The consequences of ignoring rock properties when predicting pore pressure from seismic and sonic velocity

Edward Hoskin1* and Stephen O’Connor1 set out why standard pore pressure algorithms must only be applied after the rock properties have been assessed fully and examples are given of the circumstances where velocity data, both sonic and seismic, may never allow an accurate pressure assessment.

Rock properties are shaped by the geological history of the basin into which they have been deposited. The environment of deposition (and eroded hinterland provinces) controls the mineralogy and resultant rock type, while geological processes such as uplift, denudation, or constant deposition and burial will all shape the development of porosity in rocks. These factors may all play a part, to some degree, in the development of any abnormal pressure (herein termed overpressure; pressure in excess of the hydrostatic pressure) within formations. The more processes that have occurred, the more complicated the task will be to accurately predict this anomalous pressure. Typically, velocity data such as seismic interval velocity and sonic logs are used with industry-standard algorithms in all geological settings and lithology types to predict pore pressure. This paper will set out why standard pore pressure algorithms must only be applied after the rock properties have been assessed fully and examples are given of the circumstances where velocity data, both sonic and seismic, may never allow an accurate pressure assessment. Brief mention will also be made of why additional care must be taken before using seismic velocity to predict pore pressure.

How do we determine the overpressure in a well?
The interpretation of a well for overpressure has been documented in many papers over the years. Pressure data are available in two forms from a well:

(i) From reservoirs (sands, porous carbonates e.g. packstones and grainstones and also fractured units). These include direct pressure measurements from wireline formation tests (WFTs), Drill Stem Tests (DSTs), and kicks. Pressure data from DSTs and WFTs are the only unambiguous sources of pressure information from a well. (ii) non-reservoir (such as shale, and in some cases marl) pore pressure information can come from observations of drilling parameters such as rate of lithology penetration (ROP), incidents of stuck tool, and well-site observations regarding trip and connection gases and shale cuttings, all in relation to the circulating and static mud-weight used at the time. Any interpretations regarding pore pressure from these observations are ambiguous, but nevertheless very useful.

To gain a more quantifiable estimate of pore pressure in non-reservoir shales, industry-standard algorithms such as Eaton (1975), Equivalent Depth Method and Bowers (1995) are used; the causes of the overpressure dictating which of these methods to use. The algorithms work by comparing porosity at the depth of burial against the expected porosity trend if shales were normally compacting, that is the normal compaction trend (or NCT). If porosity in the shale is higher than expected from the NCT, the shale is said to be overpressured. However, not all shales are the same. Different shales behave differently to stress and so will have different porosity for the same overpressure (Yang and Aplin, 2004). At elevated temperatures clay diagenesis produces silica which if at sufficient saturation can precipitate as sheets within shales (Thyberg and Jahren, 2011). This affects shale velocity such that a link between velocity, porosity and pressure is lost. Conversely, high Total Organic Content (TOC) in shale results in a slower, less dense shale which could result in an interpretation of the formation as overpressured, yet in fact it may be normally pressured. Carbonates are largely stress-invariant e.g. Bathurst (1971), Scholle (1977) and Lubanzadio et al. (2002). The porosity/permeability characteristics of sandstones allow fluids to flow in and out of such rocks so their porosity is rarely directly attributable to overpressure alone, unlike in shales.

A note on seismic velocity data specifically
Although the aim of recording and processing seismic velocity is to derive a velocity field as close to ‘real’ (as measured by Vp) rock velocity as possible, there are many reasons why this aim is often unachievable. For instance, well-based Vp data is much higher resolution than surface seismic e.g. resolution of ~30-60 cm, vs. ~45 m, respectively. Therefore, Vp can show many more velocity oscillations related to bed thickness. If seismic resolution is particularly low, the

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velocity field can miss reversals that pertain to overpressure, especially in low acoustic impedance formations such as thick homogenous shales which are likely to give rise to high overpressure. In addition, well-based Vp is measured parallel to the well bore (i.e. vertical, when the well is drilled vertically) whereas surface seismic velocity has both vertical and horizontal components. Measuring velocity in different directions is not an issue until the rock becomes anisotropic. Rock may become anisotropic through the introduction of laminations with compaction or diagenetic clay transformation e.g. kaolinite or smectite to illite. More details are given in section 4, but the laminations result in the horizontally measured seismic velocity increasing relative to the vertically measured Vp (unless the well-bore trajectory is deviated), making calibration a requirement.

In order for the seismic velocity data to be fit for pressure prediction purposes (unlike the seis Vint shown in Figure 1), the velocities have to be derived using appropriate processing sequences and algorithms. There are many different workflows for processing seismic data to generate velocity and this is where seismic velocity differs from sonic (which is acquired in a standard procedure using a down-hole tool). An important aspect of any pressure interpretation using these data is an understanding of how the velocities were derived in the first place, and their limitations and scales of resolution.

Geological situations where the use of velocity data may preclude accurate pressure prediction

The remainder of this paper focuses on rock properties and how subtle variations in constituent parts of shale, temperature, and local stress state may play a part in making pore pressure prediction challenging. These property variations cause changes which apply to both well and seismic velocity. However, there are circumstances where the effects will be more pronounced for seismic velocity.

Mineralogical variation in shales

Clay content

In isotropic material, for example unfractured basalt, sandstone with equally sized, well rounded grains, or seawater, the horizontal and vertical velocities are equal. However, when mudstone compacts it arranges in to fine layers and becomes shale. These layers or laminations cause the shale to become anisotropic. The effect becomes even more pronounced when clay diagenesis, such as smectite to authigenic illite, occurs (usually at higher temperatures) (Alberty et al., 2003). These alterations cause horizontal velocity to be 5-10% faster compared to vertical velocity and is termed vertical transverse anisotropy (VTI). Since seismic velocity has a component of horizontal velocity compared to vertically measured sonic velocity, these two velocity types may vary by up to 10% if the horizontal component is not accounted for in seismic processing. Therefore, increase in seismic velocity owing to laminated sediments could partly be a lithological effect, rather than related to low overpressure.

Variation in detrital mineralogy will affect velocity data. Katahara (2007) showed an example of shale that contained chlorite, illite and kaolinite which was normally pressured, and XRD data suggested that expanding clays were insignificant in volume in the samples. The shales showed a shift of the sonic-density trend to lower velocity and higher density with increasing clay content. Furthermore, Yang and Aplin (2004) determined the numerical values of the compression coefficients based on a quantitative description of mudstone lithology, by looking at clay content (the percentage of particles that are clay-sized, that is, < 2 μm diameter). They found that variation in clay content determined the effective stress/porosity interaction. Figure 2 shows an example from the Carnarvon Basin, Australia where several types of shale are present such that using the wrong compaction model for the shale locally developed at a prospect would lead to significantly inaccurate pressure prediction.

Total organic content

A source rock or highly carbonaceous (high total organic content, or TOC) shale will have a tendency to show slower velocity and lower density compared to an equivalent shale with little or no TOC (Passey et al., 1990). These authors demonstrated that a TOC of 3% can reduce density by 0.09 g/cm³, and sonic velocity by 14 μs/ft (see Figure 3). For 10% TOC, these become 0.35 g/cm³ and 37 μs/ft. In both

Figure 1 Data from two wells in West Africa. Note the divergence between well sonic (Vp) and the extracted seismic velocity.
cases, elevated pore pressure would be inferred as the logs are reducing in magnitude.

Further, in experiments by Hanebeck et al. (1996), TOC-rich shales (10% TOC) that were raised to temperatures of 200°C to 350°C resulted in a change in sample thickness of 4%. Such a volume change suggests the kerogen is load-bearing, and as such will have implications for pore pressure generated via load transfer/framework weakening (Osborne and Swarbrick, 1997).

**Carbonates and carbonate cements**

Studies in the Danish Central Trough, North Sea, have observed that overpressured chalks have lower sonic velocities than normally-pressured chalks. This is attributed to retardation of compaction owing to overpressure generation and reduced effective stress (Japsen, 1993). Brasher and Vagle (1996) similarly relate the overpressure in chalk fields in the Central North Sea to rapid basin subsidence. However, carbonates generally differ substantially from shales in their diagenetic history and compaction. Chalks compact by both mechanical and chemical processes (Bathurst, 1971; Scholle, 1977) such that methods of pore pressure prediction based on porosity/effective stress in shales discussed above are, from a process basis, unlikely to work in carbonates. More recent publications support this assertion. For example, shallow marine carbonate sediments buried to 10–600 m depth offshore North East Australia are so well cemented that experimental compaction of up to 50–60 MPa (corresponding to 5 km of overburden) only produced a small amount of mechanical compaction (Criozé et al., 2010). The conclusion that there is only minor or no relationship between porosity and effective stress was also stated by Lubanzadio et al. (2002) who examined North Sea chalk. These authors considered traditional pore pressure prediction techniques,
In summary, these changes include gypsum to anhydrite, and smectite to a more dehydrated form. Smectite and/or kaolinite (at higher temperatures) to illite transformation releases chemically bound water to become interstitial water. The silica released as part of these later reactions can precipitate to form sheets of microcrystalline cement (Thyberg and Jahren, 2011). A further example is presented in Hoesni et al. (2007) in the Malay Basin where trends in overpressured velocity-bulk density data have been noted in which both velocity and bulk density increase.

Figure 5 is redrawn from O’Connor et al. (2011) and features data from a Malay Basin well. The data trend is interpreted as chemical compaction of the shale mud-rock without reduction of effective stress (Swarbrick, 2012). The author suggests that it is likely that this type of compaction results in pore-filling cements and concurrent escape of displaced fluids through the connecting pores without development of additional overpressure and simultaneous reduction of vertical effective stress (or ‘VES’). The net result is that if these shales become cemented, and it is possible that silica from clay diagenesis provides this silica – they become fast (relative to their effective stress) and thus may be interpreted as high velocity and low overpressure zones. In reality, these zones may be significantly overpressured.

Sonic derived porosity data for the same well as in Figure 5 are shown on the left hand side of Figure 6. The porosity was derived using the method of Raiga-Clemenceau i.e. ones based on effective stress/porosity, to be invalid or at best, limited in carbonates.

By way of an example, in Figure 4 we show comparison of sonic data from the Muderong (brown) and Withnell (teal) Formations from selected wells. There is a clear separation between these two sets of data with the calcareous Withnell Formation shale being generally higher velocity than the non-calcareous Muderong Shale. There are several observations here; (i) in the shallow section (upper 1000 m TVD from mud line, or TVDml, the Withnell data are faster, thus resulting in large inaccuracy in defining a normal compaction trend, and related to this (ii) between the depths of 2000 to 3500 m TVDml, the Muderong and Withnell Formations have different velocity by 700 m/s but kick data in Tingate et al. (2001) suggest both formations have similar pore pressures. The conclusion here is that if the Withnell Formation NCT were used against Muderong velocity data the resulting shale pressure estimate would be too high, and if the Muderong NCT were used to estimate shale pressure in Withnell the opposite would be true.

**Temperature influence**

Diagenetic mineralogical changes occur in the shales when the temperature increases, for example above 70° C in some basins (Bruce, 1984). These changes can lead to the two main processes of secondary overpressure generation: 1) fluid expansion/volume change and 2) load transfer (or framework weakening).

**Figure 4** Comparison of Vp data from Muderong (brown) and Withnell formations (teal) from selected wells. The Withnell data are noticeably faster, suggesting lower pore pressure, whereas kick data suggest pore pressures are in fact comparable.
pressures as velocity cannot be linked to pressure owing to a change in rock properties.

Tectonic setting

Increases in vertical and horizontal stress result in overpressuring in normally consolidated low-permeability sediments; overpressuring owing to tectonic stresses can be far higher than that generated by rapid sedimentary loading. The sediment is normally consolidated to depth, and then it is sheared by tectonic forces, resulting in overpressure. The shearing occurs without drainage (low permeability), so the sediment experiences little or no porosity change with reduction of effective stress (Yassir and Bell, 1996). The porosity response to a change in effective stress is not expected in this case because it involves shear strains which will have a time-dependent component (Terzaghi and Peck, 1948). In an active fold and thrust belt, the compressive stresses further reduce the porosity and increase the acoustic velocity of the mud rocks. First, a layer-parallel shortening compacts sediments beyond what is observed for the vertical effective stress. This additional compaction is further enhanced by near thrust faults and in anticlinal forelimbs, presumably because additional shear stress in these areas (Couzens-Schultz and Azbel, 2014) present a case from offshore Sabah, Malaysia where (a) proximity to thrust faults and anticlinal forelimbs and (b) the amount of burial after fold formation are accounted for in terms of changes in pressure, overburden and porosity.
Tectonic setting directly influences the overpressure of a basin. A study of overpressure from wells drilled to depths of 500 to 4500 m MD in the Sacramento Basin, US McPherson and Garven (1999) showed a correlation between areas recently tectonically compressed and those with the highest overpressure. The areas with longest pause since last compression showed the lowest overpressure. Age of compression was identified from Late Cenozoic folding and faulting using volcanic units to constrain the absolute dates. Since few shales are present in the basin and recent burial and temperature-related sources are found to be minimal, the study concluded the main mechanism for overpressure generation is lateral compression.

Accretionary wedges form in compressional settings; here sediments are accreted on to the non-subducting plate at a convergent boundary. Studies completed in such settings have related the overpressure magnitude to the taper angle of the accretionary wedge. The shallower the taper the more likely it will be that it has a very weak basal detachment and this is shown to relate to high overpressures. The taper angle also applies to settings such as the Niger Delta toe-thrust system. Figure 7 shows the result of a study where the shallow angle bathymetric slope and low angle of decollement correlates with high shale overpressure (Bilotti, 2005).

Finally, salt movement induces stress changes at its margins. This has been documented by many authors, e.g. Sanz and Dasari (2010). The impact of these stress changes is suggested in a case study published by Salehi and Mannon (2013) from Mississippi Canyon, Gulf of Mexico. The field studied includes depleted reservoirs and is in close proximity to salt intrusions. Seismic velocities yielded erroneous results in the near-salt proximity environments, such that using Eaton (1975) pore pressure was dramatically under-predicted within 1000 ft of the salt. Wireline velocity was also affected but to a lesser degree.

**Conclusions**

Velocity data can provide a very useful tool for pressure prediction. Wireline or well sonic data offer the advantages of being high resolution but suffer in that they do not provide 2D or 3D coverage. Seismic velocity data provide this but through a remote surface process, heavily reliant on processing – there are a wide range of interpretations possible. If seismic velocities are to be used for pressure prediction, the earlier the survey acquisition and design parameters are set to account for this requirement the better (e.g. cable length, sonar/receiver spacing, etc.). Optimized processing steps are required in settings where bedding is horizontal, and there are no lateral shale pressure changes, less time consuming procedures and processes may be sufficient. In settings where there is complex geology (faults etc.), and where there may be lateral pressure changes, PSDM velocities are needed as a minimum.

However, not all rocks have predictable relationships between pressure and velocity so even if fit-for-purpose seismic velocities are generated for pore pressure and/or sonic data are used, these velocities may still not derive useful pore pressure estimates. It is vital to understand these geological limitations.

**Acknowledgements**

The authors would like to thank Jamaal Hoesni of Petronas for permission to publish redrawn images and also to David...
Mitchell from Afren. We would also like to thank Guy Markham and Patricia Kelly for their proof reading and editing of the paper.

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