Relevance of the stochastic stratigraphic well correlation approach for the study of complex carbonate settings: Application to the Malampaya buildup (Offshore Palawan, Philippines)

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Abstract

The stochastic stratigraphic well correlation method considers the stratigraphic correlation of well data as a set of possible models to sample and manage uncertainty in subsurface studies. This method addresses the incompleteness of typical subsurface data such as limited seismic resolution, seismic blindness due to the lack of impedance contrast between distinct stratigraphic formations, borehole preferential location.

The stochastic stratigraphic well correlation method is applied to the Malampaya buildup (a well documented offshore gas field located North-West of the Palawan Island, Philippines), aged upper Eocene to lower Miocene, and developed on the crest of a tilt-block. Among the available data, ten wells, seven of which are cored, have been drilled and a high resolution 3D seismic survey was acquired by Shell Philippines in 2002. Previous studies highlight that rock petrophysical properties are mainly controlled by diagenesis. Correlation rules are thus developed in order to adapt the stochastic stratigraphic well correlation method to the study of diagenetic units. These rules are based on wireline log shape and diagenetic units types.

Four stratigraphic correlation models are generated using the proposed correlation method: a deterministic one corresponding to the most probable model considering only well data and three stochastic ones. These correlation models are bound with geostatistical methods to build static reservoir models. Synthetic seismic profiles are computed from facies models conditioned to acoustic impedance models. It leads to comparable seismic amplitude images, highlighting the importance of considering several well correlation models for one given seismic survey. Stochastic stratigraphic correlations are shown to have a first order impact on reservoir unit characterization, rock volumes and fluid flow response on the reservoir model.

The Malampaya gas field is a well documented carbonate buildup located North-West of the Palawan Island, Philippines (Grötsch & Mercadier, 1999; Neuhaus *et al.*, 2004; Fournier *et al.*, 2004, 2005; Fournier & Borgomano, 2007)(Fig.1). Reservoir rocks belong to the upper Eocene to lower Miocene aged Nido Limestone formation (Sales *et al.*, 1997; Williams, 1997). Deposition of the Nido limestone occurred on the edge of a tilted block resulting from the rifting phase of the China sea (upper Eocene to lower Oligocene). Development history, paleo-environments and diagenesis of the Malampaya buildup has been studied by Fournier *et al.* (2005, 2004). Meter-scale, 4^{th} to 5^{th} order subtidal cycle bounded by exposure sur-

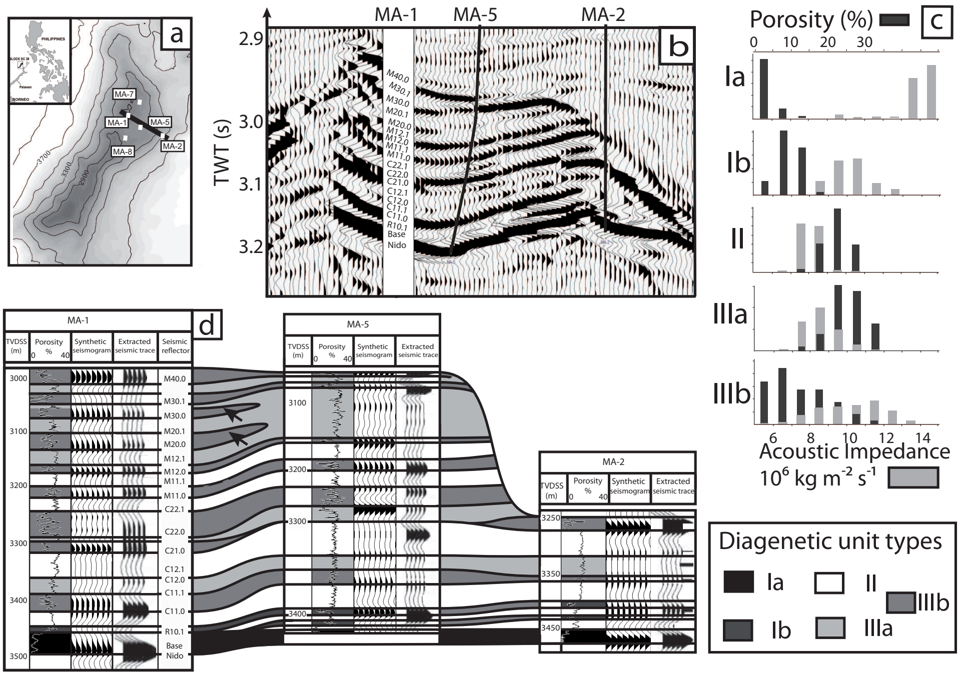

Figure 1: *(a) Topographic map (in meter sub-sea) of the top horizon of the Malampaya gas reservoir located offshore western Palawan island, Philippines. (b) Seismic line between wells MA-1 and MA-2 displaying Malampaya interior reflector. (c) Porosity and acoustic impedance histogram for the different diagenetic unit types. (d) Stratigraphic model proposed by Fournier & Borgomano (2007) on the basis of wells and seismic interpretation. Modified after Grötsch & Mercadier (1999) and Fournier & Borgomano (2007).*

faces are interpreted as constitutive of the buildup.

Fournier & Borgomano (2007) studied petrophysical properties of the Nido limestone of the Malampaya buildup and show that reservoir properties are mainly controlled by diagenetic processes affecting carbonate rocks. They defined five types of diagenetic units (Ia, Ib, II, IIIa, IIIb) characterized by: coherent set of diagenetic transformations (meteoric diagenesis and late burial cementation and leaching); specific statistical porosity and acoustic impedance distributions (Fig.1); pore types; porosity-permeability relationships; and well-log signatures. From well-to-seismic ties, Fournier & Borgomano (2007) showed that the main seismic reflectors within the buildup image the boundary of diagenetic units. The 3D picking of the reflectors and well correlation of diagenetic units thus provide an envelope of geobodies characterized by specific pore type and reservoir properties. Diagenetic units also define the layering of the reservoir and impact the 3D architecture, showing in particular an alternation of porous and tight diagenetic units. Hence, it impacts the understanding of the reservoir flow behaviour on fluid flow modelling.

Fournier & Borgomano (2007) proposed a stratigraphic model of seismo-diagenetic units of the Malampaya buildup on the basis of well logs and interpretation of an high resolution seismic survey(Fig.1d). However, in common subsurface studies the well-to-well stratigraphic correlation process is subject to uncertainties due to limited seismic resolution, ambiguity between rock types and well logs and inherent variability between boreholes. The objectives of this study are to question if the seismic response of the Malampaya buildup may be explained by alternative well-to-well stratigraphic correlation models of diagenetic units and to assess the impact of well correlation uncertainty on reservoir description and dynamic behaviour. Different possible sets of diagenetic units are automatically generated by a stochastic well correlation process and used to produce a static and dynamic model of the Malampaya buildup.

Different approaches and well descriptors (markers, facies, wireline logs, *etc.*) have been

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proposed to perform computer-aided stratigraphic well correlations. For instance, deterministic methods have been proposed to correlate wells on the basis of logs (Zoraster, 2004) or lithostratigraphic description (Griffiths & Bakke, 1990). Recently, Lallier *et al.* (2009) have presented a stochastic procedure for generating several plausible stratigraphic well correlations from a given set of wells, described by depositional facies.

In the first part of this study, an adaptation of the stochastic method proposed by Lallier *et al.* (2009) to the stratigraphic correlation of diagenetic units is presented. It relies on the correlation rules proposed by Fang et al. (1992). Using this proposed approach, four stratigraphic correlation models of diagenetic units are generated and used to construct cross sectional models of these units. Geostatistical simulations of porosity, permeability and acoustic impedance are then performed. The impact of stochastic stratigraphic correlation is then evaluated on the basis of synthetic seismic computation and fluid flow modelling.

Stratigraphic correlation method

Correlation rules

Two rules are used here to perform stratigraphic well correlation of diagenetic units identified by Fournier & Borgomano (2007) from well logs, thin-section, cuttings, cores and well logs: (1) Two units are correlated only if they are of the same diagenetic type. This rule implies that diagenetic units are correlated as geological bodies; (2) Two units are correlated if they display a comparable well log pattern as explain below.

Evaluation of the value of a correlation between two units

An automatic method of well correlation requires a mathematical formulation of correlation rules. Several methods have been proposed to evaluate the similarity between two well log curves. Olea (2004) used the product between standardized similarity coefficient and Pearson's correlation coefficient to evaluate similarity between two parts of a wireline log. These two coefficients suppose that for the two considered units the same number of points are sampled, hence may call for re-sampling the well log for the considered unit. Moreover in the case of lithostratigraphic correlation, the use of this correlation coefficient assumes a globally constant preservation rate between the two wells (*i.e* no distortion in the signal). The sedimentary record is also assumed to be quasi-complete between the two units, *i.e* there is no erosion on a studied stratigraphic unit which is not recorded in the other unit.

In this study, we use the method proposed by Fang *et al.* (1992) to evaluate similarity between well logs of two diagenetic units. This method, based on the dynamic programming approach, follows a workflow with three steps (Fig.2):

Transformation of well logs into pattern primitives. Well log curves are filtered to extract points that are representative of a log pattern. This method is called "adaptive" by Fu (1980) and is performed in two steps. First, a generalized difference log $\mathbf{d}$ is computed along the well at each point at depth i:

$$d_i^2 = (s_{i-\alpha} - s_{i+\alpha})^2 \tag{1}$$

where d_i is the value of the generalized difference log $\mathbf{d}$ at depth i; $s_{i-\alpha}$ the slope of the considered well log between the point at depths i and $i-\alpha$; and $s_{i+\alpha}$ the slope between the point at i and $i+\alpha$. The half-window α is to be defined according to the well log resolution and noise characteristics. Then for each peak of the generalized difference log, the value of the studied log at peak depth is selected and used to build a filtered log. Finally, the obtained simplified log is transformed into a string of pattern primitives according to the dip angle of the filtered log segment.

Similarity evaluation. Considering two stratigraphic units a and b transformed into two strings of pattern primitives (respectively $[a^1, ..., a^i, ...a^n]$ and $[b^1, ..., b^i, ...b^m]$), the best match is searched between a and b using dynamic programming (Levenshteiti, 1966) where the penalty of an insertion and a deletion equals 1 and the penalty of a mismatch is equal to the difference between a^i and b^j. Finally, the similarity between the two units a and b has a value C which equals 0 if a and b are similar and increases with the difference between a and b:

$$C = \frac{T}{(4 \times L)} \tag{2}$$

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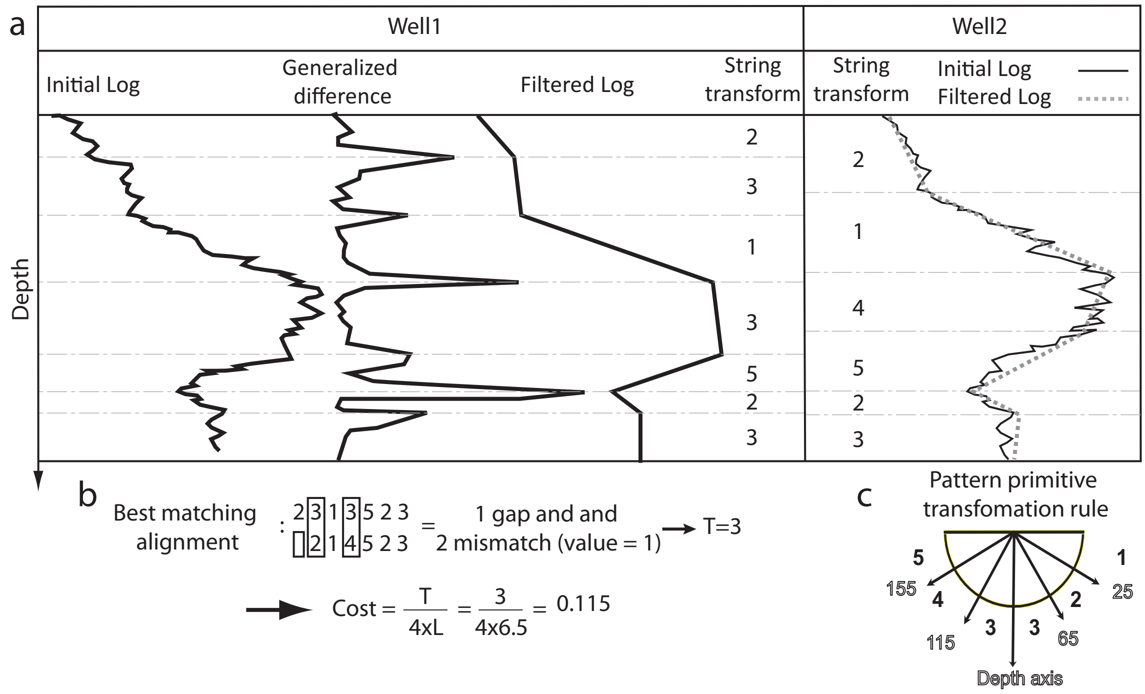

Figure 2: *Evaluation of similarity between log responses of two units. Well logs are first filtered using generalized difference (a) and transformed into strings of pattern primitives according to dip angle of filtered log segments (c). Cost is computed as the difference between the two strings representing the two considered units (b). After Fang et al. (1992)*

where L is the mean length of the strings and T the cumulative penalty of association between a and b. This method has two main advantages: (1) it handles possible distortions of the initial signal through a string of pattern primitives; (2) it manages a missing events in a unit with regard to the other unit through the use of dynamic programming.

Most of the time, more than one well log is available. Given n wireline logs noted $\lambda_\mathbf{1}$ to $\lambda_\mathbf{n}$ (for instance, a density log, a porosity log and a sonic log), the possibility of a correlation between two considered units can be evaluated using a weighted sum of cost $C^{\lambda_\mathbf{i}}$ computed for each available well log:

$$C^{\lambda_\mathbf{1},\ldots,\lambda_\mathbf{n}} = \sum_{i=0}^{n} w_i C^{\lambda_\mathbf{i}} \tag{3}$$

where w_i are weights defined according to: (i) the redundancy of information contained in the wireline log; (ii) the relevance of the rock property recorded by the log.

Automatic stratigraphic correlation between two wells

Once the similarity between stratigraphic units has been computed, the global correlation between the considered wells can be built. The goal of this study is to handle uncertainties in stratigraphic well correlation and to stochastically generate correlation models constrained by well logs. Lallier *et al.* (2009) proposes the use of a stochastic variation of the Dynamic Time Warping algorithm (DTW) (Levenshteiti, 1966; Myers & Rabiner, 1981) which automatically builds correlations between two ordered series. The correlation between two wells u and v, on which stratigraphic units u^1 to u^n and v^1 to v^m are defined, is determined with a recursive function $D(u^i, v^j)$:

$$D\left(u^i, v^j\right) = S\begin{pmatrix} \alpha = m(u^i, v^j) + D\left(u^{i-1}, v^{j-1}\right), \\ \beta = g(u^i) + D\left(u^{i-1}, v^j\right), \\ \gamma = g(v^j) + D\left(u^i, v^{j-1}\right) \end{pmatrix} \tag{4}$$

where:

(a) $D(u^i, v^j)$ is the cost of the correlation between units u^1 to u^i of w_1 and units v^1 to v^j of w_2;

(b) $m(u^i, v^j)$ is the cost of a correlation (match) between the units u^i and v^j;

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(c) $g(u^i)$ is the cost of a gap of unit u^i, *i.e.* the unit u^i of the well u is not recorded on well v and end as a stratigraphic gap between the two wells;

(d) $g(v^i)$ is a cost of a gap of units v^j of v;

(e) $S(\alpha, \beta, \gamma)$ is a value equal to cost α (respectively β or γ) with a probability inversely proportional to the relative cost $\frac{\alpha}{\alpha+\beta+\gamma}$ (respectively $\frac{\beta}{\alpha+\beta+\gamma}$ or $\frac{\gamma}{\alpha+\beta+\gamma}$).

Applying equation 4 from $i = 1$ to n and $j = 1$ to m minimizes the cost $D(u^n, v^m)$ of the correlation between wells u and v and thus builds correlations which are consistent with rules used to compute $m(u^i, v^j)$, $g(u^i)$ and $g(v^i)$. In the original deterministic version of the DTW (Myers & Rabiner, 1981), the S function is not a stochastic one, and returns the minimum value of α, β and γ ensuring that the DTW algorithm builds the minimum cost correlation between wells u and v. This correlation is called deterministic.

In this study, the correlation between two diagenetic units is considered only if they are of the same diagenetic type. Considering two units u^i and v^j of a diagenetic type respectively $t(u^i)$ and $t(v^j)$, the cost of a match is computed as following:

$$m(u^i, v^j) = \infty \text{ if } t(u^i) \neq t(v^j)$$
$$\text{else}$$
$$m(u^i, v^j) = C^{\lambda\mathbf{1},\ldots,\lambda\mathbf{n}}, \text{ as in} \text{Fang } \textit{et al.} \text{ (1992)} \quad (5)$$

The analysis of the match function $C^{\lambda\mathbf{1},\ldots,\lambda\mathbf{n}}$ highlights that the cost of a match between two units has a cost lower than 1 if log patterns of u^i and v^j are similar and higher than 1 if no similarity appears between the considered units. Therefore, we set the gap costs $g(u^i)$ and $g(v^j)$ to 1 so that units with comparable log patterns have a higher chance of correlation than pinch out.

Results and discussions

Stratigraphic correlation models

Four stratigraphic correlation models (Fig.3) are built between wells MA-1, 2, 5, 7 and 8: a stratigraphic correlation model (DSM) corresponding to the minimum cost correlation ($S(\bullet) \equiv Min(\bullet)$) and three stochastic stratigraphic correlation models (SSM1, 2 and 3).

Validity of the well correlation method. The confrontation of our DSM (*i.e.* the most probable stratigraphic correlation model regarding used correlation rules, Fig.3a) with the stratigraphic model proposed by Fournier & Borgomano (2007) (Fig.1d) serves as validation of the method. Several points can be highlighted: (i) all of the diagenetic units correlated by Fournier & Borgomano (2007) are also correlated in the DSM; (ii) hiatuses interpreted by Fournier & Borgomano (2007) are also present in the DSM; (iii) the only difference between the two models is the interpretation of the units marked with an arrow on figure 1d which are interpreted as pinching out diagenetic lenses by Fournier & Borgomano (2007)(Fig.1B) and top-lap in the DSM. This difference comes from a modelling decision we made: the presence of diagenetic lenses has been interpreted by Fournier & Borgomano (2007) based on a high resolution seismic survey on which the abrupt disappearance of seismic reflectors (labelled M20.0 and M30.0 on figure 1b and d) corresponding to the diagenetic units indicates pinch out. In our case, only well log data on which no indication of such pinch out could be identified, are considered to preform stratigraphic well correlation. As a consequence, we did not design our stratigraphic correlation algorithm to manage units that pinch out. However, the likeness between the DSM and the stratigraphic model proposed by Fournier & Borgomano (2007) suggest that our algorithm generates an acceptable stratigraphic well correlation.

Geometrical model building. The four possible stratigraphic correlation models are combined with top and bottom Nido horizons geometry interpreted from 3D seismic to build 3D stratigraphic grids (Mallet, 2002) conforming to diagenetic units (sections of these grids are shown in Fig.3). In addition to the uncertainties due to the correlations, there are uncertainties due to the way horizons are interpolated between the correlated markers (Goff, 2000; Caumon *et al.*, 2007; Seiler *et al.*, 2010). To limit the influence of this geometric uncertainty, we focus on the neighbourhood of wells MA-1, 2 and 5 (Fig.1a). This restriction is necessary since the internal geometry of the reservoir is only constrained by well marker positions and by the top and bottom reservoir horizons.

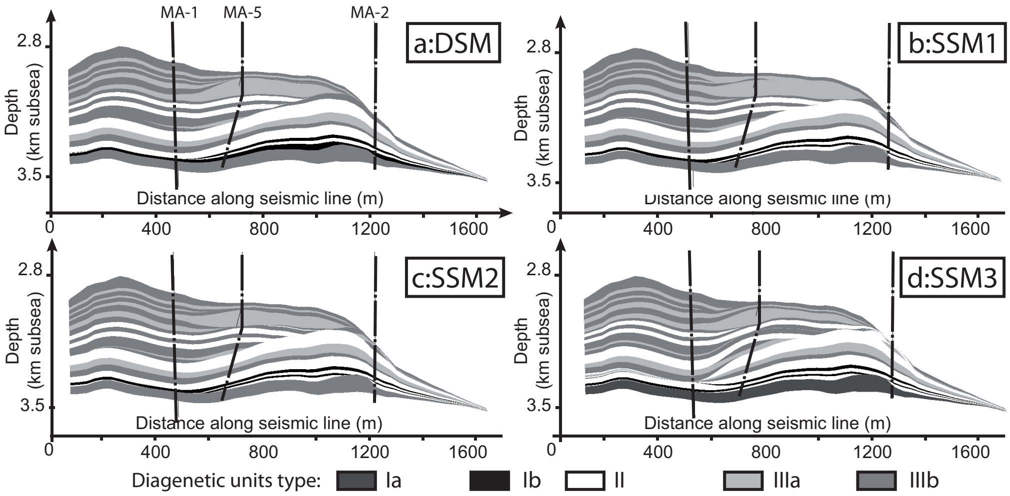

Figure 3: *Sections of the diagenetic units model built from stratigraphic correlations computed using the proposed algorithm. The deterministic model is the minimum cost one. For reference, wells MA-1, 2 and 5 are projected on the section.*

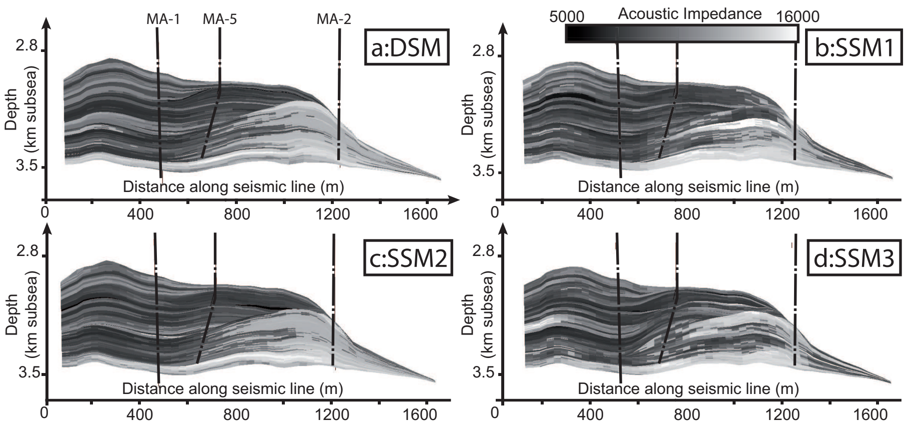

Figure 4: *MA-1 to MA-2 cross-section of acoustic impedance models generated on grids built from DSM (a), SSM1(b), 2(c) and 3(d) using Sequential Gaussian Simulation.*

Property modelling

3D stratigraphic grids are populated with porosities property using Sequential Gaussian Simulation (SGS) conditioned by well porosity logs on wells MA-1, 2, 5, 7, and 8. As shown by Fournier & Borgomano (2007), petrophysical properties are controlled by diagenetic history and thus diagenetic unit type. Therefore, in this study, petrophysical properties are considered second order stationary on each diagenetic unit type. Univariate, bivariate and spatial analyses are performed for each diagenetic type. Experimental histograms (Fig. 1c) are used as target distributions for the SGS. Due to lack of information (data are provided by five wells), variogram model can not be discriminated between diagenetic units as expected theoretically. A unique spherical variogram model is thus built and used to perform SGS with a range of 950 m horizontally and 40 m vertically. Porosity is then simulated on each stratigraphic grid. The same process is used to simulate acoustic impedance.

Seismic response to alternative stratigraphic models

The value of a stochastic correlation model can be questioned when high quality seismic data allows us to follow stratigraphic units between wells. Moreover, since the petrophysical properties distribution through the Nido Limestone is controlled by the geometry of tight and porous diagenetic units imaged by seismic survey, we could question if the seismic response of the Malampaya buildup can be explained by alternative internal architectures.

Synthetic seismic computation. A realisation of acoustic impedance is presented for each correlation model in figure 4. Synthetic seismic amplitude models are computed by convolving the acoustic impedance models (DSM, SSM1, 2 and 3) with a Ricker 50Hz wavelet extracted from the seismic data by Fournier & Borgomano (2007)(Fig.4). A realisation of convolution is presented for each correlation model in figure 5.

Qualitative comparison of synthetic seimic. Synthetic seismic amplitude models are visually compared with MA-1 to MA-2 section of high resolution 3D seismic presented by Fournier *et al.* (2005) and Fournier & Borgomano (2007) (Fig.1b). Synthetic seismic shows a good visual correlation with original reflectivity data. The major features of the original high resolution seismic data (Fig.5A) are present on the synthetic seismic section: top and bottom reservoir reflectors, major internal reflectors and antiforms located on the eastern part of the buildup (Fournier *et al.*, 2005). This visual comparison allows us to validate our reservoir model on a first order. When comparing all of the synthetic seismic models together, it is hard to discriminate which geometrical model (Fig.3) or acoustic impedance model (Fg.4) has been used to generate the synthetic seismic model in figure 5. It appears that even when good quality reflection data are available, internal architecture of the Malampaya buildup can be explained by several stratigraphic correlation models of diagenetic units.

Quantitative comparison of synthetic seismic. The normalized root mean squared difference (NRMS) of the MA-1 to MA-2 cross-section is computed to evaluate the likeness between synthetic seismic models. Considering one reference seismic model r and one alternative synthetic seismic model a, the NRMS at a seismic trace between top (t) and bottom (b) reflectors is defined by:

$$\begin{aligned} NRMS &= \frac{2 \times RMS(r_i - a_i)}{RMS(r_i) - RMS(a_i)} \\ \text{with } RMS(x_i) &= \sqrt{\frac{\sum_{i=t}^{i=b}(x_i)^2}{N}} \end{aligned} \tag{6}$$

where N is the number of samples between t and b.

We define the synthetic seismic computed from the convolution of one realisation of acoustic impedance on the DSM as our reference seismic. From ten simulations of acoustic impedance, ten synthetic seismic models are computed on each stratigraphic correlation model (DSM, SSM1, 2 and 3). Figure 6 shows the NRMS computed between our reference model and each of the forty alternative synthetic seismic models. The mean value of NRMS of each stratigraphic correlation model (Fig.6b) shows that the difference between the reference seismic model and DSM-based alternative models is comparable with the difference between the reference model and SSM-based seismic models. Moreover, figure 6c and 6d show that the NRMS variability is similar for DSM-based and SSM1-based models, both reaching minimum and maximum values of the envelope of all the realizations. Dispersion at the well location observed on figure 6 are explained by well deviation

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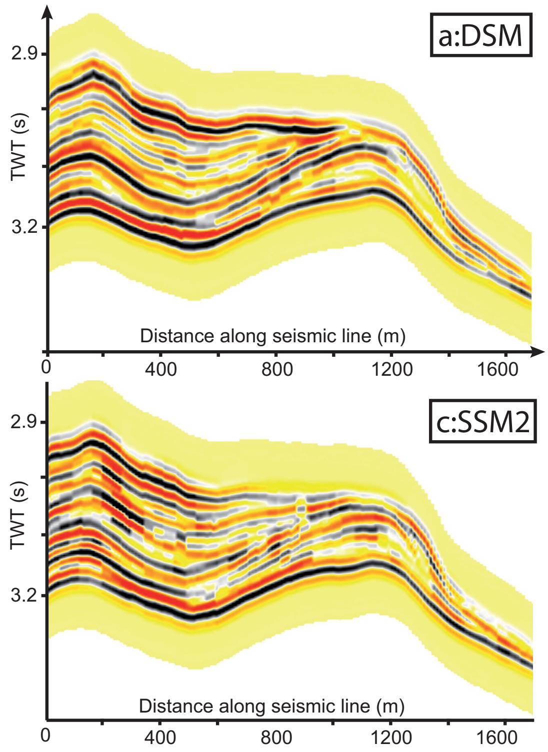

Figure 5: *MA-1 to MA-2 cross-section of synthetic seismic amplitude model computed by convolution of acoustic impedance model (Fig.4) with a 50hz Ricker wavelet. All of the four seismic sections display comparable internal reflectors and may result in similar stratigraphic interpretation.*

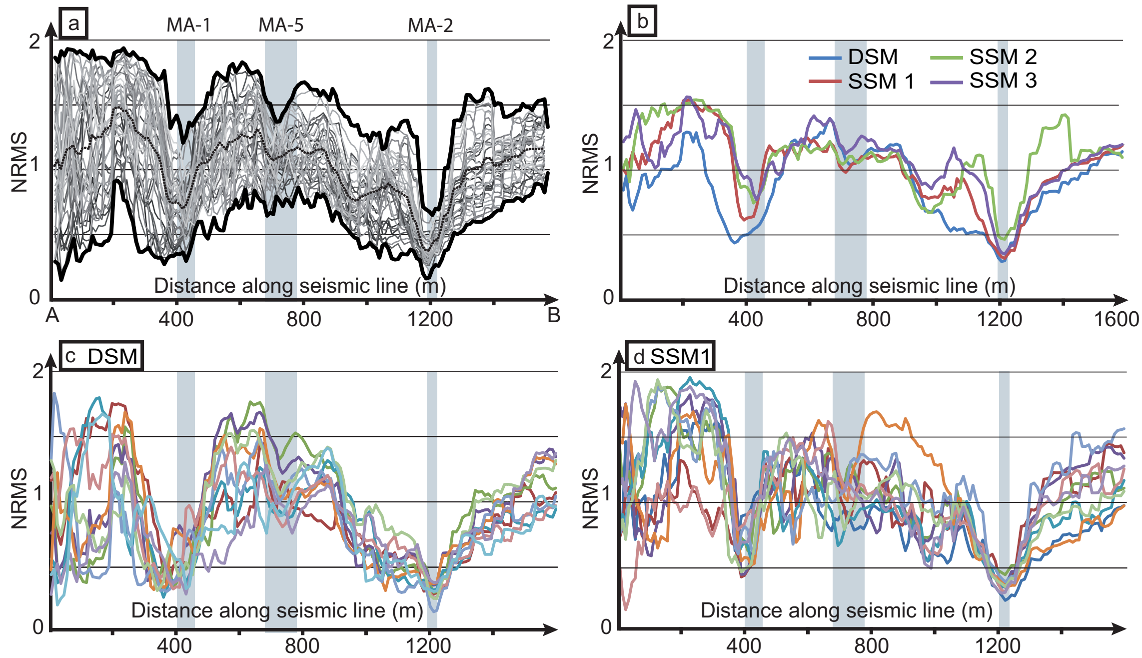

Figure 6: *NRMS computed along the MA-1 to MA-2 section between one reference seismic amplitude model computed on DSM and forty alternative seismic models computed on DSM, SSM1, 2 and 3 (ten on each). On (a) are displayed all forty computed NRMS lines, maximum and minimum values (thick line) and mean values. (b) Mean values of NRMS for each stratigraphic correlation model show comparable values. The ten NRMS computed on DSM (c) and SSM1 (d) show comparable variations. NRMS dispersion observed at well location (grey zones) are due to well path deviation. The well MA-5 trajectory is projected on the studied cross section which explains the amplitude of dispersion at its location.*

and grid rescaling between acoustic impedance simulation and synthetic seismic computation.

From this quantitative analysis, it appears that synthetic seismic data computed from different stratigraphic correlation models are comparable. One of the consequences of this observation is that several stratigraphic correlation models should ideally be considered when performing seismic interpretation.

Implication on fluid flow modelling

Flow simulation are performed on the MA-1 to MA-2 cross-section model, using the GPRS flow simulator, to evaluate the impact of alternative stratigraphic frameworks on flow response.

The porosity is simulated with SGS conditioned by wells MA-1, 2, 5, 7 and 8, using the same random walk as that used to simulate acoustic impedance and synthetic seismic models (Fig.4 and Fig.5 respectively). The permeability has been modelled using porosity-permeability cross-plots presented by Fournier & Borgomano (2007). To highlight the influence of correlation uncertainty on the recovery in a classical reservoir setting, we consider: (i) Malampaya as a black oil reservoir without an aquifer; (ii) a water injector close well to well MA-2; (iii) a productor well close to well MA-1; (iv) an initial oil saturation of 0.8. Figure 7 shows permeability models and oil saturation at four different time steps. The visual evaluation of saturation at different time steps shows that the use of alternative stratigraphic correlation models significantly impacts connectivity between porous/permeable units. This results in different drainage areas and may impact decision-making in reservoir development. The stratigraphic correlation models generated with our approach can be used to generate an *a priori* set of models representing reservoir stratigraphic uncertainties. A model screening method based on production data (Suzuki *et al.*, 2008) could be then used to efficiently select acceptable stratigraphic correlation models with regard to observed reservoir flow behaviour.

Conclusions

The stratigraphic well correlation of units identified along section is a hazardous task even if high quality data are available. This study shows that different stratigraphic correlation models may produce similar seismic images, and hence several stratigraphic well correlations models may be considered from the initial data (including in, our case, 5 wells and seismic data). As shown by the computed synthetic seismic models, seismic data may not discriminate stratigraphic correlation models. However, stratigraphic correlation models have a significant impact on fluid flow.

This paper demonstrates the necessity and the technical feasibility of a numerical management of uncertainty on stratigraphic well correlation. Additionally, model screening approaches could be used to select only stratigraphic models compatible with production data or well tests.

Limits of the proposed approach should be pointed out; in particular, the inability of our stratigraphic well correlation method to deal with diagenetic lenses. A way to manage this issue could be found in using improvement of the DTW algorithm proposed by Waterman & Raymond Jr. (1987). In the version of the DTW we use, a stratigraphic unit can be correlated to only one other unit ("one to one correlation") excluding diagenetic lenses. The "one to many correlation" configuration proposed by Waterman & Raymond Jr. (1987) makes it possible to correlate several successive stratigraphic units of one well to one unit on another well and thus to manage lenses. However, such a configuration calls for computing a correlation cost associated to the "one to many correlation". The mathematical expression of this cost is not easy to formulate honestly and requires additional development.

As highlighted by Bashore *et al.* (1994), the choice of the well correlation strategy affects not only the geometrical model used to guide the geostatistical simulations, but also dynamic reservoir model and the associated fluid flow predictions. This study corroborates their conclusions and points out that even when stratigraphic well correlation rules are defined, several well correlation models have to be considered. In the presented case study, diagenetic units are correlated using lithostratigraphic rules. However, in other geological settings such as carbonate ramps, significant lateral facies variability may exist. In such a case, correlation rules presented in this study are unsuitable. The DTW algorithm should then be associated to correlation rules managing lateral facies transitions as proposed by Lallier *et al.* (2009).

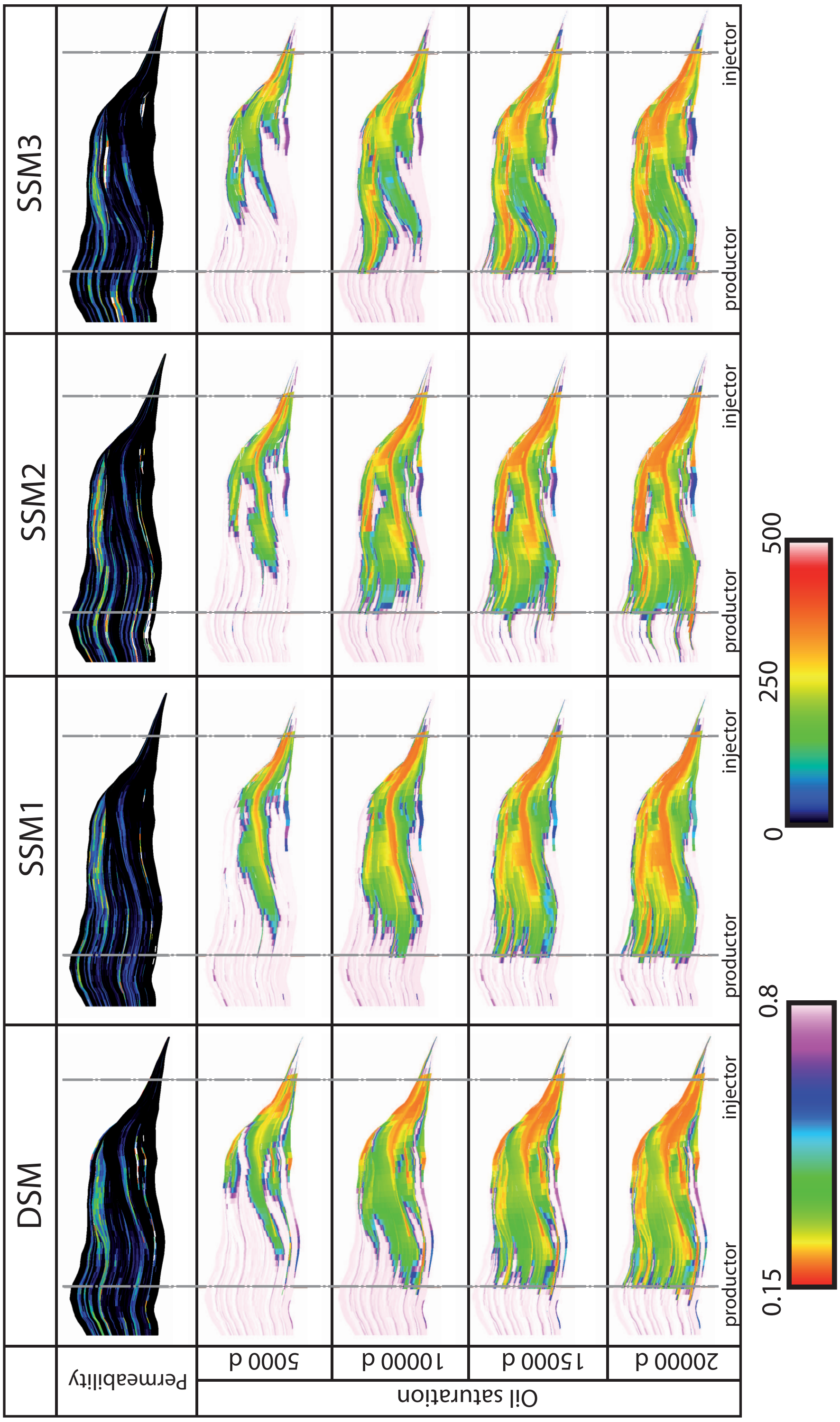

Figure 7: *Permeability models and oil saturation at different time steps (d = days) show that stratigraphic correlation uncertainty impacts fluid flow patterns.*

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