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Research paper

Increasing the predictive power of geostatistical reservoir models by integration of geological constraints from stratigraphic forward modeling

Quinto Sacchi [a, *], Eloisa Salina Borello [a], Gert Jan Weltje [b], Rory Dalman [c]

[a] Politecnico di Torino, Department of Environment, Land and Infrastructure Engineering, Corso Duca degli Abruzzi 24, 10129 Torino, Italy
[b] University of Leuven, Department of Earth and Environmental Sciences, Celestijnenlaan 200E, 3001 Leuven-Heverlee, Belgium
[c] TNO, Netherlands Organisation for Applied Scientific Research, Princetonlaan 6, 3584CB Utrecht, The Netherlands

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ABSTRACT

Current static reservoir models are created by quantitative integration of interpreted well and seismic data through geostatistical tools. In these models, equiprobable realizations of structural settings and property distributions can be generated by stochastic simulation techniques. The integration of regional (or basin) scale knowledge in reservoir models is typically performed qualitatively or semi-quantitatively (for example, through the definition of regional property trends or main channel-belt orientations). This limited use of regional information does not allow an assessment of the impact of the uncertainties associated with the regional knowledge on the overall uncertainty of the reservoir model.

A novel approach is proposed in this study, which allows us to consistently integrate basin-scale information into reservoir models. A new type of data, related to the distribution of the potential hydrocarbon-bearing volumes at basin scale, was obtained from a 2-DH process-based stratigraphic forward model (SFM) and integrated as a soft constraint in the geostatistical reservoir modeling. As a consequence, reservoir models are quantitatively consistent with the large-scale geological setting defined by the SFM output. Furthermore, the uncertainty associated with each SFM parameter can be propagated to reserve estimation. Thus the partitioning of the overall uncertainty affecting a reservoir model into the contributions of the uncertainties at the basin and reservoir scales can be quantitatively assessed.

Several synthetic case studies were carried out with and without conditioning to SFM output, which verified the effectiveness of the method. A logical next step is to apply the proposed methodology to a real-world case.

1. Introduction

Geological reservoir modeling encompasses all aspects related to the definition of the structural, stratigraphic, lithological and petrophysical properties of subsurface rocks, leading to the estimation of the spatial distribution and the volume of hydrocarbons in place (Mallet, 2002).

Available information for geological reservoir modeling includes static and dynamic data at different scales (Fig. 1), ranging from centimeters (core data) to kilometers (2D/3D seismic). Typically, reservoir models result from the quantitative integration of available static data, i.e. well logs, core data and seismic data (Cosentino, 2001; Benetatos and Viberti, 2010). These kinds of data are complementary because well data are characterized by high vertical resolution (log sampling is usually in the order of decimeters) and low horizontal resolution (well spacing is usually some hundreds of meters to some kilometers and wells are not uniformly distributed), whereas seismic data is characterized by relatively high horizontal resolution (tens of meters) and low vertical resolution (tens of meters). In creating static reservoir models, depth horizons derived from seismic data provide the structural description, whereas well logs give information about the vertical distribution of reservoir lithologies.

Generally, due to the low density of wells in the oil industry, the vertical trend corresponding to the average proportional abundance of lithofacies encountered in the wells is assigned to the

* Corresponding author. Corso Duca degli Abruzzi 24, 10129 Torino, Italy.
E-mail address: quinto.sacchi@polito.it (Q. Sacchi).

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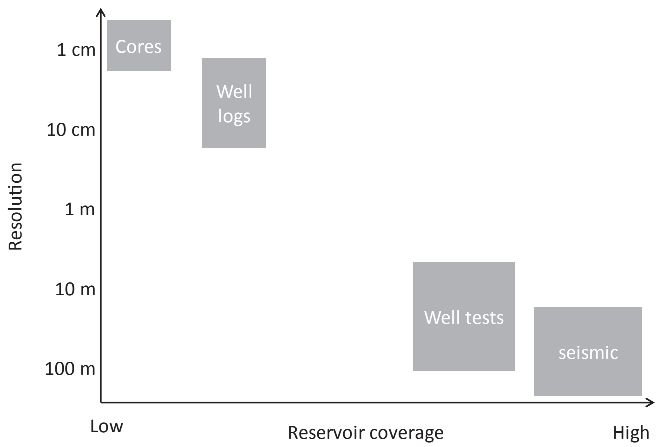

Fig. 1. Resolution and coverage of a typical data set for geological reservoir modeling.

entire domain in the form of a vertical proportion curve. This assumption of stationarity assumes that statistics from wells are representative of the 3D field properties. However, stationarity cannot be easily justified from a sedimentological point of view, and the extent to which vertical proportion curves represent the actual mean lithofacies abundances depends strongly on the number and pattern of wells (Massonnat, 1999). Approaches based on stationary random functions therefore often lead to inaccurate reservoir models (Labourdette et al., 2008).

If the stationarity hypothesis does not hold true in the volume of interest, additional geological information should be incorporated into the modeling workflow to constrain stochastic simulations. Several approaches have been developed during recent years to quantify the lateral variability of reservoir lithology: (1) Information extraction from seismic surveys (e.g. Beucher et al., 1999; Marion et al., 2000; Strebelle et al., 2003; Zachariassen et al., 2006); (2) Building of a 3D paleobathymetry grid from sedimentological well data (Massonnat, 1999); (3) Using analogous geological situations (Howell et al., 2014); (4) Integrating dynamic data, such as well-test interpretation and production data (e.g. Oliver, 1994; Wen et al., 1998); (5) Integrating sedimentological cross sections (Labourdette et al., 2008), and (6) incorporating local prior probability in stochastic reservoir simulation (e.g. Deutsch, 2002; Mallet, 2002).

In this study we propose a novel methodology to quantitatively integrate basin-scale information into reservoir models and account for the associated uncertainty. The proposed methodology allows the construction of a quantitative prior 3D probability cube of lithology (or lithofacies) proportions, by introduction of additional basin-scale information, not extractable from either well or seismic data, but obtainable from stratigraphic forward models (SFMs). In a previous study (Sacchi et al., 2015) we illustrated how the most likely scenarios could be selected from a series of SFM realizations by an objective function which quantifies the discrepancy between the actual and predicted elevation of a regional seismic reflector corresponding to the reservoir top. In the present study, we show that the SFM constraints permit us to reconstruct a geological reservoir model by geostatistical techniques, which may be used to downscale the results of the SFM to the reservoir grid. In particular, we show that we can successfully interpolate the local information derived from well logs by imposing a spatial correlation expressed in terms of covariance. The uncertainty associated with spatial prediction is modeled by random function theory. In a follow-up study, we intend to apply the methodology proposed by Sacchi et al. (2015) and the present study to a real-world case.

2. Methodology

The workflow proposed in this study aims at integrating typical data sets used for geological reservoir modeling, made up of well and seismic data, with a potentially new kind of data, represented by the parameters estimated by a quantitative Stratigraphic Forward Model (SFM). The SFM provides the channel-belt architecture at basin scale, which can be expressed as a non-stationary 3D probability distribution of depositional lithofacies proportions. This probability cube was used as additional input for the geostatistical reservoir model. The proposed workflow was applied to a fluvio-deltaic environment.

Two geostatistical approaches are in widespread use for modeling reservoirs in fluvio-deltaic environments (Daly and Caers, 2010), namely Object-Based Facies Modeling (OBFM) (Georgsen et al., 1994) and Multiple-Point Statistics (MPS) (Strebelle, 2002). The first technique directly addresses the issues of geometry and connectivity, producing a model that contains explicit representations of the channel features conditioned to data. However, in some circumstances conditioning to data can be difficult, for example with dense well data sets or with multiple soft probability fields (Tetzlaff et al., 2005; Strebelle, 2012; Caers and Zhang, 2004). The second technique complements traditional variogram driven cell-based modeling as well as the object modeling approach. In fact, it is a cell-based approach that uses a training image to estimate the multivariate distribution of quantities of interest, instead of a variogram-based algorithm that expresses a simple bivariate distribution. Both approaches were considered in this study, and their ability to integrate basin data whilst preserving realistic geometry was analyzed and compared.

Incomplete information on the geological features and geophysical parameters characterizing the subsurface induces uncertainty in every aspect and in every phase of reservoir geological modeling (Caers, 2005). Uncertainty of the integrated basin information was taken into account and propagated to the reservoir scale. The proposed workflow is summarized in Fig. 2, and is described in detail in the following subsections.

2.1. Stratigraphic forward model

For basin-scale simulation an aggregated, 2DH (depth-averaged

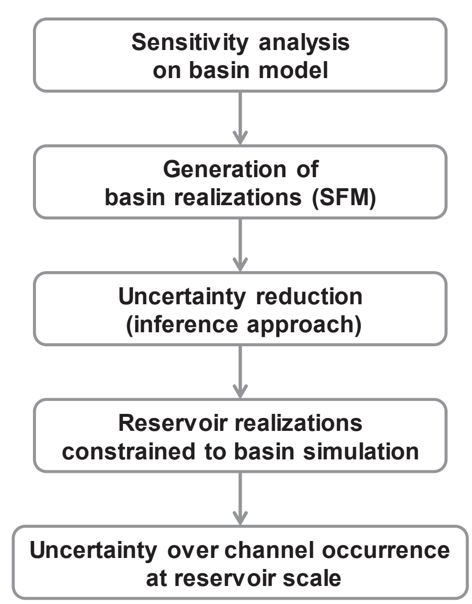

Fig. 2. Geological reservoir modeling workflow proposed in this study.