Application of PSDM Imaging for Reservoir Characterisation in the Northern Malay Basin: A Case Study

Abstract

Seismic imaging in the northern Malay Basin frequently suffers due to the limitations imposed on Kirchoff Time Migration by the complexities of structure, lithology, stratigraphy and fluid effects that occur in the area (Reilly et al., 2008 and Gosh et al., 2010). A recent Pre-Stack Depth Migration (PSDM) project not only enhanced the reservoir imaging, it enabled the production of amplitude preserved volumes that were used to improve reservoir characterisation studies for gas pay prediction.

Reservoir characterisation studies within 4 producing gas fields of the northern Malay Basin have successfully used offset stacks and seismic inversion products Acoustic Impedance (AI) and Poisson’s Ratio (PR) to target gas pay sands for development drilling. These sands display a weak type III AVO response. One field contains less of the type III AVO sand facies and displays lower seismic contrast; in an effort to improve reservoir prediction, the multi linear analysis EMERGE process was applied to generate target logs Volume of Sand, Porosity, Gas Saturation and Pay Flag. Although more successful in identifying pay sands, data quality issues hampered results. Shallow gas effects such as amplitude absorption and time distortion of underlying reflectors, in addition to fault shadow effects negatively impacted the pre stack and post stack data and the derivative inversion and EMERGE data. Although not a complex structural or velocity environment, PSDM processing was applied to 2 of the gas fields with the greatest data quality issues and generated improved pre and post stack data. The EMERGE process was re-run and delivered improved target attribute cubes. Simultaneously an inversion trial was run to test potential uplift in PSDM derived AI and PR data. The PSDM derived AI was of slightly better quality than the original while the PR was clearly superior; the data quality uplift is attributed predominantly to the improved PSDM pre stack data input. Acoustic Impedance and to a lesser extent PR form significant inputs to the EMERGE multi-attribute process and full re-inversion of the PSDM data is under consideration to use in future characterisation studies.

Introduction

Pre Stack Depth Migration (PSDM) processing is often associated with imaging in complex geological areas that contain large lateral or vertical velocity variations such as sub-salt and carbonate build ups (Bevc et al., 2005). In this case study we examine the application of PSDM in a relatively benign velocity environment - a continuous vertically stacked clastic section. An uplift in data quality was observed in both the pre- and post-stack domains with a subsequent improvement in seismic inversion and multi-attribute data that were used in reservoir characterisation studies. Two separate reservoir studies were carried out in parallel, a multi-linear analysis to generate petrophysical volumes and a pre-stack inversion trial over the development areas. This paper reviews geological and geophysical background and challenges associated with reservoir characterisation. The benefits from PSDM processing are discussed together with qualitative interpretation improvements.
Background

Carigali Hess Operates four gas fields in the northern Malay Basin within Block A-18 of the Malaysia Thailand Joint Development Area (MTJDA): Bulan, Cakerawala, Suriya and Bumi (Figure 1). Gas pay in these fields occurs within multiple stacked sandstone reservoirs that range in depth from less than 4000 feet to over 10,000 feet subsea. The fields are currently being developed and host a total of 37 appraisal and 75 development wells, with gas delivered 50% to Thailand and Malaysia from 6 well head platforms at a contract rate of 790 MMscfd to year 2029 (source: MTJA website www.mtja.org).

The reservoir interval consists of a vertical succession of over 6000 feet of Pliocene to Early Miocene clay rich sediments deposited in an upper delta plain to shallow marine environment (Carney et al. 2008). Reservoir sands were deposited in fluvial to tidal estuarine and shallow marine settings with the best quality sands occurring in tidal distributary channels (Barr et al. in prep. this conference). Within the deeper intervals fluvial influence increases and the channel sands are frequently interbedded with tidal to overbank muds and thin coals. Across the succession the depositional setting fluctuated between fluvial and tidal to shallow marine, with coals more common in the deeper reservoir zones. The trapping style of the four gas fields consists of these predominantly shallow marine reservoirs draped laterally across low relief horst blocks, tilted fault blocks and four-way-dip closures.

The gas fields are covered by a 3D seismic survey acquired in 2005 and processed to Pre Stack Time Migration (PSTM) stage. Water depth is very constant across the area at approximately 180 feet. Seismic attributes from this survey have been used to successfully identify and target gas pay sands; shallower gas reservoirs display weak type III AVO anomalies, while deeper reservoirs generally display type I AVO anomalies. Reservoir characterisation studies typically used offset stacks and seismic inversion data to identify gas sands. In areas of lower seismic contrast these data were supplemented with multi-attribute data generated using the multi-linear analysis “EMERGE” process.

Seismic imaging is impacted by shallow gas above 1000 feet subsea, coals, carbonaceous rich layers and gas filled reservoirs: shallow gas generates two-way-time (TWT) delay and amplitude distortions in underlying reflectors, while coal and carbonaceous layers dominate the reflectivity (Figure 2a). A number of north-south trending faults are present in the area and prominent fault shadow effects are observed.

The data quality degradation mentioned poses problems for interpretation and resource estimation. To reduce these imaging artifacts and produce amplitude-preserved seismic data, PSDM processing was applied to two fields within the study area in 2009.

Data Quality - Shallow Gas and Fault Shadow

Seismic data quality within the area is characterised as ‘good’ except where shallow gas is present in the near sub-surface. Energy attenuation and low velocity effects associated with the gas cause amplitude dimming and TWT delay or ‘sags’ of up to 30 milliseconds within the underlying data (Figure 3). The gas is reservoired in fine grained non-calcareous sandstones of non-uniform thickness that ranges up to 150 feet and is observed on seismic data as high amplitude reflectors. Wireline logs have been run over this interval at well C where poor quality logs infer a single reservoir interval with up to 30% porosity and 25% gas saturation. Occasional discrete top and base gas boundaries are observed on seismic with the most prominent amplitude distortions and travel-time delays occurring beneath the thickest intervals. Where reflectors are composite or incomplete, shallow gas distribution was further determined by the Background Amplitude - defined for this case study as the RMS amplitude over a 1 second window relative to a prominent seismic marker: target horizon A at approximately 1.2 seconds. Areas of low background amplitude lie beneath zones of thicker shallow gas and correlate well with the gas isopach. An indication of the magnitude of the travel-time delay is provided by wells B and C drilled approximately 2.3 km apart: both wells penetrate primary target A at the same depth yet have a 27 millisecond TWT difference.

A series of north-south trending faults subdivide the survey into the 4 major field areas. Most of the faults dip at approximately 45 degrees and extend from deep in the section to the seafloor. Within a vertically aligned triangular zone beneath these faults from about 800 milliseconds, the seismic reflectors become discontinuous and display localised swales and folds inconsistent with reflectors elsewhere. This is interpreted as an artifact within the data and has been targeted by the PSDM processing.
Velocity Profile

The vertical velocity profile across the area follows a compaction trend consistent with the continuous sediment deposition. Structural relief is low and time-velocity functions, as defined by Vertical Seismic Profiles (VSP’s), display a very consistent trend – offset only by the magnitude of the shallow-gas time sag (Figure 3). The velocity over the shallow gas is low while the presence of an overpressure zone between 6000 feet subsea and 10,000 feet subsea also adds low velocity character to the trend. On a semi-regional scale, however, when compared with traditional PSDM environments, the lateral and vertical velocity variation within the Northern Malay Basin is low and could be considered benign.

PSDM Processing

PSDM processing was principally run to improve image quality around faults and compensate for amplitude absorption and TWT delay caused by shallow gas. The inability to regionally map the top and base of the shallow gas and scarcity of shallow well data meant velocity modeling was difficult to constrain with available data. A velocity model derived using the PSTM stacking velocities as input and grid-based tomography on a 300m by 300m grid was used in the depth migration to correctly position reflectors. The tomography was constrained using fault planes to compensate for fault shadow effect. The restriction of velocity model updates specifically to the fault plane zone using the method described by Birdus (2006), allows the building of velocity models with the very high resolution needed in those zones where tomography alone is not sufficient. Anisotropy parameters to be used during migration were derived from VSP data to ensure the correct positioning of reflectors in the depth domain at well locations.

Surface Consistent Amplitude Correction combined with an Amplitude Tomography technique was used to compensate for the amplitude distortion effects. Amplitude tomography, as described by Xin et al. (2009), accounts for ray path trajectories through shallow gas and with the use of scalars, compensates for seismic energy absorption effects. This process is very effective for medium to large wave length shallow gas anomalies, as it compensates for amplitude loss and restores AVO response.

Reservoir Characterisation

Seismic attributes have routinely been used within the four gas fields to successfully identify and target gas pay sands for appraisal and development drilling; shallower gas reservoirs display a type III AVO response, while deeper reservoirs generally display a type I AVO response. Rock properties vary with depth and in the shallow section good quality gas sands are acoustically soft compared to the surrounding shales, typically displaying low density and medium P-wave velocity for a combined low acoustic impedance log response. In addition, the Vp/Vs or Poisson’s Ratio is low, consistent with the type III AVO response observed on pre-stack data.

Seismic inversion was applied to the PSTM data in 2006 to assist reservoir characterisation studies and derived Acoustic Impedance (AI) and Poisson’s Ratio (PR). In addition a dual attribute analysis was performed that combined both low AI and low PR. The identification of gas pay sands proved most successful within the shallower reservoirs using offset stacks and the AI data. Coals and carbonaceous shales, however, also have relatively low acoustic impedance and can mimic gas pay sands adding ambiguity to the interpretation. The dual attribute cube that combined both low AI with low PR defined the best quality reservoirs. Of the three output inversion datasets, the AI cube was the most stable as it is equivalent to a Normal Incidence response. The PR cube was less stable than acoustic impedance as it relates to the magnitude of the AVO effect and is thus subject to noise that is inherent in the seismic gather. It proved however to be a useful lithological discriminator, as coals and carbonaceous shales have high Poison’s Ratio.

In the most eastern field the proportion of lower quality reservoir increases and seismic contrast of the shallow gas sands is reduced: AI and PR based reservoir characterisation proved less successful. In an effort to improve reservoir and pay prediction, the inversion data was supplemented with multi-attribute data generated using a multi-linear analysis process.

Multi-linear Analysis Process EMERGE

The multi-linear approach, termed EMERGE by D. Hampson et al. in 2001, aims to correlate seismic attributes to well log data. The process is divided into 3 main steps: (1) Determination of appropriate attributes by examination of target logs and seismic data at wells; (2) Derivation of the relationship between the target log and the attribute
set using multi-linear regression or Neural Networks; (3) Application of the derived relationship to create a 3D SEGY volume of the desired petrophysical attribute.

An EMERGE project was first performed in 2008 with the objective of improving gas sand prediction rates by mapping shallow target reservoirs directly from petrophysical attributes such as Volume of Sand (VSand), Porosity (Phie), Gas Saturation (Sg) and Net Pay Probability (NPP). NPP is a neural network derived approximation of the petrophysically defined Pay Flag. Predicted petrophysical trends observed within the output datasets are consistent with well results and the Pay Probability cube, in particular, was useful in confirming drilling candidates. Although prediction rates improved, poor data areas remained a challenge as zones of shallow gas are commonly located above the fields being developed. For one of the fields a prominent east-west depression was proven to be false by the drill bit, while in the other, zones of gas pay were represented by areas of dim amplitude where high amplitude was expected. Following PSDM processing it was decided to re-run EMERGE to benefit from the imaging and amplitude improvement.

In the first EMERGE study, different generations of Vshale logs were normalised for slightly different amplitude distributions. In the 2010 study, the petrophysics for the anomalous logs was re-run to ensure consistent petrophysical and elastic curves for all wells. The consistency of trends and log responses is mandatory to obtain good results not only for EMERGE but also for any quantitative interpretation process. Inconsistency in well logs can lead to instability of the derived relationship and poor prediction with large errors.

The input seismic data was a combination of the 2009 PSDM full-stack, angle stacks, derived AVO attributes, and results from the Pre-Stack Inversion of the 2006 PSTM data. The use of a 2010 PSDM inversion as input would have been optimum, but due to operational constraints these data had not been generated at this time. Several combinations of seismic attributes were tested to derive the optimum relationship to predict target logs. The prediction was performed in the following order: VSand, Phie, Sg and NPP. The order of prediction is important as predicted VSand volume formed one of the input cubes for the Phie prediction.

Pre-Stack Inversion Trial

In parallel with the EMERGE re-run, a pre-stack inversion trial was carried out on 3 sub-areas of the 3D survey using the proprietary 3D algorithm described by Reiser et al. (2005), and Coulon et al. (2006). Input data consisted of well data and five angle stacks generated from the final PSDM gathers. The pre-stack inversion is model based with the initial model consisting of a stratigraphic grid framework populated with low frequency trends of Vp, Vs and Density derived from well data. Detail is added to the model through co-located co-kriging of the well data and seismic data. Building the initial model is an iterative process requiring interpretive input to validate the elastic property trends. During the inversion, the initial model is iteratively perturbed and using an optimization scheme, known as simulated annealing, the algorithm simultaneously optimizes the match between all the input angle stacks and the corresponding computed synthetics angle stacks. The synthetic stacks are calculated by convolving full Zoeppritz reflectivity equations with the corresponding angle stack wavelet.

Conditioning of input stacks is a key aspect of all pre-stack inversion studies; seismic data was carefully checked to ensure optimum normal move out correction (NMO) and a consistent AVO response with well data. Independent wavelets were derived for each corresponding angle stack and were used to invert the selected areas. Results were validated by direct comparison with well data.

Review and comparison of results

PSDM processing improved the reflector continuity beneath the areas of shallow gas and reduced the fault shadow effect with the most positive benefits observed deeper in the section (Figures 2a and 2b). Faults are crisper at all levels, with greater detail present in the areas of fault interplay. Some slight loss of frequency content at the shallower level is offset by the improved data quality, while the depth version of the dataset eliminates the structural sags seen in the time mapping and more closely honours the well data. Event continuity in the shallow and deep section is vastly improved and can be quantified by simple auto-tracking comparison with the earlier data. Some localised residual velocity anomalies, and thus depth distortions, remain in the data in areas where the shallow gas thickness varies rapidly.

The initial EMERGE project confirmed the location of the best quality pay sands and completed the objective of expanding reservoir prediction into areas of lower quality pay. There were, however, some questionable results outside known field limits and in areas of the poorest PSTM data quality. The re-run of the EMERGE process using the PSDM data as input shows further improvement in shallow reservoir delineation (figure 4). The output
datasets better match field limits while geological trends are more clearly imaged. An analysis of input attributes to the EMERGE process shows that Pre-stack inversion data has a dominant role in the petrophysical attribute cube prediction. This is interpreted to be a consequence of inversion data more closely mimicking the petrophysical target logs. Deeper reservoirs interbedded with coals remain a challenge and inversion results are questionable. The similarity of rock properties between coal and gas sands (such as acoustic impedance), changing reservoir properties with depth, in addition to lower resolution of the seismic, results in these sands being poorly discriminated. To improve reservoir delineation, targeted investigation windows centered on each main reservoir interval could be tested.

A comparison of pre-stack inversion results from the PSTM and PSDM seismic data shows similarities in the output AI volumes even though different algorithms and initial models were used. The main differences, however, are observed in the PR volumes, with the 2010 trial showing a better estimate of the low PR intervals observed at the wells. In addition the 2010 PR volume is consistent with the 2010 EMERGE Pay Probability result, with both outputs acting as indicators of the presence of gas pay. This is attributed to the input PSDM gathers producing angle stacks that more closely honour the AVO behaviour predicted by well data. Close examination of the 2006 inversion results show that low PR values are present but the property range is strongly under estimated due to the poor AVO response on PSTM gathers. Any future study is expected to be preceded by inversion of the full PSDM data.

**Conclusions**

PSDM processing within the study area of the northern Malay Basin has delivered improved pre-stack and post-stack seismic data, having a positive impact on reflector continuity and amplitude distribution. Fault shadow effects are reduced and amplitude preservation in the pre and post stack domain is improved.

Shallower reservoirs within the study area display a weak type III AVO response and seismic inversion products Acoustic Impedance (AI) and Poisson’s Ratio (PR) are useful in identifying gas pay sands for drilling. A dual attribute combining low AI and low PR highlights the best quality reservoirs. The multi-linear analysis process EMERGE combines multiple attributes to produce petrophysical cubes Volume of Sand, Gas Saturation, Effective Porosity and Pay Flag. The Pay Flag cube delineates more of the poorer quality reservoirs than the single or dual attributes. Re-running the EMERGE process delivered improved petrophysical output cubes with the improvement in attribute generation attributed to the input data – globally re-processed log data re-run in 2010 and the PSDM angle stacks and AVO attributes.

Reservoir characterisation of deeper reservoir intervals using the inversion and multi attribute data was questionable due to the interference effects of coal and carbonaceous shales and the variation in rock properties with depth. The use of shorter targeted intervals may address these effects.

EMERGE results for the shallow reservoirs showed a dependency on the pre stack inversion attributes as the seismic inversion data closely correlates the elastic log response. Improving the inversion result will likely have the added benefit of improving the quality of reservoir properties predicted by multi-linear analysis. The seismic inversion trial indicates PSDM will produce improved products relative to the PSTM. Future reservoir characterisation studies will most likely be preceded by inversion of the 2010 PSDM data.

A general improvement in the delineation of pay intervals was demonstrated by the PSDM dataset compared to previous pay delineation attempts made from the PSTM data.

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Figure 1: Location Map (MTJA web site)

Figure 2a: 2006 PSTM Random Line

Figure 2b: 2010 PSDM Random Line
Figure 3: Time sag map

Figure 4: Multi-Variate analysis Comparison
Figure 5: Poisson Ratio Random line