Oil Sands Reservoir Characterization: A Case Study at Nexen/Opti Long Lake*

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Introduction

The Athabasca oil sands contain more than a trillion barrels of oil within the Cretaceous McMurray Formation of northeastern Alberta. The McMurray Formation is generally considered to be a compound estuarine valley system characterized by multiple cuts and fills. It is bounded below by Devonian rocks at the pre-Cretaceous unconformity and above by the widespread transgressive marine shales and sands of the Wabiscaw Formation. In the Long Lake area (Figure 1), it is 60 to 100 m thick, with net pays of greater than 40m. Still, its complexity is legendary. Stacked channel deposition exhibits a high degree of reservoir variability both vertically and laterally making lithological predictability difficult.

Traditionally, at least 8 and often many more vertical wells per square mile are drilled and cored to obtain enough data to be confident in defining a Steam Assisted Gravity Drainage (SAGD) project area. For more details, visit http://www.nexeninc.com. Even then, significant variations occur between wells. 3D seismic data has been used successfully in the past mainly to define the base of the zone of interest (there is a strong reflector at the Cretaceous-Devonian boundary), and the gross thickness of the interval. Various attempts have been made to decipher the internal composition of the channeled interval with limited success.

Objective

In this article, I describe the method, application, and results of a technique of quantitatively extracting and classifying elastic rock properties from seismic data. The extraction process uses 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 through the McMurray Formation shows a strong correlation to the gamma ray log and is therefore a good lithology indicator. Recent work directed at determining facies from seismic relies on an estimate of density from the seismic data. In the process I incorporate an estimate of density obtained from seismic using a neural-network approach (Dumitrescu et al., 2005).

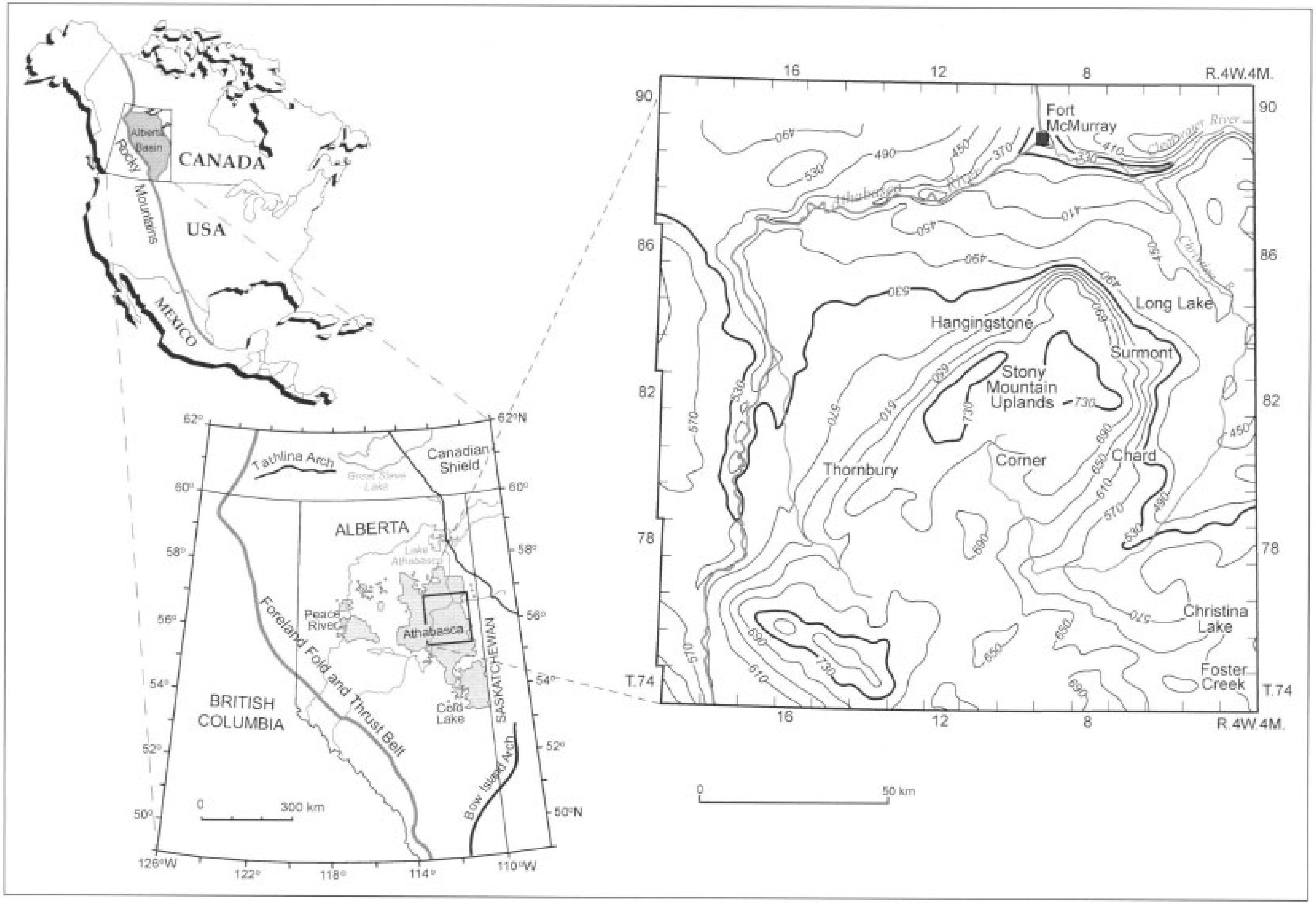

Figure 1. Location map for Long Lake area in Athabasca Oil Sands Region, northeastern Alberta (from Barson et al., 2001).

Method

Wireline logs directly (or indirectly) measure P-wave velocity, S-wave velocity and density. Integrating this data with core and log analysis, the lambda and mu properties are calculated and assigned lithologies and fluid properties. Detailed quality assessment and cross-plot analysis is carried out to assign empirical limits and guidelines for lithology and fluid discrimination based on the measured rock physics properties (Figure 2). The determined relationships are then used to calibrate and classify the seismically-derived properties. The result is a seismic volume transformed to a detailed lithological characterization of the reservoir within the zone of interest. Drilling results are shown to validate and quantify the success of the method (Figure 3).

Applying this technique over a project area allows more confident mapping of the channels and the reservoir quality and continuity within the channels. A few of the potential benefits in oil sands areas include fewer vertical wells required to define the resource area and more confidently placed horizontal wells for optimal production.

Core Aspects

The cores shown represent facies types that cluster on a lambda*rho – mu*rho cross plot. The 5-13 well facies are typical for the oil sands area, with the clean sands and shales nicely separated on the cross plot (Figure 4a and 4b). The 7-16 core is interesting because it is almost all mud and at first glance, appears to be an abandoned channel 30m thick. However, when the lambda*rho – mu*rho points are plotted on the cross plot, they are all in the 'non-reservoir' part of the plot, but they fall into two distinct clusters (Figure 5a). If the points in the clusters are highlighted in different colors and identified in depth (Figure 5b), it is apparent that the middle portion of the mud has different properties than the upper or lower. With this information, the lithofacies can be interpreted differently, perhaps as stacked abandoned channel fills. This interpretation is also supported by the seismic facies volume (Figure 6).

References

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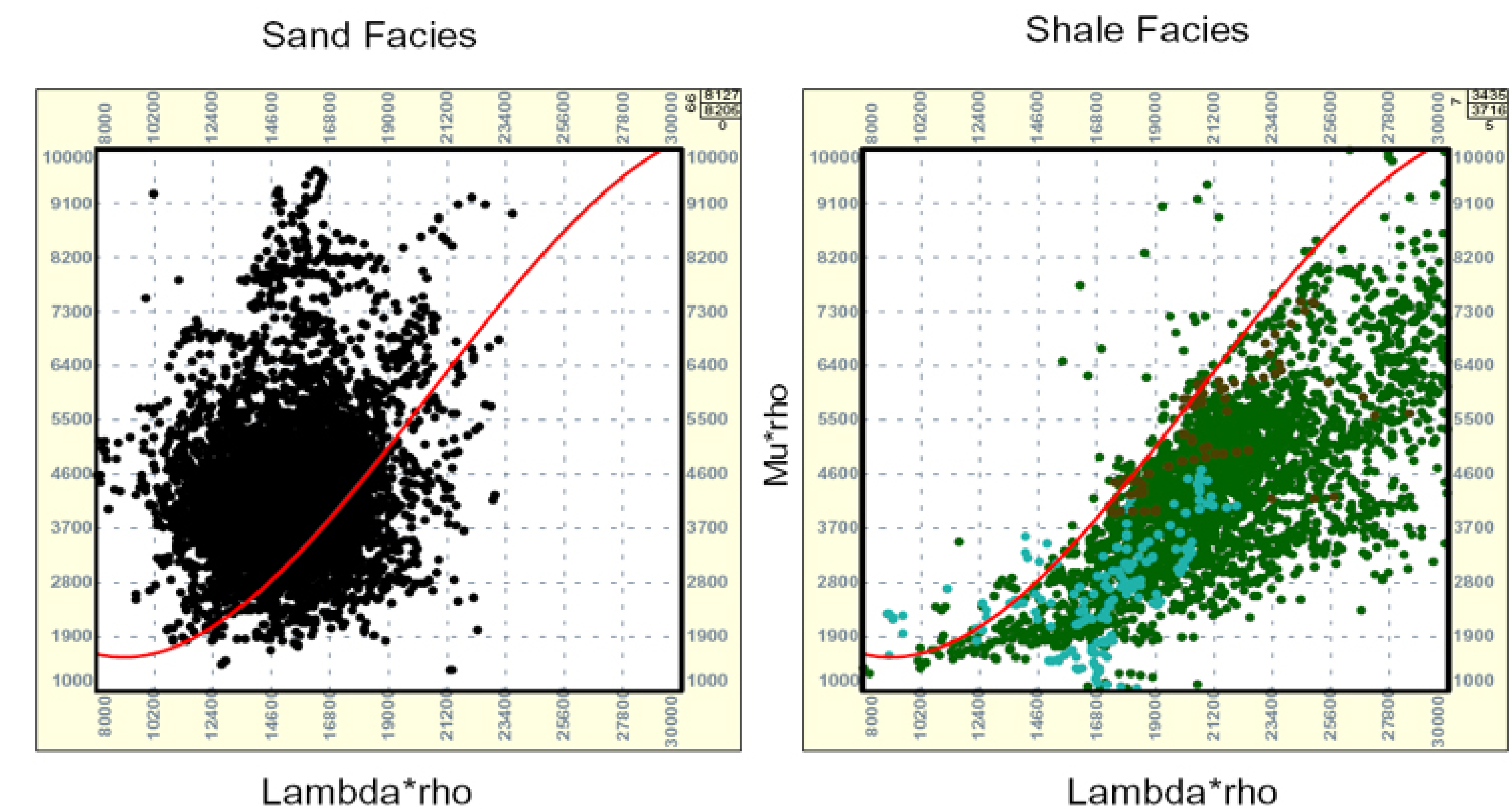


Figure 2. Cross plots of computed well logs from 85 wells with dipole sonic logs, separated by core facies. The curve shows the empirical limit of shale facies which when plotted on the sand facies plot shows the extent of facies overlap. The number of sand facies points that plot on the shale side of the line is less than 20% of the total.

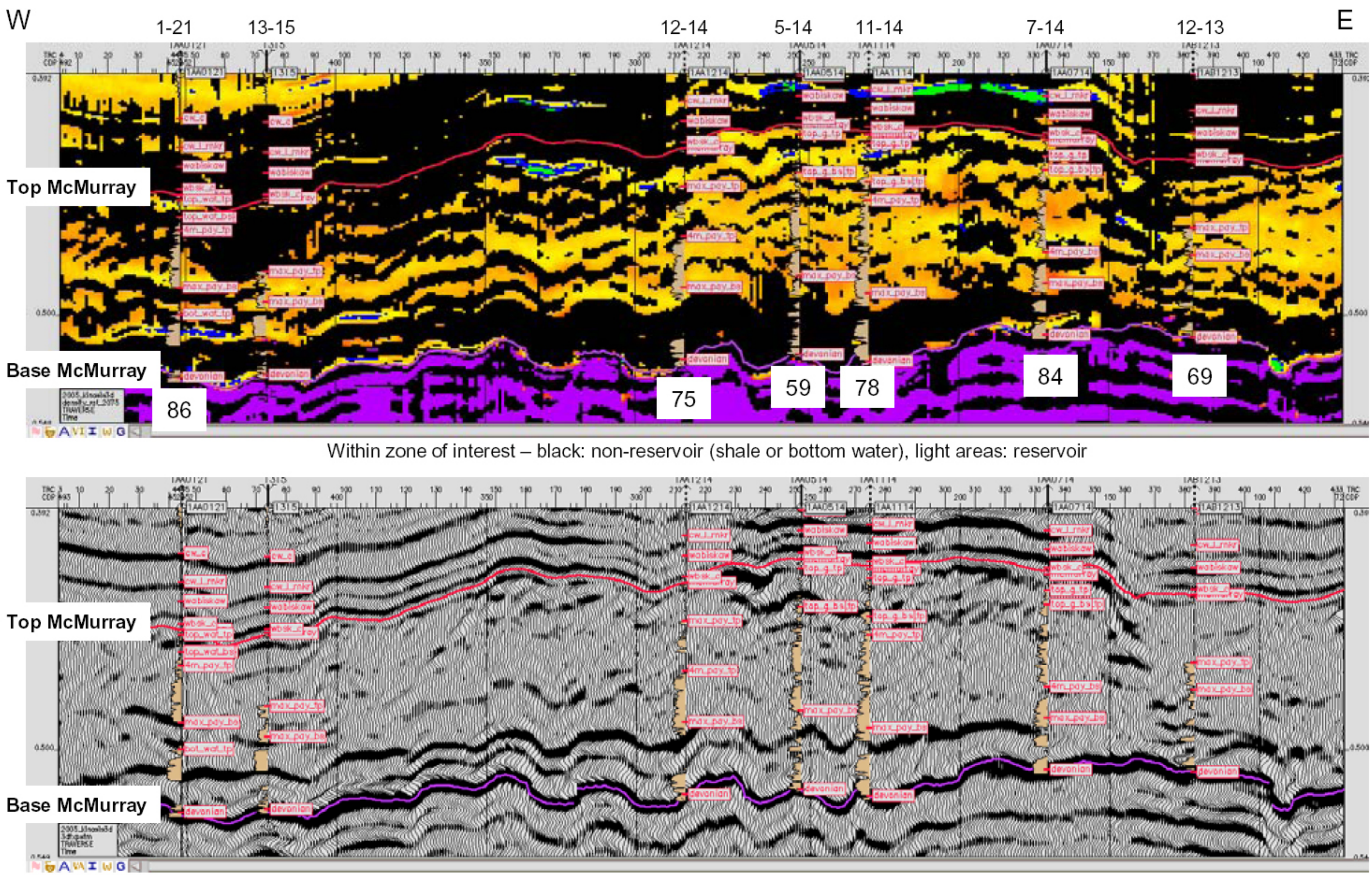
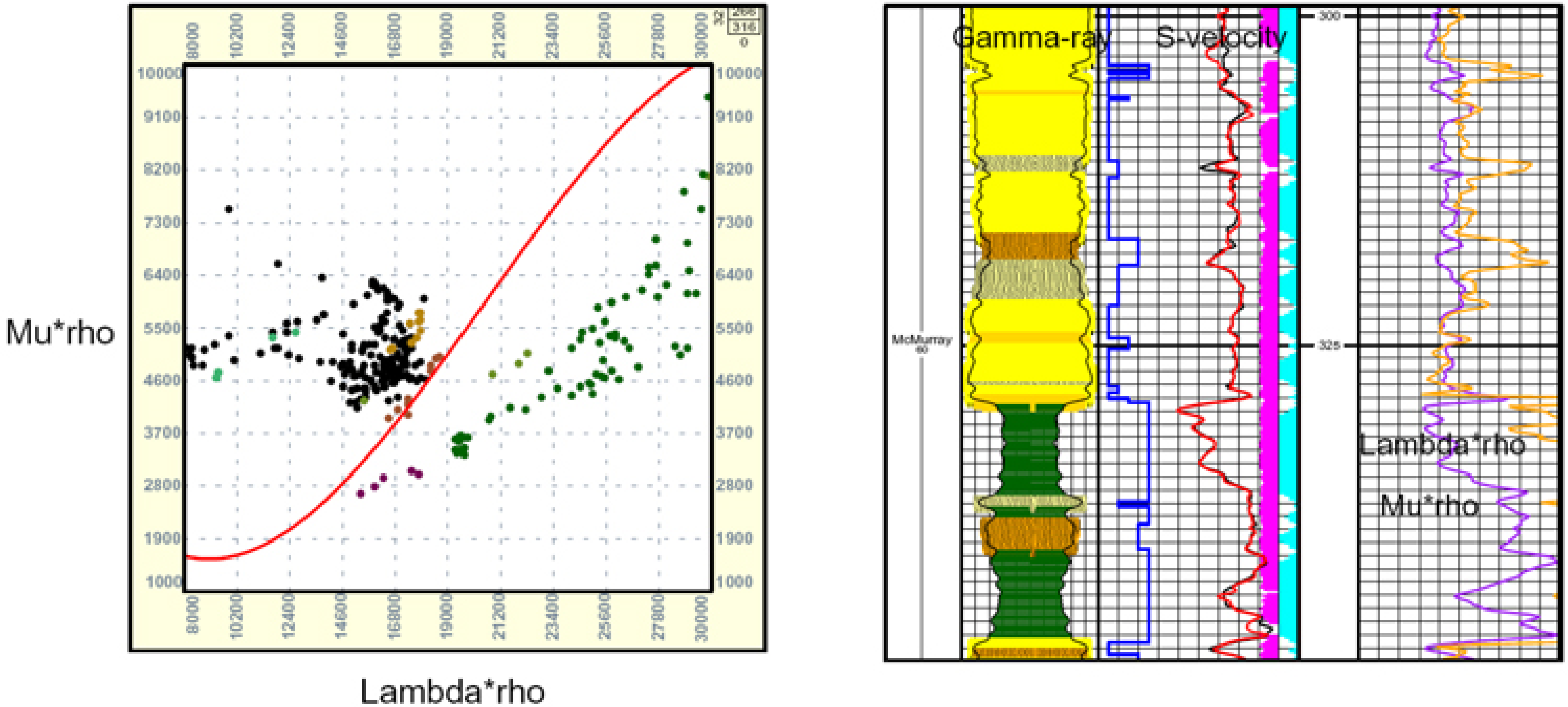


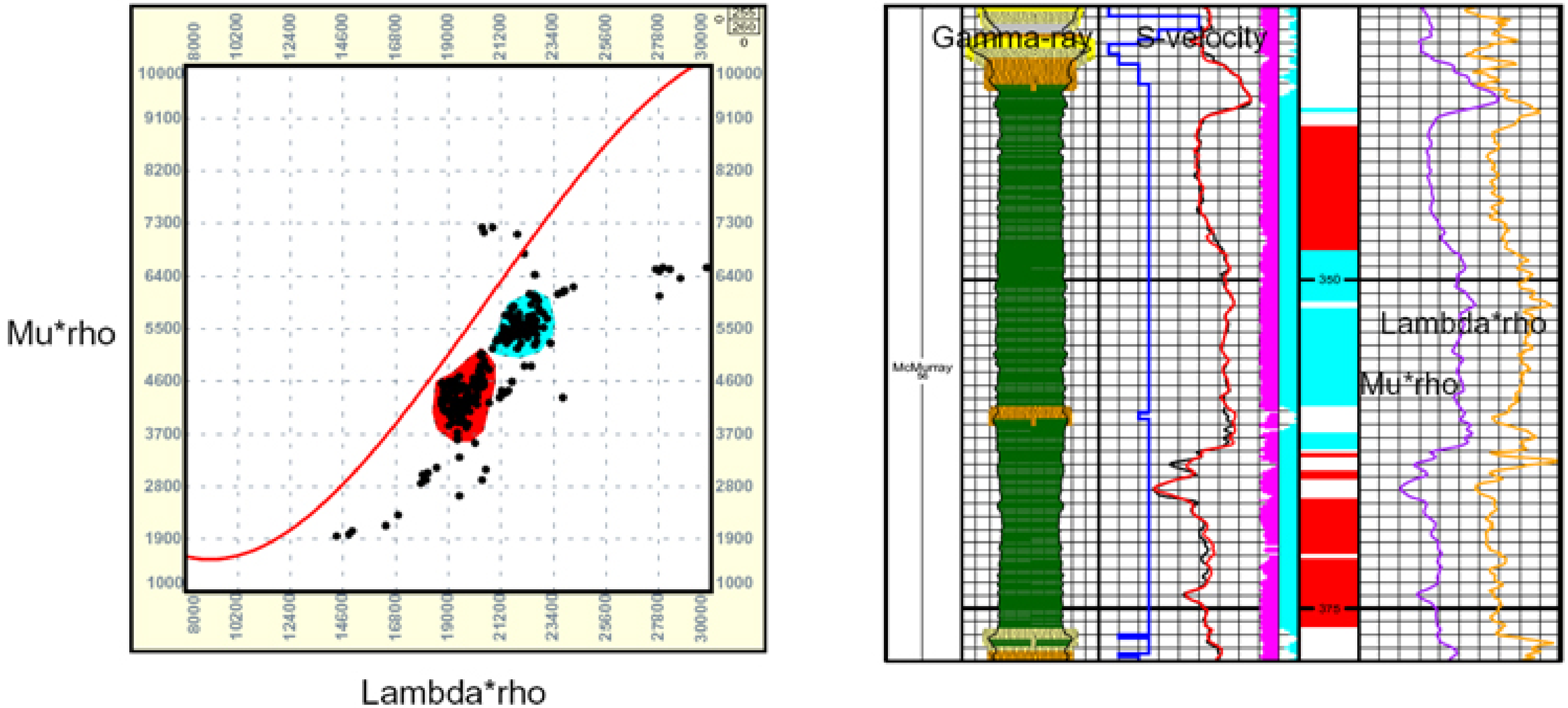
Figure 3. Comparison of conventional seismic profile (bottom) with derived facies profile (top). Black represents non-reservoir (shale or bottom water), light areas are bitumen reservoir. Gamma ray logs with 0 to 70 (at baseline) api range are displayed on the profiles. 13-15 was the only well on this profile used in the derivation of facies shown above; the rest were drilled after the facies volume was completed. The numbers shown below the well bores are the percentage match on a meter-by-meter basis of the predicted facies from seismic with the actual facies from logs within the zone of interest.



a

b

Figure 4. a) Crossplot showing lambda*rho, mu*rho points from well 5-13 colored by facies. Points above the curve are reservoir facies and points below are non-reservoir. b) Log display for well 5-13.



a b

Figure 5. a) Crossplot showing lambda*rho, mu*rho points from well 7-16 with shale clusters highlighted. b) Log display showing crossplot polygons highlighted in depth.

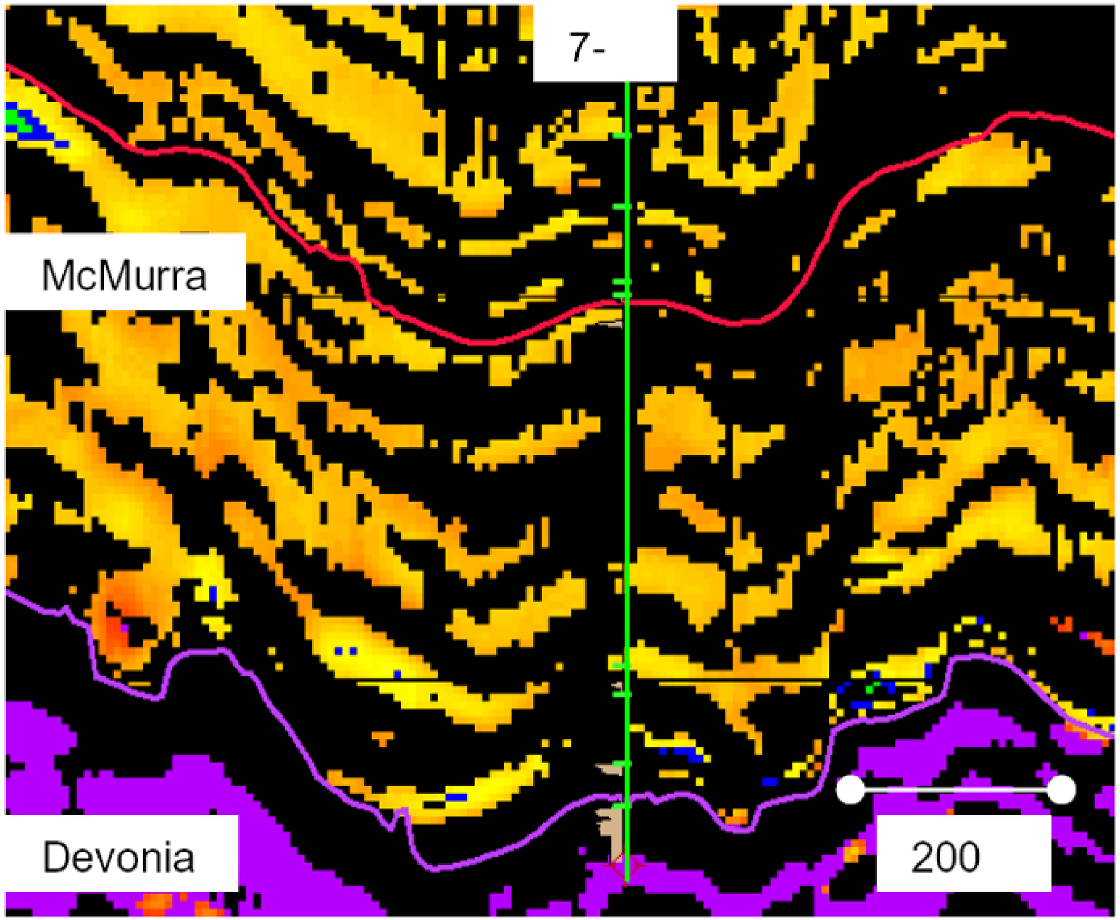


Figure 6. Cross-section from seismic facies volume at well 7-16 showing extent of shales away from well. Light areas are reservoir facies, black is shale.