IATMI22-172

Black Gold From An Old Field: Redefining Methods To Revive Hydraulic Fracturing As An Effective Stimulation For Sangasanga's Tight Oil Potential

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Abstract. Generally, East Kalimantan reservoirs consist of deltaic sand bodies deposited as lenses with high heterogeneities. As the tight formations of these reservoirs are often uneconomical, some are left undeveloped due to the necessity of stimulation job. In addition, operators are typically faced with numerous operational and technical challenges such as thin layer reservoirs, weak shale barriers, coal streaks, high pour-point oil, and over-pressure zones. Over the past decade, few major oil companies in this region have performed frac operations, with less than 10 wells fracced per year with varying and unpredictable results.

Afterall, Sangasanga still has remaining reserves for further development. Fracturing efforts in this field are intended either to expedite production or proving up reserve. Over the last 8 years, 25 frac operations have been performed in more than 10 different formations. With limited data and low reservoir uniformity, statistical analysis is challenging as there are little to no trends in the key parameters. As a result, fracturing success ratio dropped from 70% to 30%, mainly because of inaccuracy and inconsistency between the predicted and actual results.

A detailed review of previous fracturing design and execution was conducted to revise the fracturing approach workflow. The main sequences are data normalization and applying unique coefficient of key parameters. Trial and error approach is used to match the coefficient against the production outcome. The results are then summarized in a simple yet conclusive graph. In addition, several key factors and cut-off values to consider when selecting fracturing candidates were identified. DFIT campaigns were also performed to gather data to help predict the fracturing outcome and plan for the operational resources required for execution.

Keyword(s): Mature Field; Hydraulic Fracturing; DFIT

1 Historical Background

Sangasanga has more than 100 active wells with more than 5 potential layers for each well. Some of those layers was identified to be tight by e-log and MDT test, yet still show hydrocarbon content. For 9 years period, the average of hydraulic fracturing activities in Sangasanga is considerably low, with less than 5 wells fractured annually. This is because the inconsistency of result due to reservoir heterogeneity in lenses deltaic formation in Sangasanga. On the operational side, many innovations have been done to optimize fracturing execution, and some technologies has also been applied. But nonetheless, these attempts were not followed by consistent fracturing results.

The other factor that contributes to various results of fractured wells also comes from limited available layer to be fractured. So, statistical analysis will be challenging due to very little sample that represented the same layer. Further improvement should be done to accommodate heterogeneous layer (a general parameter must be identified).

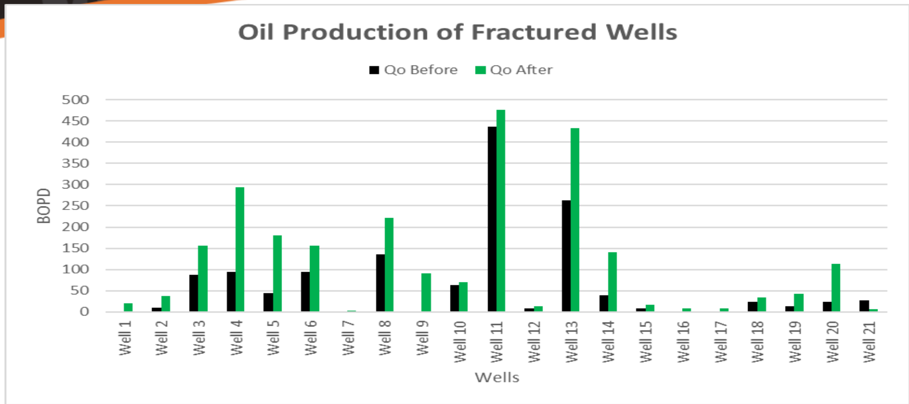

Figure 1 Result of Hydraulic Fracturing in Sangasanga (2014 - 2020)

As for fracturing execution, Sangasanga has relatively "safe" subsurface environments from rock properties and P/T side of view. With average YM of 3MMPsi, 2.5PR and 0.75-0.9psi/ft closure pressure with <200F BHT, has made fracturing execution is somewhat predictable. This is the contributed factor that make screen out ratio in Sangasanga is less than 10% (2 out of 21 fractured wells).

2 Problem Identification

At first, hydraulic fracturing candidacy in Sangasanga is rely on reservoir characteristics defined by Geological, Petrophysics and Reservoir Engineering aspects. These include parameters as follows :

- Net Pay Thickness
- Reservoir Pressure
- Permeability
- Water Saturation
- Remaining well basis reserve
- Adjacent Well Performance

Well schematic, rock mechanics and historical fracturing on that specific layer has also been considered in designing optimum treatment. However, candidate selection is considered to be defined "qualitatively", rather than "quantitatively", due to the fact that some engineers will have their own perspective on how to evaluate some number, whether it is on high or low side.

Secondly, without accurate calculation, especially regarding the expected result of fracturing jobs, we cannot justify the job cost and project economics. On the other hand, accuracy also led us to replicate the successful job, or not doing the failed job in the future.

3 Proposed Solution

a. Fracturing Candidate Matrix

This method was first initiated to "mimic" machine learning concept, where several parameters will be weighted to match with historical result, so that it can foresee output for given inputs. As we know, several techniques that are frequently used to selecting well candidate has collaborate many parameters that could not be integrated into single formula, due to some considerations that correlates with engineering judgement (fuzzy variables). Thus, the competency and experiences of every individual will contribute to the success ratio of the job.

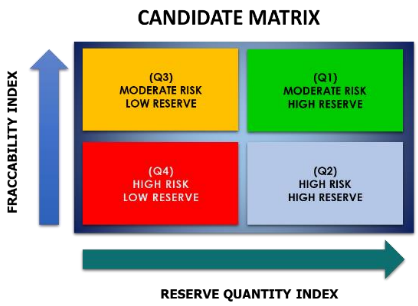

Figure 2 Hydraulic Fracturing Candidacy Matrix

First, 4 quadrants are defined to assess reservoir potential (x-axis) and operational concern (y-axis)

RESERVE INDEX

Criteria	Unit	Percentage	Weighted Value Parameter 0		2		4		6		8	
Permeability	mD	10.0%	0	10	10.1	30	30.3	50	50.5	100	101	1000
Sw	%	5.0%	70	100	60	69	50	59	40	49	0	39
LFA	NA	5.0%	Water, N/A		Gas		Filtrate, BP Oil/gas		Oil with water/gas		Oil	
Net Sand	mD	15.0%	0	5	5.05	10	10.1	15	15.15	30	30.3	100
Production Gain	BOPD	15.0%	0	50	50.5	100	101	150	151.5	200	202	1000
OWC from OH Log	NA	5.0%	Yes								No	
Remaining Reserves	MSTB	20.0%	0	20	20.2	50	50.5	100	101	200	202	500
Oil Type	NA	10.0%	HPPO		-		-		-		Light	
WC Reference	%	15.0%	70	100	60	69	50	59	40	49	0	39

FRACCABILITY INDEX

Criteria	Unit	Percentage	Weighted Value Parameter 0		2		4		6		8	
EMW Pressure	sg	15%	0	0.4	0.404	0.7	0.707	0.85	0.8585	1.01	1.0201	2
Barrier Thickness	m	20%	0	5	5.05	10	10.1	15	15.15	20	20.2	50
Prop/Thickness	lbs/ft	15%	0	100	101	300	303	500	505	1000	1010	5000
Shale/Sand Ratio	fraction	10%	0	0.1	0.101	0.2	0.202	0.3	0.303	0.4	0.404	5
Near Coal Presence	NA	5%	Yes		-		-		-		No	
Cement Integrity	NA	20%	Bad		-		-		-		Good	
Refrac/Not	NA	10%	Yes								No	
Screenout/No	NA	5%	Yes								No	

Table 1 Weighted Parameter of Hydraulic Fracturing Candidate

Then, every axis is broadened to 5 parameters for each, with correlate weight. These parameters are designed to be interpretation free, easy to obtain and less processed data.
Some trial-and-error phase to determine each parameter weight has been done, and give the final result of following graph:

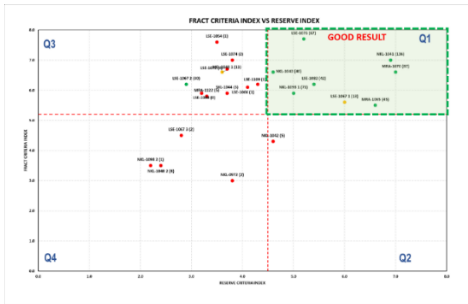

Figure 3 Matched Matrix with Historical Data

This graph will represent how every candidate positioned compared with other candidate, that could make execution and risk prioritizing easier.

b. Transmissibility Trend

Dealing with low permeability reservoir, there are several factors that we assessed to be main contributor to fracturing success ratio:

- Actual permeability beside petrophysical data
- Actual hydrocarbon existence in the reservoir
- Treatment pressure due to rock mechanics and geomechanics model (MEM is just rely on e-logs)
- Frac geometry and the strength of shale barrier

Those are the main contributor that based on fracturing historical statistic, is defining whether the frac result will be accurately defined or not.

To accommodate more accurate data and pre-requisite for fracturing candidate wells, there are three methods that applied so far, which are: DFIT, Temperature Log, and Bottomhole Gauge installed in the end of wellbore string while perform injection.

- *Diagnostic Fracture Injectivity Test (DFIT)*

DFIT is a method for estimating reservoir parameters for low permeability reservoirs that would otherwise not flow prior to fracturing(1) . in this case, DFIT or Mini Falloff test could be assumed to be "frac simulation" with less risk and cost. Especially for low permeability reservoir, DFIT is mean to determine reservoir characteristic with the similar result of PBU, because as we could see, tight reservoir commonly have no capability to provide stable flow that required to conduct PBU Test.

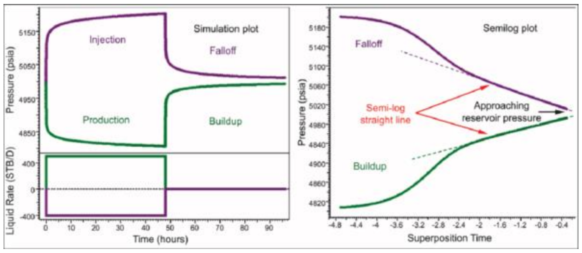

Figure 4 Differences between PBU and DFIT

After injection is done and decline pressure is recorded, analysis could be done using fracturing software or well test software. As of our experiences, the typical fracturing simulator software (Stimplan, FracPro, MFrac, and FracCade) could do After Closure Analysis (ACA) and obtain necessary parameters.

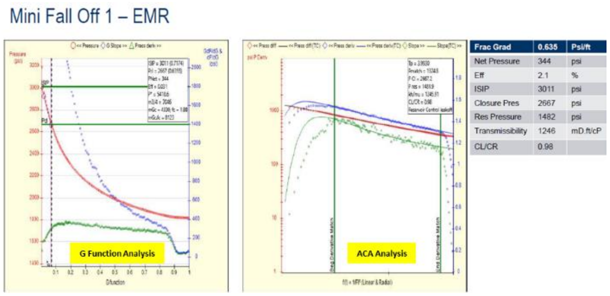

Figure 5 DFIT Analysis on SS-XXX

Parameters obtained from ACA then combine with fracturing parameter (in Fracturing Matrix) to develop candidacy trend. This final parameter will differ for each field, but it could easily adjusted by changing the constant.

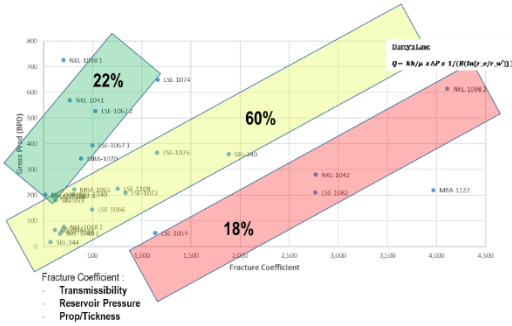

Figure 6 Matching Historical Fracturing Parameter with Fracturing Result

From the graph above, 60% of the population is matched with the trend, with 22% is better form the trend, while remaining 18% is showing worse result.

- *Temperature Log*

In the event of injection, there will be temperature changes along the wellbore and reservoir. Ambient temperature liquid that injected to the reservoir will brings reservoir temperature down by some degree for a period of time until it increases again to equalize with existing reservoir. The range (height) of this cooling down effect will occur as the amount of volume injected, and equalizing period will affect by the delta temperature between injected fluid and reservoir existing temperature. By the end of injection, although a well will begin to reach pressure equilibrium at the moment injection ceases, the total flow of fluid will be small; hence, the effect of heat transfer by convection will be negligible. Therefore, temperature decay will occur by conduction [2].

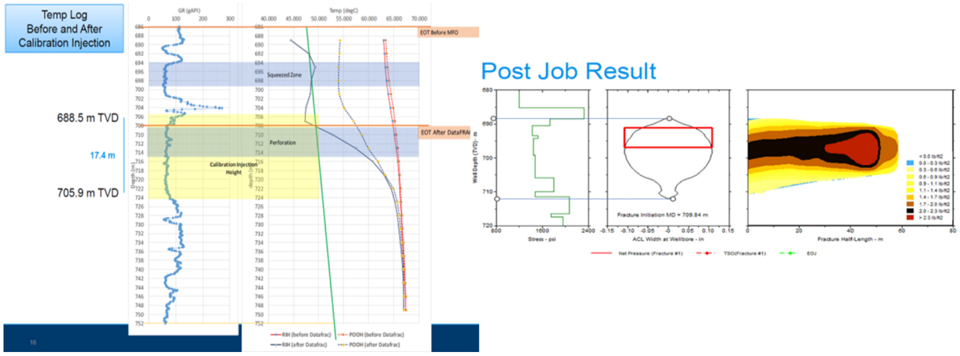

Figure 7 Temperature Log and Actual Fracture Geometry

On the actual temperature log figure above, it shows that fracture created is match with simulator software (otherwise, temperature log result could also be a reference to adjust rocks mechanical properties so that simulator will give adjusted fracture geometry). And it also showed that temperature reading at EMR RIH and POOH gives a slight differences in cooling down effect, that confirmed that temperature equalizing is happened in very short time (that made the “golden” period to do temperature log is very limited). It is recommended to have 2-4 hours period after ISIP to run EMR until its final depth to make sure all of cooling down effect is still identified.

Nonetheless, from several implementations of Temperature Gauge, some of these operational concerns has to be addressed prior to execution:

- Prioritization between closure pressure detection or running EMR. This is because at some operation, the opening of wellhead crown valve may compromise pressure decline monitoring.
- Slickline and/or wireline lubricator maximum allowable pressure has to be match with fracture decline pressure trend, since that lubricator will be exposed by wellbore pressure when crown valve is opened.
- Temperature logs can only detect fracture height at its depth, so operator has to make sure that there is no limitation or obstruction that could avoid EMR to reach desired depth.
- It is recommended to record temperature on both RIH and POOH of EMR, especially if EMR record by using slickline (not real-time readout gauge).
- At some cases, temperature reading while the EMR is still inside tubing (or above packer setting depth) somehow shows different trend (presumably due to annulus fluid). So, it is recommended to set the end-of-tubing depth above the interested zone, to make sure consistent reading of temperature.

- *Downhole Monitoring Gauge*

The use of DMG by installing EMR on tubing string will give operators the capability to measure downhole pressure. The main advantage is to eliminate the uncertainty in calculating tubing friction due to pumping treatment. As Sangasanga utilize used tubing to perform fracturing, friction is harder to calculate due to the degradation of tubing roughness. This will lead to miscalculation of NWB, which could refer to suboptimal decision/action taken. Net pressure calculation, especially in net pressure matching during main-frac is also could be define more precise. Decline pressure monitoring, although it is be done in static condition, could also be beneficial from DMG, since for depleted (low reservoir pressure) zone, fracturing fluid could be at overbalance condition, that make surface pressure reading reaches 0 psi faster than what actually happened downhole.

Stage		Step Rate Test		
		Well 1	Well 2 (DMG)	Well 3 (DMG)
Fluid		4% KCl	4% KCl	4% KCl
Surface ISIP	psi	1951	1843	1152
BH ISIP	psi	3770	3666	3004
Rate (max)	bpm	16	8	15
NWB Press*	psi	1280 *(No EMR)*	408	374
NWB analysis		perforation Dominated	tortuosity dominated	tortuosity dominated
Extension Rate	bpm	2	1.84	2.99
Extension Press	psi	4150	3601	2981

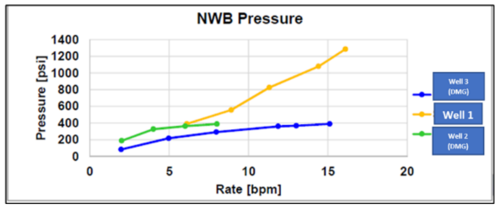

Figure 8 NWB Calculation

Those 3 wells located in the same structure, with similar depth and well schematic. However, 2 of 3 wells that use DMG shows more lower overall NWB value compared with the well without DMG. Although the conclusion cannot be taken just based on this graph, but surely the convenient level of operator will be bigger in the well with DMG.

4 Result

These methods were implemented in 4 fractured wells and although not all the oil wells produced at high rate, but all of those 4 wells were accurately predicted to have given result.

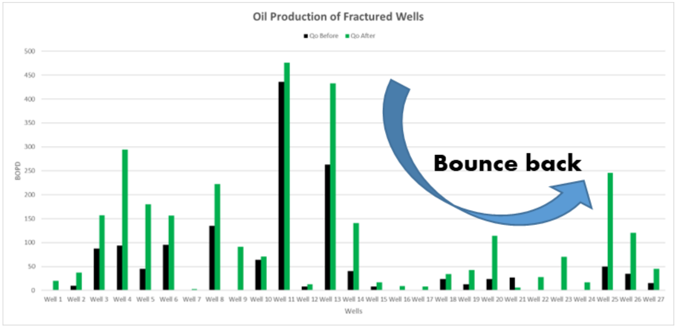

Figure 9 Sangasanga Fracturing Result after Implementation

5 Conclusions

- By applying candidate matrix, candidate evaluation could be done more objective and quantitatively.
- DFIT that cost around 15% than hydraulic fracturing operation, could led to more accurate fracturing design and well candidacy, thus could be combined with proppant less stimulation.
- Transmissibility is a general parameter that could be use in heterogenous reservoir.
- Temperature Log and Downhole Monitoring Gauge utilization can escalate the hydraulic fracturing operation success possibility.
- With historical fracturing jobs in one field, weighted matrix and transmissibility trend could be implemented with proper adjustment.

References

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