

Grand Rapids Oil Sands 3D Seismic – Incorporating and Comparing Multiple Data Types for Reservoir Characterization

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Summary

Several advanced seismic methods were employed, incorporated and compared in this project with the objective of creating a detailed representation of reservoir lithology and fluids as accurately as possible. The respective results were assessed by the ultimate measure: the match with existing wells and the prediction of drilling outcomes.

Interpolated seismic data, densely-acquired seismic data, converted-wave (PS) seismic data, multi-component vertical-seismic-profile (VSP) data and dipole sonic logs were all integrated into comprehensive geological characterizations predicting bitumen-filled reservoir, water-filled reservoir and multiple facies types. Preliminary results have shown the VSP to be essential in calibrating PS and conventional P-wave (PP) data for pre-stack quantitative processes, the interpolated data to be adequate for predicting lithology but lacking in the subtle detail required for accurate prediction of fluids, and the PS data to be enigmatic.

Introduction

The Albian (late lower Cretaceous) age Grand Rapids Formation is younger, generally shallower and thinner than the more extensive McMurray Formation in the oil sands area of Northern Alberta, Canada. Nevertheless, its clean shoreface sands are more homogeneous laterally and vertically with fewer impairments to vertical permeability than the McMurray estuarine deposits and are therefore very attractive to producers who are planning and executing thermal operations. Laricina Energy is one of those producers and holds 63 sections (163 km²) in the play fairway with an estimated 2.5 billion barrels in place in the upper Grand Rapids.

The Grand Rapids zone is broadly divided into lower, middle and upper reservoir units capped by the Joli Fou shales. The bitumen resource is contained in the 15 to 30m-thick uppermost sand unit at approximately 205m depth as shown in figure 1. An irregular bitumen/water contact defines a basal water zone in the upper sand that can vary from 0 to 8m thick. An upper transition zone may also be present with the remaining bitumen pay ranging from 8 to 24 meters.

The objective of the integrated quantitative seismic investigation was to accurately image the gross reservoir zone and identify the various components affecting horizontal well planning, production predictions (simulations), and resource estimation to optimize ultimate recovery. These components include the depth and overall thickness of the reservoir, the thickness and extent of the upper transition zone and the basal water, the extent and presence of any shale zones, and the extent and presence of high density lenses or 'hard streaks' that may impact fluid flow.

To address these challenging objectives, multi-component 3D seismic was acquired in the Germain area in 2010. The acquisition included a densely-sampled zone (DZ) within a more sparsely-sampled overall program. The sparsely sampled data was interpolated in processing for a direct comparison of interpolated seismic data with acquired seismic data within the DZ.

Converted-wave (PS) data was acquired and processed although not interpolated and a multi-component walk-away VSP was acquired at a well within the DZ. Finally, dipole sonic logs were available for many of the wells tying the seismic data. This presentation will show how the different data types contributed to the geological predictions and compare the relative merit of the various seismic methods. Comparisons will also be shown between predictions of undrilled wells and actual results.

Method

The map in figure 2 shows the geometry of the 3D seismic acquisition highlighting the DZ and the well locations. The higher density acquisition was decimated to the equivalent geometry of the rest of the survey and then the entire volume was interpolated using a 5D algorithm. Both were processed appropriately for pre-stack seismic operations. The multi-component walk-away VSP was acquired at the 100/16-33 location and used to determine the phase of the P-wave seismic and the phase and PP-PS time registration of the PS data. All data types at the 100/16-33 location are shown in figure 3.

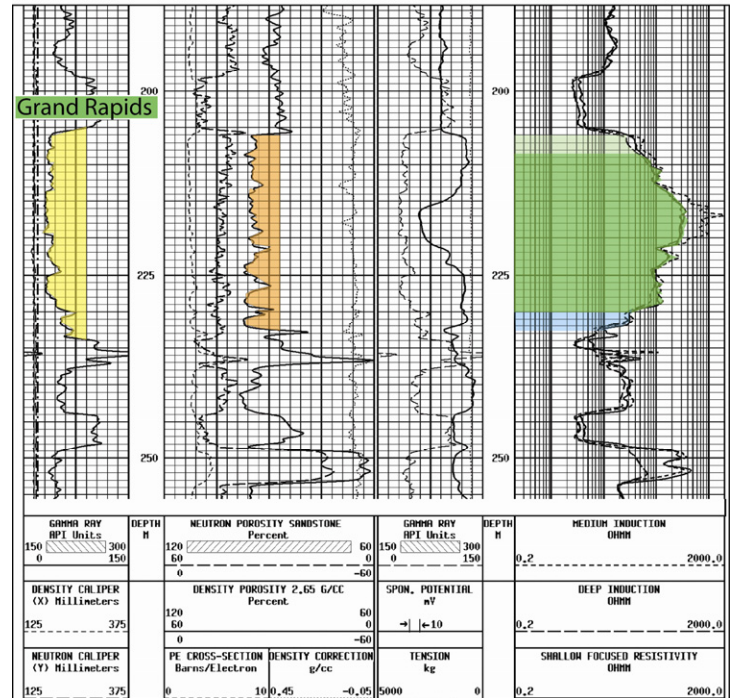


Figure 1: Grand Rapids type log 1AA/06-03-085-22W4/00

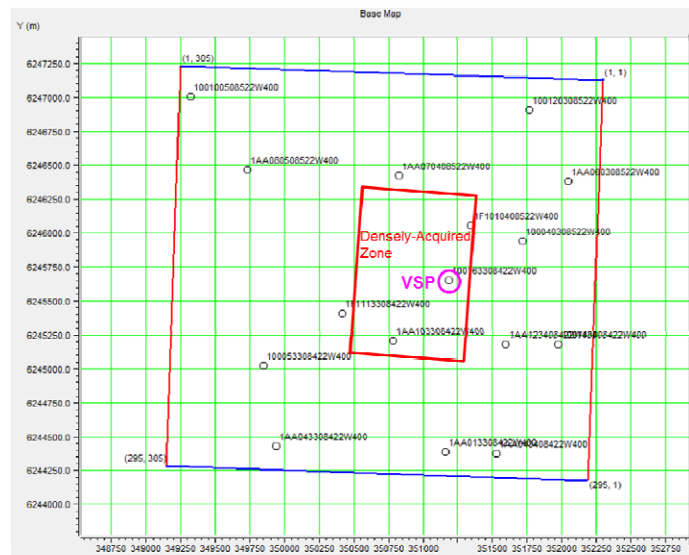


Figure 2: Germain 2010 3D seismic and well base map showing the densely acquired zone outline and the location of the VSP.

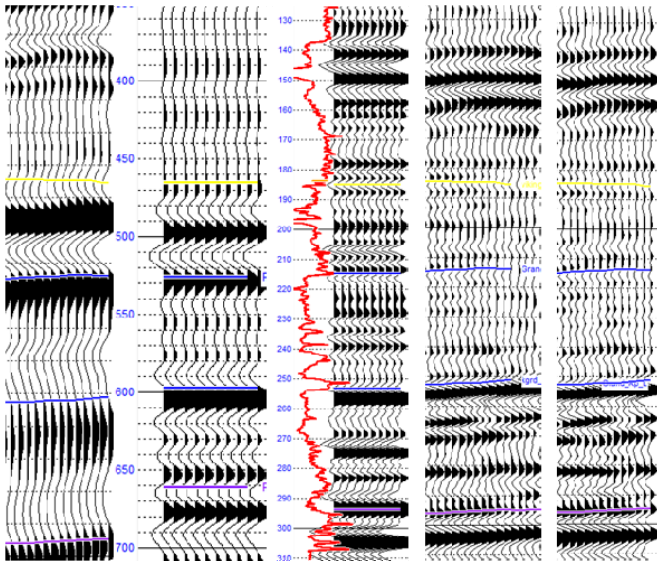


Figure 3: From left: densely-acquired PS seismic, near offset PS VSP, 100/16-33 density log, near offset PP VSP, interpolated PP seismic and densely-acquired PP seismic.

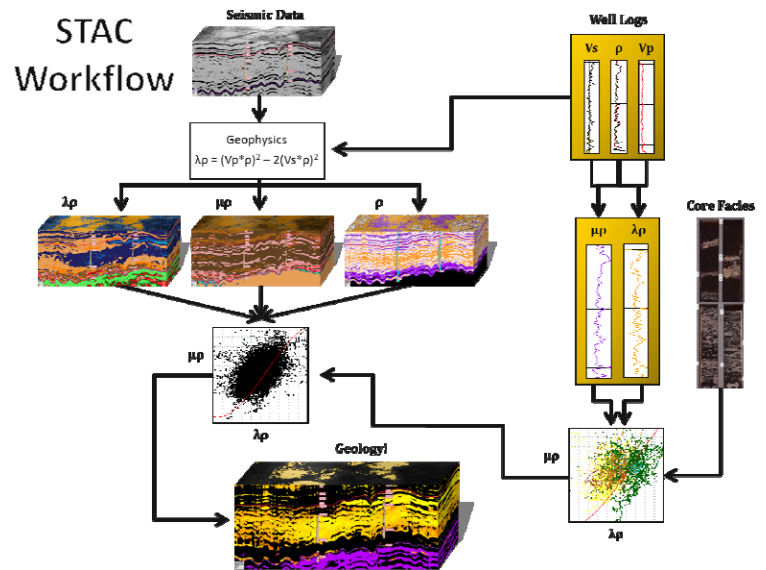


Figure 4: Seismic Transformation and Classification (STAC™) workflow.

The geological characterization was accomplished using the general workflow in figure 4 illustrating two main analysis components: well log analysis and seismic attribute analysis which are combined to create a volume of predicted geology at seismic scale. Where possible, the parameters in this process were held constant between data volumes to ensure the most direct comparisons.

Examples and Results

Although the comparison between the interpolated and the densely-acquired seismic data in conventional view (figure 5) displays slight differences that may appear insignificant, the geological significance of these differences is not fully apparent until the final classification step in the STAC

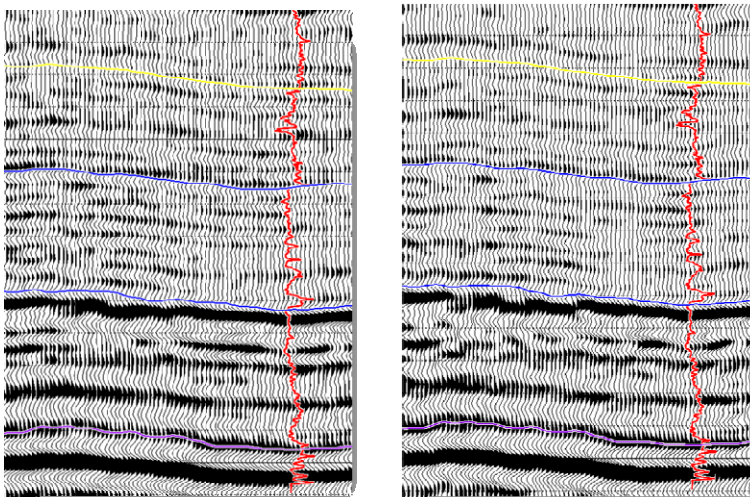


Figure 5: Conventional seismic view of the same inline for the interpolated volume on the left and the densely acquired volume on the right. A density log is displayed at the well.

workflow. For example, the sensitivity of the fluid classification to subtle seismic differences is apparent in the cross-plots shown in figure 6. Figure 6 on the left shows log data points coloured by log-derived water saturation with a reasonable cutoff between wet and bitumen reservoir represented by the gray line. Analysis of the equivalent seismic attributes (figure 6 right) shows a different data distribution using the interpolated data than the densely acquired data. The data from the DZ shows a tighter, more definitive representation of the reservoir points into two separate clusters. Adjusting the fluid cutoff based on the DZ seismic clustering resulted in a

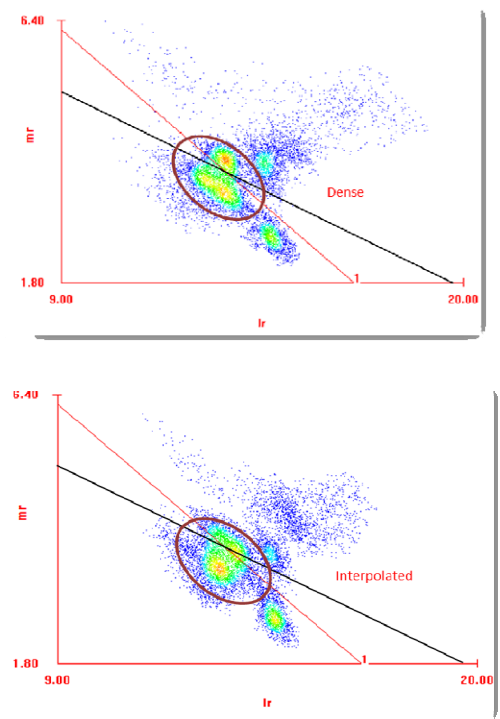
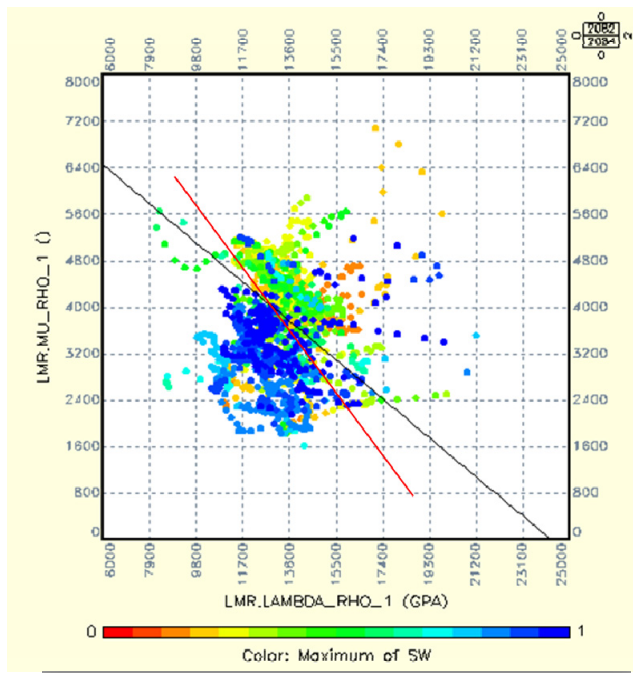


Figure 6: Left: well-log-derived lambda*rho vs mu*rho cross-plot with points coloured by water saturation; right: seismic-derived lambda*rho vs mu*rho with colour signifying cluster density for the densely-acquired data (top) and the interpolated data (bottom). The gray line on all plots is the cutoff between water and bitumen based on log data. The red line is the adjusted cutoff based on densely-acquired seismic clustering and the oval encloses the reservoir points.

better match between the wells on the 3D and the fluid classification in not only the DZ (figure 7), but also the entire interpolated volume. After depth conversion, predictions made for two new wells on the 3D survey were within 1-2m of actual values for the top and base of the reservoir and the thickness of the basal water (see table). Prediction of upper transition zone was less accurate, however it is more of a gradual saturation change over several meters and was also less critical for engineering decisions. The combined thickness of the upper transition zone with the bitumen thickness is fairly accurately predicted. Additional wells are planned for this area and have also been predicted in detail based on the results of this study.

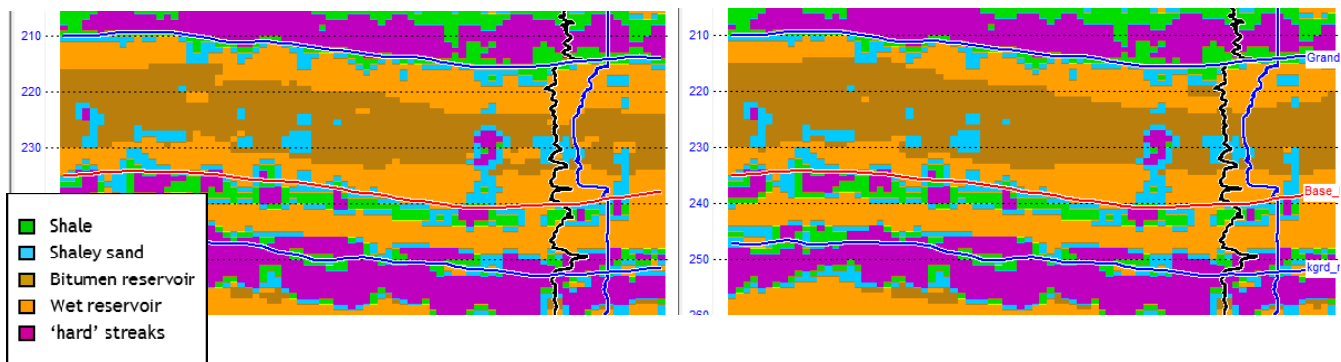


Figure 7: Final facies and fluids volumes: Left – densely-acquired volume with log-derived fluid classification and right – densely-acquired volume with fluid cutoff adjusted for seismic clustering. Density log at the well displayed in black; water saturation log in blue.

Well	100/15-33			102/16-33		
	Predicted Interpolated	Predicted Dense	Actual	Predicted Interpolated	Predicted Dense	Actual
Top Grand Rapids	215m	215m	213.7m	216m	216m	214.4m
Upper Transition Zone Thickness	8m	6m	3.5m	8m	8m	2m
Bitumen Thickness	13m	15m	20m	15m	13m	19m
Basal Water Thickness	5m	6m	5.5m	3m	7m	7.8m
Total Reservoir Thickness	27m	27m	29m	27m	28m	28.8m
Base Grand Rapids	242m	242m	243.2m	243m	244m	244.1m

Table showing predicted vs actual drilled for two wells.

Conclusions

The integration of several data types in this project highlighted the sensitivity of attribute analysis and classification to subtle seismic variations. The VSP calibration of the PP and PS data provided a confident starting point for the detailed analysis and minimized the uncertainty related to phase and time shifts between the volumes. The comparison between interpolated sparse acquisition geometry and more detailed data acquisition showed that while interpolated data is adequate for lithological classifications in this area, more detailed acquisition is useful and preferred when accurate fluid prediction is necessary. Confirmation of these methods and conclusions has been provided by comparisons with existing well control and new drilling. The clearly identified sand base and bitumen/water contact will greatly assist in the efficient exploitation of the reservoir.

Analysis of the PS data continues and will be elaborated on in the convention presentation.

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