

Integrated reservoir fluid characterization in thinly laminated formations – A case study from deepwater Sabah

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Abstract: Reservoir properties such as fluid compositions, formation pressures, and fluid contacts are critical in the early phase of the well life and represent the key inputs for comprehensive production and reservoir engineering studies in the development phase. Accurate measurements and evaluations of reservoir fluid properties tend to become more complex in challenging drilling environments, coupled with complicated reservoir facies such as the thinly laminated formations. To reduce the uncertainty in the estimations of hydrocarbon in place and fluid contacts in clastic reservoirs, it is paramount to integrate various measurements such as core data, log analysis, image logs, pressure data, and fluid sampling results for a holistic and meaningful evaluation approach. Several methods are available nowadays for reservoir fluid characterization but each method has its own limitations and advantages. However, technical advancement achieved in individual technology alone may not necessarily provide a complete solution for the formation fluid evaluation task. To reduce this uncertainty and to improve reservoir fluid evaluations, an integrated approach that combined various methods such as Advanced Mud Gas Logging (AMG), wireline Downhole Fluid Analysis (DFA) and PVT laboratory analysis is developed, based on a case study of an exploration well from deepwater Sabah. The integrated approach and workflow that combined these independent measurement methods proved to be the key to the success for formation fluid characterization. This paper is focused on how the integration of various methodologies can complement each other through the following strategies: assessment of reservoir fluid properties, starting from the early stages of open hole measurements, can be complemented by measurements obtained from AMG logging and wireline DFA and sampling. The AMG provides an early approach to reservoir fluid identification through its capability to generate a continuous fluid facies logged across the entire drilling interval. This study presents a successful case evaluation conducted for two drilling sections of the investigated exploration well. It demonstrates the strategies used for accurate fluid characterization assessments in a challenging deepwater environment, which is beneficial as a comparison for the subsurface assessment of other discoveries made in similar depositional setting.

Keywords: deepwater Sabah, fluid characterizations, petrophysics, thin laminations, wireline logs

INTRODUCTION AND GEOLOGICAL SETTING

The early quantitative assessment of fluid compositions and sampling optimization of potential pay zones can help in making timely decisions during the exploration or development phases. This approach aids in reducing data acquisition risk, and optimizes operation time spent by correctly evaluating zones of interest during the appraisal phase. At a later stage, the fluid compositions and PVT information can provide important inputs for petrophysical analysis to more precisely evaluate the reservoir properties and volume of hydrocarbons present in the reservoirs. This can reduce geological uncertainties at an early stage of the field development (e.g. Ko *et al.*, 2014), which is critical for the development and production of high-cost deepwater discoveries such as those found in offshore Sabah turbidity channel-fan systems (Jong *et al.*, 2016). Based on the fluid samples and wireline data acquired in the reservoir sections of an exploration well located in deepwater Sabah area, this paper discusses the integration of the fluid properties that can be used for formation petrophysical evaluation to reduce the uncertainties of these reservoir properties for a better estimation of hydrocarbon in place and fluid contacts in thinly laminated formations.

The Sabah fold-thrust belt, where the investigated exploration well “B-1” is located, is one of the most actively explored areas in Malaysia, with significant oil and gas discoveries proving a world-class working petroleum system. This area is located in the Sabah outboard deepwater area within a compressional tectonic regime (Figure 1). Structures are formed as elongated toe-thrust features, trending NE-SW (Mohd Asraf Khamis *et al.*, 2017 & 2018).

Multiple Miocene turbidite depositional events have been documented in this area, which are named Keabangan, Kinarut, Kamunsu and Pink Fans; ranging from stratigraphically older to younger sections (Figure 2). These turbidite fans represent key regional reservoirs for deepwater Sabah exploration. Thick hemipelagic mudstones and mass transport complexes (MTCs) are often interlayered with these reservoirs and act as both regional and field-scale intraformational seals (Algar *et al.*, 2011). “B-1” found hydrocarbons in sand/shale sequences of alternating deepwater MTCs and turbidite deposits trapped in the toe-thrust structural four-way closure. The well confirmed oil accumulations in multiple reservoirs including the Kamunsu and Kinarut sands with oil samples taken from the reservoirs and mud-gas samples acquired at regular intervals throughout the well bore. In addition, a comprehensive wireline log suite was also acquired across the oil-bearing intervals.

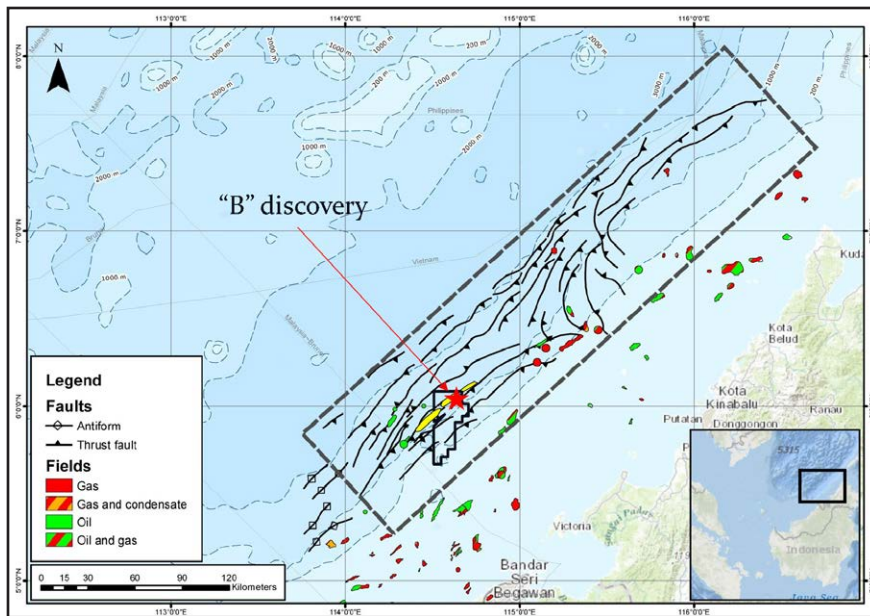


Figure 1: Location map of the study area offshore deepwater Sabah, where a discovery was made by the “B-1” exploration well within “Block X”, operated by JX Nippon as enclosed in the dark line polygon (from Ogawa & Jong, 2016).

PRINCIPLES AND INTEGRATION OF ANALYTICAL TECHNIQUES

Advanced Mud Gas logging (AMG)

AMG provides continuous measurement of the fluid facies and fluid composition, while drilling, of the hydrocarbons extracted at surface from the drilling mud. The AMG logging technology provides gas chromatographic data in the C_1 - C_5 range and analysis of longer chain hydrocarbons (C_6 - C_8 including light aromatics and methylcyclohexane; Ivan *et al.*, 2015). The AMG acquisition system consists of a heating extractor at both the flow line and in the active pit, a non-condensing transportation line and a high-resolution Gas Chromatograph-Mass Spectrometer (GCMS) analyser (Figure 3). The setup and the main components of the AMG has been widely discussed by Ivan *et al.* (2015).

Downhole Fluid Analysis (DFA) measurement

DFA is a process to identify the fluid types and perform fluid property measurements at downhole conditions using Wireline Formation Tester (WFT) fluid analyzer modules at a particular depth of interest, by withdrawing the formation fluid into the WFT flowline. The DFA technique is based largely on optical spectroscopy and mechanical oscillator measurements. The advanced downhole fluid analyzer module - InSitu Fluid Analyzer (IFA) is used, and it is a key element of this integration study discussed in this paper. The IFA real-time DFA system integrates downhole quantitative fluid property measurements to deliver a comprehensive characterization of reservoir fluids at reservoir conditions. The IFA is used to measure the hydrocarbon properties and compositions at downhole conditions (Figure 4), and provides data on absorption spectrometers: C_1 , C_2 , C_3 - C_5 , C_6 , and CO_2 composition in %wt., downhole fluorescence detection, resistivity of reservoir water, *in situ* fluid density and viscosity, flow line pressure and temperature, gas oil ratio (GOR), pH of formation water and estimation of filtrate contamination (Schlumberger, 2017).

DFA prediction - the Yen-Mullins model

Asphaltene science has evolved over the past decade especially in the oil and gas industry (Mullins *et al.*, 2007). The Yen-Mullins model provides a solid base for understanding the asphaltene dispersion in crude oil. Figure 5 shows that asphaltene can be dispersed in crude oil in three forms (Julian *et al.*, 2011); molecules with an average diameter of about 1.5 nm, nanoaggregates (has 6 molecules) with an average diameter of 2 nm, and clusters of nanoaggregates (with 5 nm diameter).

Flory-Huggins-Zuo (FHZ) has developed the Equation of State (EOS), which is based on Mullins model of asphaltene science and DFA measurements. The FHZ, the first predictive asphaltene EOS is used to estimate asphaltene concentration and help predict reservoir connectivity (Hani *et al.*, 2013; Julian *et al.*, 2013a & b). Julian *et al.* (2013a & b) stated that this technique has been successfully used to estimate reservoir connectivity, which is subsequently proven by production data.

The modified Yen-Mullins model can be used to understand the distribution of asphaltenes in the reservoir (Oliver *et al.*, 2010), as it provides clear guidelines when each structure is to be expected (based on the molecular and colloidal sizes) (Figure 5). Gravitational segregation tends to drive heavy asphaltenes down in an oil column whereas light hydrocarbons tend to rise in the column (Figure 6; Julian *et al.*, 2011).

Julian *et al.* (2010) proposed a new thermodynamic approach of EOS plus solubility model to calculate variations of asphaltene with depth in reservoir fluid columns. This approach can be used in combination with a new DFA technology to address the issues on reservoir connectivity. The fluid asphaltene EOS (Figure 7) for oil is based on sample contamination and asphaltene size, and by using the InSitu Pro (ISP) software, in many cases we can address the issues on reservoir connectivity. ISP software can predict colour optical density (OD) versus true vertical depth (TVD) for

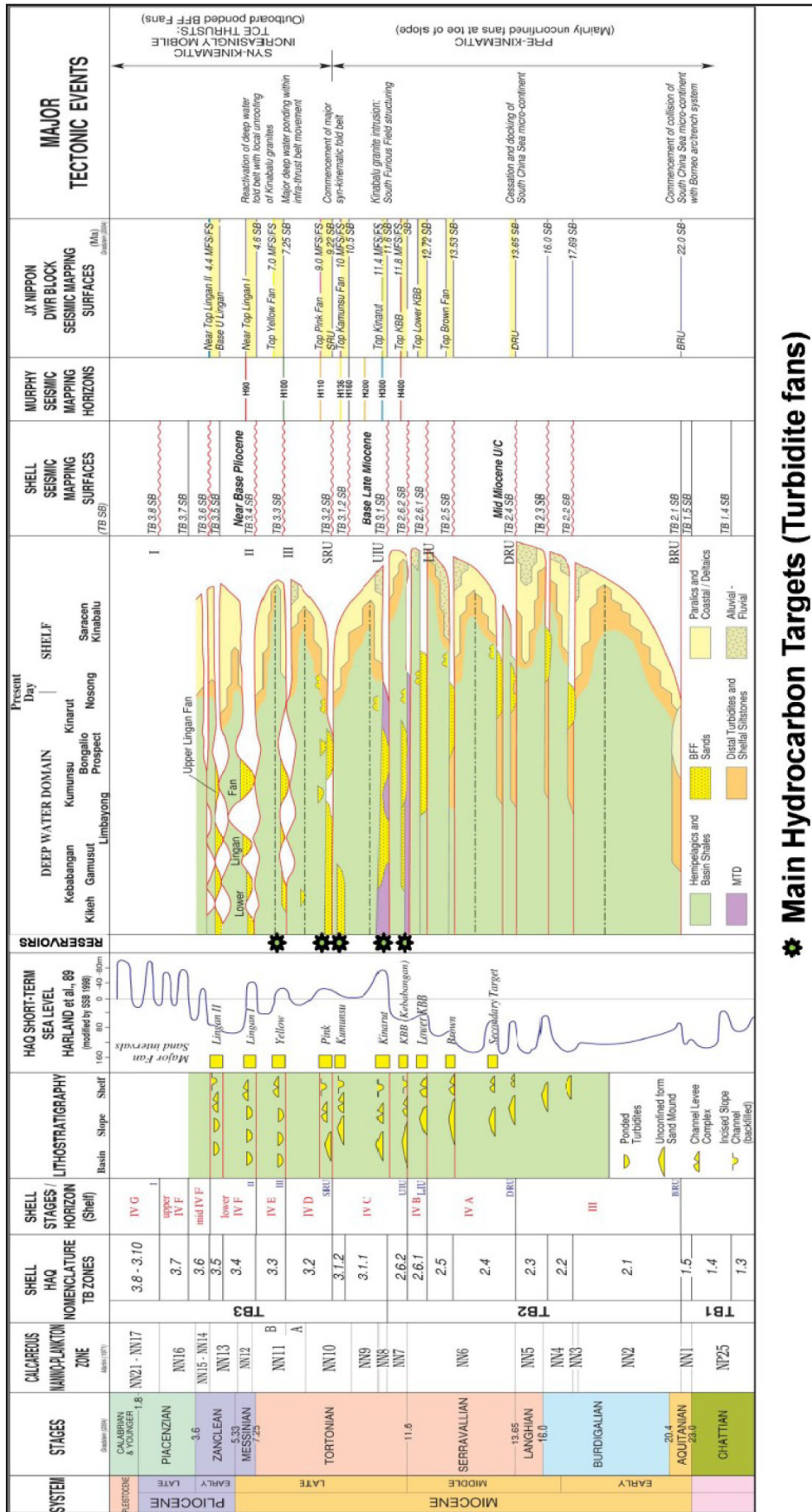


Figure 2: Sabah "Block X" chronostratigraphic scheme (from Jong et al., 2014).

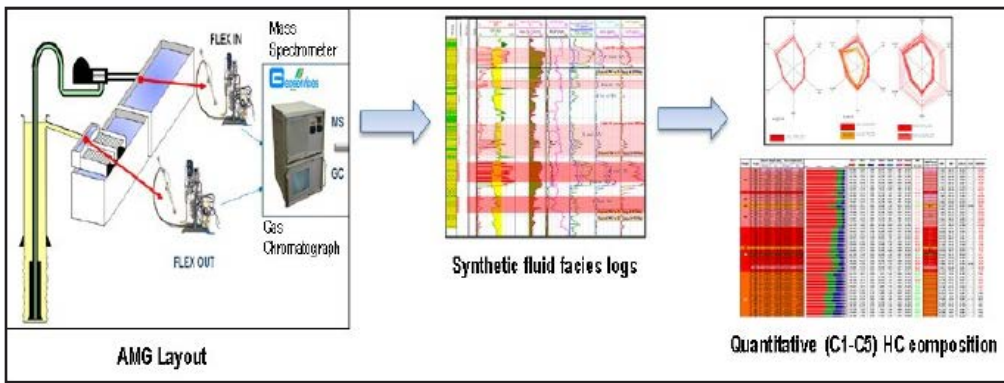


Figure 3: AMG layout and measurements output (from Ko *et al.*, 2014). The AMG acquisition system consists of a heating extractor at both the flow line, flex-in, flex-out, and a high-resolution Gas Chromatograph-Mass Spectrometer (GCMS) analyzer.

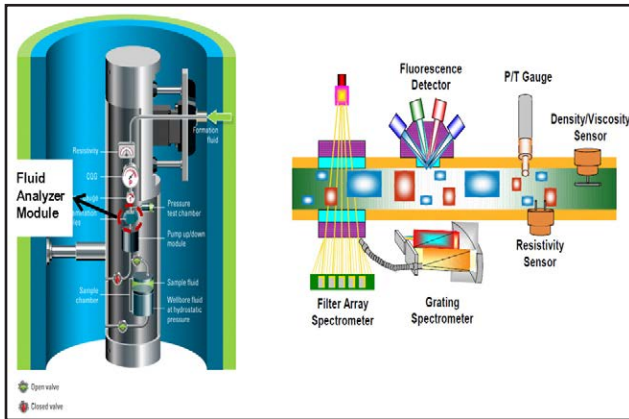


Figure 4: InSitu Fluid Analyzer (IFA) sensors. The IFA is used to measure the hydrocarbon properties and compositions at downhole conditions, and provides data on absorption spectrometers: C₁, C₂, C₃-C₅, C₆₊, and CO₂ composition in %wt., downhole fluorescence detection, fluid resistivity, in situ fluid density and viscosity, flow line pressure and temperature, gas oil ratio (GOR), pH of formation water and estimation of filtrate contamination.

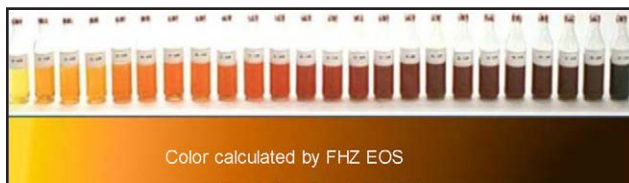


Figure 6: The colour variation of 24 dead oil bottle samples is caused by the asphaltene gradient and the corresponding asphaltene content variations (from Julian *et al.*, 2011).

an oil column at fluid equilibrium. DFA colour prediction consists of predicting the colour of the fluid in the reservoir based on DFA measurements of fluid using OD channels.

All the required parameters of the FHZ EOS as summarised in Figure 7 are available from DFA, except for the asphaltene size (molar volume, v_a). The asphaltene size is assumed from one of the three asphaltene forms (Figure 5), and compared to the DFA measured colour gradient (Figure 8).

METHODOLOGY

AMG-DFA integration process

Early Integration of the AMG and DFA is the key for a more efficient formation evaluation approach. The integration

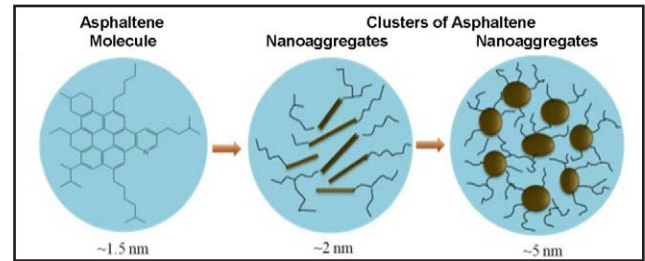


Figure 5: The Yen-Mullins model (from Julian *et al.*, 2011). The model provides a solid base for understanding the asphaltene dispersion in crude oil. The figure shows that asphaltene can be dispersed in crude oil in three forms; molecules with an average diameter of about 1.5 nm, nanoaggregates (has 6 molecules) with an average diameter of 2 nm, and clusters of nanoaggregates (with 5 nm diameter).

$$\left(\frac{OD(h_2)}{OD(h_1)} = \frac{\phi_a(h_2)}{\phi_a(h_1)} \right) = \exp \left[\underbrace{\left(-\frac{v_a g \Delta \rho (h_2 - h_1)}{RT} \right)}_{\text{Gravity}} + \underbrace{\left(\frac{v_a}{v} \right)_{h_2} - \left(\frac{v_a}{v} \right)_{h_1}}_{\text{Entropy}} + \underbrace{\left(\frac{v_a [(\delta_a - \delta)_{h_2}^2 - (\delta_a - \delta)_{h_1}^2]}{RT} \right)}_{\text{Solubility}} \right]$$

Fluid Color (Optical Density) Asphaltene Size/Fluid Density Asphaltene Size/Composition/ GOR/Fluid Density

Figure 7: The fluid asphaltene equation of state (FHZ EOS) for oil (from Julian *et al.*, 2010).

process starts by defining clear logging objectives of the well to be drilled, planning various operations and the selection of the appropriate technologies that fit the purpose for reservoir formation evaluation (Ko *et al.*, 2014).

The evaluation process consists of the following steps (Figure 9):

1. AMG fluid facies log generation used to build an understanding of fluid facies distribution,
2. AMG fluid type validation and integration with open hole logs in refining WFT fluid DFA and sampling points,
3. Observation and comparison of open hole logs and AMG data,
4. The results of the WFT DFA, AMG are used to establish reservoir fluid signatures for correlation with future well data, and
5. Integration of AMG findings with DFA prediction results allow to further analyse the vertical connectivity between sands.

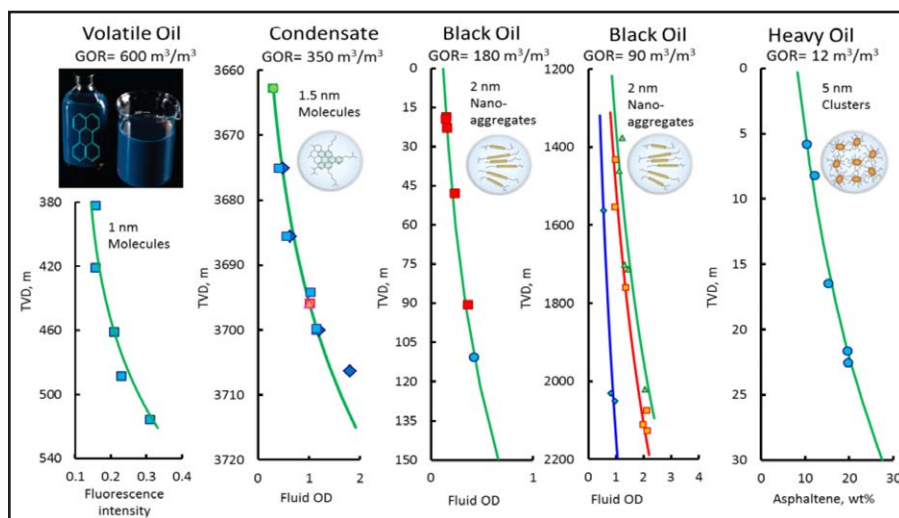


Figure 8: Examples of asphaltene gradients in five different oil reservoirs with different asphaltene size (from Julian *et al.*, 2013b).

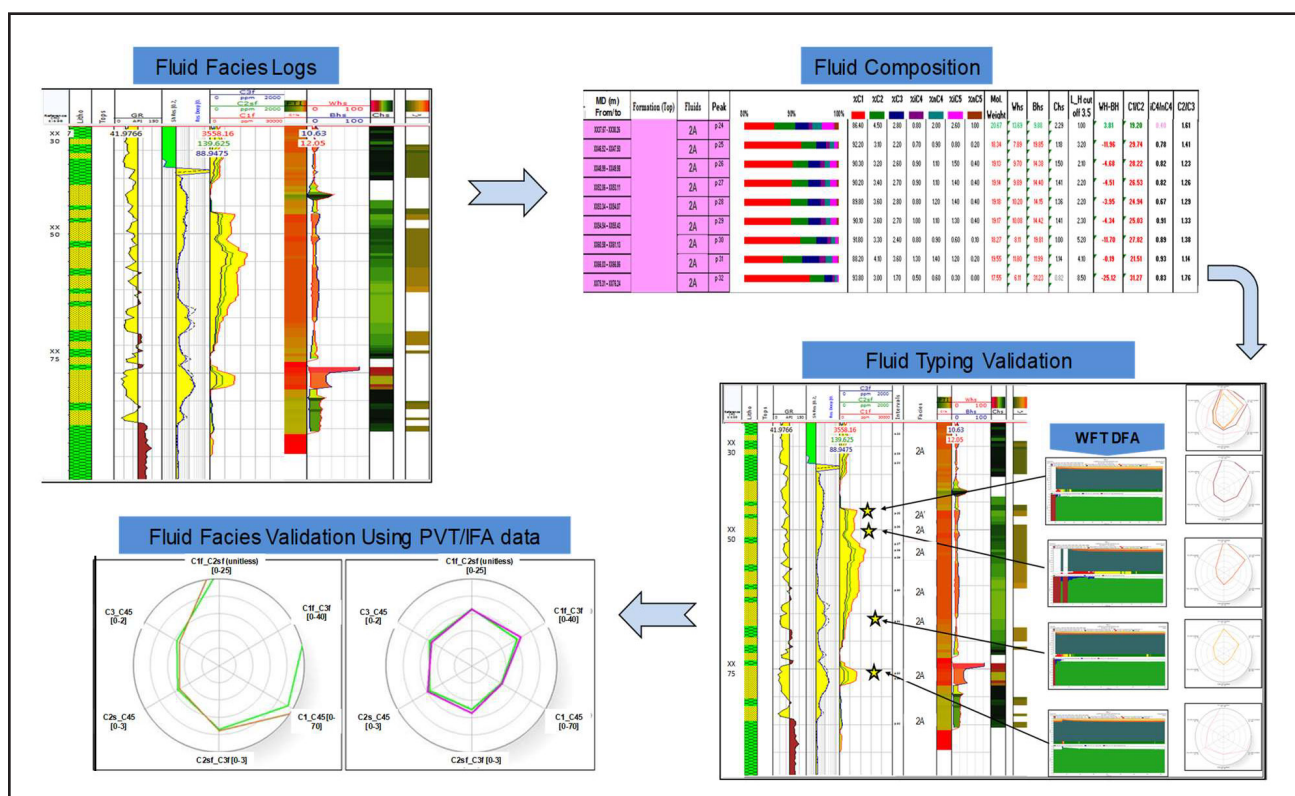


Figure 9: AMG-DFA integration process, which consists of five main steps: AMG fluid facies log generation, AMG fluid type validation and integration with open hole logs, comparison of open hole logs and AMG data, establishing reservoir fluid signatures for correlation with future well data, and Integration of AMG findings with DFA prediction results.

The AMG-DFA integration innovative approach as shown in Figure 10 shows a workflow for the quick-look analysis performed in this study. The integration process starts with AMG data acquisition while drilling and continuous fluid composition estimation (C_1 - C_8), then fluid sampling points recommendation are made with the available AMG interpretation results (based on gas peak readings and variations, in addition to group of fluids with specific signatures). Following this, the outcomes of downhole formation fluid sampling and analysis are used to validate the AMG results, and lastly to establish typical fluid signatures (from AMG, DFA and PVT results) to

correlate with future development wells in the same field (Ko *et al.*, 2014).

DFA-AMG integration can be extended to identify the presence of any possible compartmentalization in the reservoir formations by integrating the findings from both DFA prediction and AMG. Reservoir compartmentalization and connectivity is one of the biggest problems that most operators faced during the appraisal or development phases. Hence, by assuming that the reservoir is a single and connected tank may lead to undesirable consequences on the assessment of economic risks. Reservoir connectivity is defined by pressure and fluid equilibrium. Pressure gradients

are generally used to determine reservoir connectivity, and it is well-known that pressure communication is necessary, however the data are insufficient to establish flow communication (Julian *et al.*, 2011). Overall, pressure equilibrium can be achieved in years, a relative short time span whereas fluid equilibrium takes millions of years to establish; hence a hydrocarbon column at fluid equilibrium usually implies connectivity.

DFA can be used for an early understanding of reservoir compartmentalization and compositional gradients for optimal field development (Hani *et al.*, 2013), and it enables

accurate measurement of asphaltene content variations through fluid coloration *via* OD (Hani *et al.*, 2007; Dong *et al.*, 2008). In addition, DFA measures fluid properties such as composition, density, GOR, OD and fluorescence intensity. The analysis of colour gradient in oil columns in conjunction with GOR gradient and integrating with asphaltene science has become a key to discern reservoir complexity.

DFA prediction workflow

The WFT DFA prediction methodology is summarized in Figure 11, with details of each step discussed below:

1. *Determination of WFT intervals of interest:* The first step calls for data quality check (QC) of the open hole logs, WFT pressure points, and DFA/sampling results: WFT pretests, DFA, and sampling stations QC and interpretation are done in real-time to ensure representative pressure and fluid results are obtained. The second step is determining the pressure gradients and fluid types for all zones of interest, followed by the third step involving the determination of the hydrocarbon bearing zones and select the oil/light hydrocarbon zones of interest for further reservoir connectivity analysis.

2. *Contamination Analysis:* DFA analysis QC.

a. DFA/or sampling station results QC and interpretation are done in real-time by monitoring the fluid contamination level during the pump out period using IFA. For DFA prediction purpose, it is advised to obtain contamination level of less than 5% for both DFA and sampling stations (if no station time limit is imposed).

b. Contamination estimation for the DFA/sampling station. Real-time monitoring of the DFA station is required to confirm the desired fluid contamination level. The oil-based mud (OBM) filtrate contamination estimation (Figure 12) is based on OD measurements. The OD measured by DFA spectrometer responds to colour/or methane absorption is fitted with exponential regression model as a function of pumping time (Ryan *et al.*, 2016).

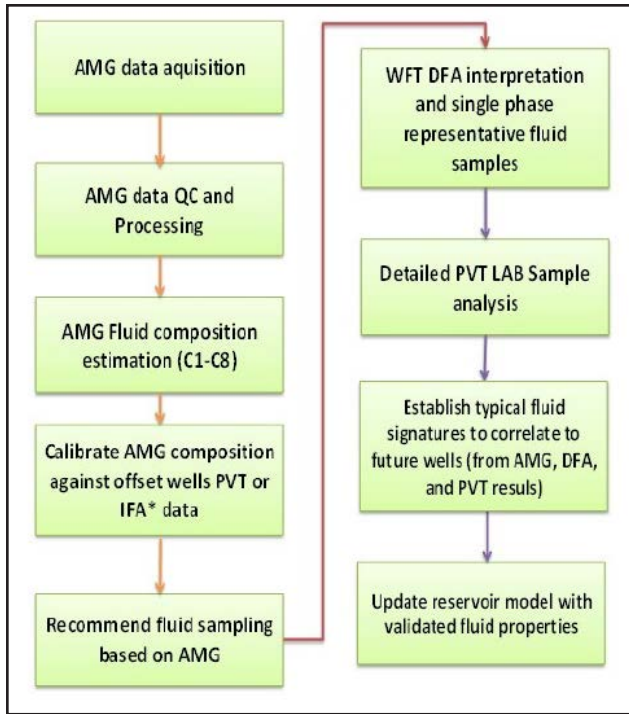


Figure 10: AMG-DFA integration innovative workflow (from Ko *et al.*, 2014).

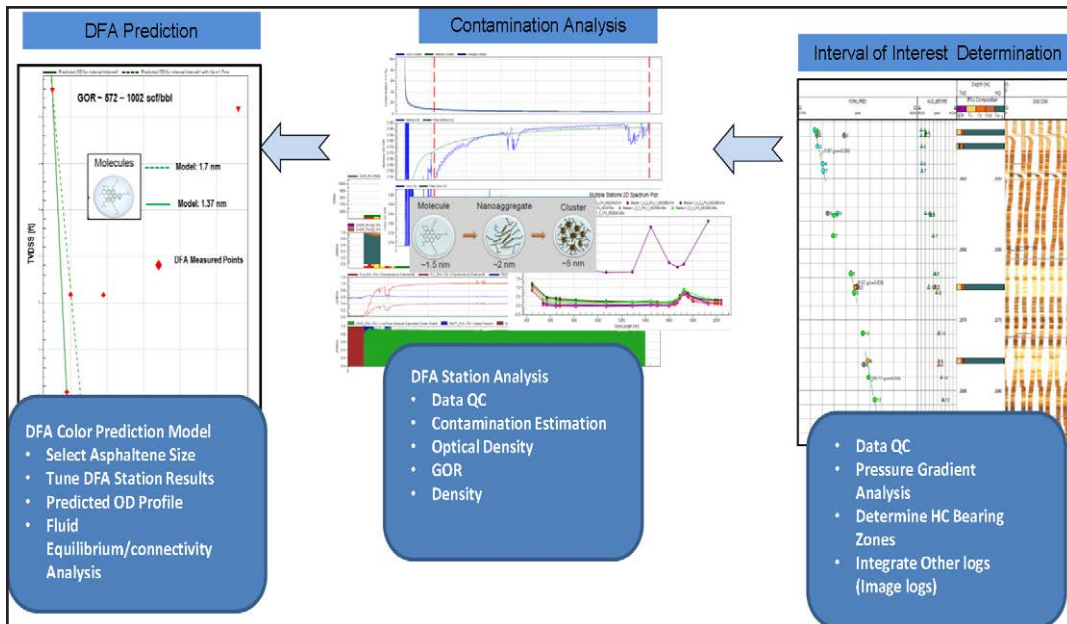


Figure 11: DFA prediction workflow is consisting of the determination of WFT intervals of interest, fluid contamination analysis, and DFA colour prediction model determination using asphaltene EOS.

3. **DFA Prediction:** DFA colour prediction model determination (Figure 13). The asphaltene EOS is applied in this case study to model reservoir fluid distribution, select appropriate asphaltene size; fine-tune DFA station results and predict OD profile to evaluate connectivity across sandy intervals of interest.

Integration of AMG-DFA predictions

The integration process can be summarized as follows (Figure 14):

1. AMG data are used to build an understanding of fluid facies distribution and to help along with open hole logs in refining WFT fluid sampling points,
2. Downhole formation fluid sampling and analysis results are used to evaluate what were observed by open hole logs and AMG data, and
3. The results of the DFA prediction are used to evaluate

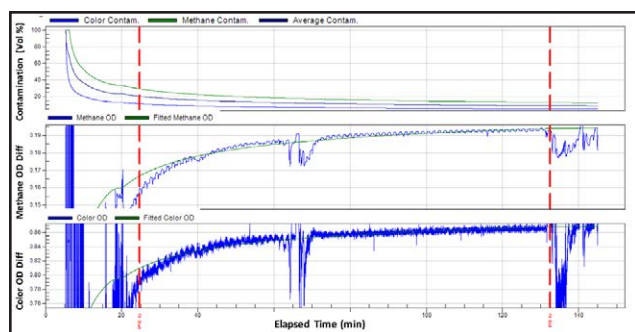


Figure 12: Real-time contamination monitoring with OCM technique (oil-based mud contamination monitoring).

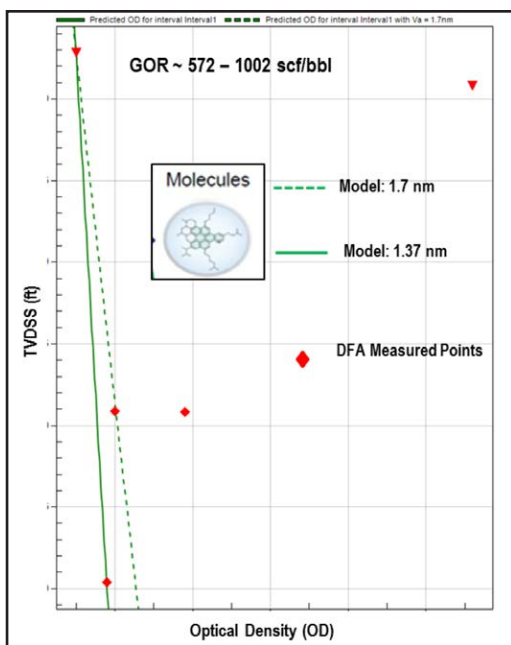


Figure 13: Asphaltene EOS is applied to model reservoir fluid distribution by selecting appropriate asphaltene size, fine-tuning DFA station results and predicting OD profile to evaluate connectivity across sandy intervals of interest. Noted that the DFA prediction indicated no clear evidence of connectivity between upper and middle zones.

any possible compartmentalization in the reservoir formations by integrating the findings from both AMG and DFA, and open hole logs.

FIELD STUDY – WELL “B-1”, AN OFFSHORE DEEPWATER SABAH DISCOVERY

The case study presented in this paper is for an exploration and discovery well “B-1” located in deepwater Sabah (Figure 1). Various zones of interest are tested to assess possible hydrocarbon accumulations. The formation targets are referred herein as Keabangan, Kinarut, Kamunsu and Pink Fans (Figure 2).

The main objectives of the drilled well were to:

- To confirm the hydrocarbon potential of the Keabangan, Kinarut, Kamunsu and Pink Fan reservoirs in prospect target, an elongate toe-thrust anticline structure.
- To acquire reservoir information by advance gas logging and electrical wireline logging of penetrated formations to assess the quality of reservoirs.
- To reduce exploration risk for the follow-up prospects.

For this integration study, advanced downhole fluid analyzer was deployed in this exploration well and used to identify fluid type in real-time to ensure the fluid samples being collected are representative. This was achieved by closely monitoring the formation fluid contamination level and flowing drawdown pressure to ensure that the formation fluid is collected as a single phase (monitor liquid drop-out or gas breakthrough before sampling).

The WFT tool string (Figure 15) consisted of one Extra Large Diameter (XLD) probe (MRPQ1), and QuickSilver probe (MRPQ2) with:

- IFA used for analyzing fluid in sampling line (pump up direction), while Live Fluid Analyzer (LFA) was used for analyzing fluid in guard line (pump down direction).
- Two standard displacement pump out modules were installed to move fluid in the flow line.
- Two multi-sample-chamber-module with 7 Multi Phase Sample Requisites (MPSR) and 5 Single Phase Multiple Chamber (SPMC) bottles were configured as normal low shock sampling for storing PVT samples.

WFT in combination with IFA and AMG logging were run in the tested well to:

- Acquire early continuous detection of fluid type aiding in improved sampling program.
- Acquire downhole fluid analysis to confirm fluid type derived from open hole logs and AMG.
- Obtain representative PVT quality samples for reservoir fluid characterization.
- Obtain real-time composition plus fluid property measurements at downhole conditions.
- Obtain formation pressures and fluid mobility for productivity analysis.
- Calibrate and verify continuous fluid facies log along entire drilling interval using WFT-DFA prior to availability of PVT sample analysis results.
- Integrate WFT and AMG results to confirm the vertical reservoir connectivity.

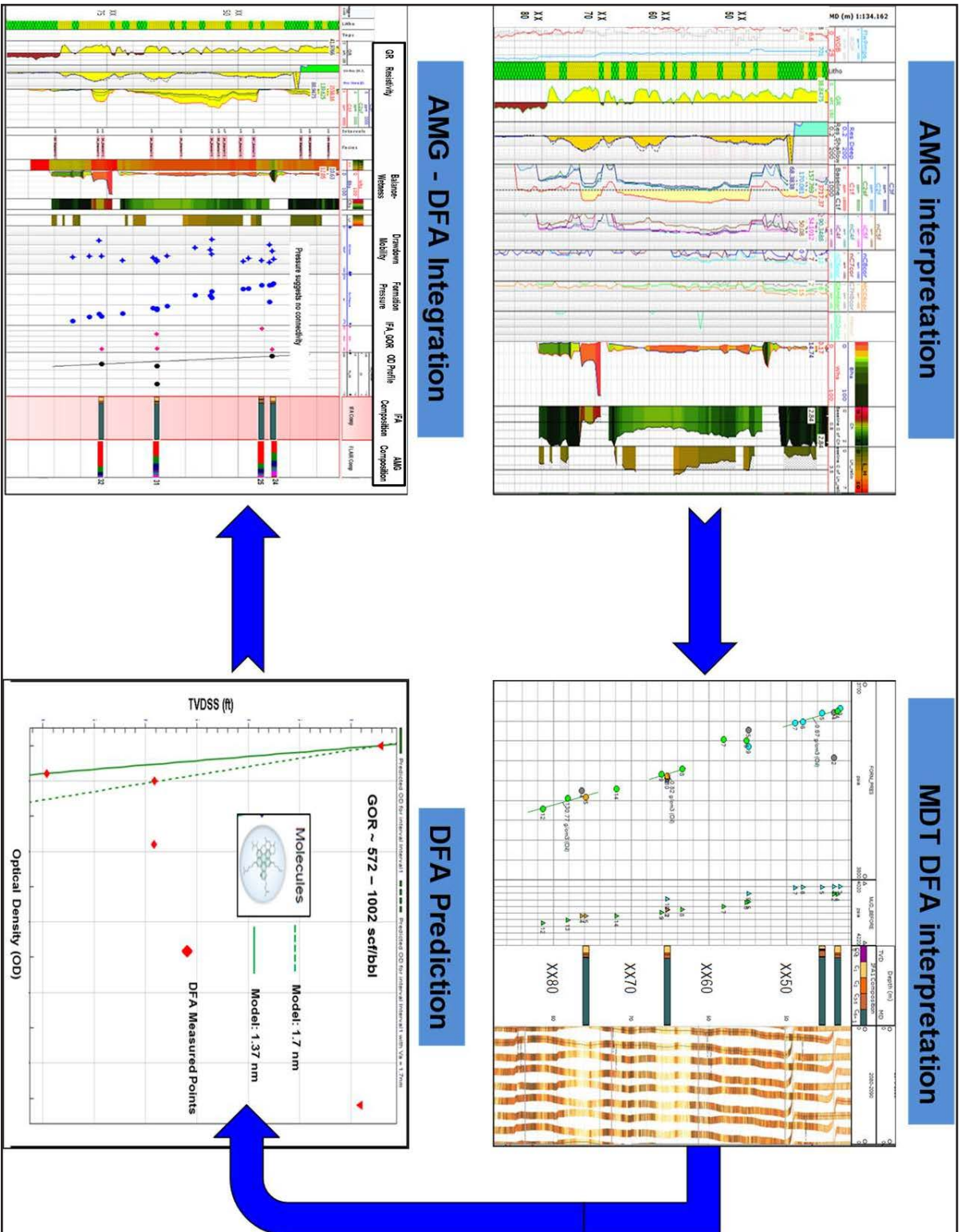


Figure 14: AMG-DFA prediction integration. The integration process consists of using AMG data to build an understanding of fluid facies distribution, followed by using downhole fluid sampling and analysis results to validate the AMG and open hole data, and after that perform DFA prediction to evaluate possible compartmentalization. Finally, the findings from both AMG and DFA, and open hole logs are integrated.

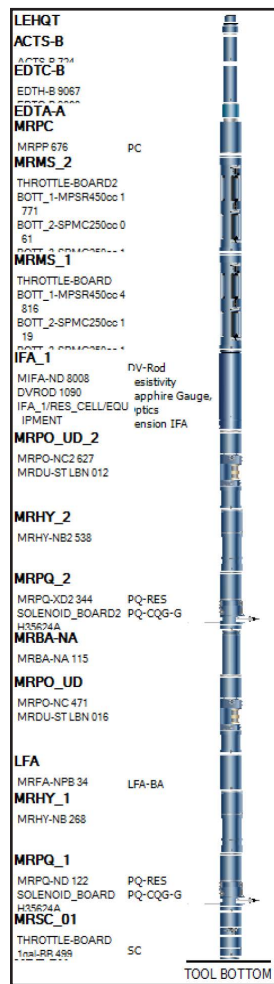


Figure 15: WFT tool configuration.

INTEGRATION PROCESS, RESULTS AND DISCUSSION

AMG-DFA integration process

1. Fluid facies log generation

During drilling the AMG provides quantitative estimation of C_1 to C_5 in % mole and qualitative C_6 to C_8 in % mole. Early reservoir fluid evaluation is done based on Haworth parameter Equations 1 and 2 below.

$$\text{Equation 1} \quad \text{Wetness, } Wh = \frac{\sum_{i=2}^5 C_i}{\sum_{i=1}^5 C_i}$$

$$\text{Equation 2} \quad \text{Balance, } Bh = \frac{C_1 + C_2}{\sum_{i=3}^5 C_i}$$

The AMG logs response need to be calibrated with fluid samples information to obtain high reliable fluid type evaluation. The proportion of C_6 to C_7 (liquid) content within overall fluid response is assessed by Light/Heavy Ratio, Equation 3. It is not a standard mud gas ratio and is only applicable with AMG measurements (scale 0-10) and the cut-off depends on extraction efficiency for C_{6+} components. The ratio is not reliable for small hydrocarbon concentrations (Crampin *et al.*, 2013).

Equation 3 (Character Ratio)

$$\text{Light: Heavy Ratio, } \frac{L}{H} = \frac{C_3 + C_4}{C_5 + nC_6 + nC_7 + C_7H_{14}}$$

Fluid facies log is generated for the entire drilling intervals in “B-1” and covers all sandy sections (Figure 16). All potential intervals are selected with fluid facies assigned. Intervals showing similar fluid fingerprint are grouped and a unique colour code and name assigned. The gas analysis is performed quantitatively on C_1 - C_5 and C_{6+} data ranges. In addition, the hydrocarbon peaks are delineated and compared to assess compositional similarities or differences.

2. Fluid families generation and fluid typing validation

Various intervals were defined to capture every gas peak and change in gas peak readings:

- C_1 to C_5 within each interval was averaged to generate a star diagram.
- Fluid with specific signature is identified and grouped as the same fluid type.

From the synthetic fluid facies log (Figure 16) one main fluid can be identified - Fluid 2, which is subdivided into four fluid types (2A, 2A', 2C, 2B') (Figure 17), that represent the main hydrocarbon fluid types detected in the well.

The validation of the AMG fluid typing results (Figure 18), with WFT DFA sampling is required to confirm the formation fluid and to calibrate synthetic fluid facies log (Figure 16). The PVT lab data from an offset well, is used to calibrate and validate the AMG results. In the case that the offset PVT well lab data is not available by the time the new well is being drilled, the WFT DFA data becomes the main source of validation. At this stage, the fluid facies log is calibrated (Figure 16), and it is ready to be used for the WFT sampling or DFA points selection.

3. DFA points suggestion by integrating AMG logs

The initial WFT points were selected based on the petrophysical logs. To improve the WFT DFA and sampling points selection especially in the intervals unfavourable for open hole loggings (bad borehole conditions), the AMG logs are integrated. The AMG helped to distinguish fine variations within the same fluid type. A WFT sampling program is suggested based on the changes observe on fluid composition (Figure 19), gas peaks reading, group of fluids with specific signatures, and by considering open hole petrophysical logs.

The exact depth of the DFA and sampling stations are fine-tuned once the WFT pretests points are acquired to consider the sweet spots with high pretest mobility (Figure 20). The sampling stations are performed at the zones with relatively high resistivity (open hole logs), high mobility (from WFT pretest), and high hydrocarbon content (from AMG).

4. Establish typical fluid facies signature

The fluid type validation is extended to the whole drilled section by validating the major fluids facies. The fluid facies validated by DFA results are compared to the

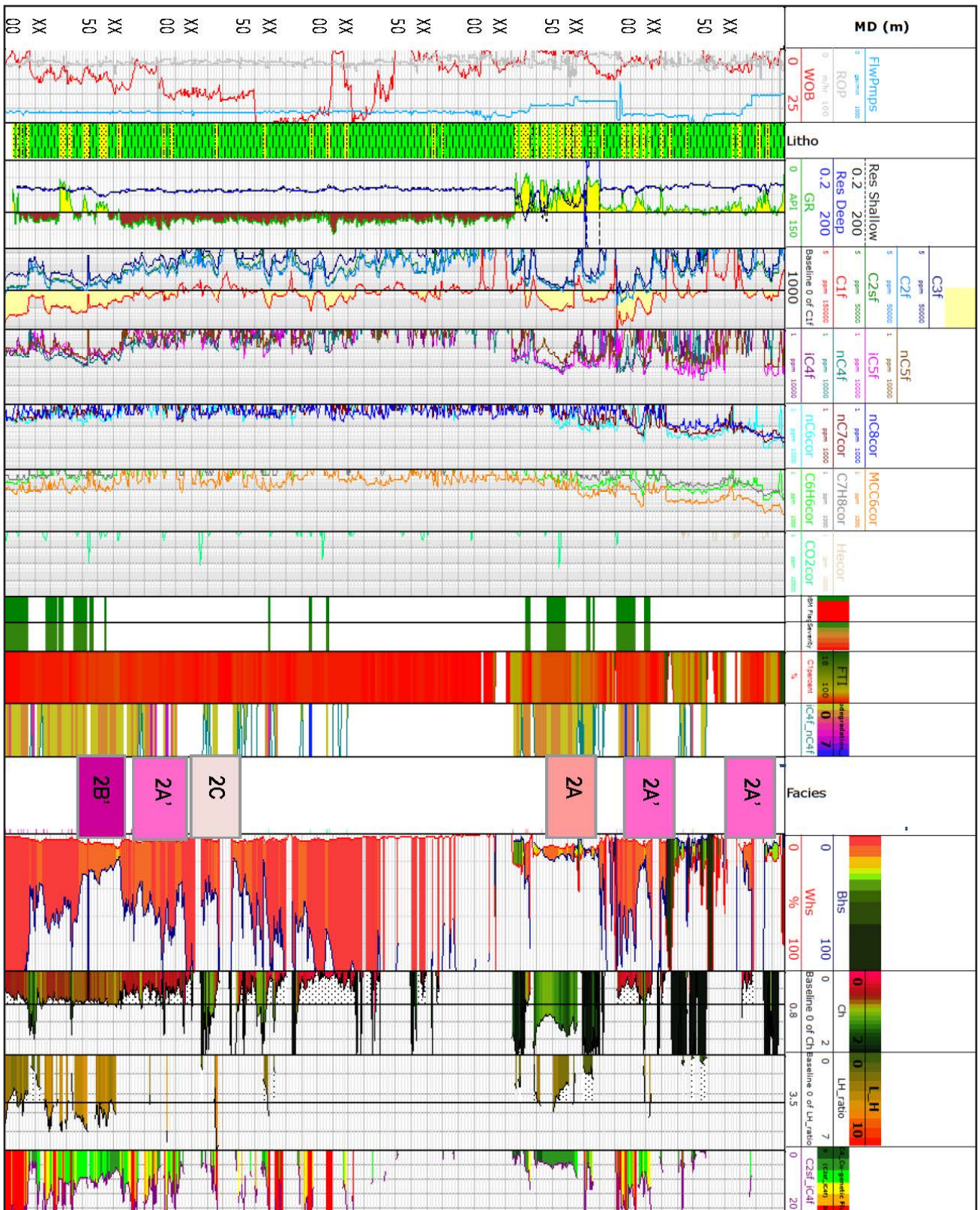


Figure 16: Synthetic fluid facies log is generated for the entire drilling intervals in “B-1” and covers all sandy sections. All potential intervals are selected with fluid facies assigned. Intervals showing similar fluid fingerprint are grouped and a unique colour code and name assigned.

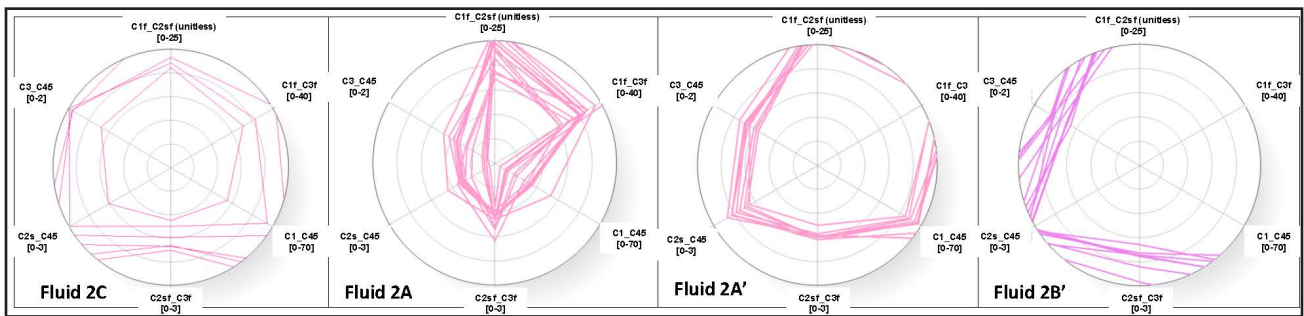


Figure 17: Fluid families based on specific fluid signature. Various Intervals were defined to capture every gas peak and change in gas peak readings: C₁ to C₅ within each interval was averaged to generate a star diagram, fluid with specific signature is identified and grouped as the same fluid type. One main fluid is identified - Fluid 2, which is subdivided into four fluid types (2A, 2A', 2C, 2B'); Figure 16).

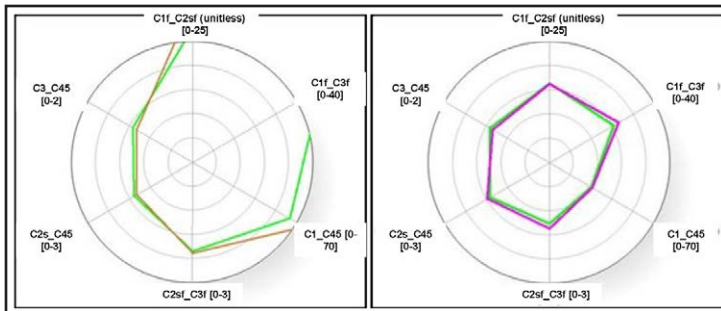


Figure 18: Fluid facies validation using PVT/IFA data. The PVT lab data from an offset well (green curve in both star diagrams) is used to calibrate and validate the AMG results. In the case that the offset PVT well lab data is not available by the time the new well is being drilled, the WFT DFA data becomes the main source of validation.

major star diagrams to extend and validate the fluid facies signature in other formations intervals (Figure 21). The validation of the AMG major fluid typing results with WFT DFA sampling is required to confirm the formation fluid and to calibrate synthetic fluid facies log. The validated fluid facies for the entire interval will be used as an input to the reservoir model for calibrating reservoir fluid properties.

5. AMG-DFA prediction integration

The AMG-DFA integration was extended to identify the presence of any possible compartmentalization in the reservoir formations (Single Well Compartmentalization Study) by integrating the findings from both DFA prediction and AMG. As noted, there is no clear evidence of connectivity between the upper and middle zones can be established (Figure 22). The identification of the reservoir compartmentalization is important for future field appraisal and planning phases, as it is the primary cause of underperforming field production. Figure 22 summarizes the main results of the DFA prediction and connectivity analysis.

AMG - petrophysics multi-mineral simultaneous solver workflow

1. AMG – real-time LWD integration

For real-time formation characterization and fluid ID identification, AMG can deliver an integrated petrophysical volumetric calculation along with the real-time LWD logs, thereby facilitating an improved monitoring and thus optimizing the drilling operations, as well as supporting formation evaluation processes and enabling timely decision making for upcoming wireline log acquisition plan and fluid sampling program. This case study well is characterized by thinly laminated formations, similar to those studied by

Budi *et al.* (2010), and standard LWD log responses were suppressed due to vertical resolution issue, resulted in an underestimation of hydrocarbon volumes compared with standard LWD evaluation.

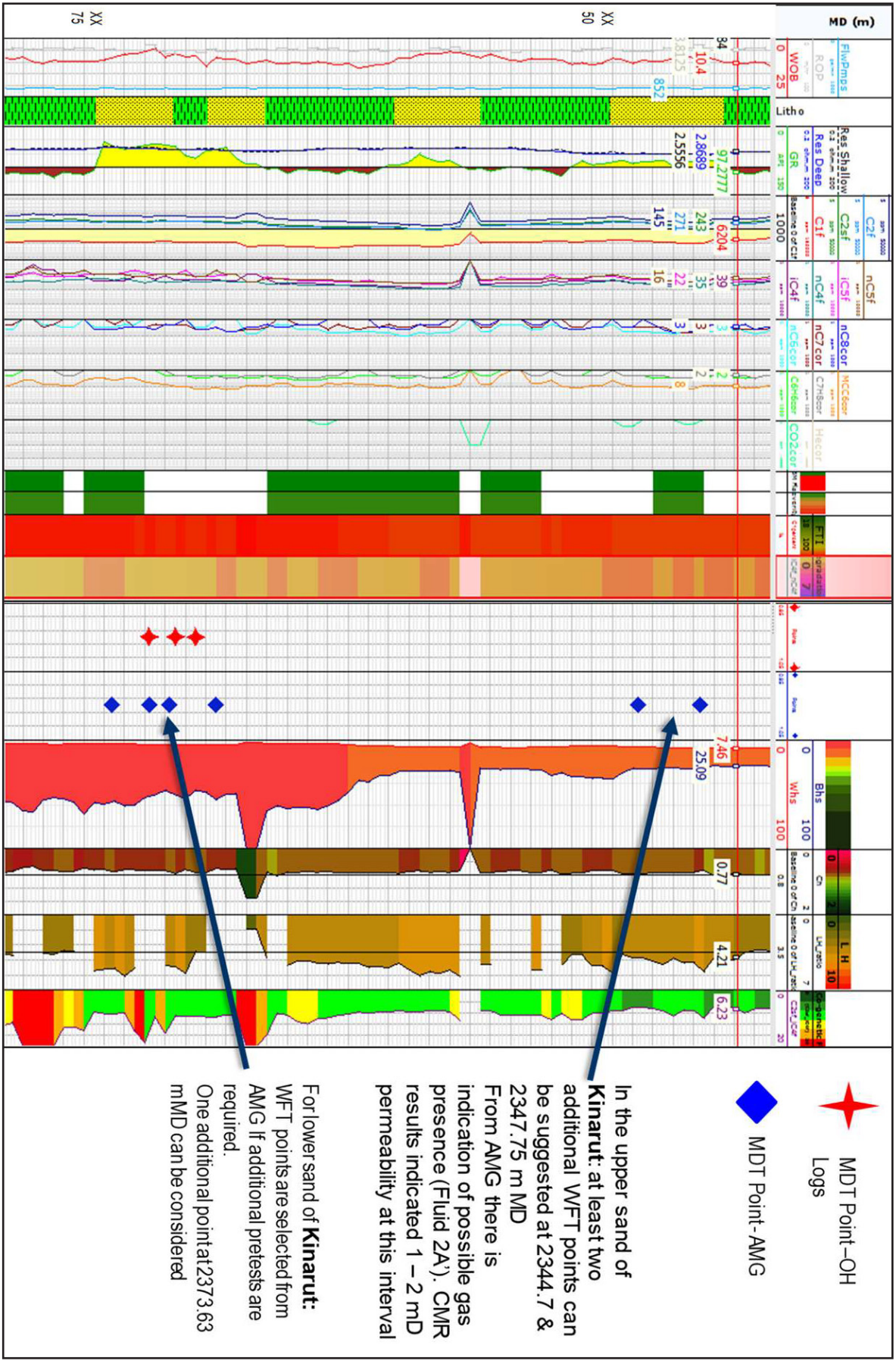
Figure 23 displayed the LWD gamma ray and resistivity shallow and deep logs indicating inadequate reservoir quality with possible high water saturation since the deep resistivity log readings is ranging from 3-4 ohm.m. However, AMG data from gas chromatographic C₁-C₅ and longer carbon chain of C₆-C₈ provided a strong evidence of hydrocarbon existence thus trigger the need for further appraisal with more inputs and core laboratory plan.

2. AMG – integrated formation evaluation with Quanti.ELAN solver

A good understanding of reservoir fluid composition is crucial for fluid volume computation and is an essential output from any petrophysical formation evaluation that have a direct impact to any resource estimation. Often, the Petrophysicist or Log Analyst tends to estimate the fluid endpoint based on the observation from log integration, which can be a good starting point. However, in the case of thinly bedded or lamination formations, the log response will somehow be affected by the nature of formation character hence making the judgment of lithology and fluid typing selection become more challenging.

The petrophysical Quanti.ELAN solver workflow enable an inverse modelling to use tool vector (*t*) where the input well logs or core - log correlation along with their known pure component endpoint (*R*) to compute for volume vector (*v*) of the formation component (Figure 24). This workflow also allows a forward modelling process, which is also known as log reconstruction, where used of *v* and *R* to compute

Figure 19: An integration of AMG and petrophysical log to optimize wireline formation testing (WFT) pressure point selection.



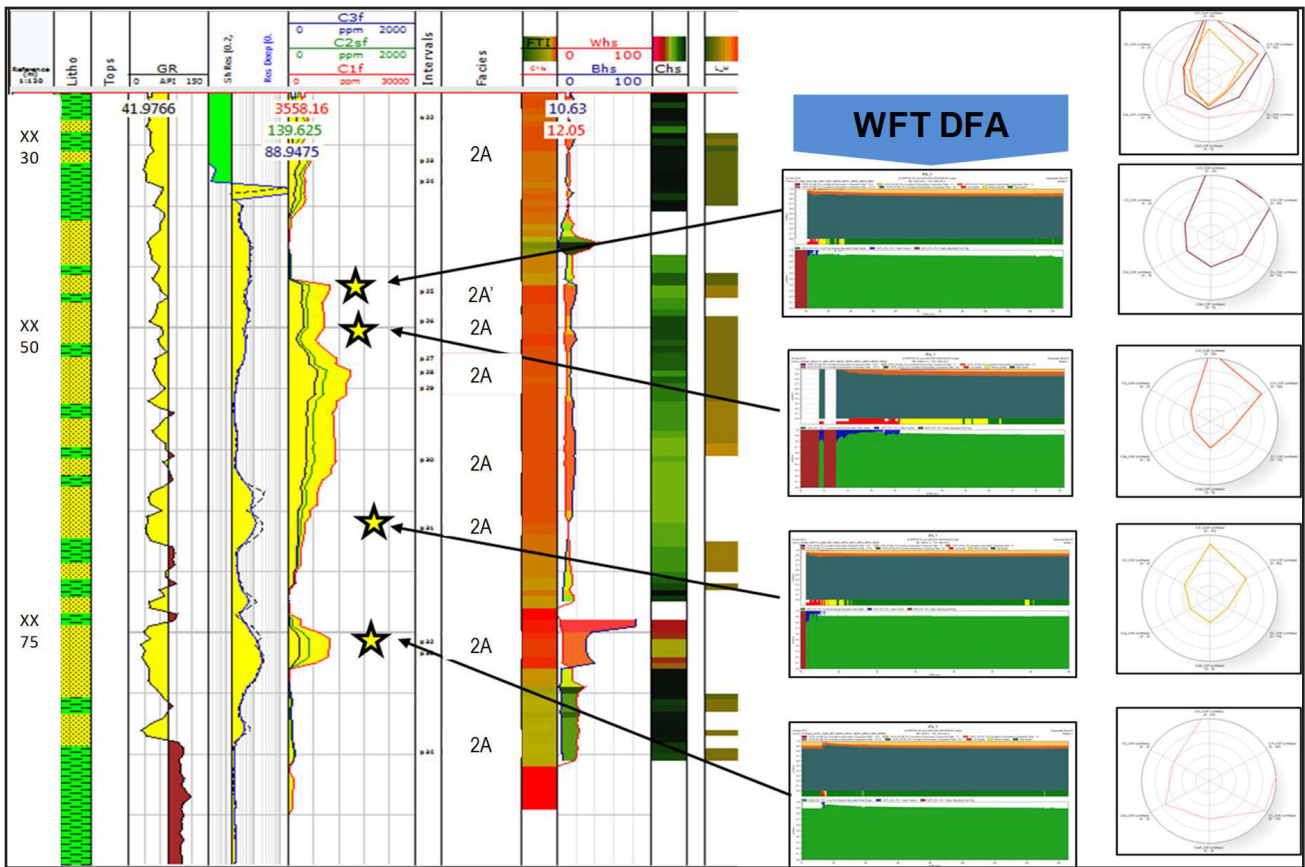


Figure 20: DFA point suggestions and fluid typing validation in real-time.

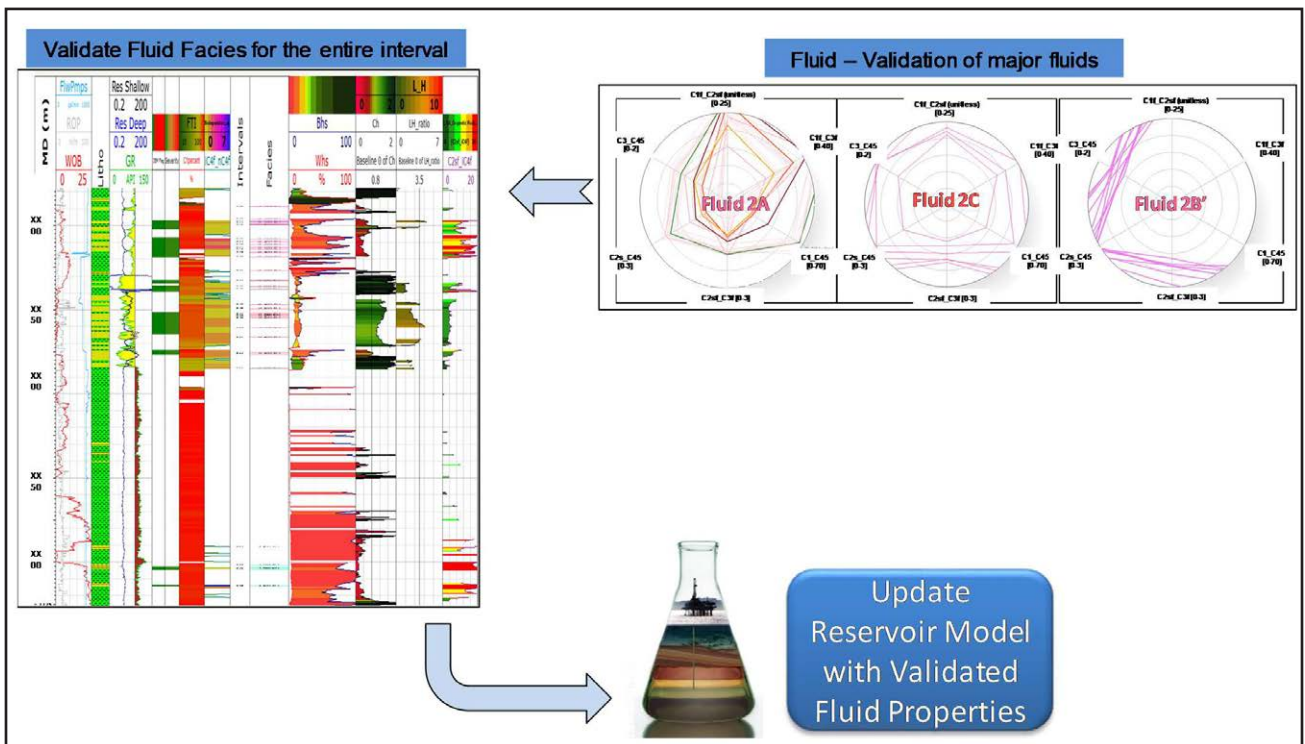


Figure 21: Establish typical fluid facies signatures. The fluid type validation is extended to the whole drilled section by validating the major fluids facies based on the major star diagrams. The validation of the AMG major fluid typing results with WFT DFA sampling is required to confirm the formation fluid and to calibrate synthetic fluid facies log.

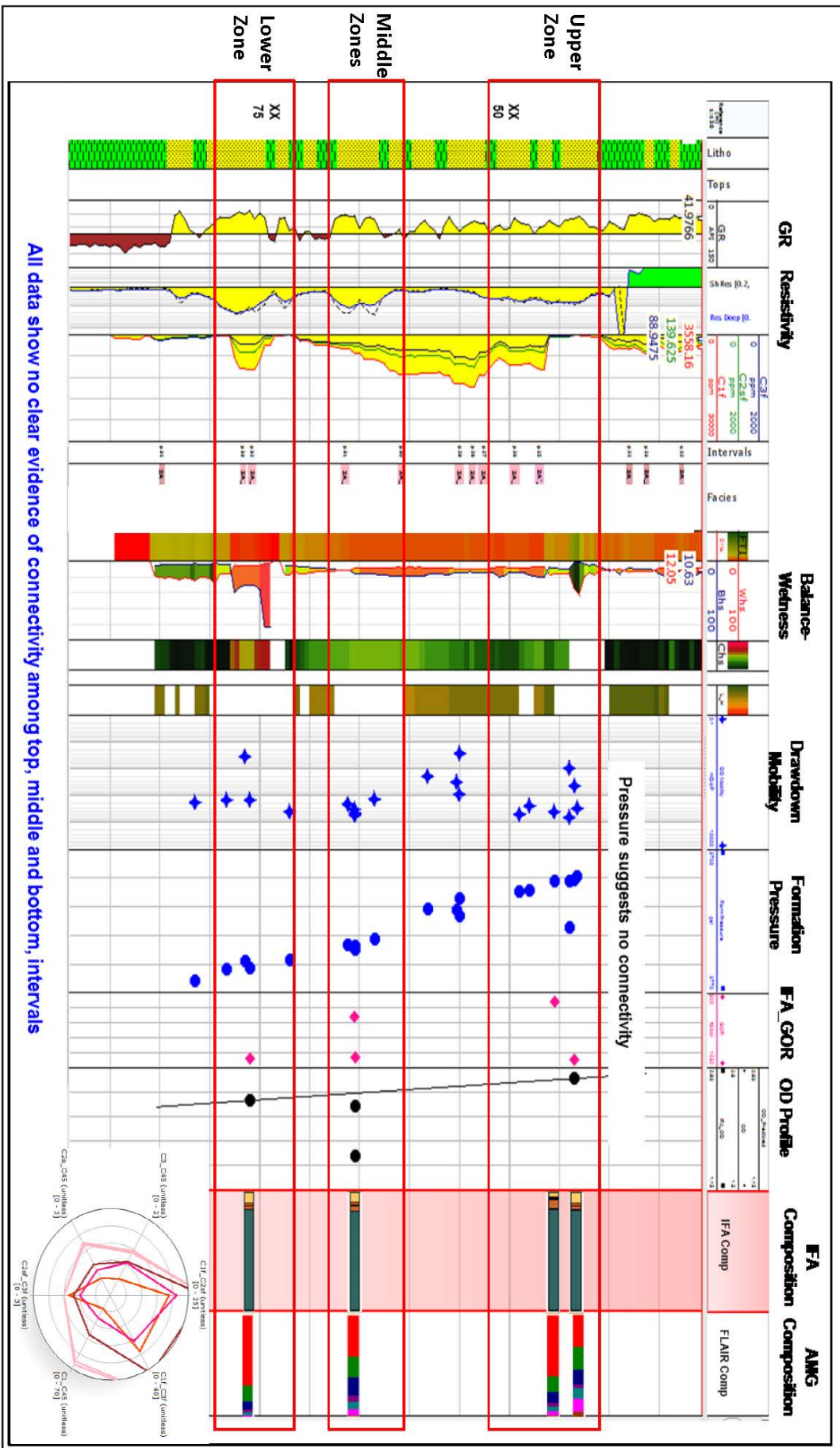


Figure 22: An integration of AMG, DFA, and petrophysical results for a better reservoir fluid characterization in well "B-1" (Lower Kamunus) reservoirs. There is no clear evidence of connectivity between the upper and middle zones can be established, as based on the fluid facies validation from the star diagram, the upper and lower zones have different fluid affinities.

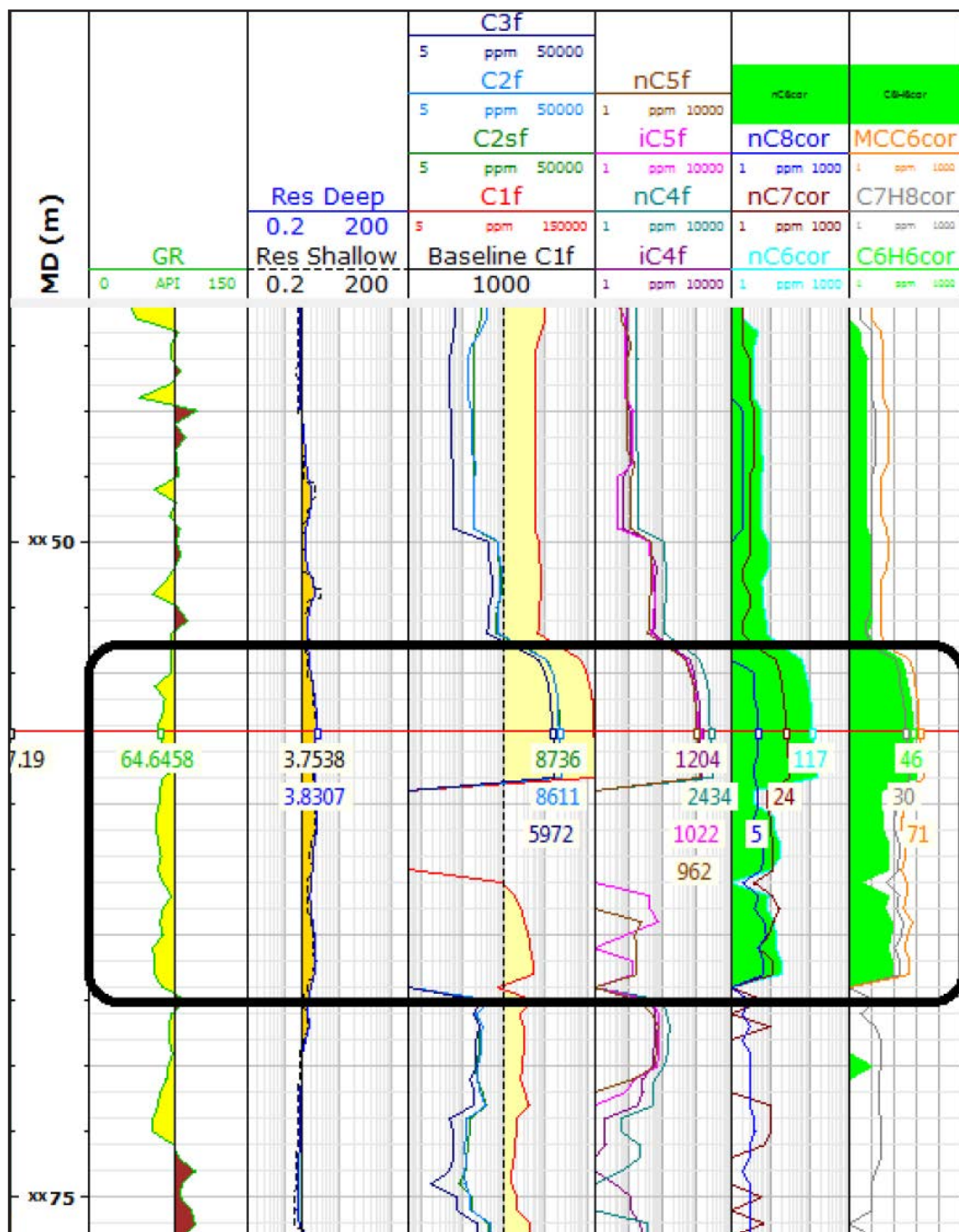


Figure 23: Data integration using LWD gamma ray and resistivity shallow and deep logs with fluid identification based on gas compositions from AMG.

for t . The forward modelling technique is adopted in the thin bed log resolution enhancement workflow namely the SHARP technique used by Budi *et al.* (2015) and Laurent *et al.* (2015), and in this case study.

In well “B-1”, the AMG data are used to compute the fluid endpoint and later feed into the Petrophysical Quanti. ELAN solver to compute the individual fluid fraction and their cumulative volumes as shown in Figure 25. The green box highlighted is the oil bearing reservoir, and the assessment is further supported by existence of C_6 - C_8 components, whereas the zone underneath is mostly devoid of C_1 - C_5 or C_{6+} , which can be potentially interpreted as water bearing zone.

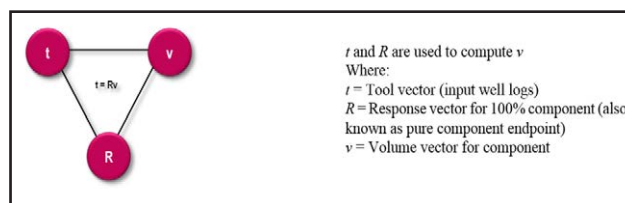


Figure 24: Petrophysics Quanti.ELAN solver workflow.

3. AMG – fluid ID with nuclear magnetic resonance fluid (MRF) station

The AMG data provides a good insight on the fluid ID while drilling and LWD operational time window, however

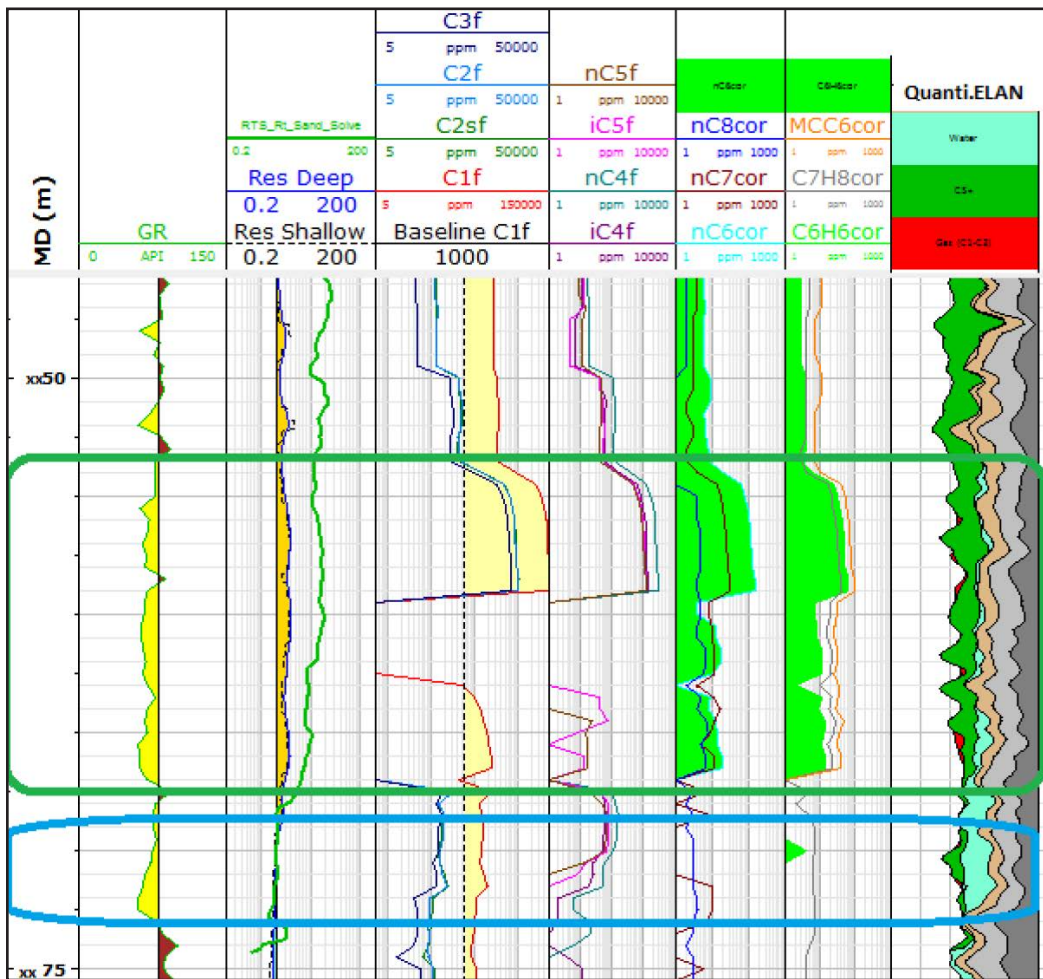


Figure 25: In well “B-1”, the AMG data (Tracks 4 to 7) are used to compute the fluid endpoint and later feed into the Petrophysical Quanti.ELAN solver to compute the individual fluid fraction and their cumulative volumes as shown in Track 8 in the layout. Interval highlighted in green box indicates the presence of C_{5+} and minor gas component in the pore volumes. Interval with blue box highlighted indicates the presence of mixture of free water and very minor C_{5+} volumes, which could be associated with the mud filtrate invaded into the formation.

the extraction of their individual fluid volume or fraction required further log interpretation. The magnetic resonance fluid characterization method is a patented technique for direct identification and analysis of hydrocarbons from station log measurements made by the CMR tool. By inverting a specially designed suite of nuclear magnetic resonance measurements with different echo spacing, the MRF method can separate water, oil and gas signals following the computation of their volumes and saturations.

The example below shows the two MRF stations (D-T1 and D-T2 maps; Figure 26) indicating the predominate fluid in the reservoir is oil with traces of water (free and bound) and gas signal. The presence of formation oil showed in Stations 1 and 2 correlates well with the AMG data. The water zone (blue box) also shows a good correlation with the wetness index as discussed in Equation 1.

CONCLUSIONS

Based on the outcomes of a case study from “B-1” well, offshore Sabah the following conclusions can be drawn:

- An integrated approach and workflow can help in better reservoir fluid characterization in thinly laminated formations and to reduce the geological uncertainties at an early stage of the field development phase, thereby saving operating cost.

- Integration of various methodologies including AMG and DFA predictions and calibrated with the acquired wireline log data has proven to complement each other and can be successfully used to address reservoir connectivity concern.
- Early quantitative assessment of fluid compositions and sampling optimization through the integration of WFT-DFA, and AMG provides a high confidence in real-time fluid typing, and helps to refine WFT sampling depths, have better adaptability of downhole sampling process planning in real-time, and improves fluid characterization for entire reservoir zone especially in a challenging drilling environment.
- The developed approach and methodology aids in reducing data acquisition risk, and optimizes operations time spent by correctly evaluating zones of interest during the appraisal phase.
- Accurate fluid composition from WFT DFA provides important inputs for petrophysical analysis to more precisely evaluate the reservoir properties and volume of hydrocarbons present in the reservoir to capture the thin lamination potential, which is normally excluded in the conventional thick bed volumetric resource assessment.
- The case study demonstrates the strategies used

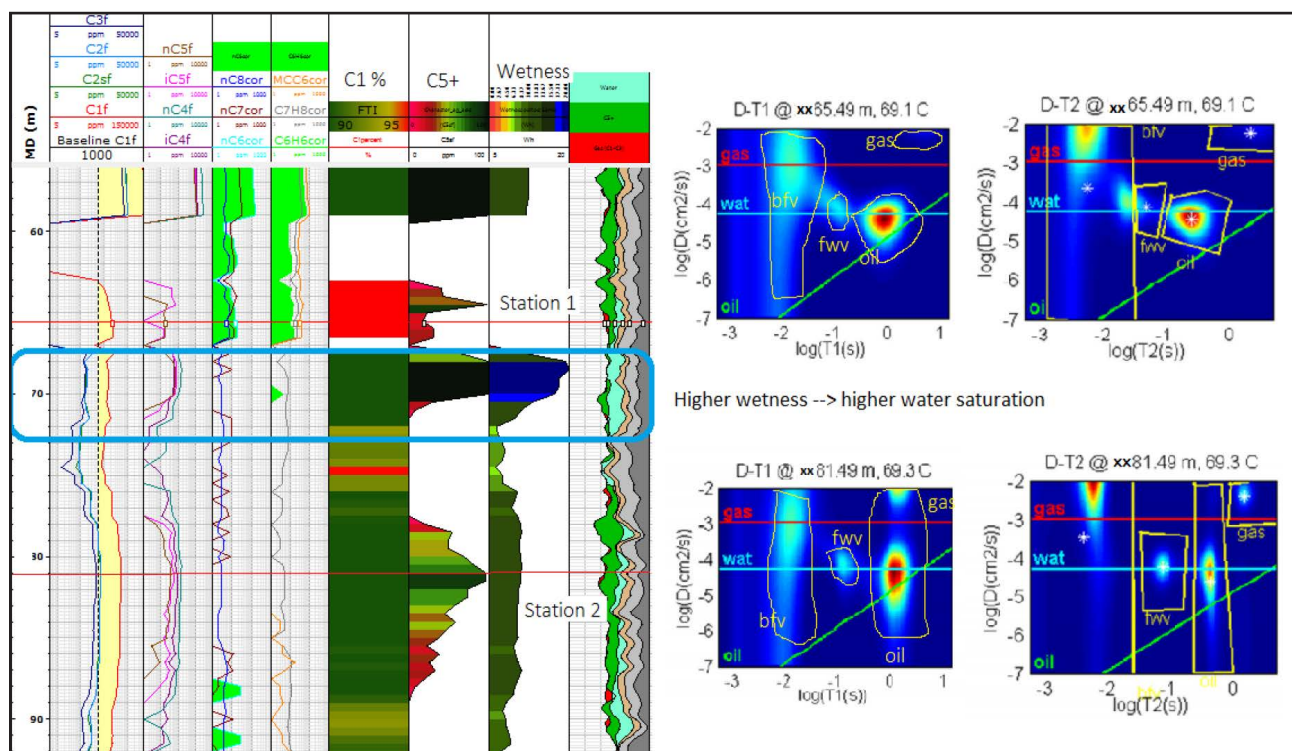


Figure 26: AMG validating the MRF fluid ID determination. The example shows the two MRF stations (D-T1 and D-T2 maps) indicating the predominate fluid in the reservoir is oil with traces of water (free and bound) and gas signal. The presence of formation oil showed in Stations 1 and 2 correlate well with the AMG data. Interval with blue box highlighted shows the high wetness presence as supported by the Quanti.ELAN interpretation of high free water volumes. The water zone also shows a good correlation with the wetness index as discussed in Equation 1.

for accurate fluid characterization assessments in a challenging deepwater environment, which is beneficial as a comparison for the subsurface assessment of the thinly laminated formations of discoveries made in similar depositional setting. It has been estimated that the resource of the thin laminations encountered in the Kikeh Field has contributed up to 20% of the total estimated in place resource of the producing field (Doug Gillies, pers. Comm.).

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