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USE OF SEISMIC TO CONSTRAIN GEOSTATISTICAL RESERVOIR MODELS: A QUANTITATIVE APPROACH USING PROPORTIONS OF FACIES.

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Introduction

Well data are the main data used to build geological probabilistic models in terms of lithological description, and petrophysical characteristics, associated with the control of the stratigraphic depositional environment. However, their spatial coverage is low, even at a development stage. Thus a lot of recent research works have focussed on the introduction in probabilistic models of secondary data characterized by a relationship, often indirect, with the reservoir properties. These secondary constraints as seismic data have a good spatial coverage but a different measurement scale than geology. Previous works have widely present new algorithms but the practical aspects of seismic information integration in the geological models are sometimes occulted.

The objective of this paper is to present a detailed analysis and evaluation of the real impact of these seismic derived constraints on the reservoir model in terms of reduction of uncertainties, heterogeneities distribution, and key geological characteristics… Using a synthetic but realistic case, different constraints, and different methods of integration are compared, and the impact of seismic is analyzed in the framework of the truncated gaussian methodology.

Non stationary truncated gaussian methodology.

A synthetic but realistic field case is used to illustrate the different steps of the methodology and to analyze and compare the impact of qualitative or quantitative seismic data in the geological model. This synthetic model has been generated in IFP and corresponds to a reservoir interval about one hundred meters thick, within a mixed carbonate-siliciclastic platform environment [1]. The reference grid has first been built in depth, and informed in terms of facies, porosity and impedance on a grid cell size of 12.5mx12.5mx1m. This grid has also been converted in time. Seven lithofacies have been identified as barriers (tight facies), low porosity carbonates, mean porosity dolomites, porous carbonates, porous dolomites, mean porosity sandstone, porous sandstone. The last three categories correspond to the reservoir facies. For the purpose of this work seven calibration wells have been extracted from this model and used as "real wells" data with the seismic in order to analyze the well to seismic relationships (fig.1).

Using these well data, the truncated gaussian method [2] has been used in order to generate the 3D facies heterogeneities in the reservoir grid, using statistical parameters calibrated from the data. This method allows in particular to work in a chronostratigraphic framework, and to be consistent with the geological sequences. Among the statistical parameters required for the simulation, the vertical proportions curves of facies, computed from the wells represent the proportions of facies at each level of the reservoir in the depositional framework (fig.2).

However, the horizontal probability of occurrence for each facies is not constant horizontally in the whole reservoir, and one single vertical proportion curve is not sufficient to describe correctly the field. It is thus necessary to compute a 3D grid of facies proportions in order to account for the lateral variations within the reservoir (fig.3). These proportion curves of facies are distributed on a grid and used in the algorithm [3] to compute the facies in each cell of the model (fig.4). The next step is to inform this geological model with porosity values, and then to compute global and reservoir volumes.

As this approach is based on geostatistical simulations, each result is linked to a random seed and represents a possible realization of the reservoir. Thus, for each of the following tests, one hundred of realizations have been computed and results are analyzed on the histograms of one hundred reservoir volumes.

Integration of seismic constraint
The truncated gaussian method in a non stationary framework allows to integrate secondary constraints through the estimations of 3D grid of facies proportions [4]. The prerequisite is that the seismic information has been calibrated in terms of facies proportions, using different approaches. The constraint may be qualitative, as for instance a map of seismic facies, mainly in exploration cases when only few well data are available for the interpretation, or it can be quantitative when estimation techniques allow to extract maps of proportions of facies from the seismic data [1].

Qualitative information on the facies distribution at the reservoir level may be extracted by analyzing the seismic character of the traces on the corresponding time window. This is done by using statistical pattern recognition algorithms, applied to classify the portions of traces, once the traces are represented in a multidimensional space generated by the attributes used to capture the seismic character [5]. Each group of traces detected in the attribute space corresponds to a similar seismic response at the reservoir level, what is usually called a "seismic facies". A seismic facies is often related to some specific reservoir characteristics, such as high versus low porosities, high sand/shale ratio, etc. A map of seismic facies is thus a 2D grid where each cell corresponds to the class of each trace. This information is resampled on the grid of proportions, using a cutoff on the number of traces of each class in the proportion cell, and a cutoff on the probability of good classification of the traces. The result is used as a mask to select the cells of the proportion grid which can be considered as areas where a seismic facies is predominant. A representative vertical proportion curve computed from the wells belonging to this seismic facies is assigned to this cell. The 3D grid is then completed by kriging of the proportions for each level of the grid and each facies (fig.5).

Other methods using estimation techniques or neural networks allow to extract a quantitative information such as a local average of the proportion of facies or net to gross [5]. This map of proportions of facies is first resampled on the grid of proportions and used as an aggregation constraint in the kriging system for the computation of the 3D grid of proportions from the well data (fig.6).

Results and discussion on the synthetic example
Using the previously presented methods on the synthetic case, several tests have been performed in order to first quantify the impact of the different seismic derived maps of seismic facies on the reservoir volumes, and second to compare the results obtained with or without using a seismic constraint in the reservoir simulation.

Sensitivity analysis have first been performed in order to test the influence of the computation parameters at each step of the workflow: size of the cells of the grid of proportions, values of the cutoff on the number of traces, on the probability of assignment of the traces in the class in case of a map of seismic facies, on the correlation lengths used for the simulation, on the porosity model associated to the geological facies. The results show that changes in these parameters have in general a minor effect on the global histograms of porous volumes of the reservoir, which confirms the robustness of the method.

Other series of tests have been carried out, using different seismic constraints to compute the 3D grids of proportions, and then perform the facies simulations and the volumetric estimations: map of seismic facies with different segmentations from 3 to 7 seismic facies, and maps of proportions of tight facies, reservoir facies, and net to gross.

Figure 7 compares the statistics on the reservoir volumes computed on 100 simulations, using well data only, and using wells and a map of 7 seismic facies. Figure 8 compares the statistics on reservoir volumes computed on 100 simulations, using well data only, and using wells and a map of reservoir facies proportions as external constraint. On these graphs, the "real" volume computed on the synthetic model is also displayed as reference model.

Discussion and conclusion

We performed extensive tests using this synthetic case, different sets of wells and different kind of seismic constraints. The results lead to some general remarks:

First, the representativity of the well set is of primary importance on the results and their analysis as it governs the proportions of facies for the whole reservoir. If the set of wells is a good statistical sampling of the reservoir, it will be sufficient to get a good estimation of the real porous volume of the reservoir. In that case, the additional information given by the seismic derived constraint will mainly be geographic, as the location of barrier for instance. On the contrary, and in most real cases, if the wells are not representative of the mean proportions of facies within the reservoir, additional seismic constraints will be important for a more accurate estimation of the volumes.

This work also points out that the volumes should not be the only parameter used to analyze the results and compare different hypotheses. In particular, the seismic derived constraint can strongly modify the locations of heterogeneities, and the connectivity of reservoir bodies in the reservoir.

References:

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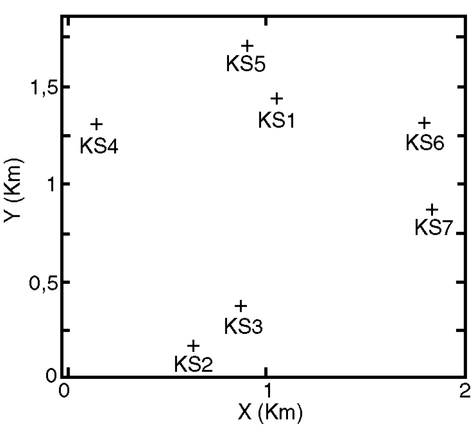


Fig. 1: location map of the wells on the synthetic case

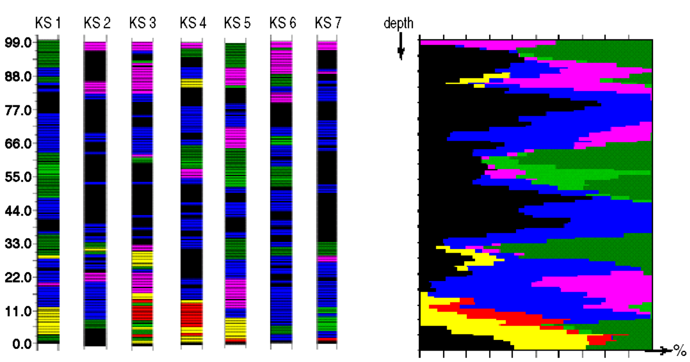


Fig. 2: computation of a vertical proportion curve (VPC) from well data

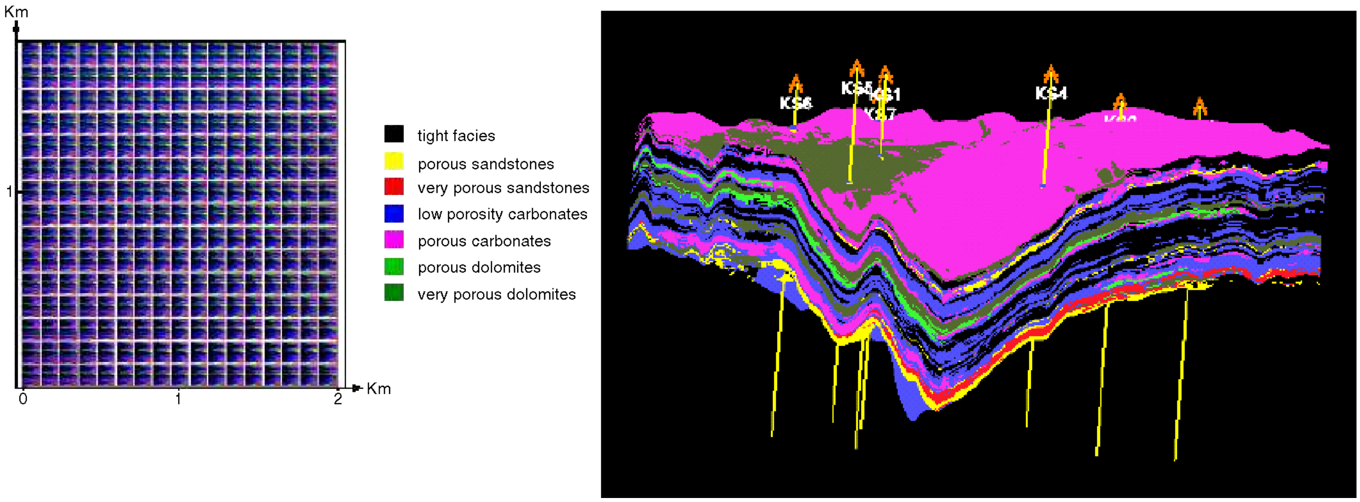
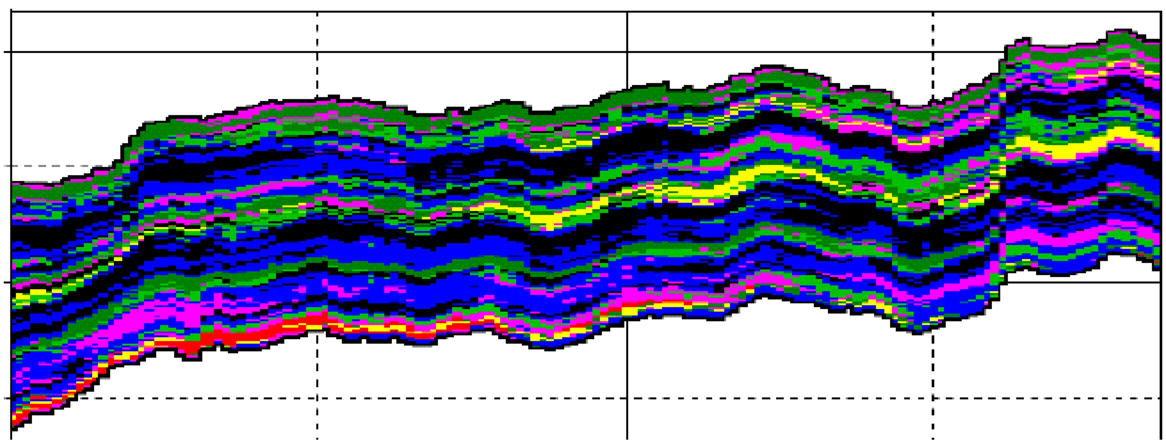
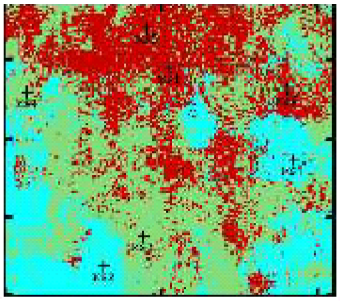


Fig. 3: example of a 3D grid of proportions. In each cell is computed the local VPC representing the local vertical sequence of facies

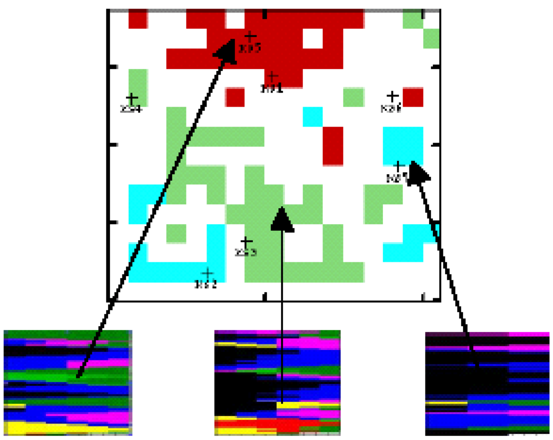


EW vertical cross section

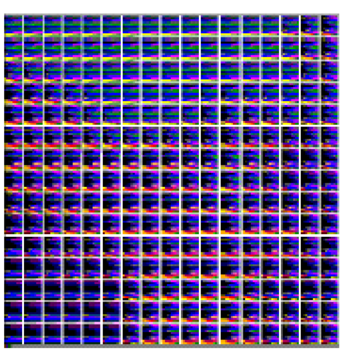
Fig. 4: result of one reservoir simulation



a - map of seismic facies.
Each color corresponds
to a class of seismic facies.

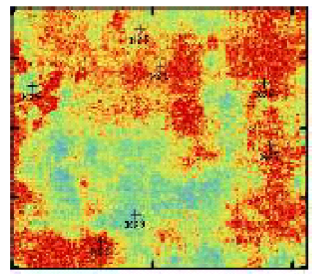


b - resampling on the previous map on the proportion grid
using a cut-off on the probabilities of classification and
on the representativity of the traces.

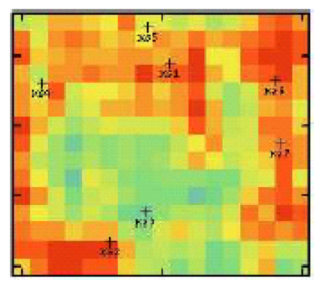


c - filling of the 3D proportion grid
by kriging of the proportions of
facies in each cell

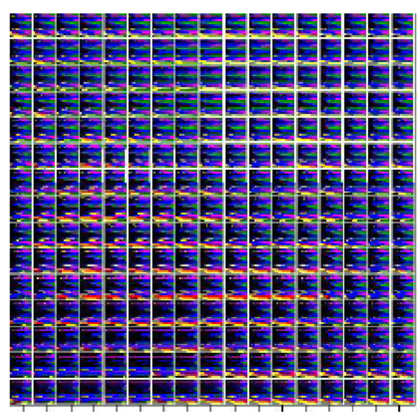
Figure 5: use of a 2D map of seismic facies in the computation of the 3D grid of proportions



a – map of proportions of reservoir facies



b - resampling of the previous
map on the proportion grid
and location of the initial well/
proportions of facies.



c - filling of the 3D proportion grid
by kriging of the proportions of facies in
each cell, using an aggregation constraint

Figure 6: use of a 2D map of mean proportions of reservoir facies in the computation of the 3D grid of proportions.

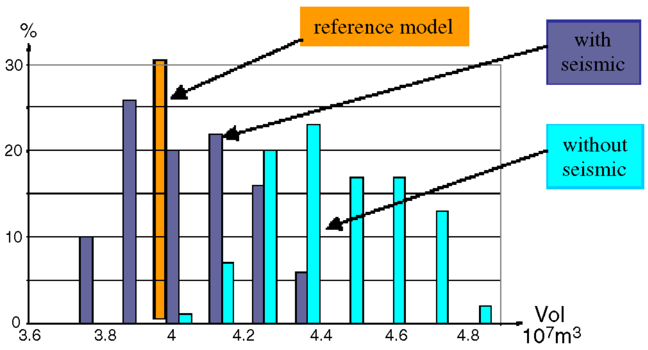


Figure 7: histograms of reservoir porous volumes computed on 100 simulations with or without seismic constraint (map of seismic facies).

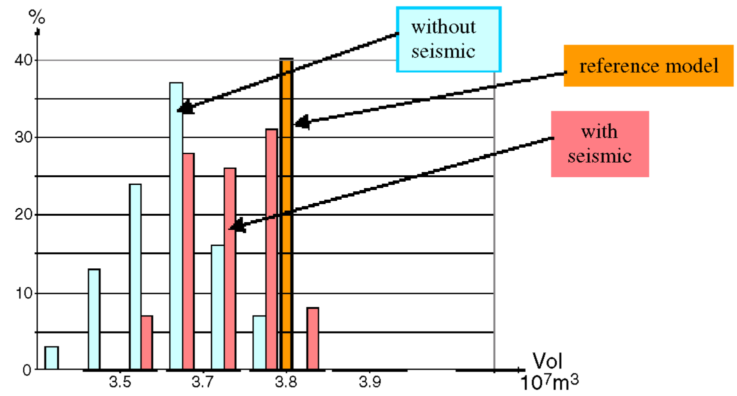


Figure 8: histograms of reservoir porous volumes computed on 100 simulations with or without seismic constraint (map of proportions of reservoir facies).