A New Well Log-Based Method To Quantify Compositional And Geomechanical Heterogeneity In Organic-Rich Mudstones: Implications For Reservoir Potential Prediction In The Devonian Duvernay Formation, Alberta, Canada

Marco Venieri*1, Per K. Pedersen1, David W. Eaton1; 1. Department of Geoscience, University of Calgary (Alberta, Canada)

Abstract

Unconventional reservoir performance is commonly predicted by analyzing mineralogical and static geomechanical analyses run on drill core. This approach has significant limitations, amongst which the approach dependence on a significant amount of available core data, and even in this case extensive sample analysis may be cost-prohibitive at the full scale of a resource play. In this research we introduce a novel workflow tying well log-estimated compositional, mineralogical and geomechanical properties of the shales to core-measured equivalent properties. The correlation obtained facilitates the extrapolation of compositional and mechanical properties of unconventional reservoirs into areas where core control is poor, but wireline logs are available. Using the Devonian Duvernay shale play of Western Canada as a natural laboratory, our analysis reveals a high degree of correlation between core-measured XRD mineralogy and 2 specific well log suites: Elemental Capture Spectroscopy (ECS) and Spectral Gamma Ray (SGR). More specifically, we show how ECS and SGR log readings, but also other more common log suites (e.g. Gamma Ray, Density/Neutron porosity, Resistivity, Sonic), can be used to identify biogenic silica-rich, clay-rich and carbonate-rich intervals within the reservoir. These represent 3 end-member petrofacies with unique reservoir properties and their co-existence has been recognized in most of the major North American shale plays. We show how these 3 well log-based petrofacies also display unique dynamic elastic moduli, suggesting that they also have unique hydraulic fracturing efficiency and thus reservoir potential. In the Duvernay Formation, carbonate-rich and clay-rich units represent sub-optimal petrofacies of exploration interest due to their lack of reservoir quality and/or suitable mechanical properties, making the biogenic silica-rich petrofacies more appealing as an unconventional target due to its good reservoir properties and fracture efficiency. Our workflow can be accordingly applied to pilot vertical wells for accurate identification of biogenic silica-rich layers to be used as a primary landing zone for horizontal wells. Similarly, on a basin-scale perspective our workflow gives insights on how to use the ratios between the thickness of each of the 3 petrofacies vs the total thickness of the reservoir to quantify reservoir heterogeneity and build contour maps highlighting areas where the biogenic silica-rich petrofacies is dominant. Since wireline logs are much more abundant than drill cores - especially in the early play exploration phase - our approach may prove critical in assessing reservoir potential ahead of the drill bit not only in the Duvernay, but in similar unconventional opportunities worldwide.
Statement of the background

Despite the large volume of published literature on geological controls over fluid production in unconventional shale plays, most of the published works are strictly core-based. This represents a problem when interpolating core-measured characteristics into areas with poor core control. For this purpose, accurate core to wireline logs tie and estimation of compositional and mechanical properties of the shales using wireline logs solely become crucial steps in unconventional reservoir characterization. This research aims to address this gap by proposing a workflow capable of predicting unconventional reservoir potential using wireline logs by virtue of a correlation between compositional and mechanical properties of the shales.

Aims and Objectives

This research has the aim of predicting unconventional reservoir potential using wireline logs. This has been achieved by developing a new workflow capable of estimating compositional and mechanical properties of the reservoir, correlating the two and accordingly sub-dividing the reservoir unit into sub-units ranked upon their compositional and mechanical characteristics. This gives crucial insights into the reservoir potential of the sub-units and allows 1) identification of the most prospective land ("sweet spots") to focus exploration interest ahead of the drill bit and 2) accurate identification of the most optimal landing zones for horizontal wells.

Materials and methods

The Duvernay Formation was deposited in Western Canada in the late Devonian in a passive margin setting at the Western edge of North America (Switzer et al., 1994). In Alberta, sedimentation was characterized by laterally extensive carbonate reefs (Leduc Formation) separated by organic-rich shales (Duvernay Formation) (Stoakes & Creaney, 1984). The large number of reefs present in the basin defines several Duvernay sub-basins. This research is focused on the Kaybob sub-basin, which is located in Western-Central Alberta and represents the area of main exploration interest. Using a comprehensive dataset counting more than 600 vertical wells with available logs, 55 cored wells with available core analyses and 650+ drilled horizontal wells, this basin represents the ideal laboratory to investigate Devonian organic-rich shales in North America. Using this rich dataset, we first developed a robust, predictive relationship between compositional and mechanical properties measured in core and their well log equivalents through cross-plotting and linear regression. Then, we deployed well log-based reservoir properties to identify areas in which the Duvernay reservoir has the most favorable properties for unconventional exploration (high reservoir quality and high fracture efficiency). More specifically, Elemental Capture Spectroscopy (ECS) and Spectral Gamma Ray (SGR) logs are used to sub-divide the Duvernay Formation into biogenic silica-rich, clay-rich and carbonate-rich petrofacies. By analyzing dynamic Young’s modulus and Poisson’s ratio logs we show how these three petrofacies also display unique mechanical properties, suggesting that the co-existence and occurrence of these three petrofacies also controls the reservoir potential of the Duvernay Formation. Finally, we show how to deploy standard, more common well log suites (Gamma Ray, Density/Neutron porosity, Resistivity) to identify these three petrofacies in wells which do not have available ECS or SGR, thus leading to a significant increase in the number of wells deployable for reservoir characterization of shale plays.

Results and discussion

This research demonstrates a high degree of correlation between XRD measured mineralogy in cores and readings from the Elemental Capture Spectroscopy (ECS) and Spectral Gamma Ray (SGR) well logs. These relations may be deployed to estimate reservoir mineralogy using these well logs in non-cored wells. By computing dynamic elastic moduli using Dipole Sonic and Bulk Density logs, reservoir intervals characterized by a unique mineralogy also show distinct mechanical properties, which suggests a major control of mineralogy and composition on mechanical properties of the shales. More specifically, ECS Calcium is a proxy for carbonate, ECS Aluminum and SGR Thorium are related to clay presence and the ECS Silicon/ECS Aluminum ratio may be used to estimate the volume of biogenic silica present in the reservoir. Biogenic silica-rich, clay-rich and carbonate-rich petrofacies display unique mechanical properties: the carbonate-dominated units display the greatest values of Young’s modulus and Poisson’s
ratio, and the biogenic silica-dominated units register higher values of Young’s modulus and lower values of Poisson’s ratio than the clay-rich petrofacies (fig.1).

By integrating more common log suites (Gamma Ray, Density/Neutron porosity, Resistivity), we show how these can be used to identify the three above mentioned petrofacies in wells which do not have available ECS and SGR logs. The biogenic silica-rich petrofacies has the best reservoir and mechanical properties, and thus represents the most ideal target for unconventional exploration. The ratio between the cumulative thickness of the biogenic silica-rich facies and the total thickness of the Duvernay reservoir can be accordingly used as an indicator of “sweet spots” for the Duvernay reservoir. Our research shows that biogenic silica-dominated areas in the Kaybob Duvernay sub-basin are located both in the open basin where clay deposition was not occurring - most likely due to bottom current reworking or reef geometry preventing excessive clastic input to deposit into sheltered areas – or proximal to the reefs just in between the carbonate-dominated debris flow channels shedding sediment from the reefs towards the basin. Clay-dominated areas are mainly located in the open basin and follow the same NW-SE orientation of the open seaway at the time of Duvernay deposition. This suggests a depositional nature of the clays. Lastly, carbonate-dominated Duvernay deposition occurs in debris-flow channels and their relative paleo-depocenters, which became preferential areas of deposition for calcit-turbidites. These are mainly located in the central-eastern part of the basin. An example of a petrofacies occurrence map covering the central-eastern part of the Kaybob sub-basin is shown in fig.2.
Fig. 2: Duvernay petrofacies occurrence map in the central-eastern part of the Kaybob sub-basin. Red areas represent portions of the basin where the biogenic silica-rich Duvernay accounts for more than 70% of the total Duvernay reservoir thickness; grey areas represent portions of the basin where the clay-rich Duvernay accounts for more than 30% of the total Duvernay reservoir thickness; blue areas represent portions of the basin where the carbonate-rich Duvernay accounts for more than 30% of the total Duvernay reservoir thickness.

By overlapping a production map of the first two years of condensate production from horizontal wells on our generated biogenic silica-rich vs total reservoir thickness ratio we find great degree of correlation between the two, suggesting significant control of geological and geomechanical properties on hydrocarbon production. Vice-versa, hydrocarbon production becomes poorer with increasing clay and carbonate in the reservoir, with the presence of thick carbonate-dominated layers having the most negative impact on fluid production due to their frac barrier/baffle effect and poor reservoir properties. Switching to a well perspective, identifying the Duvernay layers accounting for the three different petrofacies in a single well can be a valuable tool to identify the most optimal landing zone for horizontal wells by identifying clay- or carbonate-dominated units ahead of the drill bit and avoiding landing the horizontal leg therein.

Conclusions

This research provides strong evidence of a robust tie between elemental concentration, mineralogy and geomechanical properties of organic-rich mudstones. In contrast with previous studies on this topic, mostly focused on core data, in this work we are able to document the same correlation at the well log scale. Based on detailed core-calibration we use wireline logs to predict the mineralogical and mechanical properties of the reservoir, two important reservoir characteristics affecting reservoir potential in unconventional shale plays. Detailed analysis of reservoir and mechanical properties led to sub-dividing the Duvernay Formation into three main petrofacies, biogenic silica-rich, clay-rich, carbonate-rich, with unique reservoir and mechanical properties. We show how the biogenic silica-rich petrofacies is the unit with the most favorable characteristics for unconventional exploration, with clay and carbonate being less ideal due to poor reservoir...
and/or mechanical properties. By plotting the ratio between the biogenic silica-rich petrofacies versus the total thickness of the Duvernay reservoir we are able to identify areas of the basin where the Duvernay Formation is biogenic silica-dominated. These areas occur both in the open basin where low clay deposition occurred and near the Leduc reef edges in between the carbonate-dominated debris flows channels shedding debris into the basin. When compared to production data, strong correlation is observed between the biogenic silica-dominated areas and great production from horizontal wells. Vice-versa, hydrocarbon production is reduced in areas with higher clay and carbonate content within the reservoir. The decrease in production is substantial where the Duvernay Formation becomes a carbonate-dominated unit, such as near the Leduc reefs, inside debris-flow channels or within calci-turbidite basins. By integrating well logs we are able to use 300+ wells as input data points for generating basin-scale sweet spots maps or identifying the most ideal landing zones on a single well perspective, in contrast with the 55 data points we would have if we used cored wells only.

References
