Introduction

The Delaware Basin is one of the most active drilling areas in the U.S. (Mire et al. 2017). The basin is composed of a complex and heterogeneous mixture of clay rich organic mudrocks, siliciclastics and carbonate sequences from the Avalon, Bone Springs and Wolfcamp formations.

Due to the complexity of lithology, it is necessary to extract detailed spatial information about the subsurface to understand the unconventional targets from seismic data. Establishing a good relationship between the petrophysical properties of the rock (such as porosity, minerology, pore geometry, and total organic content) to the geophysical measurements (imaged elastic properties) along with a reliable geomechanical model leads to improved understanding of the reservoir.

In this study, we show a workflow that involves the integration of petrophysics, rock physics, geophysics and geomechanics for Avalon mudrocks and the Bone Springs formation. This serves as a foundation for extrapolating the well data into a 3D reservoir characterization using seismic inversion.

Method

Petrophysics

Preparing the dataset is the crucial first step before any integrated workflow and analysis. This involves mainly the following stages: inventory, planning, vectorization, and certification (Barbato et al. 2006). In our study, 11 wells were chosen from across the entire basin.

In order to understand the lithology, the mineral volumetric compositions are calculated first. It is found that there are essentially no conventional shales (clay content greater than 30%, Vernik, 2016) among the organic mudrocks of the Avalon formation. The main lithology of the Avalon formation is defined as siliceous mudstone, whereas the Bone Springs is composed of mainly carbonates, shaly sandstones and siltstones.

Another important parameter for any unconventional reservoir characterization is the total organic carbon (TOC) content. To estimate this accurately, understanding the thermal maturity of the kerogen in the basin is necessary. Vitrinite reflectance (Ro) is widely considered a reliable maturity indicator (Vernik, 2016). From a USGS report in the Permian Basin (Pawlewics et al. 2005) we compiled the Ro values from all the nearby wells for the calibration. We noticed that there is greater Ro value in the western part and it decreases as we go eastwards in the Delaware Basin. The final TOC log was computed using a weighted average of Δ-log-R technique (Passey et al. 1990) and the bulk density approach (Alfred and Vernik, 2012).

Figure 1 shows a cross-plot of TOC vs. bulk density within the Avalon formation overlaid by Vernik’s (2016) rock physics models (RPM). The lines represent constant kerogen porosity ranging from 0-0.5. The data density shows that the majority of the Avalon organic mudrocks are characterized by a kerogen porosity of 20±5% which indicates an advanced stage of the oil window (Vernik, 2016).

The next important petrophysical properties are total porosity and saturations. The porosity in conventional siltstones and carbonates is calculated using a standard bulk density approach. The matrix density log is computed using mineral volume logs. However, in the organic rich Avalon interval, the matrix density was computed using solid grain densities of organic ($\rho_o$) and inorganic phases ($\rho_{in}$) (Vernik, 2016) separately. The total porosity in this interval increases with TOC, as thermally mature organic mudrocks have enhanced porosity hosted by solid organic matter (Alfred and Vernik, 2012).
To calculate water saturation a semi-quantitative approach was followed using Archie’s modified equation for conventional siliciclastics and carbonate formations, in which the $m$ factor is highly dependent on lithology. For the organic rich interval of the Avalon formation, the water saturation is calculated using the full fluid partitioning argument following Vernik (2016) shown below

$$S_w = 1 - \frac{\phi_k V_k}{\phi} ,$$  

(1)

where $V_k$ is the bulk volume of the porous organic phase of the rock, and $\phi_k$ is the porosity of the organic phase itself.

Figure 1 Rho vs TOC colored by point density overlaid by Alfred and Vernik (2012) RPM with constant kerogen porosity lines.

Rock physics

Rock physics analysis is crucial in relating petrophysical properties (such as mineralogy, TOC, porosity, saturation) to seismic rock properties ($V_p$, $V_s$ and density). This understanding can then be used for 3D AVO modeling and quantitative seismic interpretation.

Figure 2 shows a cross-plot of $V_p$ vs Rho for the Bone Springs formation overlaid by Vernik and Kachanov (V-K) RPMs for carbonates and sandstones and a conventional shale, with a solid component clay fraction ($v_{cl}$) of 30%.

In a complex mixed mineralogy like we typically see in an unconventional play, it is misleading to fit the entire dataset shown in Figure 2 with a single trend (linear or non-linear regression). The red carbonate RPM is consistent with lowest $v_{cl}$ data, while the black sandstone RPM passes through more siliciclastic rich samples and the blue clay-rich shale RPM acts as an upper bound for this dataset. The Avalon data points (not shown) tend to plot more to the south-west of the Bone Springs data, due to the effect of elevated kerogen content.

Often in an unconventional play, shear wave velocity is not available in all the necessary zones. Hence, predicting the $V_s$ log is crucial for any type of AVO modelling and analysis. For conventional type sandstones and carbonates, a number of theoretical and empirical models can be used for shear wave prediction. For an unconventional rock such as the Avalon formation, the presence of kerogen needs to be considered. Using an empirical relationship between $V_p$, $V_s$ and TOC (Vernik, 2016) the shear wave log data is predicted using equation 2:

$$V_s\left(0^\circ\right) = b V_p\left(0^\circ\right) + \left(a_{ref} - a_0\right) \frac{TOC}{TOC_{ref}} + a_0 ,$$  

(2)

where $a_0$ and $a_{ref}$ are the intercepts of linear models relating $V_p$ and $V_s$ for constant values of TOC; $b = 0.58$ is the slope of the lines and $TOC_{ref}$ is the reference TOC value for the Avalon mudrocks in our data set. We also note that equation 2 describes velocities measured perpendicular to bedding.
An important relationship in any Rock Physics analysis is the relationship between $V_p$ and porosity. For the carbonates, sandstones and siltstones in the Bone Spring formation, the V-K conventional RPM fit the data very nicely. However, the organic rich Avalon mudrock showed a steep trend and the V-K conventional shale RPM is not the best match in this case. This implies that rather than porosity, TOC is the main factor affecting the velocities. Hence a non-linear relationship between $V_p$ and TOC was established using a V-K RPM (Vernik, 2016).

In linking petrophysics and rock physics with seismic data, forward synthetic modelling provides the quantitative link between them. Using V-K RPMs it is also possible to construct ‘what-if’ scenarios for different TOC ranges to understand how the corresponding seismic amplitudes can be expected to vary. In figure 3 we show in situ isotropic, anisotropic and a ‘what-if’ scenario case where the original TOC was reduced by 50%, along with the corresponding elastic log data. The typical unconventional Class IV signature is most apparent in the anisotropic synthetics. Reducing the TOC by half reduces the intercept by almost half resulting in the low amplitudes. This can be further used for different feasibility studies before conducting any inversion analysis.

**Geomechanics**

A 1D mechanical earth model (MEM) provides a guide to the stresses and strengths of subsurface formations and also aids engineers in optimizing horizontal well production. In our study there were no core data available, and so we relied on the simplest anisotropic $S_{\text{min}}$ model (equation 3) to build a 1D MEM that does not take tectonic strains into account:

$$S_{\text{min}} = K_0 \left( S_v - \beta_v P_p \right) + \beta_h P_p,$$

(3)

where $P_p$ is the pore pressure, $S_v$ is the overburden stress, $\beta_v$ and $\beta_h$ are the Biot parameters and $K_0$ is the stress coupling factor (for TI rocks this depends on the anisotropy parameter $\delta$). The distribution of $S_{\text{min}}$ in the Bone Springs showed higher values in the carbonate zones. The Avalon formation is more anisotropic with $E_1 > E_3$ where $E_1$ and $E_3$ represent Young’s moduli parallel and perpendicular to bedding plane respectively. Presence of DFITs in the wells can enhance the accuracy of the calculations. These results combined with the oil saturation calculated earlier can be used for deciding better landing zones for the horizontal wells.

**Conclusions**

For an unconventional reservoir characterization, a proper petrophysics and rock physics analysis is important. We have shown examples of rock physics models being calibrated to the unconventional formations found in the Delaware Basin, which leads to a better understanding of the formation properties as well as the ability to construct ‘what if’ scenarios from a restricted data set. The benefits also extend to the seismic domain, where synthetic seismic data constructed from elastic models can build a framework for understanding amplitude variations across an area. Finally a reliable
A geomechanical model is important to understand the stress regimes and to design efficient drilling campaigns. Presence of core data can enhance the accuracy in these computations. All of these will ultimately enhance the search of sweet spots and guide decisions on better landing zone, fracking design and finally improve production.

Figure 3 Forward modelled synthetic gathers showing from left: mineral volumetrics, original TOC, TOC reduced by 50%, Vp, Vs, Rho, isotropic synthetics, anisotropic synthetics and synthetics for the 50% reduced case scenario.

Acknowledgements

We would like to thank Ikon Science and Inter-rock for supporting and giving permission for publishing this research.

References

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