

An introduction to this special section: Reservoir modeling constrained by seismic

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Reservoir modeling is recognized as the construction of a 3D numerical representation of the hydrocarbon reservoir, in depth, comprising the reservoir structure (e.g., as delimited by stratigraphic horizons and faults); internal architecture (e.g., depositional facies); petrophysical properties (e.g., porosity, permeability); and fluid distribution (e.g., water saturation). Some of the purposes of a reservoir model include quantification of hydrocarbon volumes, input to flow simulation for quantification of recoverable hydrocarbons, and well positioning.

Reservoir modeling is the realization of a geological concept constrained to all relevant data. These data come from various sources and disciplines; they have different degrees of reliability and relate information at scales that can vary by orders of magnitude.

3D seismic data are some of the most important constraints of a reservoir model simply because they generally cover the area of interest exhaustively. They enable the modeler to extrapolate the spatial distribution of lithology and petrophysical properties beyond well locations, with some confidence. This confidence is built by careful calibration of seismic data to information observed at the wells.

The goal of this special section of *TLE* is to provide a window into how the industry has evolved on this topic. A few years ago, this topic would have probably attracted papers on new geostatistical algorithms to incorporate and scale seismic data—mainly acoustic impedance—to guide the distribution of petrophysical properties, mainly porosity. We received no such manuscript. Instead, the focus of almost all of the papers is to tighten the link between seismic-derived information and reservoir rock properties.

Reservoir modeling is generally performed in the depth domain. The seismic data and all information derived from them must therefore be transformed from time to depth. All methodologies described throughout this special section rely on the accuracy of the underlying velocity model used in the conversion. In the first paper of this section, Vilorio et al. discuss fine-tuning a velocity model in a structurally complex geological setting by applying a two-step correction factor to calibrate the interval velocity model to match well information.

Rock physics plays a central role in understanding how seismic data respond to reservoir properties. Spikes investigates how to extract net-to-gross and water saturation values through statistical classification of amplitude data. Next, Dvorkin et al. explain the basic concepts and benefits behind digital rock physics experiments to derive porosity-permeability transforms and relative permeability curves.

Wallet et al. present a tutorial on latent space modeling, comparing three data clustering techniques to extract con-

nectivity information that cannot be seen on the raw seismic data and their attributes.

Calibration of seismic information is a difficult exercise for a variety of reasons: (1). Scale differences between seismic, modeling grid cell size, and well data. (2). Statistical bias because most wells are located in mostly good reservoir rocks. (3). Inability of seismic data to clearly discriminate petrophysical variations across the reservoir. Stright et al. tackle the issue of scale and information content differences between low-frequency seismic data and high-resolution well logs in relation to the use of seismic attributes as soft data to constrain a facies model. In their approach, rock physics and seismic forward modeling are applied to supplement calibration information outside of sampled values. Michelena et al. revisit crossplot analysis, proposing an approach to derive facies probabilities from seismic scale acoustic and shear impedance, further calibrating it to vertical facies proportions observed at the wells.

With reservoir modeling, the goal of inversion is to extract attributes that are better correlated with rock properties from the raw seismic data. The process is generally iterative. Convergence is assumed when forward modeling of the seismic response reproduces the observed raw seismic data reasonably well. Leguijt discusses a Bayesian framework for probabilistic inversion of seismic data for porosity. He illustrates the approach with a 3D seismic data set as well as with a 4D example. Singh et al. present an integrated case study in the Siwa Field, combining rock physics modeling and AVO inversion to derive seismic rock properties and then use these to constrain the final porosity distribution in the reservoir model. Tuttle et al. illustrate a two-part inversion process for porosity and saturation. In their approach, elastic inversion is used to constrain the petro-elastic inversion from which porosity and water saturation are derived.

History matching is a process similar to seismic inversion in that flow simulations are performed on the perturbed geological model until observed well productions are matched. Castro et al. propose a history-matching procedure in which 4D seismic data are inverted and used as static constraints to the reservoir model, indicating the probability of observing a channel facies away from the wells. The authors also propose a second approach that combines a fine-scale geological model, resulting in a flow simulation that performs forward modeling of 4D seismic data.

Finally, Ling et al. introduce the concept of “3.5D seismic” in which, after thorough processing and stratigraphic interpretation, production data are further used to qualify the reservoir and connectivity from seismic amplitude.

We hope you will enjoy the papers presented this special section as much as we did when reading them. **TLE**