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Reservoir Modeling of Carbonate on Fika Field: The Challenge to Capture the Complexity of Rock and Oil Types

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Abstract - The carbonate on Fika Field has a special character, because it grew above a basement high with the thickness and internal character variation. To develop the field, a proper geological model which can be used in reservoir simulation was needed. This model has to represent the complexity of the rock type and the variety of oil types among the clusters. Creating this model was challenging due to the heterogeneity of the Baturaja Formation (BRF): Early Miocene reef, carbonate platform, and breccia conglomerate grew up above the basement with a variety of thickness and quality distributions. The reservoir thickness varies between 23 - 600 ft and 3D seismic frequency ranges from 1 - 80 Hz with 25 Hz dominant frequency. Structurally, the Fika Field has a high basement slope, which has an impact on the flow unit layering slope. Based on production data, each area shows different characteristics and performance: some areas have high water cut and low cumulative production. Oil properties from several clusters also vary in wax content. The wax content can potentially build up a deposit inside tubing and flow-line, resulted in a possible disturbance to the operation. Five well cores were analyzed, including thin section and XRD. Seven check-shot data and 3D seismic Pre-Stack Time Migration (PSTM) were available with limited seismic resolution. A seismic analysis was done after well seismic tie was completed. This analysis included paleogeography, depth structure map, and distribution of reservoir and basement. Core and log data generated facies carbonate distribution and rock typing, defining properties for log analysis and permeability prediction for each zone. An Sw prediction for each well was created by J-function analysis. This elaborates capillary pressure from core data, so it is very similar to the real conditions. Different stages of the initial model were done *i.e.* scale-up properties, data analysis, variogram modeling, and then the properties were distributed using the geostatistic method. Finally, after G&G collaborated with petrophysicists and reservoir engineers to complete their integrated analysis, a geological model was finally created. After that, material balance was needed to confirm reserve calculations. The result of OOIP (Original Oil in Place) and OGIP (Original Gas in Place) were confirmed, because it was similar to the production data and reservoir pressure. The model was then ready to be used in reservoir simulation.

Keywords: reservoir modeling, carbonate, rock and oil types, simulation, Fika Field

Introduction

Fika Field is an oil and gas producer that lies in South Sumatra Basin. Currently, the field has 38 wells, of which 24 are producers from BRF (Baturaja Formation). The formation has heterogenic properties. Some parts of the field have BRF with high permeability, while the other parts may have BRF with tight permeability that requires stimulation, such as hydraulic fracture, in order to be able to produce. The cumulative production is 8 MMSTB and more than 47 BCF of gas, which originated from associated gas and gas cap production. Oil recovery factor is expected to be more than 30%, although the gas cap has been blow- down since December 2009, which has accelerated reservoir pressure depletion and reduced oil production. In addition, hydraulic fracturing has been done in this field, resulting in an increase in oil production from 20 BOPD to 50 - 113 BOPD, while, other wells produce gas and water.

Because a high demand for gas must be satisfied, the Fika Field must produce its gas cap, which is the main reservoir drive. This will affect reservoir pressure and oil recovery. To minimize oil loss due to gas cap blow down, and to maximize gas production, a team was established to conduct a reservoir study.

The previous workers who studied Baturaja carbonates relating to hydrocarbon reservoir properties are Caroline (2005), Handayani (2008), and Erawati (2013).

The purpose of this paper is to explain how to build rock typing from carbonate which is highly heterogenic, and how to generate permeability transform and steps in model water saturation by using capillary pressure from core analysis. At the end of the paper, there is a discussion on reserve confirmation regarding static data and production data by utilizing material balance.

Geological Setting

This field has a simple geological structure and there is more emphasis on stratigraphic aspects. Musi Platform is bounded by Pigi depression in the northern area, Lematang depression in the south-east area, Saung Naga graben in the south-west area, and Benakat Gully in the eastern area. This setting indicates the possibility of reef build-up above basement high (Musi Platform), when the sea level rose (transgression) during deposition of Baturaja Formation (Rashid *et al.*, 1998). The carbonate type that grows on the Musi Platform is an isolated platform. Carbonate facies on the Fika Field is divided into reef, platform, and breccia conglomerates with different quality, uneven distribution, and relatively thin thickness (up to 20 ft below). The Baturaja carbonate is Early-Middle Miocene in age with depositional environment about neritic to shallow marine, while tectonic settings are in a sagging phase. In the study conducted with LAPI ITB (2011), the Musi Platform has hydrocarbon source rock from Lemat Formation as lacustrine environment. The lithology is lacustrine shale mixing between algal lacustrine and organic material from land origin. Oil expelled on moderate maturity (approximately 0.7 - 0.95% Ro) with kerogen type II/III derived from exinite, liptinit or algae. This generally indicates gas and oil. Lemat Formation on the studied area began 22 MYA and has moderate maturity for producing oil (early oil generation) in Benakat Gully.

Data and Method

This research was divided into various stages of data analysis, as listed below:

Seismic Data Analysis

1. Well seismic tie from seventhcheck-shots.
2. Seismic interpretation and the result as time structure and depth structure maps of reservoir and basement.

Petrophysical Evaluation

1. Review available Special Core Analysis (SCAL) data to determine of a, m, n.
   - Facies carbonate assignment after core depth matching and core description.
   - Net Overburden (NOB) core correction for porosity and permeability and Klinkenberg correction for permeability.
   - Defining matrix end-point value from crossplot: RHOB vs core porosity, DT *vs.* core porosity, NPHI *vs.* core porosity.
   - Defining a and m from the best straight line plot log F (Formation Resistivity Factor) *vs.* log porosity on every facies (rocktyping result).
   - Defining n from the slope of the line plot log Sw *vs.* log RI (Ro/Rt).
2. Analyzing log using zonation based on geological correlation.
   - Estimating Rw value for Baturaja reservoir in Fika field.
   - Calculating Vcl (mudstone) using SP log and Density- Neutron log after confirmation with XRD data correlation.
   - Calculating porosity effective and Sw using Simanduox and Indonesia. The final selection for Sw values will be based on transition zone analysis (TZA).
   - Crossplot between log porosity (effective and total) *vs.* core porosity (NOB correction).
3. Lithofacies based on core description and rocktyping determination.

4. Analyzing looping log using parameter zonation by rocktype.
5. Prediction permeability and Analyzing Transition Zone (TZA) to predict Sw based on core data.

Fine Grid Model

1. Scaling up properties
2. Analyzing data
3. Modeling variogram
4. Distributing the properties using geostatistic method.

Reserve Calculation Confirmation

1. Calculation material balance reserve
2. Calculation static model reserve (OOIP and OGIP).

Result and Discussion

Seismic Data Analysis

Seismic 3D PSTM was used for this study. Well seismic tie was implemented in the early stages of seismic well analysis, using well data (density and sonic log) and wave model (wavelet) from seismic data extraction. The same parameters as 3D seismic data were used, where positive polarity is recorded as increasing acoustic impedance on positive amplitude with zero phase. Figure 1 below shows wavelet extraction parameter, the model of extraction, and the amplitude spectrum.

The next step was to create a synthetic seismogram and to match the trace with seismic data.

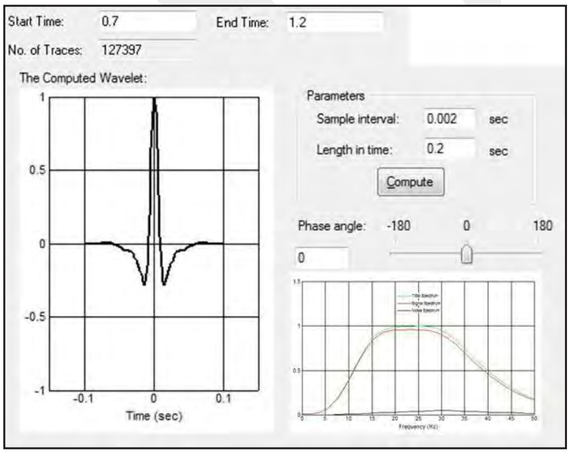

Figure 1. Parameter and the result extraction on Field 3D seismics.

Match value between synthetic seismogram and seismic trace is called coeficient correlation (r). Positive r value and near with 1 shows that synthetic seismogram and seismic trace has good correlation.

Well to seismic tie analysis was done on the seventh check shot at this field. Figure 2 shows synthetic seismogram from Fika-1 well, while Table 1 shows the resume of coeficient correlation from each well.

After well seismic tie, some main markers were defined and distributed on seismic data to obtain the geological model of each marker and to interpret the geological history of the field. The seismic mapping result of basement and Baturaja carbonate is shown in Figures 3a and 3b, respectively.

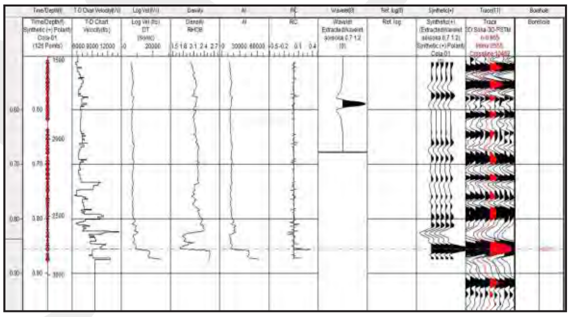

Figure 2. Parameter and the result extraction on Field 3D seismics.

Table 1. Resume of Coeficient Correlation from each Fika's check Shot Wells

Well	Coefficient Correlation (r)
Fika-1	0.605
Fika-2	0.698
Fika-3	0.781
Fika-4	0.281
Fika-5	0.447
Fika-6	0.463
Fika-7	0.845

Petrophysical Evaluation

This step begins with an analysis of core data measurement after core depth matching. It is important to make a reliable definition of the position of the carbonate facies development with depositional setting and match with the subsurface condition. Thereafter, routine core

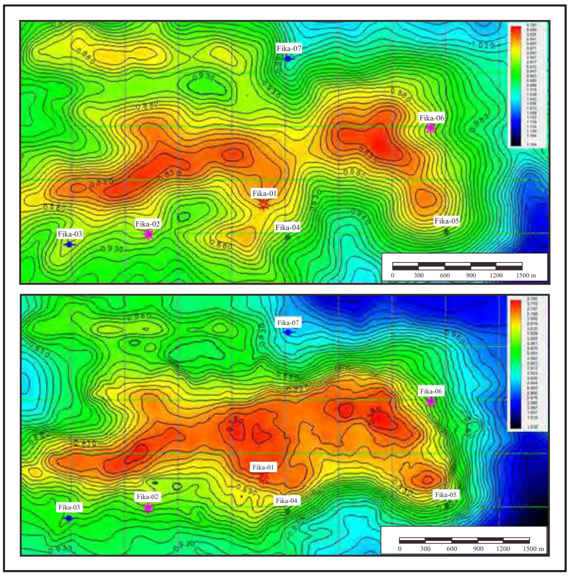

Figure 3. Time Structure Map. (a) Basement Fika, (b) Baturaja Carbonates.

analysis (RCA) and SCAL data were done. Porosity core requires NOB correction (Figure 4), while permeability core requires NOB (Figure 5) and Klinkenberg correction (Figure 6). Based on the core description, facies carbonate definition is created and zonation is needed for log analysis.

The correction factors are as below:

$$Ø_{NOB} = 0.9755\ Ø_{amb}$$

$$k_{NOB} = 0.5159\ k_{amb}^{1.0288}$$

Klinkenberg effect on permeability is estimated from available liquid permeability data and given trend from text book (Figure 6).

Based on geological setting, the carbonate facies which developed from the top of Baturaja to basement are reef, platform, and breccia/conglomerate clastics. A previous study on the

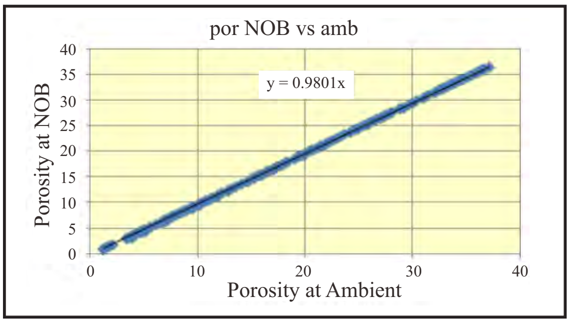

Figure 4. Porosity NOB correction on Fika Field.

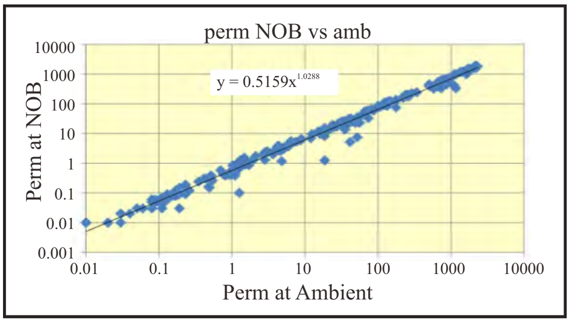

Figure 5. Permeability NOB correction correlation on Fika Filed.

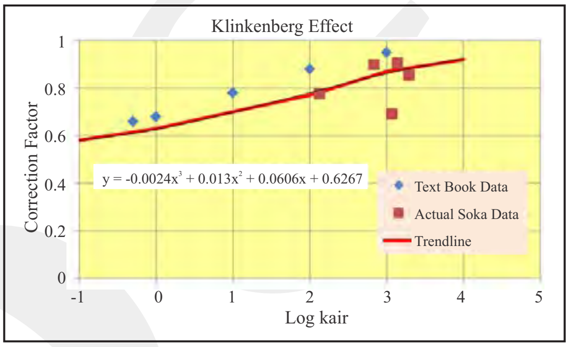

Figure 6. Klinkenberg correction correlation of permeability on Fika Field.

BRF at Fika field was carried out in a previous study which indicated that seven lithofacies can be identified based on core calibration from Fika-A1, C1, D1, E1, and F2 wells, in addition to image analysis from Fika-B4, C1, and E1 wells.

The G&G groups utilized the available seismic data and well logs to define three depositional facies (referred to as zones in the current geologic model) as follows:

1. Reef Limestone
2. Platform Limestone
3. Breccia/Conglomerate Clastics

Investigation of available core description (both whole & plugs) confirms the existence of the above three depositional facies and indicates the following lithofacies (Figures 7 and 8; and Table 2).

The distribution of lithofacies described above (from core data) does not indicate any specific relationship with subsea elevation (TVD subsea) within individual depositional facies (zones) as shown in Figure 9.

The above conclusion is supported by the previous study as indicated by the distribution of lithofacies with depths shown in Figure 10.

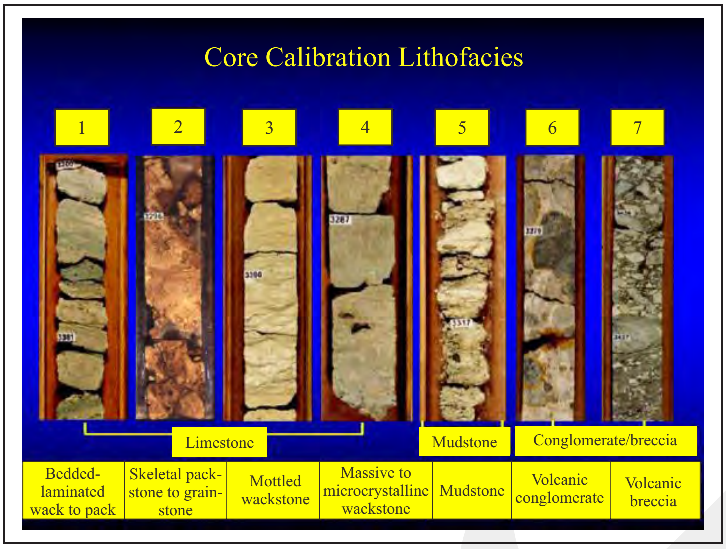

Figure 7. Core calibration lithofacies.

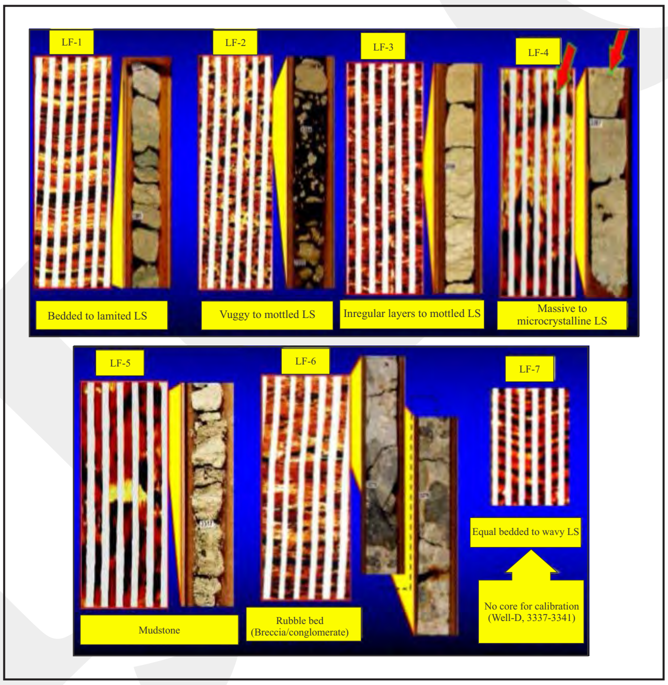

Figure 8. Image and core calibration lithofacies.

Table 2. Facies Distribution from Core Analysis on Fika Field

Depositional Facies	Lithofacies	Number of Data Points	Percentage
Reef	Vuggy Coral/Grainstone	34	11%
	Mottled Wackstone	36	12%
Platform	Vuggy Wackstone/Packstone	31	10%
	Bedded, Chalky, and microcrystalline Limstone	109	36%
Breccia/Con-glomerate	Diminant Limestone Fragments	60	20%
	Dominant Vulcanic/Basement Frag-ments	31	10%
	Total	**301**	**100%**

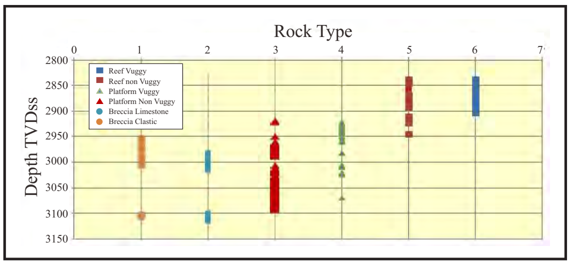

Figure 9. Relationship between lithofacies and subsea elevation on Fika Field.

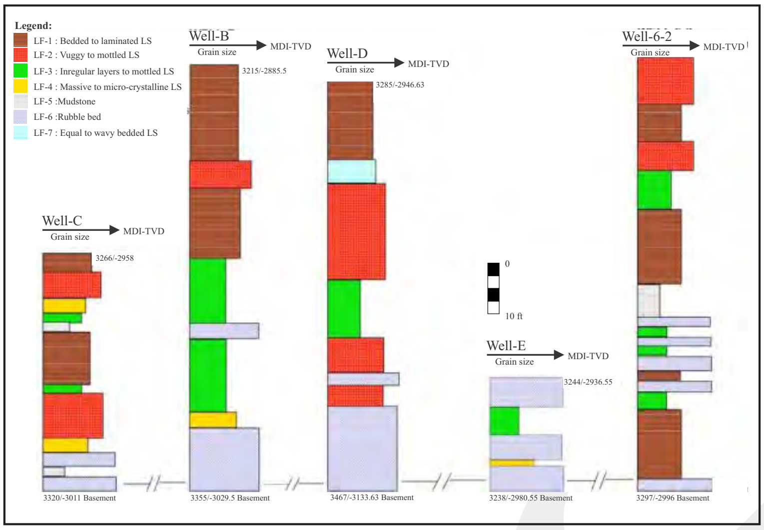

Figure 10. Relationship between lithofacies and subsea elevation on Fika Field.

The facies distribution shown in the above chart indicates that some thin intervals of breccia/ conglomerate exist within the limestone depositional facies. This phenomenon is applied in the current geologic model, where only three zones are included, as discussed above. If this situation is not acceptable, some consideration should be given to include the breccia's lithofacies (with limestone fragments and with volcanic/basement fragments) in the lithofacies distribution of limestone zones and assigning appropriate percentages to represent the thin breccia intervals within reef and platform zones.

It should be noted that the mudstone lithofacies (defined as LT-5 in the previous study) is not recognized in any core plugs, but is included in the whole core description.

Accordingly, the present model will include these lithofacies as a result of the cut-off analysis using appropriate porosity, Vms, and permeability cut-off values and will be referred to as nonreservoir facies (facies 0 in Petrel).

Based on the above discussion, the following facies code (rock type) is defined for the geologic model, was shown on Table 3.

The following lithofacies assignment (by zone) will be utilized in the model if breccia/conglomerate thin interval within reef and platform are ignored (Table 4).

After lithofacies were created on the cored wells, it was necessary to distribute the lithofacies on all uncored wells. Although it was difficult to obtain the special log character of each lithofacies, it could be done using crossplots between RHOB - NPHI, RHOB - DT, RHOB - PHIT, RHOB - SP, RHOB - PHIE, and RHOB - GR. Consequently, the lithofacies needed to be simplified in order to distribute on uncored (electrofacies) wells, as shown below (Table 5).

Low energy limestone represents mud dominated on rock matrix, while high energy carbonate represents grain dominated on rock matrix. The

Table 3. Lithofacies Code

Lithofacies code	Description
0	Nonreservoir (no log above basement)
1	Breccia/Conglomerate with volcanic
2	Breccia/Conglomerate with limestone fragments
3	Bedded, Chalky, and microcrystalline Limestone
4	Vuggy Wackstone/Packstone
5	Mottled Wackstone
6	Vuggy Coral/Grainstone

Table 4. Zone Code and Lithofacies

Zone Code	Description	Lithofaces included
0	Reef	0, 5 and 6
1	Platform	0, 3 and 4
2	Breccia/Conglomerate	0, 1 and 2

Table 5. New Zone Code and Lithofacies

New zone code	Description	Lithofaces included
0	Non reservoir	0
1	Breccia/Conglomerate	0, 1 and 2
2	Low energy LS	0, 3
3	High energy LS	0, 5
4	Vuggy LS	0, 4, 6

electrofacies distribution was based on the value of VGR and corrected SP. After reviewing all capillary pressure data, it has been concluded that the permeability/porosity ratio depends more on rock type from lithofacies and capillary pressure data. The permeability/porosity ratio will be used as a basis to create rock typing and TZA. Rock typing based on permeability/porosity ratio and TZA will be discussed later in this paper in a special section.

Based on SCAL data from four cored wells, a and m were defined from the best straight line plot log F (Formation resistivity factor) vs log porosity on each rock type (Figure 11). The n parameter was defined from the slope of the line plot log Sw vs log RI (Ro/Rt) (Figure 12). The average density was defined on each rock type. The result is shown in the Table 6.

The next step was to define matrix end-point value from crossplot between log data and core data measurement, *i.e.* RHOB *vs.* core porosity, DT *vs.* core porosity, NPHI vs core porosity (Table 7). Logically, when porosity value is zero, it is assumed as matrix value on the log data.

The preliminary log analysis used zonation based on geological correlation, after rock-typing had been defined. Log analysis uses parameter a, m, n, and end-point matrix in every rock type. Rw estimation for Baturaja reservoir was based on Picket Plot (Figure 13). The Rw estimation value was equal to 17.000 ppm salinity. A water test lab analysis result was not appropriate input for log analysis, due to the influence of mud on the water samples.

Vcl (mudstone) calculation on Fika's carbonate used GR and density-neutron log. According to the concept introduced by Asquith (2004), the sonic log usually reads matrix porosity without the effect of vugs, but both neutron and density logs indicate the effect of vugs on porosity reading. Consequently, more significant differences were expected between calculated porosity values from these logs opposite vuggy limestone intervals compared to intervals without vugs. The following chart shows this phenomenon after applying the concept to Fika's core data (Figure 14).

In the above chart, the porosity difference ratio is defined as follows:

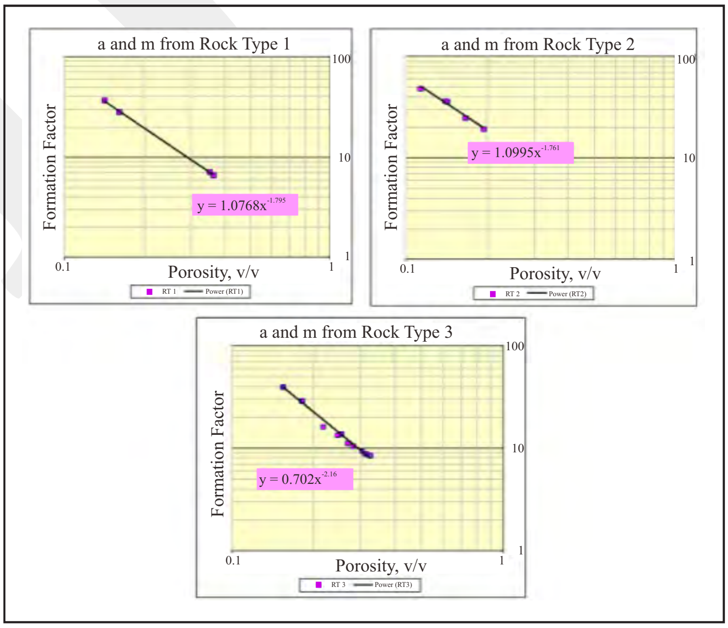

Figure 11. Formation Factor *vs.* Porosity to obtain Cementation Factor (m).

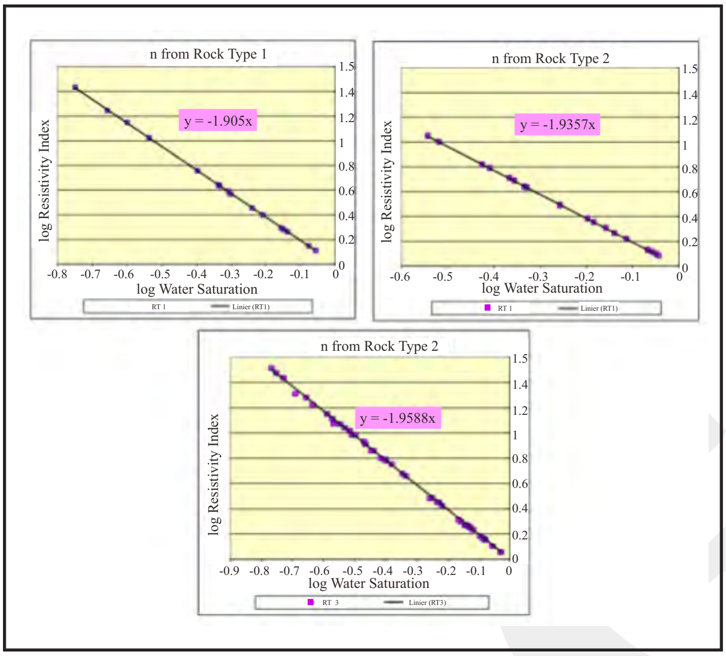

Figure 12. Formation Resistivity Index vs Brine Saturation to obtain Saturation Exponent (n).

Table 6. Resume of Average Value from a, m, n, and Grain Density on every Rock Type

	From Cross Plot		
Rock Type	**a**	**m**	**n**
1	1.077	1.795	1.905
2	1.100	1.761	1.936
3	0.702	2.160	1.959

Rock Type	Ave Grain Dens, gr/cc
1	2.705
2	2.692
3	2.699

Table 7. Resume of Average Value from a, m, n, and Grain Density on every Rock Type

Parameter	RT1	RT2	RT3
Matrix density	2.68	2.7	2.71
Fluid density	1.1	1.2	1.1
NPHI for matrix	0	0.07	0
NPHI for fluid	0.83	0.94	1.1
Matrix transit time	50	52	53
Fluid transit time	225	198	210

$$\Delta\rho_R = \frac{\rho_{sonic} - \rho_{D\text{-}N}}{\rho_{D\text{-}N}}$$

Where:

ρ_{sonic} = sonic porosity

$\rho_{D\text{-}N}$ = average porosity from density and neutron logs

It should be noted that this definition of porosity difference ratio does not align with the results from this study, since theoretically speaking, sonic porosity should be lower than density-neutron porosity for interval with vugs. However, log analysis results indicated sonic porosity to be higher than density-neutron porosity for most intervals.

Even with the incorrect definition, the results in the above chart do not indicate any correlation for defining criteria to identify vuggy intervals. It should be noted that Vsh values initialy calculated for this study were based on minimum values among several methods available in the Petrolog software. The study team revised this concept in view of the questionable applicability of GR logs in carbonate reservoirs. Accordingly, only density-neutron logs were used to define Vsh.

The core data do not include platform with vugs. Accordingly, the study team decided not to include this rock type in the current model. This decision was further supported by the geologic concept of low probability for finding vugs in platform carbonate intervals overlain by reef carbonate.

The fact that vuggy intervals that cannot be recognized from well logs is supported by visual investigation of available core material. Figure 15 shows that vugs were scattered within thin

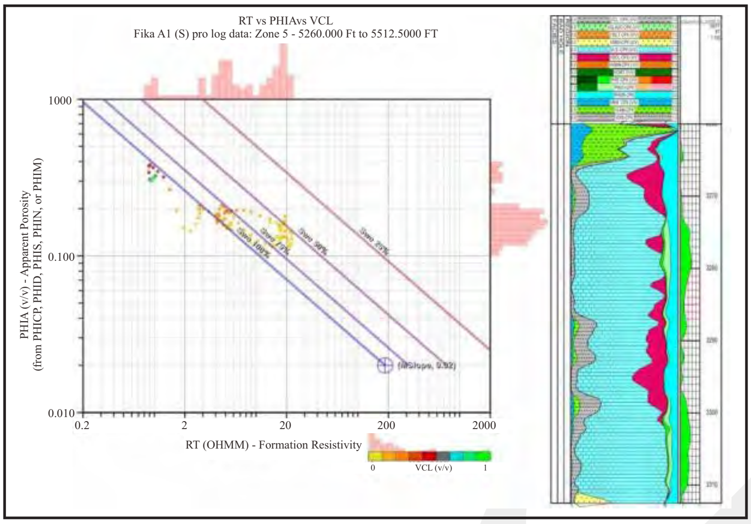

Figure 13. Picket plot to determine Rw of Baturaja Formation.

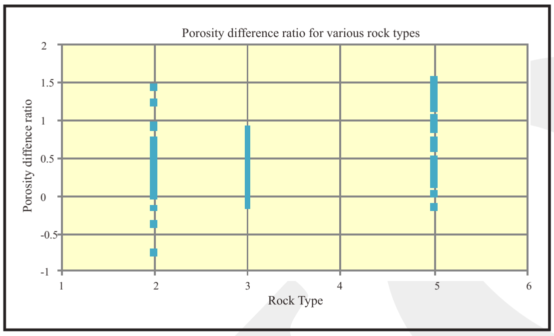

Figure 14. Porosity difference ratio for various rock type on Fika Field.

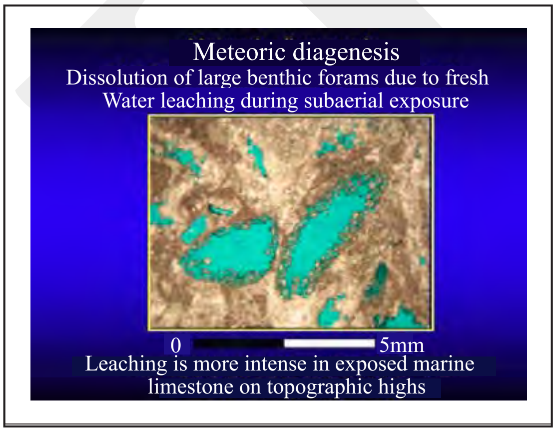

Figure 15. Meteoric diagenesis from thin section on Fika Field.

intervals that cannot be read and cannot affect log response. Investigation of side wall core samples from well Fika I1(1) as well as thin section analysis of these samples indicate the existence of an appreciable amount of mudstone within the BRF, including the reef zone. The mudstone in BRF is believed to be the result of internal diagenetic and lithification effects and probably some external effects from gravity settling of fine materials.

Three thin sections were analyzed quantitavely by Lemigas in order to determine the mudstone content in the side wall samples from well Fika-I1 (1). The results are shown below. Measured mudstone contents in the three sections are 15, 16 and 62.5% by volume. Average Vsh value for the sorted data sample is 21.6%, which is rather low for the mudstone content range indicated by thin section analysis.

After defining appropriate Vsh, total porosity must be correctly calculated to be effective porosity. Comparative results between log porosity (total and effective) *vs.* core porosity (NOB) are shown in Figure 16.

Sw calculation was made using Simanduox and the Indonesia method. The Indonesia method is more appropriate in this field, because the result is more sensitive to transition areas. The final selection for Sw values was based on TZA.

Permeability transform of four lithofacies on electrofacies was slightly modified. Vuggy limestone has data distribution near low energy limestone, so the permeability transform between low energy limestone (mud supported dominated) and vuggy limestone used the same transform value. The formula can be seen in the Figures 17a, b, and c.

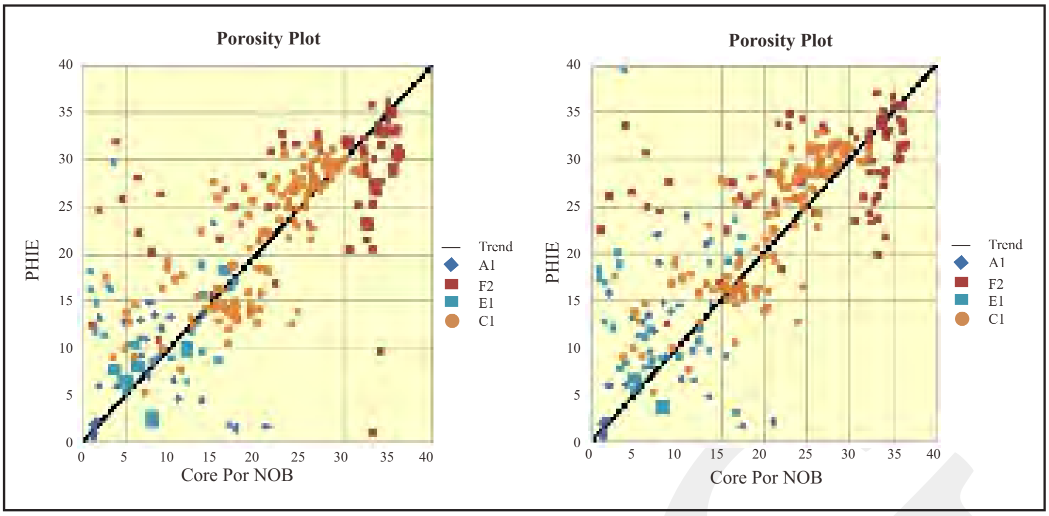

Figure 16. Comparation between plot between log porosity (total and effective) *vs*. core porosity (NOB).

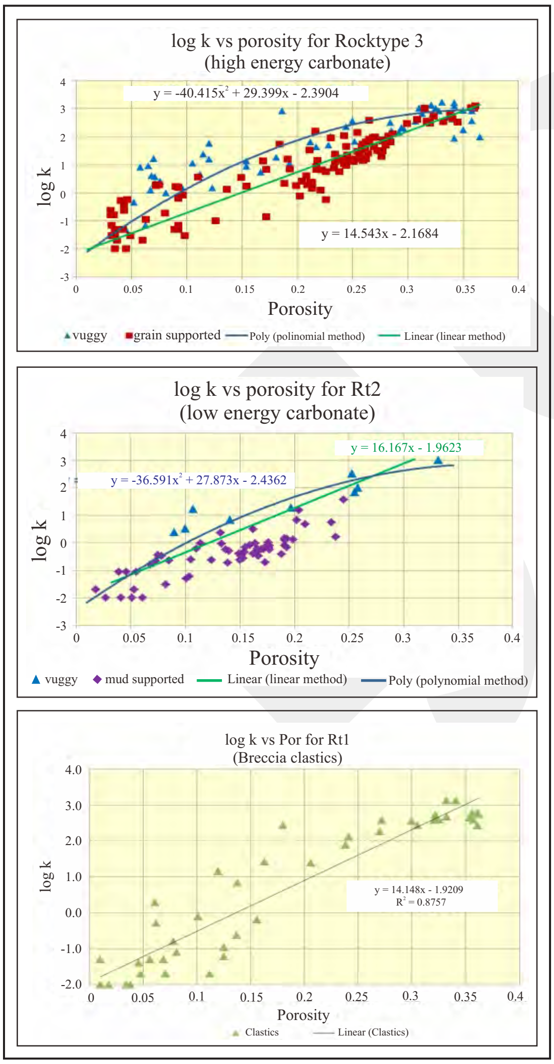

Figure 17. Permeability transform for high energy limestone (a), low energy limestone and vuggy limestone (b), and breccia clastics (c).

Transition Zone Analysis

To define Sw in each grid, transition zone analysis (TZA) was applied. The application was conducted in the following procedure:

1. Defining permeability transforms and a suitable Swc trend in terms of permeability, which for Fika Field can be seen in the following graph (Figure 18).
2. Defining J-function derived from core data and normalize all available data in a single chart. The core data were divided into three regions based on range of k/ϕ (Table 8 and Figure 19).
3. Defining J-max from chart in no. 2
4. Calculating k, S_{wc} and S_w* from the exploration well log (*i.e.* the log which was surveyed when the reservoir was not yet producing) and using it to calculate h and (Jσ cos θ) for every depth-log above OWC.

$$J\sigma \cos\theta = h(\rho_w - \rho_o)g\sqrt{k/\phi}$$

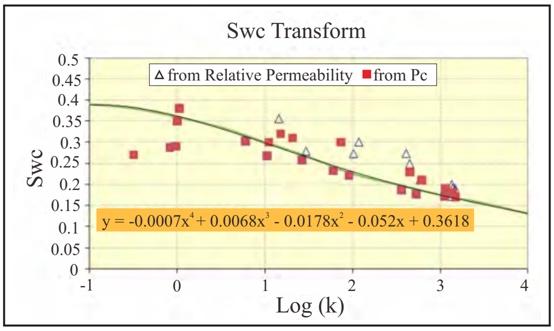

Figure 18. Crossplot between Swc vs. log permeability to get Swc transform.

Table 8. Range Definition of Rock Typing on TZA

low k/por	k/por<100
medium k/por	100 <k/por<1200
high k/por	k/por> 1200

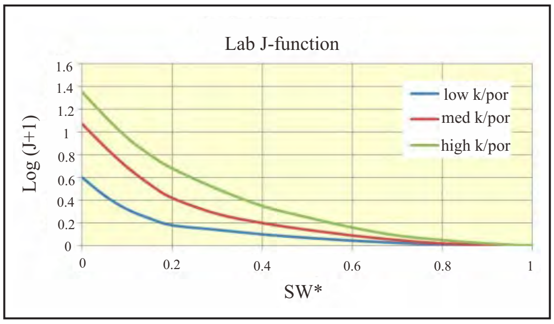

Figure 19. Crossplot between Sw* vs log (J+1) to get J function.

5. Ploting (J σ cos θ) versus Sw* and fitting the best J-function curve. Calculating $(\sigma \cos \theta)_{res}$ for each reservoir rock type at determined value of Sw*

$$(\sigma \cos \theta)_{res} = \frac{(J\sigma \cos \theta)}{J}$$

6. Calculating the reservoir J-function for each reservoir facies using the average value of $(\sigma \cos \theta)_{res}$.
7. Comparing the curves of laboratory and reservoir J-functions *versus* Sw*.The chart should show a good match, as shown in the following graph (Figures 20a, b, c):
8. Estimating the value of θ for each reservoir rock facies if σ is known.
9. Calculating the coefficient of J-function for use in Petrel model.
10. Using the reservoir J-function to formulate a transform relating S_w* to J_{res} or a selected function of J_{res}.
11. Using the value $(\sigma \cos \theta)_{res}$ to calculate required capillary pressure curves for various facies from their normalized J-Functions.
12. Calculating corresponding values of S_w*.

Fine Grid Model

The 3D geology model was built by using Petrel 2011 software. There were several stages during the process, including: 1) creating horizon, zone, and layering, 2) scaling up properties, 3) analyzing data, 4) modeling variogram, and 5) distributing the properties by geostatistic method. The area of interest was limited by polygon boundary, which was created based on oil-water contact area.

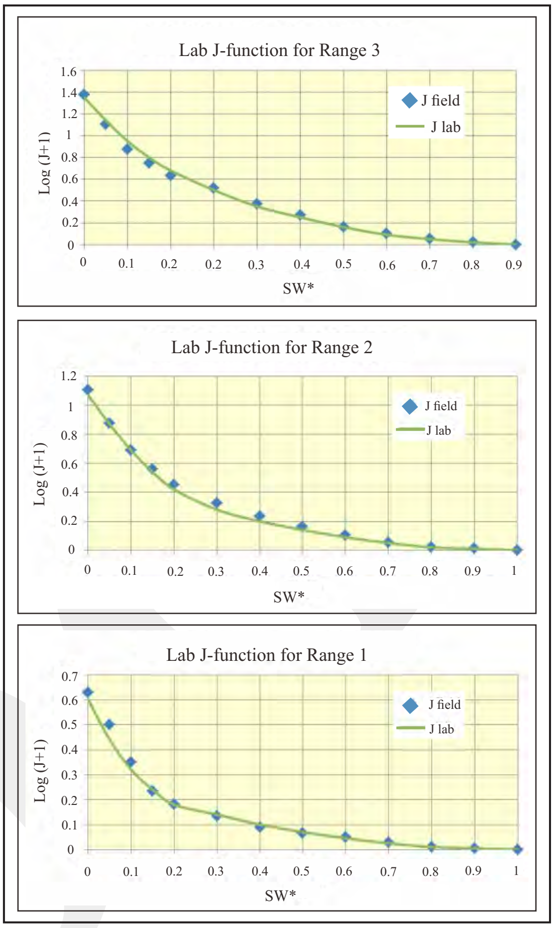

Figure 20. Curve shape for Lab J-function for range 3 (a), range 2 (b), and range 1(c).

Since there was no fault in this Fika Field, the 3D grid model was built using simple grid. The first step in creating a simple grid was creating horizon, using several surfaces as input data, such as BRF (top surface), PLTFRM, BXCGL, and BSMT (bottom surface). All of these input surfaces were already in depth domain. The next step was to determine the grid boundary, which was based on surface boundary and grid geometry, such as X minimum, X maximum, Y minimum, Y maximum, and grid size increment. After this, the grid increment was determined. The grid increment should represent the geological features on a lateral distribution and also for simulation purposes. 50x50 grid increment was chosen, because it would give a good result for distribution of reservoirs. If the grid increment exceeds 50x50, there will be a greater possibility of error when calculating bulk volume (reflected in negative value in bulk volume), and also the value of properties will not be accommodated. But if less than 50x50 is input, many active grids will be created, which will be ineffective, and furthermore the calculation process will be slowed down. As a result, there are four horizons with three zones. Zone one is reef zone, zone two is platform zone, and zone three is breccias/conglomerate zone. After creating zonation, the following step was the layering process. Each zone was divided into several layers based on cell thickness, so every layer will have an average thickness of 0.88 ft. Determining the number of layers was based on the depositional pattern of carbonate in Fika Field. As a result, the layering process created 972 layers for all zones, with a total number of 5458752 3D cells.

Scale-up properties were calculated for several well logs, *i.e.* porosity, horizontal permeability, vertical permeability, water saturation, facies and net to gross ratio. All of these properties were upscaled based on the fine grid that was created before, using weighted averages and the following criteria: a) facies and rock type: most of average weighted bulk volume, b) net to gross: arithmetic average weighted bulk volume, c) porosity: arithmetic average weighted bulk volume, d) horizontal permeability: arithmetic average weighted net volume, e) vertical permeability: harmonic average weighted bulk volume, f) water saturation: arithmetic average weighted pore volume. A histogram was used to do a comparative QC of the well logs before and after upscale logs. A similar trend in the histogram represented a good correlation between well logs before upscale and upscale logs. Data analysis was required, because the petrophysical modeling used a variogram from data analysis. The reason for this was to define the major, minor, and vertical direction of several properties.

Porosity modeling was built using SGS with conditioning to facies and subfacies for each zone. Even though the distribution of porosity followed the variogram, it also referred to the AI model with applied collocated co-kriging. So for, any area that was out of variogram, the porosity would follow the trend of AI model (Figure 21).

Similarly, permeability modeling was built using SGS and conditioning to facies and subfacies, but referred to the porosity model (Figure 22).

Meanwhile, facies modeling was built using SIS (Gslib) method, because this method was able to distribute the discrete data very well. The SGS (Gslib) honoured the well data and distributed to four different facies, *i.e.* nonreservoir, breccias and vuggy LS, low energy LS, and high energy LS, (Figure 23).

The other properties, vertical permeability, net to gross, and rock type, were distributed by applying a formula using a PETREL calculator. The water saturation was also distributed by using a formula obtained from the relationship between J-function and capillary pressure based on TZA above.

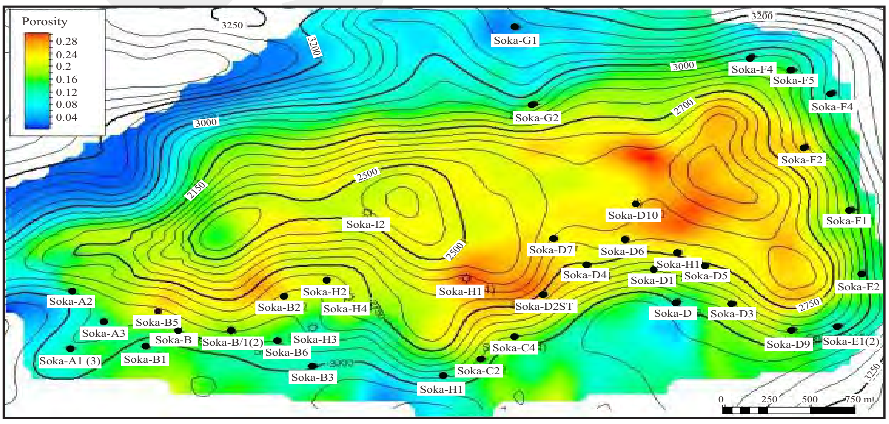

Figure 21. Porosity map after co-krigging stage.

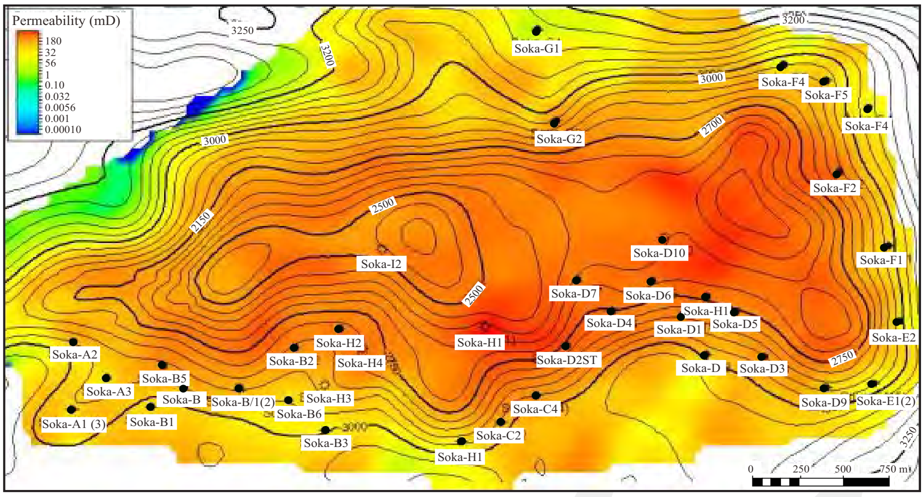

Figure 22. Permeability co-krigging stage.

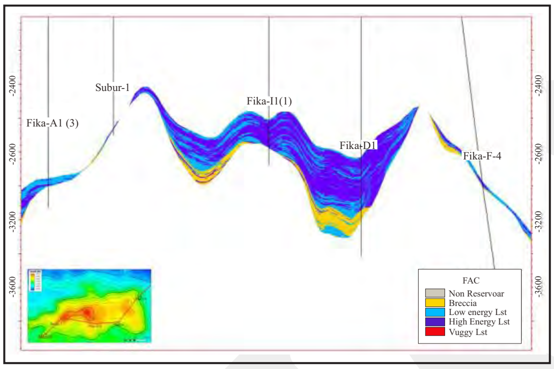

Figure 23. Vertical cross section that shosw facies modeling distribution.

Reserve Calculation Confirmation

Reserve confirmation utilizing material balance analysis

Material balance was utilized to confirm oil and gas in-place in Fika Field. This field has been producing since January 2001, so there are enough production and pressure data (Figure 24).

A straight line material balance analysis can be seen in the graph (Figure 25).

$$\frac{N_p\left[B_t + B_g\left(R_{pc} - R_{si}\right)\right] + W_p}{Y_1} = N + C\,\frac{\Sigma_1^n \left(P_{j-1} - P_j\right) Q_{D\ for\ tD_n - tD_{j-1}}}{Y_1}$$

where $Y_1 = (B_t - B_{ti}) + \dfrac{mB_{ti}(B_g - B_{gi})}{B_{gi}}$

and:

N = OOIP, STB

Np = cumulative oil produce, STB

Wp = cumulative water produced, bbl

Bt = current two-phase FVF, RB/SCF

Bg = current gas FVF, RB/SCF

Bo = current oil FVF, RB/STB

Rsi = initial solution GOR, SCF/STB

Rpc = cumulative producing GOR, SCF/STB

Bti = initial two-phase FVF, RB/SCF

Bgi = initial gas FVF, RB/SCF

m = gas cap size

P = pressure, psi

C = water influx constant, RB/psi

tD = dimensionless time

QD = dimensionless flow

j = time step index for water influx constant

n = number of time steps used in water influx calculations

From the straight line original oil in-place in Baturaja Formation = 26 MMSTB

Water influx constant = 2500 bbls/psi

The "m" value of 7.3 originated from static model (without assumption of any basement bald). This calculation used aquifer characteristics as shown in Table 9.

The material balance calculation confirmed the volumetric calculation that the OOIP was around 22 - 26 MMSTB and that OGIP was around 131 BCF.

Static model reserve calculation (OOIP and OGIP)

Volumetric calculation was done to check the original oil and gas in-place in the Fika BRF reservoir. In addition, the original oil in place results were compared with the material balance analysis to ensure there were similarities between these two methods.

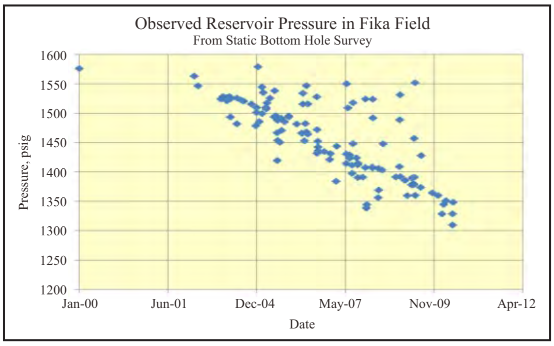

Figure 24. Bottom hole pressure profile from Baturaja Formation of Fika Field.

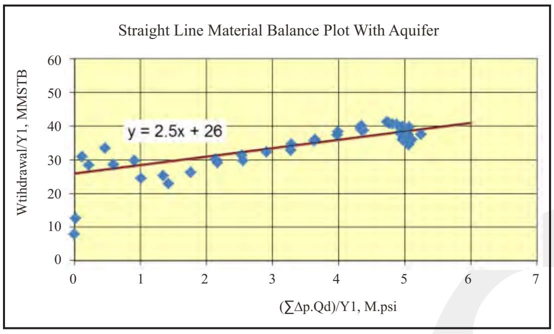

Figure 25. Straight line material balance plot with aquifer of Fika Field.

Table 9. Aquifer Propeties defined for Material Balance Analysis for Baturaja Formation in Fika Field

Aquifer Properties	
h. ft	95
k.mD	106
µw. cP	0.24
ϕ. fraction	0.18
cw, 1/psi	3.26E-06
cf, 1/psi	5.72E-06
Bw. RB/STB	1
re. ft	35.000
θ. degree	180

Based on the distribution of reservoir properties, *i.e.* porosity and water saturation, the value of OOIP was about 25.3 MMSTB, while the value of OGIP was about 131.7 BCF.

Because the hydrocarbon in-place has been already confirmed, this static model could be used in reservoir simulation (initialization and history matching).

Conclusions

Carbonate facies on Fika Field geologically were divided by reef, platform, and breccia conglomerate. Based on core analysis, the carbonate facies were divided into six lithofacies as justification on permeability prediction. TZA was divided into three rock types which represent flow unit as low quality, medium quality, and high quality limestones.

All reservoir property models were built taking into consideration the complexity of rock and oil types, because the properties were tied into facies and water saturation distribution based on the relationship between J- function and capillary pressure.

Reserve calculation from static model was confirmed by comparing reserve analysis with material balance analysis on production data of about 26 MMSTB.

Further research into the complexity of rock and oil types, mainly for reservoir modeling, should be continued using reservoir simulation so that oil flow behaviour can be observed clearly.

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