Incorporating 3-Component Seismic Data for Enhanced Detail in an Oil Sands Reservoir and Fluid Characterization

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Summary

The application of a quantitative interpretation workflow is illustrated using an example from a Canadian oil sands project. In an area with complex reservoirs, complex fluid distributions and unconventional rock property behaviour, high drilling density provides the data necessary for robust custom rock-physics templates. High quality shallow multi-component seismic data completes the conditions required for unprecedented detail in reservoir characterization, enabling accurate predictions of both lithology and fluids. The incorporation of converted-wave data shows how an under-utilized dimension of seismic data can contribute to the accuracy of the solution. Finally, comparison of actual vs predicted drilling results supports the legitimacy of the quantitative information derived from the integrated process.

Introduction

The Athabasca oil sands contain more than a trillion barrels of bitumen within the Cretaceous formations of northeastern Alberta, Canada. A small portion of this vast resource is close enough to the surface (<75m) to mine but the majority of it must be mapped and developed in-situ. With deposits from 30 – 100m thick at depths of only 100 – 450m, wells are cheap and seismic data is expensive – therefore the Canadian oil sands have always been 'geology-weighted' when it comes to evaluation. When the cost of a square kilometer of seismic data is equivalent to the cost of drilling a well, the geologists' argument for hard data over soft is often convincing.

In order to justify the relative expense of the seismic data, it must be shown to add significant value to the understanding of both the reservoir architecture and its fluid distribution. The reservoir in this case study is a laterally-extensive relatively homogenous shoreface sand. While the reservoir quality is consistent in the project area, fluids are unpredictable. Variable oil/water contacts have been fixed in their paleo-positions by biodegraded oil and subsequent tectonics, and there are occasional unexpected occurrences of water trapped by bitumen above and below.

To date, the preferred method of in-situ bitumen production is the Steam-Assisted-Gravity-Drainage (SAGD) process. Multiple horizontal well pairs are drilled to inject steam into the reservoir and pump out the heated, liquified oil. The objective of every oil sands operator is to minimize the steam-injected to oil-recovered ratio by maximizing the efficiency of the SAGD process. The position of the horizontal well as close to the base of bitumen pay as possible is obviously a critical factor in maximizing the amount of recoverable resource and minimizing the impairments to that end. Detailed knowledge of the reservoir and oil/water contacts can therefore allow for better placement of production wells leading to better management of the inherent complexity of oil sands
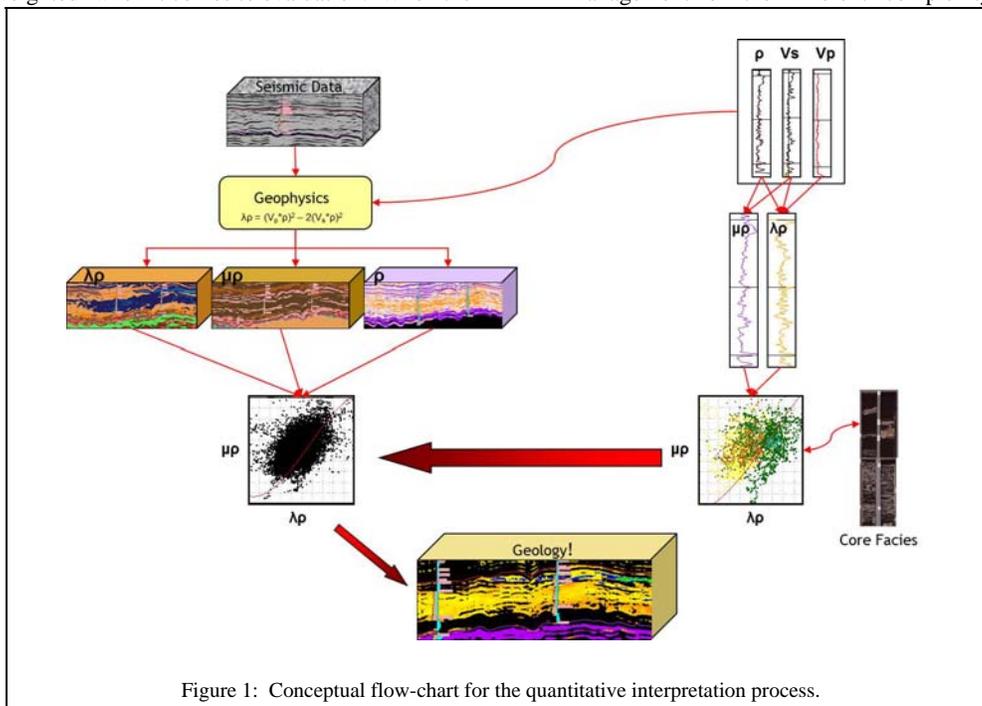

Figure 1: Conceptual flow-chart for the quantitative interpretation process.

formations. An accurate baseline reservoir characterization is also essential for subsequent time-lapse seismic analysis and comparison for production monitoring in fields that are designed to produce for 35 years or more.

The process described in this presentation integrates all available data to create a detailed volume of deterministically-derived reservoir, non-reservoir and fluid properties. The workflow is illustrated using examples from Laricina Energy's Grand Rapids project area within the Athabasca oil sands.

Method

As the conceptual flow-chart in Figure 1 shows, rock physics attributes are first determined from seismic data, then classified in terms of facies and fluids using the wireline log and core data from wells. The seismic process involves the use of AVO (amplitude vs offset) analysis to separate the compressional (P-wave) and shear (S-wave) components of the seismic data. The resulting components are then used to calculate physical rock properties such as shear rigidity (mu) and incompressibility (lambda) (Goodway et al. 1997). It is common knowledge among oil sands geoscientists that the density log shows a strong correlation to the gamma ray log and is therefore a good lithology indicator. In the following examples, an estimate of density is obtained from seismic using a multi-attribute analysis approach (Russell et al., 1997). Since the oil/water contact is a critical parameter for optimal recovery, particular emphasis is given to the estimation of water saturation from seismic using both attribute classification and multi-attribute analysis for direct prediction of log-derived Sw curves.

The crossplot in Figure 2 shows a relationship between acoustic attributes derived from well data and water saturation. The most significant effect due to the fluid type variation is apparent on the Y-axis which is Mu*Rho. Mu*Rho represents shear rigidity and as such is dependent solely upon shear impedance. The distribution on this crossplot lends support to the hypothesis that seismic attributes and PS data in particular may respond to the reservoir fluids in the oil sands.

Two methods for estimating water saturation from the seismic data are described. The first uses P-wave data alone and the second incorporates the PS data. Figure 3 shows the P-wave data compared to the PS-data on the same line with the zone of interest outlined in the red box. Both are displayed in depth and it is obvious that there are significant differences in the frequency content of the data. In fact, it is difficult to imagine that the low frequency PS data would contribute anything to increasing the accuracy
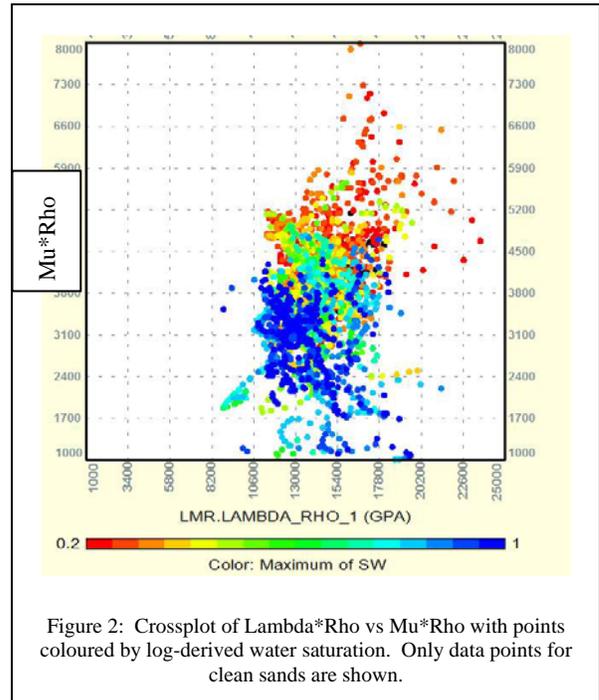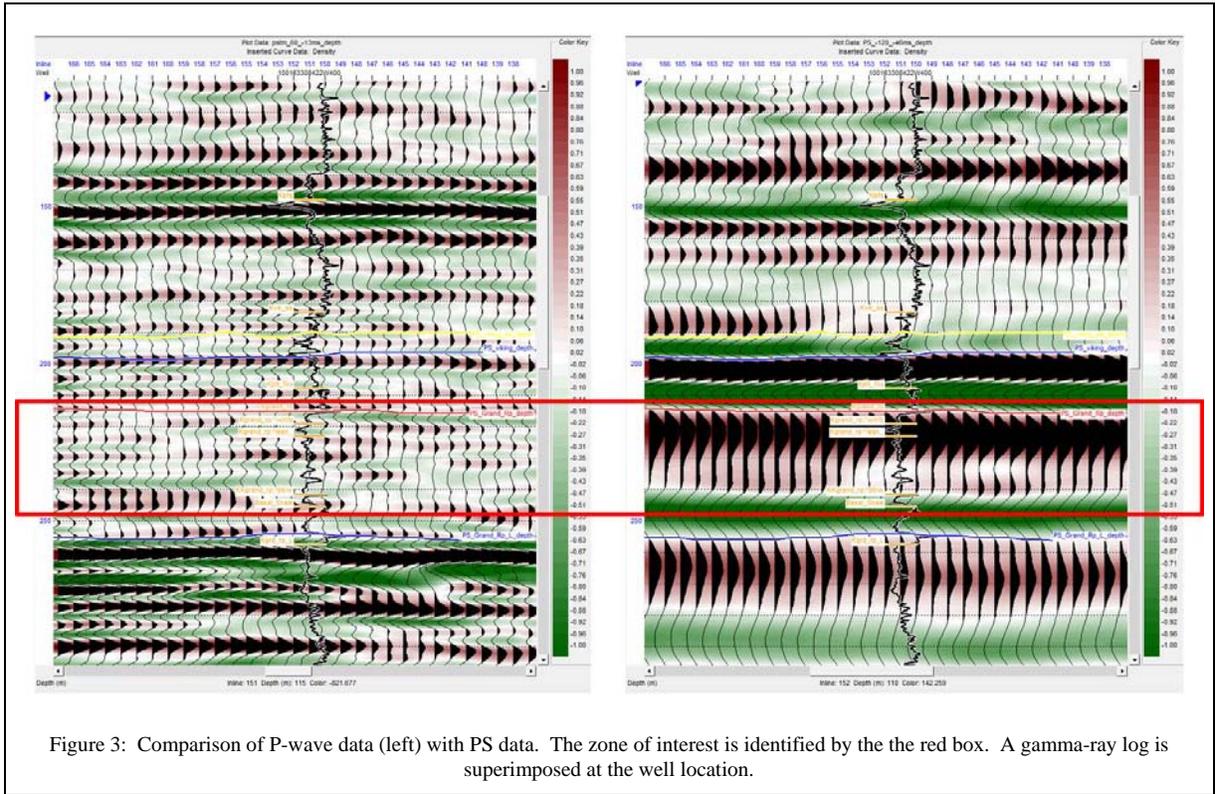

Figure 2: Crossplot of Lambda*Rho vs Mu*Rho with points coloured by log-derived water saturation. Only data points for clean sands are shown.

and resolution of subtle geophysical distinctions such as the change between oil and water.

Nevertheless, multi-attribute analysis was used to determine a function to predict the known water saturation curves at well locations and then applied to the entire seismic volume. Various seismic attributes were incorporated including shear impedance and mu*rho. A separate computation also incorporated attributes derived from the low frequency PS data. Facies and fluids were classified using the well data relationships and the final results with and without incorporating PS data were compared. Figure 4 shows the final classified seismic volume incorporating PS attributes compared with the conventional seismic display.

Bottom-water thickness maps for both versions are shown in Figure 5. While only 3 wells were used for the multi-attribute 'training', there are 11 wells on the seismic volume, leaving 8 wells as blind tests. The graphs in Figure 6 illustrate the accuracy of the predictions for both methods showing that incorporating PS data did result in a better fit with the actual values thereby contributing to increased confidence in the final map.
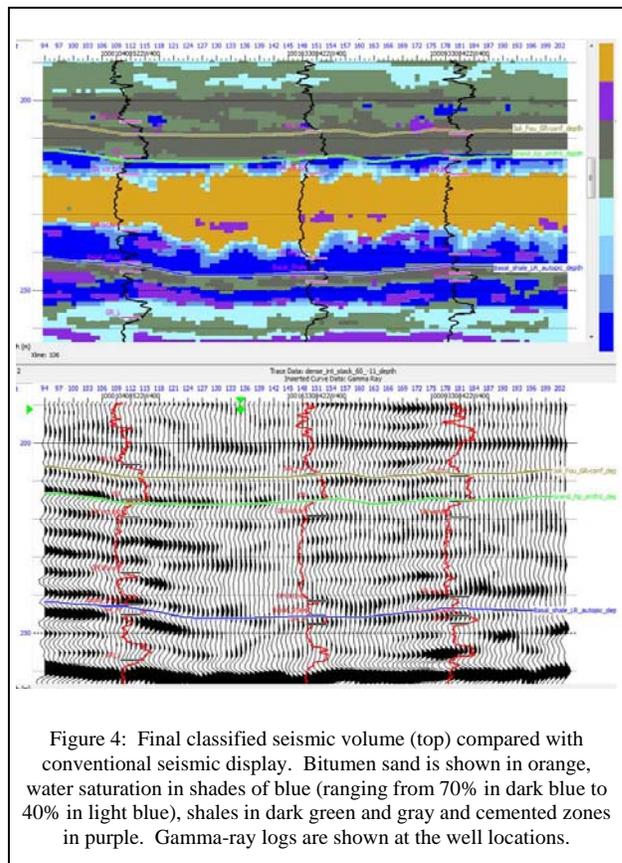
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Figure 3: Comparison of P-wave data (left) with PS data. The zone of interest is identified by the the red box. A gamma-ray log is superimposed at the well location.

Conclusions

The clean shoreface sands of the Grand Rapids formation are continuous and predictable but the fluid contacts can vary independently of structure. In a SAGD development operation, knowing where the water contacts are is critical for accurate well placement. The quantitative incorporation of multi-component data in this case has proven valuable and more effective than P-wave data alone in mapping the water.

Seismic reservoir characterization and quantitative interpretation has significant advantages in oil sands developments enabling more confident identification of the geological features and associated reservoir quality and continuity. Potential benefits include fewer vertical wells required to define the resource area, more effectively placed horizontal wells for optimal production and improved steam/oil ratios, as well as more accurate flow simulations based on deterministic facies models. After production has commenced, monitoring of steam injection and heated bitumen can be assessed by repeating the reservoir characterization process with time-lapse seismic data. In the Canadian oil sands, the value of information carried by the seismic wave is undeniable.

Figure 4: Final classified seismic volume (top) compared with conventional seismic display. Bitumen sand is shown in orange, water saturation in shades of blue (ranging from 70% in dark blue to 40% in light blue), shales in dark green and gray and cemented zones in purple. Gamma-ray logs are shown at the well locations.
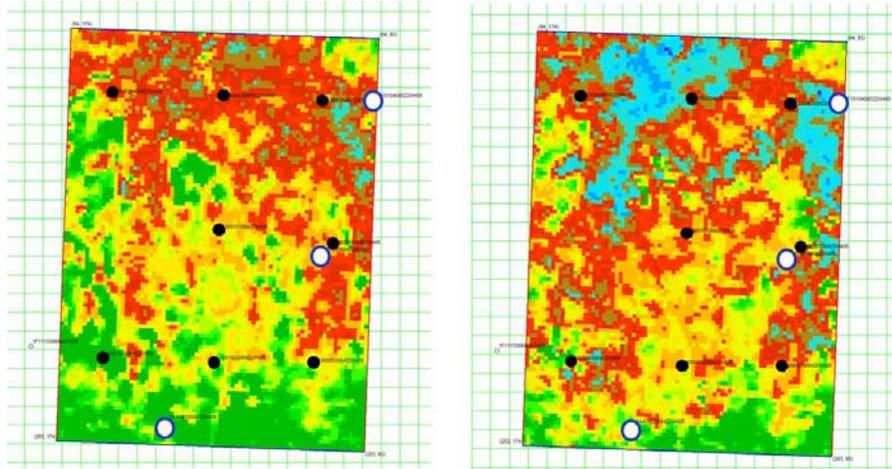
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Figure 5: Predicted bottom-water thickness for the 3D area without using PS data (left) and using PS data. White circles are control wells that were used in the multi-attribute training and black dots are blind wells.
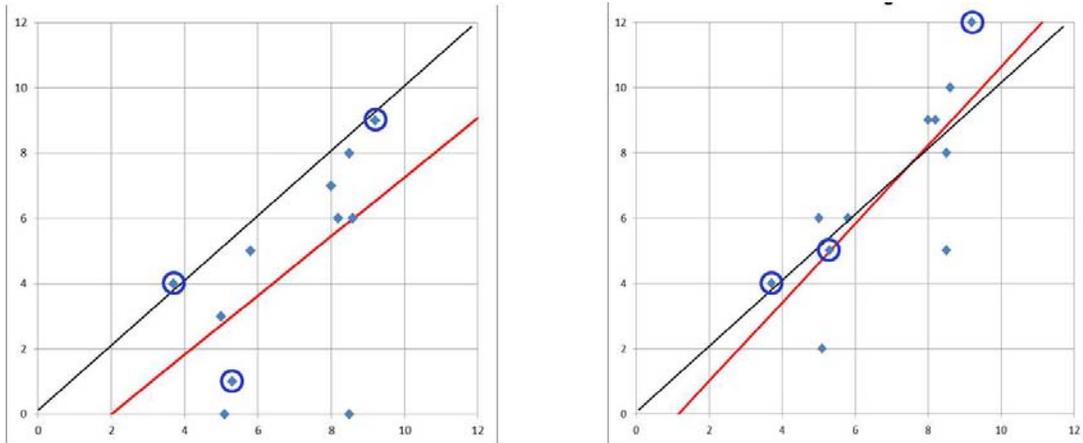

Figure 6: Graphs comparing predicted bottom-water thickness (x-axis) with actual values from well control. The plot on the left is from the map without using PS data and the one on right is using PS data. The training well data points are circled in blue. The red line shows the regression line fit to the data points and the black line is the ideal 1:1 line.

Acknowledgements