UNCERTAINTIES IN RESERVES ESTIMATIONS : SENSITIVITY TO GEOSTATISTICAL PARAMETERS

B.Doligez *, H.Beucher **, F.Geffroy **, R.Eschard *, D.Guérillot *

*** Institut Français du Pétrole, 1 et 4 avenue de Bois Préau, 92852, Rueil Malmaison, France**
**** Centre de Géostatistique, 35 rue Saint Honoré, 77305, Fontainebleau, France**

SUMMARY

In the field of reservoir characterization, numerical modeling techniques offer more and more intricate tools which allow complex and realistic geological images of a reservoir at a fine scale to be obtained. These images are then informed with petrophysical properties and can be used for the estimation of the hydrocarbon volume in place and the connectivity, which are of major importance in the early stages of exploration of a field. Then scaling-up provides consistent models for the fluid-flow simulations.

Geostatistical methods are clearly well suited for modeling heterogeneities of a reservoir at the delineation phase of a field. The uncertainties associated to the estimations on the porous volume are linked to different types of modelisation uncertainties :

- uncertainties on the data, which may be qualitative (conceptual geological model) and/or quantitative (petrophysical model, sampling, surfaces estimations...),
- uncertainties on the geostatistical model parameters (lithofacies proportions, correlation lengths, geometries of boolean objects...),
- variability of the realizations for the chosen model as the results are multiple « statistically correct » realizations that are conditioned to the data.

The choice of the model is the first factor for uncertainties, mainly when few conditioning data are available. The second factors for uncertainties are the parameters of the chosen model.

In this paper we briefly present different geostatistical methods which allow reservoir heterogeneities to be simulated. The associated parameters and the different ways to integrate external constraints derived from seismic or from production data are also summarized.
Tests of sensitivity to some parameters are performed (petrophysical properties, size of elementary channels, correlation distance and lithofacies proportions). These tests allow the critical uncertainties for volume estimations to be put in order of importance, depending on the geological environment and initial available data. This is illustrated on several examples derived from outcrops and real field data.

INTRODUCTION

In the appraisal stage of the exploration of a field, the estimation of hydrocarbon volume and associated uncertainties are of major importance for supporting HC exploration and production decision-making (Montadert and Guérillot, 1994, Floris and Peersmann, 1998). Methods for modeling prospects, mapping properties and uncertainties and building reservoir models are proposed by numerous authors (Budding et al., 1988, Henriquez et al., 1988, Harbaugh et al., 1995, Lia et al., 1997, Hefner and Thompson, 1996). The more data and constraints are used to build the reservoir model, the less uncertainty on the estimation of the reserves there will be. Geostatistical modeling techniques are well adapted to deal with data of various resolutions and are efficient for their integration.

The first objective of this paper is to present a methodology which permits the estimation of these volumetrics and uncertainty on initial hydrocarbon volume in place in a reservoir, integrating constraints derived from seismic or production data and using geostatistical tools. The method is based on a software package, Heresim (Guérillot et al., 1989, Rudkiewicz et al., 1990), which has been developed by IFP (Institut Français du Pétrole) and CG (Centre de Géostatistique), and which offers several algorithms for simulation to be used depending on the geological setting (Matheron et al., 1987, Ravenne et Beucher, 1988, de Fouquet et al., 1988, Galli et al., 1990, Doligez et al., 1992, Eschard et al., 1993). The first step is to simulate a realistic geological image of the reservoir, as a grid informed with

lithofacies at a fine scale. Then the petrophysical parameters are computed in each grid cell, depending on the lithofacies, and volumetrics computations of porous volumes and fluids in place are performed. A last step consists in scaling-up the petrophysical properties in a coarser grid which will be the input for fluid flow simulators.
The second objective of this paper is to evaluate the sensitivity of the reserve estimations to various geostatistical parameters, depending on the chosen method for the facies simulations.

In order to generate the geological model, a preliminary compilation of the database and the construction of a conceptual geological model are necessary. In particular, the sedimentological interpretation of the well data and concepts from sequence stratigraphy allow the main sedimentary units of the studied reservoir to be defined together with their geometry and the chronostratigraphic horizons which can be used as a reference level. In some cases such as differential subsidence, the units may also be defined as proportional, when the beds are concordant with the limits of the units.

In practice, from the preliminary geological studies, the following data are needed in order to perform the simulations, taking into account the sequence stratigraphy analysis :

– surfaces which form the boundaries of the units, and correspond to identified maximum flooding surfaces or sequence boundaries,
– the observed internal architecture of the simulated units (stacking pattern), which determines the correlation mode in the unit (parallel or proportional)
– the facies at wells, generally defined from core and log analysis. The wells, vertical or deviated, are first gridded on a regular grid which will be the frame for the simulation. A facies is attributed to each cell on the path of the well.

The lithostratigraphic units are simulated independently from each other, and the volume between their top and bottom surfaces is filled with facies using different geostatistical methods and parameters.
Among the stochastic simulation techniques, two different approaches are mainly used in the field of reservoir characterization:

– the « pixel » methods which consist in generating vertical and horizontal successions of facies or petrophysical parameters using different mathematical algorithms,
– the « object » methods which consist in generating geometrical objects (channels, bars, faults...)

Heresim offers the choice of both types of methods for the facies simulations, the results of which honor the well data and the variability computed from the data.

« Pixel » simulation methods

The main geostatistical parameters which are used in the simulation algorithm, based on the truncated gaussian method are the proportion curves and the variograms, horizontal and vertical, computed from the well data.

The variograms are distance dependent mathematical functions which characterize the spatial correlation of a given property or function. In this case, the variograms are computed on the facies and used to characterize the mean size of sedimentary bodies of a given facies, or the distance between the bodies. Figure 1 shows an example of experimental variograms computed from well data, along the vertical direction on well samples. Each curve corresponds to a different facies. The distance for which one curve reaches a constant value is called the range, and corresponds to the distance above which two points with the same facies are no longer correlated. Since the simulation algorithm needs a variogram model, i.e. a theoretical curve of which the equation is known, a fitting step is performed before the simulations, which consists in choosing a model which best fits the experimental curves.

Vertical proportion curves can be considered as a particular and original graphic representation of the stratigraphic sequence. They represent the percentage of each lithofacies at a given level in the lithostratigraphic unit, computed from the gridded wells, as illustrated in figure 2. In this figure, the horizontal axis represents the proportions of lithofacies, computed from the wells, and the vertical axis is the vertical direction. These vertical proportion curves are a visual and synthetic summary of the vertical stratigraphic sequence. They are also used quantitatively in the simulation algorithm.

During the simulation, a gaussian (i.e normally distributed) random function is used, which is computed using the previous variogram model. This function is truncated by thresholds, linked to the local proportions of facies to compute the facies in each cell of the grid. Sometimes, the geological depositional environment of the studied unit does not allow one single vertical stratigraphic sequence to be used for the whole area, in the case of lateral changes or depositional trends for instance. The algorithm has been extended with the use of a variable function for the thresholds to take into account these non-stationary cases. In these cases, the variable thresholds are given by grids of proportions, which are 3D grids informed with local proportion curves in each cell instead of a single vertical proportion curve for the whole unit, as illustrated in figure 3. This figure is a horizontal view of a field, divided into regular blocks which are informed with local vertical proportion curves. Different methods are available to compute a 3D grid of proportions and allowing to take into account external constraints, derived from geology, seismic or production data (Johann et al., 1996, Mouliere et al., 1996, Fournier, 1995, Fournier and Derain, 1997, Doligez et al., 1999). These constraints may be qualitative, or quantitative. The simplest way to fill the 3D grid with local vertical proportion curves consists in dividing the area into several zones and to assign one particular vertical proportion curve to each area. The geological or seismic derived interpretations are thus used as a background to define the different areas. Other methods can be used to fill the 3D block of proportions by kriging of local proportions, or of well data. Moreover, when an additional quantitative information is available, derived from seismic or production data, another constraint is added in the kriging system to account for it (Doligez et al, 1999).

This truncated gaussian simulation algorithm has recently been extended to become a pluri-gaussian method (Le Loc'h and Galli, 1997). In this approach, the lithofacies simulation is obtained by simulating two (or more) gaussian functions. A threshold rule has to be given, illustrated in figure 4, as a diagram which defines the contacts and transitions between facies. In this diagram also, the horizontal axis represents the possible values for a first gaussian function and the vertical axis the possible values for a second gaussian function. This diagram has to be combined with the vertical proportion curves. The method allows a large combination of different geological features to be simulated as illustrated in figure 4. This figure displays two different horizontal planes in a lithostratigraphic unit simulated using the plurigaussian algorithm. It is thus possible to combine different processes such as sedimentation and diagenesis in the same simulation.

At this step, it should be emphasized that the results of the simulation are numerous possible images of the studied reservoir, all of them honoring the data, and all of them having the same statistical parameters, as shown in figure 5. In this figure, the same vertical cross-section of a reservoir is displayed, after four simulations which used the same conditioning wells, the same geostatistical parameters, and generated from four different initial seeds.

« Object » and « Nested » simulation methods

Another type of simulation methods such as the boolean method uses an object-based approach. The principle is to generate geometric objects with a random shape, a random size, and which are randomly located in space. The parameters of such a model which is available in Heresim are the mean geometry of the objects, and an intensity function. For example, the channels represented in figure 6a are defined as half sinusoids, defined by six parameters and their tolerance : orientation, width, height, length, period and amplitude. Each of these parameters may also vary along the vertical direction. Other objects can be defined as half ellipsoids featuring crevasse splays or rectangles featuring fractures. The intensity function is generally computed from well information or can be manually edited. It corresponds to the probability of the occurrence of the objects along the vertical direction. One example of intensity function is shown in figure 6b, for channels which are preferentially located at the top of the studied unit.

The pixel and the object methods can be mixed as illustrated in figure 7 which displays four times the same horizontal plane of a reservoir. The background has been simulated using the truncated gaussian approach, and the channels using the boolean algorithm. On the four images, the channels have the same mean geometry and respect the data. They cross the wells shown as triangles, while there is no channel crossing the well shown as a white diamond-shape. Again this figure illustrates the geostatistical variability, as each of the simulations uses the same parameters, and only the initial seed is changed.

Reserve estimations

Once the geological model is built, using one of the previously presented methods, the next step is to inform the grid with petrophysical properties and to compute first estimations of the porous and fluid volumes in place. One of the main ideas underlying this methodology is that the petrophysical heterogeneities in a reservoir are first linked to the lithofacies heterogeneities. Several methods are available to attribute petrophysical properties to the cells of the grid, depending on the available data, and on the correlations between the facies and their properties. The porosity may be assigned as a constant mean value for each facies, or by selection of a random value in a given distribution which is defined for each facies. The permeabilities may be attributed using similar rules, or computed by regression from the porosities. In some cases, the petrophysical properties may also be interpolated or simulated directly by kriging from values at wells, for each facies. Figure 8 is an example of experimental histograms of porosities computed from well data for six different facies. These values will be used as a « statistical model » in the last part of the paper. In the same example, another model for petrophysical parameters has been defined as a « constant model » which consists in attributing a constant value of porosity (29%) to the reservoir facies and a zero porosity to the non-reservoir facies.

Just as for a classical method to estimate the fluid volumes in place, it is necessary to define the fluid contacts, WOC and GOC. It is then possible to compute the global porous volume and the fluid volumes in the reservoir. From the porosity distribution or from laboratory measurements, a capillary pressure curve is assigned to each facies. In addition, knowing the fluids contacts, a hydrostatic pressure field is calculated for each phase (water, oil and gas). The inversion of this pressure field for each cell of the geostatistical model allows each phase saturation to be calculated.

Tests of sensitivity to the geostatistical parameters

The previously described method allows well constrained images of a reservoir to be obtained, taking into account geological, geophysical and production data, which are informed in terms of lithologies and of petrophysical parameters. It has also been noticed that these images are only realizations of a geostatistical algorithm, and that it can be generated as many images as possible initial seeds, all of them honoring the well data, and all of them with the variability computed from the data. Some questions then arise: How sensitive are the final computed volumes to this geostatistical process ? How sensitive are these volumes to the uncertainties which are linked to the initial data and parameters ?

Some sensitivity tests have been carried out, which are presented in this part. Fifty simulations have been performed using the previous dataset, four conditioning wells, a non stationary truncated gaussian approach with the same models of variograms, but two different petrophysical models, the « statistical model » and the « constant model » . Five facies have been defined from well data and from the geological model which corresponds to a fluvio-deltaic environment, and a fining upward sequence in the studied unit. The facies are ordered from 1 to 5, corresponding to very clean sands, clean, medium, argillaceous, interbedded and shales. For each resulting simulation of the reservoir, the global volume, the net oil volume, and the net gas volume have been computed, and histograms of the obtained results on fifty simulations are plotted in figure 9. Figure 9a displays the histograms of the net volume of the total reservoir obtained using the two different petrophysical models. For each family of simulations, the width of the histogram, around 12%, corresponds to the geostatistical uncertainty. The two obtained histograms corresponding to the use of the two petrophysical models are well distinct, as are those which are in figure 9b corresponding to the computations of the net volume of oil. The explanation lies in the differences of the petrophysical models : the « statistical model » attributes a very high porosity to the main reservoir facies, (facies 1 with a porosity around 40% in figure 8) while the « constant model » averages all the porosities in the reservoir to 29%. Facies 1 takes up the largest part of the center of the reservoir, as shown by the vertical proportion curve (Fig.2), and the difference in its porosity has a direct impact on the volume. These differences are less sensitive if we analyze the statistics computed on the net gas volume. This is due to the fact that the facies heterogeneities are mainly located in the top of the structure, and the porous volume in the gas area does not contain a lot of very porous and very clean sands.

A second set of statistics on fifty simulations has been computed on the oil and gas net volumes, using different geostatistical parameters. A first series is computed on simulations with horizontal ranges equal to 500m in x and y directions, a second one with horizontal ranges equal to 1000m in x and y directions, and a final one with horizontal ranges equal to 5000m in the x and y directions. The results are displayed in figure 10 as histograms of the fluid volumes. It appears that these changes in the correlation parameters are not crucial for the final results in terms of net fluid volumes, in this example. The different histograms of results obtained show very close mean values, even if the uncertainty on the results in terms of width of the histograms is affected by this correlation length. The main reason of these small variations of the global porous volumes obtained with different correlation lengths is that the proportions of facies are of primary importance in the simulation process. These proportions are indeed parameters of the model which are respected by the simulations and are directly linked to the global porous volumes. This result can also be partly explained by the fact that the non stationary simulations are strongly constrained by the data, even using only four conditioning wells, and the influence of the range of the variogram is of secondary importance in that case.

Different tools are also available in Heresim to analyze and validate the results of the simulations, and help to select the best representative images of the reservoir, in particular the analysis of connectivity. For a chosen facies, it is possible to compute the number and size of connected components, corresponding to sets of connected cells (two cells are connected when they have at least one common face). This analysis in terms of connectivity may also help to select the geological images before the scaling-up process. The changes of the correlation lengths will be more sensitive on the connected components computed for one facies, specially when the proportion of this facies is mean. In our example, the sizes of the main connected reservoir bodies are not significantly changed when the correlation lengths change, because the high proportion of clean sands in the reservoir implies a high connectivity in every case. However, a detailed analysis of the results shows different shapes of the connected bodies depending on the values of the correlation lengths.

CONCLUSIONS

At a reservoir appraisal step estimation of reserves could be greatly enhanced by using geostatistical simulation. At that time, only a few wells have been drilled, and only major descriptive features are available : general reservoir architecture, fluid contacts, fluid composition... Nevertheless, identification of the type of reservoir is often possible, and analogous producing reservoirs, or outcrops can be proposed . It is then possible to consider that the geostatistical parameters determined from these analogous geological formations can reasonably be used for the studied reservoir. This lets the geologist transform its qualitative analysis into a quantified description of the reservoir. The geostatistical approach allows to handle the following problems more easily than the classical approach :

- the continuity or discontinuity of the reservoir (built-in in the stochastic model)
- the variability of the petrophysical data

Heresim offers an integrated approach which allows :

- a realistic geological model of a reservoir to be built at a fine scale, taking into account available data and constraints from geology, geophysics and production,
- this geological model to be informed with consistent petrophysical properties linked to the geological heterogeneities,
- the porous and fluid volumes in the reservoir to be evaluated, with an associated uncertainty.

It is important to take into account the presence of internal heterogeneities in the volumetric computation, depending on the geological environment. The impact of the uncertainty on the initial data and parameters on the final volumes has to be analyzed in order to help the decision process. In the example presented here, the influence of the correlation lengths used in the simulation process is not as important as the choice of the petrophysical model associated to the facies.

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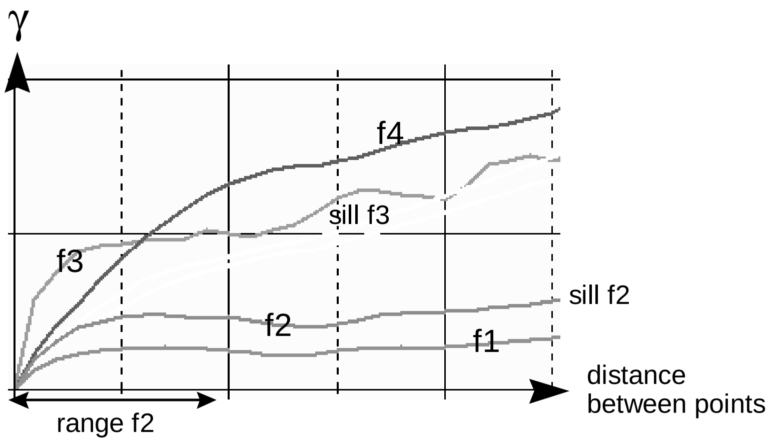


Figure 1 : example of experimental vertical variograms

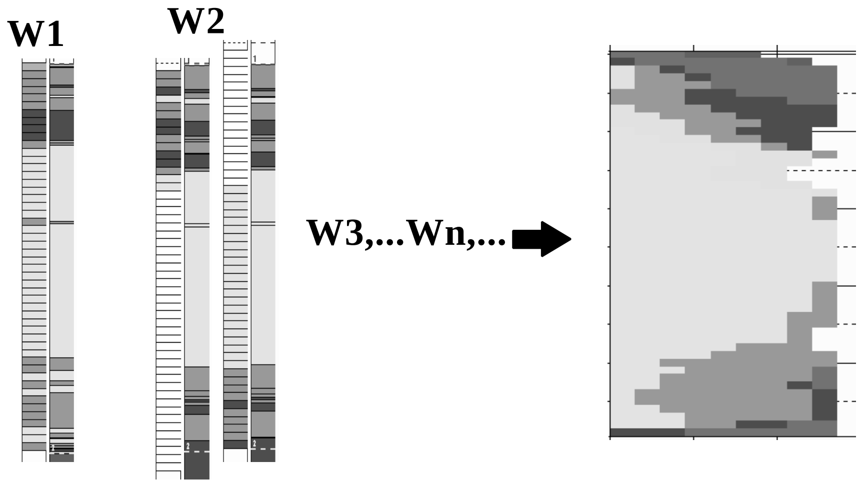


Figure 2 : example of a vertical proportion curve computed from gridded wells
The proportion of facies is computed level by level from well data

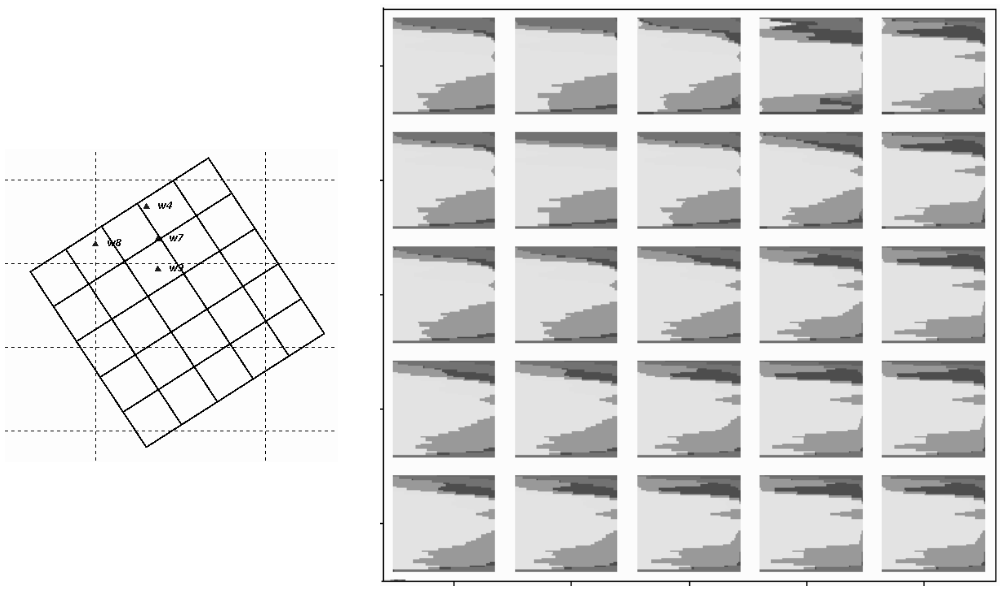


Figure 3 : example of a 3D block of proportions for non stationary simulations
A representative local vertical proportion curve is computed in each cell of the grid.

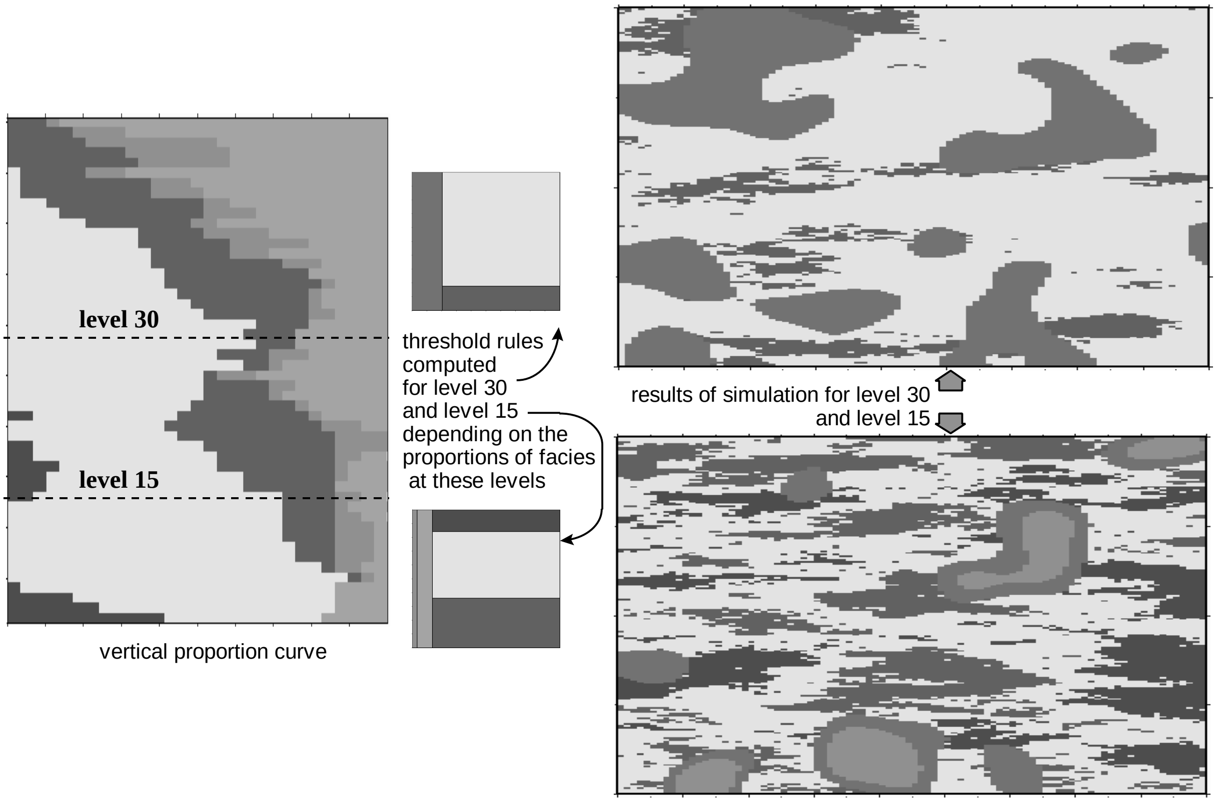


Figure 4 : illustration of the plurigaussian method

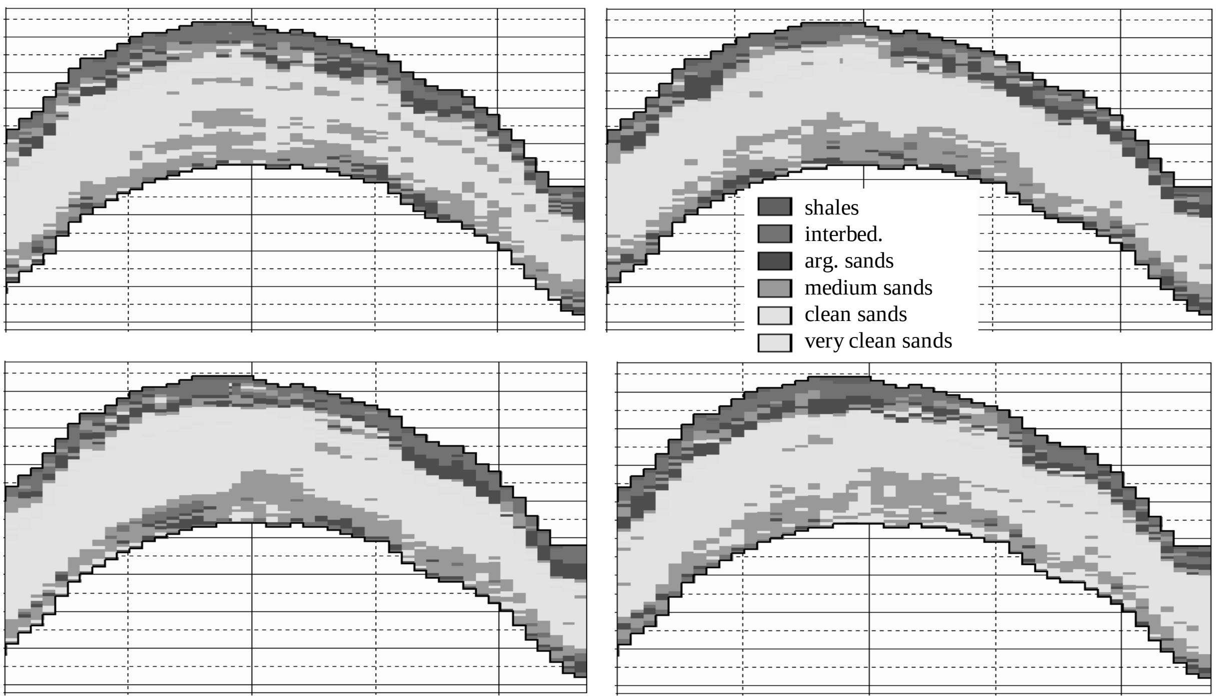
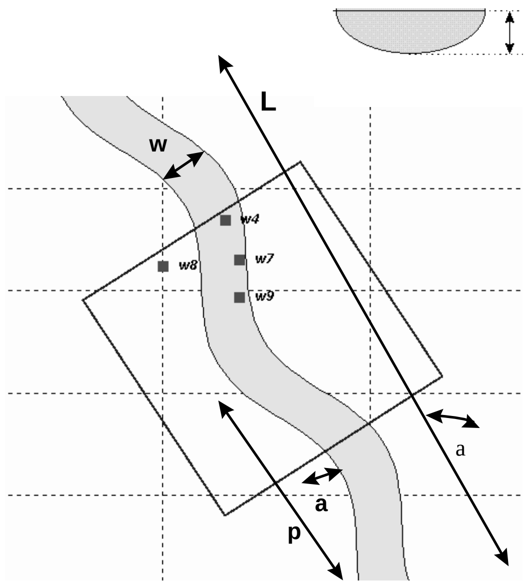


Figure 5 : illustration of geostatistical variability of the results of a pixel method:
same vertical cross section, same data, same parameters
4 different simulations using 4 different seeds



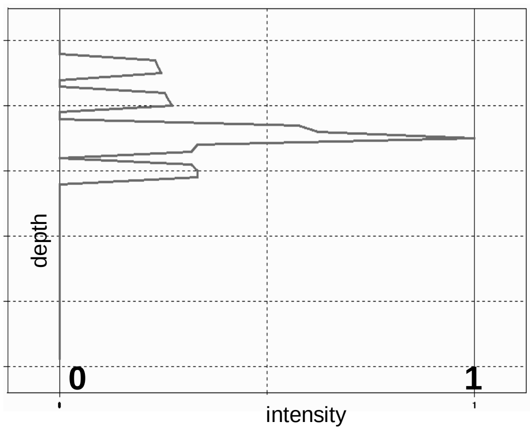


Figure 6a : geometry of an elementary object : channel

Figure 6b : intensity curve for boolean simulations

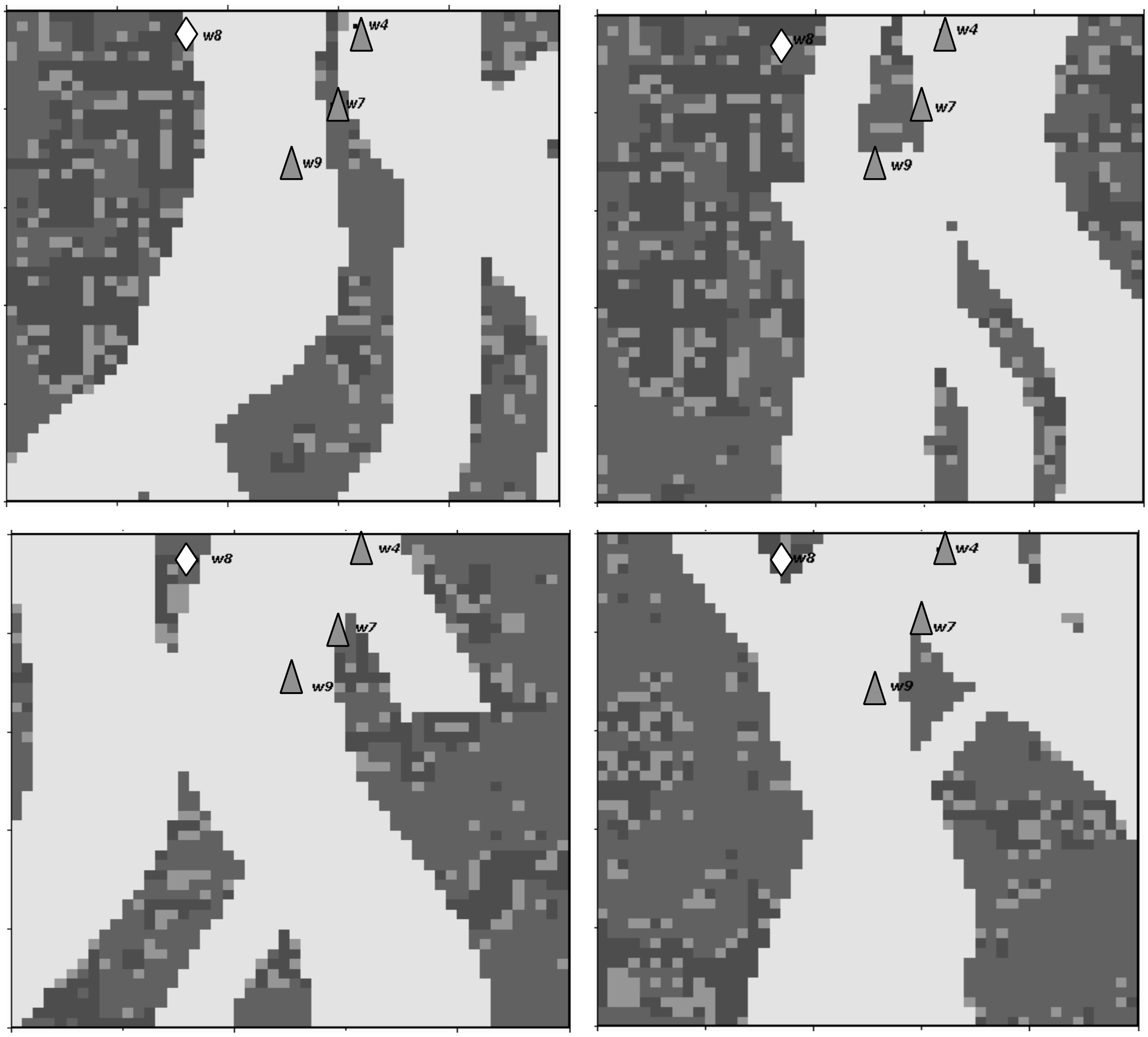


Figure 7 : illustration of geostatistical variability of the results of a boolean method:
same horizontal plane, same data, same parameters
4 different simulations using 4 different seeds

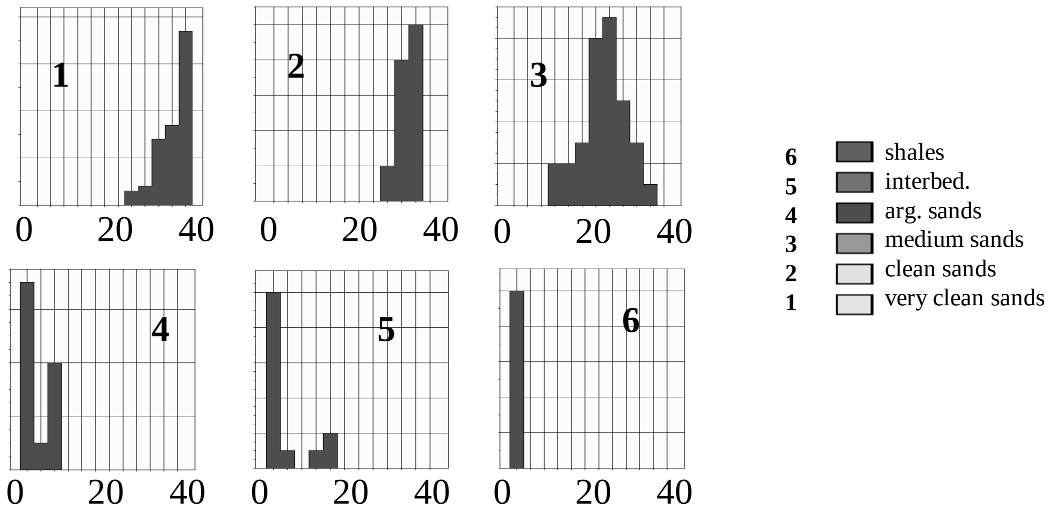
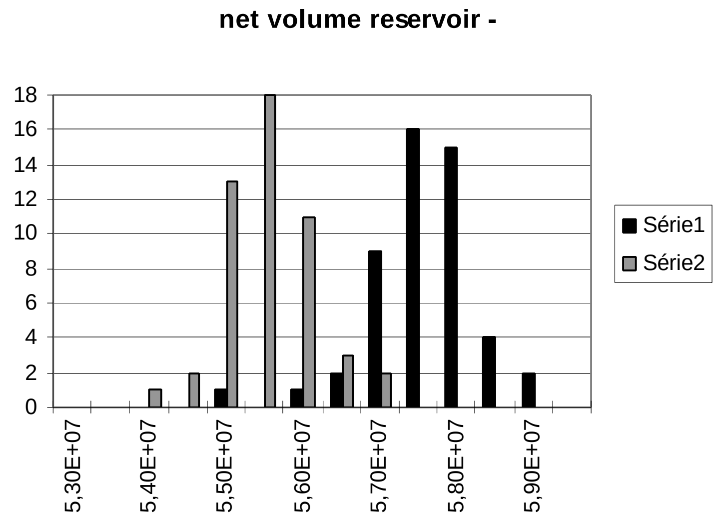


Figure 8 example of « statistical model » for porosities



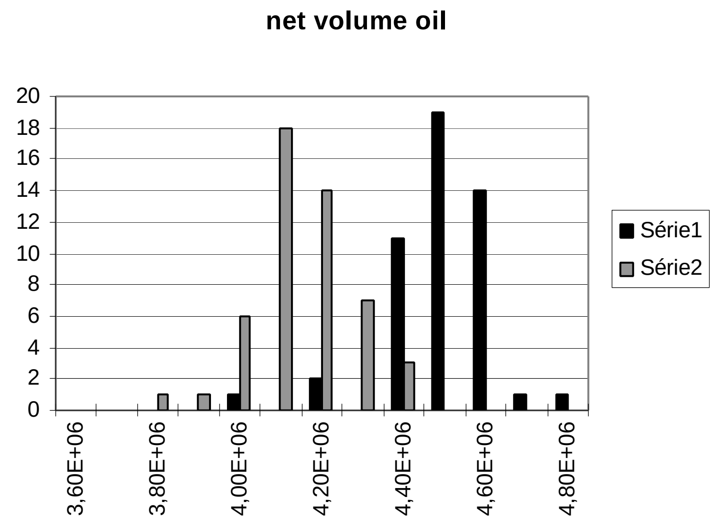
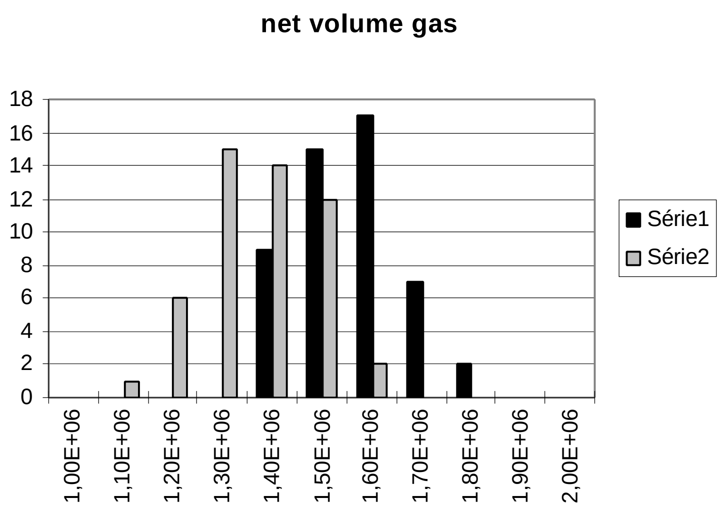
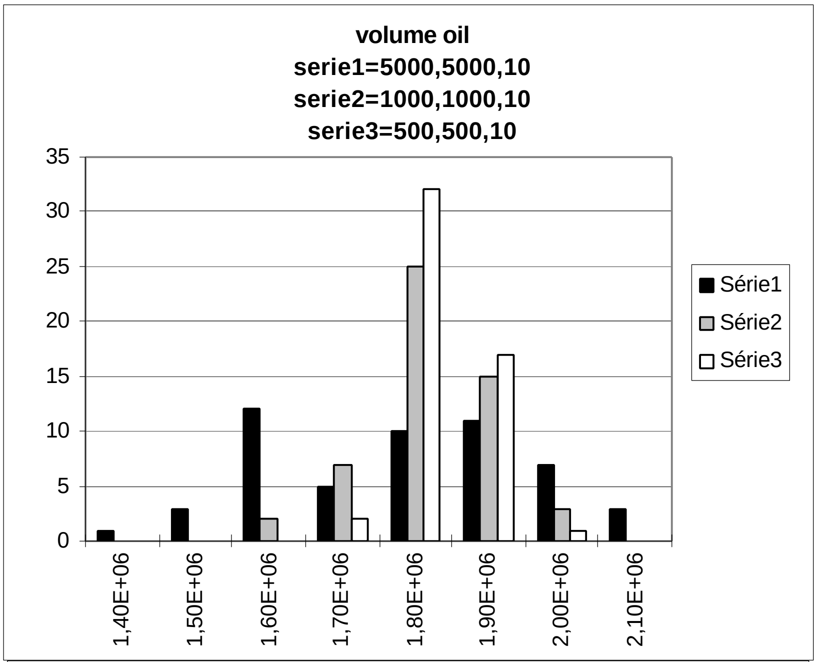


Figure 9 : global reservoir, net oil and net gas volume ; sensitivity to the petrophysical model (statistics computed on 50 simulations)

Serie1 :
« statistical » model for porosities
Serie2 :
« constant » model for porosities





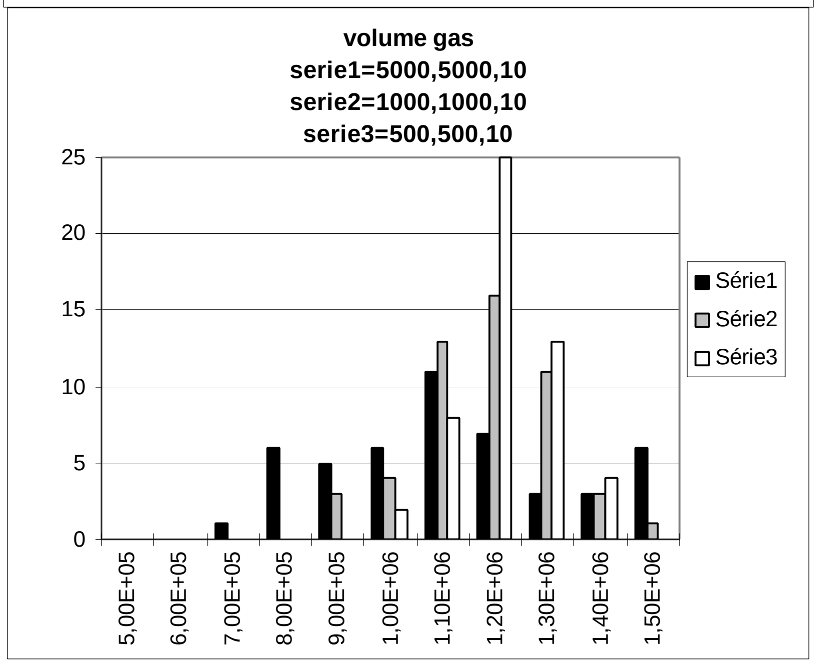


Figure 10 : oil and gas volume in place, sensitivity to the geostatistical horizontal ranges (statistics computed on 50 simulations)