Integrating Well and Seismic Data for Characterisation of Shale Plays

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SUMMARY
Shale plays have revolutionised the oil and gas industry in North America and exploitation of these kinds of plays is steadily gathering pace in other parts of the world. Because hydrocarbon bearing shales usually have insufficient permeability to allow significant flow to a well, production from these unconventional reservoirs comes with unique challenges. Optimizing recoverable reserves from shales requires strategic placement of horizontal wells: placing the well in the best areas, drilling the lateral in the proper direction and keeping the lateral portion of the wellbore in the optimum layer. It further requires production stimulation by hydraulic fracturing (fracking) of the rocks to connect the natural fractures with induced near-well fractures.

In this paper, we present a methodology to identify these optimum areas and layers in the shales using a seismic characterisation workflow where well and seismic data are rigorously integrated. The first part of the approach is well data analysis to extract petrophysical, rock physics and mechanical information. Shale formations have a complex mineralogy requiring a sophisticated petrophysical analysis. Then a seismic inversion is performed to predict rock properties, which characterise the shale reservoirs and importantly allow us to predict how the rocks will respond to fracking. The final part of the methodology is an interpretation of multiple rock property models in terms of defined shale facies. A Bayesian approach was adopted to generate shale facies models that describe the thickness and complex architecture of shale reservoirs. These facies models can be used to significantly reduce the risk of poorly performing wells and improve asset performance.

Key words: unconventional, shales, inversion, reservoir characterisation, hydraulic fracturing.

INTRODUCTION
The success of shale plays in North America has created a lot of excitement in Australia recently. Australia’s shale potential is very large. The U.S. Energy Information Agency (EIA) ranks Australia’s technically recoverable shale resources sixth in the world. When it comes to producing from shale reservoirs though, some tough questions will need to be answered:

• Where are most hydrocarbons (free and absorbed)? Hydrocarbon bearing shale formations are both source and reservoir rocks; the biogenic or thermogenic gas may be trapped within micropores of the shale, or in local fracture porosity, or absorbed onto mineral or organic matter components of the shale.

• Where are the natural fractures? What are their density, orientation and content? The presence of open natural fractures allows the gas to flow, facilitating the recovery process. However fracture communication between a water-bearing zone and the shale may render the prospective shale non-commercial.

• Where are the rocks which can be fractured? Shale formations have low permeability and the horizontal production wells generally require hydraulic fracturing (fracking) of the rocks to stimulate production. Fracking costs an estimated 1/3rd of total drilling budget and carries large risk: the production-to-frack ratios vary widely. The latter is illustrated by the following examples. A well received a total frac of 85,000 Bbl and produced in the first 5 months an average of 43 million scf gas per month. This is a production-to-frack ratio of 0.51 MCF/Bbl. Another well in the same field received a total frac of 4,700 Bbl and produced in the first 5 months an average of 60 million scf gas per month. This is a production-to-frack ratio of 12.8 MCF/Bbl, which is more than an order of magnitude higher.

In this paper we will discuss an integrated workflow that addresses these key questions. Some data examples from studies performed in North America will be used to illustrate the approach.

PETROPHYSICS
The first part of the methodology is to analyse the core data and wireline logs from all wells and describe the shales in terms of their source rock potential: total organic content (TOC), thermal maturity and kerogen. Shales may also be described in terms of their producability, using measures such as their quartz content, the presence of fractures and the pressure gradient of the rock layer.

Shales contain a complex mixture of minerals, such as clays, heavy minerals, quartz, carbonates and kerogen. This complexity calls for an advanced petrophysical analysis. A stochastic approach was adopted to estimate the mineral volumes of shale reservoirs using conventional logs (Jensen and Rael, 2012). The model results for each mineral were calibrated to X-ray diffraction (XRD) core cutting analysis (Figure 1). Once the stochastic model is derived and calibrated, it can be applied to other wells in the area.
The mineralogy, porosity and water saturation results from the stochastic are then used in a rock physics model to determine the ability of a rock to fail under stress (Poisson’s ratio) and maintain a fracture (Young’s modulus) (Figure 2). These elastic rock properties can be combined to derive a shale brittleness index (Rickman et al., 2008). The brittleness has proven to be useful to determine the suitability of the formation for fracking. Brittle shale is more likely to be naturally fractured and respond favourably to fracking. On the other hand, ductile shale is not a good reservoir, because the formation wants to heal any natural or hydraulic fractures.

The direct outputs from a simultaneous inversion are elastic rock properties: P-impedance, S-impedance and Density. The latter usually requires seismic reflection angles exceeding 50 degrees, unless other independent information is available (R. Roberts et al., 2004). The inversion results were used to compute models of Poisson’s ratio and Young’s modulus (Varga et al., 2008). A shale brittleness index was subsequently calculated from the Poisson’s ratio and Young’s modulus (Figure 3).

The relative presence of quartz in shales is important, as the more of this mineral is present, the easier it is to stimulate the shale reservoir. Therefore models of Vquartz were computed through geostatistical co-simulation, using the direct outputs from inversion and Vquartz logs from wells. The final Vquartz model was then calculated as the mean from 10 realisations.

Natural fractures can provide pathways for the oil or gas to move to the wellbore and need to be characterised, if they exist. This was done by computing discontinuity attributes (coherence, curvature) from the inversion results.

The multiple rock property models were interpreted with the aim to delineate shale facies with important producability characteristics. When deciding how to classify the shale facies, it is important that the facies not only represent classes of rocks with significant petrophysical rock properties, but also that they have reasonably distinct elastic or mechanical rock properties, so that their distribution can be constrained by the seismic inversion results. Five shale facies were defined based on Vkerogen, brittleness and Vquartz: 1) high kerogen, low brittleness, 2) medium kerogen, 3) high quartz, medium to high brittleness, 4) low quartz, low kerogen 5) high quartz, very high brittleness (Figure 4).
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The most productive shale is facies type 3. The very high brittle shales (facies type 5) do not represent good reservoir as the amount of kerogen in this facies is low.

A Bayesian approach was adopted to interpret the brittleness and final Vquartz models in terms of these five shale facies. This way a probabilistic interpretation of brittleness and Vquartz models was performed and a probability volume for each of the five shale facies was calculated. A most likely facies model is then easily computed (Figure 5).

Finally, the facies models were analysed to determine if they could explain the existing production data. The good production-to-frack ratios came from wells with their horizontal section well within a layer of facies type 3, and usually underlain by a ductile layer of facies type 1. The latter layer acts as a barrier stopping the induced near-well fractures from reaching water-bearing rocks underlying the shale (Figure 6). The poorly-performing wells had missed the optimum shale layer partly or completely.

CONCLUSIONS

We have described a methodology to characterise shale reservoirs. In the approach geology, petrophysical and geophysical data are rigorously integrated to build realistic and accurate subsurface models describing the thickness and complex architecture of shale formations. Stochastic methods are optimally suited for the petrophysical interpretation of shale mineralogy and fluids. Simultaneous inversion of seismic data provides the interpreter with a set of elastic rock properties, which can be used to predict reservoir and mechanical rock properties. A Bayesian approach offers a way to interpret a number of defined shale facies based on important producability characteristics. The facies models calculated in this manner can be used to strategically locate horizontal wells, significantly reducing the risk of poorly performing wells. Additionally the models can help to enhance the well completion and stimulation, thereby increasing the value derived from rigorous data integration.

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