3D Reservoir Characterization in the Grand Rapids Oil Sands*

Laurie Weston Bellman[1] and Marnie E. Connelly[2]

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[1]Oil Sands Imaging, Inc., Calgary, Canada (laurie@oilsandsimaging.com)
[2]Laricina Energy Ltd., Calgary, Canada

Introduction

The Grand Rapids Formation has not received as much attention as the McMurray with respect to recent oil sands exploration and development activity in Alberta, Canada. Nevertheless, industry has recognized the considerable potential in the clean shoreface sands of this formation in the Wabasca area of northeastern Alberta and several operators have identified viable projects in the area. Laricina Energy holds a total of 63 sections in the fairway with an estimated 2.5 billion barrels of bitumen in place. The Grand Rapids zone is divided broadly into lower, middle and upper reservoir units capped by the Joli Fou shales. The upper unit containing the bitumen resource ranges from 15 to 30m gross thickness. Net bitumen pay thickness ranges from 8.5 to 23.7m with average bitumen saturation of 70 percent or 11.6 weight percent bitumen.

The upper Grand Rapids shoreface sand is regionally extensive, clean and homogeneous with very rare mud interbeds and occasional thin, discontinuous high density concretions. The key aspects and concerns in the SAGD development of the Grand Rapids bitumen resource include clearly identifying the porosity base, the bitumen-water contact and any impedance to vertical permeability. To address these issues, a detailed 3D reservoir characterization was required.

This article describes the process of integrating core with information from available log and 3D seismic data in the Germain area to produce a volume of deterministically-derived lithology and fluids within the reservoir. While neither the log data nor the seismic data were ideal for this purpose, conditioning and processing of both data sets allowed for the successful results achieved in this project.

Method

The conceptual flow-chart in Figure 1 illustrates the ‘Seismic Transformation and Classification’ (STAC) workflow. 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

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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 (μ) and incompressibility lambda (λ) (Goodway et al., 1997). It is common knowledge among oil sands geoscientists that the density log through the shallow Cretaceous clastics in the region shows a strong correlation to the gamma ray log and is therefore a good lithology indicator. In this process, an estimate of density is obtained from seismic using a multi-attribute analysis approach (Russell et al., 1997).

Wireline logs directly (or indirectly) measure P-wave velocity, S-wave velocity and density. From these measured logs, the rock physics attributes, lambda (incompressibility) and mu (shear rigidity), can be calculated. Cross-plot analysis of these and various other attributes leads to empirical limits and guidelines for lithology and fluid discrimination based on core facies. For the wells in the immediate Germain area, there were no dipole sonic logs available for the rock physics attribute calculations; therefore, an estimate of S-wave velocity for these wells was obtained using a multi-attribute function derived from wells with S-wave logs in the wider geographical area (from up to 60km away). Figure 2 shows the actual and predicted S-wave velocity logs for wells with and without real dipole sonic logs.

Using attributes derived from real S-wave data only, the relationships between these attributes and facies or fluids can be determined from cross-plots. Figure 3 is a cross-plot of density vs mu*density calculated from well logs in the Grand Rapids zone with the points coloured by core facies. It clearly shows the clustering and separation of different facies in this domain. The relationships between attributes and facies determined from the cross-plots are then used to calibrate and classify the equivalent properties derived from seismic data.

The seismic component of the process requires high quality pre-stack data that is regularly sampled, with both near and far offsets well represented. In this case, the data was good quality with high frequency and high signal to noise ratio; however, because of the extremely shallow zone of interest, the acquisition geometry was not tightly spaced enough to provide the important near-offset traces. In fact, the sampling in the near offsets was variable enough to cause a significant acquisition footprint in the conventionally processed data set. To address this problem, the data was interpolated using a pre-stack, 5D method (Spitz, 1991; Lui and Sacchi, 2004). The output from this process contained eight times as much data as the input, and it was this interpolated data volume that was used for determining the seismically derived rock physics attributes.

Results

When the seismically derived attributes are classified based on the log and core analysis, the result is a seismic volume transformed to a detailed lithological characterization of the reservoir within the zone of interest. Figure 4 is an example portion of a line through the 3D classified by this method. Gamma ray logs are shown at the two wells intersecting this profile.

With the detailed reservoir volume obtained in this project, it is possible to visualize the data in numerous ways, examples of which are shown in Figure 5. The plot on the left is a total sand thickness map determined by vertically summing the samples classified as reservoir and converting to isopach using an average sand velocity. The plot on the right is a bottom water thickness map created using a similar method.

Conclusion

The objectives in this project were to clearly identify the porosity base, the bitumen-water contact and any impedance to vertical permeability. These were all successfully met in spite of the inadequacies of the original data and lack of dipole sonic logs tying the 3D seismic. This is an example of maximizing the value from limited available data with very good results which provided Laricina geologists and engineers with the information required to make decisions regarding important SAGD issues. Nevertheless, for the most accurate results, wherever possible and practical it is always preferable that actual data be used. Indeed, for their subsequent seismic and drilling program in early 2010, Laricina has improved the seismic acquisition geometry and logging program to optimize the data and parameters for this purpose.

Acknowledgements

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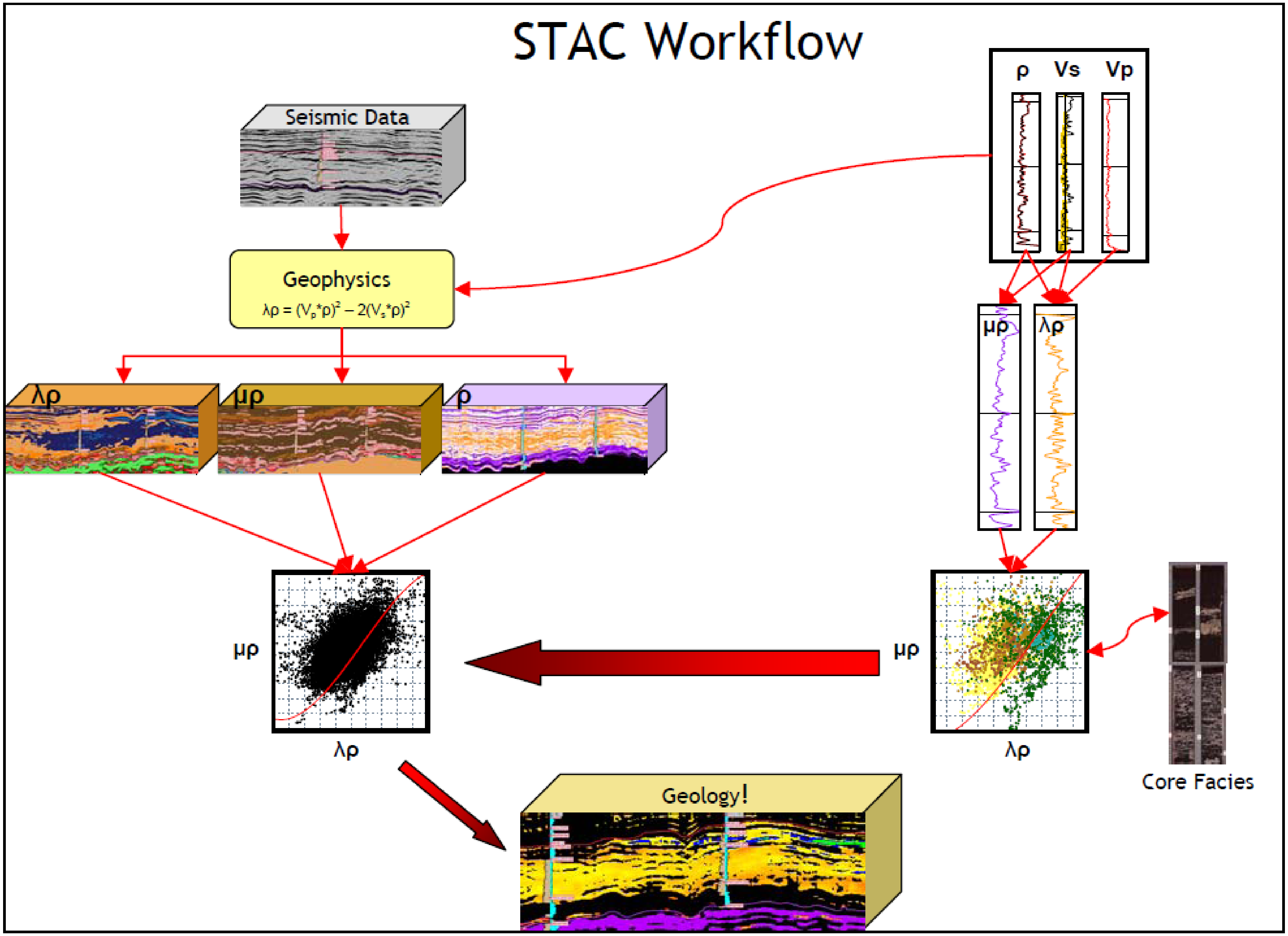

Figure 1. Conceptual flow-chart for the Seismic Transformation and Classification (STAC) process.

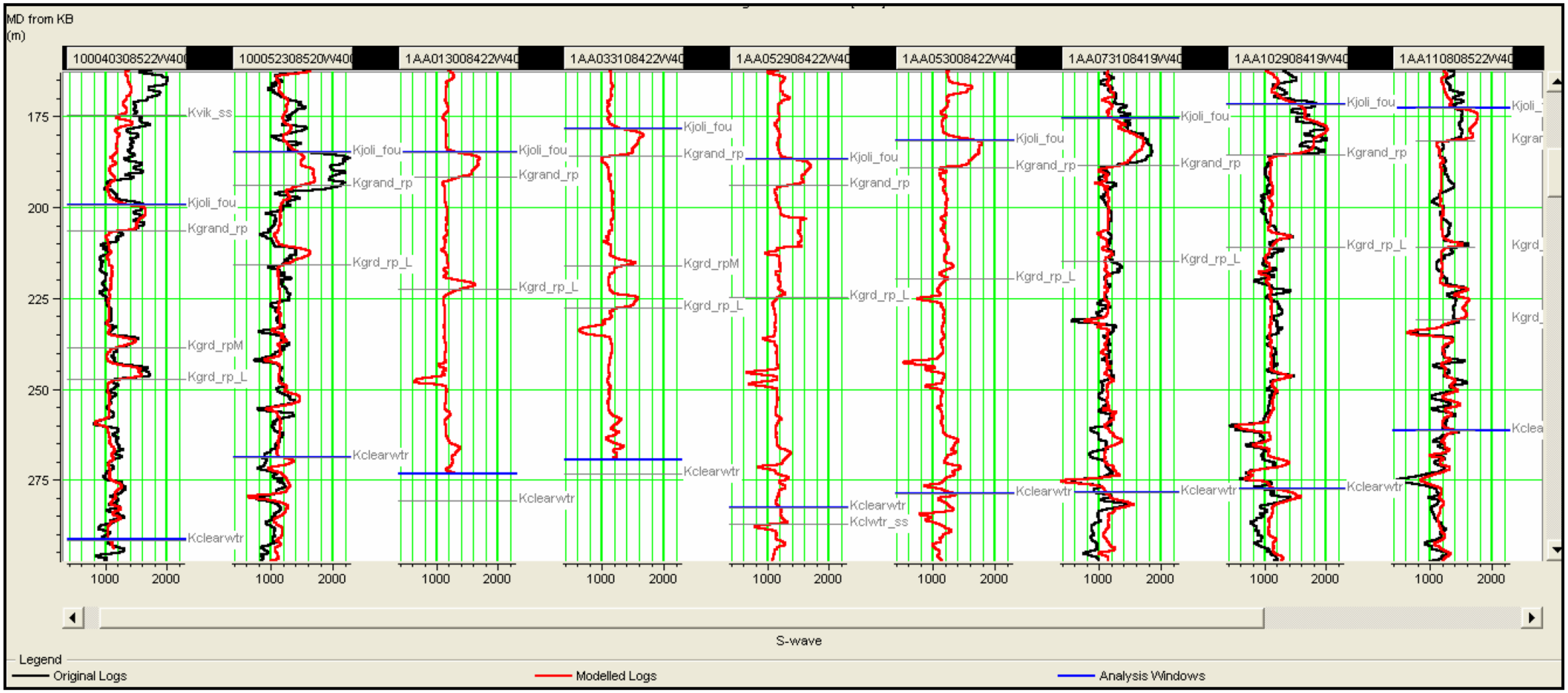

Figure 2. Shear log prediction results. Actual shear logs shown in black, predicted in red. For wells with actual shear logs, the predicted results within the Joli Fou and Grand Rapids interval matched the originals with 84% correlation accuracy.

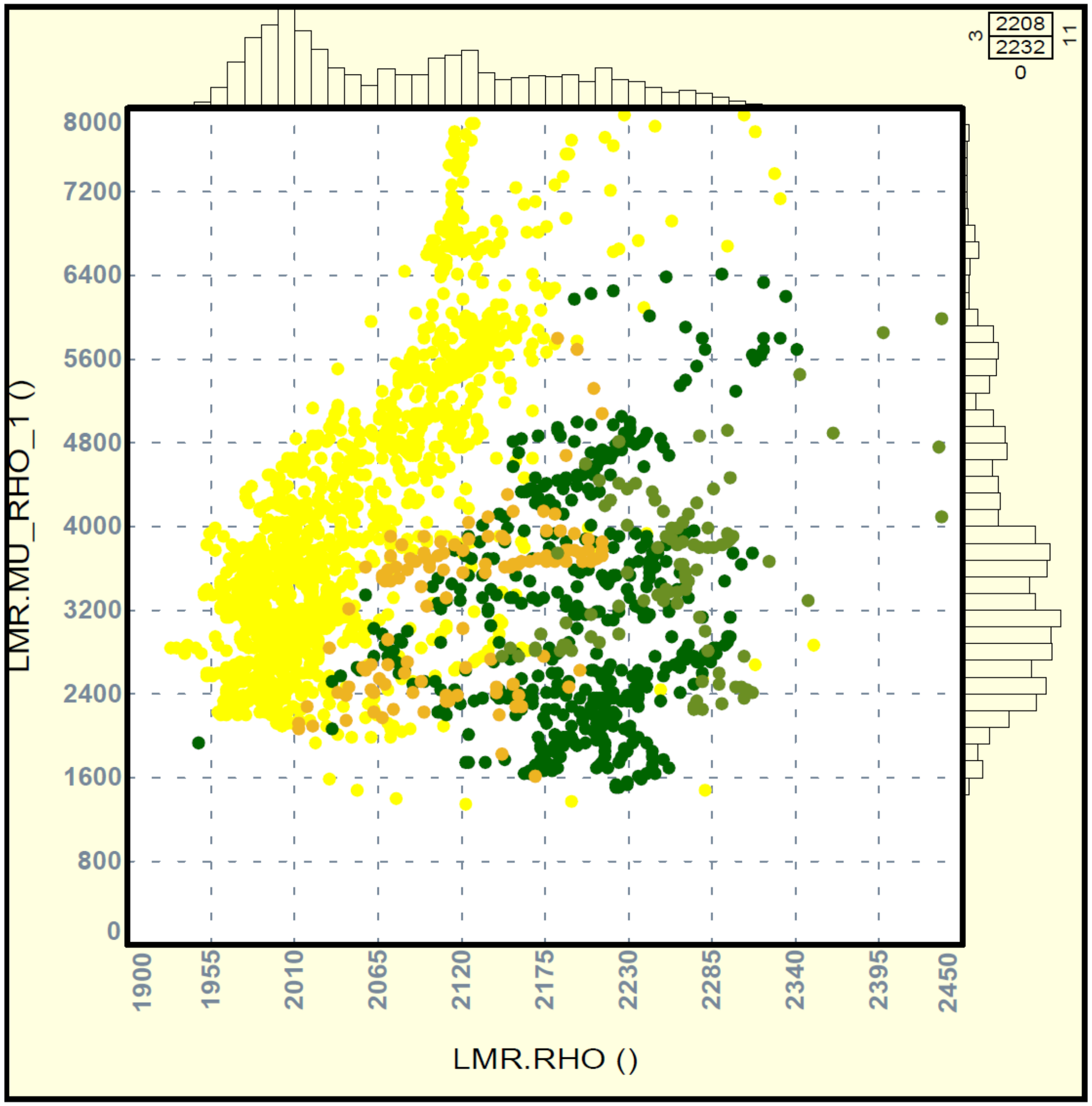

Figure 3. Log density vs mu*rho (ρ) with points coloured by core facies. Sand is yellow, shales are shown in green and mixed facies in orange.

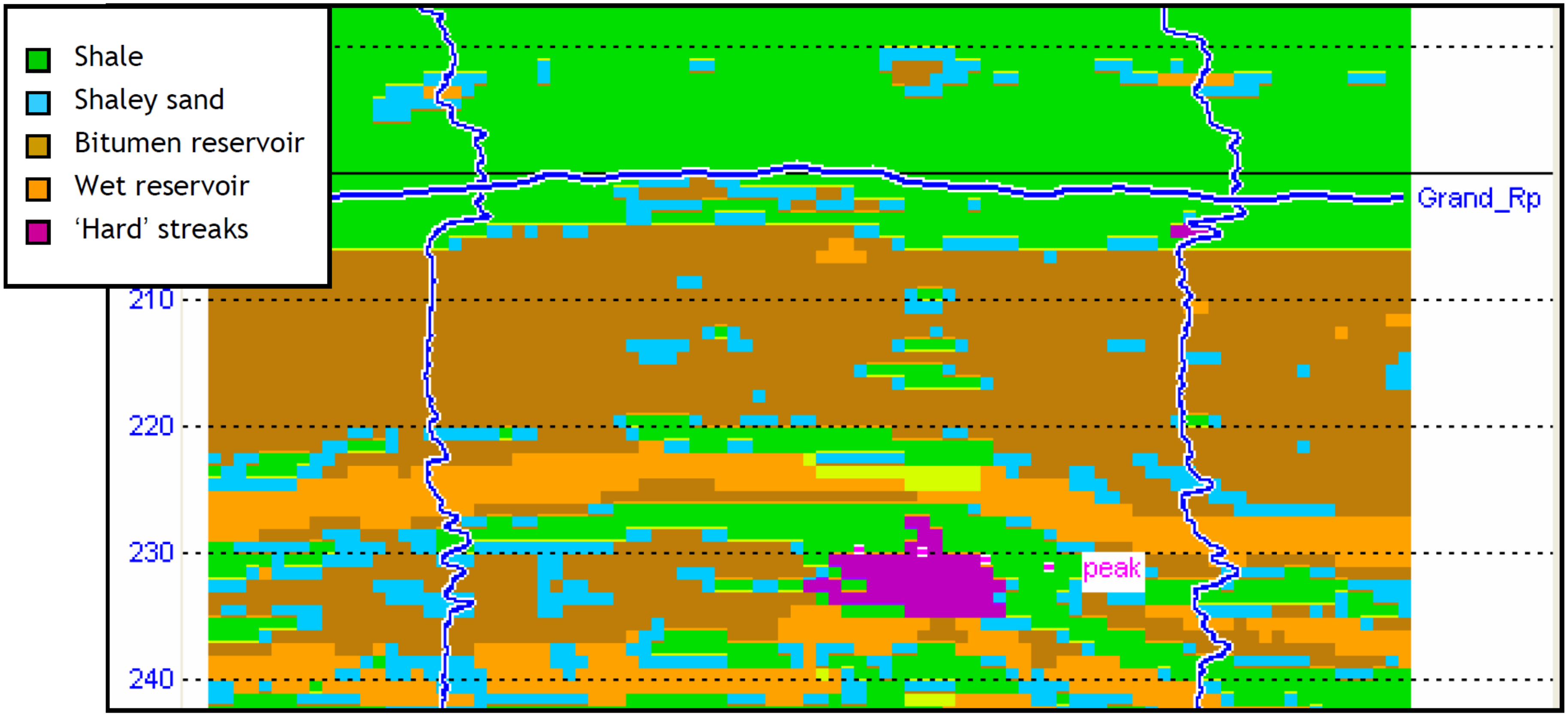

Figure 4. 3D profile through two wells in the project area. The colours represent lithology and fluids as detailed in the legend. Gamma ray logs are shown at the well locations.

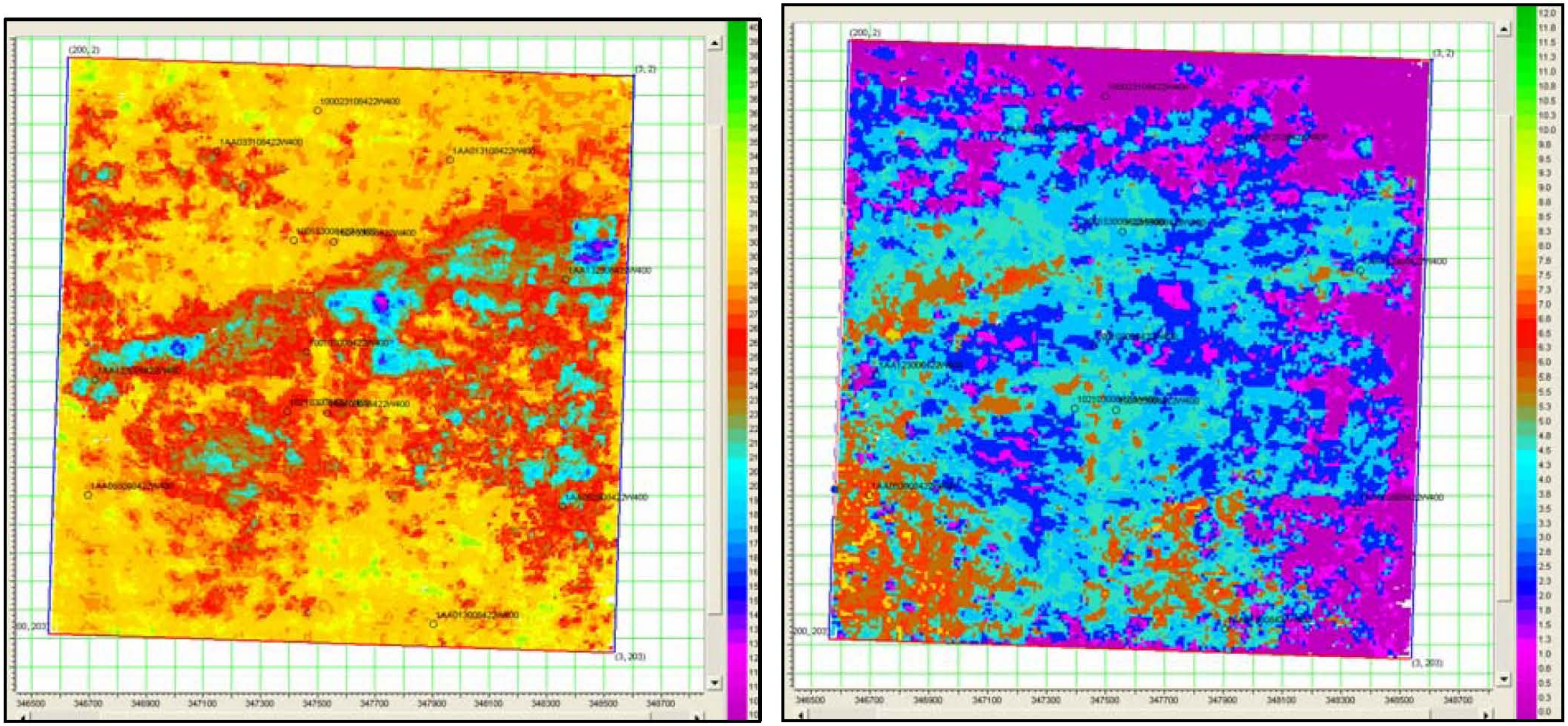

Figure 5. Thickness maps from the seismically derived reservoir volume. On the left is the total sand thickness within the upper Grand Rapids from 10m (purple) to 40m (green). On the right is the bottom water thickness from 0m (purple) to 12m (green).