Improved Time-depth Control Using Development Wells: A Case Study Offshore Malaysia

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Introduction

Understanding the relationship between time and depth i.e. velocity, is a key challenge faced in the exploration, appraisal and development phases in the life cycle of an oil and gas field. Implications of not accurately understanding time-depth are well known, and lead to increased uncertainty in:

- Seismic interpretation (through lack of, or poor quality well data, limiting control between geological markers and seismic events, particularly important in challenging geological settings where seismic is laterally discontinuous)
- Quantitative interpretation (wavelet extraction from well-tie matching techniques, analysis of seismic phase and offset dependant scaling, low frequency modelling for inversion)
- Depth conversion (implications for direct hydrocarbon indicator analysis and volumetrics)
- Well planning (wellbore trajectory, geological prognosis)
- Reservoir modelling and simulation

In heterogeneous media, such as rocks, velocity can change vertically, laterally and azimuthally. Velocity will vary as a function of pore fluid, particularly in the presence of gas. How velocity is derived from data can also have some effect, for example, if anisotropic effects are not correctly accounted for in seismic processing.

Check-shot, vertical seismic profile (VSP), sonic logs and time-depth pair data are typically considered to be the most accurate record of the relationship between time and depth, but this information is rarely collected at more than a handful of wells within the life cycle of an offshore field, with measurements only strictly accurate at the data sampling location. So how can we better understand lateral variation in velocity across a field or a wider area? Seismic velocities offer some potential, but these are only suitable for use if derived through pre-stack migration or as a stacking velocity. Often seismic velocities are too low in resolution or smooth to be useful for modelling of high resolution velocity variation, as they are interpreted solely for imaging purposes.

In building a velocity model it is important to integrate all available data at different resolutions, and ultimately the geological problems faced and data available will determine the model. This study outlines a workflow to increase the availability of high resolution time-depth information in a cost effective manner through use of rock physics modelling and well-to-seismic ties on pre-existing well log data.

Objectives

A case study is shown from an oil and gas field within the Sarawak Basin, Malaysia, with known lateral velocity variations caused through the presence of shallow gas within a stratigraphically and structurally challenging geological environment. The objective of this study is to increase well control at a number of key stratigraphic events to guide and de-risk seismic interpretation. The field is in production phase and contains a number of exploration and development wells. Three exploration wells have a full wireline log suite including measured compressional velocity, shear velocity and density, in addition to (two) measured check-shots. While development wells possess logging while drilling wireline data, limited to measured density, gamma ray, resistivity and neutron porosity. A petrophysical interpretation of mineral volumes, porosity and fluid saturation is available in all wells. The seismic data used in this study was a pre-stack depth migrated full-stack converted back to time through a velocity model. The seismic velocity model was available.
Workflow

A rock physics model is required to understand the relationships between available log data and the elastic properties of rocks. A number of rock physics models were considered, with an inclusion based model being chosen. The model aims to predict the elastic properties of a rock through variation of pore aspect ratio within a homogenous solid defined by mineral volumes and end-member elastic properties. In this case study, the model is based on a relationship between aspect ratio and a combination of neutron porosity and de-trended total porosity, as determined from the exploration wells which have conditioned measured data. Once a relationship is established, aspect ratio is predicted and used to forward model compressional and shear velocity in the development wells, with calibration to the exploration wells which have measured data. A number of iterations may be required to fine tune the model.

Forward modelled velocity data is combined with measured density data and a wavelet extracted using measured data at an exploration well to predict the seismic response. Given that velocity is being modelled ‘blind’ in development wells, if mismatches are observed between the synthetic and seismic, some further refinement of the petrophysical interpretation may be required. Consideration should be given to residual fluid saturations and lithology (for example, variation in shale mineralogy or cemented stringers) which may not be captured in the petrophysical interpretation, but can have a strong impact on velocity. It is not anticipated that check-shot data are available, so the interpreter is faced a number of options on how to form an initial time-depth model for well tie: use of check-shots directly from a neighbouring well, use of an average of regional check-shot, or integration of the modelled compressional sonic log. Direct use of check-shot data is suitable in cases where wells are relatively close to the sampling location, geology does not vary significantly laterally and structure is relatively simple. Where these conditions are not met, it is perhaps more suitable to use a transform of one or more check-shot data sets to smooth out high resolution variation. Integrating sonic data is useful where high resolution velocity changes are observed or expected, but are limited by extent of the logging range, and are not suitable in significantly deviated wells where it would be required to assume that the velocity does not vary laterally in the overburden. Once an initial time-depth relationship is determined, the time-depth relationship is fine-tuned through stretch and squeeze of velocity to provide calibration between the composite synthetic and seismic trace. As the correlation observed is dependent on quality of both the modelled log response and seismic data, it is expected that correlations should be comparable to those achieved at wells where measured data are available.

Results and Discussion

De-trended measured and modelled velocity logs show strong correlation, with coefficients of 0.824 and 0.898 achieved for compressional and shear velocity respectively. Well-to-seismic ties give correlation coefficients typically in the range of 0.7-0.75, comparable to those achieved at exploration wells using measured sonic data. A seismic section is shown through the field against which two exploration and two development wells have been tied (Figure 1), highlighting the additional well control achieved through this exercise. An interpolation of average velocity derived from well-to-seismic ties at the reservoir level (Figure 2a) shows significant lateral variation in average velocity, interpreted to be related to presence of shallow gas over the field (see Figure 1). Given that measured check-shot data are available at only three wells within the field, the increase in lateral resolution that can be achieved through this workflow is well demonstrated.
Figure 1 Seismic section showing tie of exploration (E1 and E2) and development (D1 and D2) wells to seismic section, showing increased well control between stratigraphic markers, black arrow shows event relating to shallow gas sand.

Figure 2 a) Map of average velocity interpolated (kriging, with no structural context) between well locations at reservoir level, showing lateral variation in velocity related to presence of shallow gas over field. b) Seismic average velocity (pre-stack depth migrated) extracted at same event shows analogous spatial trends. Well symbol is shown at bottom hole locations, and are coloured by well type (exploration-black, development-green).

The outlined workflow is not intended as a substitution for a thorough rock physics analysis, and it is advised that this workflow is only applied following such a study. Modelled outputs should only be considered as dependable as the input log data and the petrophysical interpretation. Where calibration data are not corrected for anisotropy or invasion, for example (as relevant to the case study), these errors will be carried forward in modelling. Where using an inclusion based model, it is vital that logs used to forward model aspect ratio and mineral volumes from the petrophysical interpretation are consistent between all wells.

While this case study utilises deviated development wells with minimal log data, it is anticipated the workflow is equally applicable to vintage wells without measured or reliable compressional velocity, shear velocity or density data, which would typically be considered non-ideal for inclusion within a
rock physics or velocity modelling study. The assumption is made that the elastic behavior of rocks is understood prior to the workflow being applied, so typical criteria of data quality for a rock physics study are not as strict.

In performing alteration of the initial time-depth relationship to fine-tune the well tie, it is important to ensure that changes made to velocity are geologically justifiable. While performing loop to loop event matching is not defendable, a stretch applied to the synthetic to compensate for velocity dispersion effects between log and seismic frequencies may be. As with any geophysical process, thorough quality control is paramount to ensure a valid and consistent story is delivered across a field or region, which can be explained in terms of geological and geophysical observations. It is suggested that following application of this workflow, an interpreter make a comparison of average velocity between all wells, use arbitrary lines to ensure the consistency of well markers in time (Figure 1), and integrate any other sources of velocity information available, such as seismic velocity (Figure 2b).

It is important to consider that a strong correlation between synthetic and seismic trace should not be taken alone as proof that an accurate understanding of the time-depth relationship has been achieved. Where the elastic response of the rocks is not correctly predicted, or an incorrect wavelet phase is assumed, it is quite easy to achieve a well-tie with strong correlation coefficient which would include an undesired shift in the time-depth relationship.

The use of an inclusion based rock physics modelling is not essential, and a number of alternate methodologies were considered prior to modelling. An inclusion model is useful as it allows for compressional and shear velocity to be forward modelled in consistent manner, as determined by physical properties estimated from direct measurements of the rock. The model has been applied successfully a number of times in studies throughout the Sarawak Basin, Malaysia, to overcome difficulties in capturing the elastic response of heteroliths through other techniques. However, it is recommended that multiple approaches based are considered to account for the geological setting and the strengths and weaknesses of the data set in question.

Conclusions

The workflow outlined provides the potential to increase an interpreters understanding of lateral time-depth variations in a cost effective manner through use of pre-existing well log data, which will becoming increasingly important as the cost of drilling and seismic profiling continue to increase. Gaining increased high resolution time-depth information through use of rock physics modelling and well-to-seismic ties has shown potential for increasing well control in seismic interpretation and to potentially improve the understanding of the location of fluid contacts.

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