

GEOMODELING: A TEAM EFFORT TO BETTER UNDERSTAND OUR RESERVOIRS

Part 6: Geophysicists and Geomodeling

By Thomas Jerome, RPS, Sher Ali, Brion Energy and Nilanjan Ganguly, Canacol Energy

INTRODUCTION

After discussing, in the last two papers, how geologists and petrophysicists can get involved in a geomodeling project, we now look at the role of geophysicists. This paper is the last one on the relationships between geoscientists and geomodelers. The next three papers will talk about the role of engineers.

Geophysicists in oil and gas companies worked mostly on 2D seismic data before the technology to acquire 3D seismic data was developed and became popular. Companies are now also using seismic data to monitor the development of their fields thanks to the acquisition of 4D seismic data. Nowadays, geomodelers still have to integrate some 2D seismic lines into their models and some are starting to work on the integration of 4D time-lapse data. But for most of us, when we think about geophysical data, we have in mind the integration of 3D seismic data into our geomodels. This topic is the focus of this paper.

First, one has to ask: Why do we need a geomodel if we have acquired 3D seismic data? After all, seismic cubes give us an image of our reservoirs between the wells. Don't they solve all of our problems? Using a technology as a stand-alone product has its use. When integrated with other technologies, such as geomodeling, that is

when it shows its potential.


A seismic cube does give us a 3D image of the reservoir; however, the resolution is usual too low to capture the level of detail engineers need to truly understand the reservoir. Wells data provides the level of detail we are looking for, but this data can be cumbersome to interpolate in 3D. The solution is to integrate well data and seismic data.

We use trends extracted from seismic to guide the interpolation of wells data in 3D. Some uncertainty about the reservoir will remain, coming both from the seismic interpretation process, from the work on the wells and from the integration of the well data with the seismic. This uncertainty needs to be taken into account as well. Integrating different type of data together and understanding the impact of uncertainties in a model: these are two tasks that geomodels are designed for.

As such, it's advisable to build a geomodel whenever seismic data and seismic interpretation are available. In the meantime, building a geomodel only based on well data while seismic is readily available would be a shame. Good seismic information will always tell us more about the reservoir than the results of pure mathematical interpolation techniques. If a geomodel is about to be built, a geomodeler should always ask if seismic data are available.

Geomodeling can be used for time-to-depth conversion. This will be covered in the first section. Secondly, seismic interpretation is extremely useful to guide how the geomodel 3D-grids shall be built. The second section focuses on the integration of stratigraphic interpretation, while the third section looks at the integration of structural interpretation in geomodeling. Lastly, considerable information about the rock characteristics can be extracted from the seismic cube, such as seismic attributes or fracture density for example. This data can be used to guide geostatistical algorithms. It will be the topic of the last section. Each of these sections will also cover the associated uncertainties.

To close the introduction, a second question is in order: who should really be accomplishing all these tasks that we will cover in this paper? The geomodeler with his geomodeling software or the geophysicist with his 3D geophysical package? Over the last few years, software companies specializing in geophysical packages have added more and more tools of grid construction, of geostatistics and of 3D-grid analysis (volume computation for example). In a similar way, geomodeling packages are now able to accomplish large parts of many geophysical workflows. So who should integrate seismic and well data and study the remaining reservoir uncertainties? The geomodeler or the geophysicist? As far





CHINOOK CONSULTING SERVICES

- Geological wellsite supervision • Remote geo-steering •
- Coring Supervision • Operations geology •
- Field Geochemistry • Petrographic studies •

International Services

{ Geological Services Excellence }



Office: 403 242 1522 • 742 Memorial Drive NW Calgary, Alberta T2N 3G7 • ops@chinookconsulting.ca • www.chinookconsulting.ca

as the authors of this paper are concerned, it doesn't matter who does the job. Our goal is to highlight aspects of a reservoir study in which we believe geophysics and geomodeling shall be combined. Each team will decide who has the time, the tools and the experience to do the agreed-upon workflow. Ultimately, it's all a team effort. It doesn't matter who is pushing the buttons on a computer, as long as the job gets done.

TIME-TO-DEPTH CONVERSION

Time-to-depth conversion means that each seismic data point in the time domain will be given a depth coordinate. Each point keeps its XY location. There is no lateral displacement, only a vertical one. Such approach is insufficient in complex domains such as structural plays or salt plays. There, depth-migration and not time-to-depth conversion will likely be applied. This topic isn't discussed hereafter. Only time-to-depth conversion is. Readers interested in depth-migration can refer for example to (Jones, 2010) for more details. For more details about time-to-depth conversion, the reader can refer to (Al-Chalabi, 2014).

Well logs, such as sonic, are used to transfer the wells to the time domain. A sonic log quantifies the reverse of the instantaneous wave velocity of the rocks in the vicinity of the borehole. Converting the wells to the time domain is also the time when the geophysicist must decide which seismic event can be associated with which well top. It guides the seismic interpretation of the seismic cube; that is to say the picking of the horizons and faults from the seismic cube. Details on how to integrate a seismic interpretation in geomodeling are covered in the two next sections. Before doing so though, the seismic interpretation must be converted to the depth domain. That's where time-to-depth conversion is being used.

While sonic logs are being used to convert the wells from depth to time in great details, sonic is usually not used for converting the seismic data to depth. It can be extremely challenging to extrapolate sonic logs data between the wells. It has the same level of uncertainty than extrapolating facies data or petrophysical data in 3D. Such an approach is sometimes needed though and the topic will be discussed in more detail later in this section.

Instead of defining the time-to-depth conversion from the sonic log, interval velocities or average velocity are used.

An interval velocity is the mean velocity between two horizons at a given XY location. Interval velocities are computed along each well. Figure 1A illustrates the concept with interval velocities computed for the shallow

unit between the ground (for onshore seismic) and the first key horizon Hr_zA, then for the unit A between Hr_zA and Hr_zB and lastly for the unit B between Hr_zB and Hr_zC. In a given unit, sonic shows that the velocity varies vertically. The interval velocity is an integration of these local vertical variations. Well tops are all we need to compute an interval velocity. The depth of top horizon and of the bottom horizon are known (by definition). As the well has been converted to time, the time two way-time (TWT) is known too. The interval velocity is the ratio between the delta-depth and the delta-TWT. If the interval velocity is more or less constant at each well, an average constant interval velocity might be assigned to the whole unit over the lease. This approach is also used when there are too few wells to interpolate the interval velocity on the map in any meaningful way. On the contrary, if we have enough wells and if the interval velocity varies from well to well, interpolation techniques are used to generate an interval velocity map between the well interval velocities. For every XY location, the interval velocity value from the map is then assigned to every point of the seismic cube at this coordinate. Having done this for each geological unit, the seismic cube can be converted to the depth domain with all the seismic interpretation. If only the seismic horizons need to be converted, it is done directly from the interval velocity maps.

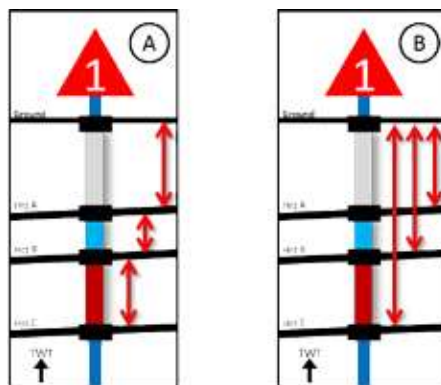


Figure 1. Interval velocities (A) versus average velocities (B).

An average velocity is the mean velocity not between two horizons, as for the interval velocity, but between the ground and a given horizon (example, Figure 1B). Once the average velocity for a given horizon is known at each well, a map of average velocity is defined, either as a constant everywhere, or using interpolation techniques. The average velocity maps are then used to convert the seismic cube and/or interpretation to the depth domain.

Interval velocities are preferred to average velocities for units with lateral changes of interval velocity (Figure 2). In this example,

the two first layers have more or less constant interval velocity of 2,500m/s and 5,000m/s respectively (Figure 2A) while the deepest layer has a sharp lateral change of interval velocity. The layer is a shale unit (3000m/s) truncated by a sand channel (4000m/s). Facies is one of the key factors to control the distribution of velocity in a geological unit. This lateral change of facies has an impact on the geometry of the seismic horizon of Hr_zC (Figure 2B). Where we are in the sand, the layer appears thinner; in the time domain, than where we are in the shale; while in the depth domain, the thickness changes smoothly between wells 2 and 3. In such a reservoir, it is essential to properly capture the limit between the zone where the wells have an interval velocity of more or less 3000m/s and are in the shale, to the zone where the wells are in the sand and show an interval velocity of 4000m/s. It means tracking the limit sand-shale between the wells and then to interpolate the interval velocities within each facies domain.

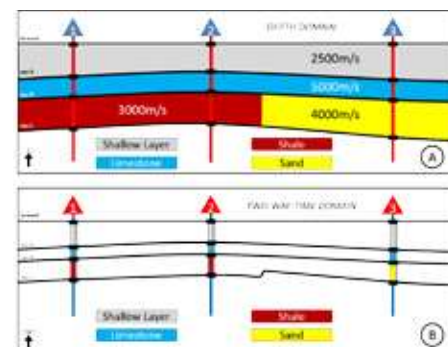


Figure 2. Reservoir with a lateral change of facies and velocity in the depth domain (A) and the time domain (B).

All these approaches of computing velocities at each well and then interpolating maps from them can also be done in a geomodeling package, if this is more convenient for the asset team to do so. Geostatistical algorithms, as introduced in the previous papers of this series, are perfect for interpolating the velocity maps. Not only to capture trends in the velocities, but also to generate multiple possible velocity maps, and so capture the velocity uncertainty between the wells.

No matter where these maps are generated, the geomodeler should make sure that these maps do include all the wells needed for the geomodeling workflow, and not only those used by geophysicist. In many projects, some wells might have facies and petrophysical logs, but they might not have a sonic log. Such wells would not be converted to the time domain by the geophysicist. It might be perfectly fine for seismic interpretation: once the time-converted wells have confirmed which seismic event shall be picked, the interpreter can follow these events in the whole cube, even around wells without a sonic log. The

(... Continued on page 16)

(... Continued from page 15)

geophysicist might have the reflex, or be forced by his software, to create the velocity maps only from the time-converted wells. As a result, the depth-converted horizons, while fitting nicely to the wells with sonic, may not match to the wells without sonic. Such mismatches can be cleaned in the geomodeling workflow, as discussed in the next section, but it might be more elegant to create the velocity maps from all the wells in the first place, as well tops are all that is required to compute interval and average velocities. Sonic is not needed.

While illustrating the concept of lateral change of velocity, Figure 2 was also overly simplistic. In many reservoirs, the heterogeneity is such that facies do change both laterally and vertically, in very complex ways, and difficult to predict from wells. The velocities in such geological units might be better defined by creating geomodeling 3D-grid in the time-domain. A 3D facies model can then be built with geostatistical algorithms, and then the velocity can be modeled by facies. In such reservoirs, it might be necessary to interpolate sonic logs by facies instead of interval velocities, to really capture the heterogeneity. This geomodel will create multiple cubes of velocity for this unit, each one representing a possible distribution of the facies and the velocity in 3D. Overall, geomodeling packages are better equipped than geophysical packages to do such complex time-to-depth conversions.

SEISMIC INTERPRETATION AND STRATIGRAPHIC MODELING

When depth-converted seismic horizon data are available, the geomodeler must consider how to integrate the data into the model. He must create horizon surfaces which respect both the seismic interpretation and the well markers. Even when all the wells, with or without sonic, are used for time-to-depth conversion, it is rare that the seismic interpretation matches precisely to the well markers. The reasons are many. The velocity maps might not have respected exactly the velocity value at each well. The time-depth conversion itself, once the velocity is modeled, might not have been exact either. This is not as rare as one might think. The reason might be also a question of timing in the team. Some well locations or some well KB elevation might have been adjusted after the depth-conversion was done. Similarly, the geologist might have modified slightly the markers interpretation after the velocity maps were completed. At last, some wells might have been drilled after the seismic data got depth-converted. Or it might be a combination of all these events. In a perfect world, the geophysicist would systematically redo the

depth-conversion. But in many projects, the team might not have the time for that. The geophysicist might have been already assigned to some other tasks (or projects)...or the final deadline for the whole project might be too close to provide an opportunity to redo the depth-conversion.

If the mismatches are large, it is still recommended to adjust the velocity model and redo the depth-conversion. But if mismatches are reasonable, then they can be fixed directly in the geomodeling package. The technique, described hereafter, can probably be applied in many geophysical packages.

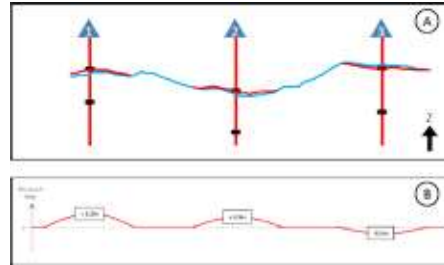


Figure 3. A) Original (blue) vs marker-adjusted (red) seismic interpretation. B) Adjustment map needed to correct the mismatch observed in (A).

In Figure 3A, a seismic interpretation (blue line) has been depth-converted using the three wells 1, 2 and 3. The interpreted horizon is close to the well markers but a mismatch remains. Should it be corrected? A general rule in geomodeling is that if well data and seismic data are partly in contradiction, the well data shall be respected in priority because well data are more precise than seismic data. In the process of adjusting to the well, we try to respect the seismic data as much as possible. Naturally, if well and seismic data are in complete contradiction, it is wiser to understand 'why' instead of enforcing this rule blindly. Once the source of the inconsistency is identified, the team might agree that the data can be corrected to make them coherent one with the other, or the team might decide that the inconsistency is the result of different interpretations (for example). In that case, several geomodels might be needed, one for each interpretation. For the purposes of this section, we assume that it makes sense for our dataset to modify the seismic horizon to fit to the well markers.

One might be tempted to simply create a surface from the seismic interpretation and then adjust this map directly to the markers. By doing this, we mean using the depth of each marker to adjust the depth of the map. Such an approach might be risky. While the markers will be respected, it is also very likely that the whole surface will be completely smoothed out even far from the wells. The adjusted map might look very similar to the map we could generate from the markers alone. If it happens, at the least the team

needs to decide if that was the intention or if a different approach is needed. Creating a map showing the difference between the original and the corrected geometry is a nice way to understand how the geomodeling process modified the map exactly.

Instead of interpolating the depth values directly, we suggest another approach which better respects the geometry of the seismic interpretation: create a map of the adjustment you need to apply to the seismic horizon map (Figure 3A, blue line) to get it to fit to the markers. Then move the seismic horizon map with this adjustment map.

The first step of this workflow is to compute the mismatch between the original seismic map and each well marker. In our example (Figure 3A), the mismatch at well 1 is +1.2m, the mismatch at well 2 is +0.9m and the mismatch at well 3 is -0.6m. A negative number means that the marker is deeper than the surface at this location. We now know that the adjustment map must have the value +1.2, +0.9 and 0.6 at the respective XY locations of wells 1, 2 and 3 (Figure 3B). We also decide that the adjustment must be null past a certain distance from each well location. It means that outside of areas centered at each well, we don't want to modify the original seismic map.

The second step of this workflow is to define the radius of these areas. More details will be given in a later paragraph. Once the radius defined, we know the displacement at each well and we know the displacement is 0m beyond the radius. All that remains to do is to use some interpolation technique to extrapolate a decreasing displacement from each well toward the limit of its associated area. On Figure 3B, it is illustrated by a bell shape around each well. Lastly, the displacement map is added to the original seismic horizon. The resulting, corrected horizon is equal to the original map far from the wells (= outside of the pre-defined radial zones around each wells) while the horizon has now changed around each well. Each marker is now respected while keeping the overall geometry of the seismic interpretation.

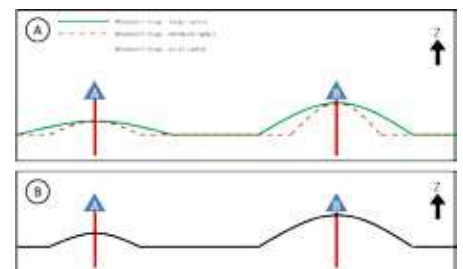


Figure 4. Effect of using different radius to compute the adjustment map. A) map resulting to three different radii (small, medium or large). B) map resulting from using at each well a radius function of the local mismatch.

As illustrated in Figure 4, the challenge is to decide what radius to use around each well. In this example, the mismatch at well A is half of the mismatch at well B. If we use a very small radius for both wells (Figure 4A, black thin line), the adjustment zone is really narrow and the corrected horizon surfaces might show an obvious bullseye around each well. Using a medium-size radius (Figure 4A, red dashed line), the bullseye effect might be less noticeable, and so acceptable, around well A, while it might still be too visible around well B. At last, using a large radius (Figure 4A, green thick line), the bullseye effect might now be minimal on both wells, but the question might become that we are altering a too large portion of the seismic maps around each well.

Ultimately, this is all a trade-off that the team must agree upon. If some mismatches are really too large or the bullseyes are too visible, then, as mentioned earlier, it might be wiser to redo the depth-conversion. An alternate approach might be to use different radii for each well (Figure 4B). The idea is to select a radius proportional to the absolute value of the mismatch: the more important the mismatch, the larger the radius. In Figure 4B, we could use a medium radius around well A and a large one around well B.

Once surfaces are created for each horizon on the well markers and a seismic interpretation exists, the geomodeler can continue taking advantage of the seismic interpretation in two ways, both illustrated in Figure 5.

Figure 5 is an extension of the example presented in Figure 4. Horizon A is the one for which a seismic interpretation existed, and got adjusted to the well markers at wells 1, 2 and 3. For the horizons B and C though, there is no seismic interpretation, only well markers.

In many reservoirs the horizons, or a subset of them, might be conformable, one with the other. If one of these conformable horizons has been picked on seismic, then it can be used as a reference to model the other horizons. In Figure 5, Horizon B is interpreted as conformable with Horizon A. We can use the geometry of the Horizon A to model the geometry of Horizon B. A thickness map of the unit between Horizon A and Horizon B is interpolated from the thickness at each well (using geostatistical algorithms). Then, the geometry of Horizon B is calculated by subtracting the thickness map to the depth map of Horizon A. This is a first additional way to take advantage of a seismic interpretation. Sometimes, none of the seismic events they can interpret correspond to any of the stratigraphic markers interpreted by the geologists on the wells. These events are linked to other change of log signatures along the

wells. When this happens, it is recommended to treat such horizon as we did here with Horizon A, and then create horizons for the real stratigraphic tops (= the horizons we do need for the 3D-grid) following the approach proposed here for Horizon B.

Other horizons known only from well markers are simply not conformable to any horizon picked on seismic. Such horizons can only be modeled from the well markers. No seismic horizon, such as Horizon A, can be used as a reference. In Figure 5, this is the case of Horizon C.

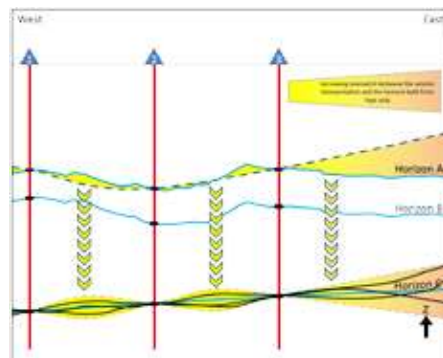


Figure 5. Modeling horizons from seismic interpretations and/or well markers and managing the uncertainty associated to the model.

Another use of seismic interpretations is for quantifying the uncertainty on the geometry of the horizons. Horizons A, B and C illustrate different type of uncertainty geomodelers have to consider.

Horizon A is the best defined horizon as it was visible on seismic. There are still two sources of uncertainty though: uncertainty in the picking itself in the time domain and uncertainty in the depth-conversion (or depth migration as discussed at the beginning of the previous section).

Horizon B was created from Horizon A. As such, it inherits all Horizon A's sources of uncertainty. An additional uncertainty must be considered too: the uncertainty on the thickness of the unit between Horizon A and Horizon B.

Horizon C, at last, is only known from well markers. As such, we have no real idea of how uncertain the interpolated surface is. Of course, mathematically, we can run different scenarios for this horizon, but which scenario bound to the uncertainty shall we use? +/- 5m? +/- 50m? More maybe? A solution is to define the range of uncertainty on Horizon C from Horizon A with the following approach.

Firstly, we create a new surface for Horizon A only from well markers. Such geometry is illustrated in a dashed blue line on Figure 5. We now have two geometries for Horizon A: the surface made from the seismic and the well markers and the geometry made

only from the well markers. The mismatch between the two maps tells us how incorrect – that is to say how uncertain – our map of Horizon A from the markers alone is. On Figure 5, the error is reasonable between the wells (yellow color), while it is very large to the east beyond well 3. One might assume that a similar range of uncertainty would have been found around Horizon C if it would have been possible to pick it on seismic. If we accept this assumption, we can simply assign the uncertainty map from Horizon A onto Horizon C (Figure 5, vertical thick arrows).

Many geomodeling packages have tools to create multiple versions of a given horizon, each version being a variation around a base case geometry. The tool is fed with an initial geometry of the horizon (Figure 5, the interpolated Horizon C map from the well markers) as well as an estimate of the range of uncertainty (Figure 5, the map of mismatches computed on Horizon A). Each variation is slightly different from the reference surface, but all surfaces fall within the range of uncertainty pre-defined by the uncertainty map. In Figure 5, a few possible variations of Horizon C are represented in thin dark lines.

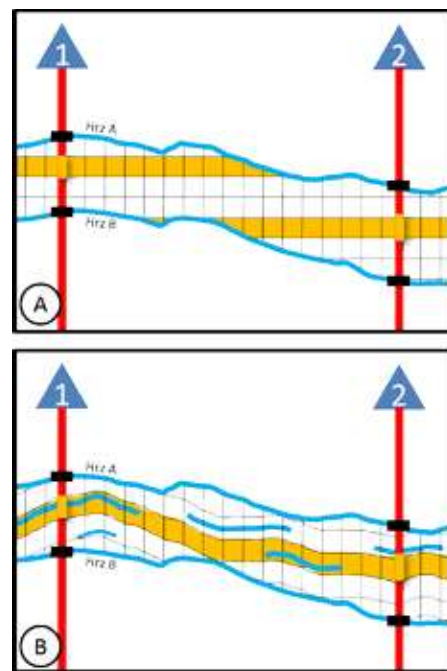


Figure 6. Reservoir in which the horizons are defined from seismic and from well tops. A) traditional approach to build the mesh of the 3D-grid (horizontal mesh). B) modern approach integrating local seismic events interpreted in the reservoir.

Up to this point, this section focused on integrating “traditional” seismic horizon interpretations. By “traditional”, we mean surfaces that can be picked across the whole seismic cube such as Horizon A on Figure 5. In the last few paragraphs of this section, we are considering the integration of the smaller

(... Continued on page 18)

(... Continued from page 17)

seismic events that can be picked inside each geological unit.

In geomodeling, once the top and bottom horizons of a reservoir are modeled, we often create a 3D-grid with a mesh parallel to the top horizon, parallel to the base horizon or proportional between the two surfaces. If it seems more appropriate for the local geology, we can instead make the mesh horizontal (Figure 6A) or parallel to a surface other than the top and bottom horizons. In all these approaches, the seismic cube is not used to create the mesh, except when the reference surface the mesh is parallel to was itself picked on seismic.

This being said, as geomodelers, we should not forget that the internal heterogeneity of the reservoir might be partly visible on the seismic, in the form of local seismic events, that geophysicists can pick. A close collaboration between the geologist and the geophysicist might be needed there to ensure that those local, internal seismic events are coherent with the geological interpretation of the reservoir. If such local events are interpreted, it is in the team's interest to see these local seismic events being used in the construction of the geomodel.

At the time this paper is written (autumn 2015), geomodeling packages start having tools to take these local events into account when creating the mesh of the 3D-grid. Figure 6B illustrates this concept as the mesh is following a few seismic events picked in the reservoir (thick blue lines between Horizon A and Horizon B). While such techniques are still not widespread, we think geomodelers should already start looking into this. Property modeling in a 3D-grid (facies and petrophysics) is primarily guided by the geometry of the 3D-grid itself. If we can add more "geology" into these meshes by using the local seismic events, we might improve the accuracy of our models.

SEISMIC INTERPRETATION AND STRUCTURAL MODELING

The technique presented in the previous section, to tie depth-converted seismic horizons to well markers, can be applied to adjust depth-converted seismic fault surfaces to fault markers. The remainder of this section provides an opportunity to discuss how geophysicists and geomodelers can collaborate to model a fault network through integration of seismic interpretation and geomodeling techniques.

In faulted reservoirs, only seismic data can really help defining the geometry of the faults and define how all these faults are interconnected to form the fault network. A

faulted geomodel is only as good as the seismic interpretation of the fault network, and how well this interpretation has been respected. In many projects, the workflow is a two-step process (Figure 7, "traditional workflow"). The geophysicist spends time creating and fine-tuning his interpretation of the fault network. Then, once the interpretation is finalized, it is transferred to the geomodeling package and the geomodeler creates the model. Building a faulted 3D-grid has been a tedious task in the geomodeling industry for years, partly because many packages were using an approach called pillar gridding. This technique is described later in this section as it is still used today. For complex fault networks, such geomodeling tasks can take a lot of time. In that context, a complex fault network would be one with many faults, maybe some faults dying in the reservoir or/and some complex fault relationships such as Y-faults, X-faults. Because it takes time to build such model, it is often impossible to circle back with the geophysicist, even if building the geomodel highlights some inconsistency in the geophysical interpretation. There might simply be no more time left in the project to do these adjustments.

Over the last few years, some geomodeling packages have added more robust and simpler techniques to build quickly a fault 3D-grid. For the geomodelers having access to such modern workflows, it allows them to work with their geophysicist in a more integrated way (Figure 7, "integrated workflow"). The idea is for the geophysicist to provide a good, but not complete initial interpretation. The detailed cleaning, traditionally done to make life easier for the geomodeler, is not needed anymore. The geomodeler builds an initial structural model from this dataset, using the modern structural modeling workflows now available. The goal is to quickly get a 3D-grid which can be reviewed by the whole team. As for the traditional workflow, the review often leads to the need for further refinement of the geophysical interpretation and/or of the geomodel itself. But here, as the initial geophysical interpretation and the initial structural model were built fast, there is still time in the project for the geophysicist and the geomodeler to refine together the structural model. The final 3D-grid represents the reservoir more accurately. For this reason, we highly recommend using such modern approaches whenever available.

Considering that pillar gridding is still used a lot, more details are given hereafter (Figure 8). On the contrary, at the time this paper is written (autumn 2015) not all the details about these modern workflows have been made public yet by the different software companies. As such, a general idea of what

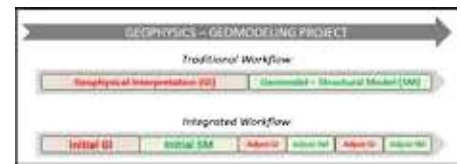


Figure 7. Geophysical and geomodeling project to build a fault network. The traditional workflow vs. a more modern, integrated one. The time spent on each task varies from project to project.

can be achieved with these techniques is illustrated in this section (Figure 9).

Figure 8A shows a faulted reservoir in which the faults F1 and F2 form a Y-fault network. The faults and the horizons A and B have been picked on seismic. The reservoir is also crossed by a well on which facies interpretation has been done (two facies zones are represented in orange and yellow). The 3D-grid represented on Figure 8A is typical of what a pillar gridding algorithm can generate. To the left of fault F1, the vertical mesh is parallel to the fault F1 near F1 and it progressively gets vertical when we reach the left limit of the modeled area. Similarly, the 3D-grid to the right of the fault F2, the mesh is parallel to the fault F2 and it gets progressively vertical the further away we are from it. Modeling the block between the faults is the challenging part. Most likely, and not represented here, the model would have been simplified to make it happen. The fault F2 will have been edited so as to remove the branching. Its geometry might have been altered to move the branching deeper, below

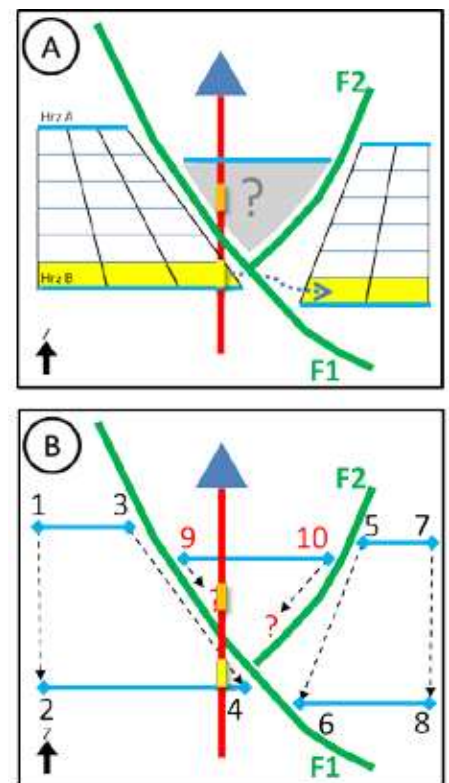


Figure 8. A) 3D-grid of a Y-fault system modelled by pillar gridding. B) Details of the pillar gridding algorithm.

the modeled year. Another option could be to make F2 vertical and completely crossing the reservoir (fault dying in the reservoir are also an issue for the pillar gridding algorithm). In some project, the fault F2 might have been simply ignored and the throw it creates on the horizon A would be smoothed out. In all cases, very likely, the geometry of this fault network would have been altered.

Figure 8B explains in further detail why this is happening. The first step in pillar gridding is to connect each extremity of the top horizon to an extremity of the bottom horizon. By extremities, we mean points labelled 1, 3, 9, 10, 5 and 7 on Horizon A and the points 2, 4, 6 and 8 on Horizon B. Point 1 from Horizon A is connected to point 2 of Horizon B because they correspond to the left extremity of the input horizons. Point 3 from Horizon A and Point 4 from Horizon B are connected because they both represent the point of contact between the horizon and the fault F1 on the left fault block. Using a similar approach, the points 5 and 6 are connected as well as the point 7 and 8. But what shall we do with the extremities 9 and 10 on Horizon A? As the block between the two faults doesn't extend to Horizon B, there is no extremity on Horizon B to associate them to. And that's where the pillar gridding algorithm is blocked. Simplifying the geometry of Fault F2 is the trick used to make sure we have as many extremities on Horizon A that we have on Horizon B. Once it's done and all the extremities are connected, the vertical mesh is further defined inside each block so as to make a smooth transition between one connection to the next one. At last, the horizontal geometry to the mesh is added.

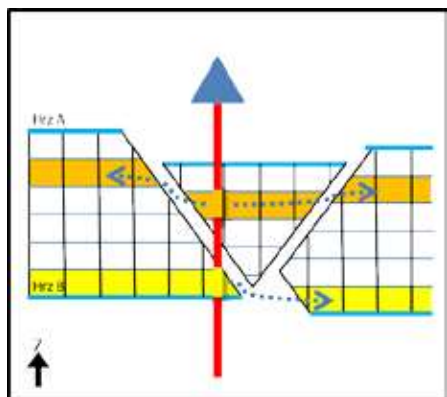


Figure 9. Example of 3D-grid built with more modern structural modeling techniques, that don't rely on pillar gridding algorithms.

The new structural modeling workflows developed over the last few years seem to focus on two things.

Firstly, they automate a lot of the tedious tasks usually done manually in older workflow. These tasks are not described in any details here, except to say that ensuring that the

model is sealed has always been one of these issues. By sealed, we mean that there must be no gap between the horizon surfaces and the fault surfaces where the former gets in contact on the later. The gap visible on Figure 8 and Figure 9 between the horizon and the fault surfaces were added only to give more clarity to the pictures.

Secondly, these new workflows try to ensure that there no need to simplify the fault network anymore. It means that they don't rely on pillar gridding algorithms. Figure 9 is an example of the type of output 3D-grid we can get. The fault block between F1 and F2 is now properly managed. Observe also how the cells of the 3D-grid are now cut by the two faults instead of being parallel to them (Figure 8). This is also an improvement as conceptually, one has to imagine that rocks got deposited before they got faulted (except around growth faults). As such, it makes sense that our facies distribution gets "cut" as in Figure 9 instead of getting aligned to the fault as in Figure 8.

As for the integration of local seismic events, described at the end of the previous section, these modern structural modeling techniques have both challenges and benefits. Challenges, because they are still new and use geomodels and we are not yet used to them. But beneficial too, as some complex reservoirs, when applied correctly, might be the key to building a really good geomodel.

GUIDING PROPERTY MODELING WITH SEISMIC DATA

A seismic cube can contain a lot of useful information to guide 3D facies modeling and 3D petrophysical modeling. Geophysicists, for decades, have been developing many techniques to correlate signature in the seismic cube to specific facies or log signature along the well. The general goal is to identify a signature in the seismic cube at the well location and to track such signature between the wells, assuming that wells drilled there would see the same log/facies signature than observed on the existing wells. The purpose of the present paper is not to detail all these geophysical techniques – it would be impossible. The reader can refer to books such as (Chopra and Castagna, 2014), (Li, 2014) and (Simm and Bacon, 2014) for some introduction on the topic. Our goal here is to see, once the geophysicist has created one or several new seismic attributes, how shall we use them in our geomodeling workflows?

On a geomodeling point of view, seismic attributes and petrophysics are similar. You can have numerous seismic attributes in the same way that as you can have many different types of logs to model in 3D. But at the end of the day, all these logs are modeled using a limited set of geomodeling techniques

and, as explained hereafter, all these seismic attributes are integrated in the geomodel using a limited set of techniques too.

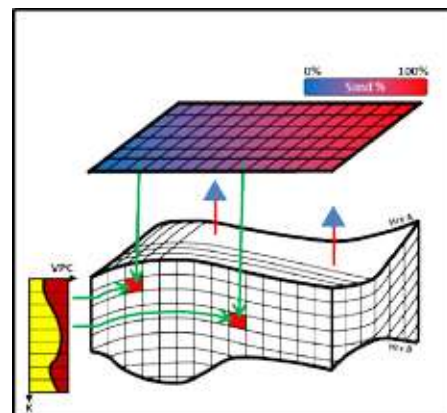


Figure 10. Cube of facies probability built from combining a VPC and a facies proportion map.

Error! Reference source not found. illustrates how a continuous seismic attribute can be transformed into a set of cubes of facies probabilities. Along each well, the facies distribution is compared with the values of the seismic attribute (Error! Reference source not found., upper part). In our example, one can see that for values of the attributes up to A, the facies on the well is always sand. We can assume that between the wells, everywhere where the attribute is in that range, we will have always sand. In these cells, the cube of sand probability is equal to 100%, while the cube of shale probability is equal to 0%. In a symmetric way, for values above B, the facies at the well is always shale. In the cells with this range of values, the cube of sand probability is equal to 0% and the cube of shale probability is equal to 100%.

If this binary behavior (either 100% chance to be in sand or 100% chance to be in shale) was true for all values of the seismic attribute, we wouldn't even need any geostatistical computation. For a given cube of seismic attribute, the facies distribution would be purely deterministic. It would mean that the seismic attribute on its own would be enough to characterize the reservoir. In practice though, the relationship is never as clear as this and there is always at least range of values for which there is probability to be either in the sand or in the shale. This is where geomodeling and geostatistics find its place: it allows throwing the dices and generating multiple facies realizations which respect that information. Concretely, for each attribute value between A and B (Error! Reference source not found., upper part) we assign the proper probability in the sand and the shale cubes.

This illustrates what was discussed in the introduction of this paper. Seismic cubes

(... Continued on page 20)

(... Continued from page 19)

can't see the reservoir at the resolution that wells can. As such, seismic attributes can't capture the details and there are always some discrepancies between the seismic information and the well information. Geostatistics, through the use of cube of facies probability, allows studying this uncertainty. The same approach would work if the seismic attribute was a discrete property.

As mentioned earlier, several attributes might have been computed. Each attribute will generate its set of probability cubes. If multiple sands and shale probability cubes exist, they can be combined into an integrated single cube. The same can be done to merge together a set of cubes coming from seismic and the set of cubes generated from merging VPC and facies proportion maps. The idea is that each cube, each data, shows one aspect of the facies distribution and to understand the whole distribution, we need to combine them.

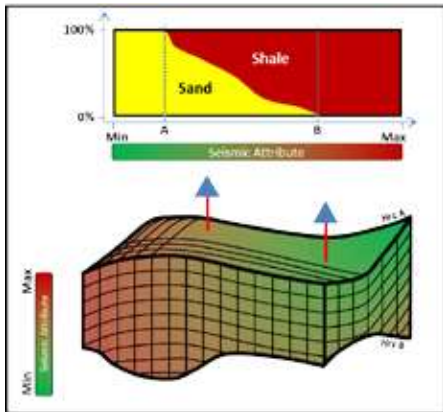


Figure 11. Combining well facies and a seismic attribute to create a set of cubes of facies probability.

If a seismic attribute relates to a continuous well log such as porosity, or fracture density, the seismic attribute is directly used as a secondary variable with geostatistical algorithms such as Collocated Sequential Gaussian Simulation (collocated SGS). The workflow is identical to the one described in the paper on petrophysics where the 3D

porosity model was used as a guide to model the water saturation in 3D. Such algorithms are able to use multiple secondary variables if needs be.

The reader can refer for example to (Doyen, 2007) for more details about these different techniques.

CONCLUSION

Geophysical data are an essential part of any geomodeling workflow and reciprocally, geomodeling techniques can complement generating certain geophysical results as well as get the most out of the different types of geophysical interpretation.

The most common mistake is to assume that seismic is only useful for guiding horizon and fault modeling. A lot of information about the reservoir characteristics can also be extracted from a 3D seismic cube. Once this accepted, a proper collaboration between the geophysicist, the geomodeler and the other team members will allow for the best integration possible.

TO GO BEYOND

As part of its training program, the CSPG offers a course on geophysics. Beyond that, those interested in these topics shall also look at the excellent training program organized also yearly by the CSEG (Canadian Society of Exploration Geophysicists), as well as to the presentations that they organize and the magazine that they publish.

ACKNOWLEDGEMENT

The authors would like to thank Maximo Rodriguez, Senior Geophysicist at ConocoPhillips Canada, and Junaid Khan, Senior Geophysicist in Husky

REFERENCES

- Al-Chalabi, M., 2014. Principles of Seismic Velocities and Time-to-Depth Conversion. EAGE Publications. 488 pages.
- Chopra, S. and Castagna, J.P., 2014. AVO. SEG. 288 pages.

Doyen, P.M., 2007. Seismic Reservoir Characterization. An Earth Modelling Perspective. EAGE Publications. 255 pages.

Jones, I. F., 2010. An Introduction to: Velocity Model Building. EAGE Publications. 295 pages.

Li, M., 2014. Geophysical Exploration Technology. Applications in Lithological and Stratigraphic Reservoirs. Elsevier. 449 pages.

Simm, R. and Bacon, M., 2014. Seismic Amplitude. An Interpreter's Handbook. Cambridge University Press. 271 pages.

THE AUTHORS

Feel free to contact the authors about this paper or about the series.

Thomas Jerome is the Calgary manager of the Reservoir Modeling team in RPS (Thomas.Jerome@rpsgroup.com). Geologist by background, Thomas has spent the last 15 years working on geomodeling projects, first in Middle-East and in Calgary, Canada, since 2008. He has worked on conventional and unconventional reservoirs, both Canadian and international. Thomas is leading this CSPG's series on Geomodeling.

Sher Ali is Senior Geomodeller with Brion Energy Corporation at Calgary (Sher.Ali@Brionenergy.com). Sher started his career from Asia and worked in Africa and Middle East before moving to Calgary, Canada in 2011.

Nilanjan Ganguly is a Senior Geophysicist with Canacol Energy Ltd (nganguly@canacolenergy.com). Nilanjan received his B. Sc. degree in Geological Sciences from Indian Institute of Technology and M. Sc. in Geophysics from University of Victoria. For the past 16 years, Nilanjan has worked on various international and frontier basins: primarily in Africa, Middle East and South America. His professional interests include exploration in highly structured areas, AVO, seismic attributes and inversion.

2016 Membership Renewal

Many CSPG memberships expire December 31st.

Watch your email for a link to renew online.

****membership is on an individual basis; you may have a different expiry date****