observed an opposite effect to the already presented, a *softening* anomaly, reflection of the Monitor impedance lessening, due to the water by gas replacement in the WAG cycle. In this region, the residual interference from interbed multiples noise and the lack of more seismic vertical resolution make it difficult to interpret the continuity of this gas front towards the producing wells P2 and P3. Uncertainty about the areal extent and geometry of the *softening* anomaly increases further toward the structural lows where the reservoir is thinner and the proportion of carbonates with clay minerals, typically “non-reservoir” rocks, is higher (Figure 8).

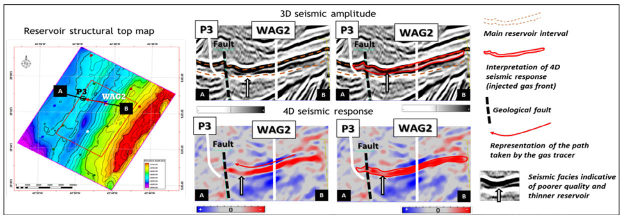

Figure 8 *– Simplified analysis of 4D softening response around wells WAG2 and P3.*

Retrieved chemical tracer information confirms that gas injected into well WAG2 has reached producer P3. In the current geological model of Tupi area this communication occurs through a few permeable layers. Our integrated interpretation of 3D and 4D seismic data (*e. g.* amplitude, derived elastic attributes, facies classifications), well-log information and production/injection history, suggests the absence of an imperative flow barrier related to the nearby geological faults and/or very low-porosity (less than 6% effective porosity) facies associations. The combination of overlapping layers of better and worse perm-porous reservoir in the structural low between producer P3 and injector WAG2 seems to only imply local loss of transmissibility. The interpretation of 4D seismic response, albeit *tuned* - Widess (1973) criterion - and *fading* at the structural low, corroborates this scenario, confirming, even, the existence of a seismic facies/feature indicative of reservoir quality degradation. Once the injected gas reaches the P3 structural high, the dissemination occurs preferentially through the ridge and bordering the fault indicated in Figures 8 to 10.

During the classic 3D seismic interpretation, the appraisal of seismic sections passing through wells that crossed clay-rich or very low-porosity levels of Barra Velha Formation, had already drawn attention to the occurrence of a *transition band* between the better-quality *updip* reservoir portion and the non-reservoir *downdip* portion. Since the seismic signature visually resembles the letter X, particularly in acoustic impedance sections, this seismic feature became known as *X-Feature*. *X-Feature* is traceable in amplitude and acoustic impedance volumes and its significance is now reinforced by 4D seismic data, as we can observe in Figures 8 and 9. The *softening* 4D seismic response turns out to be *weaker* around it, in the deepest part of the valley. The dimmed 4D signals agree with the degradation implied by the *X-Feature*: thinner reservoir of worse porosity and permeability, where fluids passage is limited.

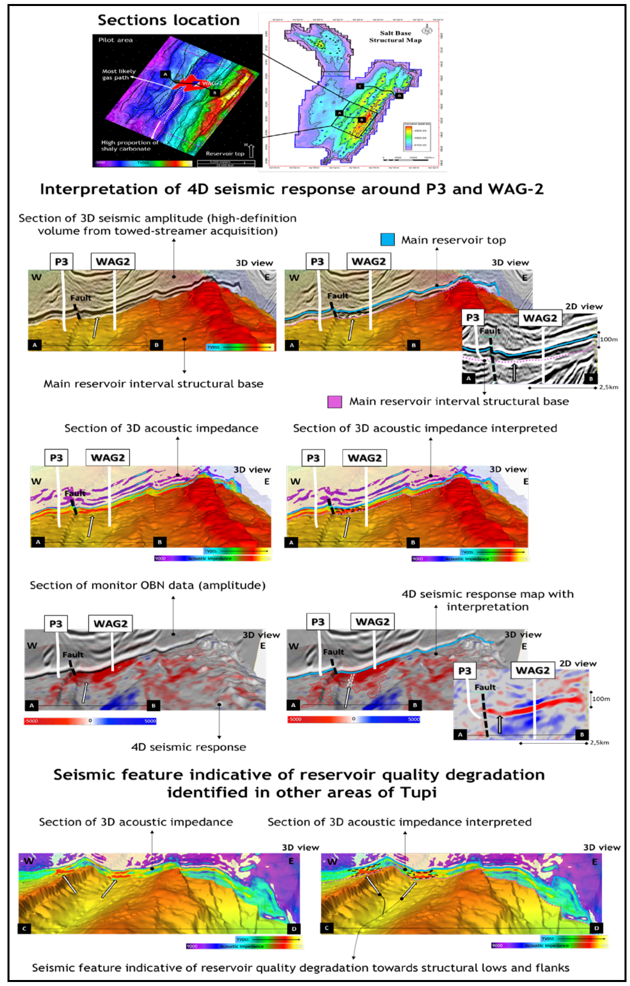

Figure 9 ***–*** *4D response around WAG2 and P3 and its relation to X-Feature.*

Attempting to better extrapolate portions of poorer reservoir quality, Bayesian classifications (Doyen, 2007) were tested, combining: i) acoustic impedance and vp/vs ratio; ii) shear impedance and vp/vs ratio; iii) impedance (acoustic or shear), vp/vs ratio and seismic depth. The Bayesian classification process considering only elastic attributes returned the worst predictions for clay-rich facies occurrence. There are several complicated factors: variable quality of input data for inversion; little well sampling in worst reservoir quality facies; overlapping of classification clusters when impedance and vp/vs values discriminating facies are too close and within error range inherent to elastic seismic inversion methods; seismic ambiguity and resolution (Avseth *et al.*, 2005; Teixeira *et al.*, 2017; Cunha *et al.*, 2019). Assuming the current structural depth of the area largely reflects paleogeography at the time of deposition, the addition of a depth constrain in the probabilistic classification process facilitates the highlighting of regional structural lows and basal portions of local structural lows as areas of clay-facies prevalence (Teixeira *et al.*, 2017). However, many doubts remain about how the transition between reservoir and non-reservoir facies takes place in the flanks and upper portion of relative/local lows. Figure 10 sections exemplify how the classifications "with and without depth constrain" do not strongly signal the presence of clay-rich facies (massive or intercalated) in the relative structural low between P3 and WAG2 and overestimate the representation of very low-porosity facies around the producer's position, not entirely matching the attained well-log information. Taking the hint from 4D seismic, was assumed a compromise solution where the fluid communication between P3 and WAG2 happens through a few permeable layers, towards the top of Barra Velha Formation. The solution honors production and injection history, but we will further investigate the area via PEM scenarios.

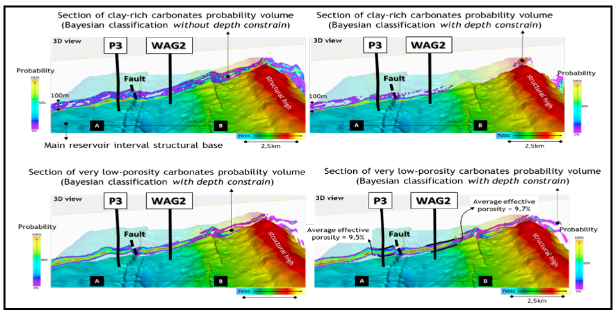

***Figure 10** – Comparison of Bayesian classifications results for the upper portion of Barra Velha Formation.*

In addition to the WAG wells already mentioned, 4D responses were identified around wells IW1 and IW2 (exclusive water injection), IG4 (exclusive gas injection spread), P4 (water breakthrough) and DG1 (CO_2 content increase - *hardening* effect). Figure 11 displays the areal expression of the main mapped 4D seismic responses, along with the flow paths confirmed by chemical tracers. To obtain a representative 4D amplitude map for the main reservoir interval, a detailed manual interpretation of envelope surfaces was performed. The envelope surfaces separated the tops of water and gas fronts, defining the interval for average amplitude calculations.

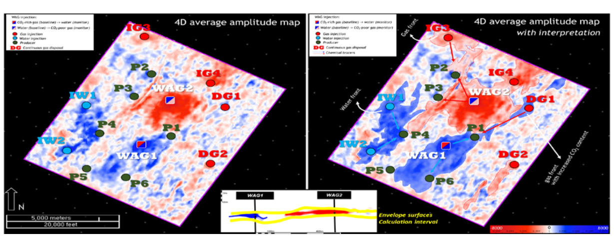

***Figure 11** – Areal expression of 4D responses, along with flow paths confirmed by chemical tracer analysis.*

Conclusions

The presented 4D seismic interpretations demonstrate the success of applying time-lapse technique for monitoring Tupi reservoirs and is a reference for the entire Pre-Salt section, motivating new OBN 4D surveys and PRM projects.

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