Closing the Loop from Petrophysics to Production: Improving Viking Sand Delineation Through Integrated Geoscience

Speakers: Rafael Zambrano[1], Daniel Baker[2]
Patrick Michetti[2], Barrie Furlong[2], Kelly Skuce[2], Andrew Mah[2], Steve Parkins[2], Sean Lacey[2], Tyler Maksymchuk[1], Francisco Caycedo[1], Jesus Sierra[1]

[1]Cayros Group, [2]Whitecap Resources Inc.

ABSTRACT

With the relationship between clay content and oil production performance, clay characterization has become a focus for evaluating prospective reservoirs within the Viking Formation. Accurate estimation of effective porosity (PHIE) in shaly-sand reservoirs requires reliable quantification of clay-bound water (CBW), which strongly depends on both the clay mineral type and abundance. Different clay minerals exhibit distinct wet clay porosity (WCLP) values, making clay characterization a critical component of petrophysical evaluation. In the Viking Formation, X-Ray diffraction (XRD) data indicate illite, smectite, and kaolinite are the dominant clay minerals, with smectite representing up to 30% of the clay fraction in certain sandy intervals. Smectite can contain significant amounts of bound water, where simplified mineral models which assume a single clay type may lead to substantial errors in effective porosity, water saturation, and permeability estimates.

This study presents an integrated core-log workflow combining conventional triple-combo logs, nuclear magnetic resonance (NMR), XRD mineralogy, and routine core analysis (RCAL) data. The workflow begins with mineralogical characterization using XRD data to identify dominant minerals and establish mineral relationships, which are incorporated into a volumetric mineral solver. The resulting mineral model is validated through comparison with XRD-derived mineral fractions and grain density measurements, showing strong agreement and confirming accurate mineral representation.

Although NMR data were not used as an input to the mineral solver, it served as an independent validation of total porosity (PHIT) and CBW estimates. Strong correlations between model-derived porosity and bound water volumes, and between NMR measurements and core porosity, demonstrate the robustness of the workflow and its ability to represent both mineralogical and pore-volume distributions accurately.

Multiple shaly-sand water saturation (Sw) models were evaluated, including Simandoux, Indonesia, Juhasz, and Dual Water. Because clay minerals make a significant conductive contribution, methods that explicitly account for clay conductivity were required. A “Two Extremes Sw” approach was used to constrain uncertainties associated with Archie textural parameters. Among the methods evaluated, the Dual Water model provided the most realistic saturation estimates, showing the best agreement with irreducible water saturation derived from capillary pressure data and with historical production performance. The resulting Sw estimates were subsequently used to calculate absolute permeability using the Coates-Dumanoir approach.

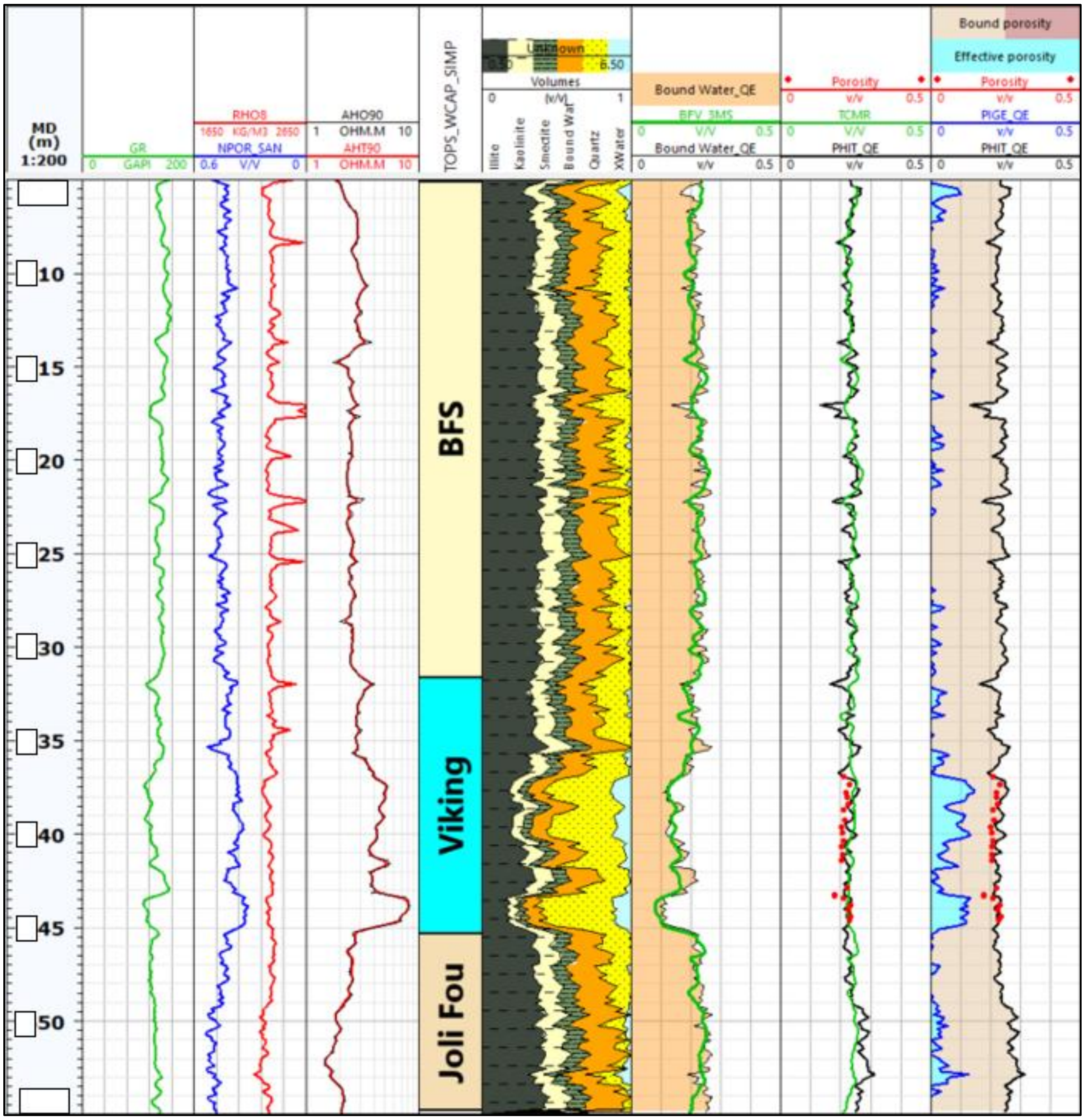


Figure 1. *The comparison plot shows a good match between the log model outputs and NMR outputs. The Bound Water QE log (black curve with orange shading) shows an excellent correlation with the BFV_3MS (green curve). Both curves refer to Clay Bound Water (CBW). Likewise, a good correlation is observed between the total porosity from the log model (PHIT_QE – black curve), total porosity from the NMR log (TCMR – green curve), and core porosity from the routine core analysis (RCAL). The good correlation between the outputs indicates the fair representation of the log model in terms of mineralogy and porosities, total and effective.*

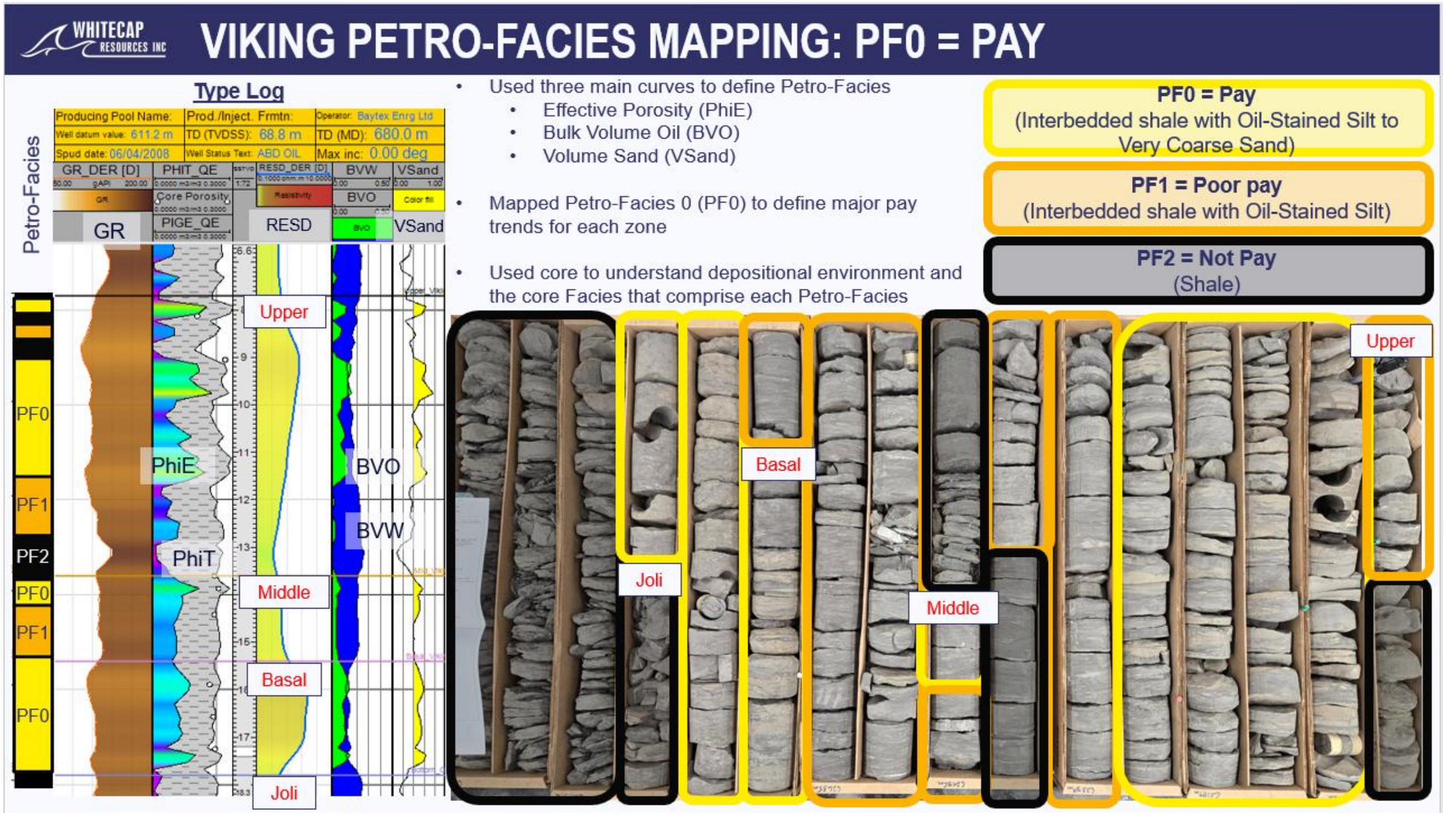


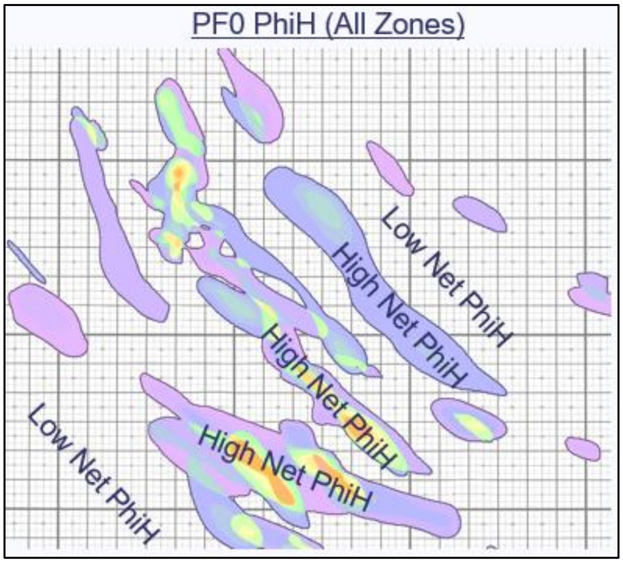
Figure 2. *Example workflow used to define Viking Petro-Facies from integrated petrophysical and core analysis. Petro-Facies were classified using effective porosity (PhiE), bulk volume oil (BVO), and volume sand (VSand) derived from petrophysical logs and calibrated to core observations. Three petro-facies were identified: PF0 (pay), PF1 (poor pay), and PF2 (non-pay shale). Core examples illustrate the facies associations comprising each petro-facies and their vertical distribution within the Viking reservoir.*

The improved petrophysical characterization provided the foundation for reservoir petro-facies classification and mapping.

Detailed clay characterization allowed for a more accurate understanding of porosity and sand concentrations within the study area. Integration of core observations with petrophysical logs allowed the Viking interval to be divided into mappable Petro-Facies. Petro-Facies 0 (PF0 = Pay) corresponds to silt to very coarse-grained sand that is bioturbated to non-bioturbated, Petro-Facies 1 (PF1 = Poor pay) represents finer-grained intervals with a higher shale component, and Petro-Facies 2 (PF2 = Not Pay) consists of laminated shale with sparse silt lenses.

The distribution of Petro-Facies 0 was mapped using a barrier-bar/shoreface depositional model, revealing sand bodies that trend parallel to the interpreted paleoshoreline. The goal of mapping PF0 was to understand depositional trends and to define tighter productive reservoir edges. The result demonstrated that PhiH (effective porosity multiplied by PF0 thickness) could differentiate production within the study area and refine production forecasts.

The strong agreement between the mineral model, XRD, NMR, and core measurements demonstrates that detailed clay characterization is fundamental to reliable petrophysical evaluation of Viking shaly-sand reservoirs. The resulting petrophysical framework enabled reservoir petro-facies mapping and improved prediction of production performance, thereby linking petrophysical characterization directly to field development decisions.



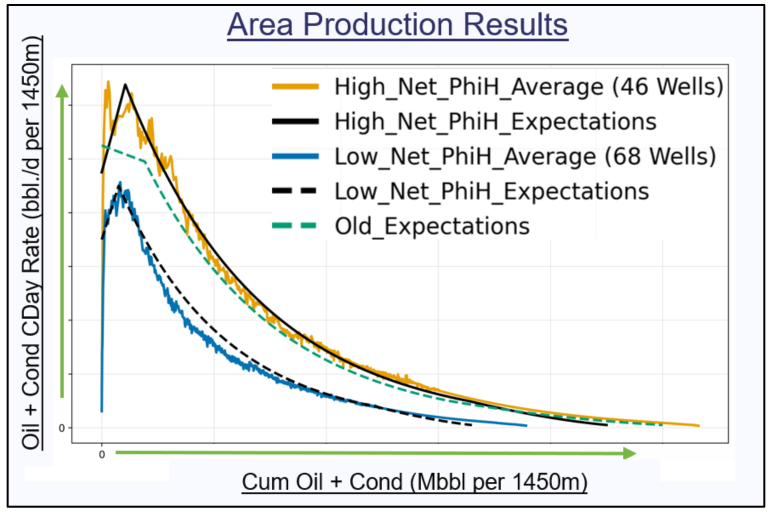


Figure 3. *Petro-Facies 0 (PF0) porosity-thickness (PhiH) mapping was used to identify high- and low-quality reservoir trends across the study area. The PF0 PhiH map shown on the left represents the cumulative thickness of pay-quality reservoir (PF0) from the Basal, Middle, and Upper Viking zones defined in the Figure 2 type log. Wells were grouped according to their location within mapped high and low net PhiH fairways, and production performance was normalized to a 1,450 m horizontal length. Average production profiles demonstrate that wells completed within high net PhiH trends (46 wells) consistently outperform wells located within low net PhiH trends (68 wells) and exceed historical field expectations. These results highlight the predictive value of petro-facies mapping for reservoir characterization, well placement, and development planning.*