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Prospects Maturation of Unique Globigerina Limestone by Integration of Formation Evaluation and Pre-Stack Seismic Inversion Analysis

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Abstract

The Globigerina Limestone (GL) reservoir is a unique carbonate with exceptional up to 50% porosity and permeability ranging from 0.01mD to 500mD. Exploration wells have encountered varying facies from wackestone to grainstone, from poor (MBJ-1) to very good (MBH-1) reservoir quality. To avoid poor reservoir quality, formation evaluation, and pre-stack seismic inversion analysis were combined in prospect maturation.

The formation evaluation provides reservoir properties such as clay volume, porosity, flow units, permeability, and water saturation to identify sweet-spot intervals. On the other hand, pre-stack seismic inversion analysis techniques such as AI, SI, LambdaRho, and MuRho were used to identify potential reservoirs and predict rock quality within gas-bearing areas. This research used core data, wireline logs, and 3D seismic data.

Results from this study indicate that pre-stack seismic inversion is a powerful tool for identifying areas with hydrocarbon potential around the Bangau-3D seismic area. Additionally, integrating reservoir characterization, elastic parameters, and pre-stack seismic inversion products can help distinguish the poor to the best quality of reservoir rock that should be targeted for future exploration wells in certain prospects.

Keywords: carbonate reservoir, mature basins, petrophysics, seismic inversion.

Introduction

The Madura Strait PSC is located in the Northeast Java Basin, Indonesia. One of the most widely spread reservoirs in Madura Strait PSC is the Globigerina Limestone (GL) reservoir from the Mundu – Selorejo sequences (Figure 1). The reservoir mainly produces biogenic gas and contains more than 96% methane. The exploration wells were drilled and discovered gas inside the GL reservoir. GL reservoir is a heterogenic carbonate reservoir characterized by exceptional porosity of up to 50%, with permeability ranging from 0.01mD to 500mD (Figure 2).

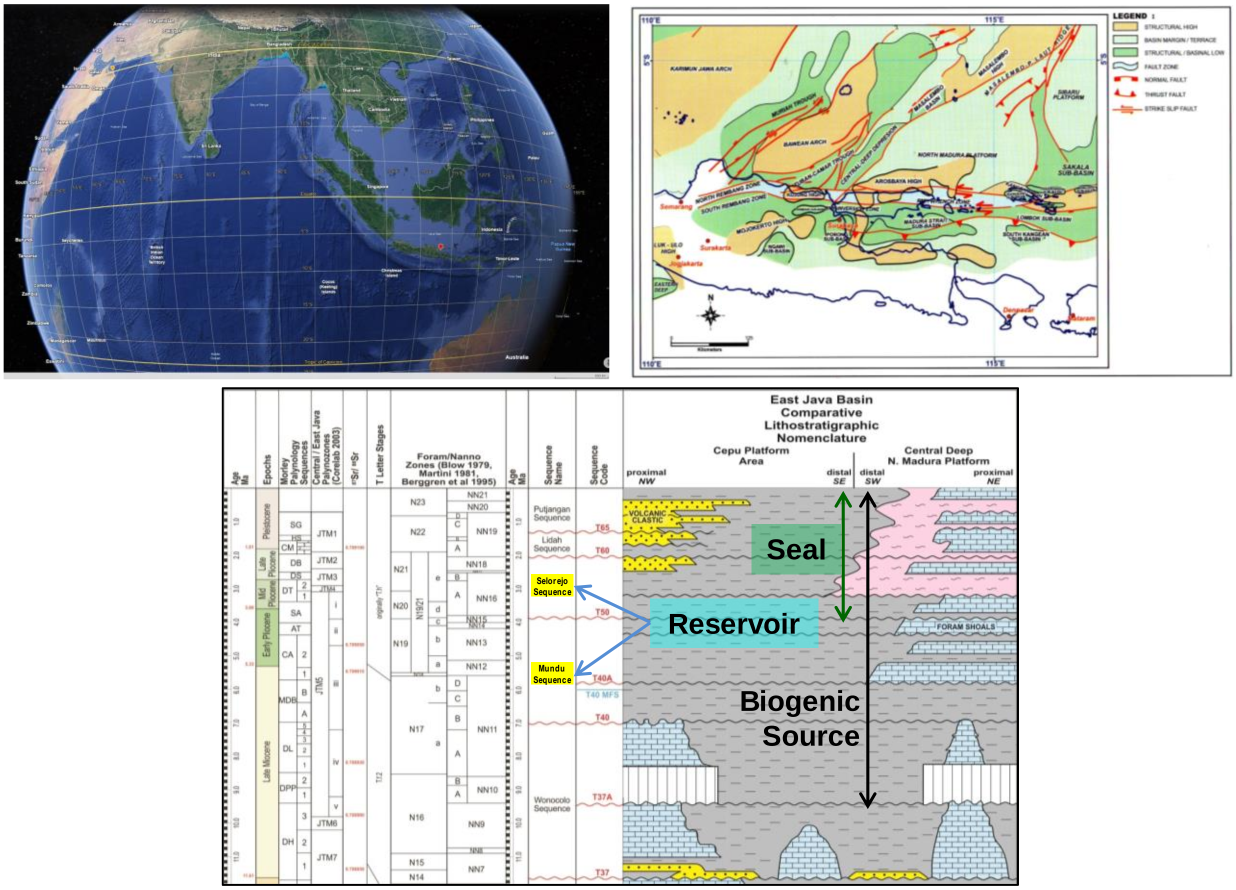

Figure 1. Regional Geology and Petroleum System in Madura Strait PSC.

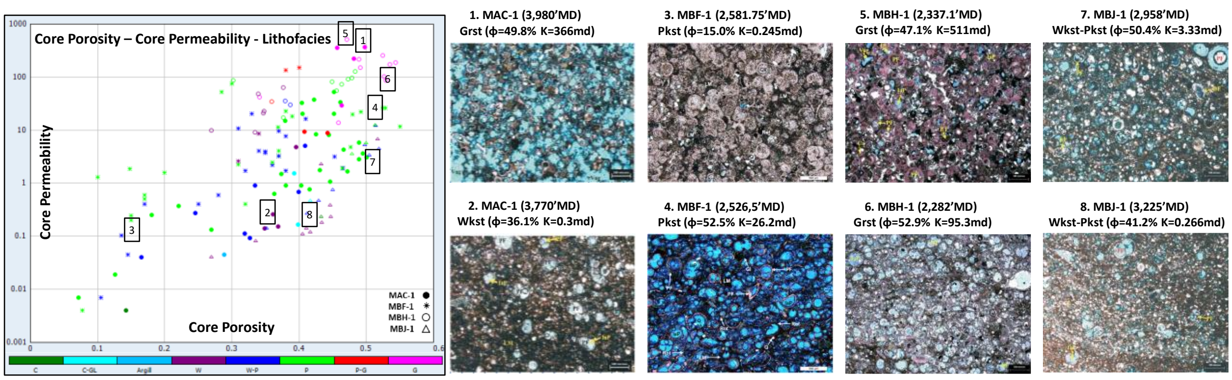

Figure 2. MAC-1 - MBF-1 - MBH-1 - MBJ-1 Core Data and Thin Section Petrography.

Madura Strait PSC has three production facilities with the biggest capacity of up to 175MMscfd, named FPU Trunojoyo 01 (Figure 3). The current gas production is around 120MMscfd from MBH - MDA Field. To fulfill the capacity of FPU Trunojoyo 01, near-field exploration needs to be executed. This study focuses on formation evaluation and pre-stack seismic inversion analysis to avoid dry wells and poor quality reservoirs (prospects maturation) in BI, BE, and BG.

Figure 3. Madura Strait PSC Assets Summary.

BI, BE, and BG prospects are covered by Bangau-3D seismic which was acquired in 2011. Due to seismic data quality issues from shallow gas masking, most GL prospects have uncertainty regarding seismic lateral continuity below the shallow gas (Figure 4). This causes the lateral continuity on the top of the gas reservoir to be uncertain. Because of this concern, Bangau-3D seismic data was re-processed in 2014 with extra treatment in compensating shallow gas masking. The presence of a Direct Hydrocarbon Indicator (DHI) is an expected anomaly during the qualitative analysis, not only serving as a leading indicator for a hydrocarbon existence but also unfortunately may be misleading for the interpreter. This pitfall of using DHI as a guide for prospect maturation and exploration well placement is dangerous, since with only a few percentages of gas saturation, the compressional velocity will drop significantly and create the same DHI response. Quantitative seismic interpretation demonstrates how pre-stack seismic inversion analysis can be applied to predict reservoir parameters, such as lithologies and pore fluids, from seismically derived attributes (Avseth, P., Mukerji, T. and Mavko, G., 2011). The lack of certainty in the qualitative analysis will be reduced by the quantitative analysis approach.

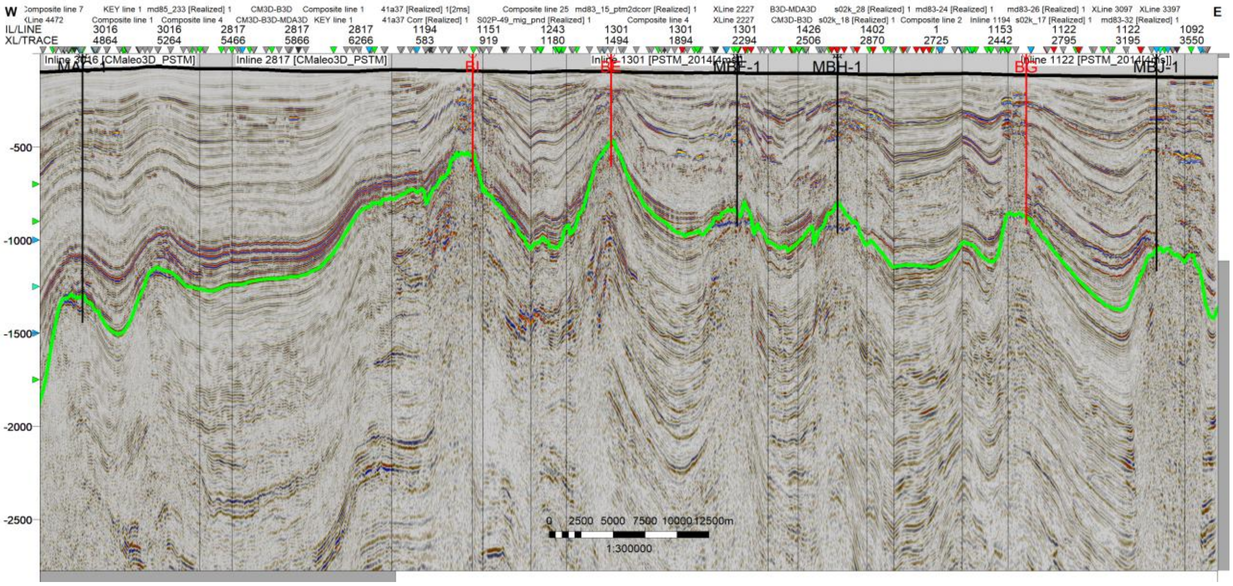

Figure 4. Seismic Section thru MAC-1 - MBF-1 - MBH-1 - MBJ-1 and BI, BE, BG Prospects.

Methodology

The data availability for this study consists of mudlogs, logs, well testing, core data from exploration wells that were drilled targeting the GL reservoir, and Bangau-3D seismic data (Figure 5). Four exploration wells successfully found gas with heterogenic reservoir quality from very good (MBH-1) to poor (MBJ-1). All the wells acquired log data, consisting of gamma-ray, resistivity, neutron, bulk density, Vp, and Vs. Core data sets from the laboratory such as vertical and horizontal permeability, porosity, grain density, petrography (SEM, XRD, and Thin Section), formation resistivity, and capillary pressure were used to conduct integrated reservoir characterization and to validate petrophysical property results.

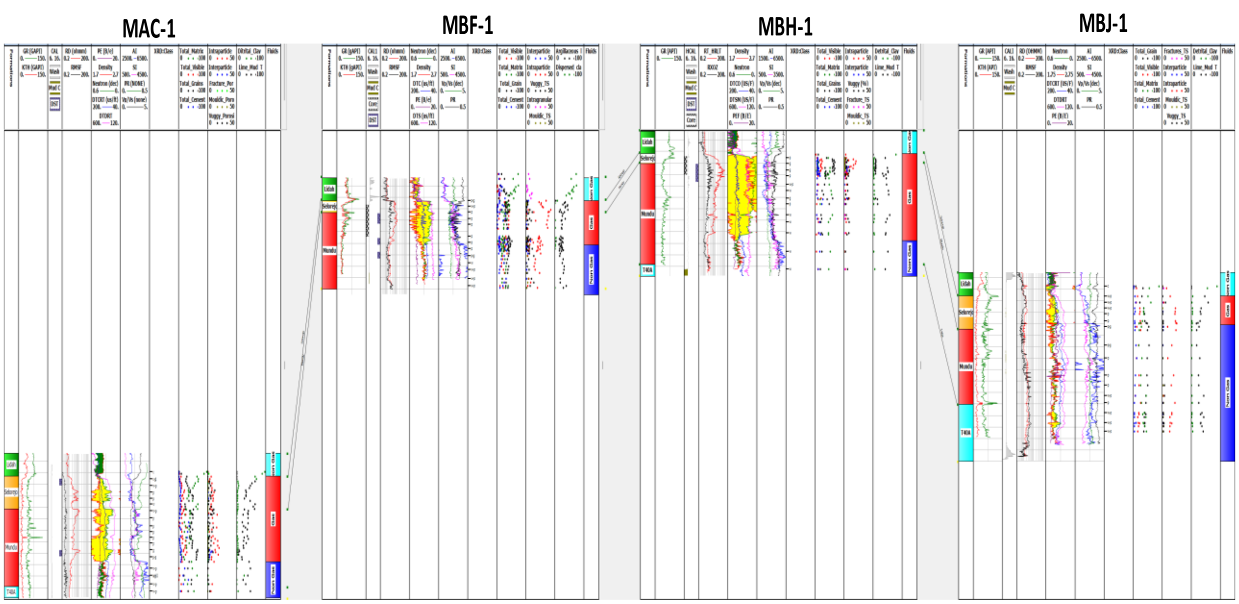

Figure 5. Exploration Wells Correlation and Data Availability.

Integrated reservoir characterization is related to understanding vertical and lateral reservoir heterogeneity. In terms of reservoir quality, based on petrography, lithofacies, core porosity, and core permeability observation, the GL reservoir has high heterogeneity. The clusters of core porosity-permeability cross plots, which represent carbonate facies based on Dunham's classification, are scattered, as shown in Figure 6. The poor core porosity-permeability relationship in carbonate rocks implies that porosity is not the only parameter affecting permeability, it is also influenced by lithofacies, facies deposition, and diagenesis shown by grain size distribution, texture, roundness, pore type, pore geometry, pore throat size, cement, mineral composition, and connectivity (Lucia, F. J., 2014). Therefore, the initial approach of reservoir characterization for the GL reservoir was applied using a quantitative method through a hydraulic flow unit (HFU). HFU analysis technique has been introduced by Amaefule, J.O., and Mehmet Altunbay (1993) by calculating flow zone indicator (FZI) from pore volume to solid volume ratio (Φz) and reservoir quality index (RQI). From FZI values, samples can be classified into different HFUs. Samples with similar FZI values will have the same HFU. Each HFU on a log-log cross plot between RQI vs normalized porosity index will yield a straight line with a specific unit slope. The intercept of each unit slope with $\Phi z = 1$, designated as FZI is a unique number for each HFU. Data points that plot along a constant FZI exhibit similar flow quality across a wide range of pore-perm values. Thus, these ratio lines can be used as a scale to evaluate and rank reservoir quality. Air Brines Capillary Pressure (ABCP) or High Pressure Mercury Injections (HPMI) also have been analyzed by calculating pore throat and saturation height function to integrate with each rock type as shown in Figure 6. The propagation of HFU in uncored intervals, applied electrofacies methodology using neutron, density, and resistivity logs. Furthermore, a permeability log was obtained using the permeability transformation of each HFU from its porosity value.

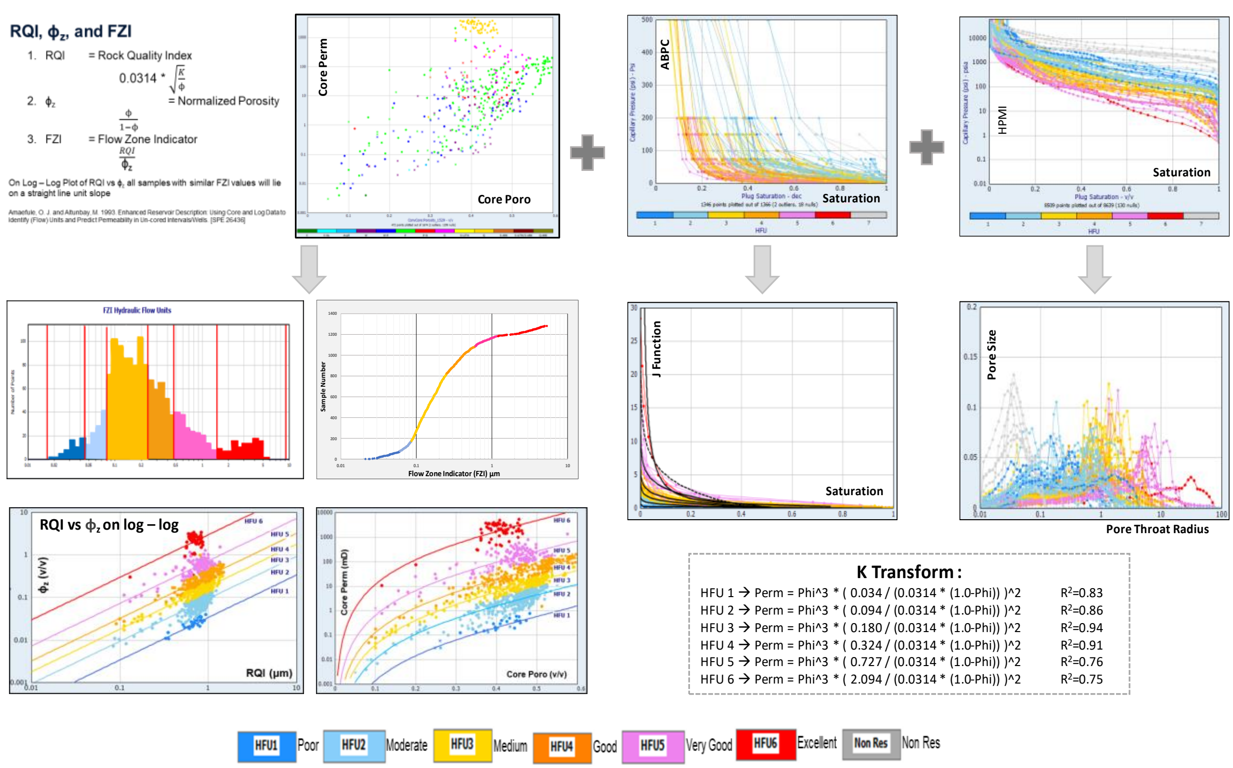

Figure 6. Integrated Reservoir Characterization and Flow Units Classification.

Formation evaluation's main objectives are to transform well log information into reservoir properties such as mineral volumes and fluid contents in the invaded and un-invaded zones. The formation evaluation started with quality control (QC) of log data, which included log patching, removing tail, merging, depth matching, and pseudo log generation. The log QC starts with environmental correction to correct the drilling mud inside the borehole and surrounding the tool. Complete environmental corrections such as mud properties (mud weight, mud resistivity, mud content), tool position in the borehole (standoff), tool size, sensor type, borehole diameter, and mud cake were directly generated. After loading and checking all logs data, it was found that most of the logs are aligned in depth so does not require any depth shift. The effects of tool position, tension, current fluctuation, and cycle skipping, have been understood carefully. Clay volume is the first step to be estimated using gamma-ray only or combined with neutron-density logs. Neutron-density logs are used to calculate porosity and resistivity logs for water saturation. Analysis of petrophysics applied appropriate petrophysical parameters and formulas for clastic carbonates and validated them with core data and well-testing results (Figure 7).

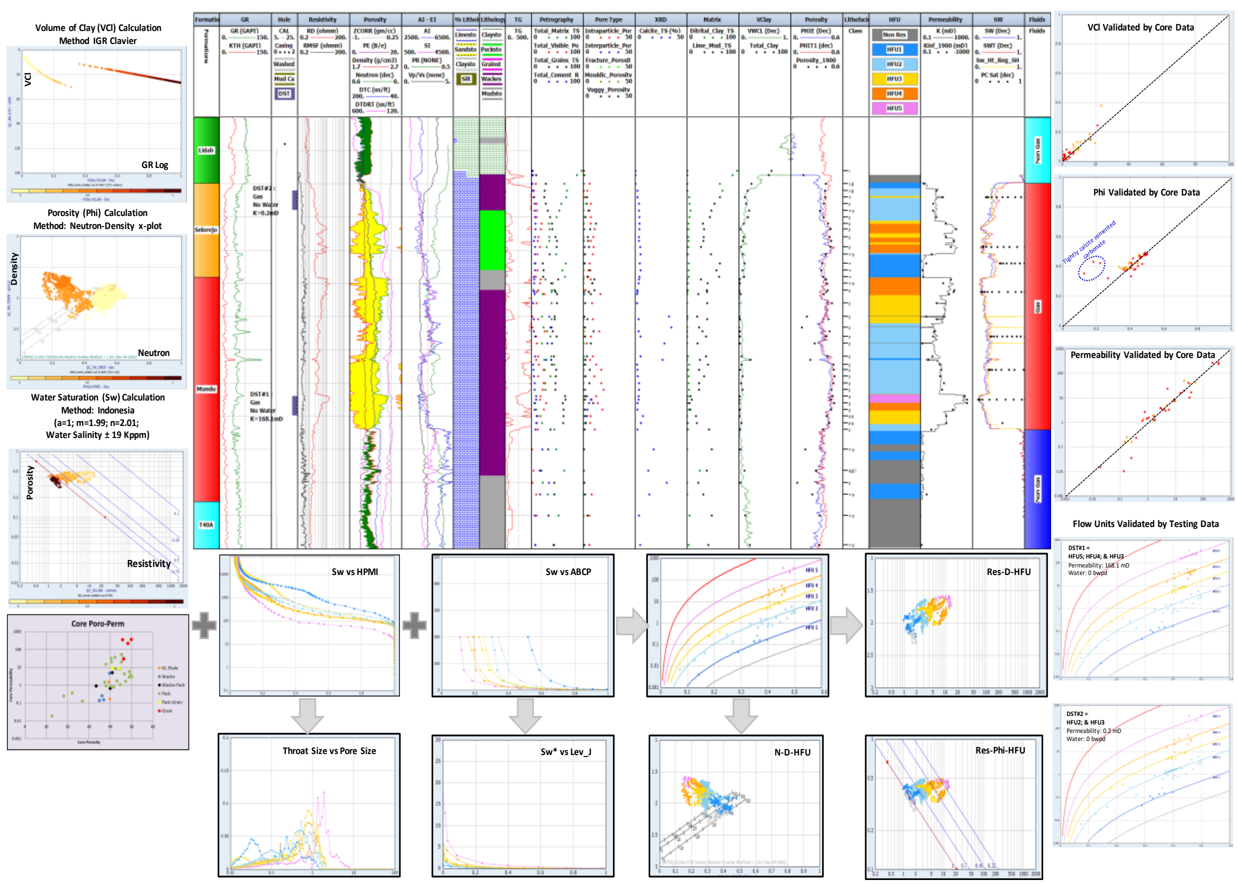

Figure 7. Formation Evaluation and Log to Core Validation.

The pre-stack seismic inversion workflow starts with a blocky model with four initial block models generated, Zp, Zs, density, and Vp/Vs. The reflection coefficient in pre-stack seismic inversion deals with angle-dependent reflectivity based on the Aki-Richards equation that was re-expressed by Fatti et al. (1994). The angle-dependent reflectivity can be calculated using P-wave velocity, S-wave velocity, and density as the main input, creating synthetic seismic gathers.

$$R_{PP}(\theta) = c_1 R_P + c_2 R_S + c_3 R_D$$

Where: $c_1 = 1 + tan^2\theta$ $c_2 = -8\gamma^2 tan^2\theta$ $c_3 = -0.5\, tan^2\theta + 2\gamma^2 sin^2\theta$ $\gamma = \frac{V_S}{V_P}$

The three reflectivity terms, R_P, R_S, and R_D are derived from:

$$R_P = \frac{1}{2}\left[\frac{\Delta V_P}{V_P} + \frac{\Delta\rho}{\rho}\right]$$
$$R_S = \frac{1}{2}\left[\frac{\Delta V_S}{V_S} + \frac{\Delta\rho}{\rho}\right]$$
$$R_D = \frac{\Delta\rho}{\rho}$$

The synthetic seismic gathers are compared with the original seismic gathers iteratively together with the matching process between the original logs and modeled logs. In the end, when the difference between synthetic seismic gathers with original seismic gathers is small, the iterative changing of modeled logs is no longer needed and the simultaneous pre-stack inversion is finished. One indicator to show how successful a pre-stack inversion process is a good correlation between synthetic seismic compared with original seismic, and modeled logs compared with the original logs.

Many parameters can distinguish the internal reservoir properties. In this study, pre-stack seismic inversion analysis techniques such as Acoustic Impedance (AI), Vp/Vs ratio, Shear Impedance (SI), LambdaRho (**λ**ρ), and MhuRho (μρ) were used to identify potential reservoirs and predict rock quality within gas-bearing areas.

$$AI = \rho Vp$$
$$SI = \rho Vs$$
$$LambdaRho\ (\lambda\rho) = \rho^2(Vp^2 - 2Vs^2)$$
$$MhuRho\ (\mu\rho) = \rho^2 Vs^2$$

The vertical heterogeneity from the exploration well is a combination of rock quality and fluid (gas hydrocarbon). P-wave is pretty much affected by the presence of gas, due to its natural ability to propagate and transmit in any medium, gases, liquids, and solids. It is pretty much slowing down in the medium of gas. Unlike P-wave, S-wave can't propagate in gas and liquids, and slowly propagate in solids medium. The properties behavior leads to a distinct effect in terms of reservoir sensitivity. The GL reservoir properties are captured on a cross-plot of AI vs Vp/Vs ratio; AI vs SI; AI vs LambdaRho; and AI vs MuRho (Figure 8). The P-wave impedance can be divided into three clusters, the very good (magenta) with range AI of (2400-3200) gr/cc*m/s^2, the good to medium (orange-yellow) with range AI of (2800-5000) gr/cc*m/s^2, and the moderate-poor (blue) with range AI of (3800-5500) gr/cc*m/s^2. Since S-wave propagates slower than P-wave, the value of S-impedance will be smaller compared to P-impedance. The Vp/Vs ratio can be divided into three clusters, the very good-good-medium (magenta-orange-yellow) with a range Vp/Vs ratio of (1.6-2.0), the moderate (light blue) with a range Vp/Vs ratio of (1.6-2.0), and the poor (blue) with range Vp/Vs ratio of (1.8-3.0). The S-wave impedance can be divided into three clusters, the very good (magenta) with range SI of (1300-1700) gr/cc*m/s^2, the good-medium (orange-yellow) with range SI of (1700-2700) gr/cc*m/s^2, and the moderate-poor (blue) with range SI of (1700-3000) gr/cc*m/s^2. The LambdaRho can be divided into three clusters, the very good (magenta) with a range LambdaRho of (2.0-5.0) GPa_gr/cc, the good-medium (orange-yellow) with range LambdaRho of (3.5-12.0) GPa_gr/cc, and the moderate-poor (blue) with range LambdaRho of (5.5-30.) GPa_gr/cc. The MuRho can be divided into three clusters, the very good (magenta) with a range MuRho of (1.5-3.0) GPa_gr/cc, the good-medium (orange-yellow) with range MuRho of (3.0-9.0) GPa_gr/cc, and the moderate (blue) with range MuRho of (1.5-11.0) GPa_gr/cc.

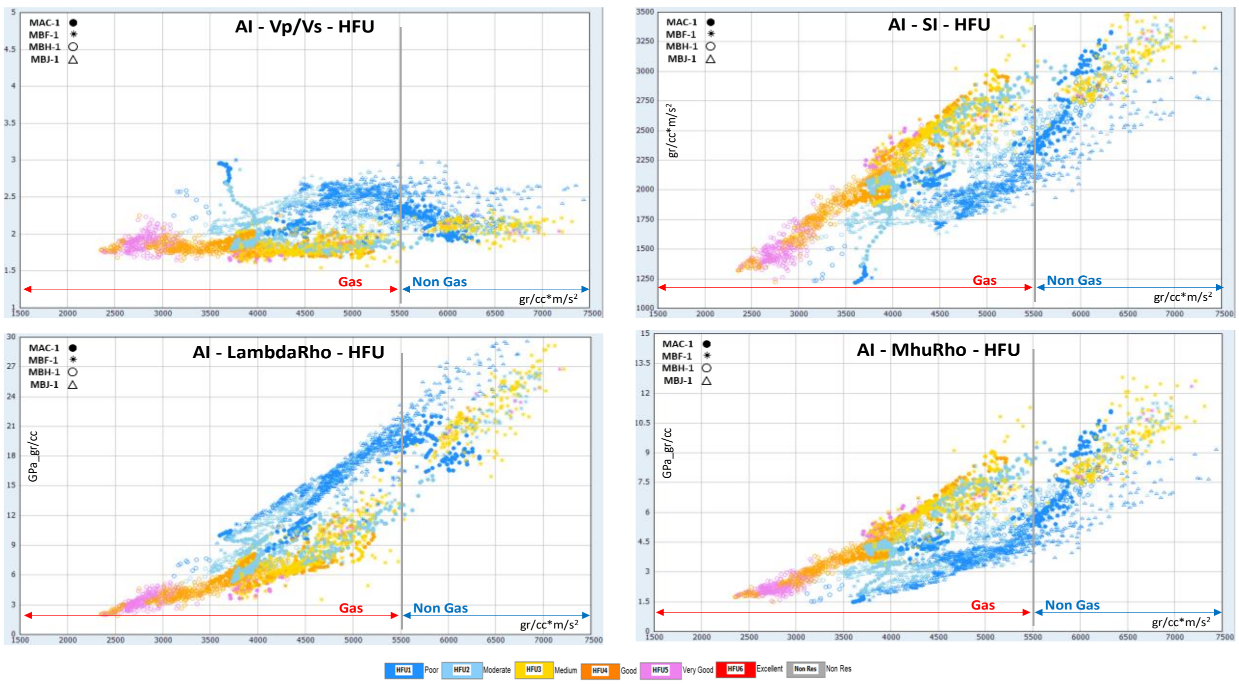

Figure 8. Sensitivity Analysis from MAC-1 - MBF-1 - MBH-1 - MBJ-1 wells reference, AI vs Vp/Vs Ratio; AI vs SI; AI vs LambdaRho; AI vs MuRho.

Result and Discussion

GL reservoir porosity is typically supported by matrix porosity and grain-to-grain porosity. The reservoirs have a total porosity of up to 50% volume with permeability ranging from 0.01mD to over 500mD. From petrography analysis, the major porosity types encountered in this reservoir are intra-particle porosity within the foraminifera shell and inter-particle porosity (between foraminifera). Lime muds are the predominant material in the matrix with only minor amounts of detrital clay observed. The best reservoir has less lime mud matrix filling and less clay association. Characteristics of GL reservoir are indicated by the presence of 6 HFUs class, from Poor (HFU1), Moderate (HFU2), Medium (HFU3), Good (HFU4), Very Good (HFU5), and Excellent (HFU6).

The final petrophysical results of four representative wells have Vs data are shown in Figure 9. The quality-controlled logging curves are shown at tracks 2–6 which consist of gamma-ray; borehole condition, conventional core and DSTs interval; resistivity; density; neutron; compressional and shear velocity; acoustic impedance, shear impedance, compressional-shear velocity ratio, Poisson's ratio. The petrography data shown in tracks 7-10 consist of lithofacies; grain, matrix, visible porosity, cement; pore type; calcite cement; detrital clay, and lime mud. Meanwhile, the interpretation result validated with core data, is shown in tracks 11-15 which consist of volume of clay validated with total clay from XRD; porosity log validated with core porosity; HFU; permeability log validated with core permeability; water saturation. The petrophysical results from discovery wells in the GL reservoir obtain varying thicknesses from 120-280 ft with NtG 15-100%. GL reservoirs are clean with a clay content of less than 15%. Dominant pore type comes from intra-granular porosity, which makes porosity in the reservoir very excellent within the range of 20-50%, meanwhile, permeability varies from 0.2-560 mD and Sw 15-65%. The formation evaluation provides reservoir properties such as VClay, porosity, flow units, permeability, and water saturation. The higher quality of HFU will have higher porosity and permeability, lower clay volume, and lower water saturation and can be identified as sweet-spot intervals.

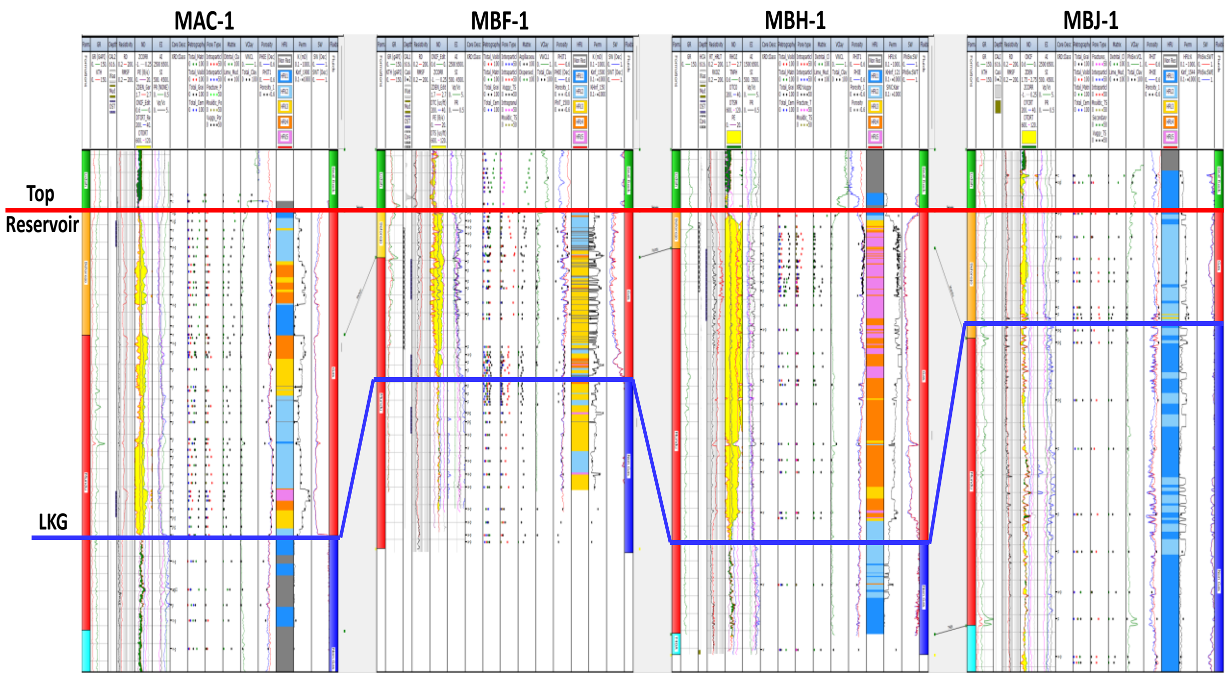

Figure 9. Formation Evaluation Result.

Bangau 3D-seismic data consists of post-stack data and pre-stack gathers. The availability of measured Vp, Vs, and density, opens the possibility of doing pre-stack seismic inversion. The reflectivity depends on how big the contrast of impedance between the two layers. Meanwhile, the post-stack seismic inversion only assumes that the angle of the incident is always zero, with the Fatti et al. equation (1994), the analysis can now include angle-dependent reflectivity. Therefore, the blocky initial model in pre-stack simultaneous inversion consists of Zp, Zs, density, and P/S velocity. Utilizing sensitivity analysis cut-off for the AI vs Vp/Vs ratio; AI vs SI; AI vs LambdaRho; and AI vs MuRho, the reservoir characterization can be done in BI, BG, and BE fields. Based on the cross-plot, the optimum parameter to predict lateral distribution of reservoir quality in BI, BG and BE prospects is AI vs LambdaRho. The lateral distribution of reservoir quality shown in Figure 10, based on AI and LambdaRho classification with reddish color (low) showing better reservoir quality compared to greenish color (high), meanwhile the white color showing above the cut-off value of AI and LambdaRho. The reddish color correlate with grainstone – packstone facies and the greenish color correlate with packstone – wacketone facies. Finally, integrating reservoir characterization and pre-stack seismic inversion analysis techniques can help to distinguish the medium to the best quality of reservoir rock that should be used as a target for exploration wells.

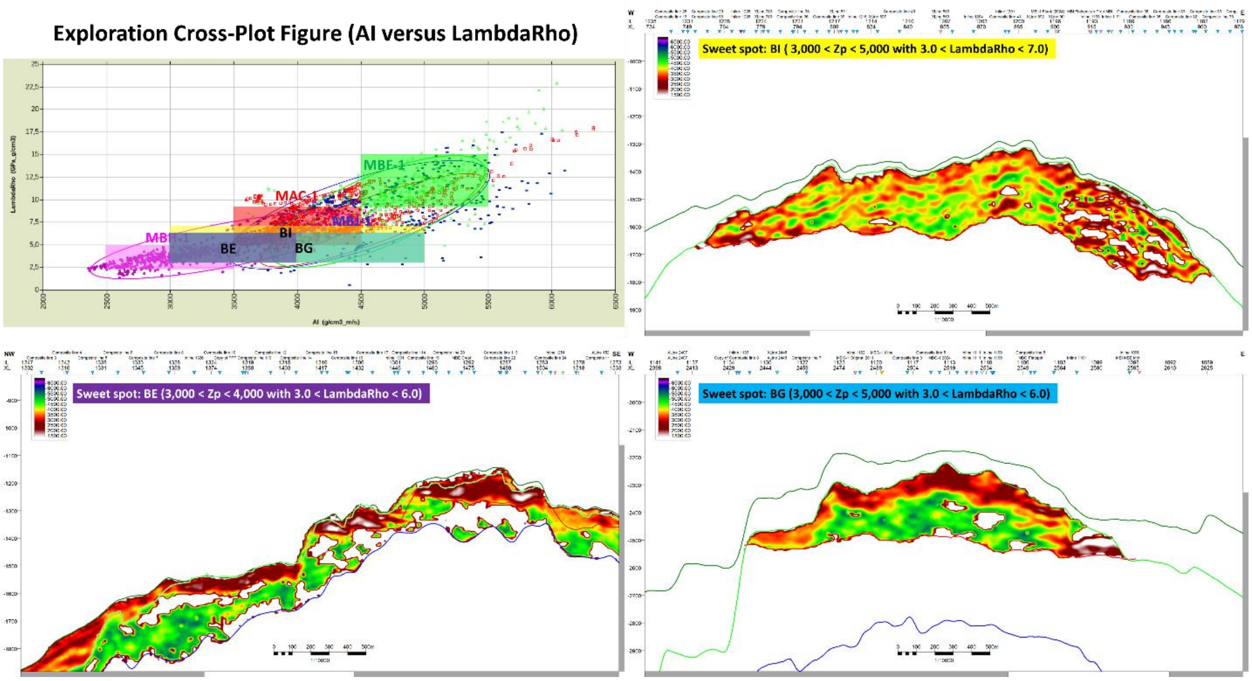

Figure 10. Pre Stack Seismic Inversion Result for BI, BG and BE Prospects.

Conclusions

Results from this research are six flow units determined as reservoir rocks which have different qualities; Poor (HFU1), Moderate (HFU2), Medium (HFU3), Good (HFU4), Very Good (HFU5), and Excellent (HFU6). Lithofacies, lime mud, content, and diagenesis control the HFU quality. The petrophysical properties obtain varying thicknesses in the range 120-280 ft with NtG 15-100%, clay content less than 15%, porosity range 20-50%, permeability varies from 0.2-560 mD, and Sw 15-65%. Pre-stack seismic inversion results concluded that using a certain range of AI combined with Vp/Vs ratio, SI, LambdaRho, and MuRho can help to identify hydrocarbon potential areas, predict and distinguish rock quality (poor-medium-very good) in certain prospects in Bangau-3D seismic. The recommended drill-able ranking prospects are BI, BG, and BE.

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