Application of Critical Technologies Enabling Low Cost Development of Thin-Bedded Heterogeneous Gas Reservoirs in the North Malay Basin


In addition to technical challenges, critical to unlocking these volumes is the economical optimisation of the cluster development, within a consistent portfolio management framework. This is done by using modelling at various levels: 3D modelling at field level, testing different geological concepts and the associated key uncertainties; those are then scaled up into an integrated surface-subsurface nodal network model to optimise the development of the discoveries as well as the near field potential remaining prospects.

Introduction

CS Mutiara Petroleum is a Petronas Carigali – Shell Malaysia joint operating company formed in 2001, operating since then the PM301 and PM302 exploration PSCs. The company has enjoyed so far a 100% exploration success rate in the North Malay basin, with a total of eight discoveries, six of which in PM301, and is now rapidly transitioning into a development venture.

Block PM301 and PM302 are located in the Northern-most part of the Peninsular Malaysia acreage, just south of the Malaysia-Thailand joint development area (MTJDA) as shown on Figure 1.

Geologically the acreage covered by PM301 may be divided into three zones; the Basin Centre, Hinge Line and Platform/Southwest Flank areas (Figure 2). Distinct plays exists within each area and a total of fifteen exploration/appraisal wells have been drilled by various operators; mostly in the Basin Centre where the core of the PM301 development sits, one in the Hinge Line and two on the Platform area, testing all three play areas. CSMP has drilled to date eight wells in PM301, discovering and appraising six discoveries: B.Melati, B.Kamelia, B.Angerrik, B. Zetung, Bumi South, and B.Kesumba.

The block PM302 is located in the northeastern portion of the Malay Basin. Geologically the block may be divided into two zones; the Basin Centre and Northeast Flank areas (Figure 2). Distinct structural trapping styles exists within each area and a total of eight exploration/appraisal wells have been drilled; four wells in the Basin Centre and four wells on the Northeast Flank, two of which are CSMP discoveries. All wells in PM302 have encountered hydrocarbons, mostly gas...
accumulations that remain economically challenging to develop.

Since CSMP started out its exploration activities, a total of eight discoveries have been made within blocks PM301 and PM302. It is believed that a cluster development is the most effective way of maximising value for CSMP shareholders. The discoveries would be developed in a phased manner, PM301 first and then PM302, most likely sharing common processing and evacuation facilities towards a host platform. Synergies with other ongoing developments by neighbouring operators are key opportunities to increase value through lowering costs.

Whilst PM302 discoveries tend to be from relatively deeper sands (down to 3000m tvdss), all PM301 discoveries are relatively shallow sands (1000-1200m tvdss) sharing a common depositional environment of tidal estuarine to shallow marine. All exhibit stacked, thinly laminated pay intervals, organised in four main stratigraphies (B sands, Base B, D2A and D2B) each being of variable thickness, from a few meters up to 25m. The key uncertainties remain similar for all discoveries, with a varying level of severity; these are in order of importance: volumes in place, stratigraphic connectivity and production profile risks such as water encroachment.

These common set of challenges call for an integrated approach to reservoir characterisation, risk management and development strategy. Specific technologies and tools are selected and applied to reduce the uncertainties and their impact on the economics of the venture. This paper will highlight the experiences of CSMP with technologies and tools such as low-resistivity pay evaluation, geophysical modelling, subsurface & development scenario as well as portfolio management tools.

Key challenges for the venture

Complex geology at the heart of the subsurface uncertainties

The uncertainty on volumes in place and intra-field reservoir connectivity uncertainty appears to be controlled by the depositional environments. The age of the sequence of interest spans from a lower Pliocene (B and Base B sands) to uppermost Miocene (D2 sands), and is set within a tidally influenced coastal to shallow marine depositional setting. Within this setting, a number of environments are present: large-scale tidal flats and bars (10+km), cut out by meandering channel systems, as well as for the deeper sequences (D2B) a generally more marked shallow marine influence. Biostratigraphy data indicates for most stratigraphic levels, across the fields, an assemblage of these environments can be present. High heterogeneity is a key feature of the sands, with lithofacies ranging from massive relatively clean channel sands to laminated and highly laminated tidal bars and tidal flats. Bed thicknesses within these environments range from millimeter to centimeter in range with decimeter thick sand deposits being much less common. Bioturbation within this environment is common in both the sand as well as the shale sequences, and is believed to have an impact on vertical permeability. Examples of some of these features are included in the figures.

Two key subsurface uncertainties characterise the development risks and the cluster economics

Two key uncertainties are dominating the risk assessment of the cluster economics: the volume in place, and the lateral reservoir connectivity.

The uncertainty in volume in place is now mainly a consequence of the net pay distribution uncertainty, whilst the lateral extent of the reservoirs and the petrophysical parameters such as saturation and porosity are of secondary order.

At an earlier exploration stage, reservoir delineation (area) and saturation were having a larger impact on the overall volume in place uncertainty as depicted on the Tornado plot for stage 1. Figure 6. Low-resistivity petrophysical evaluation (shown on stage2) and the validation of the geophysical techniques (shown stage3) from exploration success have reduced considerably the uncertainty range for saturation and areal extent. Going forward, much of the geophysical and geological modeling work is geared towards reducing the key remaining uncertainty of net pay distribution (stage4, Figure 6).

The lateral reservoir connectivity is mainly believed to be controlled stratigraphically, and a function of the distribution of the different reservoir facies. In addition, the limited thickness of the reservoir layers may render the field vulnerable to potential sub-seismic faulting. The risk associated to this uncertainty is likely to be a combination of cost increase (as more wells are required to drain the field), and/or lower ultimate recovery.

The current strategy to limit the impact of these uncertainties on the development plan economics is as follows:

- To push reservoir characterization with geophysical technologies to the limit, complemented with a focus on improving the geological understanding.
- To manage the risks through a phased approach to the development, allowing learning and optimisation of the cluster development.

Deploying critical technologies

Key to the exploration success: advanced geophysical techniques

Fundamental to success of the exploration campaign to date with a total of eight discoveries made in CSMP’s acreage, was the application of a number of geophysical techniques to image potential reservoirs by predicting the presence of gas sands. The thinly-bedded nature of the reservoirs, as well as their variable vertical distribution in stacked thin intervals
(mostly in the 5-15m range) increased the challenge for the exploration team.

These reservoirs often exhibit heterolithic (sand-silt-shale) interbedding with vertical heterogeneity manifesting as stacks of thicker and thinner beds. Gross rock properties and ultimate seismic response for these mixed units is a function of their net-to-gross or combined sand and interbedded shale rock and fluid properties. Gas filled reservoirs typically manifest as slightly soft (negative) to soft impedance reflections. There are a number of challenges in imaging the target reservoirs:

- The increasing shale ratio tends to reduce the overall impedance contrast and dampen AVO responses. Highly laminated reservoirs are therefore more difficult to image,
- The presence of thin coals at the Base B level – one of the key reservoirs, manifests itself with high amplitude anomalies, strong impedance responses, and therefore need to be segregated out to allow gas sand imaging.
- Finally, reservoir thicknesses vary from 1-2 to 25 meters and can commonly occur in thicknesses close to or less than wavelet detectability (4-5 meters).

Under various combinations of the above circumstances, reservoir identification, characterization, and quantification – particularly net pay and reservoir quality prediction from seismic is challenging. Yet, despite these imaging complexities, identifiable signatures for laminated gas sands can be cautiously extracted using selected techniques from the data while living with the inherent uncertainties.

The exploration strategy focused on identification and high grading of prospects using traditional AVO techniques as well as more sophisticated ones such as simultaneous inversion and lithology probability classifications prepared by a third party contractor. All these efforts were geared towards increasing the likelihood of finding multiple gas sands: essentially a reservoir sweet-spot identification to increase exploration POS (Probability Of Success).

Whilst conventional AVO techniques provided insight on gas sand distribution within the basin, some features such as coal at certain levels, notably at Base B level, required cross-plottings of the product of simultaneous inversion of Acoustic Impedance (AI) and Poisson Ratio (PR), to effectively isolate the coal response from the seismic signal (Figure 4). When this technique is used, the coal effect can be removed from the seismic and allow mapping of the field reservoir extent (Figure 5).

As the project transitions to development planning and reservoir modelling, the evaluation procedures now include inversion updates using new well control and refinements to lithology classifications, as well as calibrated seismic facies volumes derived from multi-attributes (Figure 7). Whilst this technique is currently being trialed and may require potential iterations, the early results suggest that it can be used to further improve the understanding of the reservoirs, and form relevant input into the field development planning activities (3D modelling, well planning etc). To this purpose, it is important to develop an understanding of the uncertainty associated with the various seismic classification schemes (sand vs shale, facies) so that these can be integrated within the typical uncertainty workflow and scenario modelling.

Capitalising on selected industry available geophysical technologies has been a key enabler to a successful exploration and appraisal drilling campaign. Going forward it will remain an important tool to help reduce the range and impact of the two main uncertainties:

- The volume in place in these discoveries, by improving the prediction of net pay from seismic attributes, which is now a key focus for geophysics studies
- The field-scale connectivity at production scale through a better understanding of lateral facies distribution. Early production data from the first phase of the cluster development will be calibrated to the seismic attributes and should improve confidence in the seismic derived facies distribution maps.

A consistent, value-based data acquisition programme through the exploration and appraisal phase

Based on the evaluation of earlier wells drilled within the acreage, and the understanding that low-resistivity pay evaluation was fundamental to unlocking potential volumes in PM301 acreage, the exploration team designed a comprehensive data acquisition programme for the campaign, with the following philosophy outlined:

- Maximise low-cost data-collection such as wireline logs (low cost, high potential value)
- Embrace new technologies and use multiple tools to improve reservoir characterisation through cross-calibration of techniques
- Build a comprehensive portfolio of data: core, logs, production tests in a cost-effective manner, applying a portfolio approach to data-acquisition
- As much as possible, strive for consistency of tools, whilst building a close working relationship with contractors and service providers

This philosophy remained unchanged through the exploration and appraisal phase, yielding a good quality dataset with eight wells. In particular, the following logs were acquired in the majority of the wells:

- While drilling: MWD (resistivity, GR)
- Wireline: check-shots, sidewall core samples, high-resolution resistivity, density neutron, formation imaging (FMI)
- Probe MDT for massive sands, dual-packer in more laminated sands

In addition, in a selected number of wells, core was acquired (two conventional cores and one mechanical sidewall core), as well as nuclear magnetic resonance log (NMR) in one well to calibrate the assessment of connate water saturation and permeability with other high-resolution tools.
Transient well test data was acquired in a number of wells, complementing a rigorous formation testing programme, though probe MDT, but also dual-packer formation testing, targeted specifically at the more highly laminated pay zones encountered in the D2A reservoir. Dual-packer MDT allows to successfully test and collect sample from not only lower grade reservoirs, but also eliminates the risk of the probe being unluckily placed on a shale streak within a productive laminated system. The deployment of dual-packer formation testing has been key to proving up reservoir quality in lower grade stratigraphies, and provides an excellent calibration to thin-bed log evaluation (see next section).

**Advanced thin-bed, low resistivity modelling is key to reservoir characterisation and volumes assessment**

The type and quality of the log data allowed to perform a high resolution thin-bed analysis, underpinning the bulk of the efforts to effectively characterise the laminated pay intervals that form a large part of the reservoirs encountered in the PM301 discoveries.

This thin bed analysis technique uses the high resolution thin bed facies model derived from the image based sand count (The facies are: sand, silt, shale, wet sand, and tight sand.). After assigning log response parameters for each facies, it uses 1D convolution filters to match thin bed modeled log curves to their corresponding measured responses. An example of the resulting thin bed petrophysical model is shown in Figure 9. The display contains the logs and the evaluations at standard resolution and at the resolution of the borehole image. The bed facies column, the NMR T2 distribution and the borehole image are also displayed. Over this thin-bedded interval, fine sand laminations (yellow) are identified by the borehole image within a predominantly silty matrix (green). The porosity, gas saturation and permeability are enhanced by the image-based model, and the pay count is clearly defined. These logs are then used as input for formation evaluation to yield enhanced resolution volumetrics, including porosity, water saturation and permeability.

The thin bed analysis can be compared to both the borehole image log and the core photograph, as a quality control step – this is shown on Figure 10. In addition, core sand counting is carried out to give a more quantitative assessment of the match between high-resolution log and core data, and possibly refine the analysis.

Compared to conventional wireline evaluation (with a low resistivity cutoff), the typical effect of thin-bed analysis is restoring gas saturations to a more realistic (higher) level, whilst providing a better (generally lower) net-to-gross assessment, and a minor porosity correction. In most cases, the hydrocarbon column remains unchanged through the process, but occasionally increases, depending on the conventional wireline cutoff applied and the severity of the lamination. It is important to cross-check thin-bed analysis with formation testing derived mobility data and/or NMR type logs to ensure that the pay zones contain movable hydrocarbons. Another important QC area is ensuring that saturations derived through the thin bed are generally in line with the prediction of saturation height-functions obtained from special core analysis.

**Portfolio and risk management: a scenario approach**

Whilst reservoir characterisation technologies can help reduce subsurface uncertainties, first-hand development experience and production data from proximal local analogues is a very useful calibration and therefore tool for successful decision making. This is particularly relevant with marginal developments, where the subsurface risks can easily bring the economics below a minimum threshold.

With a portfolio of discoveries, there is the opportunity to phase the development, and, since they share similar subsurface uncertainties, to learn from one field or group of fields to the next. Investment decisions can therefore be staged in order to ensure learnings are incorporated in successive development plans, and risks mitigated accordingly.

**Portfolio ranking: assessment of key uncertainties and field phasing**

Given the generally wide areal field extent of each of the PM301 and PM302 discoveries, the assumed average drainage radius based on analogue information, and the additional high-confidence near-field potential accumulations that can be tied back, a large number of wellhead platforms (7-10 for PM301) is required to capture the entire resource base.

A set of reference assumptions is established for each field notional development plan (number and type of wells & platforms, tie-back configuration). Then each field is assessed against the main uncertainties: volume in place, connectivity and water encroachment, so that their respective field development risk profile can be generated. This step is essentially an ANOVA (analysis of variance) exercise, which can be plotted as a typical Tornado chart. To rank the portfolio, a metric needs to be selected: unit development cost (EUR/Capex) was found to provide a simple means of capturing economic attractiveness since it combines both revenues (EUR) and costs (Capex).

The fields can then be ranked using various criteria (e.g reference unit cost, low case unit cost, recoverable volumes etc) so that a reference phasing or order of priority is eventually chosen for the development of the fields.

**Generating cluster development scenarios using an outcome/decision tree**

Building on the field ranking, a simplified subsurface scenario tree was built to capture the possible range of subsurface outcomes, for each field or group of fields, mapped against development phases. The outcome tree can simulate either a phased development with decision making based on the outcome of the precedent phase economics (using UDC as an economics proxy), or at the other extreme an all-in cluster development without any phasing of the investment decision-making (all risks are borne at project sanction).
The basic building blocks of the tree are (Figure 11):

- Groups of fields arranged in three separate phases – the nature of each phase varies based on the outcome of precedent phases
- For each phase and subsurface scenario a computed GIIP and predicted UR & Capex corresponding to the combination of subsurface uncertainties levels. Those are responses in Experimental Design terminology, and they are approximated from the variance analysis (ANOVA), assuming a multiplicative effect of the various parameters.
- A set of two UDC criteria for each phase a “success” and “stop-loss” UDC that control the decision of going to the next phase: either continue as plan, accelerate the development or exit (stop/cut losses), as per shown on Figure 8.
- An assignment of likelihood for each case within the tree, based on the uncertainty level (each level is assigned a probability), as well as a conditional logic between the outcomes: e.g: it is assumed that there is a conditional link between the outcome of one phase and the next. We assume that similar uncertainties occur in all fields, and therefore, for example, if a low case volumetric occurs on the first phase of developments, there is an increased chance of a lower volume outcome on the next group of developed fields.

The tree is shown on Figure 12.

The basic principle of the tree is to simulate a series of decisions based on the outcome of previous phases. By varying the UDC threshold criteria, a variable level of risk-taking can be simulated, and the range of outcomes for the entire portfolio can be calculated and displayed as a cumulative probability function of the three responses: Capex, UR, UDC. The Figure 13 shows the comparison between a reference, high and low risk profile: with a higher risk acceptance, more volumes are delivered (the UR at P90, P50 increase) but more outcomes carry a high cost and therefore high UDC.

The tree is used to support the optimisation of the cluster development – technically but also commercially, as the simulation of the range of outcomes through the tree helps understanding the upside as well as downsides at portfolio level, associated with a chosen risk profile. Representative deterministic cases can be extracted from the tree (for instance, a representative P90 case) and can be simulated through an integrated production forecasting tool. As required, 3D static and dynamic modelling help refine the assumptions on uncertainties ranges and hence the input into the integrated model.

With a range of deterministic cases simulated, the phasing of the various developments as well as optimum gas sales rate and tenure commitments can be better understood across the range of possible outcomes determined by the tree.

Conclusions

Selecting and applying a set of critical technologies throughout the exploration, appraisal and onto development phase has been and will remain fundamental in realising potential from the shallow Pleiocene-Miocene North Malay basin play. In particular, geophysical and high-resolution log evaluation technologies have proven key to improve reservoir characterisation of the challenging PM301 discoveries. Going forward, scenario modelling, at both field level (geological 3D modelling) and portfolio level (with an integrated forecasting tool) is becoming key to optimise the overall cluster development plan.

With technology at the heart of the venture, CSMP intends to continue nurturing an open-minded, outward-looking and decision-focused environment. Drawing from the respective strengths of its shareholders, CSMP is actively working at turning a highly successful exploration campaign into a viable, cost-effective development of its discoveries.

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Figures

Figure 1: Malay basin play area

![Malay basin play area](image1)

Figure 2: Petroleum system in the PM301-PM302 area

![Petroleum system](image2)
Figure 3: Discoveries to date by CSMP

Figure 4: AI vs PR cross-plot (exploration well Bunga Zetung-1)
Figure 5: Full Stack amplitude (left) vs AVO (Far-Near) amplitude (right)

Figure 6: Volume in place uncertainty Tornado (ANOVA) for Base B reservoir at different stages of the project
Figure 7: Calibrated seismic facies

20 Gray-Blue: Laminated Wet Sand
30 Dark Blue: Blocky Wet Sand
40 Brown: Ratty Gas Sand
50 Yellow: Laminated Gas Sand
60 Green: Blocky Gas Sand
70 White: Channel

Figure 8: Phasing based on reacting to previous phase outcome

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<tr>
<th>Phase 1</th>
<th>Phase 2</th>
<th>Phase 3</th>
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<td>FID</td>
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<td>FID</td>
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PM301 Scenario Tree
- Build in development phasing learning time
- Assume dependencies in subsurface outcomes (similar uncertainties)
Figure 9: Sharp analysis log panel

Figure 10: High-resolution log matched to core
Figure 11: Basic building blocks of the scenario tree

Key uncertainties at ADP level can be combined (27 realisations)
All combination possible for first phase

Based on actual UDC results of the first (n-th) phase, a strategy is decided going forward to next phase:
- **Exit:** No further investment, cut losses since un-mitigable Low case
- **Reference:** pursue as planned
- **Accelerate:** take additional risks since High case materialised

**Stop-Loss UDC** is defined as unacceptable returns (VIR=0 at screening Gas Price)

**Next phase:** assume links between subsurface outcomes (better / same / worse)

Figure 12: Scenario tree, conditional relationships and discreet scenario selection

Tables with uncertainty outcomes (L,M,H) for given development phase

Conditional logic built-in with uncertainties: relationship between outcomes of phases

Discreet scenario

Simulated responses for portfolio: Capex, UR, UDC
Figure 13: Comparison of outcome PDF for reference (phased) high risk (left) and low risk (right)
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