Integrating Seismic Imaging and Inversion

Combining depth imaging and inversion workflows into a single consistent process has the potential to provide more accurate models in a shorter time than achievable to date.

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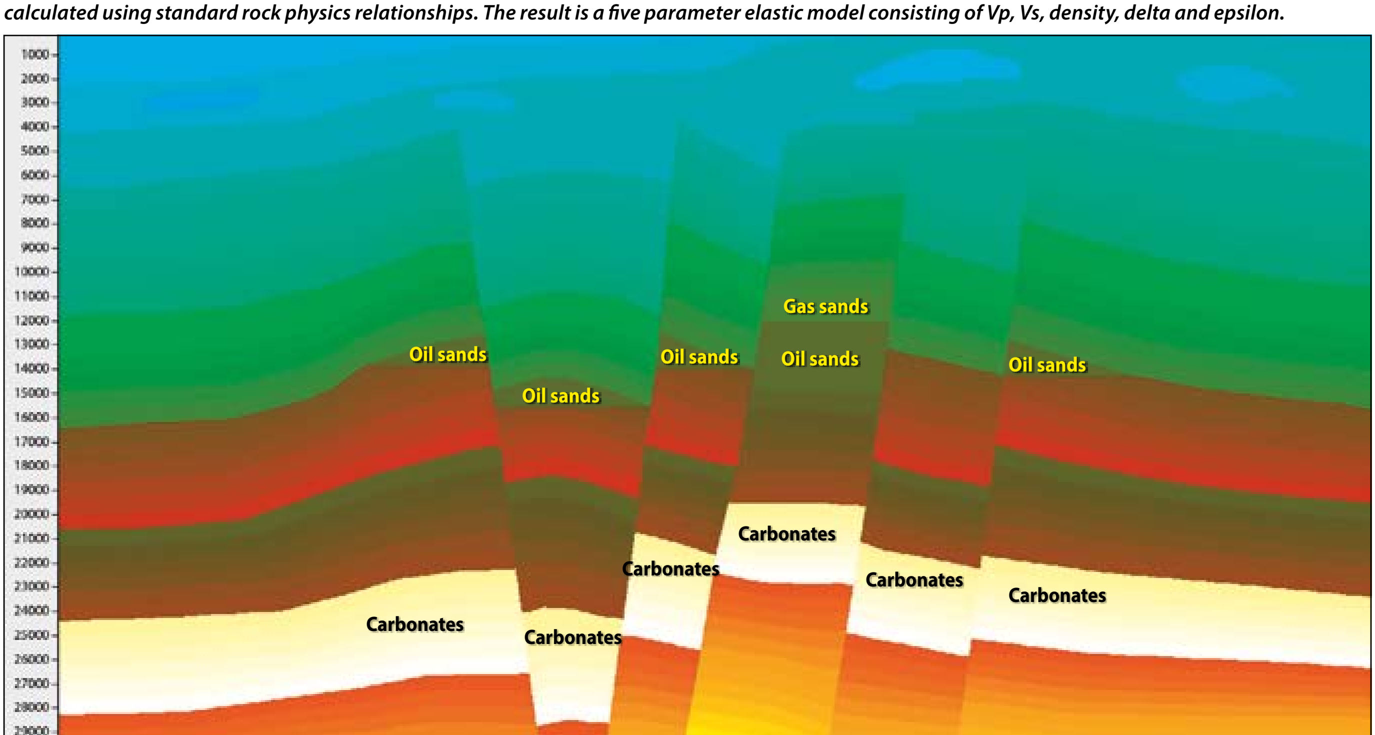
The hydrocarbon industry is exploring in ever more complex environments, and the demands for efficient extraction of identified reserves require accurate imaging of reservoir architecture and robust characterization of rock and fluid properties. Depth migration algorithms exist to assist in determining reservoir architecture; however, these are often applied in isolation from the subsequent seismic inversion and reservoir characterization steps required to build static reservoir models. The result is in many cases a disconnect between structure and properties, i.e. between rock properties provided in the time domain and well planning as required by engineers in the depth domain. Addressing this disconnect has the potential to improve reservoir models, and can also lead to a significant improvement in efficiency and reduction in turn-around time as duplication of steps is avoided.

Using PSTM Gathers in Inversion

Today depth imaging is at the core of seismic data processing. PSDM volumes are used for interpretation and prospect generation and, if accurately created, will consist of seismic events imaged at the correct depth and spatial location. However, although seismic imaging is done in depth, in many cases impedance inversion is still done using pre-stack time (PSTM) gathers. There are a number of disadvantages to inverting PSTM data. Firstly, if the gathers input into the inversion process are not migrated to the correct spatial location, then the inversion results will also be incorrectly positioned. Secondly, incorrect imaging will lead to erroneous impedances, particularly true for pre-stack inversion when positioning errors will induce erroneous AVO effects. Moreover, when impedance inversion results are delivered in the time domain they need to be converted to depth for comparison with well log or other geophysical data, and to build reservoir models for resource development and management. Without a valid model, which is developed during depth imaging, there is no reliable way to correctly convert time domain seismic data to depth.

The reason for the use of PSTM gathers in inversion is historical. In the past, PSDM used to be of lower frequency and due to variations in illumination, amplitude was not preserved. Over the years PSDM technology has been greatly improved

Figure 1: Geological model used for the study. Lithology and fluid properties were assigned to each layer, and from these, elastic parameters were calculated using standard rock physics relationships. The result is a five parameter elastic model consisting of Vp, Vs, density, delta and epsilon.



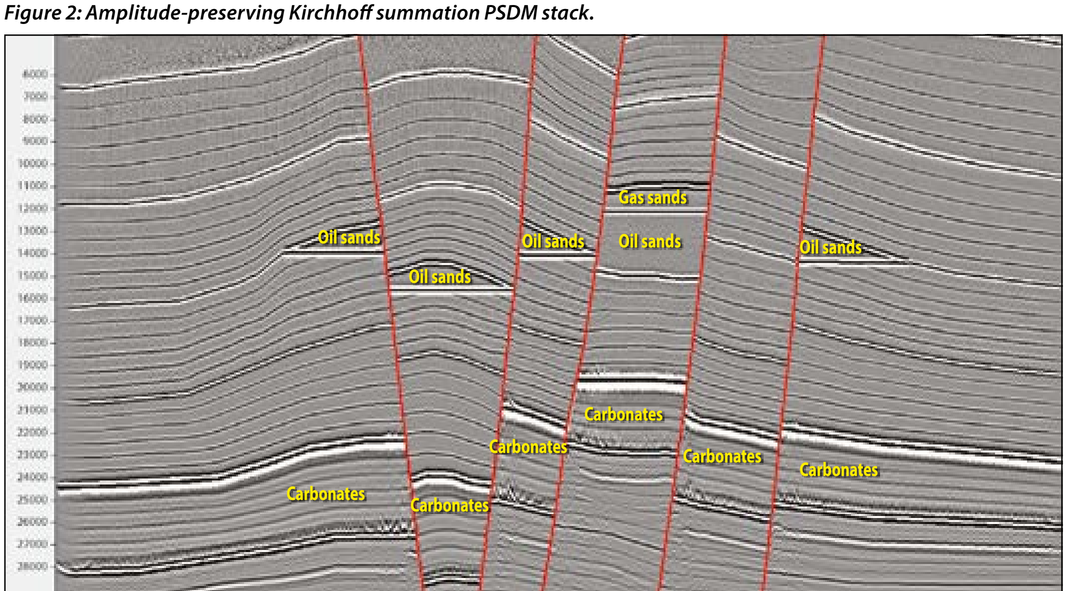
and today's PSDM data is as high frequency as any PSTM data. Amplitude is preserved in areas of uniform illumination and the industry is working to produce amplitude-balanced PSDM even in areas of variable illumination. The study presented here examines the accuracy of rock properties computed from impedance inversion undertaken using PSDM gathers.

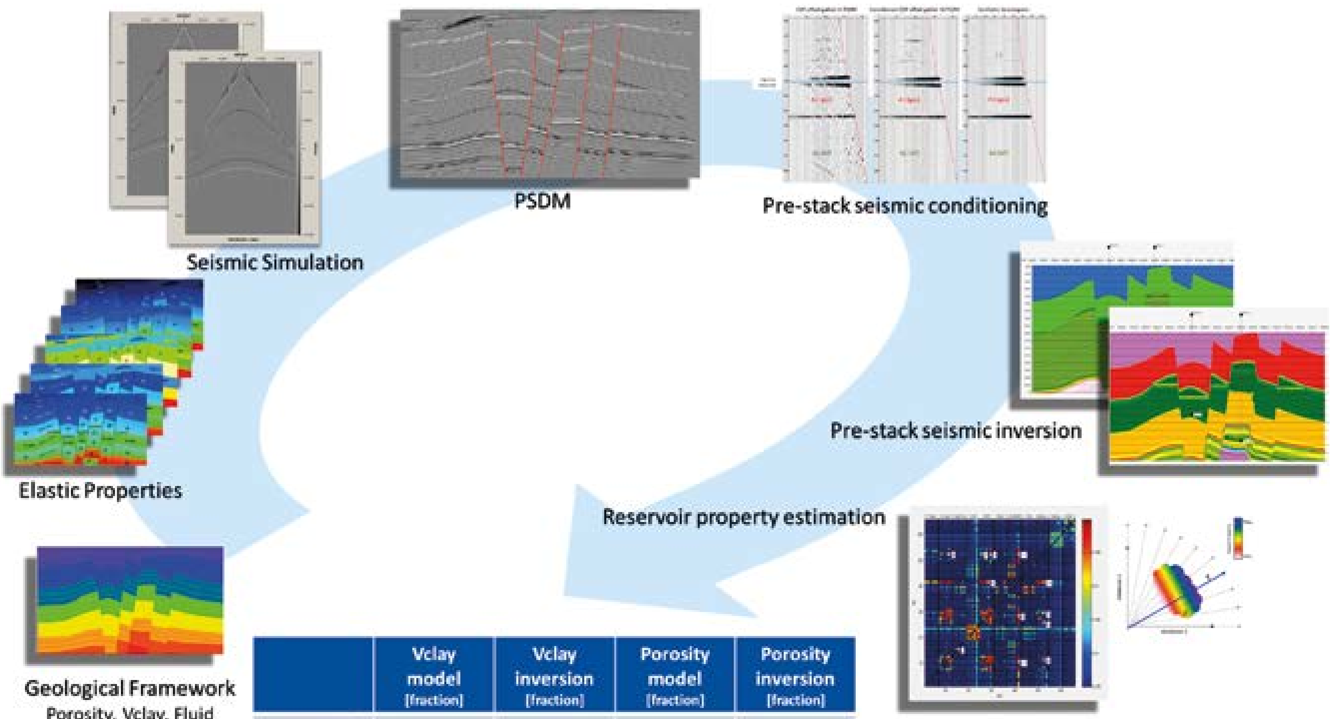
Testing Seismic Depth Imaging

In order to test the accuracy of seismic depth imaging combined with impedance inversion, simulated seismic data generated from a synthetic model (i.e. when the answer is known) was used. An elastic model was developed and seismic simulation using the full elastic wave equation was undertaken to generate a realistic seismic dataset. The faulted geological model used consists of a series of normal and reverse faults (Figure 1). The elastic parameters were calculated from porosity and clay content values provided for each layer using standard rock physics relationships. Porosity in the oil sand and gas sand was set to 20% and the clay content set to 1%. Using these values, a five parameter anisotropic elastic model was built.

A non-dispersive recursive migration operator application (Kosloff et al., 2008) was used to generate simulated shot gathers from the anisotropic elastic model. The simulated shots were then migrated using an amplitude-preserving Kirchhoff summation PSDM algorithm. The results of PSDM are migrated image

Figure 2: Amplitude-preserving Kirchhoff summation PSDM stack.





	Vclay model [fraction]	Vclay inversion [fraction]	Porosity model [fraction]	Porosity inversion [fraction]
Gas sand	0.01	0.00	0.2	0.2
Oil sand	0.01	0.03	0.2	0.18
Wet sand	0.01	0.08	0.2	0.17
Shale	0.70	0.72	0.2	0.23

***Figure 3:** Workflow applied in this study and numerical results from reservoir property estimation through the multi-attribute rotation scheme (MARS).*

gathers at the correct spatial location, and a stack of these gathers produces the final PSDM stack (Figure 2).

The PSDM gathers formed the input to the simultaneous elastic impedance inversion, which operates in the time domain and therefore required the PSDM gathers to be stretched to time prior to inversion. The gathers were conditioned to remove residual noise (such as multiples) in preparation for inversion, and a low frequency model was constructed based on the input model at brine-saturated conditions. The conditioned gathers and low frequency model were next input to a simultaneous elastic impedance inversion (Tonnellot et al., 2001), from which P impedance and S impedance were obtained. These were stretched back to the depth domain, using the same velocity model that was used to stretch the depth domain PSDM gathers to the time domain. Note that the depth to time conversion and time to depth conversion steps, applied respectively before and after the impedance inversion, are robust, and are required as the seismic inversion assumes a stationary time-domain wavelet.

Calibrating with MARS

As the final step, the seismic inversion results were used to calculate rock and fluid properties using the multi-attribute rotation scheme (MARS) (Alvarez et al., 2015) and compared to the values used to construct the model. Observed misfit of the predicted reservoir property values in comparison with the actual model are small (Figure 3) and are mainly due to the limitations resulting from using only elastic measurements to predict rock properties. Fluid and lithology responses move in non-orthogonal directions when only seismic inversion derived attributes are used. Therefore, there will always be a fluid imprint on the lithology measurements and vice versa. In this case, the transform used was estimated with reference to all fluid phases (wet, oil and gas). As a consequence, the volume of clay predicted in a location with only two fluid phases, wet and oil, will trade off the lack of separation from the background with a decrease in reservoir rock quality (i.e. an increase of volume of clay).

However, results indicate that PSDM preserved the relative amplitude of the data and therefore rock properties can be successfully predicted and positioned in the correct spatial location and depth using a robust seismic reservoir characterization technique.

A Step-Change

Combining depth imaging and inversion workflows into a single consistent process has the potential to provide more accurate models in a shorter time than achievable to date. Although simple, the synthetic example presented illustrates that amplitudes can be preserved in depth imaging, and the resulting PSDM gathers can be used to robustly determine reservoir properties in depth. Work is on-going to extend this principle to more complex geological models and environments. The results will represent a step-change in the quality of sub-surface information available to explorers and reservoir engineers, and the efficiency with which it can be provided.

References available online. ■