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Reserves Volumetric Estimations. Mapping vs. Geomodeling: Review of these two Approaches, their Pros and Cons, the Recommendations from the COGEH and the SPE-PRMS and the Practice in the Industry

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Summary

Estimates of the reserves and the resources in their portfolio are essential parameters that companies must present to their shareholders. Through the years, industry committees have defined how reserves and resources should be computed. The goal is to define rules that are based on sciences and not business-driven a priori. Two references documents are COGEH [1] and the SPE-PRMS [2]. The first one must be followed for companies registered on the Toronto stock-market. The second one is used by US-based companies.

Volumetric methods are part of the toolbox defined in these documents.

Hereafter, I'm focusing on the estimation of the HCPV (Hydro-Carbon Porous Volume) instead of the reserves.

The traditional volumetric approach is based on the following steps (Figure 1):

- Evaluate the area of the reservoir from contour maps.
- Evaluate the gross thickness and the net thickness from the well logs.
- Evaluate the average porosity and oil (or gas) saturation in the net portions of the wells.
- At last, Compute HCPV by multiplying all these properties together.

This deterministic workflow can be easily extended to become a probabilistic workflow. A range of uncertainty is associated for each of the input parameters (areas, gross and net thicknesses, porosity, oil/gas saturation) and a Monte Carlo approach is used to compute the resulting range of HCPV.

Computing volumes has also been in the toolbox of every geomodeling package for decades. In geomodeling (Figure 2), the reservoir is represented by a 3D grid which capture the geometry of the geological units. Contacts (OWC, GOC…) are associated with the 3D grid. At last, geological facies and then petrophysical properties (porosity, water saturation) are modeled by facies in 3D. Geostatistics are usually the techniques used to populate facies and petrophysical properties. Hundreds of models can be easily generated, each representing a variation around the input constraints provided by the user (like well data, concept of geological environment…). HCPV is calculated for each model and as such the asset team ends up with a probabilistic estimate of the in-place volumes (Figure 3).

With geomodeling packages wide-spread availability, even to small O&G companies, some questions came up: shall we continue using the mapping approach to report reserves or shall

we replace it by the extraction of volumes out of a geomodel? What are the pros and cons of each approach in the context of in-place volume estimation? Also, do the official rules impose a specific approach over the other? And how are things done in practice in O&G companies?

In this presentation, the author will review these different aspects in the hope of helping the audience better understand the current situation and how they can choose one or the other approach.

References

[1] COGEH (Canadian Oil And Gas Evaluation Handbook), https://spee.org/resources/canadian-regulations
[2] SPE-PRMS (SPE Petroleum Resources Management System), https://www.spe.org/en/industry/reserves/

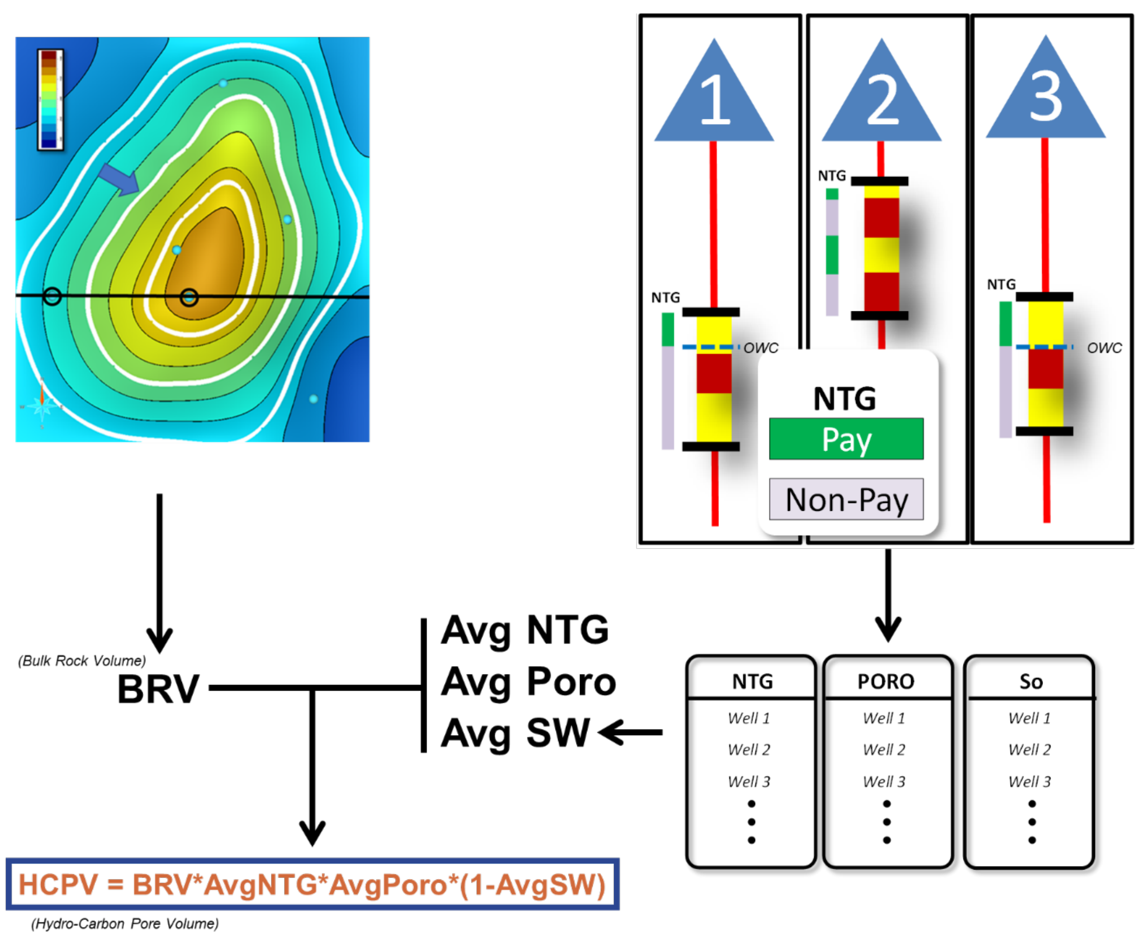

Figure 1. Estimating HCPV through mapping (deterministic approach which can be extended into a probabilistic approach)

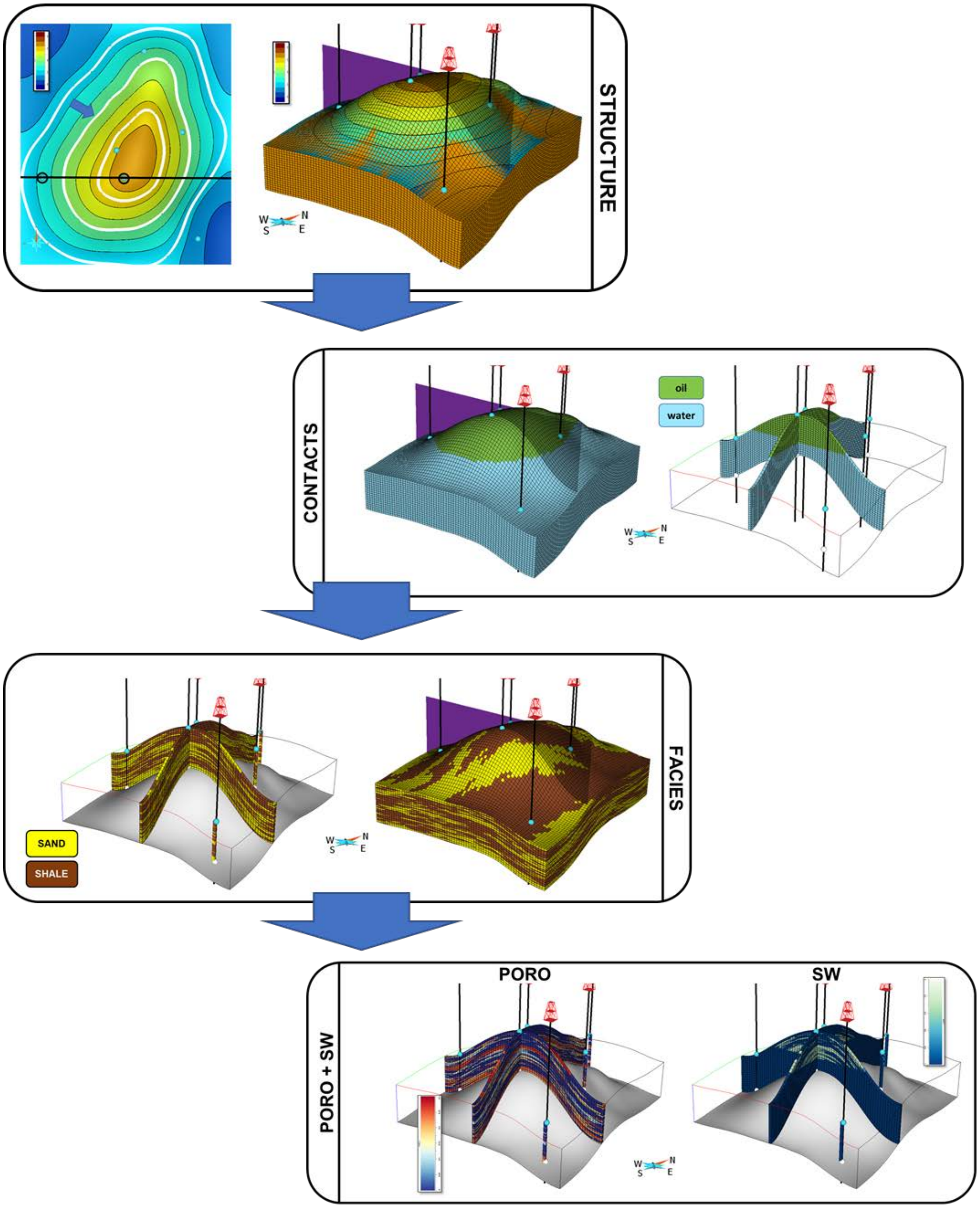

Figure 2. Geomodeling workflow from capturing the Structure in 3D Grid, to modeling the contacts, the geological facies and the petrophysical properties by facies.

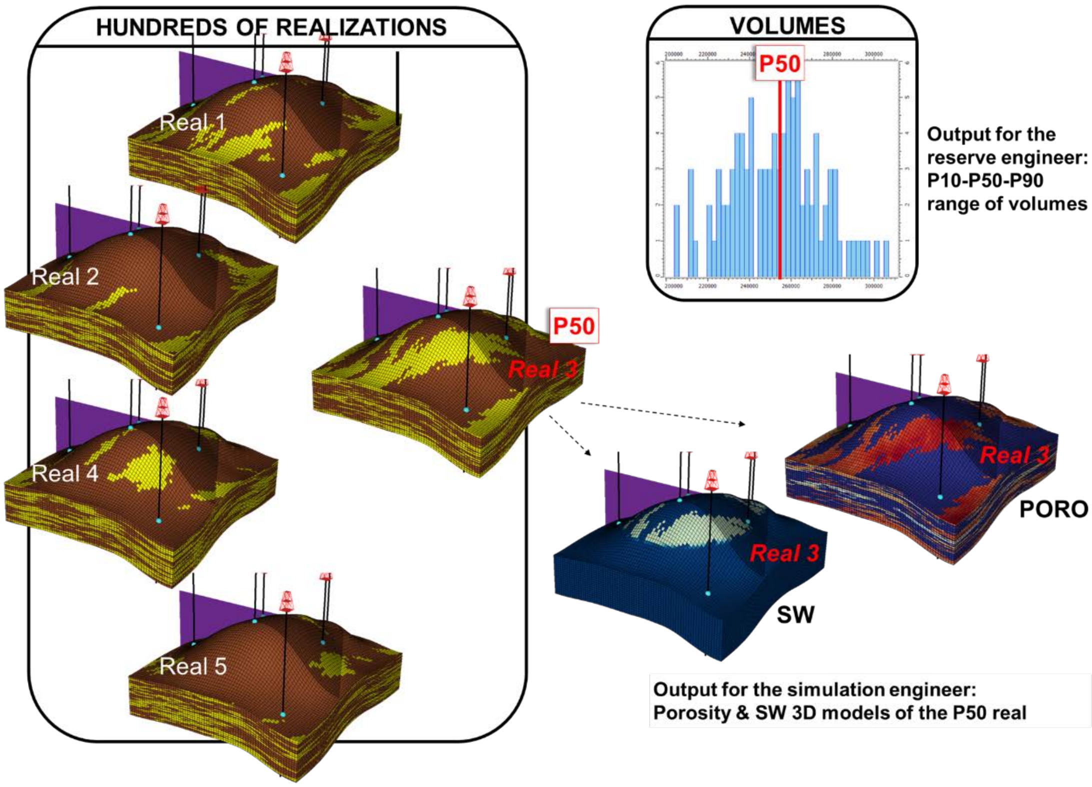

Figure 3. Running hundreds of realizations to get stochastic HCPV and to get realizations to send to flow simulation.