Direct hydrocarbon indications from fluid contacts - stop calling them “flatspots”!

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SUMMARY

So called “flatspots” rarely have the appearance of flatness, even at proven gas and oil fields and on seismic data that has been converted to depth using best-practice methods. The appearance of fluid contacts on seismic reflection data is influenced by several controls, most notably, fluid type; burial depth; saturation; and the size of the “flatspot” anomaly compared to the imaging velocity resolution. Many cases of non-flatness are caused by lateral velocity variation in the overburden. Often the structural form of the trap itself is the cause.

Non-flat seismic hydrocarbon contacts are seen at shallow gas hazards in Sakhalin, Russia; at oil fields in the Santos Basin, Brazil; and at “gas on oil” accumulations in the Browse Basin, Australia. So, it appears that non-flat “flatspots” are ubiquitous, suggesting an urgent name change is needed for this form of DHI.

The interpretation of DHIs is aided by a new 2D synthetic modelling method that characterizes the time-depth behaviour of a field or prospect simultaneously with its amplitude response. The software interactively models seismic cross-sections using rock physics or seismic velocities to compute AvO synthetics at significant layer boundaries. Hydrocarbon porefill effects can be modelled using Gassmann fluid substitution to modify the elastic properties within the proposed trap.

DHIs are thus characterized at (1) the top of the trap; (2) the base of the trap (if base sealed); and (3) at the contacts between different fluid types, such as a gas/water contact; oil/water contact; or gas/oil contact. We propose a more representative terminology, referring to DHIs as either top reservoir indicators; base reservoir indicators or contact indicators, thus removing the rarely met implication that “flatspots” ought to appear flat on a depth converted seismic section.

Key words: DHI, flatspot, quantitative interpretation, AvO.

INTRODUCTION

Seismic flatspots have been used to find potential hydrocarbon resources for probably as long as the bright spot method, which had its origins in the Gulf of Mexico (Ostrander, 1984). The earliest published work on dates to the 1970s (Hammond, 1974), but it might be argued that some oil companies had been using similar methods for some time before this. Thus, it is impossible to be sure who can claim credit for recognizing the first valid seismic flatspot anomaly.

Flatspots and event amplitudes are potential indicators of hydrocarbon porefill within porous reservoirs. Like all amplitude-based indications of hydrocarbon, their use comes with a range of pitfalls. Many explorers have mis-interpreted flat events to infer hydrocarbon porefill and drilled dry holes as a result. We refer to these as “false positive” indicators. Conversely, some explorers have ignored or given insufficient credence to flat, or more likely semi-flat, indicators and as a result have missed opportunities to discover hydrocarbons. A better understanding of these indicators should reduce these missed opportunities in the future and allow reappraisal of targets previously passed over and never drilled.

Wise explorers implement processes to try to improve their exploration success rates using seismic amplitude information. For example, they might implement a consistent process to rank different seismic amplitude indications (Nixon, *et al.*, 2018) to reduce the chance of drilling false indicators and to increase the chance of missing “hidden pay”. Having implemented similar schemes within a few oil companies we are big supporters of this strategy, although we feel that a formulaic approach may not fully capture the potential complexity of seismic flatspots.

We seek to understand more about the nature of seismic flatspots across a wide variety of exploration settings. The key to this lies within seismic AvO modelling and it is vital to simultaneously consider amplitude/AvO and traveltime effects, both within the reservoir interval and the overburden. We argue that limitations in resolving seismic velocities during seismic processing regularly cause flatspot indications that are not very flat at all. We propose alternative terminology that might help explorers to make better use of seismic amplitudes overall to improve drilling success rates.

DEPARTURES FROM FLATNESS

25 years of personal experience in hunting for seismic amplitudes to support exploration drilling has resulted in a collection of hits and misses. One of the key learnings is that flatspots often aren't so flat. To build greater confidence in QI studies, it may not help to continue calling them that. Embracing their non-flatness might also result in discoveries that have previously been passed over.

At what point would we consider that a hydrocarbon contact indicator is not flat? Perhaps an error of half a wavelength is the point where one might become concerned that another event might be interfering? This amount of discrepancy would also need to persist for a statistically significant number of traces (e.g., 20) otherwise it might be dismissed as random noise.

It is worth reviewing examples of proven flatspot anomalies to try to understand what circumstances might lead to departures from flatness. Let's start with examples of near perfect flatness (Figure 1) from offshore Indonesia, Brazil, and Nigeria. Typically, we find that these are accompanied by benign overburdens, flat sea floor profiles and low-relief structural containers. Often a glimpse of a flatspot anomaly may only appear within a single layer of limited thickness, such that it is perhaps not possible to properly test whether it would depart from perfect flatness.

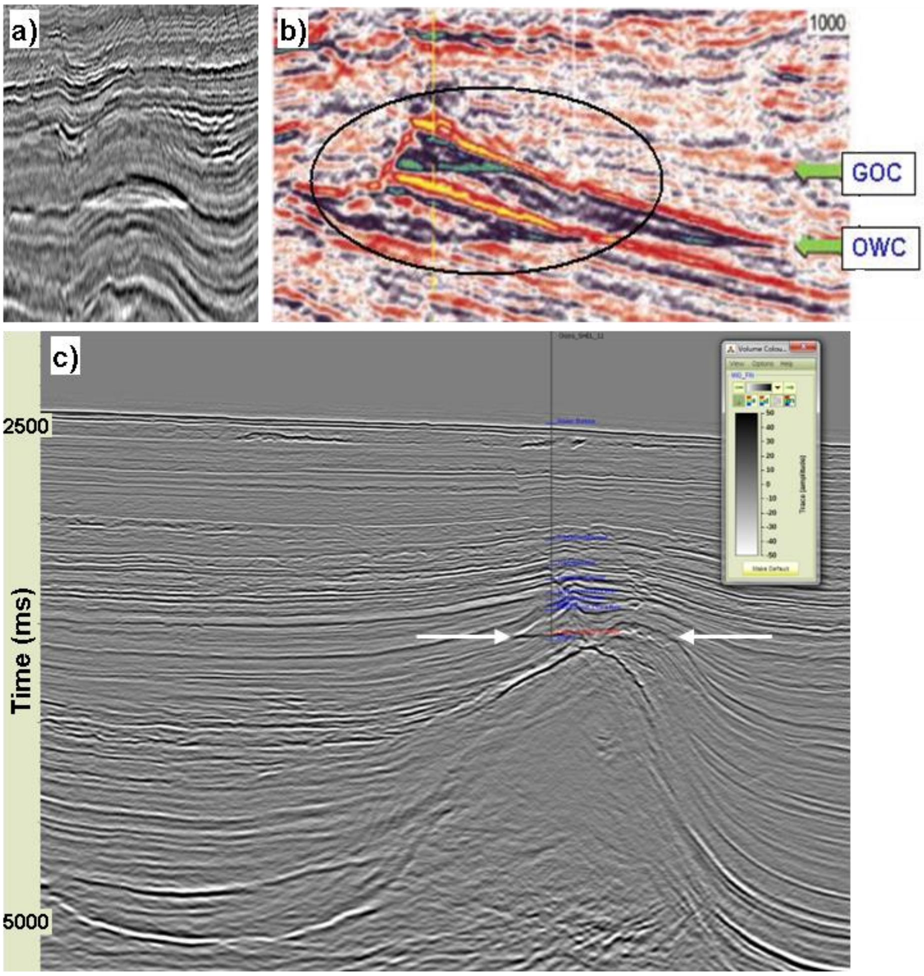

Figure 1. A collection of proven flatspot DHIs that appear almost perfectly flat: a) Timpan-1 gas discovery, Andaman Sea, Indonesia; b) offshore Nigerian gas on oil field; c) Campos Basin, Brazil.

The examples we have collected of imperfect flatness, without being overly quantitative, meet our criteria for imperfect flatness as described above. The examples come from proven oil and gas fields and thus the cause of non-flatness is either known or can be reasonably guessed.

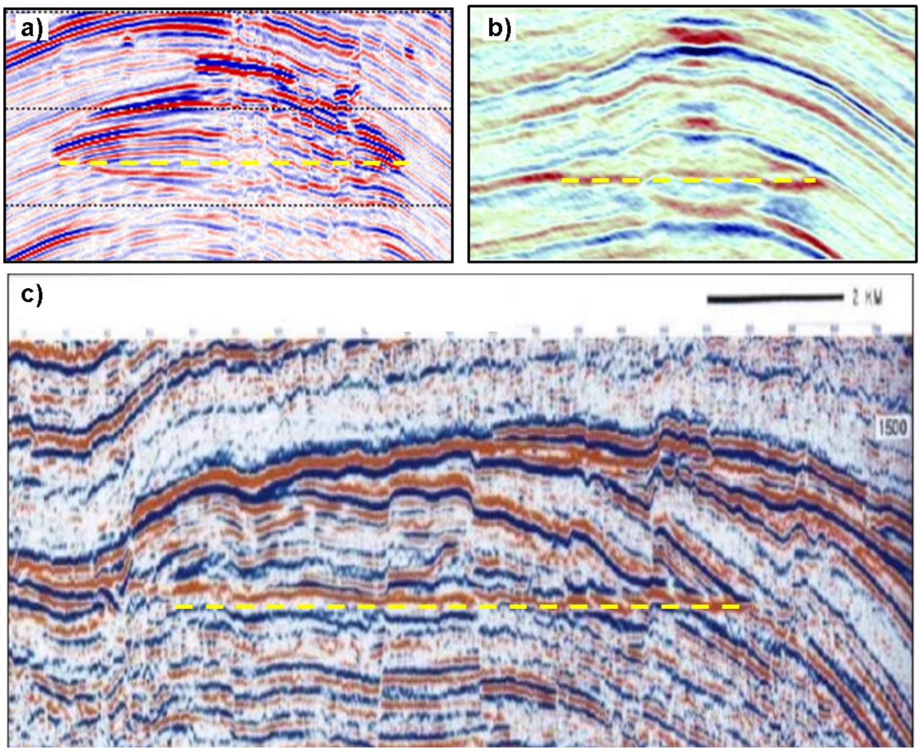

Figure 2. A collection of proven flatspot DHIs that appear imperfectly flat: a) time sag associated with shallow gas Sakhalin, Russia; b) dim spot AvO Mexico; c) gas/oil contact, Troll field, Norway.

Figure 2a shows a shallow anticlinal gas hazard in Sakhalin Russia and the cause of non-flatness is the time sag associated with the slow transit of P-waves through the centre of an anticline (vs the flanks) within an unconsolidated (porous) gas filled sand.

Figure 2b originates from offshore Mexico and is taken from a paper by Brown and Abriel (2014) discussing DHIs in situations where the top event amplitude is a “dim spot”, which places extra emphasis on the correct interpretation of a flatspot anomaly. In their example, interpretation of the gas/water contact appears to be hampered by internal variations in the reservoir quality, evidenced by amplitude variations in the top reservoir amplitude. Time sag effects from hydrocarbons above were also noted, however these only appear to impact the crest and not the contact interpretation.

Figure 2c shows a gas/oil contact indicator over a trap that extends several kilometres encountering subcropping units within the reservoir. These variations occur at a scale that is below the resolution of seismic imaging velocities. The inevitable errors in estimating velocities over limited time intervals results in time to depth conversion errors within the subcropping units which in turn affects depth conversion of the contact indicator. In short, the problem is caused by the practical limit of seismic velocity resolution.

Depth conversion problems are a common factor in each of the 3 non-flat examples shown. In our experience, even when using modern 3D datasets imaged using full-waveform inversion, it can be difficult to accurately depth convert hydrocarbon contact indicators. It is especially difficult to achieve in an exploration setting before the contact depth is known. As a result, candidate flatspot indicators are almost always either assessed in a pseudo-depth domain or in the time domain.

When we think about the velocity models underpinning the examples shown in Figures 1, the simplicity of the overburdens, structures and reservoirs involved means that our “pseudo-depth” domain assessment is close to a true depth assessment and as a result we see flat contact indicators. For the examples in Figure 2, the velocity model needed to get to true depth is beyond our ability to estimate and as such we get strong, but non-flat contact indicators. As a result, we conclude that depth conversion is regularly the primary cause of non-flat contact indicators.

There are other reasons why hydrocarbon contact indicators may not be flat, even in the case where perfect depth conversion is possible. These include hydrodynamic effects (caused by meteoric aquifers); aquifer depletion prior to seismic surveying; semi-permeable reservoir barriers; and reservoir heterogeneity (this list was sourced from: wiki.aapg.org/Fluid_contacts). The latter effect potentially causes lateral changes in hydrocarbon saturation because of capillary effects in reservoirs with spatially variable permeability. The effect on contact indicators would be to observe flat events at different depth levels across a heterolithic reservoir, with deeper indicators noted in better reservoirs and shallower indicators suggesting reservoir facies with lower permeabilities.

Of course, we should never forget that a candidate contact indicator may not appear flat because the seismic event might not be reflecting the presence of hydrocarbon! Potential false indicators include depth-dependent diagenetic effects (i.e., opal A to opal CT transition); residual multiples; volcanic intrusions; channel bases and unconformities.

For the case study examples in Figures 1 and 2 we had enough anecdotal information to interpret the results. However, a more general understanding can be obtained using modelling to look ahead at a wider range of possibilities for obtaining non-flat contact indicators.

HOLISTIC AVO MODELLING

To interpret candidate seismic DHIs we suggest modelling complete profiles over the key components of the prospect, namely the top seal, base seal, reservoir, and pore-fluid changes, covering crestal to flank locations (Figure 3). Generic models can be helpful, but ideally the layer interpretation should be guided by and scaled to the available seismic data.

Better interpretations can be achieved by modelling the depth structure of the prospect simultaneously with its amplitude/AvO response because both elements of the prospect assessment are dependent on the same P-wave velocity information. This point cannot be stressed enough because antiquated methods for performing quantitative interpretation focus on modelling single events (or maps), thereby forcing a match with elastic properties that may not explain adjacent events. In using the term holistic AvO modelling, we refer to both the simultaneous modelling of traveltime and amplitude effects with the goal of explaining the prospect in its entirety.

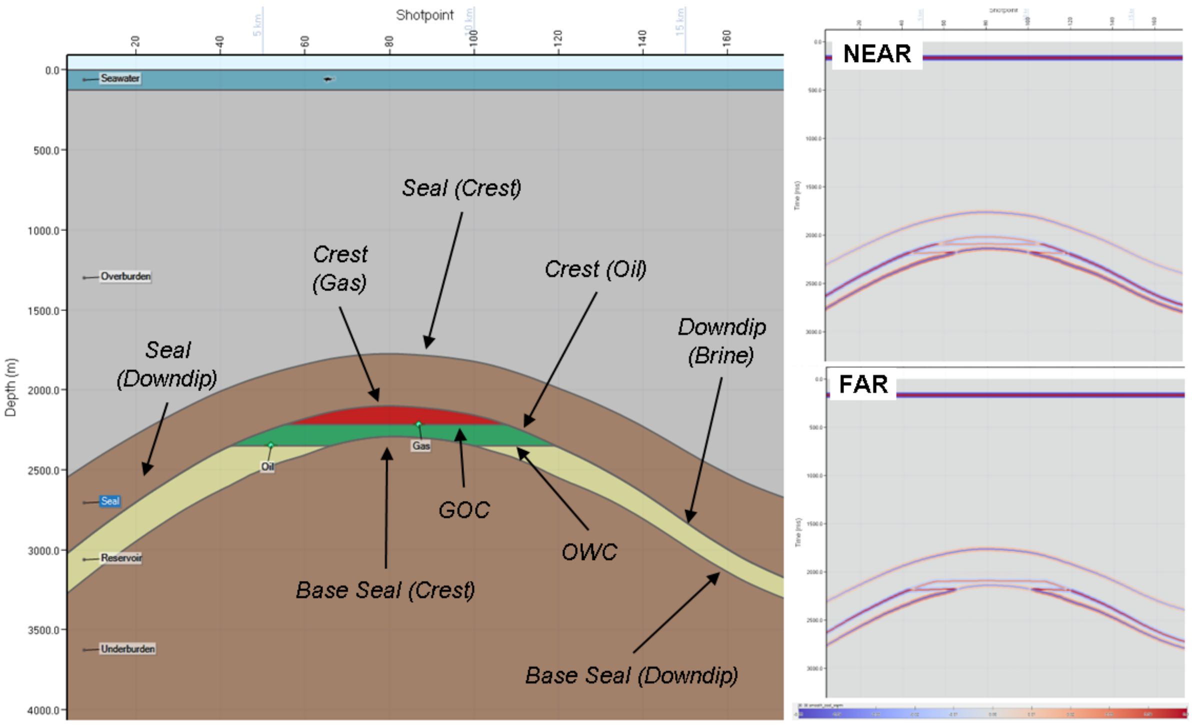

Figure 3. Holistic AvO modelling of hydrocarbon prospects using Quiacito™, where the goal is to explain the observed AvO seismic data at all elements of a prospect.

Data can be used to constrain the modelling wherever it exists, such as seismic velocities; VSP velocity trends; and rock physics models based on well logs. Rock physics models are assigned for the reservoir (in the brine case) and sealing lithologies, optionally including burial effects, such as compaction and diagenesis. Hypothetical hydrocarbon contacts can be added to reservoir layers using Gassmann fluid substitution to change the elastic properties and the resulting AvO synthetics, which are computed at lithologic and fluid boundaries within the proposed trap.

To develop a predictive AvO model, it is essential to match AvO synthetics to a cross-section of AvO seismic data acquired over an exploration prospect. Setting aside issues concerning data quality and the synthetic computation itself, elastic model building must incorporate and parameterize a wide range of subsurface properties including any dependencies between them. Better models are more likely to be made when sequence stratigraphy, reservoir diagenesis, basin modelling, rock physics, and reservoir engineering information inform the assignment of P-wave velocity, S-wave velocity and density within the model and thus drive the modelling of seismic amplitudes (Dunne, 2011).

Throughout this paper we use a new software method (Quiacito™) that models seismic sections interactively and simultaneously in terms of event traveltimes (driven by P-wave velocity) and event amplitudes/AvO (driven by S-wave velocity; density; and the same P-wave velocity). Models can be built interactively in both time and depth domains using seismic to define layer boundaries. Hybrid models can be built using stratigraphic controls to switch between model properties derived from different underlying data sources. The rapidity with which models can be built enables multiple alternative scenarios to be compared against the seismic.

Rock physics models are assigned for different lithologies and then used to link P-wave velocities with S-wave velocities and densities to produce AvO synthetics at layer boundaries. They allow burial effects, such as compaction and diagenesis, to be represented accurately and forge critical links between elastic properties and rock and fluid properties of economic interest, including porosities and formation pressures. Alternative pore fluids can be added to porous layers using Gassmann fluid substitution to modify the elastic properties and resulting AvO synthetics within a proposed trap.

CONTROLS ON FLATSPOT APPEARANCE

A systematic understanding of the nature of flatspot DHIs can be achieved through a series of controlled experiments using AvO modelling that includes both amplitude and traveltime effects on the modelled section. In each example, we examine the results in the time domain, to simulate the common situation whereby seismic velocities are not resolved sufficiently to accurately depth convert the contact indicators.

Effective stress is one of the primary controls on elastic rock properties and in most sedimentary basins it can be correlated directly with burial depth, often referred to as “depth below mudline”. Figure 4 is from the Tarakan Basin (Celebes Sea, Indonesia) which investigates burial depth impacts on the flatspot indicators. As burial increases, the porosity of the sands shown decreases according to a mechanical compaction model. In some basins, typically those with high thermal gradients, extra porosity loss can occur through chemical compaction (diagenesis, for example via quartz cementation), so in such basins we should expect hydrocarbon contact indicators to become weaker and flatter at shallower depths.

Lithology is also a primary control on elastic rock properties. Flatspots within alternative reservoir lithologies can be assessed, for example in the gas case at a common burial depth of 2000m (bml) and holding all other model settings constant. Departures from a default sandstone model, including shale-laminated and carbonate reservoirs, can show measurable effects on the flatness of contact indicators. It is difficult to generalize about the dependency of flatspots on lithology because each case varies depending on details of the model used. For example, the shape of the trap and typical depth dependency of P-wave velocity within the reservoir exert strong controls over the time-domain appearance of the contact indicator, resulting in push-ups, pull-downs or flat behaviour. A more general hypothesis drawn from these experiments is that reductions in porosity and net reservoir tend to control the strength of the contact indicator.

For the case of a sandstone reservoir, Figure 5 shows differences in contact indicator flatness caused by the hydrocarbon type itself, once again assuming that depth conversion is performed on a much larger scale and is unable to correct for the differences in velocity within the closure. A small impact on contact indicator flatness occurs and, as might be expected based on a general knowledge of hydrocarbon fluid properties, this effect is larger for the gas case and smallest for a degassed (dead) oil. The effect of varying hydrocarbon saturation (not shown here) is even smaller, with almost no impact noted in oil or gas cases requiring a reduction to very low saturations (due to the Wood’s mixing effect) before any significant effect can be detected.

The effect of reservoir quality on contacts was discussed earlier as a likely explanation for non-flatness in situations where accurate depth conversion can be performed. Long transition zones of 50m or more above a pressure data-derived free-water level have been predicted from special core analysis for Paleocene oil fields in the Santos Basin, Brazil. Characteristic saturation vs column height functions can be incorporated into the AvO modelling within some software packages, to reveal seismically resolvable variations on the contact anomaly depth.

The ability to create multi-layered synthetic models of oil and gas fields with hydrocarbon contacts that can be readily adjusted has helped to reveal interference as another control on the appearance of “flatspots”. Seismic wavelets derived from nearby seismic-well ties often have significant sidelobe energy and this can result in constructive or destructive interference from bright reflectors. One example of this could be traced to a bright onlapping package, whose pinchout and resultant sidelobe interference was varying laterally near the predicted flatspot to an extent that obscured the true contact anomaly response.

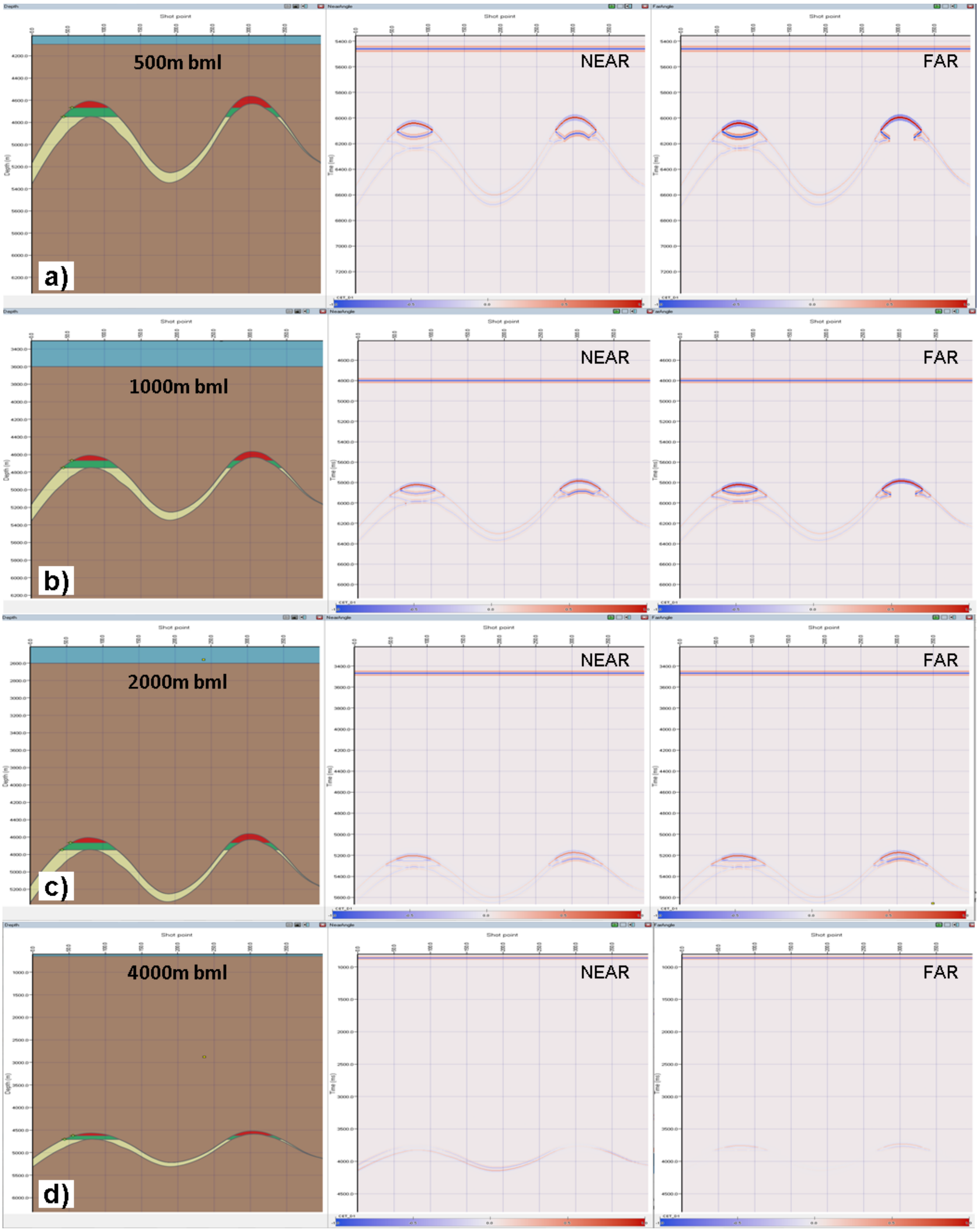

Figure 4. Burial depth controls on AvO event synthetic amplitudes and flatspots modelled using Quiacito™ using a rock physics model appropriate for the Tarakan Basin, Indonesia.

Modelling the entire seismic section, or at least from surface to target level, also helps to reveal other common situations where significant distortion of contact indicators is likely to occur. The following examples are again caused by our general inability to fully resolve velocities for accurate depth conversion, especially in complex structural settings, for example underneath rugose sea floors (canyons, reefs), underneath salt diapirs and below shallow gas hazards. Trap geometry can also play a role, for example, with tilted low velocity mudstones causing localized distortions within the tilted Jurassic unconformity traps of Australia's northwest shelf.

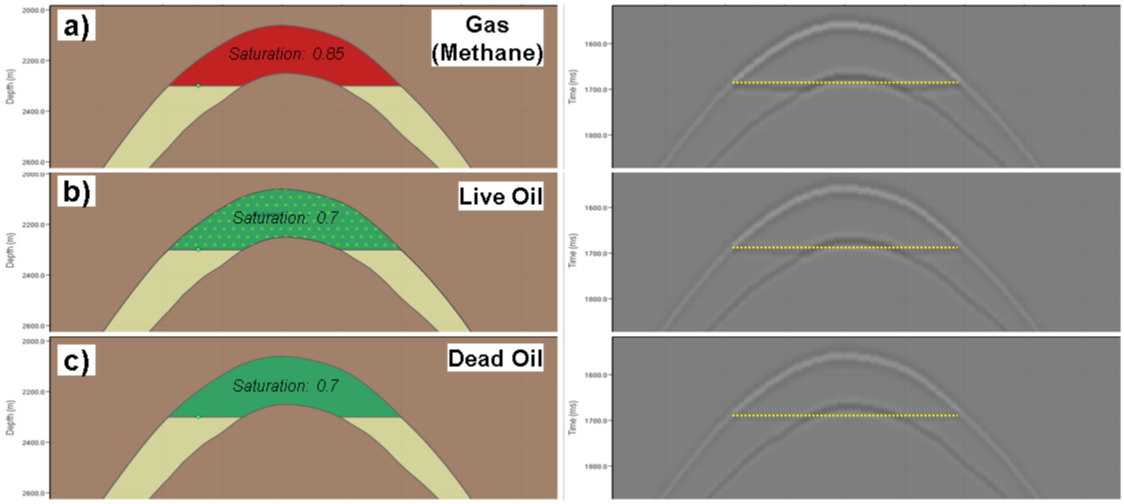

Figure 5. Hydrocarbon fluid type controls on full stack synthetic flatspots modelled using Quiacito™ using a rock physics model appropriate for the Vulcan and Browse Basin, Australia.

Figure 6 shows a case study covering the Gwydion oil field in the Browse basin, where holistic synthetic modelling helped to unravel a complex set of causes of non-flatness at the known hydrocarbon contacts within the field. Firstly, a series of small shallow gas zones created a cumulative time sag beneath the crest of the main field accumulation. Secondly, the shallow target depth and high porosities, including the presence of low velocity glauconitic grains in the upper reservoir, all contribute to a further large sag within the gas filled part of the main reservoir. The oil rim probably contributes a minor additional time sag too. In total the sag from flank to crest is 12ms (approximately double that of our half a wavelength "flatness criterion" of 6ms). None of these effects appear to have been corrected by depth converting using a modern 3D PSDM and this apparently simple, shallow field remains difficult to interpret, even with the aid of sophisticated synthetic models.

DHI VARIABILITY IN DIFFERENT SEDIMENTARY BASINS

Individual modelling results can be insightful, but we also should try to remove any bias in our understanding resulting from a deep focus in a single geographical area. Figure 7 shows a compendium of modelled indicators from different sedimentary basins around the world for a common burial depth. The results are shown in the time domain, once again under an assumption that depth conversion cannot be performed on this scale given practical limits on seismic velocity resolution. This compendium is part of a much larger set of results covering burial depth ranges from 500m to 5000m.

There are many observations that could be made on this comprehensive suite of results, for example, the AvO response of different events, and the strength of the gas and oil events and their contact anomalies. Some of these observations may form the basis of future research papers and so we focus here on observations relating only to hydrocarbon contact anomalies.

With regards to the flatness of the various contact indicators, at 2000m burial (depth below mudline), we note that contact indicators can be flat, but also that they can dip substantially in either direction (in other words, as a pull-up or time sag). This longitudinal study further supports the observations made on data and modelling examples discussed here, again highlighting the need to model each oil and gas prospect individually to determine the degree of seismic amplitude support for hydrocarbons.

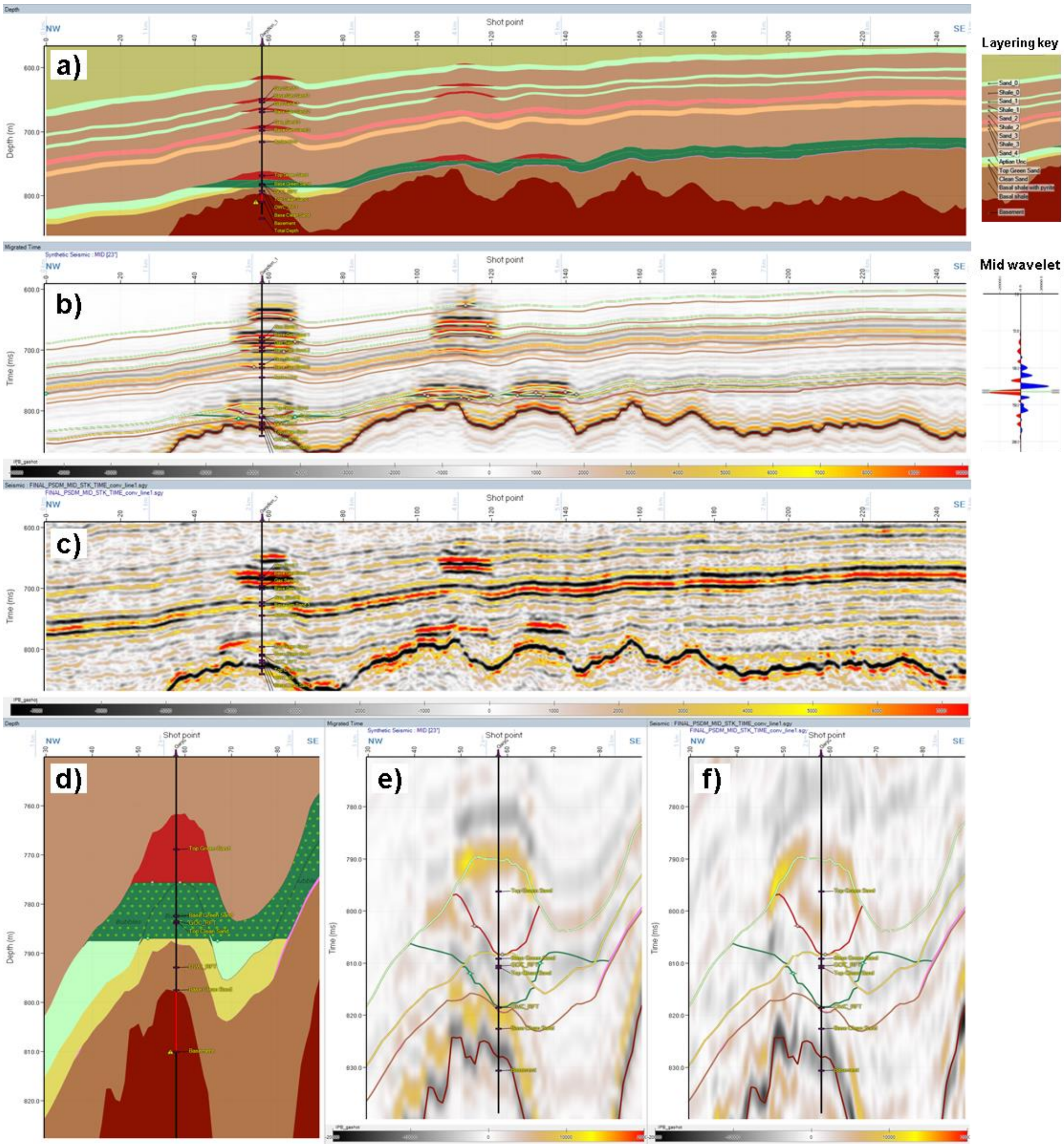

Figure 6. Holistic AvO modelling at the Gwydion oil field, Browse Basin, Australia comprising a) layered stratigraphic model and multiple fluid contacts; b) mid-angle 2D synthetic; c) mid-angle seismic line through the field and adjacent prospects; d) zoom up on model at main target level; e) zoom up on mid-angle synthetic; and f) zoom up on mid-angle seismic. A complex flatspot interpretation results from cumulative delay effects through shallow gas traps and from low velocities within the gas filled part of the greensand reservoir interval.

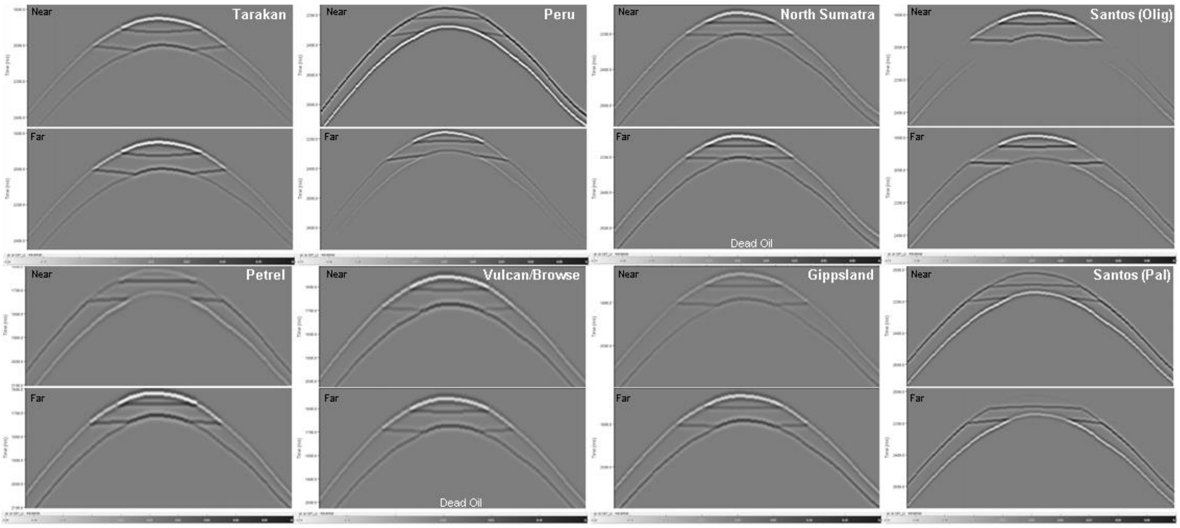

Figure 7. Hydrocarbon AvO event amplitudes and flatspot responses for a gas on oil anticline model using rock and fluid physics models from different basins around the world, shown in this example for a 2000m burial depth.

CONCLUSIONS

Simultaneous modelling of the amplitude/AvO and traveltime of a prospect's hydrocarbon response can help to interpret a wide range of anomaly responses that may exist in sedimentary basins around the world. It remains important to interpret flatspot (and event amplitude) anomalies in the time domain because it is unrealistic to estimate seismic velocities at the resolution needed to achieve full flattening of hydrocarbon contacts. Simplistic, or subjective views, on the quality of contact indictors based only on flatness criteria could leave significant oil and gas fields undiscovered, or dry holes drilled.

The results discussed essentially constitute an anatomy of a seismic DHI. To improve the risking of exploration prospects, candidate DHIs should be assessed at (1) the top of the trap; (2) the base of the trap (if base sealed); and (3) at the contacts between different fluid types, such as a gas/water contact; oil/water contact; or gas/oil contact. We propose a more representative terminology, referring to DHIs as either top reservoir indicators; base reservoir indicators or contact indicators, thus removing the implication that "flatspots" ought to appear flat on depth converted seismic sections. Abandoning this semantic bias and any ensuing dogmatic assessment of "flatspots" could lead to the discovery of oil and gas resources that would have otherwise been overlooked.

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