An Integrated Multimineral Petrophysical Model for the Montney Formation Using Conventional Logs: A Case Study from the Attachie Area, Northeast B.C.

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Summary

Petrophysical evaluation of the Montney Formation presents several challenges, including: (1) its complex mineralogy compared to conventional reservoirs, and (2) the presence of Total Organic Carbon (TOC) affecting all log responses. The variability in mineral composition and the presence of TOC significantly impact the petrophysical and geomechanical properties of the reservoir. Most published studies on unconventional petrophysics focus on the standard density-porosity model (Passey et al. 2010, 2011; Sondergeld et al. 2010; Glorioso et al. 2012), where the matrix density has a much greater influence than fluid density in low-porosity reservoirs. To better understand the variations and distribution of mineralogy and to accurately account for their effects on determinations of critical petrophysical parameters—such as porosity and water saturation, a comprehensive multimineral petrophysical model was developed through core-log calibration. This model integrates a variety of core data, including X-ray diffraction (XRD), Rock-Eval analysis, routine core analysis (RCA), and mercury injection capillary pressure (MICP) data to evaluate the reservoir. The model sequentially solves mineral contents, followed by porosity, water saturation, and permeability using a deterministic approach.

This presentation outlines the petrophysical workflow, showcases the model's ability to determine multimineral abundances using conventional logs, and highlights some key aspects of the modeling process.

Methodology and Workflow

A total of 14 ARC core wells were selected as calibration wells for developing the petrophysical model, and 8 additional ARC and competitor cores were utilized to test the model's accuracy.

Mineral abundances in weight percent were predicted one by one by calibrating XRD data with conventional logs. For instance, total clay content was estimated using a combination of neutron-density and sonic-density separations. Notably, a strong correlation was found between total clay and sonic-density separation, in concert with the well-established clay ~ neutron-density separation correlation, as illustrated in Figure 1. Carbonates in the study area are predominantly dolomite; however, cemented intervals with high calcite content (up to 80%,) were also identified. The Photoelectric Factor (Pef) log was utilized in distinguishing between calcite and dolomite. Figure 2 presents a cross-section of four wells, illustrating the comparison between log-predicted mineral contents and XRD data.

Previous research indicates that the organic matter in the Montney Formation is primarily solid bitumen (Wood et al. 2015, 2018). This raises the question of whether TOC should be considered part of the porosity or part of the rock matrix. A cross-plot of grain density from routine core analysis (RCA) versus TOC, using collocated RCA and Rock-Eval samples, reveals a clear correlation: grain density decreases with increasing TOC, Figure 3. This relationship indicates that TOC significantly influences grain density and suggests that the solid bitumen is largely insoluble and remains within the core samples during RCA analysis, thereby reducing the grain density. Since TOC is a solid phase that does not contribute to pore space, it should be treated as part of the rock matrix. Two distinct TOC models were developed to address organic-rich and organic-lean facies separately.

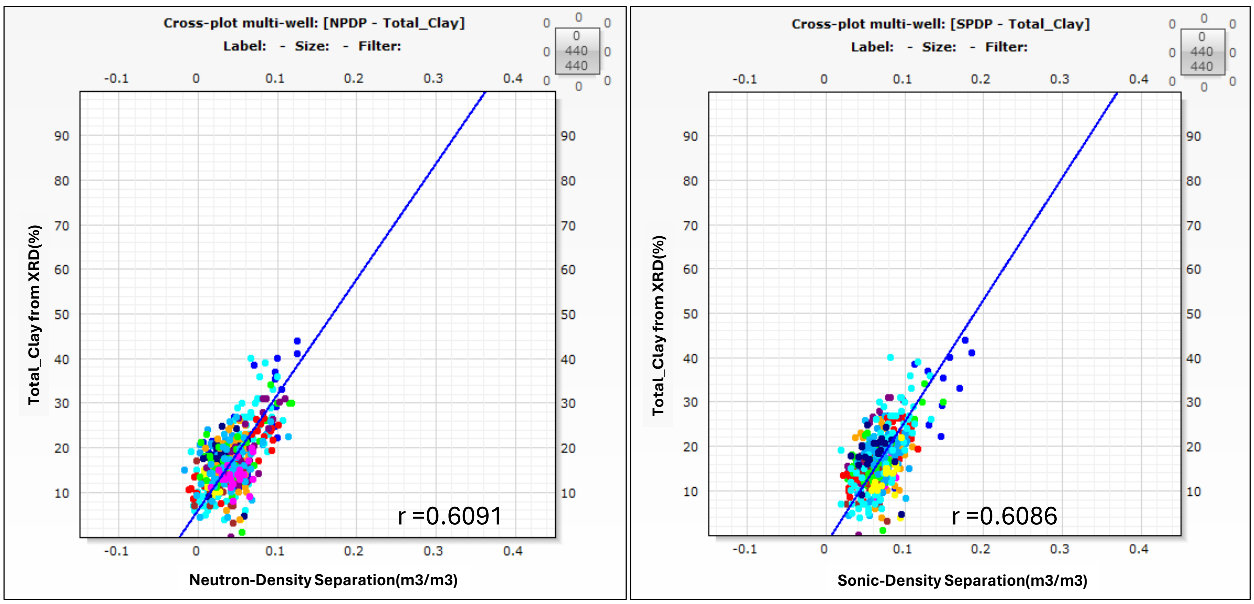
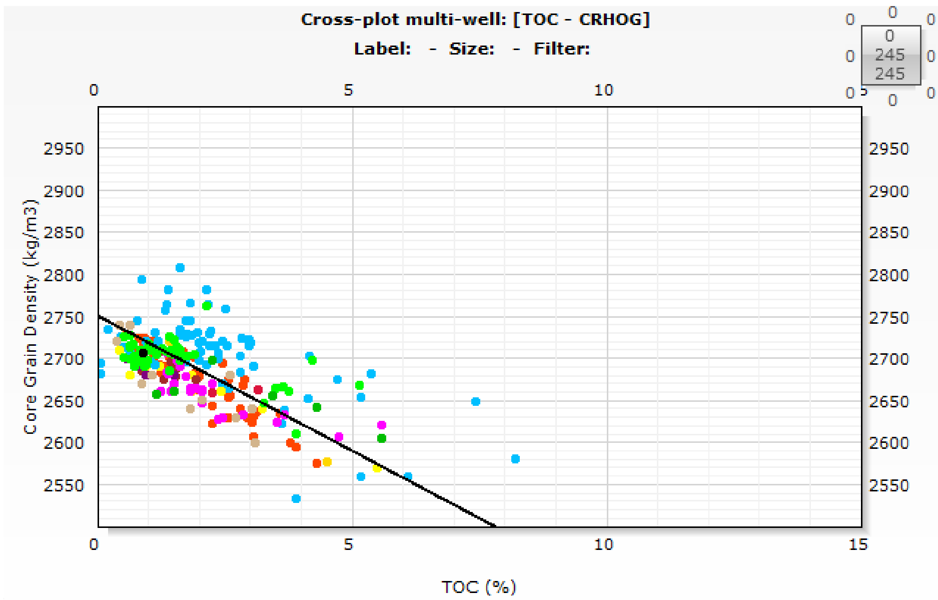


Figure 1: Cross plots showing that total clay from XRD is correlated to both Neutron-Density separation and Sonic-Density separation (Note: Data points are colour-coded based on UWIs, which have been anonymized to protect proprietary information**).**

Once the total organic carbon and mineral abundances were obtained, the total weight percentage, including TOC, was normalized to 100%. This enabled accurate calculations of grain density based on mineralogical composition. RCA grain density was used for calibration at this stage, with density endpoints of each component adjusted and optimized to ensure that the calculated grain density agreed with the RCA-measured values. This calibrated grain density was then applied to the standard density-porosity equation to calculate porosity. The core-calibrated mineral contents and TOC provide an accurate estimation of grain density, ensuring reliable porosity and saturation predictions. Figure 4 displays the cross-section of the same four wells depicted in Figure 2, showing the petrophysical outputs of grain density, porosity, and water saturation in comparison to core data.



Regressions:

Reg1 (type = RMA X/Y; R^2 = 0.4097; R^2 adj = 0.4072; RMSE = 1.10244; r = -0.6401; nb = 245)

Equation: TOC = - 0.03116381 * Core Grain Density + 85.7209

Figure 3: Grain density ~ TOC cross plot showing a clear correlation suggesting that TOC is a significant factor affecting grain density, and that TOC is mostly retained with routine RCA cleaning protocols (Data points colour-coded based on UWIs).

Literature indicates that formation water in the Montney Formation has exceptionally high salinity, up to 150,000 ~ 300,000 ppm (Wood et al., 2015, 2021; Canadian Discovery, 2019). Due to this extreme salinity, the additional conductivity associated with clay minerals is likely negligible. Hence, shaly-sand water saturation models are not recommended. Introducing more variables into the equation is unnecessary, given the existing uncertainties in parameters such as M, N, and Rw. The BVW ~ Resistivity correlation reported by Wood (2013) has also been observed in the Attachie area, using RCA residual water saturations from core cut with oil-based mud. This aligns with the fundamental physical principle that higher bulk water volume leads to higher conductivity. Upon re-arranging the equation, it was found that Wood's correlation follows the same structure as Archie's equation but with an unrealistically low Rw value. Nonetheless, this correlation is consistently observed across different parts of Montney. A pseudo-Archie's equation was developed through a custom regression on the BVW ~ Resistivity cross plot, yielding M=N=1.68, while honoring the reported salinity values.

Permeability was estimated using a simple K~PHI regression calibrated to MICP Swanson permeability, though this estimation relied on a limited number of core samples.

The petrophysical model outputs have been utilized for rock physics modeling to support seismic inversion, as well as for geomodelling and reservoir simulations.

Conclusions

In the Montney Formation, the solid bitumen is largely insoluble and does not contribute to porosity. Therefore, it should be treated as part of the rock matrix. Different TOC models were developed for organic-rich and organic-lean facies separately.

The good agreement between log-based predictions and core-measured values (Figure 2 and 4) has proven that solving for multiple mineral contents using conventional logs is not only feasible but also ensures reliable predictions of porosity and water saturation.

Water saturation can be calculated using a pseudo-Archie's equation, adjusted based on Wood's correlation.

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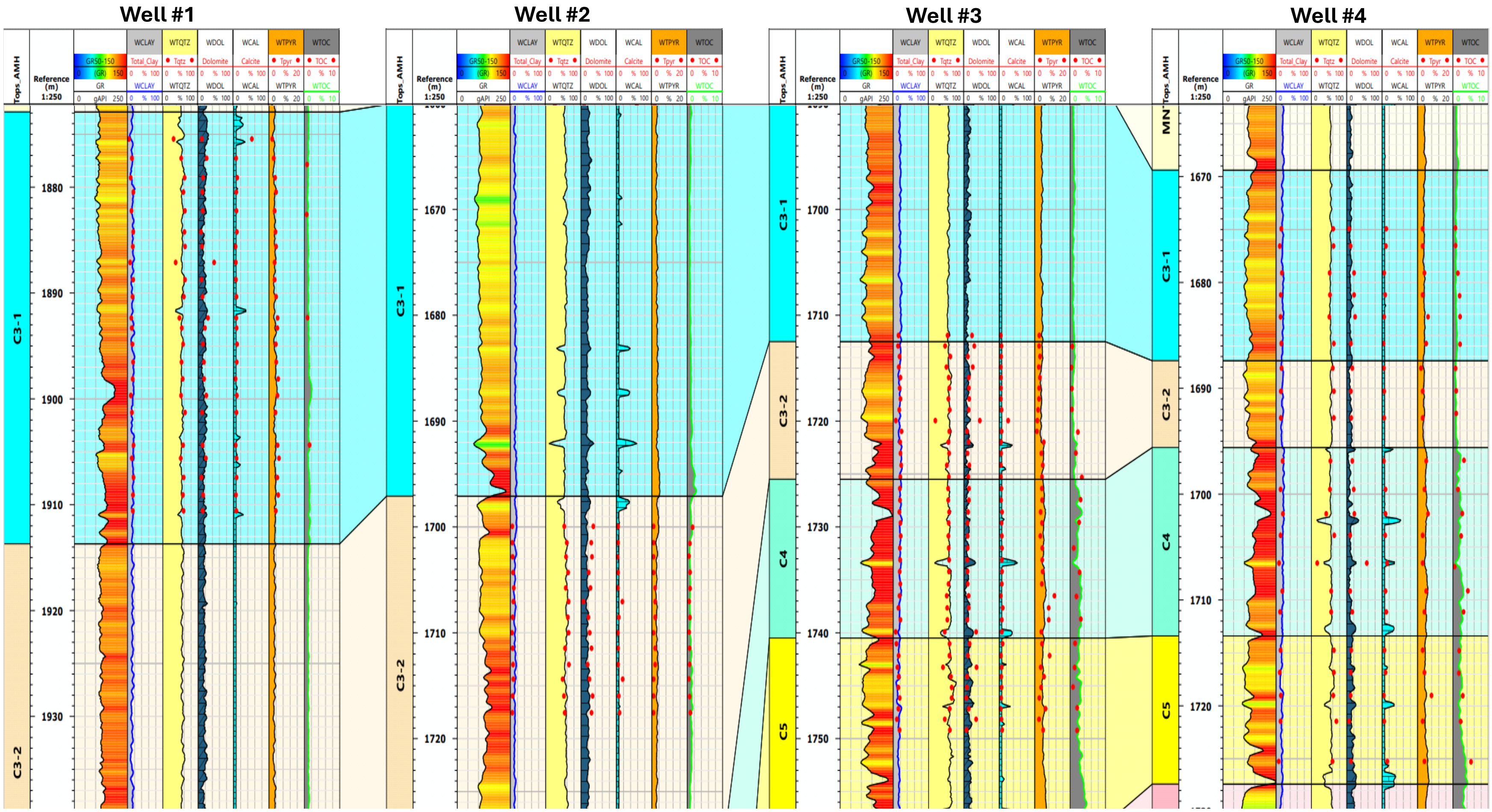

Figure 2: Cross section of example wells showing the comparison of log-predicted mineral contents and XRD data.

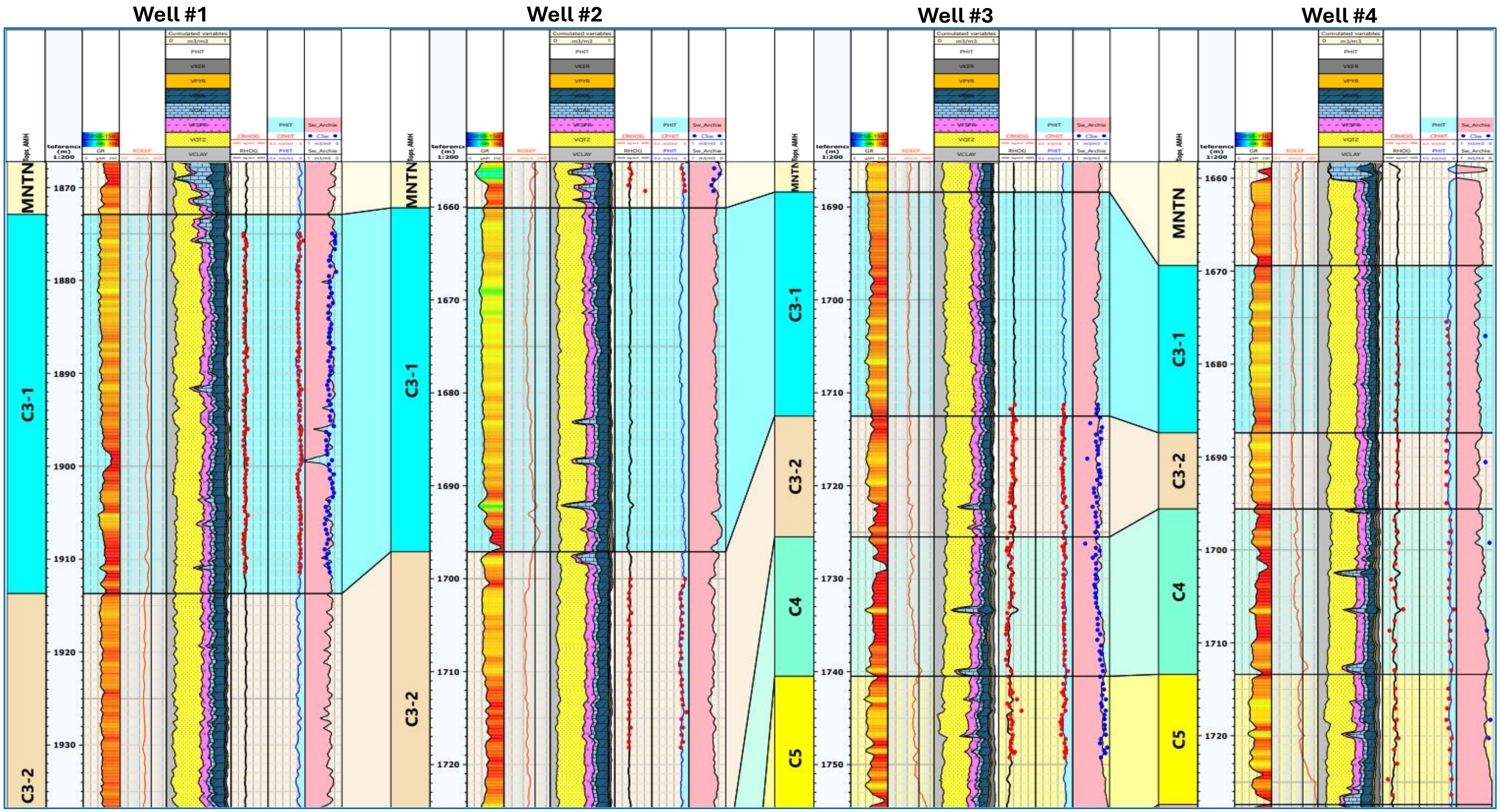

Figure 4: Cross section of example wells showing the log-derived petrophysical parameters (grain density, porosity, and water saturation) in comparison to core analysis data.