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Rock physics characterization of shale reservoirs: a case study

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Abstract

Unconventional resources are typically very complex to model, and the production from this type of reservoirs is influenced by such complexity in their microstructure. This microstructure complexity is normally reflected in their geophysical response, and makes them more difficult to interpret. Rock physics play an important role to resolve such complexity by integrating different subsurface disciplines. This study presents two rock physics workflows for a deeper understanding of shale reservoirs with regard to their matrix brittleness and kerogen content maturity. It first employs petrophysical stochastic modelling on the available conventional well logs. Then, the results of well log interpretation are used as input into a rock physics model to generate a complete set of elastic logs. Furthermore, these elastics logs are converted to Young modulus and Poisson's ratio for highlighting brittle zones, which were confirmed by production figures. Moreover, another rock physics workflow is proposed to combine geological information and petrophysical data to characterize total organic carbon content of the shale. This rock physics model inverts velocity into its main geological components (organics, clay and clean velocities), which could furthermore be used for velocity interpretation considering geological processes. One of the velocity inverted components has a direct relationship with total organic carbon and its maturity that is normally calculated using Passey method. Passey method uses three different well logs for modelling kerogen maturity along a well path. However, implementation of this model at locations far away from the well is a big challenge for field development. The reason is the difficulty of tying Passey method results with the elastic properties and seismic cubes. The proposed geology guided rock physics model enables us to find a relationship between kerogen maturity and P-wave velocity from sonic logs. This model, furthermore, can provide a tool to somehow extend Passey method into seismic cubes.

Keywords: rock physics, unconventional reservoirs, Shale gas, seismic reservoir characterization

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1 Introduction

Increasing of global demand for energy and declining trend in the conventional resources make oil and gas companies search for unconventional resources such as tight oil and gas, heavy oil, shale oil and gas etc. Shale reservoirs are categorized as one of these unconventional resources with low permeability and porosity. These resources are difficult for hydrocarbon's production using conventional methods; however, a combination of horizontal drilling and hydraulic fracturing can pretty much address this difficulty. In this method, fracture stimulation is used to increase porosity and permeability of shale reservoirs along the horizontally drilled wells. This makes their production process more difficult and expensive compared to conventional reservoirs. Therefore, improved reservoir knowledge using sophisticated technologies can make the production of these widely distributed resources economically viable and more efficient. This efficiency of using improved technologies has now resulted in the production from shale reservoirs by more companies around the globe. To achieve commercial production, these reservoirs are stimulated through massive hydraulic fracturing using horizontal wells as a mean to enhance productivity, which allows hydrocarbon to flow more freely and profitably (e.g., Passey et al., 1990; Liu et al. 2013). The success of such procedure depends on a right combination between geological and petrophysical properties like layer thickness, total organic carbon (TOC), maturity, porosity, high hydrocarbon in place and fractability to identify sweet spots for further fracturing operation. The key components between these factors are modelling of rock brittleness and TOC content (e.g., Rickman et al., 2008; Passey et al., 2010; Varga et al., 2012; Yenugu and Han, 2013; Scotchman, 2016). This study proposes two rock physics modelling approaches for detecting brittle rocks with high and matured TOC contents.

The concept of rock brittleness that combines both Poisson's ratio and Young's modulus (Rickman et al., 2008) can reflect the rocks ability to fail under stress (Poisson's ratio) and maintain a fracture (Young's modulus) when stress is removed. In terms of Poisson's ratio, the lower the value, the more brittle the rock is, and as the value of Young's modulus increase, the more brittle the rock will be (e.g., Varga et al., 2012; Vernik, 2016). Therefore, the Poisson's Ratio and Young's Modulus models of targeted formations are of particular interest for drilling and completion engineers to understand the optimum stimulation and completion for emerging shale reservoirs (e.g., Carcione and Avseth, 2015). These mechanical rock properties (Poisson's ratio and Young's modulus) can be determined using actual core or cuttings measurements and/or wireline analysis. The advantage of using petrophysical interpretation (through stochastic modelling) over the core method is that it is much more common to have a log across the zone of interest than to have core data (e.g., Jensen and Saberi, 2014). Additionally, cores measurements are more expensive for whole wells and applying a stochastic model using petrophysical interpretation can provide a cost-effective way of extending limited core measured data to a larger number of wells with the acceptable quality. However, rock physics modelling should then be applied to estimate elastic properties (e.g., P-wave and S-wave velocities) and elastic constants (e.g., Poisson's ratio and Young's modulus) from the determined mineralogy and fluid compositions. Interpretation of these elastic constants within each well track can finally pinpoint brittle zones for stimulation

purposes (e.g., Bandyopadhyay et al., 2012; Carcione and Avseth, 2015; Hu et al., 2017).

Total organic carbon and its level of maturity is another major parameter to assess the potential of shale reservoirs. There are different approaches to calculate TOC quantitatively in petrophysics. The 'DlogR' method (Passey et al., 1990) is the most popular one and is widely used in the shale gas reservoirs. Passey et al. (1990) method normally uses porosity, sonic and resistivity well logs. However, there are different challenges with this method like having false positive indication of TOC and baseline determination using wrong inputs like calculated porosity. Porosity determination in shale reservoirs is complicated by very small pore sizes and, thus, large surface area and associated bound water (Passey et al., 2010). Therefore, this method will be generating different TOCs having multi porosity logs. This means that a very good estimation of porosity is necessary for having this method work correctly (e.g., Sondergeld et al., 2010; Carcione and Avseth, 2015; Vernik, 2016; Hu et al., 2017). Another main challenge with this method is the difficulty with tying the results of this method with the seismic cube to populate kerogen maturity through the entire reservoir. Therefore, there is a need to have a link between TOC and kerogen maturity and sonic velocities. Such a link should be able to make a connection between petrophysical and elastic parameters, and rock physics modelling can assist us in establishing such a relationship.

This study focuses on modelling brittleness and TOC content and its level of maturity using two different rock physics models. Figure 1 show a simple picture of this workflow, which has been applied during this study on a shale reservoir to identify sweet spots. This shale reservoir is an active oil and gas field with high hydrocarbon production, and the provided logging data are conventional logging suite. Two wells named as well A and well B are chosen for this study. Well A is provided with a complete set of log suit and core measurements and is considered as control well for petrophysical interpretation and stochastic modelling. Then this stochastic model is applied on well B for validation purposes. Once a valid stochastic model of porosity, minerals and fluid compositions of the rocks has been generated, these mineral and fluid fractions are used in a simple rock physics model to determine elastic properties. This step fills in missing data for elastics (like S-wave velocity in well B) and is used to convert these elastics into mechanical properties of the rock to define rock brittleness zones (e.g., Bandyopadhyay et al., 2012; Jensen and Saberi, 2014). These zones are compared with the production figures of the associated well to confirm their accuracy (Jensen and Rael, 2012). Furthermore, a more sophisticated rock physics model is developed to decompose sonic velocity into its principal component (Saberi, 2014). This model is based on a conceptual model for kerogen maturity in shales and uses TOC and kerogen volumes as the input, and generates a velocity that is sensitive to kerogen maturity. It can be seen that there is a very good correlation between one of the component of this modelled velocity, TOC content and kerogen maturity. The advantage of this modelled velocity compared with petrophysical methods is its ability to be tied with seismic to populate that information within a broader area using seismic surveys.

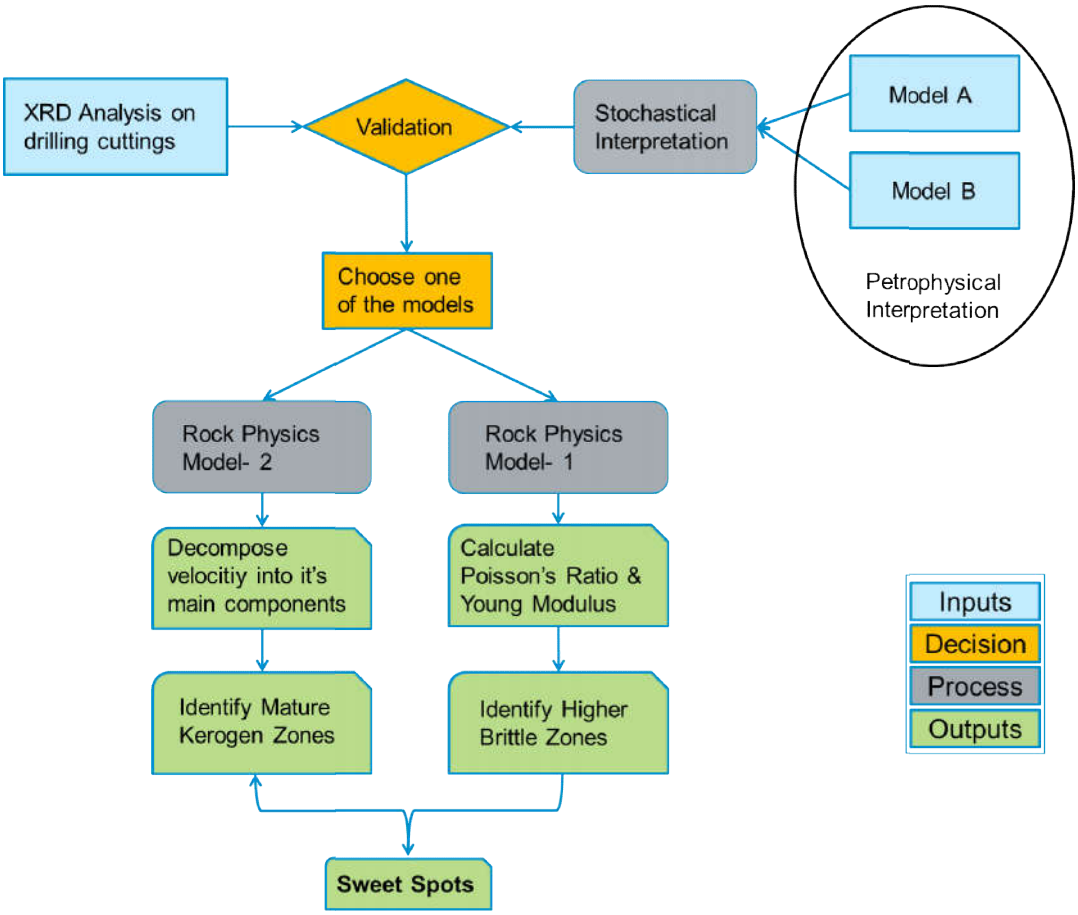

Figure 1. A simple sketch of the applied workflow within this study to identify sweet spots in the shale reservoirs.

2 Petrophysical stochastic modelling

The first step in any characterization project is normally defined by petrophysical analyses and interpretation. The importance of this step is even more significant in shale reservoirs as a more sophisticated method is needed for characterization of these low porosity and permeability rocks. They are normally composed of quartz, clays, and calcite along with significant quantities of dolomite, pyrite, and kerogen. Petrophysical stochastic modelling is a good approach to address uncertainties associated with these types of reservoirs especially their porosities. Stochastic models combine statistical analysis in a framework where the outcome is anticipated but unknown. These models do not provide a unique solution to a problem, but rather provides a model that best fits the available data. The key to successful stochastic modelling is that you know the answer for at least one well before the modelling begins in order to validate your results. A particular advantage to this type of analysis is that it can be done with existing logs from conventional wells along with core data to generate probable solutions. Core data is the optimum control mechanism; however, cuttings or mud logs also have a good value for this purpose. This paper applies the statistical log analysis approach introduced by Mitchell and Nelson (1988) on Well A for calibration purposes. This well is provided with drilling cuttings, and all of the modelled minerals and fluid volume calculations using this statistical approach are checked against them (Figure 2).

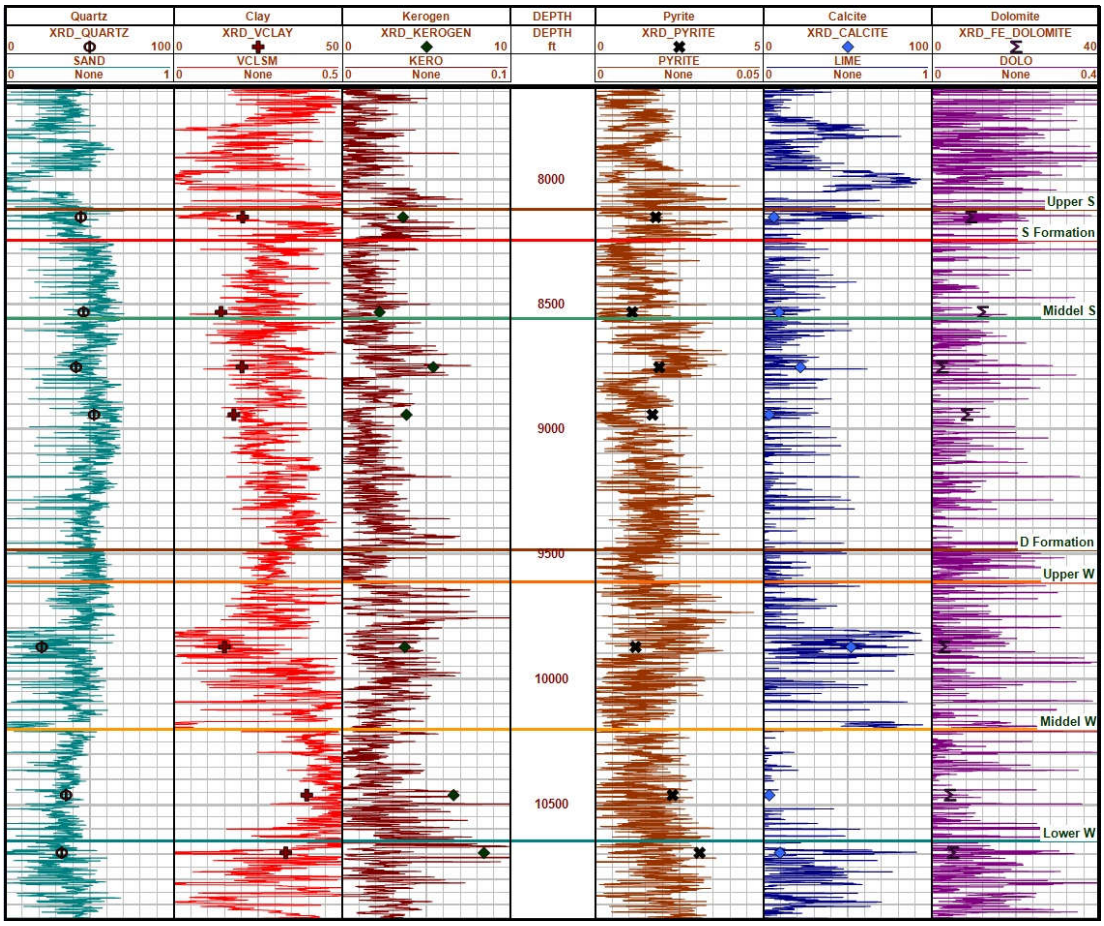

Figure 2. Volumetric mineral results compared to XRD analysis of cuttings from well A. The solid curve in the Kerogen track is the estimation of kerogen from Passey method.

It is also always desirable to limit the number of variables when building stochastic models and to use deterministic methods to estimate some of the mineral volumes. In this study, shale volume was estimated using the potassium thorium curves from the spectral gamma ray data, and porosity was estimated using Density-Neutron shale corrected porosity (Jensen and Rael, 2012). Shale is a fine-grained sedimentary rock that forms from the compaction of silt and clay-size mineral particles, and a correct shale volume calculation is very critical for determining TOC content. Then, Passey (1990) method is used in an attempt to model the kerogen volume, which is an important input to the stochastic model. When performing a petrophysical interpretation of a complex formation, it is valuable to have a baseline to measure the accuracy of the model. In the case of unconventional reservoirs, this usually takes the form of core or sample data whether that data is in the form of whole cores, rotary cores, or cuttings from the mud returns. These measurements of the rocks are then used to calibrate an initial model that can then be extended to other wells in the area. However, whole cores are expensive and a quality stochastic model is a cost-effective way of extending limited core data to a larger number of wells. Figure 2 shows the volumetric mineral modelling results on Well A and their comparison with X-ray diffraction (XRD) analysis of cuttings. This model is then used on Well B for validation purposes. The final step of the

stochastic interpretation will involve comparing results generated by a different model to highlight the power of this technique. Multiple models can generate solid results, and it is this fact that makes this technique so effective (Mitchell and Nelson, 1988). One of the realizations from this stochastic modelling is assumed as the final answer and is used in the rest of the study (Jensen and Rael, 2012; Jensen and Saberi, 2014).

3 Rock physics modelling for brittle zones

The key technologies that have made unconventional reservoirs commercial are horizontal drilling and new techniques in fracture stimulation. The key components for both of these processes are the knowledge about the distribution map of the brittleness and kerogen maturity within the shale reservoir. This valuable knowledge can, furthermore, be provided to us through a proper rock physics model for the targeted formation. Therefore, once a valid stochastic model has generated accurate mineral and fluid compositions of the rocks, these minerals and fluid fractions should normally be used in a rock physics model to determine the bulk elastic properties. In this paper, the stochastics petrophysical interpretation will be used to locate brittle zones and then a conceptual rock physics model will be introduced to model kerogen maturity inside brittle zones (Figure 1). This conceptual rock physics model defines a rock physics attribute that is sensitive to kerogen maturity.

Brittleness is a rock property index that quantifies fracturing probability in a rock or a facies due to the exceeded stress. It is now well known that rock brittleness is a complex function of different factors like lithology, TOC, diagenesis, maturity, etc., and can be related with a good accuracy to P- and S-wave velocities. These velocities are normally used to estimate Poisson's ratio and Young's modulus, which are of particular interest to the drilling and completion engineers. Higher Young modulus and lower Poisson's ratio is as a good indicator of rock brittleness (e.g., Hu et al. 2017). Laboratory measurements of these two properties can be used for calibration purposes. However, in the examples used in this study, no such data was available, and also elastic properties are missing at some intervals. Therefore, a rock physics model was used for computation and calibration purposes. In these two wells, Xu and White (1995) algorithm gives a good match in the intervals with available information and, as a result, is also used to fill in the data gap in both wells. Xu and White (1995) is a hybrid rock physics model, which is originally proposed for shaley sand mixture. It uses the below steps to model saturated rock velocities (Saberi, 2017):

First, time average model is used to mix all existing minerals together. Wyllie (1956) time average model reads travel time (Δt) needed for a wave passing through a rock with porosity φ as:

$$\Delta t = \varphi \Delta t_{fl} + \left(1-\varphi\right)\Delta t_{ma}\,, \tag{1}$$

where Δt_{fl} *and* Δt_{ma} are the fluid and matrix travel times, respectively.

Differential Effective Medium (DEM) (Berryman, 1992) method on Kuster-Toksoz (1974) model is used to mix effective minerals (step 1) and dry pore (vacuum state). DEM model used to model dry rock properties is defined as (Berryman, 1992):

$$\begin{cases} \left(1-f_2\right)\dfrac{d}{df_2}\left[K^*\left(f_2\right)\right] = \left(K_2-K^*\right)P^{*2}\left(f_2\right) \\ \left(1-f_2\right)\dfrac{d}{df_2}\left[\mu^*\left(f_2\right)\right] = \left(\mu_2-\mu^*\right)Q^{*2}\left(f_2\right) \end{cases}, \tag{2}$$

where K^* and μ^* are the effective bulk and shear modulus, and f_2, K_2 and μ_2 are the volume fractions, bulk modulus and shear modulus of inclusions, respectively. The coefficients P^{*2} and Q^{*2} are geometric factors for the second medium (inclusion in this case) (Mavko et al., 1998).

Finally, Gassmann (1951) model for filling inside the mixture (step 2) with the effective fluid (to give the low-frequency velocity) is used. Low-frequency Gassmann (1951) model is written as:

$$\begin{cases} \dfrac{K_{sat}}{K_0 - K_{sat}} = \dfrac{K_{dry}}{K_0 - K_{dry}} + \dfrac{K_{fl}}{\varphi\left(K_0 - K_{fl}\right)}, \\ \mu_{sat} = \mu_{dry} \end{cases} \qquad (3)$$

where K_{sat}, K_{dry}, K_{fl} and K_0 are the bulk modulus for saturated rock, dry rock, fluid and mineral, respectively. The effective fluid can be calculated using Wood (1955) model.

The aforementioned algorithm (Equations (1) to (3)) can effectively model multi-mineral rocks considering different pore aspect ratio for shaley and non-shaley fractions, and is an industry standard procedure for modelling of elastic properties in the shaley environments. In this study, shale portion is given an aspect ratio of 0.04, while for non-shale portions (other minerals) aspect ratio of 0.15 is considered based on the best practice approach on similar fields (Xu and White, 1995; Jensen and Saberi, 2014; Saberi, 2014). Furthermore, these modelled velocities are converted into elastic constants (Poisson's ratio and Young's modulus) for interpreting brittle zones within each of the given wells.

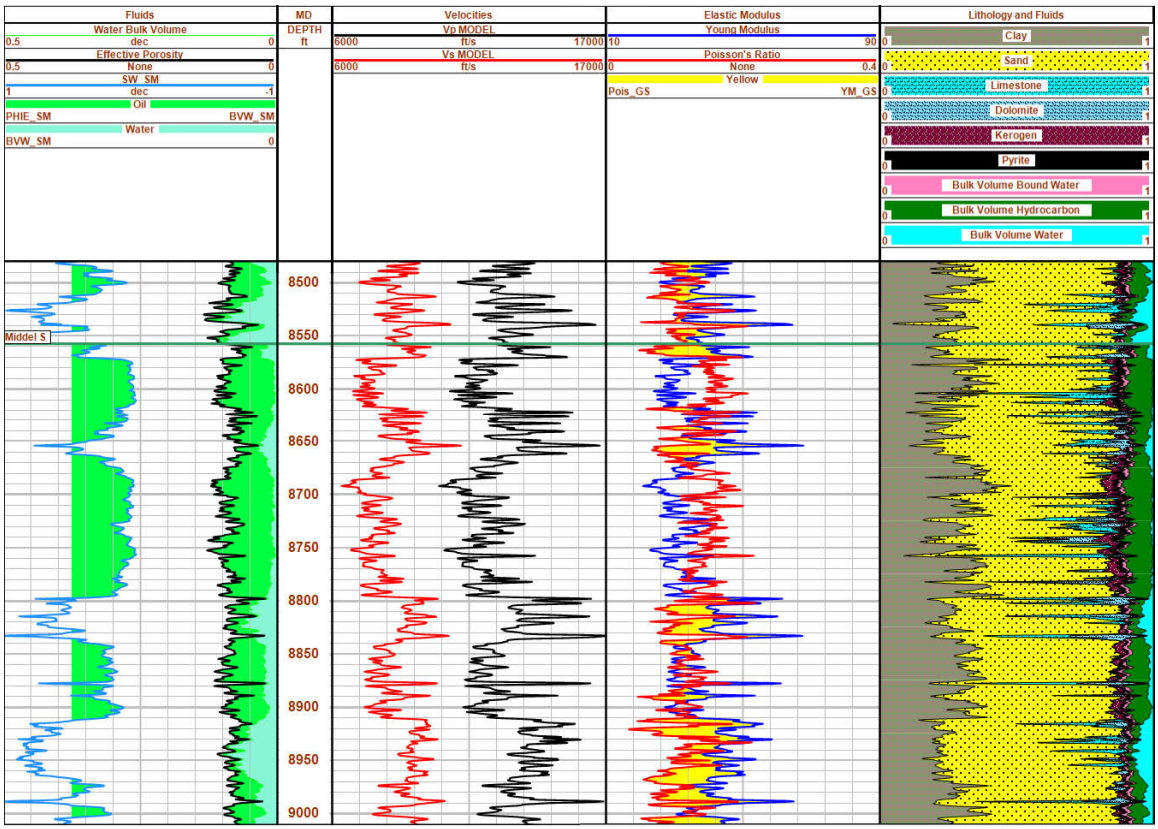

Figure 3. The lithology and fluid analysis results from the stochastic model along with the modelled velocities (P-wave and S-wave velocities), Poisson's ratio and Young's modulus. The intervals with low Poisson's ratio and high Young Modulus are filled in with yellow colour (an indication of more brittle zones).

Figure 3 shows the calculated Poisson's ratio and Young's modulus using modelled velocity with mineralogy and fluids inputs from stochastic petrophysical modelling. The interpretation of elastic constants indicates that the hydrocarbon bearing zones around 8600 feet and 8725 feet have low Young's modulus and high Poisson's ratio, while the water bearing-interval around 8950 feet has high Young's modulus and low Poisson's ratio (Figure 3). Therefore, water-bearing zone at 8950 feet is more brittle compared with the hydrocarbon bearing zones at 8600 feet and 8725 feet, and as a result, is more suitable for fracture stimulation. These results are consistent with the production associated with this wellbore in that considerably more water is being produced than oil (refer to Jensen and Rael, 2012).

4 A geology guided rock physics model to identify TOC and quantify kerogen maturity

Now that the intervals with high brittleness has been recognized and confirmed with production data (refer to Jensen and Rael, 2012), we can go into more details of such intervals for kerogen maturity. Kerogen maturity will spot zones inside these brittle intervals with hydrocarbon potentials. Kerogen is a low density and high neutron porosity component of shale reservoirs. The terms immature and mature are commonly used to describe the current state of the kerogen. It is observed that hydrocarbon-filled pores in the organic matter are generated during different maturity levels. This has been reported by Ahmadov (2011) where different shale samples at mature and post-mature states have been tested. Figure 4 shows a conceptual model based on his experiments where kerogen maturity is divided into three stages: immature, mature and post-mature. Immature state refers to the initial depositional environment where organic matter and stiff silicate minerals all are deposited together. Progressive digenesis cause reduction in porosity and occurrence of pyrite in the available pore spaces that will lead to transition from immature to mature state. Here, preferred orientation of clay particles is achieved (converting to vertical transverse isotropy), and hydrocarbon generation begins. In the mature state, organic matters are filled with hydrocarbon and contribute in the general stiffness of the rock while porosity is lost and pyrite occurs frequently in the pore space. As diagenesis continues, most of the pores will be occupied by pyrite and organic matter will finely scattered through the rock (they are not load-bearing part anymore). Then, hydrocarbon will be expelled outside organic matter pores. This stage is referred to as post-mature state, and is the scenario for most of the conventional reservoirs. In conventional reservoirs, source rock generate hydrocarbon and this hydrocarbon migrates to reservoir rocks where a good seal can accumulate the generated hydrocarbon in one place with high porosity. The aforementioned geological process potentially changes elastic behavior of a rock containing kerogen when kerogen maturity is changed (due to kerogen saturation changes as well as load-bearing materials). Saberi (2014) presented a rock physics model based on this conceptual model of kerogen maturity by classifying mineralogy and porosity into three mineral groups and three pore types, respectively.

The minerals are divided into three mineral groups named as: clean (like calcite, dolomite and quartz), clay and organics (like kerogen and pyrite). Pore spaces are also divided into three different types as: hydrocarbon-filled

pores (ϕ_h), bound-water filled pores (ϕ_{bw}) and free-water filled pored (ϕ_{fw}) following below equations:

$$\begin{aligned}
&\phi_T = \phi_h + \phi_{bw} + \phi_{fw},\\
&\phi_h = (1 - S_w) \times \phi_T,\\
&\phi_{bw} = S_w \times (\phi_T - \phi_E),\\
&\phi_{fw} = S_w \times \phi_E
\end{aligned} \tag{4}$$

where S_w is the water saturation and ϕ_E is the effective porosity. This classification on porosity makes the rock physics model more flexible to model different maturation states (kerogen saturation). For instance, at mature state organics, the mineral porosity can be fully filled with hydrocarbon (ϕ_h), while clean mineral porosity kept fully filled with brine (ϕ_{fw}). Furthermore, these three groups of mineralogy and three types of porosities are mixed together in a way that follows Ahmadov (2011) conceptual model by going through the below steps:

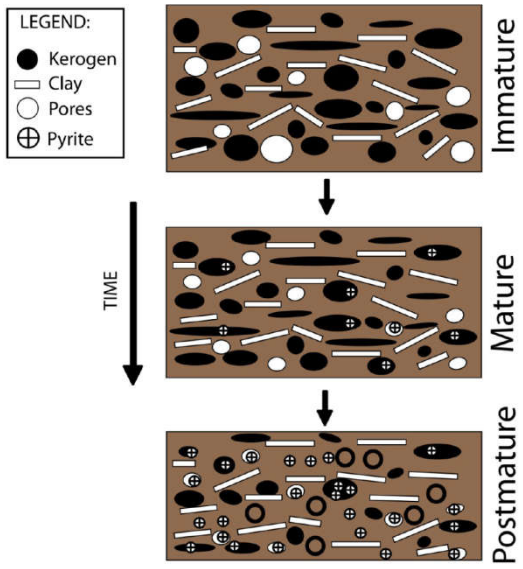

Figure 4. The conceptual model used for kerogen maturity evolution path based on some shale samples (Ahmadov, 2011). This model is used as the basis for a new rock physics model.

Hill (1952) average is used to model clean minerals elastic properties. Therefore, the effective moduli of clean mineral (like calcite, dolomite and quartz) are calculated using Hill (1956) model. Hill average is defined as:

$$M = \frac{\left[\sum_i f_i / M_i\right]^{-1} + \left[\sum_i f_i M_i\right]}{2}, \tag{5}$$

where M_i and f_i are the elastic modulus and volume fraction for the i^{th} constituent of the rock.

Upper Hashin-Shtrikman (1963) bound is used to model organics group (like kerogen and pyrite) elastic properties. The upper Hashin-Shtrikman (1963) model for calculating the effective bulk (K^+) and shear (μ^+) modulus of two components can be defined as below assuming stiffest material as term 1:

$$\begin{aligned}
K^+ &= K_1 + \frac{f_2}{(K_2 - K_1)^{-1} + f_1\left(K_1 + \frac{4}{3}\mu_1\right)^{-1}},\\
\mu^+ &= \mu_1 + \frac{f_2}{(\mu_2 - \mu_1)^{-1} + \frac{2f_1(K_1 + 2\mu_1)}{\left(5\mu_1\left(K_1 + \frac{4}{3}\mu_1\right)\right)}}.
\end{aligned} \tag{6}$$

1- Differential equation medium (DEM) given in Equation (2) (Berryman, 1992) is used to calculate bulk and shear modulus of clean, clay and organics groups mixed with dry pores.

2- Then, relevant fluid is introduced into the dry pores of these three mineral groups applying Gassmann (1951) model following Equation (3). Moreover, brine with volume fraction equal to ϕ_{fw} is introduced into 'clean minerals', brine with volume fraction equal to ϕ_{bw} is introduced into 'clay minerals' and hydrocarbon with volume fraction equal to ϕ_h is introduced into 'organics minerals'.

3- Now, it is needed to mix these three saturated mineral groups ('brine clean', 'wet clay' and 'organic filled with hydrocarbons') with each other to build

the saturated rock. First, upper Hashin-Shtrikman (1963) bound (Equation 6) is applied to mix the 'wet clay' and the 'organic filled with hydrocarbon' groups together (so called shale group).

4- Then, this shale group (step 5) is introduced as spherical shale inclusions into clean matrix using DEM model (Equation 2). This step ensures that both sand and shale act as load-bearing components.

This workflow models a scenario in which organics are filled with hydrocarbon and the rest of the rock is filled in with brine (step 4). This condition is equal to mature state in the Ahmadov (2011) conceptual model. This, furthermore, implies that we should achieve a good match with the measured log if reservoir condition is the same (mature state). The modelled velocities will be under-predicted or over-predicted if other scenarios are valid (like immature and post-mature states). Figure 5 displays the modelled velocity (red curve) for Well B following the aforementioned steps. Finally, P-wave velocity track compares the modeled and measured P-velocities using this rock physics workflow. It can be observed that, in general, modeled velocity is in good agreement with the measured one. However, this modeled velocity can be split into velocities for 'brine clean', 'wet clay' and 'hydrocarbon organics' groups (results of step 4). These decomposed

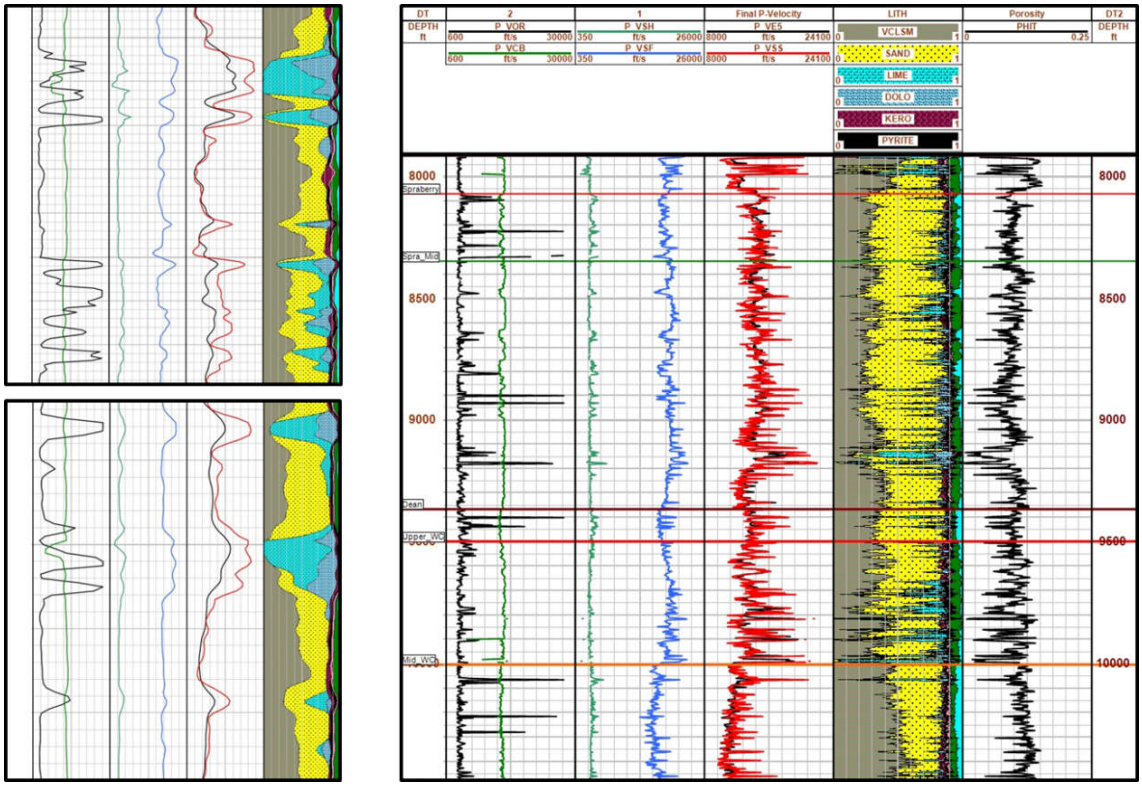

Figure 5. Comparison between modelled velocity using presented rock physics workflow (red curve) and measured velocity (black curve). Track 1 shows velocities for 'brine clean' (blue curve) and 'hydrocarbon shale' (green curve) groups. Track 2 gives velocity components for 'hydrocarbon shale' that consists of clay (green curve) and organics (black curve) groups. Two zoomed pictures of brittle zones are shown on the left where velocities are over-predicted and organics group (black curve on the most left track) velocities are sharply increased. These intervals can be interpreted for having post-mature kerogen (higher concentration of pyrite and expelled hydrocarbon out of kerogen) based on the modelling assumptions. Note that modelling for organics group velocity is independent of the calcite or dolomite volume fractions (Saberi, 2014).

velocities can clearly provide more information about the microstructure of the rock like kerogen content, which cannot be deducted from the sonic velocity alone. Looking into brittle intervals (higher Young modulus and lower Poisson's ratio) reveals that the modeled velocity is over-predicted and 'organics group' velocity (velocity given at step 4) increases sharply (Figure 5). Based on the modeling assumptions, this over-prediction should be resulted from kerogen content (organics velocity). Therefore, they can be interpreted as intervals with post-mature kerogen. This interpretation justifies more water production from these brittle zones, which have already been observed in the previous step on rock brittleness.

5 Discussion on results

Quantifying total organic carbon of a shale play with a minimum amount of 1.5 to 2 wt% is crucial for quality and economical evaluation of any shale reservoir. There are several methods that can be used to determine *TOC* by interpretation of various logs. One of these methods is proposed by Passey et al. (1990) to identify the volume of total organic carbon by overlaying resistivity and sonic logs on each other. They observed that the density, neutron and sonic logs have a direct correlation with *TOC*, and developed an overlay technique using porosity and resistivity logs. Then, the curve separation between these two logs that is measured in logarithmic resistivity cycle (named as $\Delta logR$), and the volumes of *TOC* are written as:

$$\begin{cases} \Delta \log R = \log\left(\dfrac{R}{R_{baseline}}\right) - 0.02\left(\Delta t - \Delta t_{baseline}\right) \\ TOC = \left(\Delta \log R\right) \times 10^{\left(2.297 - 0.1688 \times LOM\right)} \end{cases}, \quad (7)$$

where R and Δt are resistivity and sonic logs, respectively, and the baseline is the non-source interval where resistivity and sonic are lean together. *LOM* is the level of maturity with a range of 7 for the onset of maturity and 12 for the onset of post-maturity. In practice, it is rare to have both *TOC* laboratory measurements and reliable organic maturity data. In these situations, it is possible to choose a value for *LOM* that will result in a match with available *TOC* data. Equation (7) predicts zero *TOC* where there is no curve separation (baseline conditions). And the baseline *TOC* content of shales is usually determined from laboratory measurements or using local knowledge. However, in either hydrocarbon reservoir rocks or organic-rich shale sections, $\Delta logR$ may show values other than zero (separation between the curves). Therefore, using gamma-ray curve is a good recommendation to identify reservoir intervals.

This method shows a direct relationship between *LOM* and *TOC* content of a shale play. Increasing *LOM* will result in increasing *TOC*, and this makes *TOC* volume fraction as a good indicator for kerogen maturity (*TOC* despite *LOM* can be measured in laboratory and can be tied with core data). This method also allows organic richness to be assessed in a wide variety of lithologies and maturities using common well logs. It has been applied to many shale reservoirss worldwide, and works best in traditional shale sections where there is high clay content and no permeability. In unconventional shale reservoirs, the best results come from reservoirs that are self-sourcing and self-sealing. This requires at least one well with core data for calibration purposes (mainly on *TOC*). However, Passey et al. (1990) is a one-dimensional approach for quantifying *TOC* using resistivity and sonic well logs. Therefore, using it with a seismic cube to have a three-dimensional image is not possible (three-dimensional volume of *TOC* as an indicator of *LOM*).

The requirement for generating such a cube can be achieved by linking *TOC* prediction with seismic cube and removing its dependency on non-elastic logs (resistivity log).

The rock physics model introduced in this paper for quantifying kerogen provides a method to remove such dependency from other non-elastic logs. It enables us to decompose modelled sonic velocity into its components. 'Organic group filled with hydrocarbon' curve (black curve in the most left track of Figure 5) is one of these components, which can be generated by mixing hydrocarbon and organic components of the rock. Figure 5 shows clearly that this curve can be linked with the *TOC* content and, as a result, *LOM* of the kerogen. It uses Passey et al. (1990) result as one of the inputs (through volume of *TOC* for organic components). Then, it modifies this curve using other available information along the well having described rock physics model implemented. The output of this mixture is the 'organic group filled with hydrocarbon' curve, which can easily be linked with any seismic cube. Figure 5 shows that this velocity increases for intervals with mature kerogen (velocity peaks) and for the rest, it will show the normal trend. Furthermore, Figure 6 compares this elastic curve with the *TOC*

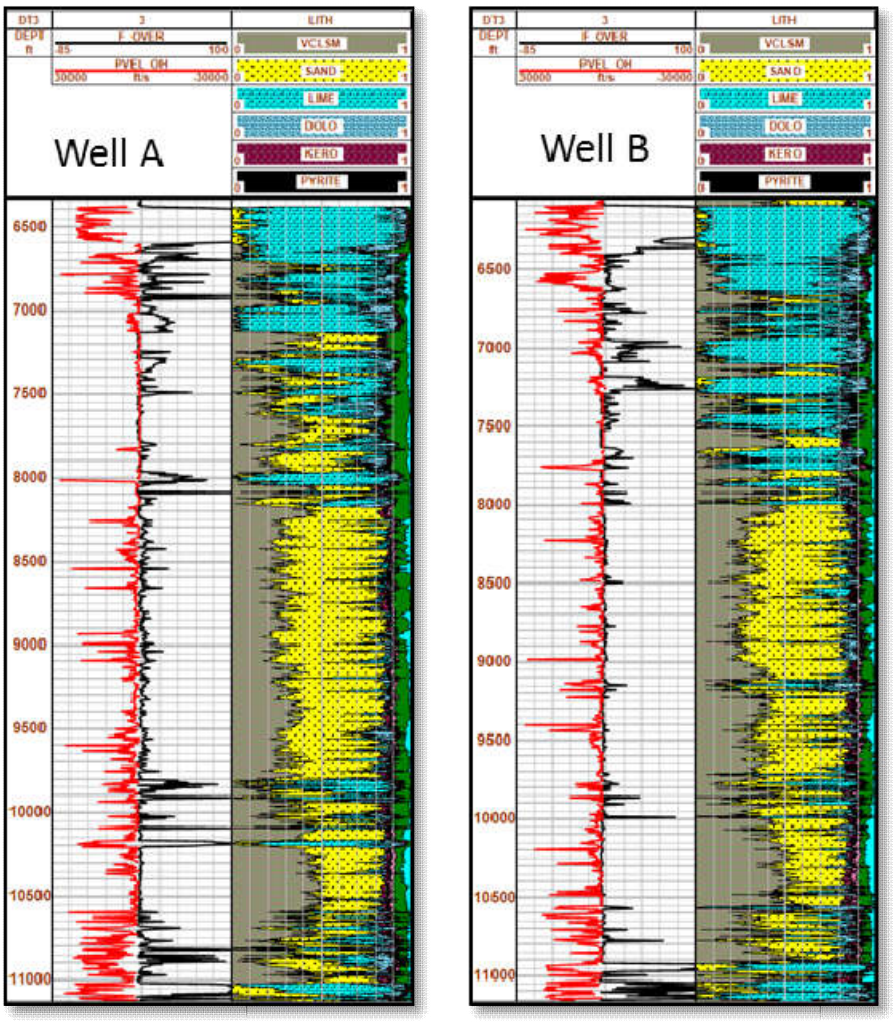

Figure 6. Comparison between 'organic group filled with hydrocarbon' (red curve) and Passey et al. (1990) result (black curve) at Well A and Well B locations.

curve resulted from Passey et al. (1990) method for well A and well B. It can be seen that in general, there is a good agreement between these two curves especially for thick intervals with high value of *TOC* volume. Note that the *TOC* curve resulted from Passey et al. (1990) method has a direct relationship with *LOM* and can be considered as an indicator for matured kerogen. This direct relationship is more accurate for the intervals with high *TOC* values. Besides, Passey method depends on resistivity logs while the aforementioned rock physics curve ('organic group filled with hydrocarbon') is an elastic log with the capability of making link with the seismic cube.

6 Conclusions

This study confirms that petrophysical stochastic modelling can provide the most relevant inputs for rock physics modelling to generate acceptable elastic properties. This could be linked to elastic constants particularly Poisson's ratio and Young's modulus for brittleness calculation and interpretation. Such interpretations can provide us with useful information on rock strength and pressure environment to optimize fracture treatment, and should be refined using core data measurements. This paper also investigates the determination of kerogen maturity in shale plays using a geology constrained rock physics model. This model enables us to highlight intervals with mature kerogen content. The results of the proposed rock physics model, which are in elastic domain, can also be compared with the volume of total organic carbon calculated from Passey method. The good agreement between these two curves indicates that elastic logs can be used as an indicator for kerogen maturity in unconventional reservoirs. Furthermore, the results of this rock physics model can be implemented in seismic characterization studies for mapping volume of the total organic carbon and its level of maturity.

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