GEOMODELING: A TEAM EFFORT TO BETTER UNDERSTAND OUR RESERVOIRS

Part 4: Geologists and Geomodeling

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INTRODUCTION

The previous two papers introduced the general geomodeling workflow as well as geostatistics. This paper and the next two review how geoscientists can contribute to a reservoir modeling project. We focus this month on geologists, before looking next month at the collaboration with petrophysicists and then with geophysicists. Seismic data is not available for all reservoirs or at least not in the initial stages of most projects. For this reason, this paper and the next one on petrophysics present techniques based on wells only. These techniques will be reviewed in a few months from now in the paper on geophysics, to take seismic into account.

The role of geologists is to interpret the available well (and seismic) data to characterize the reservoir. As far as reservoir modeling is concerned, this leads to two different types of collaboration (Figure 1). On one hand, the geologist does all the interpretation before the modeling is started. Once the interpretation is complete, it is fed into the geomodeling workflow. The other approach is one where the geologist still starts his/her interpretation before the modeling begins, but he/she also uses the reservoir model and the visualization and interpretation tools embedded in the reservoir modeling software to test, improve and finalize his/her interpretation while the modeling is in progress.

The first type of collaboration is still popular as it corresponds to the traditional separation of tasks in teams: one specialist accomplishes a task and the outcomes become the input to the next specialist's work. Unfortunately, this approach leads to less integration between specialists and sometimes it can potentially lead to misinterpretation of the reservoir.

The second type of collaboration requires more project management, as tasks are partly done in parallel. This increases the likelihood of data, ideas and knowledge integration within the team. We favour the second approach in this paper and that we will support in the subsequent papers in this series (both for collaboration with geoscientists and with engineers in the second half of the year).

In the first two sections, we illustrate the benefit of linking geological interpretation and reservoir modeling. The third section of this paper explains how geologists can guide the geostatistical algorithms of facies modeling by defining vertical proportion curves (VPC) and facies proportion maps. It is also important that the geologist helps the modeler in capturing the ranges of uncertainties associated to these inputs. This will be the focus of the last section.

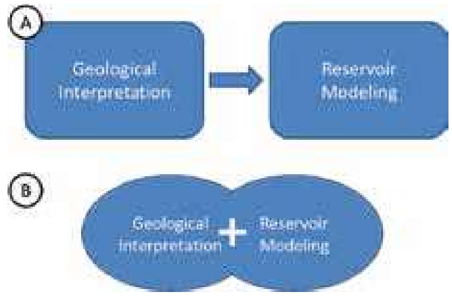

Figure 1. Collaboration between geological interpretation and reservoir modeling. A) Traditional approach where tasks are done sequentially. B) More integrated approach where tasks are done partly in parallel.

RESOLVING AN OCCASIONAL MISUNDERSTANDING BETWEEN GEOLOGISTS AND MODELERS…

Most modelers and geologists understand the benefits of collaborating one with the other. Nevertheless, problems between geologists and modelers do surface once in a while. Not often, far from that, but still enough to make it useful for us to try to resolve any misunderstanding. This is the focus of this section. Once this has been addressed, then we can talk about collaboration.

Some geologists would say that "us geologists, we do geology, you in modeling, you do mathematics", implying that modelers focus too much on mathematics, statistics and geostatistics, and don't create models which are "geologic enough". Some modelers have the exact opposite view of geologists: "us modelers, we are more rigorous because we rely on mathematics, while you geologists, your results are too interpretative".

Of course, these criticisms might be punctually true, but overall, they are largely misconceptions about what each side wants/ can do.

The source of this misconception seems to be rooted in the opposition between hand-contouring and automated contouring in the 70s and 80s. Then, through the decades, this original reciprocal suspicion has somehow impacted the relationship between geologists and 3D modelers. Reinvestigating briefly the original questions around contouring will help us going passed this misunderstanding.

Before the age of computers, geologists relied heavily on manual contouring techniques to predict rock properties between the locations where samples were available (Tearpock and Bischke, 2003). Manual contouring was applied, and is still applied today, to create everything from structural maps to property maps (porosity maps, net-to-gross maps…). As computers became more powerful and readily available, many experts looked at how they could replace the manual contouring by automated interpolation techniques (Watson, 1992). In these automated approaches, contours are no longer modeled per se. Instead, the property is interpolated at each location of a grid, using the data point as input parameters. Then, a set of contours is extracted from the property distribution on the grid, as a visual tool to review the results. Some software packages allow editing the spatial distribution by manually adjusting these contours. Otherwise, editing the maps is done by changing the input data or changing the parameters used in the mapping algorithm.

While these new techniques became progressively more common, some opposition grew. Some supporters of manual contouring concluded that computers can't be trusted to give a realistic, geological result. Hand-drawn contours will take into account the data but also the experience of the geologist and the local geological context. Computer-geneated gridding relies too heavily on the data and only the algorithm, thereby creating mathematically correct but geologically incorrect maps. Meanwhile, some supporters of automated mapping maintained that only mathematical algorithms ensure "objective" mapping. Gridding algorithms are "free of any geological bias or interpretation" (AAPG Wiki, webpage on "contouring geological data with a computer"), which is considered an improvement over "the subjective nature of manual contouring (which) was inimical to precision in maps" (Watson, 1992, page 40). Given the same set of input data and the same gridding parameters, everyone would get the

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same output map. Of course, proponents of automated gridding argue that gridding parameters must be selected carefully otherwise the maps might not make much sense. But at the end of the day, these subtleties were overshadowed by the more general question: who can we trust? Mankind and its intuition or machines and their advanced mathematics? This philosophical question still somehow underlies the opposition between some geologists and some modelers.

We are not suggesting that this debate can be settled in a few lines. Very humbly, we are only suggesting that one should look at this question from a different angle. Ultimately, a map is "good" if it is using the known (or assumed) geological characteristics of the reservoir to transform the input data into geological information (the map), and if it is useful in making predictions. Such a "good" map can be made by hand or by computer, in the same way that a "bad", non-geological map can be created by hand or by computer. Yes, manual maps might be an easier way to include geological knowledge rather than mathematical algorithms. And yes, gridding algorithms are more easily repeatable (a more neutral term than "objective") than hand-made maps. But at the end of day, as long as the resulting map is meaningful, it doesn't really matter how it is created.

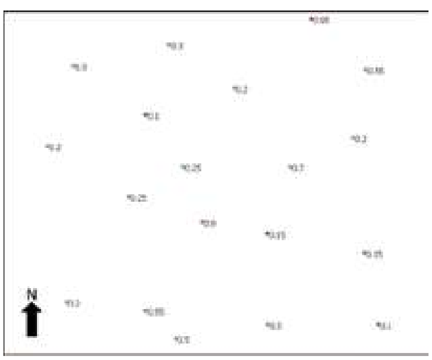

Figure 2. Location with known sand proportion values in the reservoir.

Figure 2, Figure 3 and Figure 4 illustrate this point. A sand/shale reservoir has been sampled by approximately 20 vertical wells. The sand proportion in the reservoir varies from location to location (Figure 2) and we are asked to create a map out of this data. A grid of cell size 100m*100m is created and a simple spline interpolation algorithm is run to interpolate the sand proportion between the wells (Figure 3). The result is "objective" – to use the old-school terminology one last time: all the data points are respected, no geological "bias" has been introduced and the map is repeatable. But is it geologically-correct?

A closer inspection shows that most wells have a low sand proportion, between 10% and 30%, except for several wells which are aligned along an approximated North-South axis in the middle of the map. There, the sand proportion rises to 55%, 70% and even 90%. Upon review of the well data, the reservoir is interpreted as a general plain with low sand content which was later incised by a single large channel rich in sand. With this in mind, it is in fact a mistake to interpolate between data points from the plain and from the channel. They must be treated separately to create a more realistic map (Figure 4). Firstly, the geologist drew a general shape for the channel (Figure 4, white lines delimiting the lateral extent of the channel). Then, the spline gridding algorithm was used first to interpolate the sand proportion in the plain and then to interpolate the sand proportion in the channel. The final map combines these two maps.

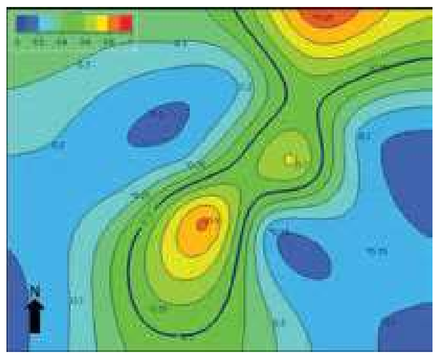

Figure 3. Gridding of the sand proportion samples with a spline interpolation technique

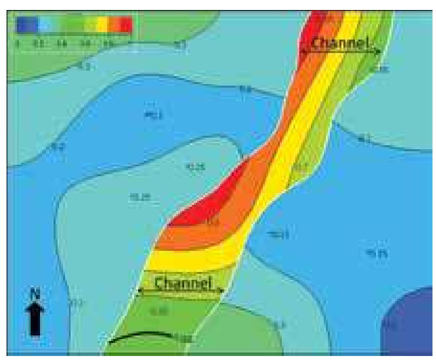

Figure 4. Gridding of the sand proportion samples by combining geological interpretation and the spline interpolation technique.

The map could be further refined, but this is not needed for us to draw our conclusions. Firstly, by "blindly" applying some default gridding algorithm, we will generate maps which are visually appealing and mathematically correct, but geologically wrong (Figure 3). But realistically, a less experienced geologist lacking any deep geological experience might have also created a very similar-looking map by doing hand-contouring. The final, "good" map required more time and effort to properly combine our understanding of the reservoir (concept of the channel) with the data. This "good" map, shown here, is created with a more complex usage of our gridding algorithm. A geologist experienced in hand-contouring would have drawn something similar using pencil and paper.

Again, the quality of the final product (the map) is more important than the means by which it is created. Reservoir modeling can't be done by hand, of course. Nevertheless, geologists doubting geomodeling need to realize that current modeling techniques allow for the integration of their geological expertise with the data. In return, modelers who believe that mathematics are the alpha and omega of their work must meet with geologists, listen to their understanding of the reservoir and then find ways to translate their geological concepts into mathematics. Doing so, men and computers can work together and not in opposition.

INTEGRATING GEOLOGICAL INTERPRETATION AND GEOMODELING

Let's assume that geologists are (now) all convinced that modelers will be able to respect their interpretation while building their models. We are still in a situation where the interpretation is completed before the modeling is done. It is not necessarily wrong to do so, but it's also possible to get better results by using the modeling to at least test and if needed improve the interpretation. An example illustrates this point (Figure 5 and Figure 6).

Figure 5 shows two wells A and B in cross-section, again in a sand-shale reservoir. They are part of a complete 3D dataset. The geologist decided to correlate the sand A1 of well A with the sand B1 of well B, as well as the sand A2 and B2. The sand A3 is not correlated to any sand in well B. From there, the geologist created a thickness map for the upper sand (A1-B1) as well as a thickness map for the lower sand (A2-B2) and the team starts making plans on how to develop this field. In parallel, a reservoir model was created to be fed to flow simulation (Figure 6). The two wells A and B were used in the 3D modeling, but not the geological interpretation itself due to limited communications between the geologist and the modeler: the team assumed that the model would necessarily match the geologist's interpretation, so minimal time was spend on this. The result is drastically different from what the geologist had in mind though: in the geomodel, the sand A1 is not connected to well B, while we have two massive sands A2-B1 and A3-B2. If the model was to be sent as is to flow simulation, the team would now have two different representations of their reservoir: the one expressed in the early sand thickness maps created by the geologist and now the 3D model.

From our personal experience, this situation occurs more often than not and this example illustrates two important points.

Firstly, as was mentioned earlier, a model needs to be built from the data (the wells) and the geological interpretation, not just the data. The next section will give more details about this. Secondly, the model can be used to test the geological interpretation. In this example, maybe the data, once looked through the prism of geostatistics and 3D gridding algorithms, make it more geologically reasonable to connect the sands as per Figure 6 and not as the geologist first thought. A 3D model will of course not always improve on what geologists interpreted up-front. Most of the time, the model will simply concur with their analysis. But at least the model should be used to validate the geological hypotheses. Then, after looping through interpretation and modeling several times and when a unique representation of the reservoir is agreed upon by the team, it is then time to

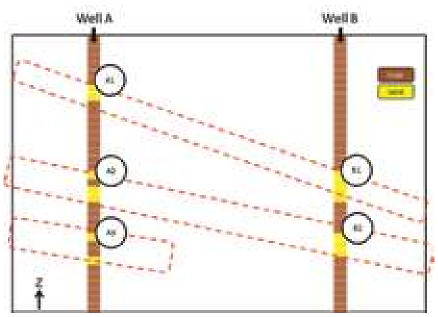

Figure 5. Geologist's interpretation on how the sands on two wells could be connected.

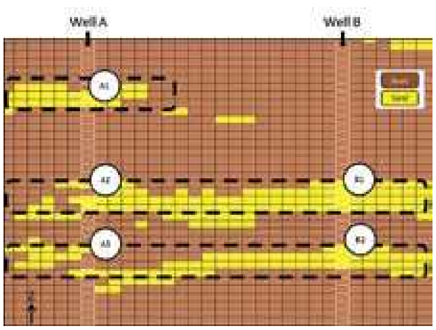

Figure 6. Reservoir model built around these two wells.

extract some useful maps (for example) to help guide the development of our field.

GUIDING FACIES MODELING

Modeling facies is a crucial step of reservoir modeling as it conditions how the petrophysical properties will be distributed afterwards. Geologists and modelers should work together on the different aspects of this modeling.

The main depositional information should be captured in the internal geometry of the 3D grid. Were the rocks deposited parallel to the base of the geological unit? parallel to the top maybe? Shall we go deeper and take into account some more complex trends identified by dipmeter data or by seismic interpretation? As explained in the second paper (Figure 6 and associated text in the March issue of the Reservoir), the internal geometry of the 3D grid will have a huge impact on how the facies will be distributed. For this reason, the geometry of the 3D grid must be built with care.

Once the 3D grid is built, geostatistical techniques will likely be the tools of choice for distributing the facies data. The third paper of this series explained the fundamentals behind these techniques (see the April issue of the Reservoir). As explained in the previous paper, the most common techniques for facies modeling are indicator kriging and indicator simulation. These techniques use statistics and variograms as input. They can also take into account some secondary variable which give some extra information on how the facies proportions should vary from place to place in 3D. These secondary variables are an efficient way for geologists and modelers to capture trends in facies.

Facies proportion maps, such as the one described in the first section (Figure 4), are an example of such secondary variables. These maps will guide geostatistical algorithms in terms of how the proportions of the different facies should vary aerially. On the other hand, Vertical Proportion Curves (VPCs) detail how the facies proportions vary vertically in the reservoir. VPCs are described below. VPCs and facies proportions maps are complementary. They can be combined into a 3D cube of facies probabilities. In such a cube, each cell of the grid will be assigned with the local probability of having each given facies. At last, multiple cubes can be combined together into a single cube. Some input probability cubes might be coming from well analysis while others might be coming from seismic analysis.

How VPCs are created and stored is described here through an example (Figure 7 to Figure 12).

The wells used to create the sand probability map (Figure 4) are hereafter used to populate facies in a 3D grid using indicator simulation (Figure 7). The reservoir is a box with flat top and bottom horizons. The 3D grid is made with a horizontal layering and cell sizes of 100m*100m horizontally and 2m vertically. The concept of having a large channel North-South is used here as well. It means that, in the same way that the sand proportion map was made in two separate zones (plain and channel), the geostatistics in the 3D grid will be applied in each zone individually. Instead of using the sand proportion map, the vertical distribution of the facies is looked at and stored in VPCs.

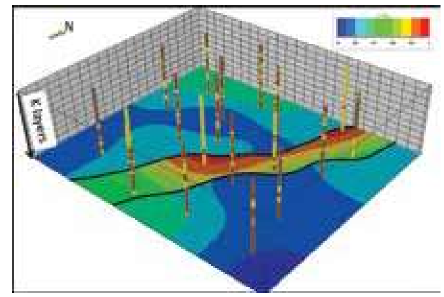

Figure 7. 3D view of the input well data used to create the sand proportion map and a 3D model.

A VPC is represented as a two-dimensional plot (Figure 8). The vertical axis represents the different horizontal layers in the 3D-grid (the different K layers – see Figure 7). For example, the top line (Figure 8, circle 1) represent the first K layer (K=1). In this specific 3D grid, the K layers are increasing from top to bottom, so the layer K=1 represents the upper two meters of the reservoir. For each K layer, the VPC captures the proportion of the different facies in that layer and this is stored in the horizontal axis of the VPC. In this VPC, the layer K=1 has about 70% of shale in average. This number is computed by looking for all the wells crossing the layer K=1 and then checking how many of them have sampled shale and sand at this depth.

In this reservoir, the proportion of shale does vary with depth. For example, from K=10 to K=15 (Figure 8, circle 2), we find about 40% of shale, while from K=15 to K=25, the proportion of shale progressively increases to 70-80% (Figure 8, circle 3). This is to compare with the global proportion of shale of 60% (Figure 8, dashed red line) which might give a false sense that one finds about 60% of shale at every depth in the reservoir.

This VPC is a global VPC as it is computed using all the data in the reservoir. Local VPCs can also be computed to check if the VPC won't change from one side of the model to the other. Typically, one would first compute a global VPC, then split the reservoir aerially into a few blocks of same size and compute local VPCs at this scale. If each block still contains enough well data, the reservoir is split into even finer blocks. The process continues until the blocks are too small to contain enough (or any) well data. The process also stops once it is shown that the VPC are now homogeneous (splitting one more time doesn't make any new variations to appear).

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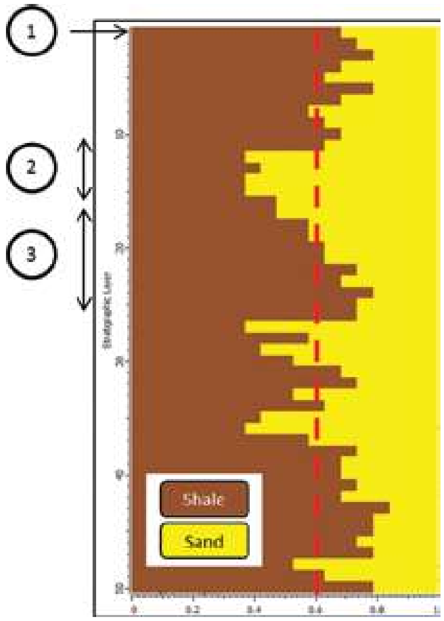

Figure 8. Global VPC of the sand/shale proportions.

Without going to multiple levels of local VPCs, it is also useful to check if the reservoir is not split into several major zones of different deposition history. In our case, we have two such zones: the plain and the channel. When computing a VPC for each zone, one can see that they are quite different (Figure 9). The VPC in the channel shows a lot of sand at all depths (Figure 9A), while the VPC in the plain shows a lot of shale everywhere (Figure 9B). Because of this, the global VPC should not be used and we need to consider these two VPCs as input for our geostatistics.

VPCs are basically nothing more than statistics, but computed at each K layer. As such, we find the same problem with VPCs than with computing any global statistics: the value of a VPC in a given K layer can't be trusted if this K layer is not crossed by enough well data point. The statistics in such K layers are undersampled. This appears in the VPC of the channel as the facies proportions tend to "jump" from one value to another from K layer to K layer. In comparison, the vertical changes are much "smoother" in the VPC for the plain. 6 wells are in the channel area while 13 are crossing the plain area. As a result, the VPC for the plain can be trusted more than the one for the channel.

Based on this analysis, facies are modeled in the channel by indicator simulation without VPC – we decide to ignore the VPC there. For the plain, two approaches are tested, to illustrate the impact of using a VPC. In a first model, the facies are modeled in the plain by indicator simulation without VPC (Figure 10). In a second model, the facies are modeled with VPC (Figure 11). Lastly, the VPC in the plain of each of these two distributions is computed (Figure 12). Until now, we computed VPCs from the well data as part of our data analysis and our desire to feed the geostatistical algorithms with some proper input. But it's also possible to use VPCs to check how the facies ended up being distributed in a given model. Such VPCs are computed from all the populated cells and for us, it's a way of checking that the modeling did (or did not) respect the input VPC.

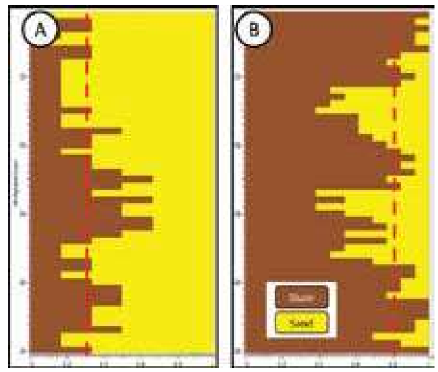

Figure 9. VPC of the sand/shale proportion in the channel (A) and in the plain (B).

In both models, the facies are distributed the same way in the channel area (Figure 10 vs Figure 11). This is normal as, in both cases, we used the same parameters for the indicator simulation without VPC. On the contrary, and as expected, the facies are distributed differently in the plain area. Visually, it seems that the sand is distributed vertically in a more homogeneous way in the model computed without VPC (Figure 11) than in the one using VPC as input (Figure 10). The VPCs from the two models confirm this impression. The VPC of the model computed with secondary variable is very similar to the input VPC (Figure 12A vs Figure 9B). In the meantime, the VPC of the model computed without secondary variable is not as close (Figure 12A vs Figure 9B). In both models, we have 80% of shale in the plain (this was the input global proportion). But in the model computed without VPC, at each depth, we are closer to this average 80% of shale than what the VPC from the wells was showing. This test shows that even in a reservoir like this one, where many wells are available, using VPCs ensure that we respect the general geological organization of the facies better. VPCs give a better geological control to us by removing some mathematical freedom to the algorithm as to where to distribute the facies.

Geomodeler should be a lead when analysing, cleaning and selecting VPCs ; but in this process, geologist's input is crucial to make sure that the final product looks geologically right. The same can be said for creating facies proportion maps.

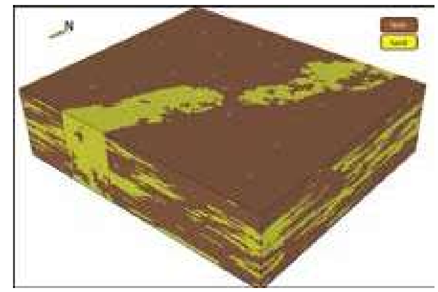

Figure 10. 3D distribution of the facies. No VPC used in the plain.

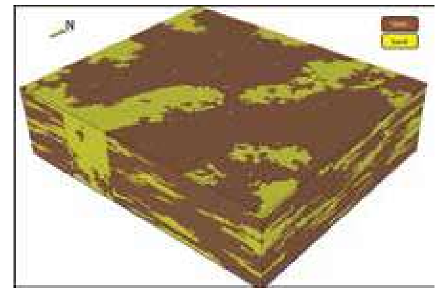

Figure 11. 3D distribution of the facies. VPC used in the plain.

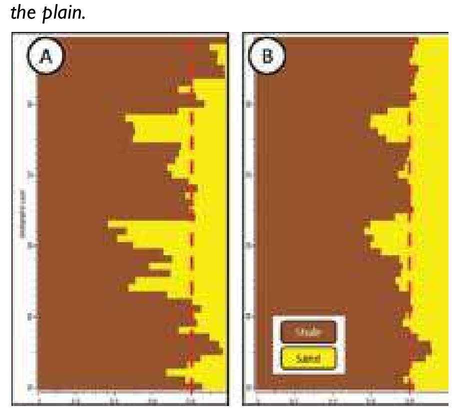

Figure 12. VPC of the facies distribution in the plain modeled with input VPC (A) and modeled without input VPC (B).

GEOLOGICAL UNCERTAINTIES

When modeling facies, it is common to run multiple realizations with the indicator simulation algorithm. As explained in the previous paper, to understand the true range of uncertainty in a reservoir model, it is also useful to study the impact of using range of variograms as well as a range of global facies proportions. Uncertainty on the VPCs and facies proportion maps should also be considered.

The sand proportion map previously built (Figure 4) has two main sources of uncertainty. Firstly, we don't know the exact lateral extent of the channel. This uncertainty can be modeled either as a set of separate scenarios (an optimistic and a pessimistic geometry where the channel is respectively as large or as narrow as possible), or as a continuous range of lateral extents from which multiple "values" are picked by statistical techniques. Secondly, geostatistical techniques to grid the maps themselves should be used instead of a deterministic spline approach.

Uncertainties in VPCs are usually found in K layers with too few well input data and in K layers not crossed by any well at all. The former case was mentioned in the previous section. It is equivalent to the problem of under-sampled distributions in classical statistical studies. Figure 13 gives an example of the latter case. Only the horizontal internal layers (the K layers) are represented. The top layer (dashed red) and the deepest layer (dashed green) are not crossed by the two wells. The VPC is undefined for these K layers. It is up to the geologist to assign facies proportion values there, by extrapolation of the valid VPC values found in the other K layers. In both of these cases, the fact that a guess has to be made for some K layers might justify to create several versions of the VPC, which will change only in these problematic layers.

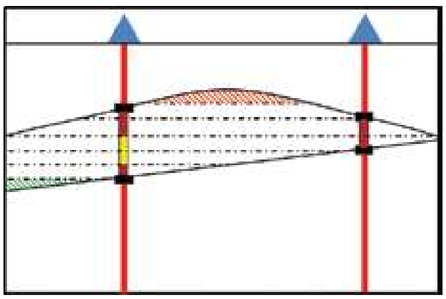

Figure 13. 3D grid in which some K-layers (dashed red and dashed green) are not crossed by any well.

For fields with many wells, it is possible to build several sets of local VPCs, by splitting the domain different block sizes. Each set of VPCs could be used as one scenario. For example, how does the modeled facies really vary between using the global VPC versus using VPCs computed by splitting the domain in blocks of 5 square kilometers or by splitting the domain in blocks of one square kilometer?

Lastly, one should keep in mind that changing the internal layering of the 3D grid will completely change the VPCs. If several 3D grid geometries are tested, then each one should have its own set of VPCs.

CONCLUSION

Ideally, geomodelers should work closely with other team members, and particularly with geologists. Geologists will bring a lot of information about the reservoir as their work efficiently combine geological, petrophysical, geophysical and engineering data with considerations such as paleodepositional environments, diagenesis and burial history. Geomodelers should not replace a geological interpretation by a cold, purely mathematical logic but respectfully translate the geological interpretation in a mathematical language understood by software.

Geomodeling software provide powerful 3D visualtization tools that are helpful for geologists and other team members to improve understanding of reservoir characteristics, also 3D models are easy to explain geological characteristics to management and non-technical stakeholders.

The next paper will focus on how petrophysicists and gemodelers collaborate together.

TO GO BEYOND

(Pyrcz and Deutsch, 2014) and (Ringrose and Bentley, 2015) contain more details about using vertical, horizontal and 3D proportion facies data in geostatistics.

This paper should be in press a few weeks before the GeoConvention in Calgary (May 12 – May 14 2015, www.geoconvention.com). The technical program contains session on geomodeling. Some of these talks might be of interest to you.

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