INTEGRATED 3D MODELING IN A MATURE OILFIELD: A CASE STUDY IN LAPANGAN HIJAU OILFIELD, CENTRAL SUMATERA BASIN

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ABSTRACT

Lapangan Hijau oil reservoir is located in the Southern part of Rokan PSC, Central Sumatera Basin, Indonesia. It is one of the high potential and prolific fields that have been producing oil for over 40 years. Lapangan Hijau has hydrocarbon accumulations in tidal sediments, mainly in proximal tidal bars deposit. Those sediment bodies are deposited through vertical interval ranging from 10 to hundreds of feet. Nowadays, the challenges are to identify and exploit remaining oil reserves in these high water saturation reservoirs. This reservoir is locally known as the “Z sands”. It was deposited at depth between 4500ft to 5000ft. During the last few years, considerable efforts have been done to develop and optimize oil production from the “Z sands”. This paper describes the efforts to gain better geological understanding by integrating all available data including core, well logs, and well test data. As a result three new well locations and two existing deepening opportunities were identified. This paper highlights the importance of using an integrated approach to further develop a mature waterflood oil field.

I. INTRODUCTION

Lapangan Hijau is located in Rokan Production Sharing Contract Area, Riau Province, Sumatera (figure 1). Since being put on production 1971, the field has yielded more than 300 MBO. Hydrocarbon accumulations are most often located within a series Early Miocene tidal dominated sandstone reservoirs and are principally characterized by thrusted four way anticline traps. Currently more than 400 wells have been drilled in Lapangan Hijau.

Lapangan Hijau is known to be a complex, highly compartmentalized field which exhibits significant production and pressure anomalies. Compartmentalization is supported by several lines of evidence: radical changes in reservoir character over short distances; wide variation in pressure data; anomalously low water saturation values in recently drilled wells and inconsistent "water cut" values.

To address these problems, an integrated 3D reservoir model and petrophysical study was conducted. A 3D reservoir modeling will help to achieve this goal and define the area of pay distribution in term of facies and rock properties (porosity, permeability, and water saturation). To delineate the area with the best rock properties, a petrophysical study based on well log data has been conducted to get cut-off values of the main parameters: porosity, permeability, and water saturation. These cut-off were applied for defining the “sweet spot” in interval “Z sand”. This “sweet spot” is related with most productive area in Lapangan Hijau in “Z sand” interval.

II. REGIONAL GEOLOGY

The Lapangan Hijau is a northwest - southeast trending asymmetrical anticline, with the steeper northeast flank formed by enechelon normal faults, downthrown to the northeast. The anticline has a vertical closure of about 650 feet and is complicated by a subtle saddle between the north and south domes. The anticline is transacted by smaller faults that trend northeast - southwest and northwest - southeast.

The main thrust fault is trending NW-SE and is located at northeast of the field parallel to
field structural high. Some small normal faults lie perpendicular to the main thrust fault and generate potential compartmentalization of the field. The anticline is asymmetric from the Julia X sand thru the Julia Z sand with a steeper dip to the NE compared to the SW. The general reservoir dip is about 3-4 degrees, but in the NE approaching the main fault the dip is more than 30 degrees.

There are 2 formations of producing sands in the Lapangan Hijau. These are Diniar formation and Julia Formation. The Diniar Formation was deposited on the top of the Julia Formation, it is commonly separated by marine shale and has been categorized into 5 sand body reservoirs named the Diniar-A (T-A), Diniar-B (T-B), Diniar-C (T-C), Diniar-D (T-D), and Diniar-E (T-E). The Julia Formation is divided into 3 major sand bodies Julia X, Julia Y and Julia Z.

### III. METHOD

Kind of data that used in this study are well log data and core data. Log data is used as main data for looking back at the well. Total 455 wells are used in this study. Core data used as main data to interpret depositional environment and sedimentology study in research area. Total 14 core data are used in this study. Correlation, petrophysic, and geomodeling are main analyses in this research.

### IV. DATA AND ANALYSES

#### Core – Well Tie

The correlation of core and well data show that the cross-bedded – coarse sandstones facies has an association with bell shape log GR pattern. The bioturbated – fine sandstones facies has an association with irregular log GR pattern. The bell shape pattern of GR log is interpreted as graded bedding succession in the tidal bar, while the irregular shape indicates bar deposits – if its thickness is rather thin, it may indicate tidal effect. Whereas high value of GR log is represent subtidal marine facies, and it’s interpreted as non-reservoir facies (figure 2). Each type is collected and interpreted coherently into a particular facies model. This electrofacies determined as a key for detail correlation for the entire well which is not have core data.

#### Well Log Correlation

Characteristically, in Lapangan Hijau, the well-log curves of adjacent wells are very similar, but the degree of similarity decreases in more distant wells. By working with a series of closely spaced wells, the geology condition of Lapangan Hijau will clearly show. Three markers were used to correlate 445 wells, named T_JZ, B_JZ, and T_JZ2. The correlated markers were interpolated to generate depth structure maps. The structural geology in the study area was adopted from the previous interpretations. Hundreds wells have penetrated the “Z Sand” Julia. The log motif corresponding to all well section show the fining upward to blocky nature and occasionally coarsening upward at places. The sands appear to be more silty and clayey at places. The well correlation clearly demonstrates the better reservoir distribution and its heterogeneities within the field. The thickness of the “Z sand” varies from 10 to hundreds ft, it increase at NW trend, and decrease at SE trend (figure 3).

#### Facies Map

The facies map is generating based on numerical stratigraphic data (relative thicknesses). The isopach map of the stratigraphic unit is used as base map for the facies map, and the interpretation of the facies patterns is closely related to interpretation of the isopach lines. The isopach maps show the morphology of the thick and thin sand intervals. The sand isopach maps and core descriptions are used to interpret the depositional environment of “Z sand” interval. Based on previous study about core “Z sand” description, study area is
located on tidal bar sub-depositional environment.

The “Z sand” is determined to represent a dynamic environment that has a high degree of reworking due to tidal energy. The patterns of sand deposition (isopach maps) of the “Z sand” at Lapangan Hijau conform to the regional geologic interpretation of the environmental interpretation of the Early Miocene deposition in the depositional basin in that those sands were part of an overall Tidal Dominated Delta depositional system. The sand patterns of the “Z sand” series suggest a tidal dominated delta. The “Z sand” shows lobe switching of delta (transgression) to occupy the increasing of accommodation space (figure 4). The tidal bar sand facies that has the thickest sand is in the LH427 well (74 ft) and the thinnest net sand is in the LH111 well (28 ft). This map also indicating that sediment supplies come from NE area (Sundaland).

**Petrophysics**

Values for delimiting permeability and porosity are very important to better estimate the correct thickness of net pay. The porosity cut off is selected to provide sufficient permeability to ensure economic production. Determination of this value relies on generating porosity – permeability relationship from the well log data. For computing the porosity and permeability cut off in “Z sand”, well log data from proven oil well was used (figure 5), according the following steps:

a. Values from porosity and permeability are filtered on “Z sand” region only
b. Values from porosity and permeability are filtered from proven oil well through single perforation type
c. Porosity value plotted as X-axis
d. Permeability value plotted as Y-axis
e. Choose lowest point of each porosity and permeability

Final results are:
- Porosity cut off = 12.67%
- Permeability cut off=56.625 mD
- Porosity and permeability of study area have high linear correlation
- Pores with porosity less than cutoff value (12.67%), are bad/non reservoir rock
- Pores with Permeability less than cutoff value (55.625 mD), will not allow fluids to flow

**Evaluation of Bulk Volume Water**

Evaluation of porosity and water saturation was used to predict the type and possibly estimate rate of production of “Z sand” in Lapangan Hijau, so it would be possible to recognize whether the “Z sand” still profitable or not. Evaluating the value of porosity and water saturation, will give us more information about “Z sand”.

Theoretically for given type of rock and/or grain size, there is a relationship between water saturation (Sw) and porosity. The product of water saturation and porosity is known as bulk volume water (BVW). This relationship can be expressed by a hyperbolic equation:

\[ Sw = \frac{C}{\phi} \]

Where, \( C \) = Constant for type of rock and/or grain size

If the plotted points form a cluster very close to a hyperbolic curve and above the porosity cut off that was calculated, means that the sandstone is at irreducible conditions and no water could be expected. This also gives indication of uniform grain size. On the other hand, when layer is water bearing, the bulk volume of water becomes scattered and apart from the hyperbolic pattern. In this case the
sandstone will produce more water than it can hold by capillary pressure.

Cut off value for water saturation was equal to 50%, just for indicating hydrocarbon production rates. If the cluster is below 50% in Sw, “Z sand” will produce high rates of hydrocarbon with no water. Points in the region of Sw>50% result in water production or no flow. This cut off value it will be apply in the water saturation model to identify the “sweet spot” area.

From plotting result, “Z sand” indicates that it’s in irreducible conditions and transition condition (figure 6). On irreducible zone, we can observe that the plotted point in this zone are relatively follow the hyperbolic curve and it assemble in left side, so theoretically there is more oil in this zone. Whereas on transition zone, the point that plotted in this zone are very scattered and doesn’t follow the hyperbolic curve, theoretically there is more water in this zone (but still produce oil). If data from well that only produce water in “Z sand” are plotted on the graph, the point will very scattered, like on LH-026. So the water saturation cut off will be somewhere between transition zone and water zone (LH-026), it’s about 50%. However a good production in “Z sand” is expected.

### V. 3D RESERVOIR MODELING

The 3D reservoir modeling was performed using GOCAD software. Basic concept for 3D reservoir modeling (static modeling) started with building a consistent structural model as the base for distributing the geological facies and rock properties (petrophysics parameters).

#### Structural Modelling

Structural modeling is the first step in building 3D models and it subdivided into three main processes:

a. Fault modeling

There are 11 main faults. Most of them have NW-SE trend and are located at northeast of the field parallel to the field structural high. Some small normal faults lie perpendicular to the main thrust fault

b. Gridding

The grid used in this study was 50m x 50m (X,Y). All of grids are adjusted to 127.5°, honoring the boundary orientation.

c. Horizons, Zoning and Layering

The layer thickness of this modeling is about 2 ft. Total there are 62 layers that built.

All three main processes are tied together into one single 3D grid. Total there are 5,022,000 grids cells.

#### Facies Modeling

There are two main macro-facies in this study, reservoir and non reservoir. In this study the macro facies reservoir-non reservoir was calculated using Vshx parameter, and the cut off value is 0.3 (according to previous study). Calculation of facies model using the following formula:

- Vsh 0<Vsh<0.3 = sand
- Vsh 0.3<Vsh<1 = shale

This cut-off value means if the value of Vshx is less than 0.3, it’s interpreted as sand (reservoir). If the value of Vshx is more than 0.3, it’s interpreted as shale (non-reservoir). The reservoir code was defined as 1 and non-reservoir code as 2. The snapped facies logs were propagated to the entire grid using SIS (Sequential Indicator simulation). This method was selected because: 1) facies log are discrete data 2) it is simple propagation process (only two macro-facies). Depositional environment map also used as facies probabilistic trend. So the propagation of Vshx parameter was controlled by depositional environment map. Final result, facies model have similar trend with depositional environment map (figure 7).

#### Petrophysical Modeling
After finished with facies modeling and attached to it, simulation method was applied to propagate such as porosity, permeability, and water saturation. In this study, Sequential Gaussian Simulation (SGS) was used. SGS can handle sparse and high heterogeneity data.

Porosity Modeling
The distribution of porosity values is constrained to the reservoir facies model. Therefore, it’s important to adjust input data (statistic properties) to get a more stable modeling. Crossplot graph Vshx and porosity parameter gives good correlation coefficient, it’s about 0.73. Therefore, facies model can be used to control porosity propagation. Final result porosity model have similar trend with facies map (figure 8).

Permeability Modeling
Similar with porosity, the permeability 3D distribution has been defined, but in this case the distribution is constrained by porosity model. Furthermore, before applying geostatistic modelling with porosity as secondary trend, it is necessary to make sure correlation coefficient between both is good enough. Collocated co-Krigging technique was applied. This technique will assure a good consistency between porosity and permeability values, avoiding conflict values in certain location in the grid (e.g. very low values of porosity and high permeability values assigned to the same grid cell). After setting these parameters, permeability simulation was performed. Figure 8 show the good agreement between porosity and permeability simulation after applying cut off values.

Water Saturation Modeling
In this study, SWE (effective water saturation) was used to express current water saturation condition. Effective water saturation data acquired from log interpretation which have been used for defining pay zone for “Z sand” reservoir at current condition. Using the same workflow for porosity and permeability, Sequential Gaussian Simulation was used. Water saturation model was guided by porosity model.

According with previous experience with BVW, a cut off of 50% was applied for these sandstones. The final result of water saturation is showed in figure 9. Distribution of low water saturation can help to delineate the best area. This model could be excellent indicator for defining the sweet spot area.

VI. RESERVE CALCULATION
Based on the technical assessment presented in the previous chapters, especially those described in reserve calculation parameter, we have been exercised to determine the reserve in study area. Reserve Calculation had been done in reservoir interval in “Z sand” with accurate reservoir parameter and volumetric method. The reserve calculation performed in this study has been using the basic formula as follows:

$$STOIP \ (STB) = \frac{7758 \times V_b \times \Phi \times (1 - S_w)}{B_o i}$$

Where:
- $V_b$ : volume reservoir, acre ft
- $\Phi$ : porosity
- $Sw$ : water saturation
- $B_o i$ : formation volume factor

Probabilistic calculation has been used in this study. There are three parameters that adjusted into probabilistic mode when calculating OOIP. There are lowest known oil (LKO), permeability, and porosity. These parameters adjusted like on Table 1.

Total reserve in OOIP calculation is equal to:
- Less than 86,000 MSTB at low case
- More than 90,000 MSTB at mid case
- More than 100,000 MSTB at high case
VII. RECOMMENDATION

The distribution of oil in a reservoir interval can be visualized by making hydrocarbon pore thickness map. The hydrocarbon pore thickness for this study is equal to isopach map x porosity x water saturation. These were created by combining the three dimensional volumes of porosity, water saturation to give a hydrocarbon pore volume which could be contoured in two dimensions. Based on this map, we propose 3 new wells location (figure 10). Based on reservoir simulation analyses, these 3 wells give very good cumulating production result (265000 MBO) for 7 years ahead (figure 11). There are also 3 wells which recommended to deepening. These well are located on sweet spot area based on HPT map, but doesn’t reach “Z sand” (figure 12).

VIII. ACKNOWLEDGMENT

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TABLES

Table 1. Parameter Calculation Of OOIP

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FIGURES

Figure 1. Study area is located on Rokan PSC

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