Velocity Modeling and Pore Pressure Imaging Using Tomography, Rock Physics and Burial Diagenesis of Shale

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Summary

In this paper, I present a discussion on a new approach to pore pressure prediction technique. This technique, developed by Dutta et al (2011, 2014) suggests that the seismic interval velocities obtained from the well-known technique such as reflection tomography that is commonly used for depth imaging could benefit significantly from constraints imposed on the inversion process to reduce and manage the inherent non-uniqueness and ambiguity. We use rock physics principles to determine the acceptable ranges of expected velocities of rocks (such as shale) under varying states of effective stress (and hence, pore pressure through a knowledge of overburden pressure), and impose these constraints on the seismic tomography. This model also includes chemical kinetics of rocks to account for burial diagenesis. This integration results in "physically" meaningful interval velocities from tomography that are close to the "true earth velocity" and hence, ready for pore pressure prediction. Further, this constrained interval velocity model, when migrated, results in better image. I illustrate the methodology with an application that resulted in better pore pressure that is consistent with geology.

Introduction

Pore pressure prediction is an integral part of any exploration program as it relates to not only the size and the migration pathway of hydrocarbon accumulation but also to drilling safely to reach targets without damage to life and environment. The use of seismic velocity for pore pressure prediction is well known ever since the pioneering work of Pennebaker (1968) and Hottman and Johnson (1965). Many authors (e.g., Reynolds, 1970, 1973; Reynolds et al, 1971; Dutta, 1997; Bilgeri and Ademeno, 1982) described how seismic velocities can be used for geopressure analysis. The seismic methods detect changes of interval velocities with depth from a velocity analysis of the common midpoint (CMP) seismic data. These changes are then related to various attributes associated with pressured formations in comparison with a normally pressured rock at the same depth; (1) higher porosities, (2) lower bulk densities, (3) lower effective stresses, (4) higher temperatures, (5) lower interval velocities, and (6) higher Poisson's ratios. Each of these indicators affects seismic interval velocities and reflection amplitudes which are the keys to seismic detection of geopressure. In the article that I wrote earlier (Dutta, 2002), I commented that *"unfortunately, the seismic velocities, obtained from a stacking velocity analysis of CMP gathers, have quite often been misused for pore pressure analysis."* It was true then and it is still true now except in handful of cases where the practitioners of pore pressure prediction are familiar with <u>both</u> the limitations of conventional seismic velocity analyses as well as the need of a versatile subsurface rock model. This is discussed further below along with an alternate solution (Dutta 2011, 2014) that has been found very useful.

Theory and Method

<u>Limitations of Conventional Approaches</u>

A typical workflow relating seismic velocity to pore pressure is outlined in Fig. 1. The major steps are: create an interval velocity model such as tomography (Woodward et al. 2008) that relies on "gather flattening" as a major criterion (done by mostly seismic analysts with very little knowledge of subsurface pressure mechanisms, pressure data and petrophysical analysis of logs), empirically relate the seismic velocity model to either effective stress or pore pressure directly using empirical methods such as Eaton (1968, 1972) or Bowers (1995); calibrate the model using well data (mostly sonic logs and mud weight data and often done by a geomechanics or petrophysicist with little knowledge of seismic velocity analyses techniques), and then use the model for prediction elsewhere (also done mostly by a geomechanics / petrophysics team). However, the limitations of this approach are many:

- Pressure model is not propagated in 3D (the seismic velocity is in 3D) and so propagation of anisotropy is often incomplete in the pressure domain.

- Curve fitted relationships (velocity to pressure) may need to be extrapolated beyond their range of validity with no guarantee that the extrapolation beyond the calibration range (wells are in 1D) will be valid, especially when the lateral and vertical geology may be changing.

- Empirical methods such as Eaton or Bowers require establishing a Normal Compaction Trend (NCT); this is often based on sonic / resistivity log analysis with poor results as there is no check whether the model for NCT is rock physics compliant – typically, these are not. Further, this sort of analysis assumes that the shale velocity trends are independent of its mineralogical composition as well as diagenetic alteration of shale due to thermal variation or other causes. While some authors (Lopez et al 2004) use Cation Exchange Coefficients (CEC) to define the shale velocity trends, the approach is still incomplete as the attendant kinetic effects due to the burial metamorphism, as outlined by Hower et al, are not incorporated in the predictive sense.

- Empirical models are usually not valid for HPHT formations and formations with complex mineralogy and low porosity, such as older shale and carbonates.

The consequences of using the above workflow could be severe: depths generated by imaging procedures are “Seismic Depths” that is often *substantially* off from “Drilling Depths” in the zones of interest due to use of multiple velocity models in the conventional approach (seismic, logs and check shots), causing large uncertainty in exploration targets, seal definition, drilling depths, depths for casing points, mud weights and fracture pressure. In addition, errors in seismic velocity not only cause depth shifts but also incur the structure and amplitude expressions that may affect inversion attributes.

Current Method

Dutta et al (2014) discussed an alternate approach to pore pressure prediction, using anisotropic tomography velocity analysis through chemical kinetics and burial history modeling (Dutta, 1986). This model recognizes the existence of two distinct velocity models – one for imaging and the other for rock velocity (as defined by Dutta (2002)) that is needed for pore pressure analysis and then uses an iterative approach to obtain a single velocity model. An outcome of this approach is a final velocity model that is close to “the true earth velocity” – it is this velocity that will guarantee that not only the seismic gathers are flat (as needed for imaging) but also geologically plausible and physically possible (for example, the velocities be within the hydrostatic and fracture pressure limits) for reliable subsurface pore pressure estimation. Dutta et al (2014, 2015) recently reported some applications of this approach. The first successful case study using this new approach was for a project for ONGC and has been reported by Dutta et al (2014). An extension of the approach to subsalt pore pressure is also discussed in Dutta et al (2015). Details of this approach will be given in the next section.

Discussions on the Current Model

The thermal and burial history-dependent rock physics model for velocity and effective stress can be described as below:

$$\Delta\tau = \Delta\tau_m (1 + \tfrac{1}{\beta}\ln(\tfrac{\sigma_0}{\sigma}))^x .$$

Here, $\Delta\tau$ is the slowness (inverse of Vp) and σ is the effective stress. The suffix m specifies the grain of the sediment. x and σ_0 are lithology-dependent constants, and β is the diagenetic function that denotes the chemical compaction from smectite-rich to illite-rich shale minerals. Figure 3 shows a relationship between the velocity and the effective stress for various β for a set of wells taken from the public data base in the Green Canyon Area of the Gulf of Mexico (Liu et al 2015). Various stages of the chemical compaction are denoted by β. In reality, β is a continuous function of depth. At shallower depths where mostly smectite-rich shale exists, β is small. As the chemical compaction is enhanced with increasing depth and temperature, β increases and leads to a faster velocity from the effective stress trend as shown in Fig.3

The diagenesis process releases "bound" water from the shale to the pore space and increases the pore pressure, resulting in lowering of the effective stress on the rock matrix. Proper description of chemical compaction is essential in relating the changes in seismic velocity with changes in effective stress. In this context, an important observation is that for the model shown in Eq. (1), the velocity of a rock will change due to changes in <u>both</u> β and σ. For purely mechanical compaction process (in which β is almost constant), variation in the velocity is caused by variation in σ. For purely chemical compaction process (in which σ remains nearly constant), the velocity changes are mostly due to β. Therefore, the chemical compaction allows for velocity variations (lowering velocity, for example) without changing effective stress! However, since the total stress, S, acting on a rock at a subsurface depth is the sum of effective stress, σ , and the stress acting on the pore fluid, P, it is clear that with continued burial, the pore pressure will continue to increase and the velocity will continue to decrease, but effective stress will remain constant – a possibility that is an impossibility in the conventional Eaton-type approach. In Bowers' approach (Bower, 1995) an attempt is made to account for it by invoking an empirical relation between the velocities versus effective stress that is different from mechanical compaction. However, an incorrect assumption has also been made – the shale must follow a so-called "*virgin compaction trend*". In reality, this does not occur because the mineral composition of the shale is permanently altered after the onset of chemical compaction during the burial process – so it can't follow the same "virgin" trend!

For a specific mini-basin, we convert the curves shown in Figure 3 to a rock physics template (RPT) for Vp and the pore pressure as shown in Figure 4. We note that the pore pressure is denoted in pounds per gallon (ppg) – a mud weight equivalent unit that corresponds to the density of the drilling mud, and is a favorite unit of drillers. Therefore, the RPT directly links Vp to formation pressure data and vice versa. If one chooses to use "mud weight" data in lieu of "true" formation pressure data such as RFT or MDT data, considerable care must be exercised. This is because a well is rarely drilled with "balanced" mud weight (where the mud weight exactly matches the formation pore pressure), and most often the mud weight is higher than the formation pressure by an unknown amount (overbalanced drilling)

An example

In Figs. 5-9, I present an example application from Indonesia. This was also reported in an international congress in Indonesia (Dutta et al 2015). It used public well data and Schlumberger's multi-client large offset seismic data to show the value of good seismic data and the benefits of the current approach. I emphasize that in the current approach for pressure For prediction, we not only obtain reliable estimates of subsurface pore pressure prior to drilling but also a "better image" that uses the <u>same</u> underlying velocity model and a RTM process for depth imaging.

Figure 5 shows the predicted pore pressure in pounds per gallon (ppg) – a drilling unit for mud weight, using the current approach and it is compared with the "legacy" model in Fig. 6 that used the depth imaging velocity from the conventional anisotropic tomography velocity modeling approach. We note that the current model yields pore pressure that is structurally more consistent, whereas the legacy model (Fig.6) yields pore pressure at various zones that are "below hydrostatic", and hence "unphysical". This signifies that the interval velocity model for the legacy model is "too fast" at some places. This is clearly demonstrated in Fig.7 where profiles of interval velocities for both models versus depth at a projected well location are shown along with expected velocities (shown in dashed curves) for pore pressure gradient (in ppg), starting from hydrostatic condition (in blue) to higher gradients in increment of one pp (the rock physics template). It is obvious that the velocity associated with the legacy model "exceeds" the velocity for the "hydrostatic" pressure condition at several places – it is very pronounced at deeper depths. This is the reason for "unphysical" zones of pore pressure gradients in Fig. 6. But why is this? In my opinion, the reason for this is the inherent non-uniqueness associated with tomography – there are multiple velocity models that will yield "acceptable" stacked image after migration; however, the image quality as a sole criterion is "insufficient". In the current approach, we used a stricter criterion for velocity modeling, namely, judging whether the interval velocity is "physical" by using predicted pressure as a guide. In Fig. 7 the legacy stacked image is shown, and it should be compared with the stacked image obtained using the velocity model from the current approach in Fig. 8. The improvement in the image quality is significant.

Figures

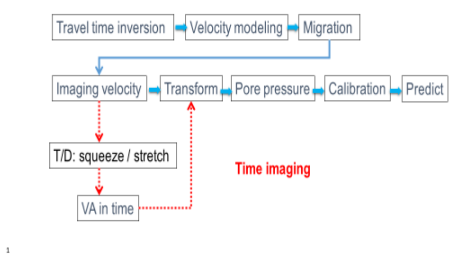

Figure 1. Flow chart of conventional approach

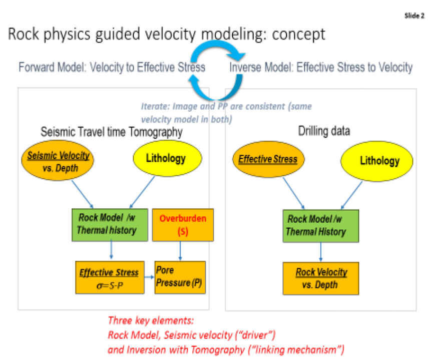

Figure 2: Schematic of the current approach. Tomography is constrained by rock physics derived velocity during the inversion process.

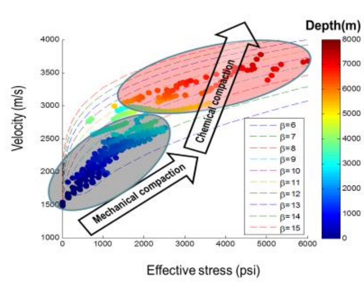

Figure 3. Model prediction of expected range of shale velocity from both mechanical and chemical compaction of shale (Dutta, 1986) and Dutta et al (2014). β is the diagenetic factor obtained from thermal history reconstruction of shale.

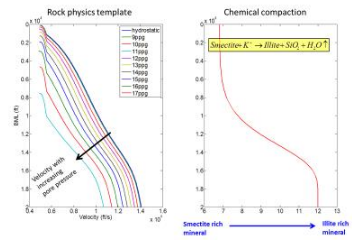

Fig.4. Rock physics template. On the left expected velocity variation of shale under increasing pore condition from hydrostatic to fracture pressure is shown. The figure on the right shows the diagenetic function, β , that controls the velocity variation.

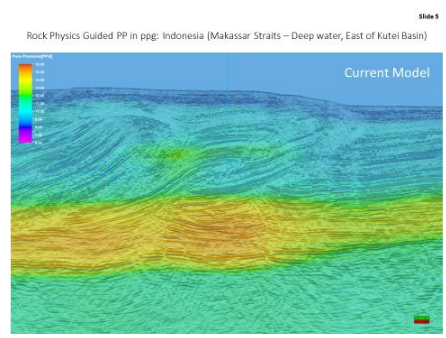

Fig. 5. Rock physics guided pore pressure in ppg using tompgraphy and burial metamorphism of shales (Indonesia, Makassar Starits – Deep water, East of Kutei Basin).

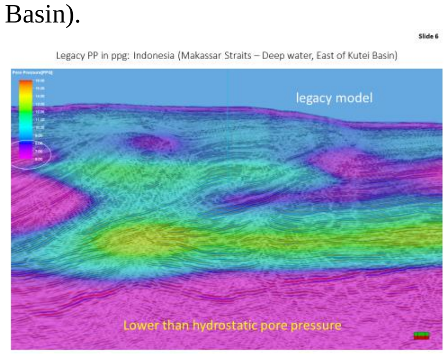

Fig.6. Pore pressure in ppg using the Legacy velocity model (Indonesia, Makassar Starits – Deep water, East of Kutei Basin).

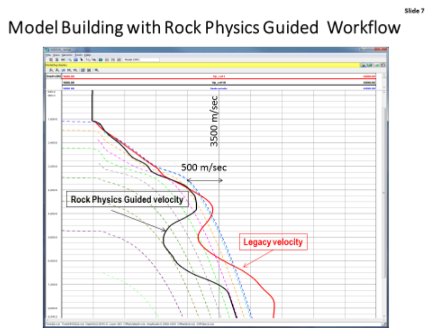

Fig.7. Two velocity models at a designated well location – the curve in red is from the legacy model (that yielded the pore pressure in Fig. 6) and that in black is the current model (that yielded the pore pressure in Fig. 5).

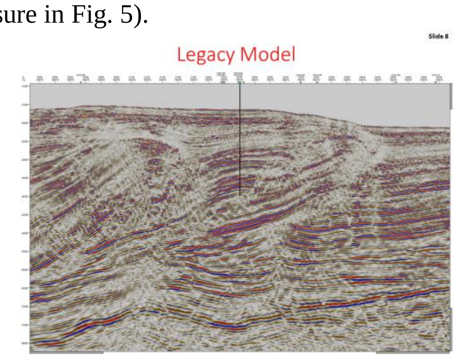

Fig.8. Stacked image after RTM using the velocity model underlying Fig. 6 for pore pressure.

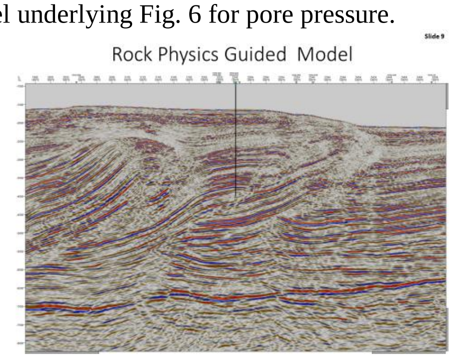

Fig. 9. Stacked image after RTM using the current velocity model underlying Fig. 5 for pore pressure

Conclusions

In this paper, I outlined a novel approach for pore pressure modeling using rock physics principles, chemical kinetics of shale burial metamorphism and seismic tomography. The approach is robust and helps minimize the non-uniqueness associated with tomography. This is accomplished by guiding the interval velocity model during the inversion process to yield a model that is physically plausible, namely, the model must yield pore pressure bounded within the realm of physics – the pressure cannot be lower than the hydrostatic and higher than the fracture pressure. This constraint on the model also significantly improved stacked images after migration.
This model can be easily incorporated in other schemes such as Full Waveform Inversion (FWI) or elastic inversion. Some preliminary results are reported by Liu et al (2015) at the Annual SEG Meeting in New Orleans.

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