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Fracturing Job in Adjacent Oil and Gas Reservoirs to Generate Natural Gas Lift: a Case Study in S-26 Well, Sungai Gelam, Jambi

Reza Rahadian[1], Reza Alfajri[1], Muhammad Ardi Septian[1], Fannopo Rikardo[1], Rachma Winurani[1], Erwin Dicky Dusyanto[1]

[1]Asset 1 Exploitation Pertamina EP
Email: reza.rahadian@pertamina.com

Abstract. Sungai Gelam-C structure is one of backbone structure in Jambi Field. Air Benakat Formation (ABF) has been known as prolific reservoirs in South Sumatra Basin. Reservoirs in Sungai Gelam-C are belong to Air Benakat Formation which well known as tight reservoirs. Fracturing job is commonly conducted to improve the ability of reservoirs to be able to produce hydrocarbon. In S-26 Well, which drilled in 2018, main targeted reservoir was unfortunately found lower than its estimated as it was below the current water contact. Whereabouts alternative target is M1 sand but it is located very close to M sand which gas bearing sand. As M1 sand is a low quality reservoir, it decided to have fracturing job. M sand which located upper from M1 sand was inevitably ruptured as well. Fracturing's post job report showed that fracture grew and also hit M sand. It was indicated by high gas oil ratio (GOR) in production report. Instead of creating gas coning effect, the gas benefits well's production by acting as reservoir's source of energy.

Keyword: Fracturing, Tight, Oil and gas phase reservoirs, Air Benakat Formation.

1 Introduction

Sungai Gelam field is located within Jambi sub-basin, onshore South Sumatra. The field physical location is at Muaro Jambi district, Jambi province about ten kilometers to the southeast area of Jambi city. The working area once operated by PN PERTAMIN in 1960-1992 and has been consolidated back to PT Pertamina EP since 2005 to operate under PSC term for thirty years.

The field anticlinal structure was established in 1958 through the discovery of S-01 and S-03 wells. The ensuing 2D interpretation in 1974 had divided the field structure into three development blocks; A, C and D which are still pertinent at this time. Each block has then been developed by production wells. The focus of this development plan activity is at the block C, or known as Sungai Gelam-C (SGC).

The SGC field currently has twenty nine (29) wells, divided further into four compartments; Block-1A, Block-1B, Block-2 and Block-3, based generally upon the fluid production dominance. Block 1A consists of mainly oil producing wells group, whereas active gas wells located mostly at the other three blocks (Figure 1).

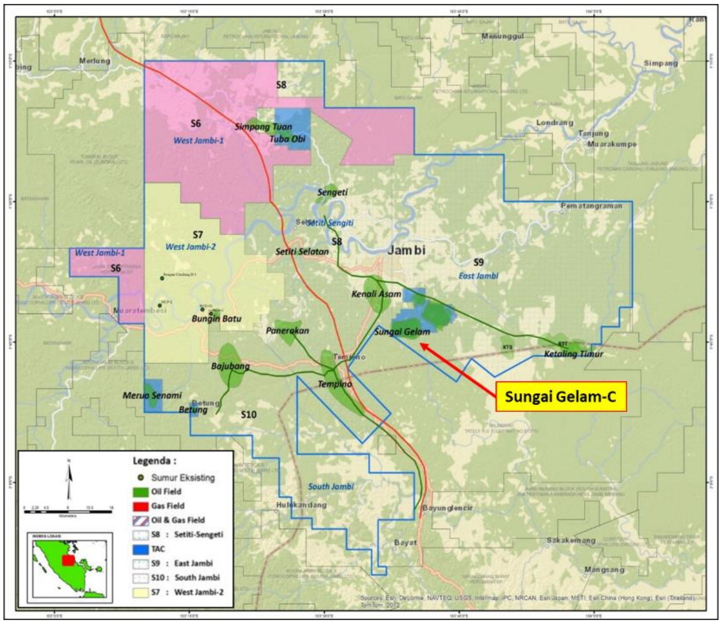


Figure 1. Sungai Gelam C is located about 10 km to the southeast of Jambi City, a capital of Jambi Province.

Sungai Gelam reservoirs produce both oil and gas. There are three productive layers within the Air Benakat Formation; Layer-M, N, and O sands. Layer-N sands mostly produce oil, whereas M sands are gas bearing layers within the field crestal area. Other potential reservoir intervals with scattered oil indications are the M1, M2, O, P, R and T sands, albeit not currently being the focus of the field development. The reservoirs initial condition has been measured from few wells and indicate separate relationship between the two fluid properties. The oil reservoir pressure variation with depth uses relation P=0.3125*Depth-187.5. Oil reservoir temperature variation with depth (T=0.0304*Depth+75). Gas reservoir pressure variation with depth (P=0.08797 *Depth–2146.2). Gas reservoir temperature variation with depth (T=0.0305*Depth+75). The measurement pressure in psia, depth in feet, and temperature in degF (Rahadian et al., 2019).

Depositional Environment

The Pre Tertiary complex comprises dominantly of Paleozoic-Mesozoic metamorphic rocks and carbonates which further deformed by intensive folding and faulting mechanism during Mid Mesozoic igneous rock intrusion. Sediment deposition in the basin commenced during Eocene to early Oligocene, known as Lemat Formation and Lahat Formation, consist of brackish and lacustrine environment. Lake environment may have been formed and may have intermittent connection with marine through the outlets on the west and south western area. Deposits consist of tuffaceous, coarse clastic sequence or granite wash conformably overlain by shale, siltstone, sandstone and coal deposits or called the Benakat member according to De Coster, G.L. (1974) and Ginger, D. and Fielding, K. (2005). The oldest dating of this formation from the Gumai Mountain outcrop, located at southwest of Lahat, indicates Mesozoic-Paleozoic age. The sediment has been identified as Tuffaceous Kikim Formation. Further fluvial deltaic sedimentation occurred during the Late Oligocene to early Miocene, known as Talang Akar Formation. The typical pattern of such

sediments at around proximal area is braided while at around distal is meandering belt. The fluvial sediment during the transgressive episode in the early Miocene had been shifted to the deltaic and marginal to deep
marine deposits. Talang Akar lithology has been identified as delta plain sandstone, shale, silt, and tuffaceous sandstone with carbonate, conglomerate, or coal interbeds. The planktonic Foraminifera analysis
indicates Banner and Blow N.3 (P.22), N.7 and N.5 zones closely related to the delta plain and shelf sediments. The transgressive process had been continued during early Miocene, known as Baturaja Formation, with marine shale sediments and shallow marine deposit at the intra basin. Carbonate rocks had growth at the basin slope and as reef carbonate at the peak of the intra basin structure. The better reservoir quality has been identified at around the southern part of basin because of the increasing sediment supply toward the area. The transgressive process continue to further accommodate sedimentation of the marine shale, silt and sandstone known as Gumai Formation, occurred during early to middle Miocene period. Glauconitic shale mainly dominates the peak of the transgression in the open marine system to form a regional seal for the area. The episode had shifted to the deltaic sediment progradation to overtake the open marine shale. The prograding process had been widespread during middle Miocene period and formed good quality shallow marine sandstone known as the actively producing Air Benakat Formation. Volcanic activity and deposits had increased during late Miocene period marked by the creation of Barisan Mountain at the western part location as sediment supplier to form fluvial deltaic and coastal swamp deposits known as Muara Enim Formation. The volcanic activity had been continued during Plio-Pleistocene period to form volcaniclastic sediment with tuffaceous, clay, sand matrix, and thin coal layers known as Kasai Formation (Rahadian et al, 2019) (Figure 2).

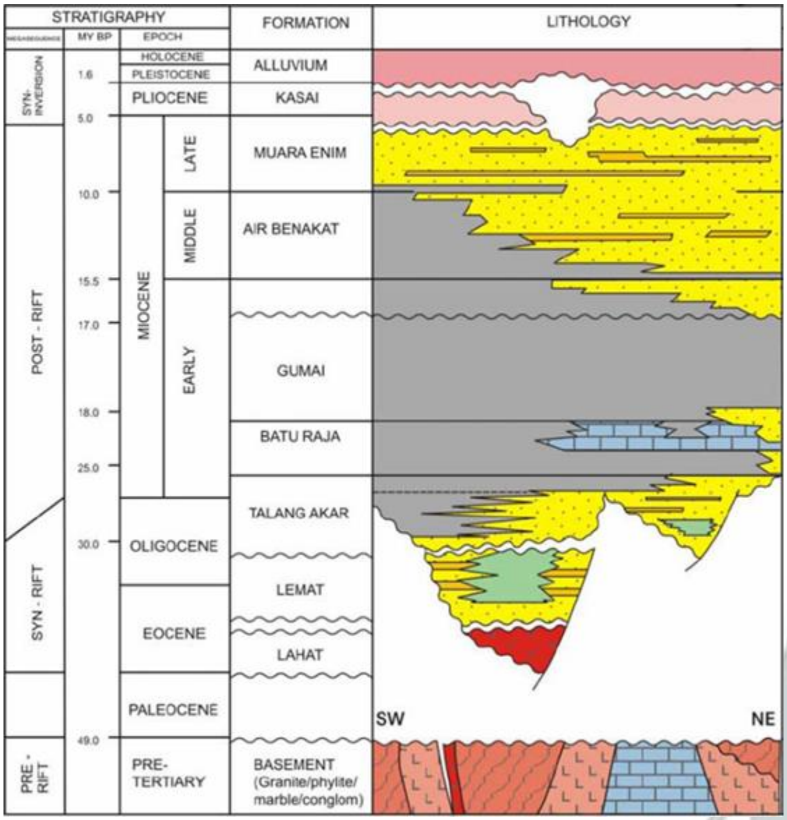


Figure 2. Chronostratigraphic of South Sumatra Basin (after Ginger, 2005).

Reservoirs in Sungai Gelam C Structures are coastal deposits which highly influenced by sea level changes. No stratigraphy trap evidence is found within this area, meaning Sungai Gelam structures is a structural trap related. In 2018, Pertamina EP drilled 2 (two) wells which both of those wells are unfortunately located on flank of the main target's structure (Figure 3). M1 sand is interpreted to be oil-contained reservoir.

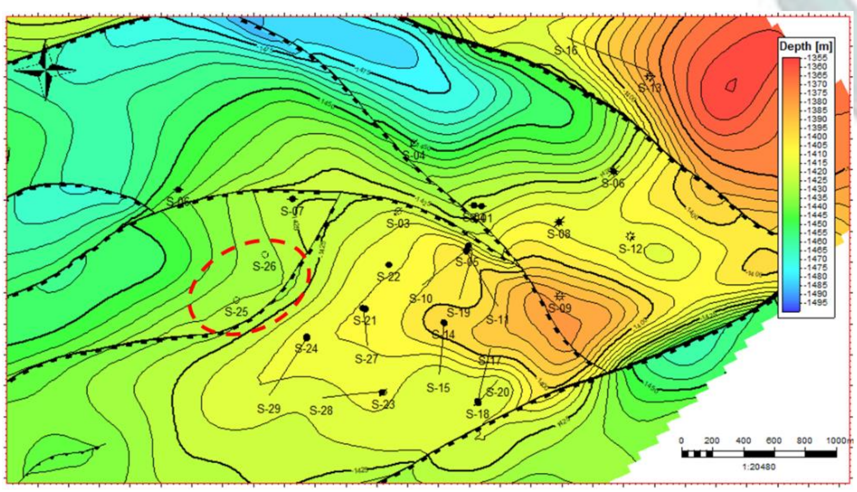


Figure 3. Location of wells drilled in 2018: S-25 and S-26 which exist on structure's flank (red circle).

2 Methodology

Further analysis by well to well correlation, ratio gas analysis, petrophysical analysis, and data acquisition led to yield M1 sand to be prominent candidate to produce. Typically, M1 sand is a tight sand, pressure test acquisition by wireline logging indicating mobility value of 2.41 md/cp and permeability calculation is about 1.6 mD. On the other hand, M1 sand is separated only 2.5 meters away from M sand, which is a gas sand reservoir (Figure 4). M1 sand is previously perceived as non-potential sand but pressure test and fluid

identification technology had helped to capture its potential (Figure 5). The low quality reservoir is required stimulation job to be implemented in improving oil production rate. Figure 6 shows rule of thumb to choose suitable stimulation treatment for a reservoir.

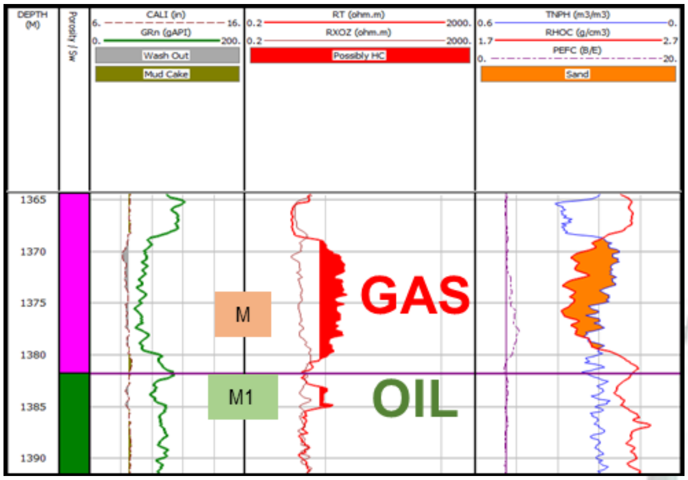


Figure 4. Fluid identification of M1 sand resulting oil contained.

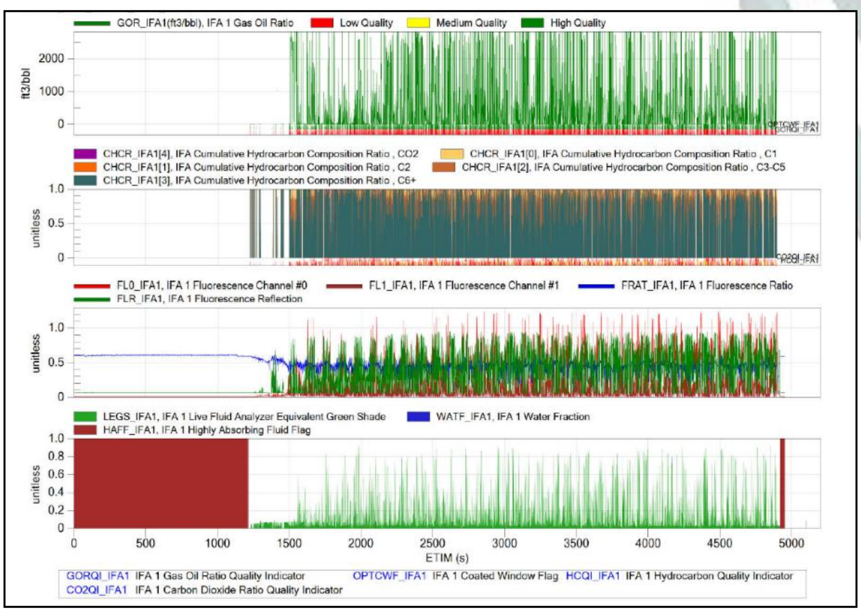


Figure 5. Fluid identification of M1 sand resulting oil contained.

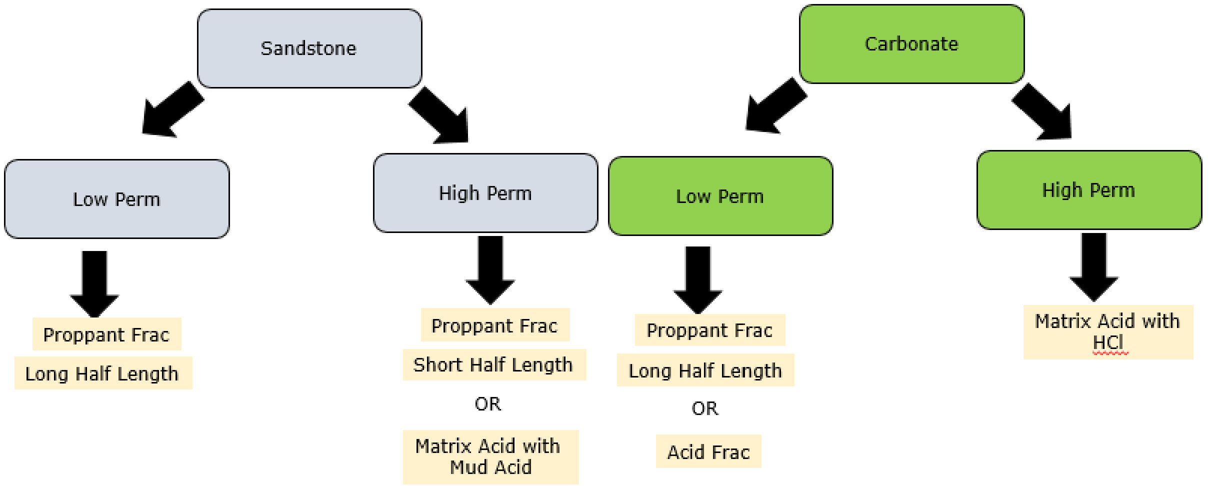


Figure 6. Stimulation rule of thumb.

Since M1 sand is a tight sand with permeability only around 1.6 mD, proppant fracturing that targets long half length was chosen as the treatment to produce the well. In order to prevent fracture's growth to M layer, which contains gas, fracturing design was made to be conservative enough. However, since shale break between these two adjacent layers is only 2.5 m, it is almost certain that M sand will be affected by the treatment. Figure 7 shows rock properties graphic plot for fracturing design based on open hole log of Well S-26. Based on these properties fracturing design was created and updated for final design after performing step rate test and data frac job. Figure 8 shows simulation result for the final fracturing design and Table 1 and 2 shows proppant design summary and pump schedule plan for the job.

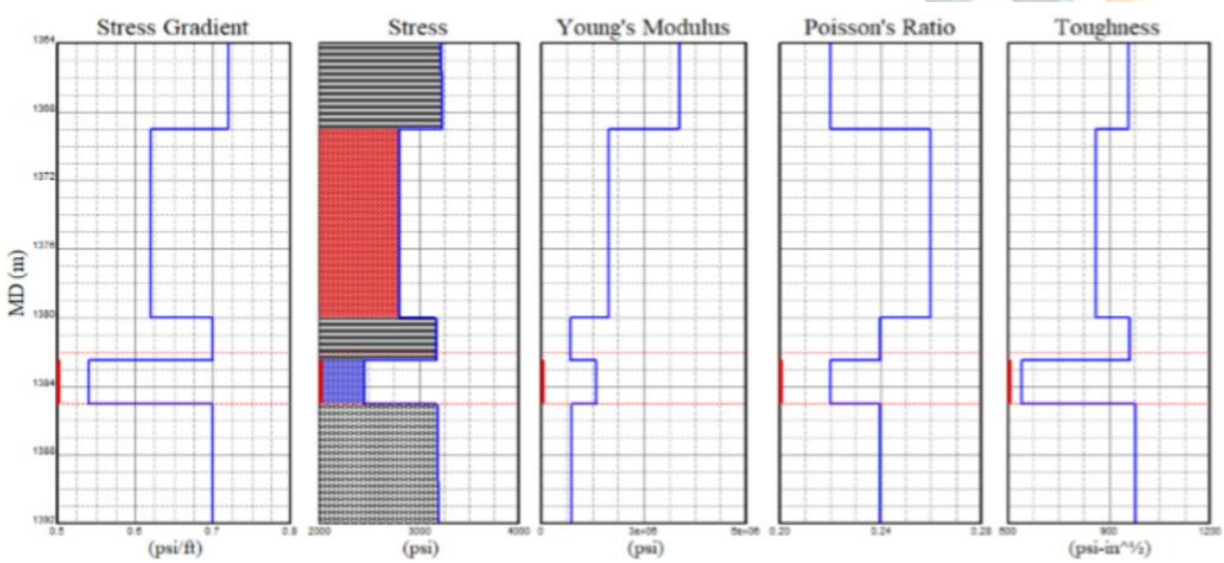


Figure 7. Rock properties graphic plot for fracturing design.

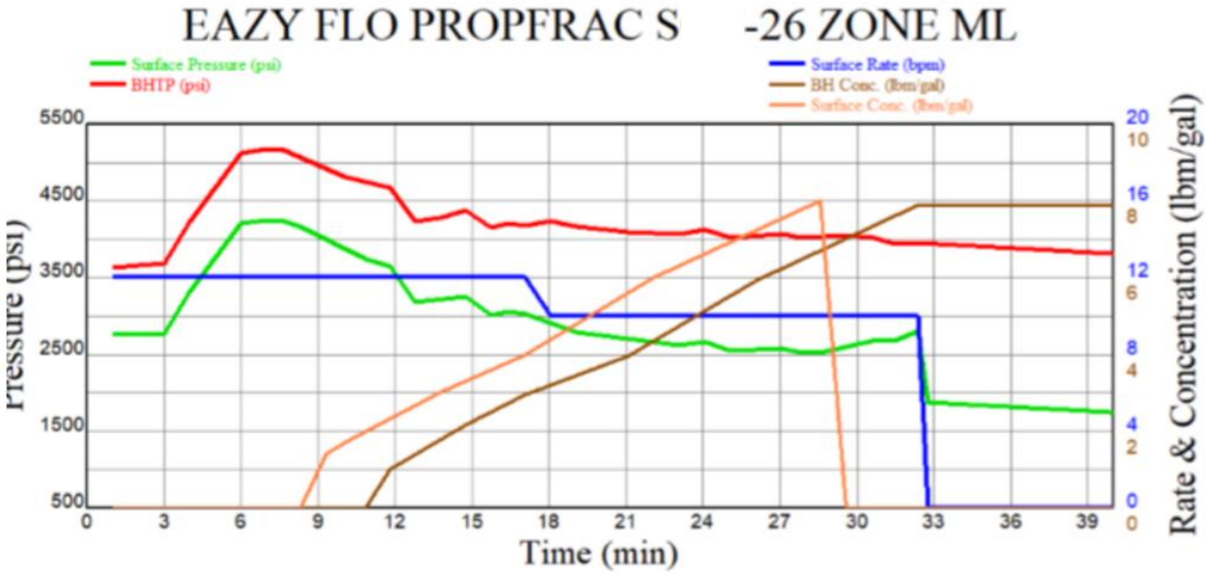


Figure 8. Simulation result for fracturing in S-26.

Table 1. Proppant design summary for fracturing job in S-26.

PROPPANT DESIGN SUMMARY

	ML Zone	
Frac Length - Created	232.71	(m)
Frac Length - Propped	107.05	(m)
Frac Height - Avg.	8.5183	(m)
Propped Height (Pay Zone) - Avg.	3.0001	(m)
Max Width at Perfs - EOJ	0.64391	(in.)
Propped Width (Well) - Avg.	0.26438	(in.)
Propped Width (Pay Zone) - Avg.	0.19427	(in.)
Conc./Area (Frac) - Avg. at EOJ	0.75722	(lbm/ft^2)
Conc./Area (Pay Zone) - Avg. at Closure	1.6005	(lbm/ft^2)
Frac Conductivity (Pay Zone) - Avg. at Closure	28484	(mD-ft)
Dimensionless Frac Conductivity (Pay Zone)	6.7583	
Beta	0	(1/ft)
Avg. Fracture Permeability	1759.4	(darcy)
Propped Fracture Ratio (EOJ)	0.26156	
Closure Time	94.221	(min)
Screen-Out Time	0	(min)

Table 2. Pump schedule for fracturing job in S-26.

Treatment	Fluid	Rate	Clean Fl	Slurry	Prop Conc'n		Stg Prop	Tot Prop
			bbl	bbl	PPA	PPA	Lbs	Lbs
Pad	PA-FG40	15	100.0	100.0	0.0	0.0	-	-
Slurry 1	PA-FG40	15	28.1	30.0	1.0	2.0	1,773	1,773
Slurry 2	PA-FG40	15	31.5	35.1	2.0	3.0	3,310	5,082
Slurry 3	PA-FG40	15	34.6	40.1	3.0	4.0	5,092	10,175
Slurry 4	PA-FG40	15	41.0	50.2	4.0	6.0	8,600	18,774
Slurry 5	PA-FG40	15	49.6	65.3	6.0	8.0	14,594	33,368
Flush	PA-FG40	14	15	15	0	0	-	33,368

2.1 Result and Discussion

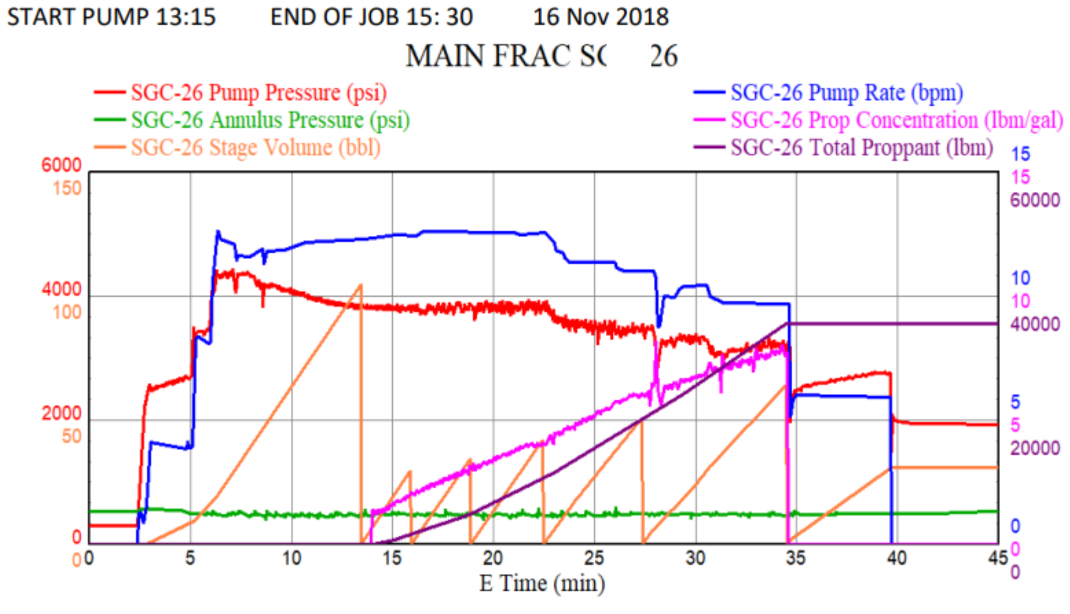
Pressure regime of M and M1 sand indicates that they are in different reservoir "tank". Swab job in Well S-26 showed that there is oil in reservoir. However reservoir properties is too tight for the well to be able to produce. After fracturing job, the well produced 60 BOPD and flowed naturally. Since fracture's growth to M sand couldn't be avoided, the fracturing job in M1 sand was designed to be conservative enough in order to minimize the effect to M sand. Fracturing's post job report showed that fracture grew and also hit M sand. It was indicated by high gas oil ratio (GOR) in production report. Until now, the well is still producing and gas from M sand contributes to the increase of the well's oil production rate. Instead of creating gas coning effect, the gas benefits well's production by acting as reservoir's source of energy.

The actual pump sequence and pump chart during fracturing job is shown in Table 3 and Figure 9 respectively. Fracturing result is shown in Table 4, and fracturing geometry are shown in Figure 10 and 11.

Table 3. Actual pumping sequence.

Treatment	Fluid	Rate	Clean Fl	Slurry	Prop Conc'n		Stg Prop	Tot Prop
			bbl	bbl	PPA	PPA	Lbs	Lbs
Pad	PA-FG40	13	100.0	100.0	0.0	0.0	-	-
Slurry 1	PA-FG40	13	28.1	30.0	1.0	2.0	1,773	1,773
Slurry 2	PA-FG40	13	31.5	35.1	2.0	3.0	3,310	5,082
Slurry 3	PA-FG40	13	34.6	40.1	3.0	4.0	5,092	10,175
Slurry 4	PA-FG40	13	41.0	50.2	4.0	6.0	8,600	18,774
Slurry 5	PA-FG40	13	49.6	65.3	6.0	8.0	14,594	33,368
Flush	PA-FG40	13	39.6	39.6	0	0	-	33,368

Table 4. Fracturing result in S-26.



	ML Zone	
Frac Length - Created	255.21	(m)
Frac Length - Propped	***125.83***	***(m)***
Frac Height - Avg.	8.33	(m)
Propped Height (Pay Zone) - Avg.	***3.0001***	***(m)***
Max Width at Perfs - EOJ	0.58853	(in.)
Propped Width (Well) - Avg.	***0.22664***	***(in.)***
Propped Width (Pay Zone) - Avg.	0.1785	(in.)
Conc./Area (Frac) - Avg. at EOJ	0.74424	(lbm/ft²)
Conc./Area (Pay Zone) - Avg. at Closure	***1.4731***	***(lbm/ft²)***
Frac Conductivity (Pay Zone) - Avg. at Closure	***26171***	***(mD-ft)***
Dimensionless Frac Conductivity (Pay Zone)	***5.2829***	
Beta	0	(1/ft)
Avg. Fracture Permeability	***1759.4***	***(darcy)***
Propped Fracture Ratio (EOJ)	0.31572	
Closure Time	65.806	(min)
Screen-Out Time	0	(min)

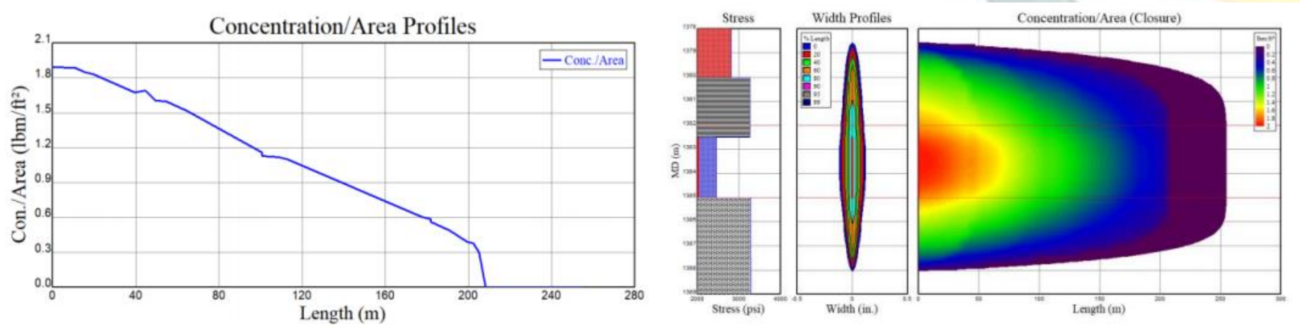


Figure 10. Proppant concentration area in fracture geometry created.

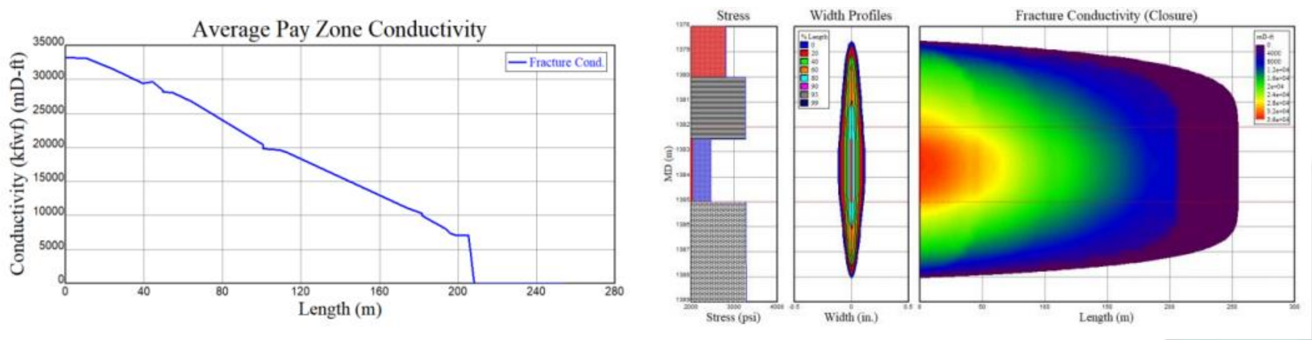


Figure 11. Fracture conductivity distribution in fracture geometry created.

In fracture geometry that was created after the treatment, it can be seen that fracture's growth broke shale break barrier and ruptured the lower part of M layer. As a result when well S-26 was produced, it could flow naturally but there was added production of gas from layer M. The well produced around 0.5 MMSCFD and 60 bbls of oil initially (GOR 8333 scf/stb). This high number of GOR can only occur if gas from accidentally fractured M layer flows through producing zone (M1 layer). The silverline is that this gas from M layer becomes source of energy and acts as in-situ gas lift for the well to flow naturally with quite stable production performance.

3 Conclusion

In conclusion, performing a good fracturing design could turn adjacent gas reservoir as source of energy to improve oil production as natural / in situ gas lift. This well can be used whether as an example for the next job in the future to utilize adjacent gas layer as source of energy, or as an evaluation whether to execute fracturing job if there is a threat of unwanted gas production from the adjacent gas layer.

References

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